Reducing Blackout Risk by Segmenting European Power Grid with HVDC Lines

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***Abstract*—The utilization of high-voltage direct current (HVDC) lines for the segmentation of the European power grid has been demonstrated to be a highly effective strategy for the mitigation of the risk of cascading blackouts. In this study, an accurate and efficient method for determining the optimal power flow through HVDC lines is presented, with the objective of minimizing load shedding. The proposed method is applied to two distinct scenarios: first, the segmentation of the power grid along the Pyrenees, with the objective of segmenting the Iberian Peninsula from the rest of Europe; and second, the segmentation of the power grid into Eastern and Western Europe, approximately in half. In both scenarios, the method effectively reduces the size of blackouts impacting both sides of the HVDC lines, resulting in a 46% and 67% reduction in total blackout risk, respectively. Furthermore, we have estimated the cost savings from risk reduction and the expenses associated with converting conventional lines to HVDC lines. Our findings indicate that segmenting the European power grid with HVDC lines is economically viable, particularly for segmenting the Iberian Peninsula, due to its favorable cost-risk reduction ratio.**

***Index Terms*—European power grid, blackout risk, optimal power flow, grid resilience, high-voltage direct current (HVDC), power transmission grid, uncertainty.**

I. Introduction

MODERN power systems are confronted with the challenge of transitioning to renewable energy sources, necessitating the replacement of conventional power plants with renewable energy systems. This transition introduces significant difficulties in maintaining frequency control and ensuring energy balance, given the primary reliance on variable generation sources such as solar and wind power. Conventional wisdom suggests that large power systems with extensive synchronous zones offer enhanced reliability. However, recent studies have demonstrated that this is not invariably the case, and that the segmentation of power systems can be advantageous [1]-[3]. In this context, the high-voltage direct current (HVDC) technology provides an efficient means to control power flow in direct current (DC) lines while enabling the interconnection of two alternating current (AC) nodes (or more in multiterminal HVDC schemes) [4]. The utilization of HVDC is particularly advantageous in long-distance transmission systems employing underground or submarine cables (over 100 km) or overhead lines (over 600 km) as referenced in [5]. A notable application of HVDC is in the connection of disparate synchronous zones while preserving their non-synchronous state. This scenario arises in systems operating at distinct frequencies or at the same frequency but with non-synchronous behavior. The latter case is the focus of this paper, wherein HVDC is proposed as a method of segmenting the European power grid into discrete zones. Prior studies have evaluated the effectiveness of DC segmentation in interconnected power systems as a strategy to mitigate large blackouts, showing that HVDC segmentation can significantly reduce the risk of cascading failures [6].

Recent advancements in dynamic modeling approaches for power converter-dominated grids have further emphasized the importance of HVDC systems in modern power networks. For example, studies have examined the role of power converter control in grids comprising multiple AC and DC subgrids [7] and the development of hybrid parallel-in-time-and-space transient stability simulations for large-scale AC/DC grids [8]. These approaches underscore the significance of integrating HVDC technology to improve grid controllability and stability.

The present study focuses on the controllability of HVDC lines through their power converters, emphasizing how tuning power flow can effectively reduce blackout sizes during cascading failures [6], [9]. The ability to control power in HVDC lines can act as a firewall, preventing the spread of certain blackouts. A range of methodologies exists to ana-

Manuscript received: July 20, 2024; revised: December 20, 2024; accepted: February 21, 2025. Date of CrossCheck: February 21, 2025. Date of online publication: March 27, 2025.

This work was supported by MCIN/AEI/10.13039/501100011033 (No. PID2021-122256NB-C22, No. CEX2021-001164-M) and the European Union's Horizon 2020 Research and Innovation Programme (Grant Agreement No. 957852, VPP4Islands). We acknowledge access to Uranus, a supercomputer cluster located at Universidad Carlos III de Madrid (Spain). Oriol Gomis-Bellmunt was supported in part by FI-AGAUR Research Fellowship Program, Generalitat de Catalunya, and the ICREA Academia program.

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DOI: 10.35833/MPCE.2024.000768

lyze cascading failure dynamics [10], [11] (see [12] for a comprehensive overview of emerging methods for risk assessment, modeling, and simulation). A graph theory approach can also determine which lines to add or remove to adjust connectivity and contain damage [13]-[17].

In this paper, we propose a method to efficiently determine the optimal power flow through HVDC lines during a cascading failure to minimize load shedding. The proposed method is applied to the European power grid to assess the benefits of segmenting it into two parts, with the focus on the reduction of blackout risk. The blackout dynamics of the European power grid are modeled using the ORNL-Pserc-Alaska (OPA) model [12], [18]-[22]. To accurately reproduce actual blackout dynamics, the model is calibrated with data reported by ENTSO-E [23]. Once the model has been validated, it is employed to explore changes in blackout risk when HVDC lines are introduced to segment the grid at various points.

Our main findings are as follows. ① The proposed method is highly accurate and efficient in determining the optimal power flow through HVDC lines to reduce load shedding. ② The OPA model reliably reproduces blackout statistics for the European power grid, indicating a near-critical state. ③ Segmenting the power grid with HVDC lines significantly decreases blackout risk by reducing the size of blackouts affecting both sides of the HVDC lines. ④ The savings from risk reduction could amortize the investment in converting conventional AC lines to HVDC lines within a few years.

The structure of this paper is as follows. In Section II, we describe the OPA model used to study the blackout dynamics of the European power grid and the method employed to control the power flow through HVDC lines during cascading failures. In Section III, we analyze the reference case, which includes only AC lines. Section IV presents the results obtained with the proposed method when segmenting the European power grid at two different locations: first, by segmenting the Iberian Peninsula from the rest of Europe with HVDC lines; and second, by segmenting the power grid into approximately two halves connected by HVDC lines. In Section V, a cost analysis is performed, comparing the economic savings from reducing the probability of large blackouts with the costs of converting the necessary AC lines to HVDC lines. Section VI provides a discussion of the results, and finally, in Section VII, some concluding remarks are presented.

II. OPA Model and Proposed Method

The OPA model has been developed for the purpose of estimating the blackout risk in power grids [18], [19]. It integrates two distinct timescales: fast timescale dynamics, in which blackouts are simulated through cascading transmission line outages, and slow timescale dynamics, which capture the evolution of the power grid over years. The latter incorporates random daily demand variations and long-term demand growth. During the fast timescale dynamics, power dispatches are repeatedly performed as long as line outages occur, until a stable solution with no further line failures is reached, potentially resulting in some load shedding. The power grid, encompassing transmission lines, loads, and generators, is modeled using a DC load flow approximation, which assumes linearized and lossless real power flows and uniform voltage magnitudes. The power dispatch is determined by minimizing the cost function:

$$Cost = \sum_{i \in N_g} C_g(i) P_g(i) + \sum_{i \in N_l} C_{LS}(i) \cdot LS(i) \tag{1}$$

where N_g is the set of generators; N_l is the set of loads; $C_g(i)$ is the cost per MWh of the power $P_g(i)$ generated at node i; and $C_{LS}(i)$ is the cost per MWh of load shedding $LS(i) \geq 0$ at node i. To penalize the loss of power, much larger values of $C_{LS}(i)$ are typically used than $C_g(i)$. Following [24], we take $C_{LS}(i) = 100$ and $C_g(i) = 1$. The optimization is performed using the simplex algorithm, including the necessary constraints on power balance, line flow, and generation limits [24]. The simplex solution determines the power generated at each plant, the power flowing through each line, and the amount of load shedding. While load shedding is typically zero, the simplex algorithm sometimes converges to a solution with some load shedding due to line failures.

The slow timescale dynamics involve the progressive upgrade of the parts of the power grid impacted by blackouts. Line upgrades occur in response to outages, and generation upgrades address the constant increase in demand. This combined dynamic continually pushes the power grid to its operational limits, where a random failure can easily trigger a cascading blackout. With properly chosen parameters, the simulation results replicate the statistical properties of blackouts, including their frequency and size. These results can then be used to estimate the overall blackout risk of the power grid [1], which is computed as:

$$Risk = AP \int \lambda(S) S^2 \, \mathrm{d}S \tag{2}$$

where $S = LS/P$ is the load shedding LS relative to the total demand P; $\lambda(S)$ is the probability of having a blackout of relative size S; and A is an undetermined constant, so it is convenient to normalize the risk to a reference case. *Risk* provides information similar to the standard system average interruption index (SAII) [9].

The OPA model has been validated with blackout data from the Western Interconnection in the USA [25]-[27]. Enhanced versions of the OPA model have been proposed and validated in the literature [20], [22]. In [28], a modified version of the OPA model is also used to develop real-time risk assessment methodologies for cascading failures in power systems with high proportion of renewable energy. In this work, however, the original model is used for the sake of simplicity, as it already captures the features of blackout statistics necessary for the purpose of this study.

The original OPA model incorporates only conventional lines, characterized by their impedance and power flow limit. However, recent modifications to the model have been made to incorporate power lines capable of modifying their instantaneous power flow during cascading failures, like HVDC lines [9]. In this modified model, power flow is indirectly controlled by adjusting the impedance of each HVDC line. It is important to note that HVDC lines are considered part of the grid infrastructure and, akin to conventional lines, are susceptible to failures during cascading events. In [9], the optimal impedance value that minimized load shedding during cascading failures was determined using a Monte Carlo method. This method involves repeatedly dispatching power with random impedance values to explore a significant portion of the parameter space, ultimately finding an approximate optimal value. However, this method is computationally expensive and inefficient, especially with a large number of HVDC lines.

In this work, we propose an alternative method that is faster and more accurate for determining the optimal power flow through HVDC lines to minimize load shedding during blackouts. This method incorporates the power flow of HVDC lines as additional optimization variables in the simplex algorithm, which is used to solve the dispatch problem. Unlike the Monte Carlo method, where the impedances of all lines are predefined and the power flow of each line is derived from these values, our method directly optimizes the power flow of HVDC lines.

In the original OPA model, the simplex variables include the generation power $P_g(i)$ and load shedding $LS(i)$ at each node. Constraints enforce the power balance at each node and limit the power flow $F(l)$ through each line to a maximum value $F_{\max}(l)$. The power flow $F(l)$ through each line l is derived from $P_g(i)$ and $LS(i)$ values using the impedance matrix of the power grid. In the proposed modification, the power flow through each HVDC line is not derived anymore: it becomes a new optimization variable. This requires updates to the simplex constraints to ensure local power balance at nodes adjacent to HVDC lines and to enforce limits on the maximum allowable power flow through HVDC lines $F(l)$. Since HVDC impedances are not included in the impedance matrix, their values remain flexible and are determined after solving the optimization problem.

This method introduces only a small set of additional variables, equal to the number of HVDC lines, and has a minimal impact on the computational cost of the simplex solver. Furthermore, the cost function remains unchanged, and the modifications do not affect the non-linear iterative loop of the OPA model. Simulations show that the number of iterations required for convergence is barely affected by these changes, demonstrating the computational efficiency of the proposed method. By optimizing the power flow through HVDC lines in this way, the proposed method significantly reduces the blackout risk in power grids. The following sections analyze the effectiveness of this method when applied to the European power grid.

In this work, the OPA model is implemented on the European power grid. The data used to construct a network consisting of 1497 nodes and 2199 lines, which reproduces the European power grid, are provided in [29]. Figure 1 shows a geographically realistic representation of the European power grid, using the coordinates of the nodes. Panels (a) and (b) in Fig. 1 highlight the specific lines (marked in red) used to segment the power grid in the two scenarios studied. In panel (a), the Iberian Peninsula is segmented from the rest of Europe using 4 HVDC lines across the Pyrenees. In panel (b), Eastern Europe (EE) and Western Europe (WE) are separated using 18 HVDC lines spanning central Europe. The power grid is divided into zones corresponding to the different member states of the European Union. From this perspective, the power grid is highly inhomogeneous, as countries vary significantly in size. Figure 2 illustrates the different zones of the European power grid.

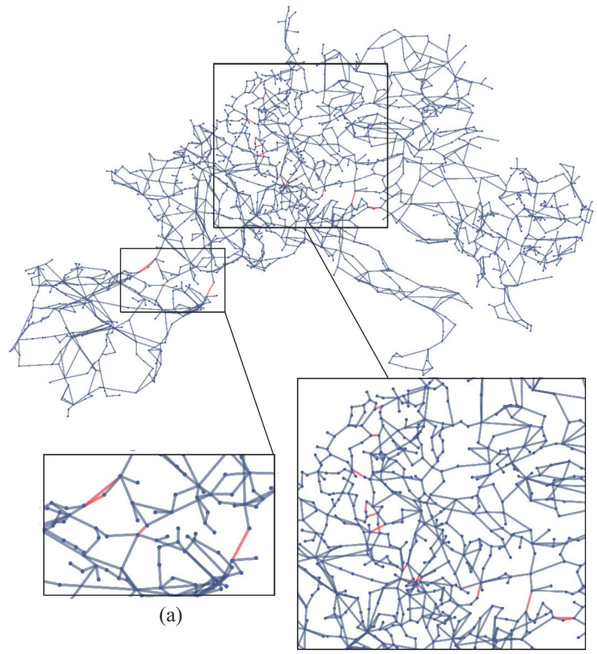

Fig. 1. Geographically realistic representation of European power grid.

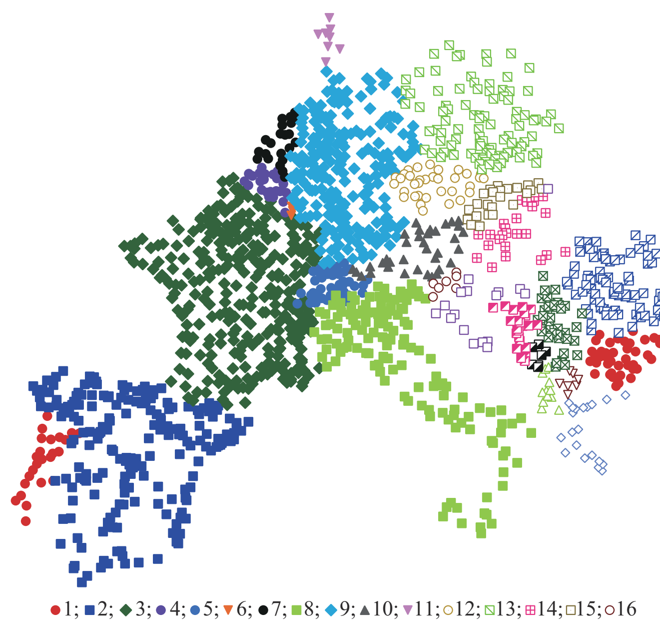

Fig. 2. Different zones of European power grid, with each zone represented by a distinct color or symbol to indicate its geographical grouping.

To accurately reproduce the dynamics of the European power grid, some of the basic parameters of the OPA model, namely, the random failure probability rate p_0 of transmission lines and the instantaneous failure probability rate p_1 of an overloaded transmission line during successive iterations of a cascading blackout, must be determined from data. A transmission line is considered overloaded when its power flow exceeds 90% of its limit.

Information on blackouts in the real system, needed to estimate the parameters of the OPA model and validate the model, is obtained from European Network of Transmission System Operators for Electricity (ENTSOE) [23]. The dataset covers blackouts from 2010 to 2015. From this information, the frequency of blackouts and their size distribution can be calculated. These metrics allow for a preliminary estimation of the parameters p_0 and p_1.

The calibration process begins with constructing the Rank function of blackout sizes from the ENTSOE data, as shown in Fig. 3. The Rank function, also known as the Survival function, represents the cumulative probability of experiencing a blackout larger than a given size [9]. This provides an intuitive way to compare the observed and simulated size distributions of blackouts. A series of OPA model simulations is then performed with varying values of p_0 and p_1 to match the observed Rank function, the frequency of blackouts, and long-range correlations. Specifically, the parameters are adjusted iteratively until the simulated results closely align with the empirical data. This approach ensures that the model reproduces both the frequency and size distribution of blackouts observed in the European power grid.

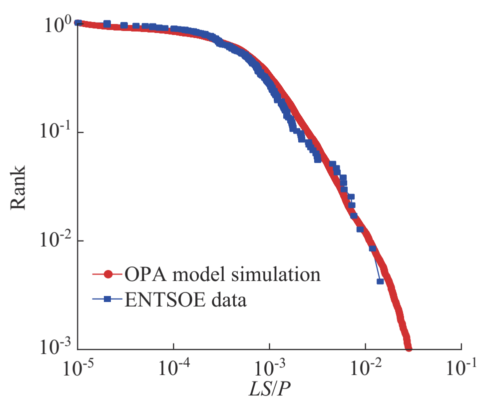

Fig. 3. Comparison of Rank function (or Survival function) of blackout sizes from ENTSOE data and OPA model simulations.

We find that the set of parameters $p_0 = 0.000205$ and $p_1 = 0.02$ reproduces well the frequency of blackouts of 0.11 blackouts per day in the ENTSOE data, as well as their size distribution. The Rank function obtained from the OPA model simulations is also shown in Fig. 3, demonstrating a reasonably good agreement with the observed ENTSOE data, particularly for medium and large blackouts. This alignment confirms that the chosen parameters provide a reliable representation of the system dynamics, ensuring that the risk for different scenarios can be calculated with sufficient accuracy. Some discrepancies are observed for smaller blackouts, which may be attributed to underreporting of small events in the ENTSOE data or the inherent limitations of the OPA model in fully resolving minor cascading failures. However, these differences do not significantly impact the reliability of the model in assessing the risk of large blackouts, which is the primary focus of this study.

The value of p_1 obtained by fitting the data corresponds, in the OPA model, to a value very close to the critical point [18]. For values of p_1 below the critical point, failures rarely propagate, while for values above the critical point, a random failure can trigger very large blackouts within just a few iterations. Near criticality, however, blackouts of all sizes are expected, with their sizes following a power-law distribution [18]. Achieving very low values of p_1 is challenging from an engineering perspective, as overloaded lines are inherently prone to failure. Conversely, power grids with lower-quality components or insufficient maintenance are likely to exhibit larger values of p_1.

According to the OPA model, power grids such as the Western USA interconnection or the European power grid studied in this work appear to operate near a critical point, which explains the small but non-zero risk of large-scale cascading failures. The proximity to a critical point can be quantified by the generalized autonomous generational average λ_{gaga}, a measure of cascading propagation that peaks at the critical point [30], where cascading failures are most likely to propagate extensively. In Fig. 4, the value of λ_{gaga} computed for different values of p_1 is shown for the European power grid. Error bars represent the standard deviation of the numerical results. The value of p_1 that best fits the data, marked by the vertical black line, is very close to the maximum, further indicating the proximity of power grid to a critical point, where blackouts of all sizes are statistically possible.

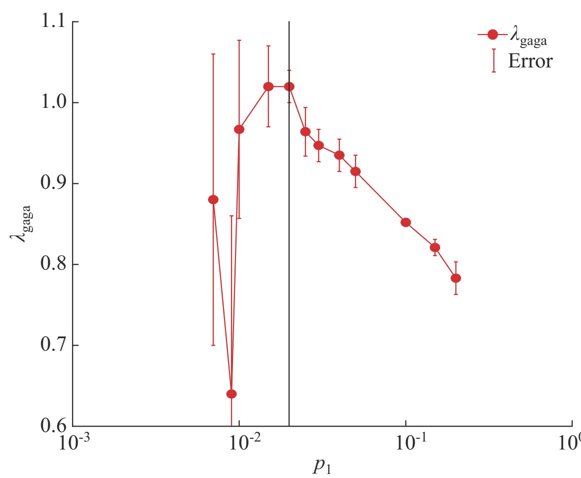

Fig. 4. Value of λ_{gaga} computed for different values of p_1

III. Reference Case

The present European power grid (not including HVDC lines) is used as the reference case. In order to achieve accurate risk assessments, extensive statistical data are required due to the influence of very large and rare events. In this study, the OPA model simulations were conducted over an operational period of 400000 days. This extensive simulation provides a robust dataset for failure statistics, resulting in a normalized root-mean-square deviation in the calculated risk of 4%. During this period, 44500 blackouts were recorded, which is consistent with the known frequency of blackouts in the European power grid. The majority of these blackouts are confined to a single zone, with only a small number propagating across multiple zones.

Blackouts that are confined to a single zone are more frequent and typically involve relatively minor load shedding, contributing less to the overall risk. However, in certain instances, cascading failures can occasionally result in extensive blackouts that propagate across the power grid, affecting substantial portions of the power grid. These large blackouts have the potential to impact one or two major zones or even multiple zones simultaneously, thereby significantly increasing the overall risk. Table I provides details of one of the largest blackouts observed in the OPA model simulations as an example. This blackout impacted 3% of the total European electric power, leading to the overloading of 1391 lines, with 29 of these lines ultimately failing. The blackout affected a total of 11 zones (see Fig. 5) and persisted through 16 successive iterations, with at least one line failing in each iteration. The final state of the European power grid is depicted in Fig. 5, where the 29 line outages caused by the blackout are marked in red. A video illustrating the progression of the blackout can be found in Supplementary Material A. It is evident that such large blackouts exhibit highly complex and non-local dynamics, where failures in very distant lines can occur simultaneously or in successive iterations.

TABLE I
DETAILS OF ONE OF THE LARGEST BLACKOUTS OBSERVED IN OPA MODEL SIMULATIONS

Iteration	Zone affected	Number of line outages	LS/P (10^{-3})
0	Czech Republic	1	0.77
1	France	3	2.50
2	France	3	2.60
3	France	1	1.50
4	France	1	0.66
5	Germany	1	6.80
6	France, Switzerland, Italy, Luxembourg, Bulgaria	4	4.40
7	France	1	0.66
8	France	1	0.81
9	France	1	0.50
10	Spain, France, Italy	3	1.10
11	France, Romania	2	1.80
12	Spain, Germany	2	0.15
13	France	1	1.00
14	Austria	1	1.90
15	Portugal, France	3	4.80

The number of blackouts affecting each zone of the power grid is not uniform, which is expected given the significant differences in zone sizes. This variability is illustrated in Fig. 6, where the probability that a blackout affects each zone is plotted. The zone numbers correspond to the legend in Fig. 2. It is important to note that a single blackout can impact multiple zones (as shown in Fig. 5), although most blackouts are confined to a single zone. The zones most affected by blackouts in OPA model simulations (red line in Fig. 6) are, in decreasing order, zones 3, 2, 9, 13, and 22, corresponding to France, Spain, Germany, Poland, and Romania, respectively. The simulation results generally align well with the empirical data, capturing the relative blackout probabilities across zones. Discrepancies observed in some zones may stem from differences in regional reporting practices. Despite these differences, the overall trends validate the ability of the OPA model to reproduce spatial variations in blackout probability.

Fig. 5. Final state of European power grid following a large blackout with details in Table I.

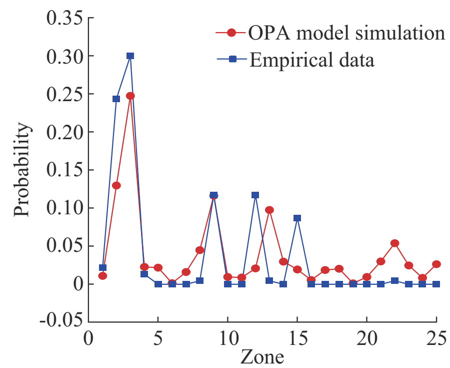

Fig. 6. Probability of blackouts by zone: comparison of OPA model simulations with empirical data.

Despite having only 230 empirical data points (compared to the 44500 blackouts simulated with the OPA model) and lacking data for several zones, the agreement between the probability distribution of blackouts by zone obtained from the OPA model simulations and the empirical data (blue line in Fig. 6) is quite good. The major discrepancy between the empirical data and the OPA model simulations is observed in zones 12 and 13, corresponding to Czech Republic and Poland, respectively. While the data show a peak in zone 12, the OPA model predicts a higher number of blackouts in zone 13. Additionally, differences around zone 22 may stem from incomplete or inaccurate data for certain zones. Another possible source of discrepancy is that the Europe power grid is connected to other power grids such as those of the United Kingdom and Scandinavia via HVDC links, which are not accounted for in our model.

IV. Results Obtained with Proposed Method

Segmenting a large power grid into two smaller grids connected by HVDC lines offers advantages in controlling frequency instabilities and reducing blackout risks [4], [9], [31]. However, there is no general optimization procedure for selecting the specific AC lines to convert into HVDC lines for segmentation. Different physical and economic criteria can justify one segmentation over another. In Sections IV-A and IV-B, we analyze two different segmentations of the European power grid based on geographical and size criteria, respectively.

A. Segmenting Iberian Peninsula from the Rest of Europe

In this subsection, the four lines connecting Spain and Portugal to France and the rest of Europe are converted from AC to HVDC, and the proposed method is applied to minimize the blackout risk. These lines, marked in red in panel (a) of Fig. 1, have been selected based on geographical criteria. Due to its weak connection with the rest of Europe, the Iberian Peninsula power grid is known to function as an "energy island" in terms of generation-consumption balance and frequency regulation.

As explained in Section II, applying the proposed method to these lines involves determining their optimal power flow to minimize load shedding during each dispatch performed in the course of a cascading blackout. In this subsection, results are obtained for the same simulation period as in Section III, i. e., 400000 days, and are compared with those from the reference case.

The proposed method proves particularly effective in reducing the size of blackouts that simultaneously affect both sides of the HVDC lines – specifically, the Iberian Peninsula and France or the rest of Europe. This effect is evident in the significant reduction in the probability of medium-to-large blackouts of this type, as shown in Fig. 7.

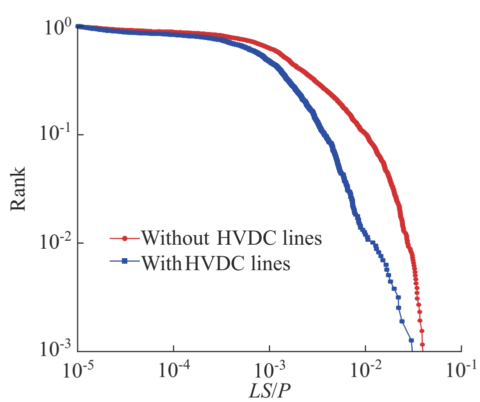

Fig. 7. Rank function of blackouts affecting both sides of Pyrenees simultaneously: comparison of cases with and without HVDC lines when Iberian Peninsula is segmented from the rest of Europe.

The proposed method is highly effective in reducing the size of these blackouts, as demonstrated by the shift in the Rank function. Overall, the results indicate a significant reduction in blackout severity, emphasizing the potential of the proposed method for mitigating large-scale cascading failures. Furthermore, the number of large blackouts in zones 2 and 3, which correspond to Spain and France, located on either side of the HVDC lines, is substantially reduced, as shown in Fig. 8. Large blackouts are defined as those involving load shedding exceeding 1% of the local demand. This demonstrates the effectiveness of segmentation with HVDC lines in mitigating large-scale cascading failures, especially in zones directly connected by the HVDC lines.

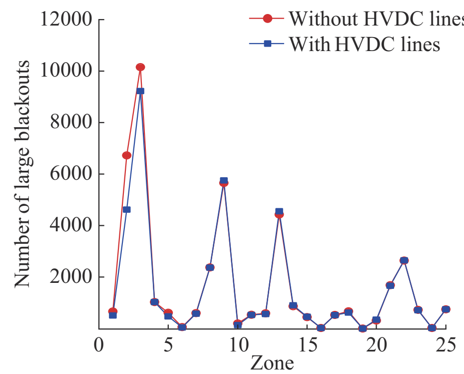

Fig. 8. Number of large blackouts by zone: comparison of cases with and without HVDC lines when Iberian Peninsula is segmented from the rest of Europe.

Globally, with HVDC lines there is an important reduction in the probability of medium-to-large blackouts, corresponding to the reduction of the blackouts affecting both sides of the HVDC lines simultaneously. But these blackouts represent only a portion of the total blackouts affecting the European power grid. Therefore, when accounting for all blackouts, the global reduction in the probability of medium-to-large blackouts is smaller (blue line in Fig. 9).

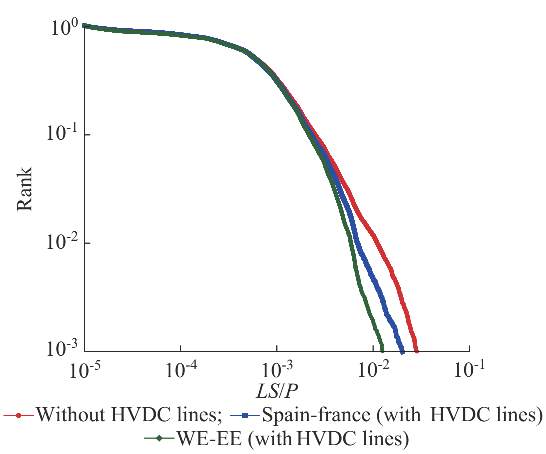

Fig. 9. Comparison of Rank function of blackout sizes accounting for all blackouts in European power grid for cases with and without HVDC lines.

Also, a better result is observed for the WE-EE case with respect to the Spain-France case. This is because a significant number of medium-to-large blackouts, affecting only one part of the power grid, are not as efficiently mitigated by the proposed method. Additionally, there is no substantial reduction in the frequency of blackouts. Overall, this results in a 46% reduction in the global blackout risk in this case, as shown in Table II.

TABLE II
RISK REDUCTION WITH RESPECT TO REFERENCE CASE

Case	Risk reduction (%)
Spain-France (with HVDC lines)	46
WE-EE (with HVDC lines)	67

This result becomes even more significant considering that Portugal and Spain account for only about 14% of electricity production of Europe. Previous studies on other networks have shown that segmenting a zone that represents a small fraction of electricity production and consumption with HVDC lines typically does not result in a significant global impact [9].

B. Segmenting European Power Grid by Half

In this subsection, we attempt to further reduce the overall risk of blackouts by segmenting the European power grid into two parts of similar sizes, linked by HVDC lines. This approach has yielded better results in synthetic networks [9]. One part consists of Portugal, Spain, France, Belgium, Switzerland, Luxembourg, the Netherlands, and Italy, which will henceforth be referred to as WE. The other part contains the rest of Europe, referred to as EE (see panel (b) in Fig. 1). A total of 18 HVDC lines are required to segment the power grid into these two regions.

This segmentation offers a better balance, as the WE region accounts for 54% of the total electricity production. In this case, a larger reduction in blackouts is achieved compared with the previous subsection (see Fig. 9), resulting in a 67% decrease in global blackout risk compared with the reference case (see Table II). As before, the primary cause of this reduction is the control of medium-to-large blackouts affecting both sides of the HVDC lines, whose probability is significantly reduced. Figure 10 shows the size distribution of these blackouts. The introduction of HVDC lines significantly reduces the size of these simultaneous blackouts, as indicated by the shift in the Rank function. This demonstrates the effectiveness of HVDC lines in mitigating the propagation of large-scale failures between the two regions.

The number of large blackouts in each of the zones has been reduced compared with the reference case (see Fig. 11), with the most significant reduction observed in France. The frequency of blackouts remains relatively unchanged due to the occurrence of smaller blackouts. France is one of the zones where the reduction is most significant. The effectiveness of the proposed method in reducing the blackout risk relies more on decreasing the size of the very large blackouts affecting both sides of the HVDC lines than on reducing the total number of blackouts.

The critical role of France in the large blackouts of the European power grid (see Fig. 5) likely contributes to the significant risk reduction observed in the previous subsection (see Table II). The control through the Pyrenees, despite the Iberian Peninsula accounting for only a small fraction of the total consumption and production, directly impacts France and enhances the overall risk mitigation.

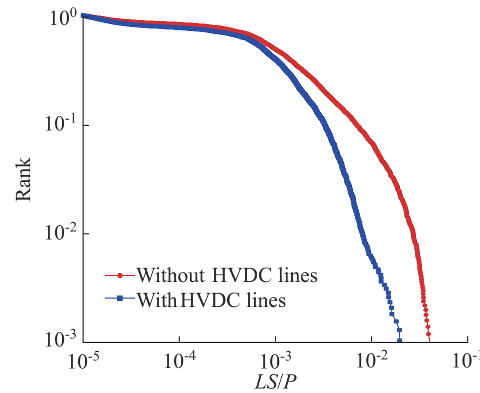

Fig. 10. Rank function of blackouts affecting both WE and EE simultaneously: comparison of reference case (without HVDC lines) and WE-EE case (with HVDC lines).

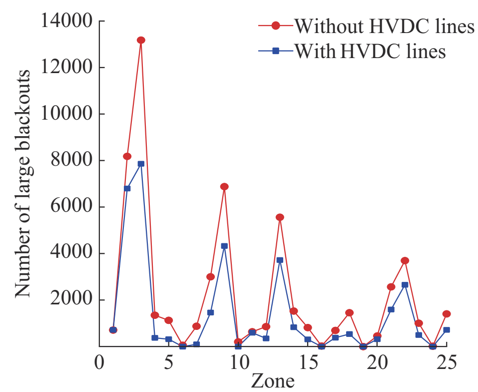

Fig. 11. Number of large blackouts by zone: comparison of cases with and without HVDC lines when European power grid is segmented into two similar halves.

V. COST ANALYSIS

One of the most challenging aspects of studying blackouts is assessing their costs. Each blackout is a unique event, with numerous types of inconveniences, some direct and others more difficult to quantify but still significant. There is limited information available regarding the monetary costs of blackouts. Electric power companies rarely provide detailed data on blackouts, and most available information comes from surveys of citizens or expert analyses.

In this section, we first estimate the cost of blackouts and then evaluate the cost of converting AC lines to HVDC lines. To assess the economic viability of our proposal, we also compare the cost of conversion with the savings achieved from reducing blackout risk.

A. Cost of Blackouts

Following [32], the cost of blackouts can be considered proportional to the lost power during the blackout. The cost of blackout k can then be computed as:

$$Cost(k) = A \cdot LS(k) \cdot Duration(k) \tag{3}$$

where A is a constant, which represents the cost per MWh lost; and $LS(k)$ and $Duration(k)$ are the load shedding of blackout k and its duration, respectively. Systematic data on these variables are only available from North American Electric Reliability Council (NERC) [33], which provides information from 1984 to 2005 on blackouts in the USA.

The OPA model does not provide information on the duration of blackouts, which depends on their size and the actions of the transmission system operator (TSO) or distribution system operators (DSOs) to restore service [34]. To approximate the duration of blackouts, we analyze the duration as a function of the load shedding in the data. In Fig. 12, the duration of blackouts is plotted as a function of their size (dots). Given the large variability in the data, we perform binning and plot the mean value (red dots) and standard deviation (black bars) for each bin. A linear fit to the data (solid red line), corresponding to the relation $Duration = 0.61\sqrt{LS}$, is shown for comparison. The variability is substantial, so this result should be considered a rough approximation.

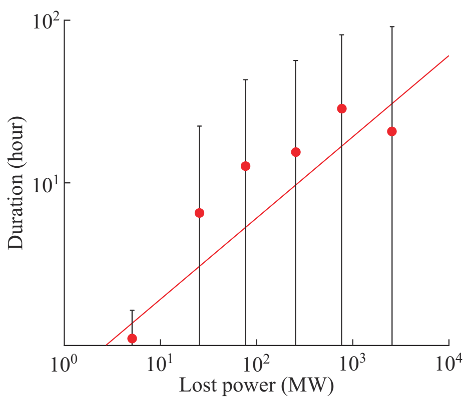

Fig. 12. Duration of blackouts as a function of their size, measured as lost power (LS), from NERC data (1984-2005) [33].

According to the relation between the duration and the LS in log-log scale (see Fig. 12), which can be fitted by a straight line with slope of approximately 1/2, the following estimation for the duration of a blackout is obtained:

$$Duration(k) = B \cdot (LS(k))^{\frac{1}{2}} \tag{4}$$

where B is the intersection point of the linear fit with the y-axis in Fig. 12, and $B = 0.61\ \mathrm{h/MW}^{\frac{1}{2}}$. The cost of blackouts can then be estimated as:

$$Cost(k) = A \cdot 0.61 \cdot (LS(k))^{\frac{3}{2}} \tag{5}$$

The US Department of Energy has estimated that the losses due to blackouts per year amount to $\$1.5 \times 10^{11}$. Using (5) and blackout data from the 23-year period mentioned above, we can calculate the average cost per year and determine the cost per MWh lost as $A = 3947$ \$/MWh.

The value of A is also estimated for the 1977 blackout in New York City (USA) using information on both direct and indirect costs, as shown in Table III [35]. As the total unserved power during the blackout is 101.4 GWh, the cost per MWh lost is estimated to be $A = 3405$ \$/MWh, which is surprisingly close to the previous estimation. In what follows, we will use (5) with $A = 3947$ €/MWh (assuming an approximate USA Dollar-Euro parity) to evaluate the cost of blackouts in the OPA model simulations.

TABLE III
Direct and Indirect Costs of 1997 Blackout in New York City (USA) [35]

Object	Direct cost (M\$)	Indirect cost (M\$)
Business	34.0	160.4
Government	0	12.5
Power company	12.0	65.0
Insurance	0	33.5
Public health service	0	1.5
Transportation	9.1	17.3
Total	55.1	290.2

In the OPA model simulations, since the total demand steadily increases, only the blackout size relative to the total demand at the time of the blackout is meaningful. Therefore, we use the actual average power peak demand P_D to set the proper scale of blackouts in (5): $LS(k) = LS_{OPA}(k) \cdot P_D$, where $LS_{OPA}(k)$ is the relative size of blackouts obtained from the OPA model simulations. In the European power grid, the average power peak demand is approximately $P_D = 6.150 \times 10^5$ MW. The yearly cost of the blackouts for the reference case without HVDC lines, as well as for the two cases with HVDC lines, are shown in Table IV, calculated using (5).

TABLE IV
Estimated Yearly Cost and Saving of the Blackouts in European Power Grid

Case	Yearly cost (M€)	Yearly saving (M€)
Reference case	5980	0
Spain-France (with HVDC lines)	4096	1884
WE-EE (with HVDC lines)	3063	2917

B. Extra Cost of HVDC Lines

We assume that the cost of AC and DC power lines is similar, with the main additional cost for HVDC lines arising from the necessary converter stations. Following [36], the cost C_{conv} of an HVDC converter station with rated power P_{conv} can be estimated by:

$$C_{\mathrm{conv}} = \alpha_0 + \alpha_1 P_{\mathrm{conv}} \tag{6}$$

where $\alpha_0 = 7.85$ M€ and $\alpha_1 = 0.305$ M€/MW, using 2024 updated costs for voltage source converter (VSC) stations from the Midcontinent Independent System Operator (MISO) Transmission Cost Estimation Guide [37]. It is important to note that, with the use of VSC stations, the risk of HVDC blocking caused by commutation failure is avoided. This is a significant advantage of VSC technology, with respect to older line commutated converter technology.

For the segmentation discussed in Section IV-A, which involves four HVDC lines between Spain and France, the cost of constructing eight converter stations, one at each end of the power lines, must be considered. Based on the power capacity of these lines (note that the current exchange capacity between Spain and France is 2800 MW, which is expected to be increased to 5000 MW with the construction of a new HVDC interconnection), we assume $P_{\text{conv}} = 1000$ MW. This power transfer capacity is adequate for standard 400 kV AC/±525 kV DC converter stations. The total extra cost is presented in Table V. For the case of segmenting the power gird between EE and WE, the cost of 36 converter stations (18 HVDC lines) with the same rated power is considered.

TABLE V
EXTRA COST OF HVDC LINES

Case	HVDC cost (M€)	Yearly operational cost (M€)
Spain-France (with HVDC lines)	2501	88
WE-EE (with HVDC lines)	11254	394

Additionally, we have considered the costs over time of implementing HVDC lines to provide a more comprehensive analysis. According to [37], the expense factor of an HVDC converter station in USA, which accounts for property taxes, cost of debt, and operations and maintenance, ranges between 2.76% and 3.74%, depending on the state. For this study, we have assumed a representative expense factor of 3.5% and computed the corresponding yearly operational cost for each case considered, as shown in Table V.

VI. DISCUSSION

The control of the power flowing through the lines connecting two distinct zones within a large power grid constitutes an efficient method of reducing the blackout risk. Such control can be achieved using, for instance HVDC lines, although it is possible to obtain similar results using other technologies. Using the proposed method, HVDC lines are effective in avoiding the propagation of cascading failures from one side to the other, reducing at the same time the load shedding caused by the contingency. The finding of this study demonstrates that HVDC lines can help in mitigating some of the largest blackouts, thereby substantially reducing the risk of such events.

In this study, we consider multiple ways of dividing the European power grid and select three configurations that required the fewest HVDC lines for segmentation. Two of these configurations are presented in this study, while the third, separating Portugal, Spain, and France from the rest of Europe, is omitted as it yields results similar to the WE-EE segmentation. Additionally, we use a sinusoidal-like demand profile to account for seasonality, ensuring that our results reflect the variability in demand patterns across different seasons.

Alternative grid topologies using synthetic networks were also analyzed in a previous study [9], which demonstrated that segmented power grids consistently exhibit a substantially lower blackout risk compared with their original configurations.

While the current parameters p_0 and p_1 are well-calibrated based on historical data, we acknowledge the need for updated data to reflect the evolving nature of modern power grids. The increasing penetration of renewable energy sources introduces new dynamics that can significantly influence blackout risk. Notably, the increased risk associated with renewable energy sources is primarily due to their intermittent nature [38], which can lead to generation shortfalls during periods of high demand, rather than changes in the lines that can affect parameter p_0 or p_1. However, the comprehensive updates to the model, including parameter recalibration and structural adjustments, are necessary to fully capture these effects.

Sensitivity analyses of p_0 and p_1 have been performed in previous studies for other power grids (e.g., [39], [40]), and these studies indicate that the qualitative findings of the OPA model are robust to variations in parameter values. Based on these insights, we expect that our qualitative conclusions, such as the effectiveness of segmentation with HVDC lines in reducing blackout risks, would remain valid even with updated parameters. However, updated data would enable more precise quantitative estimates of blackout risk and economic savings, further enhancing the accuracy and applicability of this study.

The proposed method has the potential to be economically viable. In the case of converting the four lines connecting Spain and France through the Pyrenees from AC lines to HVDC lines and applying the proposed method, considering the costs and total savings presented in Tables IV and V, the payback time could be as short as 1.4 years. However, it should be noted that indirect costs are the majority in the estimation of total blackout costs (see Table III). When the payback time is calculated based solely on direct costs, a result of 7.2 years is obtained. This appears to be a more realistic estimation. The proposal of dividing the European power grid into two similar halves, despite reducing even more the global blackout risk, results in a longer payback time (approximately 4.5 years; 23.3 years if only direct costs are accounted), due to the necessity to convert a larger number of power lines (18 in this case).

The cost analysis presented in this study, while providing useful insights, faces several challenges. For instance, indirect costs such as those associated with societal and economic disruptions dominate the estimates but are difficult to quantify accurately and vary significantly across regions. Additionally, the lifetime and maintenance costs of power electronic converters [36], [37], [41], although partially taken into account in our analysis through the expense factor, are critical issues that influence the long-term economic feasibility of such investments. A more comprehensive analysis, incorporating regional differences and updated economic parameters, would provide a clearer picture of the financial implications. Exploring these aspects represents an essential direction for future research, as a more detailed cost-benefit analysis is necessary to support investment decisions in HVDC technology.

These estimations consider solely the advantages of HVDC lines in terms of the control of blackout propagation. However, it should be noted that HVDC lines also possess other advantages, including their capacity to contribute to frequency control. The rapid response of HVDC systems, facilitated by power electronics, enables precise adjustments of power flow on sub-second timescales, which is particularly advantageous in mitigating frequency deviations. For example, HVDC connections have been shown to stabilize frequency fluctuations in smaller grids connected to a larger system acting as an energy pool. A notable example of this is the power grid of Balearic Islands, which operates asynchronously with mainland Spain and is connected via an HVDC cable. This HVDC link is programmed to control frequency deviations beyond ± 0.15 Hz, demonstrating the potential of HVDC to enhance grid stability through effective frequency regulation [42].

The frequency of different segmented systems has not been considered in this study, and this is a topic to be explored in future research. However, the complete segmentation of a zone from the rest of the power grid, or even the division of the power grid into two, may also help avoid frequency instabilities of the kind that occurred on 8 January 2021, which resulted in the separation of the European power grid into two desynchronized areas (see [43]). The inclusion of HVDC lines, with their capacity to address synchronization issues, has the potential to further reduce the investment payback time.

The proposed method, as with other smart control systems, relies on real-time information, which introduces a potential vulnerability to telecommunication network failures. However, the ongoing trend towards a smart power grid is evident. The monitorization and digitization of the power grid are providing system operators with real-time and system-wide information. This renders the proposed method highly compatible with this evolving scenario. The proposed method does not require extensive amounts of data. Under typical grid conditions, it is assumed that the real-time data regarding node consumption and power plant generation is readily available. In the event of a line outage, a new dispatch excluding the faulty line is solved to determine the optimal power flow in the HVDC lines to minimize load shedding. The new power set point is then communicated to the HVDC converter stations, a process that generally requires a few seconds or less, assuming uninterrupted communications.

In the unlikely event of simultaneous power line and telecommunication system failures, no action could be taken, and the power flow of the HVDC lines would remain constant. However, this would not worsen the situation compared with the reference case. Conventional security relays would still operate as usual, and the load shedding would be comparable to that in the reference case but not worse.

Phasor measurement units (PMUs) and wide-area measurement systems (WAMSs) could significantly enhance the proposed method by delivering high-resolution and synchronized measurements of system dynamics. These technologies improve situational awareness, enabling the control system to respond more accurately and promptly to evolving conditions during cascading failures. By integrating PMU and WAMS data, the method could handle fast-changing scenarios more effectively and provide better protection against large blackouts.

VII. Conclusion

The findings of this study demonstrate that the implementation of HVDC lines for grid segmentation, in conjunction with the proposed method, results in a substantial reduction in the incidence of large blackouts within the European power grid. This, in turn, leads to a corresponding decrease in the overall risk of blackouts. Specifically, the analysis indicates that segmentation through the Pyrenees could reduce the blackout risk by up to 46%, while segmentation into WE and EE zones could reduce it by up to 67%. These reductions translate into estimated payback time of approximately 1.4 years and 4.5 years, respectively, based on total blackout costs. However, when direct costs are considered alone, the payback time is projected to extend to 7.2 years and 23.3 years, respectively, thereby underscoring the impact of indirect costs on the economic viability of such investments.

The method for determining optimal power flow through HVDC lines during contingencies to minimize blackout size is both fast and effective, making it suitable for real-time practical applications. It adds minimal computational overhead to existing dispatch methods, demonstrating the feasibility of integrating the proposed method into operational grid management.

The identification of the optimal locations for HVDC segmentation within the European power grid presents a complex challenge. A comprehensive examination is conducted encompassing geographical and size criteria, with the analysis extending to segmentation through the Pyrenees and the central European region. Both cases yield positive results with varying payback time. Of these two options, the segmentation through the Pyrenees appears to be more advantageous. Similar results can be achieved by segmenting other regions, such as segmenting Italy or the Balkans, and introducing multiple barriers could further enhance blackout risk reduction.

The findings of this study are reasonable despite the limited available blackout data for the European power grid. The data provided are suboptimal in that it is aggregated by months and regions, and it is not possible to distinguish between isolated blackouts as well as larger and interconnected blackouts. Furthermore, the European states included in the dataset do not correspond to the set of states incorporated in the power grid. Improved data would facilitate more precise calibration of the model and enhance the accuracy of quantitative estimates, including the cost-benefit analysis.

Finally, in addition to, or alternatively to, the complete segmentation of parts of the power grid through the replacement of existing AC lines with DC lines, other strategies for the mitigation of blackout propagation could be investigated. These include the addition of isolated embedded HVDC lines, the implementation of flexible alternating current transmission system (FACTS) devices on specific AC lines, the integration of phase shifters, and the deployment of energy storage units in selected grid locations.

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