Vulnerability analysis of HVDC contingencies in the Nordic power system

I.B. SPERSTAD[1], G. KJØLLE[1], O. GJERDE[1], T.K. VRANA[1], S.H. JAKOBSEN[1,2], J. TURUNEN[3], L. HAARLA[3]
[1]SINTEF Energy Research, [2]NTNU – Norwegian University of Science and Technology, [3]Fingrid Oyj
[1]Norway, [2]Norway, [3]Finland

SUMMARY

In the increasingly interconnected and integrated European power system, transmission system operators need to consider new kinds of risk associated with the interconnection to neighbouring systems. For the Nordic power system, there is now more than 8 GW of HVDC interconnector capacity connecting the Nordic synchronous area to other synchronous areas and almost 4 GW additional capacity currently under construction. Although the probability of contingencies involving the simultaneous loss of two or more HVDC interconnectors may be very low, such contingencies that exceed the reference incident (dimensioning fault) of the Nordic synchronous area may cause frequency drops leading to severe stability problems and load shedding. The inertia in the Nordic synchronous area is decreasing and, especially in operating states with high HVDC import, it may become insufficient to maintain operational security during events such as certain HVDC contingencies.

The objective of this paper is to analyse vulnerabilities related to HVDC contingencies in the Nordic power system, focusing on potential frequency instabilities that could follow from such contingencies in import situations. Using a complementary approach to traditional risk analysis, such a vulnerability analysis may lead to greater insight by structuring relevant consequences, contingencies, threats, vulnerabilities and barriers. For instance, blackouts in neighbouring synchronous areas is a relevant threat, and the Nordic synchronous area may be more vulnerable to HVDC contingencies where converter stations are in the proximity of each other. Furthermore, insufficient system inertia is highlighted as a generally important factor influencing the vulnerability. Important barriers against HVDC contingencies could involve monitoring the system inertia and HVDC import/export. The analysis may contribute to increase the awareness of TSOs and other stakeholders of possible vulnerabilities in the power system with respect to such events, including how these are expected to develop in the future, and to identify potential measures for mitigating consequences following HVDC contingencies. This qualitative and semi-quantitative analysis provides a broad overview of the issue of HVDC contingencies that may serve as a starting point for more detailed, quantitative analysis.

KEYWORDS
HVDC – Interconnector – Outage – Vulnerability – Risk – Security – Frequency – Inertia

1. INTRODUCTION

In the increasingly interconnected and integrated European power system, transmission system operators (TSOs) need to consider new kinds of risk associated with the interconnection to neighbouring synchronous areas. For the case of the TSOs responsible for the Nordic synchronous area (Norway, Sweden, Finland and Eastern Denmark), the capacity of the HVDC interconnectors to other synchronous areas is now more than 8 GW and will increase by more than 40 % by 2021 [1]. Overviews of existing and planned interconnectors between the Nordic synchronous area and other synchronous areas can be found in [1], [2] and [3].

The Nordic power system is planned and operated in accordance with the N-1 criterion. The reference incident or dimensioning fault (i.e. the most severe N-1 contingency) in the Nordic synchronous area is defined as the trip of the largest generator [1]. Operating states with high amounts of power import via HVDC interconnectors has so far not posed a significant threat to the system operated with the N-1 principle since even if one of them trip, the power import that is lost is less than the reference incident for the Nordic synchronous area. In some of the operating states of the power system, events more severe than the reference incident may cause frequency drops that lead to stability problems and/or large-scale load shedding. A contingency involving the simultaneous tripping of two (or more) HVDC interconnectors can be an example of such a contingency, and it is these contingencies that will be addressed in this paper. As a starting point for identifying such contingencies, we will consider the loss of HVDC transmission capacity that is higher than for the reference incident of the system.

Currently most system inertia is coming from inherent inertia of synchronous generators. The inertia in the Nordic synchronous area is decreasing, partly due to higher volumes of renewable generation from wind power and phasing out of nuclear units, and partly due to more frequent occurrences of high power import through HVDC interconnectors. Therefore, especially in operating states with high HVDC import and a high share of renewable generation, the system may sometimes not have sufficient inertia to maintain operational security after certain contingencies involving multiple HVDC interconnectors [1]. The rate of change of frequency in the system is related to the system inertia. With insufficient inertia, frequency drops can be too rapid, causing the frequency to reach the load-shedding thresholds before reserves have reacted sufficiently.

Contingencies involving simultaneous tripping of multiple HVDC interconnectors can be regarded as high-impact low-probability (HILP) events [4]–[7]. Although highly unlikely, HILP events occasionally do occur. Historically, their probability of occurrence is furthermore higher than what would be expected from traditional risk analysis assuming independence of events [7] and neglecting e.g. common-cause failures. A vulnerability analysis, on the other hand, is less concerned with attempting to estimate probabilities. It is a complementary approach to traditional risk analysis [5] that may help give some insight into HILP events, their potential consequences and how they may be mitigated.

The increasing importance of HVDC interconnectors for the operation of the Nordic power system raises the question of possible vulnerabilities associated with them. There already are analyses highlighting the severe market impacts of HVDC contingencies [8]. However, there are not yet available analyses of possible HILP events associated with HVDC contingencies. There are two implications of increased import through HVDC interconnectors that motivate such an analysis: 1) The number of possible contingencies becomes larger, and 2) in operating states with high HVDC import, there is a relatively smaller amount of generation providing inertia to the system.

The objective of this paper is to analyse and map the overall vulnerabilities related to HVDC contingencies in the Nordic power system. The purpose of this analysis is to increase awareness of TSOs and other stakeholders of possible vulnerabilities in the power system with respect to such events and to identify potential measures for mitigating consequences following HVDC contingencies. The main contributions of the paper are to, for the first time, provide a broad and systematic overview of threats and barriers that are relevant to HVDC contingencies in particular.

Authors' manuscript, published with permission from CIGRE,
of report B4-131 presented at CIGRE Session, Paris, 2018.
(Available online: https://e-cigre.org/publication/SESSION2018-2018-cigre-session.)

The rest of the paper is organised as follows. Section 2 outlines the methodology of the vulnerability analysis and delimitates the study. The vulnerability analysis is presented in Section 3 and some limitations and implications are further discussed in Section 4. Section 5 summarizes the analysis and suggests some more detailed, quantitative analyses that could be carried out on the basis of this work.

2. METHODOLOGY

The vulnerability analysis is based on a framework for analysing HILP events in power systems and a methodology for vulnerability analysis related to such events [5], [6]. An underlying premise of the methodology is that vulnerability analysis, compared to risk analysis in general, is mostly concerned with identifying vulnerabilities related to the events with critical consequences. The definition used for the term “critical” is therefore a decisive point for the analysis. In general, what is regarded “critical” has to be determined by or together with the relevant stakeholders (i.e. TSOs, regulators, other authorities) before the analysis is carried out. As will be explained in more detail in Section 3, we are for this analysis building on the understanding of criticality developed in a previous vulnerability analysis of the Nordic power system that was carried out in cooperation with Nordic TSOs [9].

The starting point of the vulnerability analysis methodology is the possible consequences that, although unlikely to occur, would be critical if they do. In a sense, this approach reverses the sequence of steps carried out in traditional risk analysis starting with possible threats. In the methodology, the vulnerability analysis is carried out as a sequence of six steps that can be generally described as follows:

Step 1: Identify critical consequences
Step 2: Identify critical contingencies potentially leading to critical consequences
Step 3: Identify threats that can cause the critical contingencies
Step 4: Identify vulnerabilities associated with the power system's susceptibility and coping capacity
Step 5: Identify factors influencing the power system's coping capacity
Step 6: Identify existing and missing barriers against critical contingencies

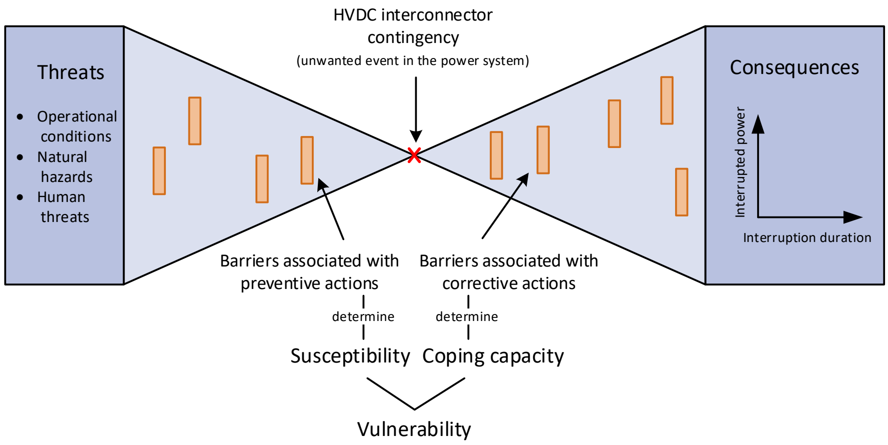

Figure 1. Bow-tie model for vulnerability analysis of HVDC interconnector contingencies, based on [6].

Figure 1 shows a bow-tie model that illustrates the framework for power system vulnerability analysis that underlies the methodology. The vulnerability of the power system is determined by its *susceptibility* to threats and by its *coping capacity*, i.e. how capable the power system is to cope with contingencies and limit their consequences [6]. The steps of the analysis are described in more detail in [5] and [6]. One should note that the contingencies identified as “critical” in step 2 are defined to be contingencies *potentially* leading to critical consequences. Depending on the level of detail in the analysis, this step could therefore be regarded as a first screening of relevant contingencies to consider more carefully.

The general methodology by itself is a framework for structuring the analysis. In applications of the methodology, different qualitative and quantitative methods can be employed for the individual steps as described in [5]. The general methodology could thus also be applied to more detailed risk assessments incorporating e.g. dynamic analysis. To ensure that safety and security concerns of the TSOs are duly considered, this paper does not describe detailed or quantitative analysis of specific vulnerabilities, and it does not consider possible intended human threats. Moreover, it does not identify any HVDC interconnector involved in potentially critical contingencies by name or location.

One crucial point in our application of the methodology described above is that we limit the analysis to consider HVDC contingencies. Thus, it considers a subset of the larger risk space considered e.g. in the previous vulnerability analysis of the Nordic power system [9]. To further delimit the analysis, we focus on consequences related to rapid frequency drops due to the loss of interconnectors importing power. Rapid frequency *increases* due to the loss of interconnectors *exporting* power are also relevant but not treated explicitly in this analysis.

3. VULNERABILITY ANALYSIS

The following subsections describe the vulnerability analysis carried out according to the six steps outlined in Section 2.

3.1. IDENTIFY CRITICAL CONSEQUENCES

The criticality of the consequences of a blackout event can be measured along several possible dimensions of criticality. Following [9] and [6], we will for this analysis use the maximum interrupted power and the average interruption duration as the two principal dimensions along which to measure criticality. In order to get a sense of the range of values for each of these dimensions relevant for the Nordic synchronous area, we show a consequence diagram with the average interruption duration along one axis and the power interrupted along the other in Figure 2. In this figure, we have also sketched the boundary beyond which the consequences are classified as “critical” or worse according to the previous vulnerability analysis of the Nordic power system [9] [10]. According to [10], a critical event is typically characterized by considerable damage and disruption of normal life, and the boundary was chosen based on Nordic surveys, including experiences from recent blackouts and discussions with TSOs [9].

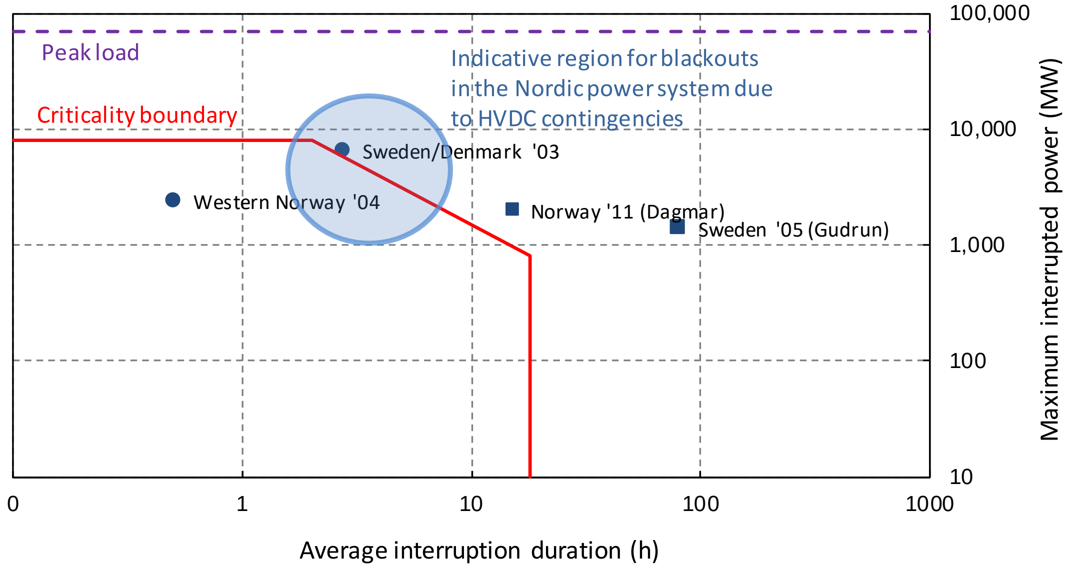

Figure 2. Consequence diagram indicating possible consequences for blackouts in the Nordic synchronous area due to HVDC contingencies, compared with historic blackout events, based on [6], with the criticality boundary suggested in [9] and peak load in the system as given in [11].

In the consequence diagram in Figure 2, we have included some historic blackout events in the Nordic synchronous area (none of which were caused by HVDC contingencies). Note that the two events depicted by square markers are associated with major storms, causing major damage to infrastructure of the power system in parts of the Nordic synchronous area, which in turn resulted in considerable interruption duration due to the need for repairs to restore power supply to the affected areas. We assume that these kinds of consequences are not characteristic to the most plausible blackout events following from HVDC contingencies. Therefore, based on interruption durations reported for previous blackout events not caused by natural hazards [12], one could estimate a plausible range of average interruption durations for blackouts due to HVDC contingencies of around 1 to 10 hours, with the duration likely to increase with the geographical extent of the blackout event. A theoretical upper boundary of the amount of interrupted power that could possibly result from contingency in the Nordic synchronous area can be given by the peak load, indicated by a dashed line in Figure 2. Such consequences are not plausible for HVDC contingencies, but much smaller blackout events interrupting power corresponding to a few percent of the peak load could still be regarded as critical according to the boundary indicated in Figure 2 [9].

For the presentation in the following sections, it is useful to outline the sequence of events following an HVDC contingency potentially resulting in consequences that can be regarded as critical, for example according to the illustration in Figure 2. If one considers the outage of HVDC interconnectors importing power to the Nordic synchronous area, the resulting power deficit would cause the frequency to decrease and reserves to be activated. If this decrease in frequency is so fast and deep that the reserves are not sufficient, then automatic Under-Frequency Load Shedding (UFLS) schemes would at some point be activated. (Given the relevant time scales for these events, outage occurrences of individual inter-connectors can for our purposes be considered simultaneous if they happen within a few seconds of each other.) UFLS would then progressively shed load in order to restore generation-consumption balance and to keep frequency in such a range that generators can remain connected. Massive load shedding can prevent a blackout, but even this controlled load shedding could be regarded as a critical consequence, and barriers meant to ensure lower consequences are still needed (discussed in Section 3.6).

3.2. IDENTIFY CRITICAL CONTINGENCIES

For this analysis, we have chosen to use the reference incident in the Nordic synchronous area as a criterion in considering which contingencies could potentially be regarded as critical. In the EU regulation [13], previously referred to as the ENTSO-E Network Code on System Operation, the reference incident for the Nordic synchronous area is defined as "the largest imbalance that may result from an instantaneous change of active power such as that of a single power generating module, single demand facility, or single HVDC interconnector or from a tripping of an AC line, or it shall be the maximum instantaneous loss of active power consumption due to the tripping of one or two connection points" [13]. Following this definition, and similarly as in [1], we consider a reference incident with a loss of active power of 1450 MW in this analysis. In the following, we will take for granted that the loss of HVDC transmission capacity corresponding to this reference incident defines the critical HVDC contingencies. We note that this choice does not consider the actual amount of power imported or exported through the interconnectors at the time the contingency occurs. More sophisticated approaches taking into account the operating state are therefore proposed in Section 5.

An approach to identifying HVDC contingencies regarded as critical according to the reference incident is visualized in Figure 3. This figure is based on the list of HVDC interconnectors currently operational [1]–[3] and considers all contingencies up to third order, i.e. all contingencies involving the simultaneous outage occurrence of combinations of up to three interconnectors. For the purpose of this analysis, each pole of a bipole system and each of the four bridges of the Vyborg Link is considered as a separate entry in the list. Note that HVDC links that are internal to the Nordic synchronous area are not included in the list of interconnectors. The contingencies are then sorted in increasing order by the power transmission capacity that is lost if they occur, and this capacity is plotted separately for first-, second- and third-order contingencies (involving one, two and three interconnectors, respectively). Finally, the power potentially lost at the occurrence of the contingencies can be compared with the red line in Figure 3 denoting the reference incident. Among those corresponding to power losses above that of the reference incident, there are 360 third-order contingencies (out of a total of 816). There are no second-order contingencies corresponding to power losses above that of the reference incident. Carrying out the analysis the same way as for Figure 3 for all HVDC interconnectors that will be operational by 2021 still gives no critical second-order contingencies.

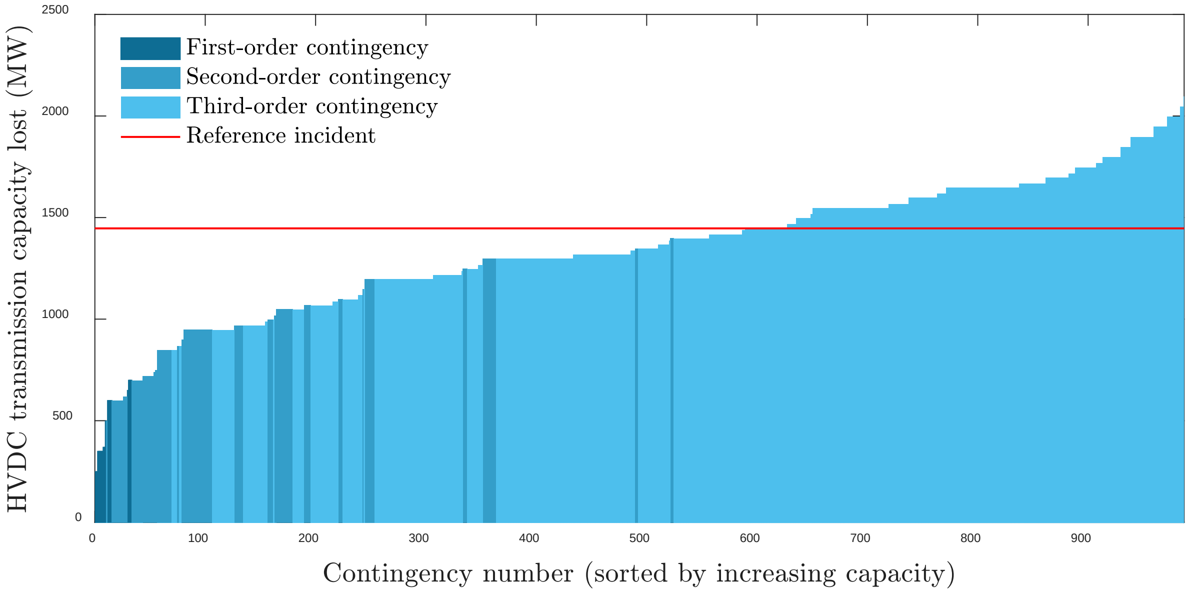

Figure 3. The severity of HVDC interconnector contingencies in terms of the maximum amount of transmission capacity lost, for the HVDC interconnectors that are currently (2018) operational and connected between the Nordic synchronous area and another synchronous area.

However, when identifying critical contingencies in a vulnerability analysis, it is important to not only consider the order of the contingencies and implicitly assume that they consist of independent outage occurrences. In this respect the approach presented in Figure 3 has some limitations, and for instance, it does not explicitly consider potential common-cause outage occurrences involving e.g. both poles of a bipole system. Relevant common-cause outages are treated in more detail in the following subsections.

3.3. IDENTIFY THREATS THAT CAN CAUSE THE CRITICAL CONTINGENCIES

The data basis for analysing failures and outages of HVDC interconnectors and their possible causes is relatively sparse, but there are some publicly available sources. The bi-annual reliability surveys by CIGRE Study Committee B4 [14] include data for HVDC systems that can be regarded as representative for HVDC interconnectors in the Nordic power system. The HVDC utilization and unavailability statistics of ENTSO-E Regional Group Nordic [2] do not include reliability data but do include some descriptions of past incidents. Some failure data are also available in Statnett's fault and interruption statistics [15]. With some exceptions discussed briefly in Section 4, these data give limited insight into threats that could cause multiple simultaneous outage occurrences. In the following, some categories of plausible threats that can be regarded as possible sources of critical HVDC contingencies are discussed, focusing on possible common-cause outages of multiple interconnectors (i.e. of multiple monopole systems or bipole systems).

Blackouts in neighbouring synchronous areas:

In risk and vulnerability analysis, threats can be understood to be something developing outside the system under study [6]. For a vulnerability analysis of the Nordic synchronous area, a blackout in a neighbouring synchronous area (Continental Europe or the system including Russia and the Baltic countries) can thus be regarded as a threat that can cause the outage of one or more HVDC interconnectors between this and the Nordic synchronous area. Depending on the size of the region affected by such a blackout, this threat could plausibly cause an HVDC contingency involving multiple interconnectors. The possible extent of such blackouts is most likely to be limited to one synchronous area (either Continental Europe or the system including Russia and the Baltic countries), but this is an extreme case, and blackouts limited to e.g. one country, one TSO control area, or a local area around one or more converter stations, are regarded more likely.

Blackouts in a neighbouring synchronous area could also pose a threat to HVDC interconnectors even if there are no power interruptions in the local region of the area where the converter station is situated.

For instance, voltage irregularities could cause commutation errors for line commuted converters (LCCs). Voltage source converters (VSCs) can on the other hand be regarded as less susceptible to local voltage problems in neighbouring synchronous areas, and new interconnectors are expected to be VSC [3]. Correspondingly, local problems in regions of the Nordic synchronous area with multiple converter stations could in principle also cause a critical HVDC contingency. However, outages of LCCs due to local voltage problems are most likely very brief and thus not likely to cause large frequency incidents.

Some insights into the threat of blackouts in neighbouring synchronous areas could possibly be found from historic events such as the 2006 European blackout [16]. During this event, uncontrolled islanding (system splitting) resulted in the North-Eastern parts of UCTE to be operated in an island with overfrequency. However, this did not disturb the operation of any of the HVDC interconnectors from this electrical island to the Nordic synchronous area. On the other hand, automatic frequency-controlled emergency HVDC actions increased export from UCTE to the Nordic system on Skagerrak and Konti-Skan interconnectors to reduce the imbalance, and the interconnectors thus contributed to stabilizing the system. Neither did the event cause the outage of the HVDC interconnector between France and the British synchronous area.

Local threats to HVDC converter stations: Individual HVDC converter stations are subject to some of the same threats as other substations, including fires, transportation accidents, etc. Those converter stations that are situated in fjords are exposed to natural hazards such as avalanches and landslides, and those converter stations or cable terminals that are close to sea can in principle be exposed to flooding. Such stations are not as susceptible to extreme weather events as transmission lines, but historically there have been occurrences of major storms causing the outage of an HVDC interconnector [8]. Nevertheless, these natural hazard threats are not particularly plausible to cause contingencies involving multiple interconnectors.

Threats to HVDC transmission lines: The submarine cable part of the HVDC interconnector may be susceptible to shipping activity as other submarine cables. In general, cables that are bundled are more susceptible to common-cause failures. However, the HVDC cables mostly (at least for monopole systems) do not follow the same trench, and shipping activity is thus no plausible threat of contingencies involving the simultaneous outage occurrence of multiple HVDC interconnectors. Parts of some HVDC transmission lines in the Nordic power system are overhead lines or underground cables [2] and are generally exposed to the same kinds of threats as AC overhead lines or underground cables.

3.4. IDENTIFY VULNERABILITIES

The description of relevant threats in Section 3.3 suggests that the Nordic synchronous area is more susceptible to those contingencies involving multiple HVDC interconnectors where the converter substations are in the proximity of each other. The implications of this effect on the vulnerability of the Nordic synchronous area is visualized in Figure 4. Similarly as in Figure 3, this figure is based on enumerating HVDC interconnector contingencies and calculating the power transmission capacity that is lost if they occur. However, in contrast to Figure 3, Figure 4 does not restrict and differentiate the contingencies by the number of interconnectors involved, but rather consider all contingencies and differentiate them by the *proximity* or the degree of *co-location* of the HVDC converters involved. For instance, a single cable failure could cause the outage of both poles of a bipole system, and contingencies denoted “co-located converter stations” can be caused by the outage occurrence of multiple converter stations that are located at the same site or facility. For each degree of co-location, the contingency corresponding to the largest power capacity is shown in the figure both for all interconnectors currently (2018) operational and all interconnectors operational by 2021.

By comparing with the horizontal red line, Figure 4 shows for which degree of co-location there exists contingencies that are critical according to the reference incident. From the analysis carried out to produce Figure 4, we found that, up to third order, there are 10 contingencies involving converter stations in the same country that are regarded as critical. The corresponding number of additional contingencies involving interconnectors connecting to the same synchronous area is 90. This is relevant for the vulnerability of the Nordic synchronous area to blackouts in (parts of) neighbouring synchronous areas. By 2021, the numbers of such contingencies will increase to 20 and 229, respectively.

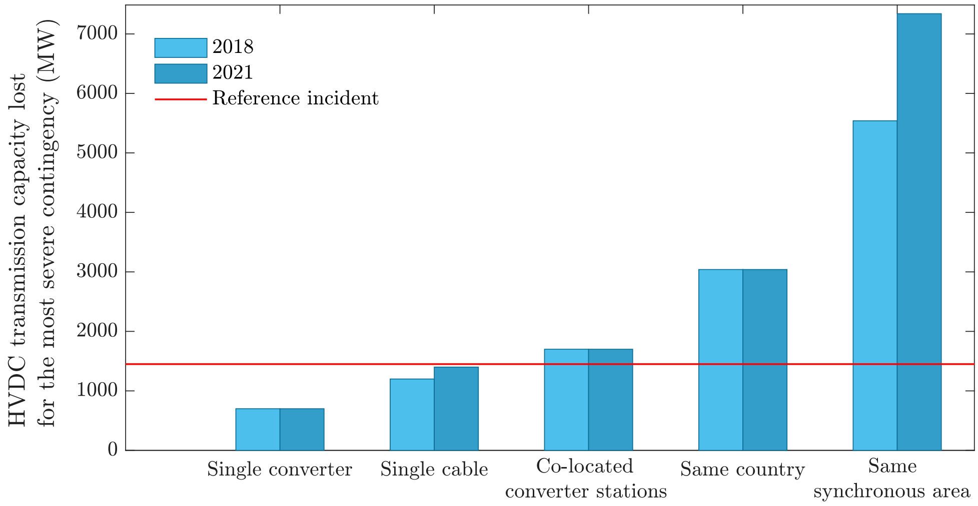

Figure 4. The severity of the most severe HVDC interconnector contingencies for different levels of co-location of the HVDC converters.

If a critical contingency occurs, the actual consequences are determined by the severity of the contingency and the coping capacity of the power system. One possibly important vulnerability associated with the coping capacity is that system inertia may be insufficient to slow the change in system frequency enough for reserves to react to avoid under-frequency load shedding. Based on the estimates in [17], inertia could have been below the required level to successfully cope with the reference incident around 4 % of the time in the period 2010–2015, and in 2025 this number could have increased to around 8 %. The lowest inertia values are observed during summer nights with high wind production [1]. And even though the inertia would be sufficient for a reference incident, this may not be the case for events exceeding the reference incident.

3.5. IDENTIFY FACTORS INFLUENCING COPING CAPACITY

As pointed out in [17], the coping capacity associated with inertial response decreases with factors such as higher shares of renewable (wind and solar) power generation, the phasing out of nuclear power generators and the occurrence of higher amounts of import through HVDC interconnectors. A related factor influencing the inertia level is the load level in the synchronous area, and the coping capacity associated with inertial response will be lowest in low-load periods (e.g. summer nights). Furthermore, the amount of generation in the Nordic synchronous area and thus the level of inertia will generally be lower when the amount of power imported through HVDC interconnectors is high. This correlation means that the coping capacity generally is lower when the potential severity of HVDC contingencies is higher.

A factor generally known to strongly influence the coping capacity of the power system is the situational awareness of the system operator [12]. In the context of HVDC contingencies, it is particularly relevant for TSOs to be aware of potentially critical import situations. Furthermore, the existing real-time monitoring of the inertia in the Nordic synchronous area and estimated frequency drops after contingencies [17] can help the TSOs to see when the situation is becoming critical, allowing them to plan or activate some remedial actions. Communication and coordination between the TSOs is therefore important for the preparedness prior to contingencies. It is also important to coordinate the restoration process following a contingency leading to blackout of large parts of the Nordic synchronous area.

3.6. IDENTIFY EXISTING AND MISSING BARRIERS

There are several existing barriers against blackout in the Nordic system as mentioned below. Some possible barriers are also mentioned that are still missing.

***Inertial response*:** System inertia is the first barrier against system blackout after a frequency incident. Rotational kinetic energy provides instantaneously active power to the grid and thus slows down the decrease in frequency. Unless one can rely solely on other barriers, described below, it is important to take measures for maintaining sufficient inertia by having a sufficient number of synchronous generators rotating, e.g. operating at zero or low active power. This is especially the case when the operational situation is critical with regards to high HVDC import. Other options for ensuring sufficient inertia are the installation of synchronous condensers or the introduction of synthetic inertia requirement into grid codes. Most of the time there has been sufficient amount of inertia, but in the future, this may no longer be the case.

***Frequency and voltage dependence of loads*:** The frequency and voltage dependence of loads can also be seen as a barrier against blackout because the total amount of load in the system decreases when the frequency and voltage decrease after an incident. Usually, the frequency dependence is more important because the entire synchronous area is affected by approximately the same decrease in frequency. However, it has been observed [18] that, the voltage dependence in some cases can reduce the system load more than the frequency dependence. Although the voltage dependence of loads therefore can be regarded as a more effective barrier against blackout, it is more dependent on the location of the incident and the operational situation in the system than the frequency dependence. In both cases there are large uncertainties and low level of control from the TSOs, making it difficult for TSOs to rely on this barrier. In addition, the load is becoming less dependent on frequency and voltage due to the increasing amount of loads with converter interfaces, and this barrier can thus be seen to be weakening.

***Reserves*:** Feeding active power to the system from any source also counteracts frequency drops. An existing source for active power are reserves from generators such as frequency containment reserves for disturbances (FCR-D). Other, faster-acting sources of active power to the system are for example power from batteries and wind turbines connected to the grid through converters, although these sources are not contributing significantly today. HVDC interconnectors connected to other synchronous areas are also a fast source, but in the case that the frequency incident is caused by the tripping of several HVDC interconnectors, there are fewer interconnectors available to contribute to this barrier. Contracted load shedding as a reserve would also be an efficient solution. Analyses from Texas show that a large share (up to 50 %) of the reserves can be load, which provides full response in 0.5 seconds and can be more than two times as efficient than primary frequency reserves from generators [19]. Increasing the amount of reserves (from generation and load) with decreasing inertia is a possible remedy against low inertia situations until a certain point [19].

Under-frequency load shedding (UFLS): Under-frequency load shedding is the last barrier against blackout of the power system after a severe contingency. In normal operation, after the reference incident the system should not reach the frequencies where the UFLS is activated, and in addition there should be some margin to the UFLS activation threshold.

Limit HVDC import in critical situations: If for some reason the blackout risk in the continental Europe is high, e.g. due to regional storm, then the HVDC import to the Nordic system could be decreased to a level that the Nordic system can withstand in case the interconnectors to continental Europe are tripped. Such measures could also be taken in situations with extremely low estimated system inertia.

Other system protection schemes against HVDC contingencies: Other case-specific event-driven load shedding system protection schemes (SPS) could be utilized as barriers against blackouts in the Nordic synchronous area. An event-driven SPS based on monitoring the continental Europe system for the risk of blackouts [20] is an example of such a protection scheme that could be considered.

4. DISCUSSION

As alluded to in Section 2, the following choices were made in the delimitation of the analysis presented above: It is primarily involving qualitative and semi-quantitative methods, it focuses on the frequency response of contingencies but does not attempt to quantify these or the following consequences in detail through dynamic analysis, and it is not attempting to quantify probabilities of contingencies or of critical consequences. Furthermore, the definition of critical HVDC contingencies in terms of the power transmission capacity relative to the reference incident is deterministic as it does not consider the operating state (import/export, system inertia, etc.) at the time of the contingency. This definition is also conservative because the power system may well cope with contingencies more severe than the reference incident. On the other hand, there may be times when insufficient inertia makes the system unable to successfully cope with an HVDC contingency less severe than the reference incident [1]. This leaves room for more detailed quantitative and probabilistic studies as future work.

Although it is not the objective of this paper to estimate the probability of contingencies involving multiple HVDC interconnectors, some insights into the probability of common-cause failures of HVDC interconnectors can be gained from [14], where information about the simultaneous failure of both poles of a bipole system are given. These data indicate that the probability of simultaneous failures is almost three times higher than it would be if the assumption of independent failures was correct. This shows that the common assumption of independence leads to a significant underestimation of the probability of higher-order contingencies.

One implication of the findings of this analysis is that although the Nordic synchronous area may not be particularly vulnerable to HVDC contingencies today, there are reasons to pay close attention to the future development of such vulnerabilities. Section 3.2 illustrated how the installation of new interconnectors with large capacities the next few years increases the number of contingencies that could potentially lead to critical consequences. Although the converter stations of the two largest of these new interconnectors are installed in Norway, which already has a number of HVDC interconnector converter stations, the new stations will be located far apart from other HVDC converter stations but close to large hydropower generators. At the same time, the general trend is that inertia in the Nordic synchronous area is decreasing, which decreases the coping capacity of the power system with respect to these contingencies. However, the TSOs responsible for the Nordic synchronous area are currently planning for measures to mitigate such risks [1].

5. CONCLUDING REMARKS

A summary of the vulnerability analysis in terms of critical contingencies, threats, vulnerabilities and barriers identified in each step is given in Table I below.

Table I: Summary of vulnerability analysis.

Step of analysis	Findings
1. Critical consequences	Blackout of (parts of) the Nordic synchronous area (due to frequency instability following from loss of HVDC power transmission greater than for the reference incident for the system)
2. Critical contingencies	There are currently no second-order contingencies but numerous third-order contingencies assumed to be critical, several of which involve interconnectors connecting to the same country and yet more of which involve interconnectors connected to the same synchronous area. The numbers of such contingencies will increase in the future as new interconnectors are installed.
3. Threats	Blackouts in neighbouring synchronous areas. (Threats only plausibly causing outage of a single interconnector: fires, transportation accidents, avalanches and landslides, flooding.)
4. Vulnerabilities	Proximity of converter stations, insufficient inertial response
5. Influencing factors	Power system inertia and its correlation with HVDC import, situational awareness, inter-TSO communication and coordination
6. Barriers	Inertial response (may become weakened), reserves (existing, but amounts of reserves could be increased when inertia is low), UFLS (existing, but could also consider contracted load shedding), limitation of import or event-driven SPSs based on real-time inertia monitoring or monitoring blackout risk in neighbouring synchronous areas (could be considered)

The vulnerability analysis presented in this paper gives a broad overview of relevant aspects of HVDC contingencies in the Nordic power system. Thus, it can contribute to increase the awareness of the issue and provide input to risk management and emergency preparedness measures at Nordic TSOs and other relevant stakeholders. The overview may also serve as a starting point for more detailed, quantitative analysis of specific aspects. We therefore conclude the paper by suggesting some directions for future work.

Firstly, extensive dynamic analysis could be carried out to assess in detail the consequences for the identified HVDC contingencies. To the best of our knowledge, only some detailed quantitative analyses are available for contingencies involving multiple HVDC interconnectors. Furthermore, since the consequences are heavily dependent on the import/export situation, system inertia etc., dynamic analysis would have to be carried out for multiple representative operating states. Ideally, such analysis should include models of relevant system protection schemes, as discussed in Section 3.6, and the possibility of failure of such barriers [21]. To ensure computational tractability, it could be interesting to test the applicability of aggregated grid models of the Nordic power system, e.g. [3], [22]. To be able to consider operating states expected in the future, it could be interesting to integrate the analysis with market models for the Nordic power system.

Secondly, estimates of the probability of critical consequences could be obtained by statistical analysis of operating states. To estimate the fraction of the time that the contingencies defined as "critical" in this analysis were in fact implying a greater loss of power than for the reference incident, one needs to consider the correlated time series of import/export for each interconnector. Furthermore, HVDC import/export is correlated with system inertia and hence how great power losses the Nordic synchronous area can cope with.

BIBLIOGRAPHY

[1] Statnett, Fingrid, Energinet.dk, and Svenska Kraftnät, "Challenges and Opportunities for the Nordic Power System" (2016).

[2] ENTSO-E Regional Group Nordic, "Nordic and Baltic HVDC Utilization and Unavailability Statistics 2016" (European Network of Transmission System Operators for Electricity, Brussels, 2017).

[3] T. K. Vrana, E. S. Aas, T. I. Reigstad, and O. Mo, "Impact of Present and Future HVDC Links on the Nordic Power Grid" (13th IET International Conference on AC and DC Power Transmission (ACDC 2017), Manchester, UK, 2017).

[4] O. Gjerde, G. H. Kjølle, N. K. Detlefsen, and G. Brønmo, "Risk and vulnerability analysis of power systems including extraordinary events," (2011 IEEE Trondheim PowerTech, 2011.

[5] G. H. Kjølle and O. Gjerde, "Vulnerability analysis related to extraordinary events in power systems," (2015 IEEE Eindhoven PowerTech, 2015).

[6] G. H. Kjølle, O. Gjerde, and Matthias Hofmann, "Vulnerability and security in a changing power system – Executive summary" (report no. TR A5962, SINTEF Energy Research, Trondheim, 2013).

[7] I. Dobson, B. A. Carreras, V. E. Lynch, and D. E. Newman, "Complex systems analysis of series of blackouts: Cascading failure, critical points, and self-organization" (Chaos, vol. 17, p. 026103, 2007).

[8] J. Lamponen, L. Haarla, and R. Hirvonen, "Aspects of HVDC connections in the Nordic region" (CIGRE Symposium: Across Borders - HVDC Systems and Market Integration, Lund, Sweden, 2015, report 212).

[9] G. L. Doorman, K. Uhlen, G. H. Kjølle, and E. S. Huse, "Vulnerability analysis of the Nordic power system" (IEEE Transactions on Power Systems, vol. 21, no. 1, pp. 402–410, 2006).

[10] G. Doorman, G. Kjølle, K. Uhlen, E. S. Huse, and N. Flatabø, "Vulnerability of the Nordic Power System" (report no. TR A5962, SINTEF Energy Research, Trondheim, 2004).

[11] ENTSO-E, "Statistical Factsheet 2016" (European Network of Transmission System Operators for Electricity, Brussels, 2017).

[12] E. Hillberg, “Perception, Prediction and Prevention of Extraordinary Events in the Power System” (PhD thesis, Norwegian University of Science and Technology, Trondheim, 2016).
[13] European Commission, “Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation” (2017).
[14] M. G. Bennett and N. S. Dhaliwal, “A survey of the reliability of HVDC systems throughout the world during 2013-2014” (CIGRE Session, Paris, 2016, report B4-131).
[15] Statnett, “Feilstatistikk” (Available online, in Norwegian: http://www.statnett.no/Kraftsystemet/Nedlastingssenter/Feilstatistikk/. [Accessed: 2018-01-03].
[16] UCTE, “Final Report: System Disturbance on 4 November 2006” (Union for the Co-ordination of Transmission of Electricity).
[17] ENTSO-E Regional Group Nordic, “Future system inertia” (European Network of Transmission System Operators for Electricity, Brussels, 2015).
[18] M. Kuivaniemi et al., “Estimation of System Inertia in the Nordic Power System Using Measured Frequency Disturbances” (CIGRE Symposium: Across Borders - HVDC Systems and Market Integration, Lund, Sweden, 2015, report 234).
[19] P. Du and J. Matevosyan, “Forecast System Inertia Condition and Its Impact to Integrate More Renewables” (IEEE Transactions Smart Grid, vol. PP, no. 99, pp. 1–1, 2017).
[20] M. H. Vasconcelos et al., “Online security assessment with load and renewable generation uncertainty: The iTesla project approach” (2016 International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), Beijing, 2016).
[21] V. V. Vadlamudi, C. Hamon, O. Gjerde, G. Kjølle, and S. Perkin, “On Improving Data and Models on Corrective Control Failures for Use in Probabilistic Reliability Management” (2016 International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), Beijing, 2016).
[22] L. Vanfretti et al., “An open data repository and a data processing software toolset of an equivalent Nordic grid model matched to historical electricity market data” (Data Brief, vol. 11, no. Supplement C, pp. 349–357, 2017).