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Market Integration of HVDC Lines: Cost Savings from Loss Allocation and Redispatching

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SUMMARY

In the last decades, over 25'000 km of High-Voltage Direct-Current (HVDC) lines have been gradually integrated to the existing pan-European HVAC system. From a market point of view, HVDC interconnectors facilitate the exchange of energy and ancillary services between countries. In the Nordic region, many interconnectors are formed by HVDC links, as Scandinavia, Continental Europe and the Baltic region are non-synchronous AC systems. In this regard, this paper presents two cost benefit analyses on the utilization of HVDC interconnectors in the Nordic countries: in the first we investigate the utilization of HVDC interconnectors for reserve procurement and, in the second, we assess the implementation of implicit grid losses on HVDC interconnectors in the day-ahead market.

The first analysis is motivated by some real events in 2018 where the inertia of the Nordic system dropped below a critical level and the most critical generating unit, a nuclear power plant in Sweden, was redispatched to guarantee the security of the system. In our analysis, we investigate the cost savings of using HVDC lines for frequency support using the Emergency Power Control (EPC) functionality instead of redispatching. Our results confirm that the frequency of redispatching actions will increase in the future and show the substantial cost savings from the utilization of HVDC lines for frequency support.

The second analysis is based on the proposition of Nordic Transmission System Operators (TSOs) to introduce linear HVDC loss factors in the market clearing. With our analysis, we show that linear loss factors can unfairly penalize one HVDC line over the other, and this can reduce social benefits and jeopardize revenues of merchant HVDC lines. In this regard, we propose piecewise-linear loss factors: a simple-to-implement but highly-effective solution. Moreover, we demonstrate how the introduction of HVDC loss factors is a partial solution, since it disproportionately increases the AC losses. Our results show that the additional inclusion of AC loss factors can eliminate this problem.

KEYWORDS

Corrective Control, Emergency Power Control, Electricity Market, Fast Frequency Reserves, HVDC, Losses, Loss Factor, Redispatch, RG Nordic, Remedial Action.

I. INTRODUCTION

The world's first commercial High-Voltage Direct-Current (HVDC) link was delivered by ABB in the 1950's. Since then, HVDC has become a common tool in the design of transmission grids, especially when technical limitations of AC transmission come into play. Indeed, the transmission of power in the DC form presents several benefits, both from technical and economical points of view [1], [2]. First, beyond a certain distance, an HVDC line has lower power losses than an HVAC of the same capacity. Second, with HVDC no reactive compensation is needed, resulting in no length limitation for submarine or underground power cables. Moreover, HVDC enables the connection of non-synchronous areas, allowing both inter-area and cross-continental long-distance power flows.

Evidence of the economic value of HVDC can be found by looking at the evolution of prices in different electricity markets. Installing transmission capacity means allowing for power exchanges between low- and high-price areas, reducing price differences and increasing social welfare. For example, Storebælt, the connection between the two bidding zones in Denmark (DK1 and DK2), has decreased electricity prices in Eastern Denmark by 2 €/MWh in average since 2010, resulting in 20-25 million euro savings per year for Danish consumers [3]. Another example is NordBalt, the link between Sweden and Lithuania: electricity prices in Lithuania dropped by 30% when the link was operated for the first time in 2016, followed by an average decrease of 5 €/MWh compared to before 2016 [4].

Furthermore, HVDC is attracting increasing attention because of the full controllability of power flows; depending on the technology of the converter stations, both active and reactive power flows can be controlled. This property can help improve the performance of AC power systems by means of additional control facilities, such as in the provision of frequency support.

Frequency stability is becoming a concern for many Transmission System Operators (TSOs) because of the gradual decrease of system inertia. This is mainly caused by the replacement of conventional synchronous generators with inverter-based non-synchronous units. Therefore, power systems are becoming more sensitive to power disturbances and TSOs have to bear additional costs for system security [5]. The current procedure to ensure N-1 security during low inertia periods is the reduction of the dimensioning incident (DI) – the largest disturbance. In Regional Group Nordic (RG Nordic), this is the loss of the most critical generating unit, a 1450 MW nuclear power plant in Sweden – Oskarshamn 3. During Summer 2018, the power output of Oskarshamn 3 was reduced by 100 MW three times [6]. The costs of these *preventive* actions for Nordic TSOs amount to 0.8 million euros. This calls for a reassessment of whether there exist more cost-efficient options which guarantee safe operation while avoiding expensive redispatching actions.

According to [7], the control scheme of all HVDC converters must be capable to operate in frequency sensitive mode, i.e. the transmitted power is adjusted in response to a frequency deviation. For this reason, an HVDC link connecting asynchronous areas can be used as a vehicle for Frequency Containment Reserves for Disturbances (FCR-D): to limit the instantaneous frequency deviation (IFD) in case of disturbance, the necessary active power can be imported from the neighboring system using the Emergency Power Control (EPC) functionality [8]. Given the high number of interconnections formed by HVDC links between RG Nordic and the neighboring groups, this *corrective* action could represent a valid alternative to expensive *preventive* redispatching.

On the one hand, HVDC interconnectors are of great value for society as they facilitate the exchange of energy and ancillary services between countries. On the other hand, HVDC operation comes with a cost for TSOs as HVDC interconnectors produce a non-negligible amount of losses that is currently not considered in the market clearing. During periods of zero price difference between neighboring bidding zones, due to equal zonal prices, the cost of HVDC losses is transferred to local Transmission System Operators (TSOs) who must procure sufficient power to cover these losses. The problem is especially pronounced in transit countries, as in the case of Denmark.

Power losses are generated both by AC and DC interconnectors; however, because of their properties, HVDC lines are often significantly longer than AC lines and thus the operation of such lines leads to a considerable amount of losses. In 2017, the total losses by all the HVDC links in the Nordic region was equal 1.14 TWh [4]. Compared to the total amount of losses in the Nordic AC system, which is about 10 TWh, this value accounts for 10% [9]. However, given that all HVDC lines connect control areas operated by different TSOs, it is often unclear who should pay for these losses.

Recently, Nordic TSOs have proposed the introduction of HVDC loss factors (also called “implicit grid loss”) to implicitly account for losses when the market is cleared [10]. The introduction of loss factors will force a price difference between the two connected bidding zones that is equal to the marginal cost of losses. This will have two advantages: first, HVDC losses are no longer needed to be purchased by TSOs in the day-ahead market but are directly paid by the market participants who create them and, second, losses are implicitly minimized, resulting in cost savings for TSOs and the society. The proposed loss factors are linear approximations of the HVDC system losses. The following questions arise: are linear loss factors a good representation of HVDC losses? Is the introduction of loss factors for only HVDC interconnectors the best possible action?

In this regard, this paper presents a cost benefit analysis on:

- The utilization of HVDC interconnectors for reserve procurement, in particular for FCR-D, using the EPC functionality to fulfil the N-1 security criterion.
- The implementation of implicit grid losses on HVDC interconnectors in the day-ahead market.

For the first analysis, we start by investigating what is the cost of frequency balancing using HVDC in the form of EPC, and then compare this alternative to the current paradigm from an economical point of view. The analysis is carried out for three scenarios (2018, 2020, 2025), using historical data from Nord Pool (2018), Rate of Change of Frequency (RoCoF) estimations from Svenska kraftnät (2020) and inertia forecasts from Nordic TSOs (2025). From these, the volume of FCR-D (EPC) vs. redispatch is estimated, and the cost of HVDC EPC is calculated based on two pricing cases considering different combinations of HVDC capacity reservation and frequency reserve pricing.

For the second analysis, we compare the results of different simulations where the day-ahead market is cleared for each hour of the year (8760 instances) using data from 2017. Each simulation is carried out with different combinations of AC and HVDC loss factors, using different linearization techniques.

The rest of the paper is organized as follows. Section II provides background information about the Nordic power system and electricity market. Section III presents the results of the cost benefit analysis on the utilization of HVDC lines for frequency support and Section IV presents the analyses on the introduction of loss factors in the Nordics. Section V gathers conclusions and final remarks.

II. NORDIC POWER SYSTEM

The Nordic transmission network is divided into two asynchronous Regional Groups (RGs): Western Denmark is connected to Continental Europe (UCTE) and, thus, it is operated at a different frequency from the rest of the Nordic countries. A schematic representation of the transmission network is depicted in Figure 1 (left).

Western Denmark is connected to Germany through different AC lines, along a corridor which is usually referred to as *east coast corridor*. Three HVDC links (*Skagerrak*, *Kontiskan* and *Storebælt*) connect Western Denmark to Norway, Sweden and Eastern Denmark. Recently, *COBRACable* HVDC link has become operational, allowing power exchanges between Western Denmark and the Netherlands.

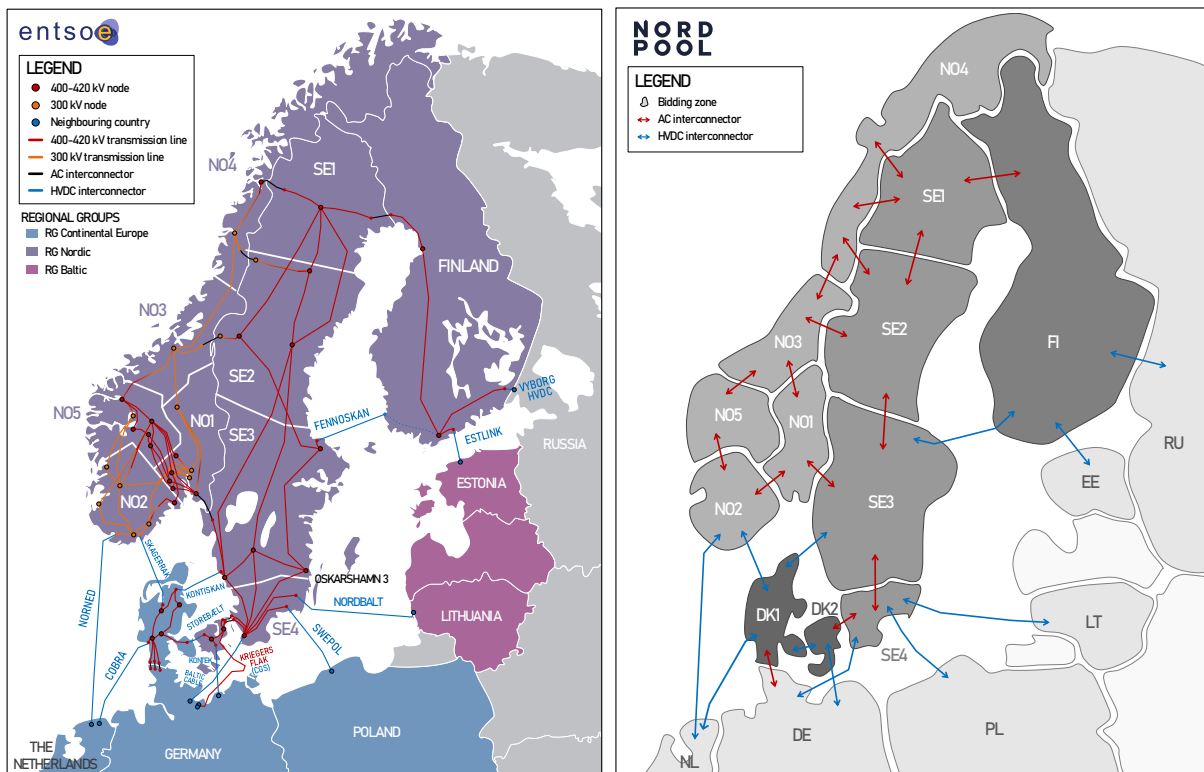


Figure 1: Nordic power grid and regional groups (left), Nordic market model (right).

RG Nordic is connected to RG Continental Europe through five additional HVDC links: *NorNed* (Norway-Netherlands), *Kontek* (Eastern Denmark-Germany), *Baltic cable* (Sweden-Germany) and *SwePol* (Sweden-Poland). In addition, *Kriegers Flak (Combined Grid Solution)* provides connection between Eastern Denmark and Germany (AC cable and back-to-back HVDC converter), integrating offshore wind farms along its path. Finally, three other HVDC links connect RG Nordic to RG Baltic: *NordBalt* (Sweden-Lithuania), *Estlink* (Finland-Estonia) and *Vyborg HVDC* (Finland-Russia).

The generation mix in the Nordic countries can be found in [11]. Almost half of the generation in Denmark comes from wind farms, while the remaining is mainly fossil fuel based (natural gas and coal). In Norway, more than 90% of electricity is produced by hydro power plants. Hydro power plants contribute to half of the generation in Sweden as well, the remaining capacity is divided between nuclear power plants, wind farms and oil-based thermal units. In Finland the generation mix is more heterogeneous; half of the Finnish electrical energy is produced by nuclear power plants and coal-based thermal units.

As for the rest of Europe, the system is operated at 50 Hz with a standard range of ± 100 mHz; Frequency Containment Reserves for Normal operation (FCR-N) are deployed to keep frequency within the normal band [12]. When frequency drops below 49.9 Hz, FCR for Disturbance (FCR-D) are activated to mitigate the impact of the disturbance and stabilize the frequency, while Frequency Restoration Reserves (FRR) are used to restore the frequency back to the nominal value. The maximum acceptable Instantaneous Frequency Deviation (IFD) is 1000 mHz and, in case frequency drops below 48.8 Hz, loads are shed to avoid total system blackout [13].

The methodology for calculating the FCR-D requirement consists in a probabilistic approach which aims at reducing the probability of insufficient reserves, based on different generation, load and inertia patterns [14]. The considered dimensioning incidents are the loss of critical components of the system, such as large generators, demand facilities and transmission lines. Currently, the dimensioning incident in RG Nordic is the loss of Oskarshamn 3, a 1450 MW nuclear power plant in Sweden (located in the bidding zone SE3) [15].

Finally, in the Nordic region, as for the rest of Europe, a zonal-pricing scheme is applied. This means that the system is split into several bidding zones and the intra-zonal network is not included in the market model. When the market is cleared, a single price per zone is defined. In case of congestion, price differences arise only among zones [16]. The current day-ahead market coupling is based on Available Transfer Capacity (ATC). In the day-ahead time frame, TSOs calculate ATCs based on the network situation and communicate them to the market operator. These values are used as bounds for inter-zonal power transfers in the spot-market. When the power exchanges are defined, TSOs manage the physical flows to guarantee these transactions and, if necessary, counter-trade at their own cost [17]. Figure 1 (right) shows the different bidding zones in the Nordic area and the equivalent interconnectors.

III. SHARING RESERVES THROUGH HVDC INTERCONNECTORS

In 2018, the power output of Oskarshamn 3 has been reduced three times, due to system inertia dropping below the acceptable limit. Such low inertia periods are considered extraordinary events where the security of the system is in danger, thus Svenska kraftnät can communicate the limitation on Oskarshamn 3 at any market stage. The low-inertia events of 2018 were forecast after the day-ahead market was cleared, and thus the reduction of Oskarshamn 3 was performed similarly to normal redispatching. When this happens, the producer should receive market compensation for the costs associated with the power limitation. First, by decreasing its power output, the producer incurs opportunity costs that are equal to what they would have received for producing an amount of power equal to the reduction. Second, by moving away from the nominal power output, extra costs are incurred due to lower efficiency (as a rule of thumb, for nuclear power plants, one can say that half of the fuel which is not used during the power reduction is wasted) [8]. Third, the decrease of power production of nuclear power plants results in a temperature transient, inducing a cumulative aging of the unit and increasing the risk of failure [8]. Finally, depending on the length of the reduction period, nuclear units might take from 6 to 72 hours to get back to their nominal power output (for example, if the limitation is performed for up to 80% of the operational period, the output cannot be increased for the remaining time) [8]. For each event of 2018:

- Oskarshamn 3 was compensated for the opportunity cost of not producing 100 MW (the compensation was equal to 49 SEK/MWh - approx. 4.64 €/MWh);
- Oskarshamn 3 was compensated for reduced efficiency and other costs associated with the power limitation (fixed amount equal to 50'000 SEK - approx. 4'740 €);
- the substitute power was procured from other generators in the regulating market (Nord Pool regulating price [18]).

As an alternative to *preventive* redispatching, HVDC lines could provide frequency support in case of disturbance. This remedial action relies on the fact that HVDC converters, equipped with fast frequency controllers, can adjust the power flow in response to frequency deviations. This control mode is referred to as Emergency Power Control (EPC). This measure falls in the category of *corrective* actions: even if the loss of Oskarshamn would lead to an IFD greater than 1000 Hz with the expected inertia level of the system, the output of Oskarshamn 3 is not reduced in advance. In case the dimensioning incident occurs (e.g. because of an outage), the EPC is immediately activated and the necessary power to keep the frequency within the limits is injected through HVDC.

Different control strategies can be used to define the response of HVDC converters. The currently implemented strategy is based on stepwise triggers: depending on the size of the power deviation and the corresponding frequency variation, a constant amount of power is injected to improve the frequency response of the system. For our analysis the injected power is calculated based on the reduction of the dimensioning incident with an efficiency of 0.87, as it can be seen in Figure 2 (blue plot). Indeed, from a frequency point of view, injecting a certain amount of power through HVDC is not as effective as decreasing the disturbance in a preventive way.

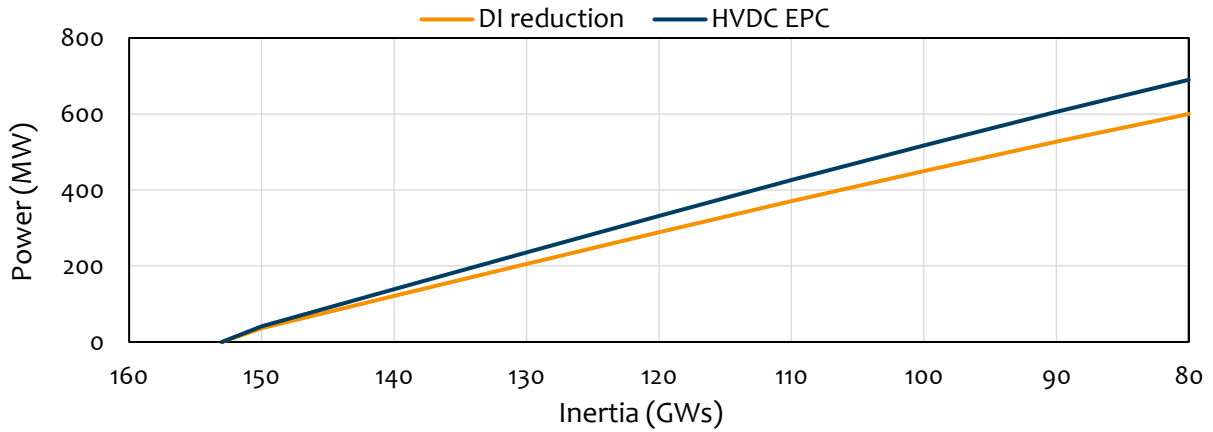


Figure 2: Required DI reduction and injected power by HVDC EPC, respectively, to maintain the N-1 security criterion in the Nordic system with low inertia.

The possible costs of HVDC EPC are the reservation of HVDC capacity and the procurement of primary reserves in the neighboring countries. For our analysis, we assume that this control method is used only to contain the frequency within the limit, while the frequency restoration uses local reserves. Since primary reserves are not paid for the energy they produce, there are no extra costs for the activation of reserves in case of contingency. In addition, the reservation of HVDC capacity and the procurement of reserves for HVDC EPC are only needed for those hours when the frequency can fall below 49.05 Hz whereas the reduction of the dimensioning incident would be prolonged for more hours due to technical limitations. Finally, the focus of the analysis is on four interconnectors - Baltic Cable, Kontek, SwePol and NorNed - and the injected power is equally shared among the four links.

The calculation of the cost of using HVDC for frequency support is based on two pricing cases. The first case, “NoCosts”, is based on the consideration that UCTE is a large system with more than 3 GW of reserves and there is no need to procure additional reserves. It is reasonable to assume that there might be, in the future, an agreement between Nordic TSOs and TSOs in RG Continental Europe and RG Baltic for the exchange of reserves in situations where operational security is in danger or just to increase system security. Regarding HVDC capacity, this case considers a certain availability of capacity or the possibility to overload HVDC lines for a short amount of time, with no need of reserving capacity. The second case, “Reserves&HVDC”, considers a possible future situation where there is a European market for reserves, and Nordic TSOs are requested to procure the necessary primary reserves through this platform. This seems to be the direction that European countries are taking, as described in [19] for automatic activated FRR. Moreover, the reservation of HVDC capacity is assumed to come with a cost. This is considered also in [8], where they assume there might be a reservation cost for HVDC in the future. The choice of these cases has been made to give a possible range of costs, since they represent the upper and lower bound on the cost of this remedial action. Whether Nordic TSOs will pay for reserves or HVDC capacity, or both, the costs calculated based on the second case, *Reserves&HVDC*, represent the maximum costs they will bear. Similarly, considering *NoCosts* for the utilization of HVDC gives an indication of the maximum cost savings that could be achieved.

The gradual decrease of system inertia is classified as one of the major future challenges for the Nordic Power System [20]. For this reason, the cost savings analysis presented in this paper starts with the events of 2018 and continues with two future scenarios for the years 2020 and 2025. For 2025, two scenarios are considered: “full nuclear” (2025 FN), based on the current situation with nuclear power plants fully dispatched, and “half nuclear” (2025 HN), where half of the nuclear production is replaced by wind, solar and HVDC imports. The methodology for the calculation of the necessary reduction of the dimensioning incident (DI) varies across scenarios based on the availability of data and it is fully described in [21].

		2018	2020	2025 FN	2025 HN
Current paradigm	Down-regulation	0.08	0.16	1.11	4.18
	Up-regulation	0.72	1.44	11.25	43.09
	Total cost	0.80	1.60	12.36	47.27
HVDC EPC	HVDC capacity	0.05	0.10	0.77	2.95
	Primary reserves	0.18	0.35	2.74	10.49
	Total cost	0.23	0.45	3.51	13.44

Table 1: Cost of the two considered remedial actions – current paradigm and HVDC EPC. All the costs are in million euros. For the cost of HVDC EPC, only the Reserves&HVDC scenario is displayed.

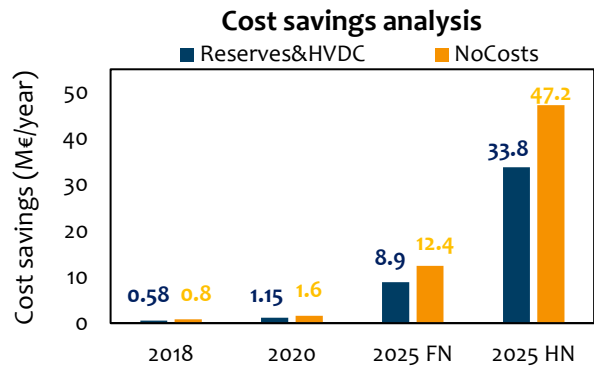


Figure 3: Cost savings by using the EPC functionality of HVDC lines for frequency support.

The number of hours with inertia below the acceptable limit is respectively 166, 294, 673 and 1901 for the four scenarios (2018, 2020, 2025 FN and 2025 HN). The average length of three low-inertia periods in 2018 was 55 hours. In order to estimate the number of events in 2020 for the fixed-cost compensation, the same average length was considered, while we assume it increases to 80 hours in 2025 for the *full nuclear* scenario and to 90 hours for the *half nuclear* scenario (this is done in order to not overestimate fixed costs). The resulting number of events are 5, 9 and 22 in 2020, 2025 FN and 2025 HN, respectively. During these hours, the amount of redispatched energy is calculated according to Figure 2 and it is respectively 16.60, 33.12, 257.88 and 987.51 GWh.

The cost of reducing the dimensioning incident is provided in Table 1. In summer 2018, the cost of downregulating Oskarshamn 3 is calculated to be around 80 thousand euros, while the procurement of the substitute power costed about 720 thousand euros, resulting in a total cost of around 0.8 million euros. The future projections suggest that there will be more low-inertia periods in 2020 and the redispatch costs will be doubled, reaching 1.6 million euros. Depending on the generation mix considered in the *full nuclear* or *half nuclear* scenarios, the cost of reduction of the dimensioning incident will range between 12.3 and 47.2 million euros per year by 2025.

In 2018, under the assumptions of the Reserves&HVDC case, the costs of using HVDC can be divided into 50 thousand euros for reserving HVDC capacity and 175 thousand euros for procuring primary reserves in the three neighboring countries, for a total cost of 225 thousand euros. Similar to the preventive reduction of Oskarshamn 3, these costs are expected to double in 2020, reaching 450 thousand euros. Then, depending on the generation mix, these costs will range between 3.5 and 13.5 million euros per year by 2025. The costs based on the Reserves&HVDC case are reported in detail in Table 1. On the contrary, if the assumptions of case NoCosts take place, then there are no costs associated with this remedial action.

The cost saving comparison between DI reduction (current paradigm) and HVDC EPC is provided in Figure 3 for all the considered scenarios. The cost of the current paradigm is used as reference, and the savings from HVDC EPC based on the two pricing cases are compared. Clearly, the economic benefit of using HVDC for frequency support during low-inertia periods can be seen even today, where potential cost savings in summer 2018 are between 0.58 and 0.8 million euros depending on the considered costs. Increasing savings are estimated for next years with potential savings up to 1.6 million euros per year by 2020. Finally, in 2025, savings are potentially in the range of 8.84-12.36 million euros per year with the current capacity of nuclear power plants (*full nuclear*), or in the range of 33.82-47.26 million euros per year if the capacity of nuclear power plants is halved (*half nuclear*).

IV. HVDC LOSS FACTORS IN MARKET CLEARING

Nordic TSOs have proposed to introduce loss factors for HVDC lines to avoid HVDC flows between zones with zero price difference. The proposal has already gone through the first stages of the

process and it is currently under investigation for real implementation in the market clearing algorithm. In [22], we developed a rigorous framework to assess this proposal; the results showed that the benefits of such a measure depend on the topology of the investigated system. In this paper, we present the results of our analyses on a detailed market model of the Nordic countries.

The focus of the analysis is on the differences between linear and piecewise-linear loss factors and between HVDC and AC+HVDC loss factors. Implementing such measures in real systems is possible: for instance, piecewise-linear loss factors are already used in real power exchanges, e.g. New Zealand Exchange (NXZ) [23], and several power markets in the US already use sensitivity factors to determine AC losses [24], [25]. Four simulations are run considering different loss factors at a time:

1. No loss factors (reference case);
2. Linear HVDC loss factors;
3. Piecewise-linear HVDC loss factors;
4. Piecewise-linear AC and HVDC loss factors.

In each simulation, the market is cleared for each hour of the year (8760 instances) using data from 2017. It is important to mention that all the cost-benefit analyses are limited to the introduction of loss factors in the intra-Nordic interconnectors, that means Fennoskan, Skagerrak, Storebælt, Kontiskan and only the AC interconnectors of RG Nordic. Indeed, the power exchanges with neighboring countries are fixed to the real exchanges, and so are the flows on the interconnectors (becoming unresponsive to any change introduced by loss factors). Moreover, because of the zonal-pricing scheme, intra-zonal losses are not considered in the analysis: all the presented results are limited to losses on the interconnectors.

With the inclusion of HVDC loss factors in the market, HVDC losses are implicitly considered when the market is cleared. Since losses appear in the power balance equation, they represent an extra cost and the solver will try to minimize them. Given that only HVDC losses are considered, the solver will use HVDC interconnectors only if necessary, i.e. in case of congestions in the AC system or for exchanges between asynchronous regions. For the same reason, when forced to use HVDC interconnectors, the solver will look at which path produces the least amount of losses. In case of linear loss factors, the slope of the linear loss functions is the discriminating factor. This might become a problem in a situation with different parallel HVDC paths, as it is the case, for example, of Skagerrak, Kontiskan and Storebælt in Western Denmark (Figure 5 - left). In such a situation, the solver will direct the flow over the line with the smallest slope (in the left chart of Figure 4, the blue one) and only when its capacity is fully utilized it will start directing the flow towards the line with the second smallest slope (the orange one), and finally towards the remaining line (the red one).

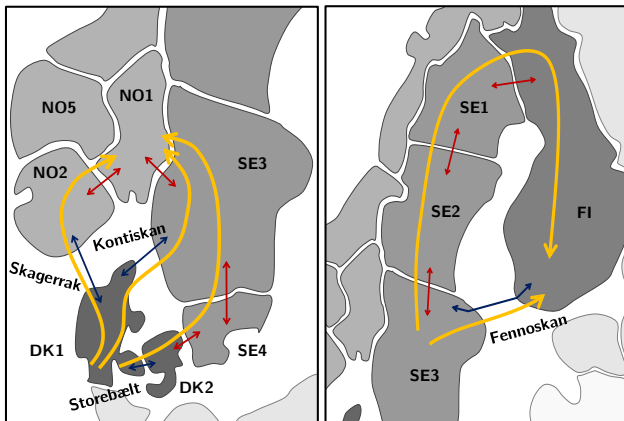


Figure 5: Example of flows on parallel HVDC paths (left) and on parallel AC and HVDC paths (right).

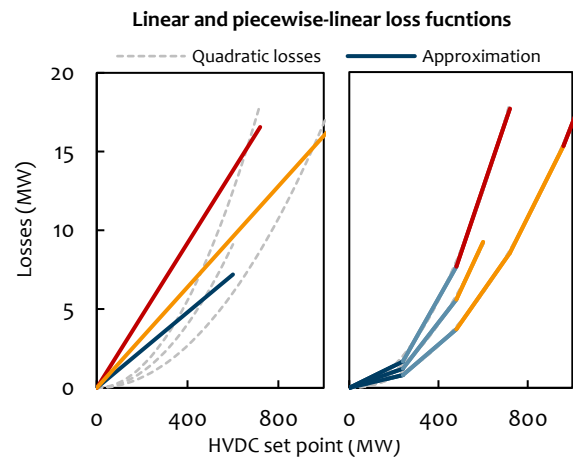


Figure 4: Linear (left) and piecewise-linear (right) loss functions for Skagerrak, Storebælt and Kontiskan. The different colors refer to the slope of the lines.

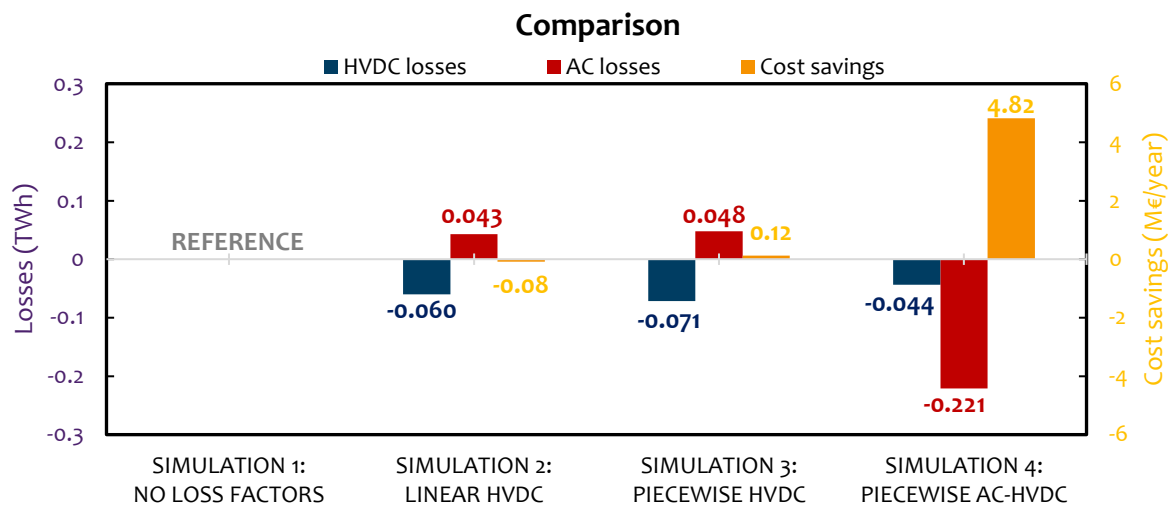


Figure 6: Comparison of the simulation with focus on AC and HVDC losses. The reference case is the simulation without loss factors.

With piecewise-linear loss functions, the solver finds the path that produces the least amount of losses by moving back and forth from one loss function to the other. As with linear loss factors, it will start with the HVDC line with the smallest slope. However, since the slope changes in the next segment, the solver will start directing the power flow towards other lines if the slope of those segments is smaller (in the right chart of Figure 4, all the blue segments). It will move back to the first line only when there are no other segments with smaller slopes, i.e. it will move to orange segments when there are no more blue segments, and so on. In this way, the quadratic nature of losses is better represented, allowing the solver to identify the best path and better distribute the power flows among the HVDC lines.

Similarly, with the inclusion of only HVDC loss factors, the solver will see HVDC lines as expensive alternatives to AC lines, whose losses are not considered when the market is cleared: if there exist parallel AC and HVDC paths, the solver will always prefer the AC option. This is the case, for example, of Fennoskan, the HVDC link connecting Sweden and Finland (Figure 5 - right). In this case, if implicit grid loss is implemented on Fennoskan and not on the AC interconnectors SE3-SE2, SE2-SE1 and SE1-FI, the solver will always try to reroute the power across the AC path. However, losses are produced in the AC system as well and, by reducing the flow on some HVDC interconnectors, we might disproportionally increase losses in the AC system. The only way to minimize losses and maximize social benefits is to include loss factors for AC interconnectors as well. By doing so, the solver will be able to identify the path producing the least amount of losses.

The comparison of the four simulations is shown in Figure 6, where blue bars represent HVDC losses, red bars AC losses and yellow bars cost savings. As expected, in simulation 2 and 3, the reduction of HVDC losses comes together with an increase of AC losses. The net reduction of losses is positive, meaning that the introduction of only HVDC loss factors can be beneficial; however, the resulting cost savings in simulation 2 are negative. This happens because linear loss factors result in a bad approximation of losses which are often overestimated, meaning that unnecessary power is provided by generators (at a higher cost for society). This does not happen with piecewise-linear loss factors because they better represent HVDC loss functions.

The results of simulation 4 show that it is possible to decrease the sum of AC and HVDC losses by 12% (compared to simulation 1, where losses on the interconnectors amount to 2.42 TWh) by introducing piecewise-linear loss factors for AC and HVDC interconnectors, while this is limited to 0.7% with only linear HVDC loss factors and to 0.9% with only piecewise-linear HVDC loss factors. Concerning the cost savings, they increase moving from left to right in Figure 6, showing the progressive benefit of having piecewise-linear loss factors and AC loss factors. In particular,

simulation 4 with piecewise-linear loss factors for both AC and HVDC interconnectors results in cost savings of 4.82 million euros per year.

V. CONCLUSION

In the Nordic countries, more than 10 interconnectors are formed by HVDC links, and many new projects are under construction or investigation. Based on this consideration, this paper explores the potential benefit of using HVDC links for the exchange of ancillary services between countries and investigates different solutions for the inclusion of HVDC losses in the market.

The first analysis was motivated by low-inertia events occurred in 2018, during which Svenska kraftnät had to reduce the output of Oskarshamn 3 to guarantee N-1 security, incurring in costs of about 0.8 million euro. Our results show that, if HVDC is used in the form of Emergency Power Control, these costs could be reduced to 0.23 million euro (or cancelled out). The extension of the analysis to year 2020 and 2025 confirms that many more low-inertia periods can be expected in the future, calling for more redispatching actions. In this regard, the method proposed in this paper would reduce the costs by 70%, resulting in cost savings in the range of 8.84-47.2 million euros per year by 2025.

The second analysis comes from the proposition of Nordic TSOs of including linear loss factors for HVDC lines to avoid flows between zones with zero price difference. Our results show that there is room for improvement in two directions. First, by using piece-wise linear loss factors. This would lead to a better representation of loss functions and to an optimal distribution of power flows, resulting in a further decrease of losses and higher cost savings. Second, by introducing also AC loss factors. This would allow for the identification of the optimal paths that leads to the least amount of losses, maximizing cost savings.

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