# Stability Assessment of VSC-HVDC Connected Large-Scale Offshore Wind Power: a North-Sea Region Case Study

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***Abstract*—Large amounts of offshore wind power plants (WPP) connected through voltage sourced converter high-voltage DC (VSC-HVDC) technology can have significant consequences for the dynamic behavior of the related onshore AC systems. This paper explores the rotor angle stability effects of the integration of 35 GW of wind power in the North Sea, connected to the European mainland, Nordic, and UK power systems. It investigates the influence of the VSC-HVDC topology (e.g. radial versus meshed) and the DC power flow control strategy on the dynamic response of the connected power systems after common disturbances such as the outage of an offshore wind power plant and short-circuits in the AC grid. The results show a significant influence of the power flow control method applied. Radial VSC-HVDC connections for offshore WPPs can be designed such that the stability effects can be minimized, whereas meshed links may propagate disturbances from one synchronous area to another.**

***Index Terms*—Offshore Wind Power, VSC-MTDC, Transient Stability**

## I. Introduction

IN the past decade, the deployment of renewable energy sources (RES) has become one of the spearheads of European Union policy. For the time horizon of 2020, the amount of installed wind power in Europe is foreseen to increase to 192 GW [1], the majority of which clustered in wind power plants (WPPs). For the 2030 time horizon, even more ambitious goals are currently being considered [2].

In the meantime, developments in power electronic grid interfaces enable the grid connection of clustered RES on the full range of transmission voltage levels. This allows the connection of WPPs far offshore through high-voltage DC schemes based on voltage sourced converter technology (VSC-HVDC). VSC-HVDC can potentially interconnect offshore WPPs to each other or to multiple infeed points, which may eventually lead to multi-terminal HVDC (VSC-MTDC) [3].

The dynamic grid integration of these systems becomes more and more challenging and demands careful consideration in terms of operation and control in the several time frames of interest. Despite the favorable controllability of VSC-HVDC [4], the power electronic interface is vulnerable especially during faults. This manifests itself by the fault ride-through (FRT) strategy, current limiting, and active power control actions taken to keep the VSC-HVDC scheme connected during and after a disturbance. These phenomena are acting on the rotor angle stability time-frame of interest and it is hence imperative to study the dynamic behavior of the hybrid AC/DC power system.

In this paper we investigate the consequences of the topology and DC power flow control strategy of a future VSC-MTDC structure in the North-Sea region on the stability of the connected synchronous areas. As such, the results of this paper can support more specific and detailed grid integration studies by indicating what effects on AC-system dynamic behavior can be expected and under which circumstances VSC-HVDC can impair power system stability. Compared to related research efforts, this paper 1) integrates a total of 35 GW offshore wind entirely through VSC-HVDC, 2) compares a radial with a multi-terminal VSC-HVDC structure provided the same unit commitment and generator loading at the AC side, and 3) shows the influence of combining several DC power flow control strategies on the dynamic behavior of the connected synchronous areas.

The commercial software tool PSS®E has been used for the modeling of standard components. By contrast, dedicated dynamic models have been developed in order to include the electro-magnetic interactions present in VSC-HVDC systems. These models are subsequently implemented inside a network model that accurately represents the dynamic behavior of the Dutch power system and its neighbors. This grid model was adjusted for the 2025 horizon. Subsequently, several AC-system disturbances are investigated and compared for several HVDC-system power flow control strategies and two different offshore topologies (i.e. radial versus multi-terminal).

The paper is organized as follows. First, the VSC-HVDC modeling and the improvements to existing work are explained. It continues with describing the AC and DC dynamic models, and the description of the VSC-MTDC system. Then, several case studies are discussed, showing the influence of three different DC-side power flow control strategies under several disturbances. The paper ends with conclusions.

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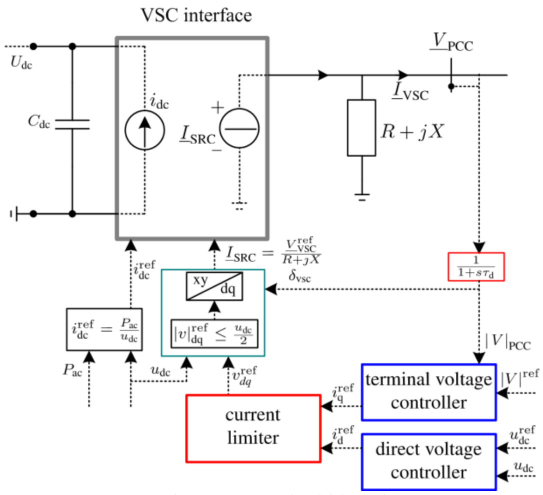


Fig. 1: VSC-HVDC control structure and grid interface.

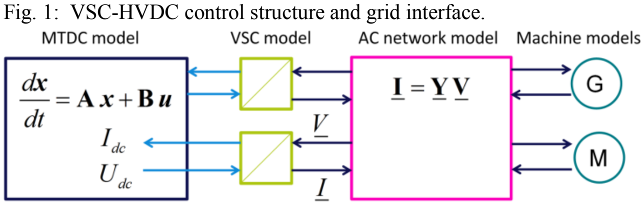


Fig. 2: Control structure and interfaces for incorporating the VSC-MTDC model into AC transient stability simulations.

## II. VSC-MTDC Modelling

### *A. Dynamic modeling requirements*

Rotor angle stability concerns the electro-mechanical interactions between rotating equipment during and after faults [5]. Rotor angle stability is divided in two sub-categories, the transient stability and small-signal stability of the power system. Severe dynamics with non-linear nature after a short-circuit inside the AC system are typical transient stability behavior, while for instance losing a large offshore WPP acts in both the transient stability and small signal stability time-frame of interest, especially during the post fault period.

Despite their excellent controllability, VSC-HVDC systems show non-linear and discontinuous behaviour during faults, most prominently caused by the lack of intrinsic overcurrent capability, DC-side voltage balancing logic, and other limiting schemes. These mechanisms cause DC-side dynamics (electromagnetic transients) to interact with the electro-mechanical dynamics inside the AC systems, and influence rotor angle stability there. A realistic inclusion of the above-mentioned controls requires a detailed representation of the DC-side transients, while the AC-part may be represented in a quasi-stationary fashion [6], allowing large-scale system studies to be performed in reasonable computation time.

### *B. Multi-rate simulation improvement of the dynamic VSC-HVDC Model*

Fig. 1 shows the VSC controls adopted in this work as well as the AC and DC grid interfaces applied. In PSS®E , the *averaged* VSC model is implemented as a user-written generator-type model, whereas a separate module was developed for the dynamic model of the HVDC transmission [7] (see Fig 2).

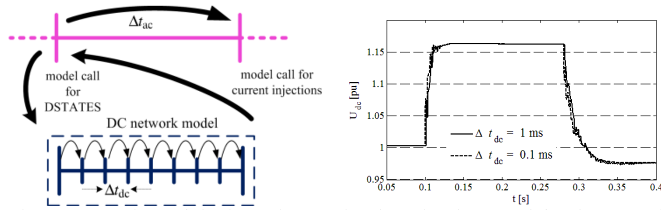


Fig. 3: Overview of the inner integration loop implemented for the DC grid model. Left: implementation. Right: direct voltage response for two different values of the inner integration time step $\Delta t_{dc}$.

The detailed representation of the HVDC link dynamics puts a computational burden on the simulation environment as the overall time step-size for numerical integration must be decreased, hence leading to long simulation times for realistic hybrid AC/DC systems. This issue was resolved by implementing *multi-rate* techniques for the HVDC dynamic model and the fault ride-through (FRT) logic. Such methods separate the numerical integration of sophisticated models from the normal solution routine. In this way, only those models that need high detail are simulated using a small time step-size for numerical integration, i.e. $\Delta t_{dc}$, whereas the remainder of the system is simulated at the normal time step size (i.e. $\Delta t_{ac} \approx 10\,\text{ms}$).

The implementation of this method into PSS®E is depicted in Fig. 3, which shows the procedure of one particular calculation step of the integration routine, and the response of the VSC-HVDC model after an onshore test disturbance. This improved implementation led to a simulation speed improvement of factor 7 with respect to a conventional stability simulation, while the simulation accuracy was not compromised.

### *C. DC power flow control strategies*

The main difference with AC-side active power control is that not the kinetic energy of the generators is the main energy carrier, but the electrostatic energy inside the DC system, which results in control system time constants that are several orders of magnitude smaller. This paper studies the impacts of three different DC system power flow control strategies:

*1) Direct voltage droop control:*

This is the DC equivalent of the conventional AC primary and secondary control strategies. This method controls the VSC's AC-side power according to a droop characteristic that is common to the entire HVDC system [8, 9]. The main advantage is that the variations in direct voltage are seen by all VSCs, which makes the method reliable and its implementation possible without advanced communication techniques.

*2) Fixed active power control:*

This type of control is the DC equivalent of generating units that do not contribute to primary control, and hence track a fixed power set point irrespective of the direct voltage. Inside the $P_{dc}$ - $U_{dc}$ characteristic, this is represented by a vertical line. This can only be applied in case at least one other VSC accounts for variations in the direct voltage.

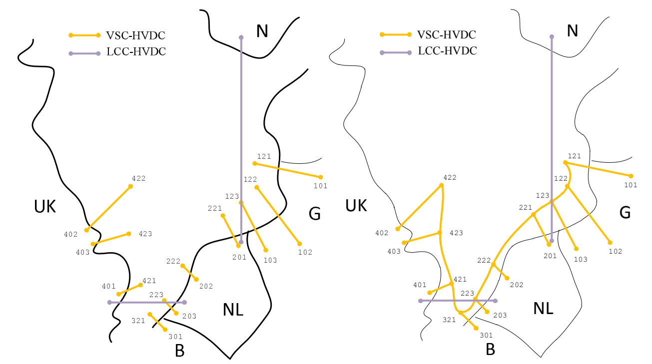


Fig. 4. VSC-HVDC system configuration. Left: radial; right: U-shaped multi-terminal.

TABLE I: IMPORT TO (-) AND EXPORT FROM (+) THE NETHERLANDS IN MW, FOR THE INITIAL POWER FLOW SITUATION USED FOR THE ANALYSIS.

| Belgium | Germany | United Kingdom | Norway |
|---|---|---|---|
| +1474 | -3750 | +1000 | -700 |

*3) A combination of fixed active power control and DC voltage droop control:*

The abovementioned two control methods can be combined by excluding some VSCs from participation direct voltage control, and thereby realizing more sophisticated system responses. This will be applied in some of the case studies in Section IV to dynamically separate two synchronous areas from each other.

## III. SIMULATION SETUP

### A. DC Network Requirements and Configuration

On European policy level, efforts are being made to foster the development of a grid offshore [10]. The *North Seas countries' offshore grid initiative* (NSCOGI) consisted of three main working groups that recently completed their work: grid implementation, market and regulation, and permission and planning.

The technological aspects of such a grid are just one of the several parameters and challenges that lead to the actual configuration and implementation. Yet, we aim at showing how some of the implementation aspects influence specific technical aspects, such as power system dynamics and stability. This is done by taking the following assumptions about the offshore network:

- The offshore WPPs currently planned in that area will be connected by VSC-HVDC. For this study, this amounts to 35 GW;
- The rating of each onshore VSC is matched to the WPP it connects, i.e. no additional overrating on beforehand for a (future) transnational offshore grid;
- The system as a whole must be able to remain connected during AC-side disturbances according to the fault ride-through grid connection requirements;
- FRT is implemented by using power electronics controlled braking resistors on the DC side, which drain the excess energy from the DC grid during overvoltages;
- The onshore VSCs participate in voltage support during faults by providing a reactive current proportional to the voltage dip depth;
- The configuration of such a transnational offshore grid will have a U-shape to prevent undesired loop flows; and
- The VSC-HVDC connected WPPs links will not contribute to the AC system's inertial response.

In order to investigate the AC-system dynamic behaviour in relation to the offshore grid topology, this paper assumes two topology variants, as shown in Fig. 4: an option that connects each offshore WPP by radial VSC-HVDC links while no transnational VSC-HVDC connections exist (i.e. the *radial* topology), and an option that interconnects all offshore WPPs through multi-terminal VSC-HVDC (i.e. via a *U-shaped* configuration). The figure also shows the existing LCC-HVDC links from the Netherlands to the UK and Norway. All WPP-to-shore connections (cables and onshore VSCs) are rated according to the nearest WPP rating.

### B. AC system description

As a starting point for the case studies of this paper, the unit commitment and economic dispatch (UC-ED) and network situation of a critical moment in time was taken from [11]. The AC network dynamic model comprises a detailed inclusion of the Dutch generation units from 50 MW upwards, as well as a detailed representation of the Dutch (sub-)transmission network. The neighbouring countries are represented by their transmission-level grid (>220 kV) and their largest conventional generators. The remaining countries of the Continental European synchronous area are represented by dynamic equivalents. The existing case study was then adjusted to represent the time-horizon 2025 more accurately.

The amount of import to and export from the Netherlands of the resulting power flow is shown in Table I. It shows a high amount of (wind-driven) power imported from North-West Germany, fully-utilised export capacity of the LCC-HVDC connections to Norway and the UK, and a high amount of power exported to Belgium.

This particular initial power flow situation contains relatively little conventional generation on-line and a high utilisation of the offshore WPP fleet, which are connected through the VSC-HVDC links. This worst-case situation can provide information about the dynamic behaviour during low-inertia periods, which will unmistakably occur in the future.

### C. System Studies

Given the previously discussed modeling and simulation set-up, this paper will investigate the following cases:

1. The influence of the DC system power flow control strategy after short-circuit disturbances in the Continental AC system;
2. The effect of the DC system power flow control strategy on the combined AC/VSC-HVDC dynamics for a multi-terminal offshore network configuration;
3. The response of the combined AC/VSC-HVDC system after losing a large offshore WPP.

The former two are specific for the transient stability problem, while the latter exhibits dynamics acting also inside the small-signal stability time-frame of interest.

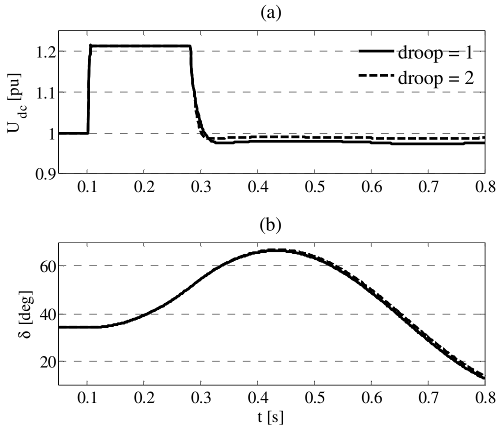


Fig. 5: Comparison of two direct voltage droop line implementations after an onshore short-circuit. (a) direct voltage N201. (b) rotor angle of a local Dutch generator.

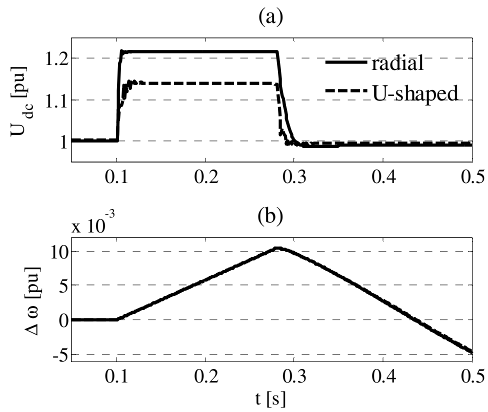


Fig. 6: Comparison between the radial and U-shaped offshore grid configurations after an onshore disturbance. (a) direct voltage at N201 (b) rotor speed deviation of a local Dutch generator.

## IV. Simulation Results

### A. *Response after a fault in the Continental European system*

The first part of the simulation study involves the combined AC/VSC-HVDC system response after a three-phase busbar fault in the Eemshaven area (bus 201 in Fig. 4). This location is chosen because the density of connected electrical installations is high in the surrounding area, and the voltage dip depth is worst case for the VSC connected at bus 201. The fault duration is 180 ms, which is considered a reasonable clearing time for the breaker failure protection. The offshore grid topology and the DC power flow control method are chosen as parameters to vary.

*1) Comparison of DC voltage droop constant:*

We start with a radial design of the offshore network (i.e. Fig. 4a), and vary the steepness of the droop characteristic the VSC operates on. Fig. 5 shows the response of the DC voltage near N201 and the rotor angle of a large local generator. It can be seen that the direct voltage very quickly rises to an unacceptably high value, and that the VSC's protection mechanism engages almost immediately after the 1.1 pu threshold value is violated. The dynamic braking resistor drains the excess energy away until the VSC is able to restore its power exchange with the AC system. The difference in the droop control parameters only manifests itself during the post-fault period, in which the VSC-HVDC scheme enters a slightly different operating point for each droop constant. The AC system-level influence of the droop line steepness is hardly visible in the rotor angle response and is therefore considered insignificant.

*2) Influence of offshore topology:*

A steeper droop line implies smaller voltage variations on the DC-side after sudden power rescheduling. A droop value of 2 is therefore taken for the next case, in which we compare between the radial configuration and the U-shaped multi-terminal HVDC configuration. Fig. 6 shows the direct voltage of VSC 201 and the rotor speed deviation from nominal (the same generator as in Fig. 5). Before the onshore disturbance, the direct voltage levels differ slightly for both topologies, which can be explained by the marginal (small) power flows between the interconnected WPPs, which on its turn is a result from the common system droop line the system is operated on.

During the onshore fault, the DC-side response is substantially different for the two topologies: the multi-terminal configuration appears to result in lower direct voltage excursions. There are mainly two reasons for this behaviour. First, the direct voltage rises across the entire VSC-MTDC system, and thereby triggering all dynamic braking resistors of the connected VSCs. Second, not all VSCs that are connected to the offshore grid experience a voltage dip at the AC terminals. The direct voltage droop control allows them to sustain in the FRT duty of the VSC-MTDC system by transporting additional active power into their connected AC systems until their current limit is hit. We can infer from this case that FRT of onshore faults is less challenging when operating an offshore grid in a multi-terminal configuration. The influence of the offshore grid topology on top of the fault dynamics itself shows to be marginal, as the generator responses almost coincide.

*3) Impact of the DC flow control method:*

The previous case showed that operating the WPP to shore connections as a multi-terminal configuration has the technical merit that the FRT duty needs less effort. We will now show what the influence of the DC power flow control method is for such a multi-terminal configuration.

All VSCs in the VSC-MTDC system help to ride through an onshore fault experienced by one or more converters, balancing the power in the MTDC grid. As such, the direct voltage droop control couples the dynamics of the connected synchronous areas through the direct voltage variations. Depending on the connection and control principles adapted by the respective TSOs, this may or may not be a desired behaviour. Therefore, the same case is repeated with two alternative DC power flow control methods. The first being that all VSCs from one particular synchronous area (here the UK) use a fixed power exchange with the DC system regardless of the voltage variations, and the second being an in-between solution in which each country has a dedicated droop-controlled converter, which accounts for the direct voltage variations. The simulation results are shown in Fig. 7.

While the differences are most obvious in the active power and direct voltage of the VSC, the faulted system rotor speed response does not show any noticeable difference for the concerned DC power flow control modes.

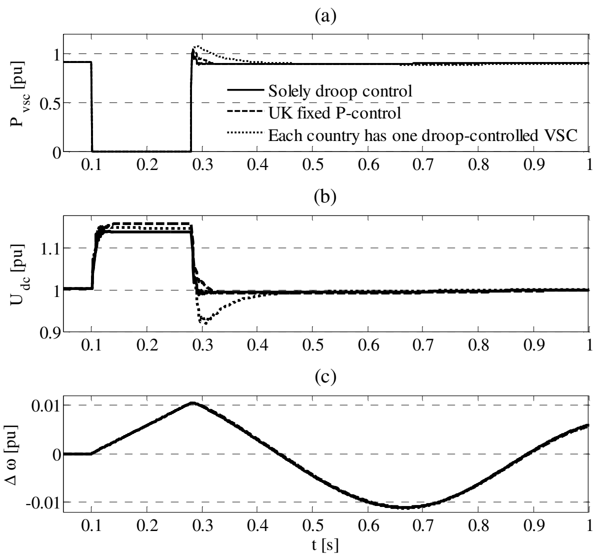


Fig. 7: Effect of different DC power flow control methods on the system response after a disturbance in the Continental European system The U-shaped offshore grid configuration is applied here. (a) AC-side active power at N201 (b) direct voltage at N201 (c) rotor speed deviation from nominal of a local Dutch generator.

This would apply for using direct voltage droop control as this method shows the smoothest DC-side behaviour. However, when also observing the rotor speed responses of the equivalent of the British system (see Fig. 8), it can be seen that the droop control causes the largest speed deviations, while the fixed active power exchange method as expected does not produce an effect on the UK system frequency.

It would be interesting to investigate whether the DC power flow control mode could quickly be changed after detecting in which synchronous area the onshore fault ignited. In such a way the merits of fixed power control (i.e. no fault dynamics propagation) and voltage droop control (i.e. improved FRT behaviour of the VSC-MTDC system) could be combined. This mode is however beyond the scope of this paper.

## *B. System response to a sudden loss of a large offshore wind power plant*

Another severe disturbance is the sudden disconnection of offshore WPPs. Fig. 9 shows the system response after disconnecting a large cluster of offshore WPPs in the German part of the North Sea (bus 101 in Fig. 4), and compares the result for radial and meshed topologies. The total power loss amounts to 3000 MW, which is close to the maximum allowed loss of generation in terms of operating reserves [12].

First we consider the radial offshore grid configuration. Because all offshore WPP connections are radial, the active power fed into the AC system at bus 101 (German grid) as expected suddenly drops to zero. This loss of generation is resolved by the synchronous generators, which gain a new operating point by using their spinning reserves. The effect on the direct voltage of the bus 201 – 221 link (the VSC-HVDC connection near the Eemshaven area) is marginal.

The response of the U-shaped offshore grid configuration is different. The direct voltage droop control actions of all connected onshore VSCs catch the loss of active power infeed by settling on a new operating point on the common droop

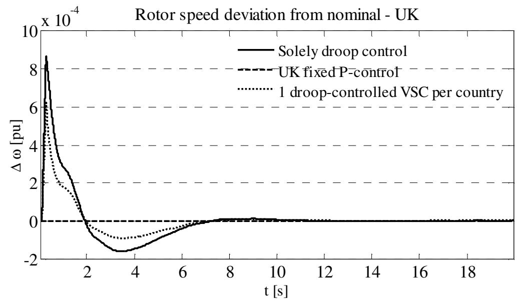


Fig. 8: Synchronous generator speed deviation in the UK power system after a large offshore wind power plant disconnection. Effect of various DC power flow control strategies.

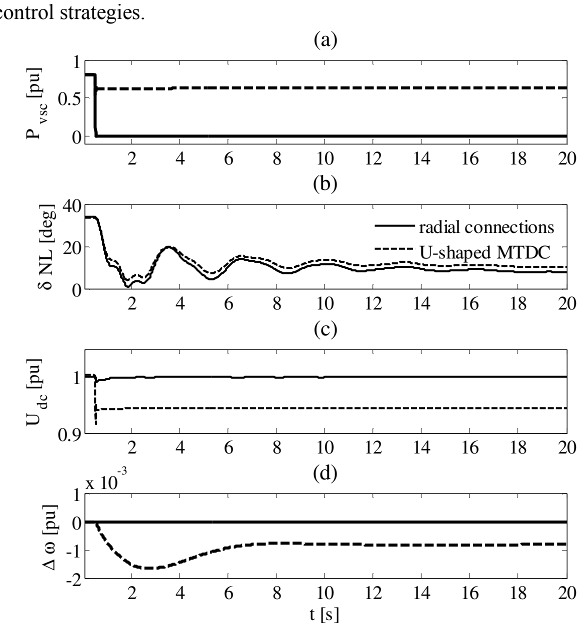


Fig. 9: System response after the disconnection of a large offshore WPP. (a) AC-side power at bus 101 (b) rotor angle response of a local Dutch generator (c) direct voltage at bus 201 (d) rotor speed deviation inside the UK equivalent system.

characteristic, which comprises a lower direct voltage and a lower active power set point. This is also the case for the VSCs connected to the UK equivalent system, in which the rotational speed of the UK equivalent generators decrease by their inertia response and primary control. Hence, the loss in generation in the German part of the North Sea is partly absorbed by the British system. The opposite would happen when an offshore WPP in the British part of the North Sea would disconnect. The above describes that both synchronous areas support each other through the DC power flow control, in this case a common direct voltage droop characteristic. This could provide TSOs technical benefits in terms of operation of primary reserves. On the other hand, such control actions introduce additional parameters for the reliability of the concerned (sub-)systems, which should fit into the policy of each TSO.

## *C. Critical Clearing Time Assessment*

Among other methods, the transient stability of a power system can be quantified by the critical clearing times (CCT) of the connected synchronous generators. Under the assumptions of the scenario discussed in Section III, the VSC-HVDC grid configurations shown in Fig. 4, and the application

TABLE II: PER-UNIT CRITICAL CLEARING TIME COMPARISON.

| Fault location / Topology | G1 (North NL) | G2 (South NL) |
|---|---|---|
| Point-to-point | 1 | 1 |
| U-shaped | 0.98 | 0.95 |

of direct voltage droop control, the CCTs of several large generators in the Netherlands have been determined. Table II compares the per unit CCTs of two generator locations for the radial and the multi-terminal configuration respectively, taking the radial configuration as a reference.

The CCTs have been calculated with an accuracy of 5 ms. Using a higher accuracy would be unrealistic due to the device modeling and (stability) simulation assumptions made. It can be seen that the CCTs are slightly more favorable when operating the grid radially. This could be explained by the propagation of dynamics that exist for the U-shaped offshore configuration, but this has not been studied extensively and given the study assumptions, no thorough conclusions can be drawn on this subject. Applying any of the alternative DC power flow strategies did not lead to considerable differences.

## V. CONCLUSIONS

The grid integration of large-scale renewable energy sources is among the most significant challenges we are facing right now and in the coming decades. In this paper we investigated the stability consequences of integrating 35 GW offshore wind power into the existing Northwest European transmission system, entirely realized by VSC-HVDC.

The study was conducted by investigating the influence of the DC grid topology and its power flow control strategy on the onshore system dynamics, for both a short-circuit inside the Continental European system and the disconnection of a large cluster of offshore wind power plants.

The influence of the direct voltage droop appeared to be limited to the direct voltage change immediately after a system disturbance; no noticeable influence on the onshore dynamics was observed. For a transnationally operated grid, the total direct voltage change will be smaller for equal droop steepness compared to radial connections due to all converters in the meshed grid responding proportionally to the disturbance.

A multi-terminal offshore grid can implement various control strategies. Among other requirements their influence on the dynamic behavior of the onshore and offshore network is of interest. It was shown that a common droop characteristic gives a clear field for the propagation of short-circuit fault dynamics from one synchronous area to the other. Without proper countermeasures, these dynamics could violate the grid connection requirements of the respective transmission systems. The same behavior was exposed when a large offshore WPP was disconnected from the transnational offshore grid. In such cases, employing direct voltage droop control may foster the restoration of the active power balance in the connected ac systems, and thereby letting the other connected synchronous areas support the primary control of the affected area. It will depend on the operation strategy of the TSOs whether or not this is a desired behavior.

These issues can be partly resolved by letting the VSCs of one particular synchronous area exactly track the scheduled power exchange while the remaining VSCs account for power imbalances in the DC network by employing droop control. More research is needed in order to draw conclusions about the practical applicability of such "mixed" control methods and their implications on topics such as operation flexibility and reliability.

The effect of a transnational offshore grid on the critical clearing times of the generators inside the continental system was also investigated. No significant influence of the VSC-MTDC grid topology on the onshore CCTs could be found. However, we consider the assumptions that have been made for this study too broad to draw firm conclusions about this topic. It is advisable to conduct additional simulations, taking a geographically harmonious, more detailed representation of the Continental European system into consideration, as well as a more detailed implementation of the local grid connection requirements.

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