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Challenges on the Road to an Offshore HVDC Grid

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Abstract— **This paper discusses the technical challenges for offshore HVDC grids, which is a promising alternative for grid connection of offshore windfarms.**

The first topic is why HVDC is necessary, and which types of converters there should be used, resulting in a clear recommendation of HVDC based on voltage source converters. There is already offshore experience with VSC HVDC and the experiences from those projects are good.

The need of standardisation is discussed. What needs to be standardized now and what can be decided at a later stage, concentrating on the voltage as the most urging parameter. Aspects of voltage selection are discussed.

For a multiterminal HVDC system the need for HVDC circuit breakers are discussed. What is needed now and what is the development stage for the more advanced breakers needed in more complex systems. In this connection the fault handling control strategy is important in connection with the protective system.

Finally the long term standardisation and the challenge of planning where project time schedules and even the likeliness of project realisation is uncertain are discussed, ending in the conclusion: Begin. The future is here today!
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I. Introduction

The large scale plans for offshore windfarms in the North Sea have trigged many visions that propose to connect the windfarms to an international offshore grid.

Those visions are based on a common sense. Due to the intermittent nature of the wind and the increasing amount of wind energy in the electrical grids, interconnections to other grids are one of the measures that will reduce the effect of intermittency. It is an advantage that the transmission systems from the windfarms to land will have available capacity and be valuable when needed in situations with little wind. This possibility will increase the value of the windfarms grid connections. Furthermore, an interconnected offshore grid can provide redundancy in case of a transmission system failure and will give possibility to reduce the number of HVDC converters, not only reducing the investment costs, but also reduce the conversion losses. All factors together, the total economy should be improved by a solution including an international grid.

The obstacles that must be overcome are many. The economical and legal framework for offshore wind differs from land to land, and within those fields there are huge challenges, but just to agree that organisations in several countries are planning to have an offshore grid, this is not a minor step. The political and legal issues are, though, not the scope of this paper which deals with the technical challenges.

II. Why HVDC and which type?

Many of the planned offshore windfarms will have a large power and a considerable cable length to a receiving grid. The use of AC cables will be limited by the physical nature of the cables. The cable can be regarded as a distributed capacitor which in AC will need constant recharging and at a given length, the critical length; this recharging current will be equal to the rated current for the cable. As a result there will not be any power transmission. The classical way to increase transmission capacity is to increase the voltage, but the reactive power increases with the square of the voltage, so the result is that the critical length will be reduced with increased voltage and power. It is likely that those problems will be overcome with time, but since 1954 HVDC transmissions have demonstrated in practice that bulk power at high voltage over long distances is possible. And despite the relative high costs of the converter terminals, the line costs are lower than for AC, because HVDC only need 2 conductors. Equally important is that HVDC allow connection of asynchronous nets, a fact that is proven by the many HVDC interconnections already existing or being built in the North Sea. An impressing example of the HVDC systems is the 700 MW, 580 km long NorNed interconnection between Norway and The Netherlands, where the transmission losses are at an almost incredible low value: 3,7 % at full load.

HVDC is not one single technique. Generally, a HVDC system consists of two converter stations with a DC line between. Depending on the control, the converter stations can operate as rectifiers converting AC to DC or as inverters converting DC to AC. Most existing HVDC converters are based on components in the valve that can be switched to a conducting state, but must remain conducting until the polarity in the connected network shifts and there is a polarity shift. The converter principle is called Current Source Converters (CSC) or Line Commutated Converters (LCC), which are technically more exact than the more general term “Classic”. The first LCC HVDC was established 1954. Worldwide there have been delivered more than 100 LCC transmissions and several more are under construction.

The newer technique is based on semiconductors in the converter that are capable of not only turning on to a conducting state on an control signal, but also is able to stop conducting on a control signal. For this type of converter the term is Voltage Source Converters (VSC). VSC transmission systems have been in operation since 1997. There are around 10 VSC systems in operation, all manufactured by ABB but competition is emerging as another vendor contributing to the list of five systems under construction. With this development, the customer requirement of more than one potential supplier has been fulfilled, and the competition between the HVDC suppliers will most likely contribute to the future development.

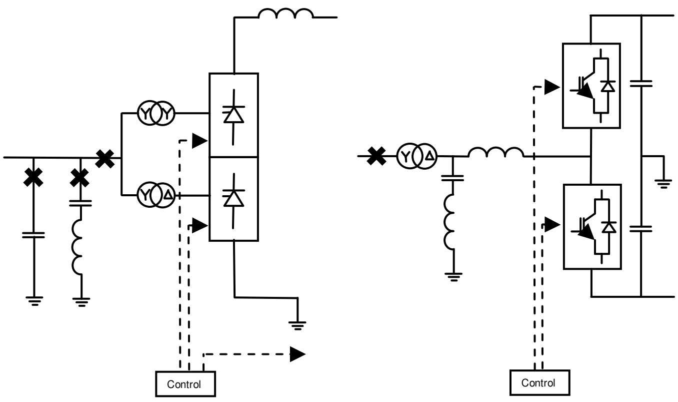


Fig. 1 The principal diagrams of LCC (left) and VSC HVDC (right)

VSC converter stations do not only have fewer components than LCC converter stations. They occupy much less space and demand much less systems studies than LCC systems; VSC HVDC has a very simple structure, since it consists of only a few main parts. Due to this simple structure, VSC HVDC is a very flexible technology.

Almost all HVDC systems build until now are point-to-point transmissions, connecting or paralleling AC transmission systems, where the main reasons for choosing a HVDC solution has been one or more of those: long (submarine) cable, connection of asynchronous systems (including different frequency systems) or just a very long transmission distance.

From a technical point of view, LCC is still developing, but nevertheless, mature. There is a high degree of consensus on how the systems should be designed and the series connected thyristors used in the converter valves have reached impressive power handling values. One way of illustrating the state of the art is that one 800 kV bipolar system being built will be able to transfer 6400 MW 2000 km. Another illustration of the development stage is that the losses in a single LCC converter has been around 0,7% for more than a decade.

For the VSC the use of fast semiconductors with high controllability has let to constructions with fewer components than there are in a LCC station. This gives a potential for further reduced investment. An example is that till now the power handling capability of a single IGBT semiconductor used in the VSC valve is much lower than the corresponding capability of a thyristor used in a LCC valve. Despite the low loss nature of the control of an IGBT the larger number of semiconductors and the many more control signals lead to higher losses in VSC than in LCC. The figure has improved much during the years VSC have been an alternative.

From a system point of view the VSC technology offers significant advantages compared to LCC. An important advantage is that the LCC requires a receiving network of a strength exceeding the power of the HVDC link. On the contrary, the VSC technology offers the so called “black start capability”, that means that a VSC link is able to start to deliver power to a network without other generation sources in the net. A LCC will require additional equipment in order to perform a black start without risk for the system and LCC has a minimum power capacity of a few percent of the rating. Of similar nature is that VSC eliminates problems with infeed to weak networks, possible interactions between several converters in the same network area and commutation failures. The latter is the situation where there is a sudden dip in the voltage, so the thyristors in the inverter valve fail to turn off, the commutation from one phase of the valve to another fails, and as result the transmission of power is for a few periods replaced by a short circuit like current a little larger than the rated current of a transmission. In some areas and plants commutation failures are common, in other those failures are a few per year, but they are a stress on the power system.

There are fundamental differences in principle between VSC and LCC. Thus control principles are different. The difference can be illustrated by the power flow control during reversal of the power flow. In LCC a reversal of the active power flow is made by reversing the polarity. The reactive power must be supplied externally and is usually done in steps with switched filters and other capacitive elements. In VSC the active power flow is changed by changing the direction of the DC current. The reactive power is controlled independent of the active power and like in AC, VSC does not need communication between stations during normal operation.

The polarity reversal in LCC gives other stresses in HVDC cables. Thus oil impregnated mass cables must be used for LCC. In VSC the high voltage stresses on the insulation systems allow the use of extruded HVDC cables.

As the VSC technology has had shorter developing time than the LCC, it is natural that the voltages and power ratings possible today are less for VSC than for LCC. But for an offshore HVDC grid, the lines must be cables. Today, the cables set the limit. In the development process towards higher cable voltages, the accessories, joints and terminations, gives the largest challenge.

III. Offshore HVDC

Offshore oil and gas has existed even longer than HVDC, so there are several areas where offshore HVDC can use the experience from this field. Similar, the existing HVDC submarine interconnections have a cable length exceeding 4000 km and those cables have been an operation record exceeding 500 years. So, in a lot of areas for offshore, there is a comprehensive experience.

30 years ago offshore converter stations were proposed, based on LCC [4], but offshore HVDC was first a reality with the VSC technology. The first project with two circuits has been in operation since 2005 and two more projects are under construction. The project in operation is the Troll A precompression project, where two 40 MW very high voltage motors uses two HVDC systems as a large scale drives systems with 70 km long DC link between rectifier and inverter. One single motor as load for a HVDC is unusual but seen from the point of offshore HVDC it is noteworthy that the operation results have been excellent, and thus it can be concluded that offshore HVDC need not cause concern: despite only 4 years of operation it is a proven and reliable technique.

It can be argued that a 2 x 40 MW, 60 kV HVDC installation in an oil and gas environment, is not representative for an offshore HVDC grid with many converters and large powers. It cannot be seen as a drawback that the safety standards of the oil and gas industry have been implemented, because that may have contributed to the very reliable design. And as a first offshore installation, the Troll A project has made the next step possible: The first offshore HVDC for wind power connection, the 400 MW BorWin1 project, which now is in the final stage of construction with the offshore converter installed in the North Sea which will be ready for commissioning later this year.

In the BorWin1 project, the special hazards related to an oil and gas installation do not exist, but the 400 MW power level is at a level comparable to the transmission capacity of many existing cable transmission systems. On the other hand, the reliability issues are on the same level as required for offshore oil and gas installations. The HVDC system is designed for unmanned operation and predicted values for availability and reliability are on a very high level. Reliability and availability demands are high on all modern HVDC installations, but offshore it must be taken in consideration that weather conditions may make access to the platform impossible.

Figure 2 shows the Single Line Diagram for BorWin1

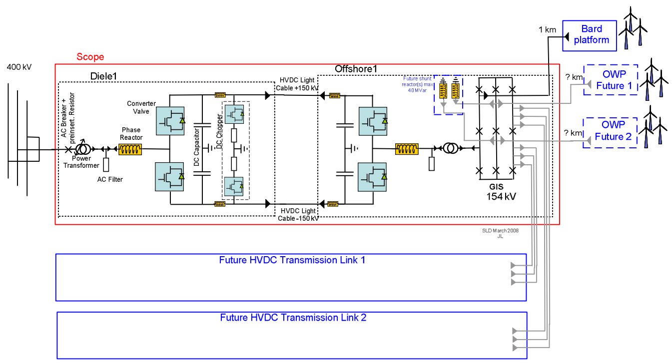


Fig. 2 Overview of the BorWin1 HVDC project

In the traditional systems there has been a large degree of redundancy in the semiconductor valves, in the cooling systems and in the control system. The redundancy in the valves includes series connected components with a failure mode that allows continued operation despite failure in one IGBT or eventually more than one. The cooling system and the control systems are duplicated and in case of a failure there is an automatic switch-over to the healthy system together with a signal to the supervisory system, so preventive maintenance can be made. In BorWin1 those functions are complemented with elimination of components on the platform where the function can be made in other ways. One example of this is that the transformer on the platform is without an on load tap changer (OLTC). The OLTC is a mechanical device which will have an impact on the reliability figure. Parts of the OLTC function can be made by using the voltage controlling capabilities of the VSC converter, and the voltage can also be regulated on land, where there not are offshore limitations in the access to maintenance. Another example is the chopper which is needed in cases where the grid in land is unable to receive the energy from the windfarm.

The spare part philosophy is an important part of the strategy for high availability figures. One of the critical failures is the failure of a transformer. For BorWin1 the solution has been use of three single phase transformers, and one is provided as spare.

IV. The First Steps in Standardisation

Technical development of complex infrastructure does not come overnight by magic like in a fairy tale. Like the AC grids developed in the beginning of the history of electricity, the HVDC grids most likely will develop from simple grids to a complexity similar to the AC grids. However, some standardisation is necessary to make it possible for early built DC transmissions to be elements in a future HVDC grid. An important question is: What needs to be standardised and when must it happen? Today the situation is rather simple. It is somewhat similar to the early days of AC: At that time, the standardisation could be limited to frequency and voltage. For the offshore HVDC grid the answer is almost similar: Type of HVDC converter and DC voltage.

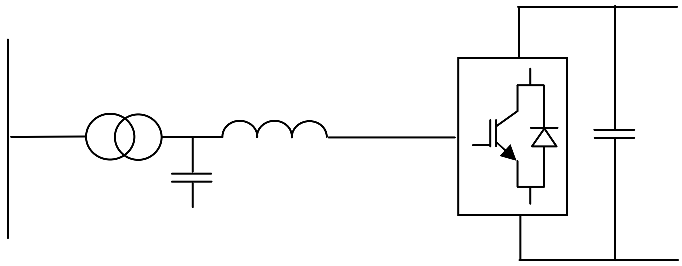
The first choice to make is LCC or VSC. Due to the different control principles, connection of LCC and VSC is not straightforward. The possibility to make hybrid LCC-VSC systems exists, but there are limitations. As VSC inherently is better suited for a multiterminal system, the first proposal is to standardize on VSC for future offshore installations in areas where an offshore is a possibility. Regarding existing HVDC systems, submarine cables built for LCC can be used with VSC, so it is possible to change from LCC to VSC converters without changing existing cables.

The most important area for standardisation is the voltage. Why must an offshore grid be based on same voltage? Technically it is not necessary. A HVDC grid could be hybrid, ranged from a solution based on point-to-point connections with intermediate AC grids. But such a solution has two important drawbacks: Installation cost and losses. The cost of a HVDC converter and especially an offshore HVDC converter with platform contributes so much to the total investment that the technical-economical optimum will be with fewest possible converters. In addition, the "unnecessary" converter will give losses increasing the operational costs. But in the voltage selection future possibilities should also be taken into account.

Today, an offshore HVDC converter is made with the topside as one single construction, where the size is depending on the voltage. A higher voltage requires higher insulation clearance distances giving increased dimensions of the enclosure. With the high voltage demanding space to mechanical structures on ground potential, the mechanical strength of the construction must be in the enclosure and thus the weight will increase much with increased dimensions. So the weight and the associated costs of installation must be taken into account when selecting voltage.

A future perspective is the HVDC systems without transformers. Theoretically it is possible to have a transformerless VSC HVDC already today, but in reality there is a gap. The transformers in a HVDC converter contribute substantial to the weight of the converter and to the converter losses, so the possibility to make a HVDC converter without transformer is definitely worth to consider. The transformer capability for voltage control has been mentioned before and is not a necessity. The main purpose of the transformer is to adapt the AC voltage to the converter voltage. With a properly selected voltage, the transformer is not necessary from that point of view. But the transformer has other tasks. One is that some faults in the AC system give voltage increases in the healthy phases. In such situations, the transformer acts as a galvanic barrier between AC and DC, and the transformer cost is lower than the cost for a HVDC valve that can withstand those voltages. But with continuing development, the valve cost will most likely decrease where transformers as mature products not will do so, so it is likely that the economical equilibrium will change.

However, it should be noticed that the galvanic barrier also will prevent DC potential to enter the AC system, so in a bipolar VSC HVDC installation the transformerless solution is not straightforward. Furthermore the reactive impedance of the transformer will reduce short circuit currents, so a system completely without transformers may not be just around the corner. But even a substantial reduction of the number of transformers will improve the overall cost picture and as such be an advantage. In a wind power application, such a reduction can be achieved by smart selection of ratios in other transformers in the system.



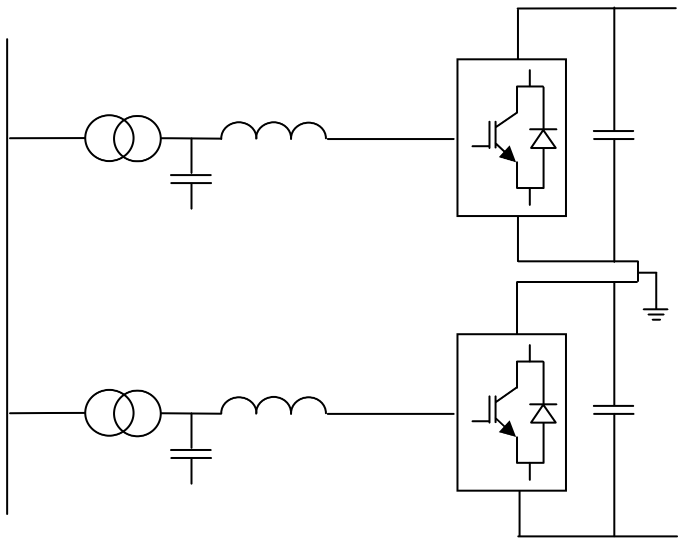
Converter monopole	Power (BtB)		
UDC	Alt 1	Alt 2	Alt 3
+/- 80 kV	99	197	296
+/- 150 kV	185	370	555
+/- 320 kV	395	789	1184

Fig. 3A Voltages and power for VSC HVDC with one converter

Till now other factors have had influence on the voltage selection. ABB propose some standard voltages. Figure 3A shows the standard proposals of today, with the voltage selection 80kV - 150kV - 320 kV. The DC voltage of 150 kV was selected to produce and transport factory mounted HVDC valves in enclosure. This factor has contributed to reduction of cost and project time schedule. The 320 kV corresponds to the voltage from a converter directly connected to a 400 kV AC system. Table I shows the AC and corresponding DC voltages in transformerless converters. Figure 3B shows how the monopolar solution can be increased to a bipole, with two conductors on the double voltage of the monopolar transmission.

TABLE I
DC VOLTAGES FOR TRANSFORMERLESS CONVERTERS

UAC	**UDC Converter monopole**	**UDC Converter bipole**
145 kV	+/- 110 kV	+/- 220 kV
245 kV	+/- 187 kV	+/- 374 kV
245 kV	+/- 187 kV	+/- 374 kV
420 kV	+/- 320 kV	+/- 640 kV
525 kV	+/- 400 kV	+/- 800 kV



Converter bipole		Power (BtB)		
UDC1	UDC 2	Alt 1	Alt 2	Alt 3
- 160 kV	+ 160 kV	197	395	592
- 300 kV	+ 300 kV	370	740	1110
- 640 kV	+ 640 kV	789	1579	2368

Fig. 3B Voltages and power for VSC HVDC with two converters

There are other factors than the voltage that must be taken into consideration when establishing an offshore grid with several vendors. Many factors need not to be taken in consideration in the first phases, but it is likely that there must be a kind of DC grid code: What influences must the converters in this system be able to accept.

Of course, the proposed initial standardisation is not sufficient in a longer perspective. But despite many of the factors are part of the design, they need not to be settled immediately. One reason is that the need for new DC systems is coming so fast that standardisation will be lagging and then selected choices can turn out to be de facto standards. Waiting for agreement may be so time consuming that it is too costly, and many of the topics may be relatively cheap to change if the initial choice did not correspond to the later agreed standard. But many of the standardisation topics are related to issues discussed later, so the standardisation needs will be discussed later.

V. MULTITERMINAL HVDC

When almost all existing HVDC Systems are point to point connections, there are systems with more than two terminals, and more have been discussed. In addition, there are many systems with more than two converters in the two terminals: A bipolar system consists of four converters and a bipolar system with two series connected converters in every pole consists of eight converters. All those systems are LCC. Among the "real" multiterminal systems, which are systems with more than two terminals, the transmission system from Quebec province to New England is the most comprehensive. This started as a 690 MW interconnection from the Canadian side of the border to New Hampshire, but was expanded with three 2000 MW terminals: One near the hydro power stations at James Bay, one near Quebec City and the last near Boston in Massachusetts. The 5-terminal system was commissioned, but the 2000 MW system is now operated as a 3-terminal system. See figure 4.

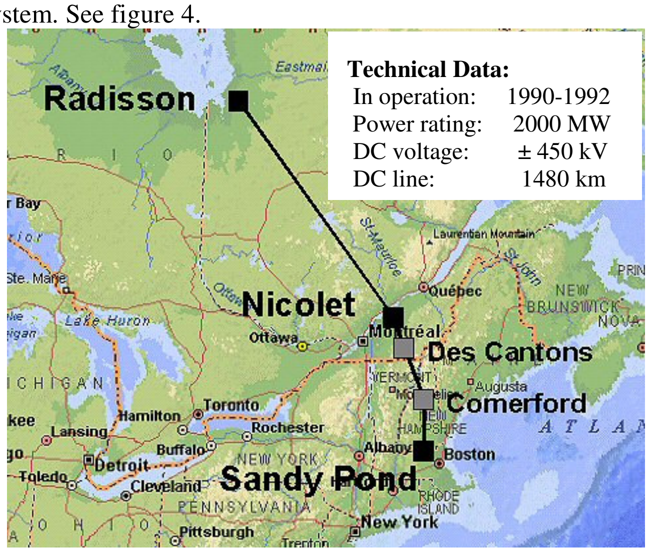


Fig. 4 The Quebec – New England multiterminal HVDC transmission

Even in the era before VSC, there were visions of very large HVDC systems. One example is the 1992 ABB vision on figure 5, which can be seen as forerunner of the Desertec vision of today [5]. Both visions are based on a combination of solving the energy problems the world is facing together with the advantages of HVDC transmission. Those visions do not stress the offshore grids, but in some parts of the world it is easier to get permits for offshore grids than for onshore grids, and as the need for new energy sources is insistent, this factor may be important.

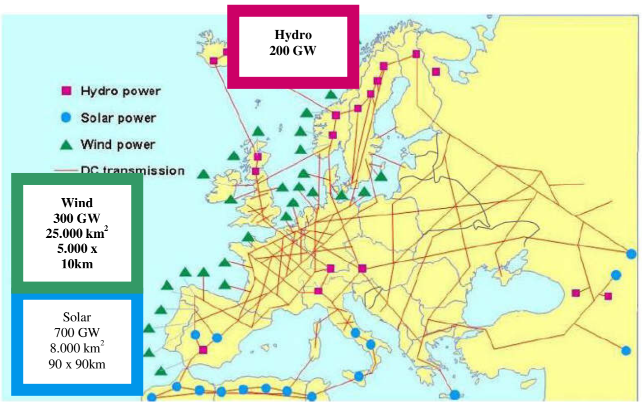


Fig. 5 ABB Vision 1992

For a multiterminal HVDC system, the fault handling is an important issue. The ambition is "at least as good as a well designed AC system". Which means that the HVDC system must have similar – or better - system behaviour during faults than an AC system: A fault must not put the entire system on risk, but should be identified and switched out of the system and immediately after the fault has been cleared, the remaining healthy parts of the system must resume operation. For AC the main elements in this behaviour are controls, protection systems including instrument transformers and switching elements, the circuit breakers, and many discussions on multiterminal HVDC systems have an approach which is similar. But the situation is not similar to AC in all respects.

Looking on a simple 3-terminal system with a symmetrical monopole (figure 6), there are shown AC switches and DC switches that can isolate a fault. But we need not think AC. Faults on the AC system will not affect the DC system (besides a possible loss of active power). But it is not necessary that all faults are isolated by the switches in the DC circuit. There are converters in the circuit that can handle many types of faults momentarily. But some faults require more: A DC side ground fault will affect the whole system. There will be an infeed to the DC system from the AC system via the converters, so one way of stopping the fault is to trip all the AC circuit breakers on the AC side of the converters. The AC circuit breakers are marked with an X on the figure. In case an interruption can be accepted by the system, the DC switches, shown as a □ in the figure, can be slow. That is, that a pole of an AC disconnector can do the function. There are no special interruption problems as the switches will operate in a de energized system. By opening the relevant DC switches the faulty section can be isolated and the remaining, healthy parts of the system can operate by reclosing the AC circuit breakers. After clearing the fault, the stations and cables can be reconnected.

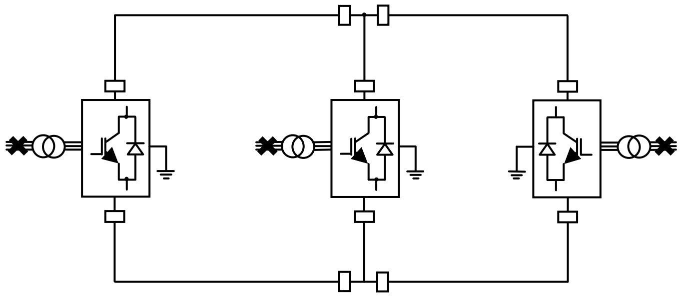


Fig. 6 Switches in a 3-terminal monopolar VSC HVDC circuit

In case only a short interruption can be accepted, just like a fast autoreclosing can be accepted in an AC system, the DC switches can be a high speed type, so a fault is cleared in a sequence, starting with AC circuit breakers tripping, then the faulty part is disconnected by a fast operating DC switch followed by AC reclosing recovering the remaining system 0,5 seconds after the start. During the process, the converters and cables remain connected and the power orders are dynamically controlled. The DC switch is basically one pole of an AC circuit breaker. That means that all elements for this type of HVDC grid exists, and for the first phases in the making a large multiterminal systems, the HVDC grids will be limited in number of terminals and the short interruption philosophy will be satisfactory. All elements HVDC grid exists.

In the large interconnected system the DC switches must clear the fault momentarily. That requires a DC circuit breaker and a detection system which is able to detect and localize the fault, so only the faulty part is disconnected.

VI. The DC Circuit Breaker

One of the advantages of AC is that the current is zero twice in every period, i.e. 100 times pr second in a 50 Hz system. The zero crossings make it much easier to interrupt AC than DC. DC circuit breakers were even predicted by the grand old man of HVDC, Dr. Erich Uhlmann: "preliminary work has already reached the stage at which it can be safely stated that a d.c. circuit-breaker will be available at the time the need for such arises". [1]

The DC interruption has been a challenge since the very first point-to-point LCC transmissions: At that time the nonlinear element in surge arresters were not as nonlinear as today's metal oxide, so it was necessary to have spark gaps in series with the nonlinear elements, and when an overvoltage incident was over, the arc in the spark gaps had to extinguish. With sufficient arc voltage in the spark gaps extinction is possible and long arcs were accomplished by magnetically blown spark gaps. Such arresters were also used in DC breakers used in the above mentioned multi-converter LCC systems, in situations where DC loops must be opened so bypassed converters can be switched back in service or when a bipolar transmission is shifting between bipolar operation and monopolar operation in metallic return mode. The development of HVDC circuit breakers at that time were developed by a collaborative research group consisting of the large European HVDC manufacturers ASEA, AEG, BBC and Siemens. This work did not result in a standard, but in a common agreement on a principle for a HVDC Circuit breaker. Described in several papers, one of them [3] and in other Cigré publications [2]

For the circuit breaker in a multiterminal VSC HVDC grid, there are two options for the DC circuit breaker: A mechanical and an electronic solution. For the mechanical solution some of the criteria from [3] are still valid: "an economic solution of the problem is only possible if circuit breaker components already manufactured for other purposes can be used". Just like the use of AC circuit breaker components are proposed above for the multiterminal systems with interruptions. One proposal is the active resonance breaker (figure 7) where a discharge of a capacitor gives a current zero crossing. The state of the art for mechanical breakers is an operation time around 60 ms, so system studies are needed to make sure that this fault clearing time is acceptable.

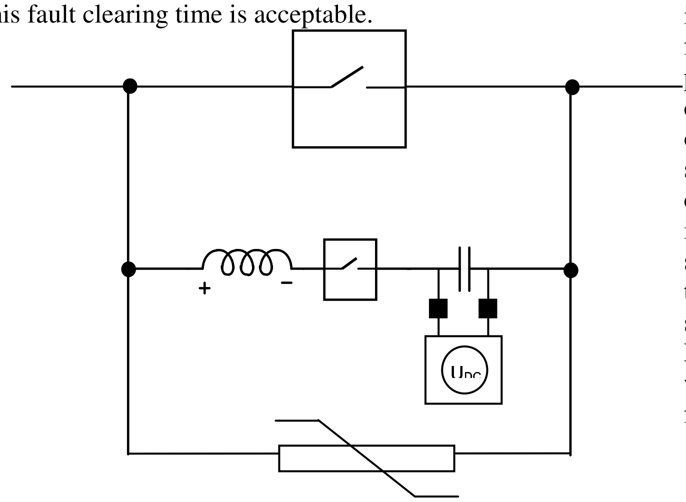


Fig. 7 Principle for an active resonance mechanical HVDC circuit breaker

The electronic solution is faster than the mechanical solution. The state-of-the-art is 1 µs, 5kA, 640 kV, based on one phase of a 3-phase converter valve. As the IGBT valve have a polarity dependence, the simplest variant only have breaking capabilities for one polarity, in case both polarities is a demand, the solution adds one more valve. The drawbacks of this solution are the cost and relatively high losses. The most important research activity is innovative ideas.

To achieve an acceptable redundancy level, DC switchyards can be made in configurations similar to AC switchyards.

VII. PROTECTIONS

Together with the fast acting switch, the protection must be equally fast. The challenge is to measure voltage and current fast in a reliable way. The measuring transducers used today will most likely only need few and small modifications to cope with the new demands, but most important is that till now there is no service experience indicating the reliability of the different proposed protective principles.

However, it should be noticed that despite the drawbacks of the present solutions, development in the field is going fast and the most advanced solutions will not be needed in the first stages of the future offshore HVDC grids. The need for interconnections is so insistent that a parallel developing of interconnections and the necessary components for a complex grid most likely is the most attractive option, based on as an example, that DC circuit breakers will be replaced when there is a need for and has been developed DC circuit breakers with the required performance.

VIII. EXPANSION

Planning always has to deal with uncertainties. When shall the grid be ready to have new elements connected and how large will they be. But it seems like the rate of change is increasing and with this development, the uncertainties have increased. The cost of terminals in a HVDC grid is larger than for an AC grid. The shift from LCC to VSC has made it possible to have small converters together with large converters, but the cost challenge has not disappeared. For an offshore HVDC grid the cost of terminals is higher than on shore, so the question is even more important offshore: How can extensions be made in an economical way. This question is very much depending on the concrete projects, time schedule, utility policy regarding redundancy and willingness to try newly developed technology. One possibility was shown for BorWin1. The overview shows a hybrid proposal: Local AC connection of several Point-to-point HVDC's and windfarms. But optimization is one of the challenges for the future.

IX. FUTURE STANDARDIZATION

A general dilemma in standardisation is the need for a standard before there is experience to base the standard on. In situations with one supplier or one dominating technique there is furthermore the possibility of a de facto standard. That need not to be bad for the development, but it cannot be assured that it will. 2008 IEC have a new Technical Committee TC 115 "High Voltage Direct Current (HVDC) Transmission for DC voltages above 100 kV" and it is likely that this will turn into standards. But the authors believe that the activities going on in the Cigré organisation will result in recommendations somewhat faster. The study committee B4 "HVDC and power electronics" have started a working group WG B4-52 "HVDC grid feasibility study" in the beginning of 2009. The participants represent many of the European manufacturers, other potential users, a number of universities, research institutes and consultants and the result shall be presented in a technical brochure in 2012.

The task of WG B4-52 is covering more issues than needed for an offshore HVDC grid, but as offshore HVDC grids may be introduced fast, the resulting recommendations will no doubt be valuable. In the discussion topics of WG B4 is interoperability of a DC Grid with the AC grid, the impact of distant faults as any fault in a DC grid will be notable at a very long distance, costs and various grid configurations with respect to reliability as well as controllability, including the controllability in a grid with more branches than nodes.

In view of reliability the grid structure will be discussed related to have sufficient redundancy, need for sectionalisation of the net by HVDC breakers and protections for several zones. Whilst DC breakers and protections have yet to be developed, the WG can look at identifying the necessary breaking current capabilities and operation times.

Starting from the standard voltage levels used for AC networks, the WG will look at the possibility of recommending standard voltages for DC Grids.

The WG will discuss the aspects of the converter station design that may need to be standardised, allowing stations from different manufacturers to be connected to a DC grid.

X. Other Aspects

With the introduction of an offshore grid we will expect that the economy for offshore windfarms will improve with regard to grid connection cost but also with respect to better market prices for the wind energy. The HVDC solution will also make it cheaper to power offshore oil & gas installations from shore and really save the increasingly more expensive fossil fuels for the purposes where grid delivered electricity is not an option.

With a HVDC connection of windfarms there may be a possibility to simplify the wind turbines in order to reduce the high offshore operation and maintenance costs. This possibility need to be investigated.

XI. Conclusions

The statement of Dr Uhlmann “It can be safely stated that a DC circuit-breaker will be available at the time the need for such arises” is even more relevant today than it was when he made the statement. With the fast advancement of offshore windfarms, there are several projects in areas with relatively easy connections for two or three countries. For such windfarms a combined windfarm grid connection and grid interconnection could be the first international offshore grid in the world. Basically all elements exist. Some need development, but the existing solutions will be able to handle the needs in the first phases. However the development will not come without need from the market. The very first DC warrior in the world, Thomas Edison once said that an invention consist of 1 % inspiration and 99% transpiration. We will say that funding is part of the transpiration part, but funding will come with the market demand.

You just need to convert as many interconnection projects as possible to VSC HVDC and believe that from a technical point of view, the future is available today and the links where there is a technological gap, it will be filled in due time when the plans materialize.

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