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DC Harmonic Filter Design and Mitigation of Induced Fundamental Frequency Currents for the NEA 800 kV HVDC Multi-terminal Project

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SUMMARY

This paper describes the DC side filtering for the North-East to Agra 800 kV HVDC transmission project. The multi-terminal nature of this transmission, with numerous possible configurations of the DC side, posed an exceptional challenge for the DC side harmonic filter design.

The design of the DC filters took into account a number of factors including: the optimum balance between shunt DC filter size and smoothing reactor size, keeping the DC filter solution as simple, economical and robust as possible, and the avoidance of amplification of low order harmonics. The design study considered the many combinations of DC side circuit possible with the multi-terminal configurations, including monopolar and hybrid as well as bipolar modes. The chosen design solution uses the same filter configuration at all stations, although with some different details and component ratings.

An important aspect relates to the possible induction, from parallel AC power lines, of fundamental frequency currents in the DC circuit. These currents may pass through the HVDC converter, undergoing a frequency-shifting modulation which produces direct current in the converter transformers, thus risking unacceptable levels of core saturation. The calculated level of induced fundamental frequency was such that mitigation measures in the HVDC system were required. The chosen solution was to install fundamental frequency series blocking filters in the neutrals of the inverter station at Agra.

DC filter component rating was critical, especially in the case of the DC side filter high-voltage capacitors at Agra, which are located indoors due to pollution. As these have to be rated for the harmonic voltage plus the 800 kV direct voltage requirement, their height becomes a crucial factor for the DC hall design.

The entire design study was the most complex since the last true multi-terminal HVDC project some 25 years previously, and provided many valuable experiences which are recounted in the paper.

KEYWORDS

Multi-terminal HVDC, 800 kV, DC harmonics, DC filter, disturbing current, AC-DC coupling, cross-modulation, fundamental frequency, blocking filter, core saturation.

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1. Introduction

1.1. The project

The ±800 kV, 6000 MW NER/ER-NR/WR Interconnector – I Project will initially have three converter stations, at Biswanath Chariali, Alipurduar and Agra, and will be configured as two bipoles paralleled on to a single HVDC line. The route is shown in Figure 1.

In Phase 1 of the project, there will be one bipole terminal at each of Biswanath Chariali and Alipurduar, each rated at 3000 MW. These will be paralleled at Alipurduar and the combined transmission of 6000 MW will terminate at Agra, where two 3000 MW bipoles will be built in a single converter station. The normal power flow direction on the DC link will be from Biswanath Chariali and Alipurduar to Agra.

Figure 1 - Route of the NEA800 multi-terminal HVDC transmission line

Later, in a Phase 2 upgrade of the project a second bipole will be built at each of Biswanath Chariali and Alipurduar, bringing their installed capacity to 6000 MW each. The first of Biswanath Chariali or Alipurduar to be uprated will remain connected to Agra, while the other will be separated from the Phase 1 system and form an independent 6000 MW transmission on a new DC line to a new inverter station, yet to be defined.

At Biswanath Chariali and Alipurduar the new DC filters which will be required in future for the second bipole will be procured and installed with the future Phase 2 upgrade implementation. However, the design of the Phase 1 DC filters had to be shown to be compatible with the future Phase 2 upgrade, despite the fact that that no firm data was yet available regarding the length or characteristics of the Phase 2 DC line.

1.2. DC side harmonics

DC harmonic filters are provided principally to limit the possible interference in neighbouring telecommunications circuits caused by harmonic currents flowing in the HVDC and electrode lines, due to the generation of harmonic voltages by the HVDC converter stations. The filters also serve to avoid potentially damaging resonances and to reduce the absolute magnitudes of the harmonic currents on the DC line.

The fact that this is a multi-terminal scheme introduced particular challenges beyond those which apply to any long distance DC line transmission:

- The number of possible combinations of circuit configuration to be studied was much higher.
- DC filters had to perform satisfactorily against a line impedance which was not just a unique value, but could have several alternative values depending on the circuit configuration,

- The two rectifier stations were much closer (432 km) than would be economical for a two-terminal system, and therefore the harmonic interaction between these stations was greater than would normally be the case with a larger intervening line impedance.

2. Low order harmonic resonance

A key consideration in the design of the DC filter and choice of smoothing reactors is the mitigation of any low-order resonance on the DC side.

Resonance at second harmonic is undesirable because it magnifies the normal stresses which appear due to the second harmonic generated by the converter in response to any unbalance (negative sequence) in the supply voltages on the a.c. side. During single-phase faults on the a.c. system, such unbalances can reach very high levels, with correspondingly high second harmonic on the DC side.

Studies of DC side resonance can be made using the same frequency domain tools and models as used in the DC filter design studies. These tools permit fast analysis of many different case scenarios. However, such methods do not fully take into account the dynamic effect of the converter and its control system. These can be included in time domain studies using programs such as PSCAD/EMTDC, which, however, take much longer to set up and run for each case. The design study used both methods in an appropriate way.

- Frequency and time domain studies, which determined the necessity for 2^{nd} harmonic filtering as part of the DC shunt filters.
- Frequency scans of the DC side frequency response in the range of fundamental frequency and second harmonic.
- Studies of the DC bias current in the converter transformer windings caused by fundamental current on the DC side, caused by various factors, including induction from parallel a.c. lines. These studies include the effect of fundamental frequency blocking filters located in some converter station neutral connections.
- Time domain studies of the response of the DC side circuit to a.c. side faults, under conditions chosen to excite any possible low-order resonances.

The results of all these studies indicate that with the system including the DC shunt filters and fundamental frequency neutral blocking filters as designed there will be no problems due to any aspect of low-order harmonic behaviour in the HVDC circuit.

The specified limits for the harmonic performance parameter ("equivalent disturbing current") was set by the Customer at a level within the range which has been applied to other long distance HVDC transmissions in India and elsewhere, and which has not resulted in any known telephone interference related to those projects.

The maximum permissible calculated equivalent disturbing current, I_{eq}, at any location along the DC line corridor or electrode lines corridors is specified as 1500 mA in balanced bipolar operation and 2200 mA in monopolar operation (metallic or ground return). These limits are to be met for minimum to rated DC power in normal power direction with the normal variations of a.c. bus voltages and a.c. system frequencies and with all DC filters in service.

3. Converter model

The 12-pulse HVDC converters were each represented as four equivalent 3-pulse harmonic generators, including the coupling to earth provided by stray capacitances in the converter transformers, as is essential for the correct modelling of DC side harmonic flow.

The phase shift over the four three-pulse generators is such that the vector sum of the non 12-pulse triplens is zero over the pole, while the 12-pulse triplens add to produce the classical 12-pulse characteristic harmonics. The importance of the 3-pulse model, however, is that the 3-pulse voltage sources drive current through the ground connections formed by the converter transformer stray capacitances.

4. Harmonic voltage generation

The harmonic voltages generated by the HVDC converters on the DC side were calculated for each equivalent 3-pulse harmonic generator. Different calculation methods were used for 3-pulse and non-characteristic harmonic voltages as described below, and the results subsequently combined.

4.1. 3-pulse characteristic harmonics

The harmonics generated by the three-pulse sources are of all orders of three, i.e., 3, 6, 9, 12, etc. The voltage magnitude of each harmonic was calculated from a trigonometric Fourier series expression considering the relevant operating parameters.

For performance calculations, the combination of Pole 1 and Pole 2 operating conditions which give the highest vectorial difference between Pole 1 and Pole 2 harmonic voltages were chosen for each individual harmonic. For the even harmonics, this means that the combination that gives the highest vector difference between the poles was used. For the odd harmonics, however, the highest disturbing current occurs when the pole circuits and driving voltages are exactly equal.

4.2. Non-characteristic harmonics

The non-characteristic harmonics for a 12-pulse converter are those harmonics which are not multiples of the 12th harmonic. These harmonics, which apart from the second harmonic are generally relatively small, are caused by asymmetrical firing of the valves, unbalance between the transformer reactances between and within the 6-pulse bridges, and asymmetries in the a.c. voltage supply.

The asymmetries in the firing instants and commutating reactances can appear in different configurations and combinations. The magnitude and phase of the non-characteristic harmonics depend on the combinations in which the deviations are being considered. The maximum magnitude of each non-characteristic harmonic has therefore been calculated taking into account all possible different patterns of these unbalances by using statistical analysis.

4.3. Cross-modulated AC side harmonics

If the a.c.-side voltage applied to the HVDC converters is not of purely fundamental frequency, but contains some harmonic distortion, then the converter will modulate those harmonics, with a change in harmonic order, across to the DC side. For example, it is common to observe DC side 6^{th} harmonic generated in this way due to ambient 5^{th} and 7^{th} harmonic voltages on the AC system.

In balanced bipolar operation, due to the nominal balance between poles, the magnitude and angle of the transferred harmonics on the DC side are almost identical for the two poles, and so the resultant ground mode component is negligible. In monopolar ground return operation however, the magnitude of DC side I_{eq} caused by such levels of AC side voltage distortion at all low order harmonic frequencies may be more significant.

The effect of such transferred harmonics on the DC side harmonic generation was been calculated and taken fully into account in the filter design.

5. De-tuning

The effects of AC system frequency deviation and component tolerances were considered independently in the calculations. The extremes of frequency deviation and component deviation were always used in the sense that their effects combined to produce the worst possible equivalent detuning.

The capacitance variation due to temperature, element failures and aging has been considered in the calculations, considering an ambient temperature range of 0°C to 50°C for Agra; 40°C for Biswanath

Chariali and Alipurduar, and taking into account the dielectric heating and possible element failures. The capacitance change due to manufacturing tolerance is taken as zero due to the fact that the taps provided on the reactors will compensate for the manufacturing tolerance.

For reactors (except for the ST filter), the taps will be provided in 1% steps. An inductance deviation of one half of a tap step, i.e. ±0.5% has therefore been considered. For the ST filter, the tap steps are 5% covering a range of -20% to +10%. The exact tuning of this filter around the selected tap is not critical to the performance.

The calculations for bipolar mode assumed that the DC filters in the two poles could be de-tuned in opposite senses. This opposite-sense detuning is applied in the polarity that results in the maximum disturbing current, when combined with the effect of the unbalance between converter pole harmonic voltages. The temperature-based deviation of the capacitance values, however, is assumed to be in the same sense in both poles.

6. Filter design

6.1. Pole filters

The DC filter design consists of one switchable harmonic filter **bank** per pole. Each switchable bank consists of three non-switchable **branches** – $2^{nd}/6^{th}$ harmonic branch, a high-pass $12^{th}/24^{th}$ harmonic branch and a single-tuned higher frequency harmonic branch to ground, whose purpose is explained further below.

The filters are of similar nominal types at all converter stations, but differ to some extent in size, tuning and damping in order to provide the optimal matching to the different line impedances as seen from each station.

The design motivations for the choice of filter branch types were as follows:

HP2/6 – Due to near resonance of the DC line with the converter station impedance in some configurations, a 2^{nd} harmonic filter was necessary both in order to limit I_{eq} and order to mitigate the otherwise high levels of 2^{nd} harmonic currents and high voltage stresses on the equipment. Additional 6^{th} harmonic filtering is added in the double-tuned configuration to restrict the 6^{th} harmonic contribution to I_{eq} in monopolar configurations. The parallel damping in this filter is chosen to limit the potentially high 2^{nd} harmonic voltages on the filter equipment.

HP12/24 – This is a well-damped filter designed to mitigate the 12^{th} and 24^{th} harmonics and a wide-range of higher frequencies.

ST – There is a low impedance return path through the DC line capacitance to ground back through the pole side of the converter; and this results in a large contribution to I_{eq} from these triplen order harmonics, especially those of the higher orders (approx. h40-h60) which are not adequately mitigated by the HP12/24 filter. The ST filter is designed to provide an alternative low-impedance return path, and so is connected directly to ground. The reactors of the ST filters have been specified with a very wide range of taps, so as to allow substantial adjustment if required during commissioning.

Figure 2 shows the principal configuration for the DC filters and smoothing reactors of one pole (identical at all of the converter stations), plus the fundamental frequency blocking filter (only at Agra).

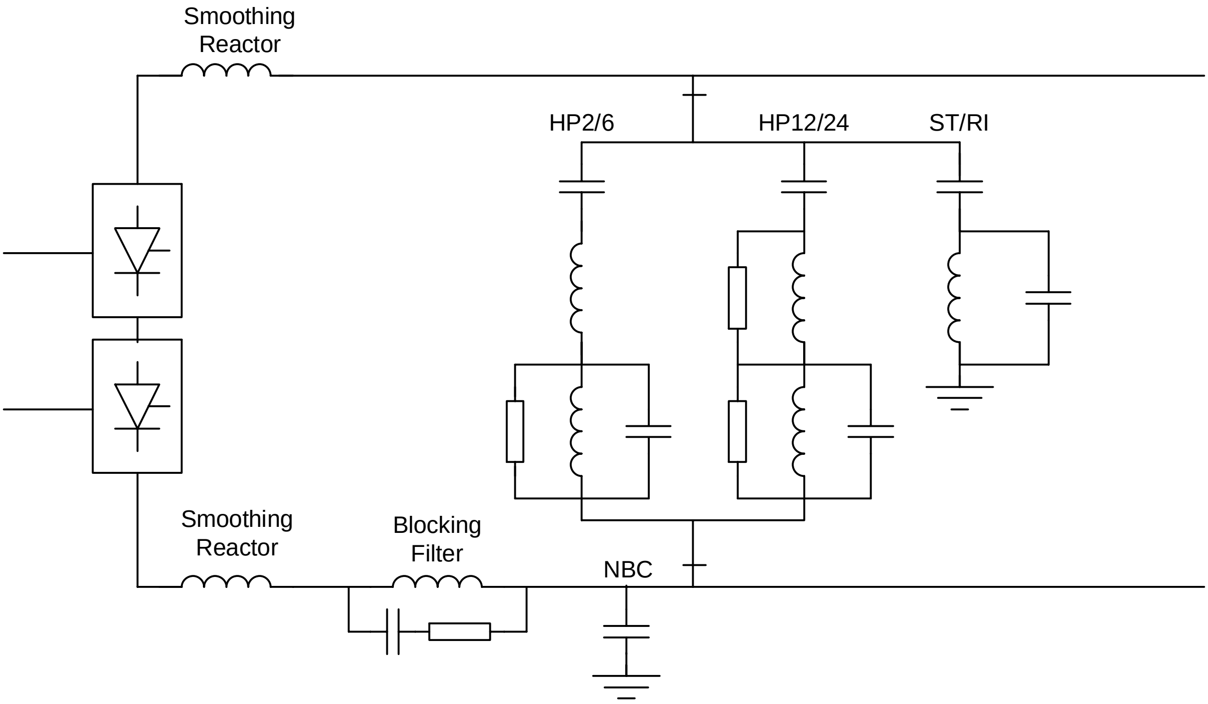

Figure 2 – Circuit diagram for one pole at Agra, showing relevant components for DC side filtering

6.2. Choice of neutral bus capacitor

Normally in an HVDC project, large neutral bus capacitors (NBC) serve to provide a low impedance in-station return path for the mainly triplen order harmonic currents driven through the transformer stray capacitances and thus minimize the flow of these harmonics in the DC line and the electrode line. The value of the neutral bus capacitance is chosen so as to provide a sufficiently low impedance path for these triplen order harmonic currents, while avoiding resonance with the electrode line at critical frequencies.

In this project the location of the smoothing reactor in the neutral alters the normal analysis of triplen harmonic flow, and a very large NBC is not necessarily advantageous. The role of the NBC is mainly to control harmonic currents in the electrode line, by providing a low-impedance in-station return path for harmonic currents.

One capacitor is connected between neutral bus and ground for each pole at each converter station. The capacitor size must be selected to avoid resonance with the electrode line at significant harmonic frequencies. The values chosen are 10 uF at Biswanath Chariali, 13 uF at Alipurduar, and 13 uF at Agra.

6.3. Pole filter outages

Disconnect switches are provided to allow removal of any one pole filter bank in the multi-terminal scheme, followed by continuing operation of that pole. There is no stipulation with respect to harmonic performance in the event of a single filter bank outage.

In the case of a DC filter bank outage in one pole in bipolar operation, it may be possible that the DC filter in the other pole in that station could also be switched out, in order to balance the bipolar circuit and reduce the harmonic disturbing current. However, the impact of this measure on I_{eq} is not large, and it is presently considered preferable for simplicity of operation to leave the remaining healthy pole filter connected.

6.4. Protection

The proposed DC filter protections consist of reactor and resistor thermal overload protections. The DC filter high voltage capacitor is of internally fused design with internal grading resistors. The grading resistors will ensure a proper voltage distribution in the capacitor bank even in the case of element failures.

6.5. Transient protection and insulation coordination

The DC filters will be protected from transient stresses due to faults, lightning, energization and other events by surge arresters. These components have no impact on the harmonic performance of the filters.

The arrester characteristics are chosen with consideration to the following criteria:

- The continuous and temporary operating voltages, crest value, including harmonic content.
- Peak current at filter discharge,
- Energy dissipation capability at filter discharge.

The DC line fault protection is designed to attempt several restarts in the event of a DC line fault which does not clear at the first restart attempt. These restarts will appear to the DC filter as repeated faults, and will therefore add to the cumulative energy to be dissipated by the filter arresters. The arrester energy dissipation has therefore been calculated for the case of two full voltage restart attempts and one reduced voltage restart attempt. The DC line voltage is assumed to be the pole bus SIPL for the initial fault, followed by full operating voltage (800 kV) for two restarts, and finally one restart at 640 kV.

6.6. Physical construction

The construction of some typical DC filter components is shown in Figure 3. The HV capacitors for the three branches are shown as constructed at Biswanath Chariali and Alipurduar.

At Agra however, due to the high level of industrial pollution and the consequent increased risk for switchyard flashovers, the decision was made to build the entire 800 kV part of the DC switchyard in a large indoor hall.

Figure 3 – DC filter high-voltage capacitors, reactors and resistors at Biswanath Chariali

7. Configurations and conditions studied

The configurations studied to demonstrate compliance with the harmonic performance criteria were:

- balanced bipolar up to 1.0 p.u. power with all DC filters in service.
- monopolar metallic return with all DC filters in service.
- monopolar ground return with all DC filters in service.

For component rating, all feasible operating conditions up to the specified limits were taken into account.

8. Fundamental frequency current in the DC circuit

8.1. Sources and effects

When a DC line shares the route along with ac transmission lines, steady state fundamental frequency component will be superimposed on the DC current because of the inductive and capacitive coupling from the parallel ac lines. This fundamental frequency current will be modulated across the converter, creating positive sequence second harmonic current and direct current on the AC side. A very small DC bias current in the converter transformer may cause an asymmetrical magnetization resulting in the core saturation. The possible sources for such DC bias current have to be investigated and the maximum predicted DC bias current must be maintained within the design limits of the converter transformer, if necessary by the use of mitigation measures.

There are two possible sources for direct current bias in the windings:

- direct current in transformer neutrals due to ground potential differences difference earthing points in the AC system, and
- cross-modulated fundamental frequency current in the HVDC circuit.

The latter may have three driving effects:

- fundamental frequency voltage induced in the DC lines due to parallel AC lines,
- firing angle unbalance, generating DC side fundamental voltage across the converter,
- AC side positive sequence second harmonic, cross-modulating to produce DC side fundamental voltage.

These three effects are now considered in turn:

1) **Induction from parallel a.c. lines**

   As the exact possible location of parallel AC lines along the route of the HVDC line was not known at the time of specification, a worst-case scenario was postulated, defined as one 100km exposure of parallel 400kV AC line, with 70m separation from the HVDC line (conductor to conductor) and with a maximum load of 500MVA. The parallel section is considered to be located at a point that results in maximum fundamental currents at each of the converter stations. The A-type 400kV AC line tower configuration is considered.

   The basic circuit model used for the calculation is shown in a simplified format in Figure 4.

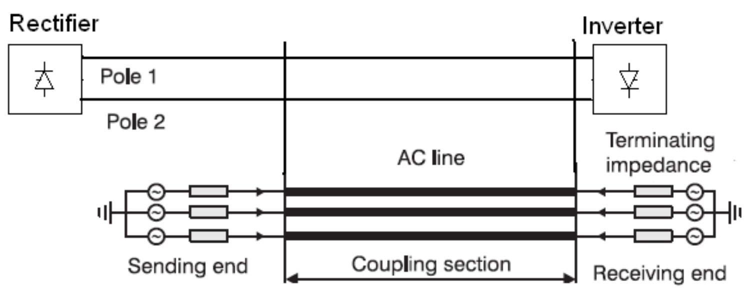

Figure 4 – Circuit for calculation of induction from parallel AC lines

Calculation of the induced current in the DC line requires proper representation of the driving sources for the coupling, i.e. the currents in the parallel AC line. (Capacitive coupling is negligibly low due to the relatively large distance between the lines.) These three phase currents can be represented by the corresponding positive, negative and zero sequence components. As the actual relative angle combinations of these sequence components in the AC line are unknown, the induced currents are calculated for each phase sequence separately and then magnitudes are added linearly. The assumed levels of negative and zero sequence current in the a.c. line are both 2% of the positive sequence current.

2) **Firing angle unbalance**
The valve firing angles are tightly controlled, but any small remaining firing angle unbalance will result in the generation of small DC side voltages at various harmonic frequencies and at fundamental frequency. For these calculations, the maximum firing angle unbalance per valve is considered which results in 0.1 kV per pole of fundamental frequency source voltage and from that the fundamental frequency current is calculated.

3) **2nd harmonic voltage on a.c. bus**
Any positive sequence 2^{nd} harmonic voltage on the converter buses will generate a fundamental frequency voltage across the converter DC terminals. For these calculations pessimistically high levels have been assumed for safety - at the rectifiers, d2 of 0.2% and at the inverter end (more industrial load) d2 of 0.4%.

Taking the above three fundamental frequency voltage sources independently, the currents in the circuit were then calculated using the same HVDC converter and DC circuit model as used for the DC filter design calculations. The maximum fundamental frequency current in each converter under any operation mode and configuration was then calculated as the quadratic sum of the currents due to these three sources. With the 3-terminal NEA800 scheme, calculations were made for a 22 different configurations of Bipolar, Monopolar Metallic, Monopolar Ground and Hybrid modes. For efficiency of calculation, the ABB frequency domain circuit analysis program was used.

In order to verify the frequency domain analysis, particularly in terms of the cross-modulation and the effective impedance introduced by the converters themselves in the DC side circuit, verification studies were made of key cases, using the time domain tool PSCAD/EMTDC. Good correspondence between the two sets of studies was observed.

Although the direct current does not transform to the line-side winding, it is convenient to calculate an “equivalent line side winding direct current” so that. To obtain the approximate corresponding magnetising effect on the line side winding, the cross-modulated current is therefore multiplied by the turns-ratio of the transformer to give the absolute maximum DC current in the line side.

The total direct current in the neutrals of all the converter transformers in each station caused by the ground potential difference at the converter station with respect to remote earth due to the HVDC electrode current is assumed to divide among the total number of converter transformers in service. This is then added to the cross-modulated “equivalent line side winding direct current” to estimate the total effective direct current in relation to the limit specified by the transformer design.

Under worst-case conditions, the total direct current in the transformer windings would have far exceeded the specified limit. Some mitigation measures were therefore essential.

8.2. Mitigation of DC side fundamental frequency current

Three possibilities for mitigation were investigated:

- A shunt 50 Hz filter would bypass the induced current from AC lines and stop its flow through the converters, but would exacerbate the other two, converter sources of fundamental current.

It would also allow very high 50 Hz currents to flow during commutation failures, and was therefore rejected.

- Firing angle modulation can be used to set up an equal-and-opposite fundamental frequency voltage across the converter, in order to annul any 50Hz current in the converter – a sort of active filtering by the converter. By itself it was found to be insufficiently effective, and also has the disadvantage of generating other unwanted non-characteristic harmonic frequencies on both the AC and DC sides.
- Installation of 50 Hz series blocking filters in the converter neutral connections, in order to insert a high impedance in the DC side circuit for fundamental frequency currents. This solution was found to be effective, has been used previously on other HVDC projects, and was therefore adopted.

Considering that the fundamental frequency current circulates in the complete DC circuit, in some such HVDC projects it has been found necessary to install blocking filters only at one location in that circuit, rather than at all stations. Studies were made with blocking filters installed at only the rectifiers, only the inverters or at both, with the conclusion that it was sufficient to install filters only at the inverter station, Agra.

Each blocking filter is composed of a single150 mH reactor unit, tuned by a parallel capacitor, with a damping resistor located in series with the capacitor to give reduced rating stress. This reactor plays no part in the normal smoothing process, as it is effectively bypassed by the capacitor at harmonic frequencies.

The blocking filters are highly effective at the exact tuned frequency, but less so at the wide detuning which would be possible due to the combination of frequency variations and the manufacturing tolerances of the reactor and capacitor. The capacitor has been designed with small tuning units which can be connected or disconnected offload to compensate for the manufacturing tolerances. This greatly increased the effectiveness of the blocking filter.

An arrester was included across the parallel L-C components, and the dimensioning energy stresses will occur during commutation failures, when very high fundamental frequency voltages are generated and appear across the blocking filter.

9. Conclusion

This paper has described the challenges entailed in the studies and design of the DC side harmonic filters for the multi-terminal project, and the mitigation of possible fundamental frequency currents in the DC circuit by means of series blocking filters.

The scheme is due to be commissioned in 2015-2016.

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HVDC LCC Technology Developments to facilitate Integration of Bulk Wind Power Resources

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SUMMARY

Today the power market and the requirements on the power transmission systems are characterized by the global environmental concerns over the use of conventional energy resources (nuclear, CO2 emissions), the increasing demand for more efficient electric energy production and transmission as well as the growing use of renewable energy resources. Power systems are becoming increasingly more interconnected and heavily loaded. Stable operation of the grids needs to be ensured under system conditions characterized by large-scale energy trading and a growing share of fluctuating regenerative energy sources, such as wind and solar power.

In response to these challenges, a new breed of efficient power converters, voltage-sourced converters (VSC) based on modular-multilevel converter (MMC) topology, was introduced into the market some years ago. The rapid technology development of larger, high efficiency VSC HVDC systems is ongoing and will continue for many years. In addition HVDC line-commutated converter (LCC) systems, especially with high power ratings, continue to play an important role in providing solutions for these challenges.

Indeed high-power HVDC systems are currently being planned across the United States and in other countries to bring the benefits of wind / renewable energy to consumers. Even if wind energy is generated onshore often such renewable resources are located far away from load centers. Existing power transmission infrastructure is often simply not capable of integrating large amounts of wind energy for transmittal and delivery to the end user. Although HVDC LCC technology is ideally suited for this task, providing an efficient and cost effective mechanism for transferring very large amounts of power over significant distances, the integration of bulk wind power poses challenges not only because of the behaviour of large wind power plants, but also in their application in AC networks. AC faults or the loss of a single pole operating at 1,500 to 2,500 MW can lead to severe disturbances in the AC systems.

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The paper discusses recent technology developments in HVDC LCC schemes to facilitate the integration of bulk power wind resources. The use of HVDC connections for intermittent generation, such as wind and solar energy, offers advantageous control capabilities. Integrating STATCOM's in LCC schemes ensures high security of the power systems and makes it possible to meet stringent performance criteria even under weak system conditions.

HVDC LCC Multi-terminal systems may be considered for collecting power from large, dispersed on-shore wind farms and could be used for power sharing over large geographic and possibly intercontinental areas.

Innovative solutions presented in the paper have the potential to cope with the new challenges of the power systems. This paper analyses some of the technical features of planned HVDC projects to integrate large scale wind power, presents some unique challenges associated with it and proposes novel solutions.

KEYWORDS

Dynamic performance; HVDC; HVDC projects; stability; STATCOM; SVC PLUS; technology; weak system operation; wind power integration

1. Introduction

Today the power market and the requirements on the power transmission systems are characterized by the global environmental concerns over the use of conventional energy resources (nuclear, CO_2 emissions), the increasing demand for more efficient electric energy production and transmission as well as the growing use of renewable energy resources. Power systems are becoming increasingly more interconnected and heavily loaded. Stable operation of the grids needs to be ensured under system conditions characterized by large-scale energy trading and a growing share of fluctuating regenerative energy sources, such as wind and solar power.

Even, if wind energy is generated onshore often such renewable resources are located far away from load centers. Existing power transmission infrastructure is simply not capable of integrating large amounts of wind energy for transmittal and delivery towards the end user. HVDC technology is ideally suited to integrate renewable energy resources such as wind and solar power into the power systems.

2. Choice of Technology

2.1. Voltage-Source Converters using Modular-Multilevel Converter Topology

In response to the challenges of the power market and transmission systems, a new breed of efficient power converters, voltage-source converters (VSC) based on modular-multilevel converter (MMC) topology, was introduced into the market some years ago. The rapid technology development of larger, high efficiency VSC HVDC systems is ongoing and will continue for many years.

Taking their distinctive features such as the capability to operate under weak AC network conditions and to supply passive loads (auxiliary power supply of the offshore wind farms), the smooth control of reactive power or AC voltage as well as the compact design into account VSC systems are well suited for the integration of large wind power plants.

Moreover, VSC schemes can be equipped with dynamic breaking valve/ resistors (chopper) to enable the fault ride through in case of AC system faults in the receiving AC network. Using modular breaking chopper modules the dynamic breaking resistors dissipate the generated power smoothly and thus ensure undisturbed operation of the wind power plant or isolated network [2].

The operation of the three large offshore grid connections in the North Sea, BorWin2 (800 MW, ±300kV), HelWin1 (576 MW, ±250kV) and SylWin1 (864 MW, ±320kV), using HVDC PLUS proves the suitability and excellent capabilities of MMC technology to facilitate the integration of bulk wind power resources. The HelWin2 project is scheduled to start commercial operation in the first half of the year 2015. Figure 1 depicts the compactness of such converter stations showing the currently largest offshore VSC platform SylWin1 in operation and the valve hall of HelWin1 [3].

Fig. 1: Offshore VSC platform SylWin1 in operation and converter hall of HelWin1

Using current technology, and some very near term developments, bipolar HVDC systems with power ratings in the range of 2,000…2,400 MW (2 kA, 500…600 kV) are available. Regardless of relatively lower power ratings the capital costs and losses are still somewhat higher than for comparable line-commutated converter (LCC) HVDC options. In addition to VSC HVDC systems, LCC HVDC schemes, especially with high power ratings, continue to play an important role in providing solutions for the new challenges of the power systems.

2.2. Line-Commutated Converter (LCC) HVDC Systems

Line-commutated converters require a relatively strong synchronous voltage for the commutation process, which can be described as the change of current flow from one thyristor valve to another in a synchronized firing sequence of the valves during operation. Thus, stable operation under weak AC system conditions with low or very low short-circuit ratio (SCR or ESCR) requires very fast control of AC voltage accompanied by further converter control features. In addition to the voltage stability aspects, low short circuit conditions of the AC system (high AC impedance) increase the demand for reactive supply in combination with the requirement for smaller AC filter or shunt capacitor bank sizes otherwise, the AC voltage change due to (sub-) bank switching exceeds acceptable levels. It is worth mentioning that the large amount of reactive supply increases temporary overvoltages (TOV) in case of large disturbances such as AC and DC faults.

Despite the operational aspects for weak AC system conditions, LCC HVDC systems are characterized by a high degree of maturity, low power losses, significant inherent overload capability, excellent DC line fault recovery performance as well as a high reliability and power availability. By the nature of the semiconductors available in the market LCC HVDC has a very high current and overcurrent capability and can be used for HVDC transmission with extremely high bulk power ratings up to 8,000 MW and up to ±800 kV DC [1].

Fig. 2: Line-commutated converter station in operation

Although HVDC LCC technology provides an efficient and cost effective mechanism for transferring very large amounts of power over significant distances, the integration of bulk wind power poses challenges not only because of the behaviour of large wind power plants, but also in their application in AC networks. AC faults or the loss of a single pole operating at 1,500 to 2,500 MW can lead to severe disturbances in the AC systems.

3. HVDC LCC Technology facilitating Integration of Bulk Wind Power

3.1. Technical Challenges

Indeed high-power HVDC systems with ratings in the range between 3,200 and 4,300 MW are currently being planned across the United States and in other countries to bring the benefits of wind / renewable energy to consumers [2]. Many of the most valuable wind resources in North America and other continents are located far away from the biggest load centers. It is difficult to deploy the great wind resources available due to the lack of transmission capacity. HVDC transmission, in particular LCC technology, has been considered as the preferred solution to transfer onshore bulk wind power taking the following aspects into account:

- well proven technology with high reliability / power availability and low losses (<1.5% for two converter stations)
- power ratings using a bipolar scheme with ±600 kV DC voltage whereas for VSC schemes a parallel converter arrangement would be required
- capability to extinguish DC line fault currents quickly including a subsequent fast and stable recovery – for VSC schemes DC breakers or full-bridge MMC would be required to ensure stable operation of the wind power plant as well as the receiving AC system
- no constraints regarding converter station footprint

Normally, large onshore wind power plants are connected to the AC system to provide additional wind power to the local AC system as well as to enable the supply of auxiliary power for the wind power plant / collector system by the local AC system. Therefore, there is not a stringent requirement for black-start capability of the HVDC system. Using tapping of transmission lines or considering single line connections (N-1 contingency conditions) to the local transmission system will result in HVDC operation under very weak system conditions. Having such a large amount of wind generation in a relatively weak grid poses a number of challenges such as the need for an optimized reactive power control scheme, operation with low short circuit level conditions as well as the lack of significant inertia associated with wind generation. For some of the projects being planned across the United States the effective short circuit ratio (ESCR) at the rectifier AC bus without wind farm contribution is in the range of 1.4 or even lower.

For obvious reasons the wind power plants are clustered into several wind parks ranging between 500 MW and 800 MW each. The HVAC wind collector system will terminate into the converter station AC bus with 4 to 6 double circuits. Furthermore, different types of wind turbine technology will be used to build such large wind parks.

In order to ensure stable and secure operation of the HVDC system as well as the local connected AC system specific aspects need to be addressed properly. Technical feasibility and compliance with the grid code requirements requires due consideration of the following aspects:

a) The AC system frequency shall be maintained within the specified limits, including temporary frequency excursions in case of contingency conditions: AC faults at inverter side, DC line and converter faults, faults within the wind power plant or the collector system.
b) The AC system voltage needs to be controlled within the specified limits taking into account over- and undervoltage conditions during faults / full- and partial load rejection and the HVDC recovery after fault clearing.
   → The weak AC system connection may require special controls to keep the AC system voltage and/ or reactive power exchange within tight bands in order to avoid / minimize disturbances on the AC system, load flows etc..
c) Over-currents flowing into the AC transmission line(s) under contingency conditions (full- or partial HVDC load rejection) shall not cause AC line-protection trips. Even if the magnitudes are lower than maximum AC fault currents such over-currents may last until the HVDC has recovered and has restored power transfer.
d) Compliance with the harmonic performance requirements as well as harmonic stability of the grids (wind collector system), characterized by a large penetration of converters, has to be ensured.
   → AC filters with low-order filters and high-pass damping characteristic provide adequate solutions
e) Start-up and shut-down sequences of the wind power plant / collector system in conjunction with the operation at minimum HVDC power transfer levels, especially for LCC systems, has to be determined thoroughly.
f) Most likely different types of wind turbine technology will be used. The different types of wind turbine generators (WTG: type 3 – DFIG, type 4 – full converter) including their controls will considerably impact the transient / dynamic response and overall system performance.

3.2. Technical Features and Novel Solutions

Technical features and solutions to facilitate the transfer of bulk wind power using HVDC LCC technology have been developed and verified using EMT-type and stability simulations. Some of the major technical challenges and corresponding solutions are summarized below.

AC frequency deviations: Due to the weak network conditions and substantial amount of wind power installed at the rectifier side, frequency deviations can be significant during contingencies. Therefore, several DC power modulation and frequency control functions are implemented in the HVDC controls to ensure stable operation and to limit frequency deviations in case of AC and DC system faults including the loss of one pole. Only in the unlikely event of the loss of the HVDC bipole is cross-tripping of wind generation required to maintain system stability.

> *Scenario - AC fault at the inverter side, resulting in an extremely weak AC system:* The AC fault is cleared by tripping the one of the most important AC lines. As a consequence, the AC system was not strong enough to enable a fast recovery of the HVDC system to 100% pre-disturbance levels. A DC power limitation (run-back), combined with other advanced control features, is initiated to quickly reduce the DC power to predefined levels (e.g. 60% of the rated power) under such multiple contingency conditions (at recovery). This power run-back function is very important to retain system stability and to avoid repetitive commutation failures. As a result of the DC power run-back, some generated wind power flows into the rectifier AC network. This is counteracted by initiating a signal from the HVDC controls to the wind power plant controllers triggering a proportional MW-output adjustment of the wind turbines. The function also prevents thermal overloads in the nearby AC system area (similar for the loss of one pole). Fast communication between the wind power plant controllers and the HVDC controls is required.

If there is an additional need to increase inertia of the wind collector AC system the integration of synchronous condensers can be used to strengthen the system. For example, synchronous condensers in combination with STATCOMs will be required, if the HVDC LCC system is operated at high power transfer levels in islanded mode with the wind collector system. In order to comply with the grid code requirements at high wind power transfer levels and extremely weak AC network conditions, islanded operation of the rectifier / wind collector with the AC system lines disconnected could be considered as alternative mode. Controlled disconnection from the local AC system prevents large disturbances on the AC system and allows operation of the wind power plant / collector system within broadened frequency and AC voltage bands.

Active power exchange with the rectifier AC network: In order to control the active power exchange between the wind power plant, the HVDC system and the connected AC network, a power exchange controller (PI controller) has been designed and implemented in the HVDC controls. The HVDC control system measures the active power flow into the rectifier AC network and adjusts the DC power reference value to control the active power exchange with the network within a predefined, narrow band. Due to the fluctuating nature of wind power, this PI controller will slowly and continuously modulate the DC power, ensuring that in steady-state conditions the AC network load flow is not altered and all generated wind power is transmitted via the HVDC system. This controller action is based on local measurements and thus does not rely on communication between the wind park controller and the HVDC controls.

> *Scenario - AC fault at rectifier side:* An AC fault in close proximity to the rectifier station results in the trip of 764 MW wind generation. After fault clearing, the HVDC system recovers quickly to pre-fault power transfer levels. Without additional measures, the lost wind power will be drawn from the rectifier AC network. However, coordinated with the

fast acting frequency controller the implemented HVDC active power exchange controller automatically reduces the DC power transfer level to minimize the power exchange with the AC network at the rectifier side (Fig. 3).

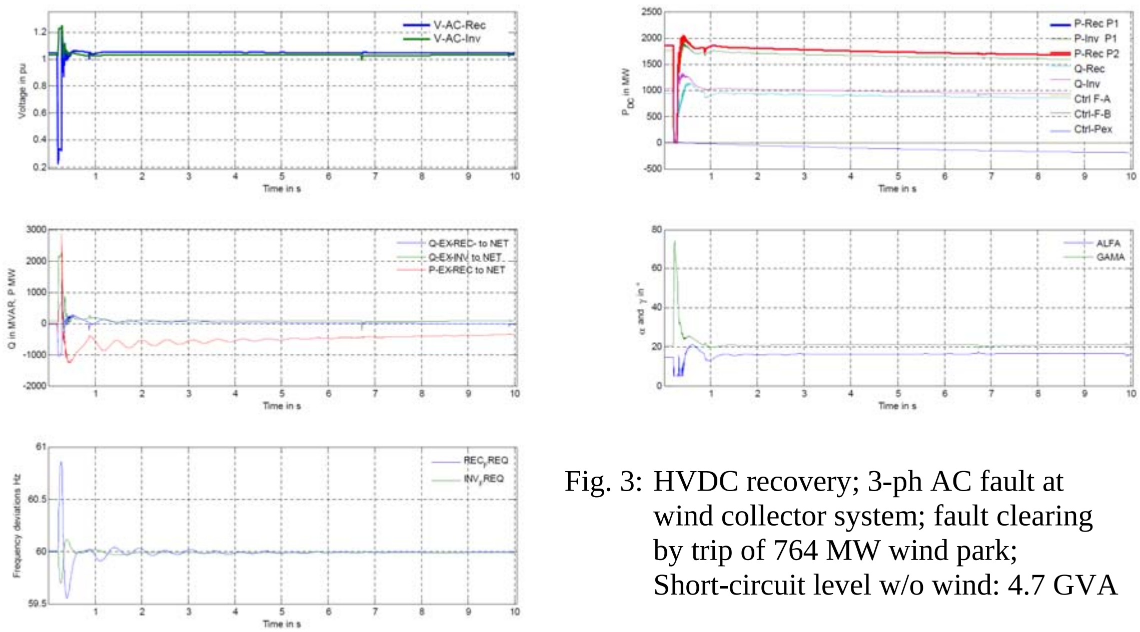
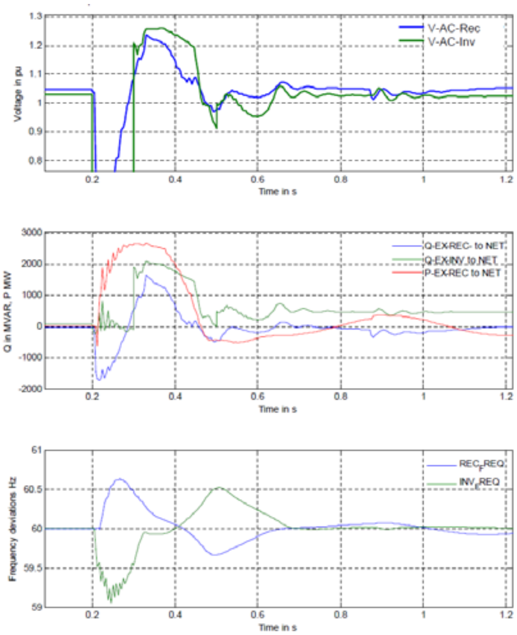


Fig. 3: HVDC recovery; 3-ph AC fault at wind collector system; fault clearing by trip of 764 MW wind park; Short-circuit level w/o wind: 4.7 GVA

Fast and stable HVDC recovery / Transient and temporary overvoltages: During AC system faults as well as DC line faults, there is a sudden loss of reactive power consumption of the converter(s). For example, an AC system fault at the inverter causes an AC voltage drop resulting in a HVDC commutation failure and the loss or reduction of DC power transfer. Immediately after fault clearing, the HVDC system starts to restore power transfer to pre-disturbance levels (recovery approx.. 200 ms). The MVAr mismatch between converter consumption and the AC filter / shunt capacitors connected to the AC bus may result in high transient and temporary AC overvoltages (before and during recovery). This can be more important if the fault-clearing weakens the AC system, i.e. trip of important transmission lines or large generators. State-of-the art multilevel STATCOM devices play a key role in this aspect by providing fast dynamic reactive compensation.

In addition to the requirement to control overvoltages, the STATCOM supports the AC voltage during the recovery by supplying maximum capacitive reactive power. This voltage support function prevents an AC voltage collapse and thus assists in avoiding commutation failures and voltage instabilities during HVDC recovery under weak system conditions. It is very important to provide a robust solution for the whole range of operating conditions including certain contingencies / pre-fault conditions (Fig. 4).

With adequate ratings of the STATCOM devices the number and size of the AC filter / C-shunts can be optimized. There is no need to install additional shunt reactors.



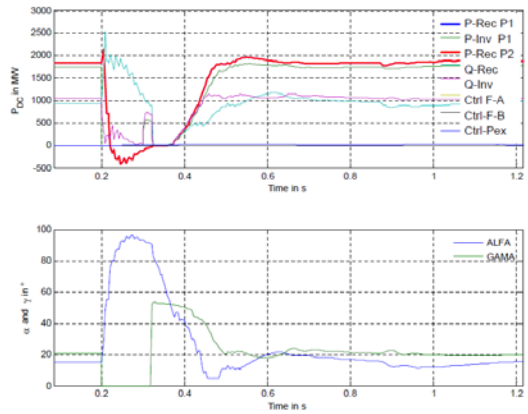


Fig. 4: HVDC recovery w/o power limitation
3-ph AC fault at Inverter
ESCR after fault clearing < 1.5 pu

AC voltage control / Reactive power exchange with the AC network: Another important design aspect is the AC voltage and reactive power control (RPC). In order to avoid an impact on the AC system voltage (or load flow) at the point of common coupling, one solution is to operate the HVDC system in "Q-mode" keeping the steady-state reactive power exchange with the AC network within a specified band. Furthermore, if the AC voltage exceeds the specified, normal range, fast voltage limitation control capability of the HVDC system with incorporated STATCOM units will be utilized to minimize AC voltage deviations. Proper coordination between the RPC of the converters including AC filters, the STATCOM units as well as the voltage controllers of the wind power plant (park pilot) ensures optimized operation and sufficient dynamic Var-control capability.

3.3. Impact of Wind Park Models

It is important to note that the optimum overall dynamic performance of the HVDC system is largely influenced by the dominant presence of wind park generation and its dynamic response during system faults, HVDC power flow disturbances and potential sudden loss of parts of the wind power plant generation. The wind park's dynamic behaviour will in fact be based on a combination of various suppliers and types of wind turbine generators. Adequate performance of the overall transmission system will necessitate a new approach to cooperate in the provision of wind park control and wind generator data with the associated models. As discussed above, the incorporation of STATCOM devices will assist in improving the AC voltage stability. However, because the size of the wind power plant is so large and is approximately equal to the HVDC transmission, its reactive power characteristics and AC voltage control will dominate any voltage support devices installed at the converter bus. The ability to influence the wind generator and wind park controller design with respect to power recovery dynamics (fault ride-through response), reactive power and voltage control among other fault response criteria is deemed to be necessary.

3.4. Multi-terminal Systems

Long distance HVDC LCC transmission systems are becoming economically attractive to exploit bulk wind power resources far from the load centers. Multi-terminal systems or mid-line taps could result in substantial benefits for the crossed region. HVDC multi-terminals or systems with taps enable to collect power from large, dispersed on-shore wind farms and could be used for power sharing over large geographic, possibly intercontinental areas. Despite the demand for a cost-optimized solution one of the major challenges is to minimize the impact of the mid-line terminal on the reliability of the main transmission system. The power transfer curtailment of the overall scheme due to tap / mid-terminal failures shall not overwhelm the benefits of the third terminal.

Detailed investigations have been carried out to study and design a ± 600 kV bipolar LCC HVDC system with the capability to deliver 3500 MW of energy to the load center. The rating of the parallel connected middle tap is only 500 MW compared to the largest station rating of more than 4,000 MW. This large difference in rating will result in increased probability of performance issues at the small tap especially when operating as an inverter.

The basic reason for the degraded performance as one tap becomes much smaller than the other parallel converters is that a small current deviation at a large converter is a much larger deviation (in percentage of rating) at the small converter. A transient current increase at the small tap inverter can cause a commutation failure even when the AC voltage is normal. As well, if the small inverter is in parallel with a much larger inverter and there is a small AC voltage reduction at the small tap, the DC current will increase and some of the current formerly flowing to the large inverter will divert to the small one, again increasing the probability of a commutation failure.

In order to improve the performance and to reduce the effect described above, the small tap has been configured as a 500 MW monopolar converter tap. Consequently, one pole is operated with three parallel converters and the other pole in a point to point operation. With this configuration the small tap rating of 500 MW is almost 25% compared to the largest converter in that pole. The DC switchyard of the monopolar converter terminal has been configured to allow bi-directional operation of the tap in both poles. Additional HVDC design measures and control features incorporated ensuring reliable and stable operation of the multi-terminal system.

4. Conclusion

It is widely acknowledged that HVDC LCC technology provides an efficient and cost effective solution for transmitting very large amounts of power over significant distances. However, the integration of bulk wind power using line-commutated converter technology poses a number of unique challenges. Design and stability studies carried out demonstrate that these technical issues can be solved with the implementation of advanced control features as well as a proper coordination between the controls of the wind power plants and the HVDC system. With the incorporation of STATCOM units, the AC voltage stability and the overall dynamic performance can be enhanced considerably. Moreover, LCC multi-terminal systems may be considered for collecting power from large, dispersed on-shore wind power plants and could be used for power sharing over large geographic areas. Innovative solutions have the potential to cope with the new challenges associated with the integration of bulk wind power resources using HVDC LCC technology.

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CIGRE Working Group B4.61 –
General Guidelines for HVDC Electrode Design

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SUMMARY

HVDC electrodes have traditionally been installed on HVDC transmission systems to provide a low resistance current return path during both monopolar and bipolar operation, using the earth and/or sea as the conductive medium. HVDC electrodes are in general less costly and have lower losses than dedicated metallic return conductors. Although environmental concerns are tending to increase, a number of electrodes have been in use more than forty years without safety issues and with very little actual measurable environmental impact.

Available literature on HVDC electrode design generally covers electrodes in simplified way using regular geometrical shapes, rule of thumb site selection methodologies, generalized discussion of impacts of electrodes on infrastructure, and provides limited information on existing electrode installations. Topics such as electrical ground potential rise and surface gradient studies to define step voltages and transferred potentials, electrode element material selection, instrumentation and auxiliaries required for an electrode station, application of electrodes for VSC HVDC systems, electrode testing and commissioning, and pond electrode analysis and design are not covered in detail.

With the development of new geophysical and geological investigation techniques, and more powerful computer simulation tools for electrical field studies and infrastructure modelling, potentially more economical designs of ground electrodes can be achieved, and the impacts of the electrode operation on existing or potential future infrastructure can be more accurately quantified. CIGRE WG B4.61 was initiated to highlight updated techniques and to formalize methodology and guidelines for the analysis, design and construction and testing of new electrodes and refurbishment or extension of existing electrodes.

This paper provides an overview of technical brochure that is being prepared by the WG with focus on the design considerations and new technologies that have become available for the electrode site assessment/selection and prediction of potential local and remote impacts.

KEYWORDS

HVDC Electrode, environmental impact, safety consideration, Site selection, Electrode design

1. INTRODUCTION

CIGRE WG B4.61 was formed in 2011 to prepare a technical brochure that provides general guidelines for the design of ground return electrode stations for HVDC transmission system.

The scope of the WG includes

1. Review of HVDC schemes, electrode configurations, and modes of electrode operation.
2. Review of electrode types, selection of type of electrode for a scheme.
3. Update a survey conducted by B4-44 on operational experience of installed electrode stations and designs of auxiliaries and monitoring systems.
4. Develop or summarize electrode design criteria including electrode duty, safety, polarity, electrical interference, corrosion impacts, and electrolysis emissions.
5. Review of site selection criteria and process.
6. Provide an update on the technology available for electrode station study and design
7. Geological modelling scenarios, including earth and water resistivity measurement technologies; field programs to collect the resistivities, and definition of extents of geological units to be modelled
8. Electrical field simulations, including modelling the electrode in the earth and/or sea model and interpretation of results
9. Land, shore/pond and sea electrode design processes and design examples including data required for environmental impact assessment.
10. Electrical interference, corrosion impact and simplified electrolysis emission analysis.
11. Electrode line termination and integration into electrode installations.
12. Auxiliary systems for electrode stations.
13. Testing and commissioning practices.
14. Operation and maintenance including possible instrumentation monitoring

Due to the limitation on the size, it is not possible to cover all the topics of Technical Brochure in this paper. Thus the following aspects will be addressed in this paper.

- HVDC configurations that result in ground return current
- Types of electrodes and selection
- Electrode site selection process
- Design considerations and methodology

2. HVDC SCHEMES ASSOCIATED WITH GROUND RETURN CURRENT

The basic configurations of HVDC systems include back-to-back, bipolar, monopolar and multi terminal systems. The HVDC schemes using electrodes as ground return path are described here. Figure 1 shows the monopole configuration with continuous earth return operation. The converter station may use either LCC Line Commutated Converter (with thyristor) or VSC Voltage Sourced Converter (using transistor as IGBT for instance). The reversal of power flow is possible with reconfiguration of pole conductor and neutral bus for a LCC scheme, and through controls without reconfiguration for a VSC scheme.

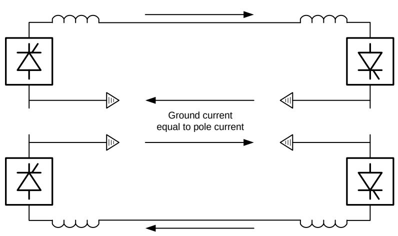


FIGURE 1 - MONOPOLE CONFIGURATION WITH ELECTRODES

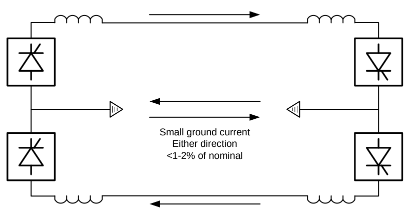


FIGURE 2 - BIPOLE CONFIGURATION WITH ELECTRODES

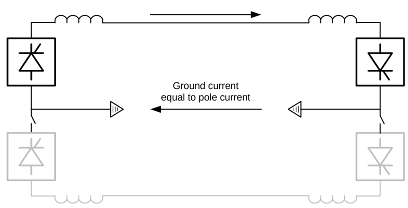


FIGURE 3 - BIPOLE CONFIGURATION OPERATED AS MONOPOLE WITH ELECTRODES

Figure 2 shows a bipolar configuration. The earth return circuit under normal operation carries only the bipolar imbalance current and full pole current including overload current under a contingency of the loss of a pole. The scheme can incorporate a metallic return provision to limit the use of earth return operation under a contingency. A bipolar system can temporarily operate as monopolar with ground return during pole trip under fault conditions as well as pole maintenance as in Figure 3. The current to ground is equal to the pole current.

3. TYPE OF ELECTRODES AND SELECTION OF ELECTRODE TYPE

There are three main types of electrodes; land electrodes, shore/pond electrodes and sea electrodes. Within each of the above categories there are possible variations in type and geometry. Generally electrode construction is most favourable in lowest available resistive media and circular geometry is applied where possible to avoid unequal current distribution due to fringing effects. However successful designs have and can be achieved even with irregular shapes and relatively high soil resistivity.

Selection of the electrode type and electrode geometry is a critical step during ground electrode design. Significant effort is required to select technically feasible, reliable, economical, site with acceptable environment impacts. In the selection of the electrode type one should consider the following factors:

- Maximum ground current and duty of electrode operation
- The predominant soil resistivity and geology in the vicinity of the converter station. Favourable soil conditions would allow land electrodes in areas where the converter is far from the sea.
- The distance between the converter station and the sea (sea/shore/pond electrodes offer the possibility of installation in very low resistive media)
- Number and types of infrastructure near the electrode that a could be affected by electrode operation
- Land use and social impact
- Operation and maintenance philosophy
- Possible environmental impact
- Cost

The type of electrode to be used normally becomes clear during in parallel with the site selection process and design process.

4. ELECTRODE SITE SELECTION CRITERIA AND PROCESS

The typical steps in the site selection process are presented in a flow chart in Figure 4.

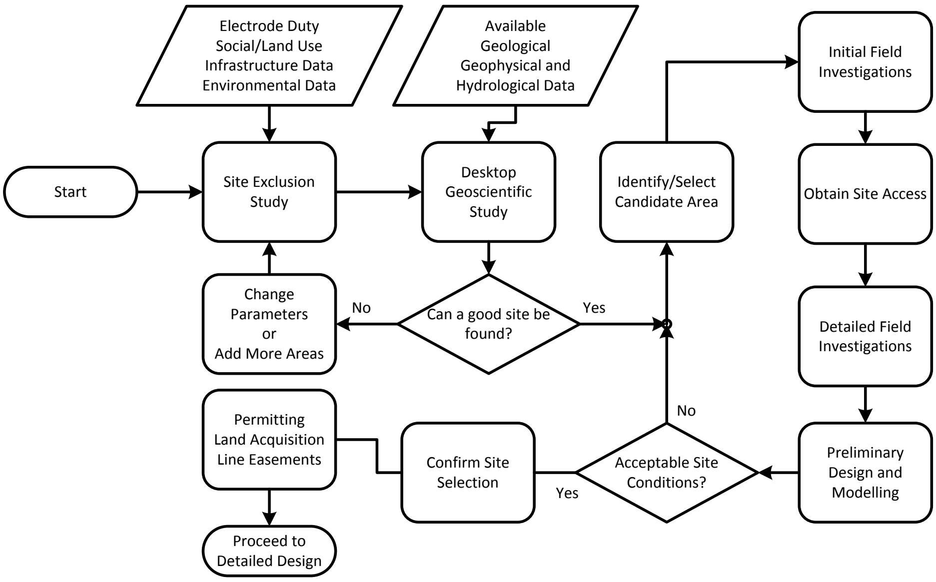


FIGURE 4 – TYPICAL FLOW CHART FOR SITE SELECTION PROCESS

The results from one step in the process will most likely influence the process for the following steps and there could be loops. It can therefore be difficult to plan the entire process in detail beforehand. Different steps in the process are described in the sections below.

The flow chart should be seen as a generalized framework. Each project is unique and the different steps in the site selection process might be carried out in a different order. Since the process is iterative and the outcome can be difficult to predict, it is important to start the site selection process at an early stage of the HVdc project.

4.1 Site Exclusion Process

The first step in determining appropriate locations for electrode station sites is usually to conduct a site exclusion study. Such a study will assist in order to quickly eliminate inappropriate sites.

As input to a site exclusion process, the following information would be required:

- The areas where the converter stations are to be located.
- The areas where electrodes will not be allowed to be built.
- The areas where electrodes might be allowed to be built, but at a high cost or with environmental impact or significant impact on infrastructure
- If the electrode line (or cable) could be routed through the local terrain.

Geospatial information tools such as Geographic Information Systems (GIS) are useful to quickly carry out such studies. The datasets can be loaded into a GIS application as spatial layers, exclusion criteria can be developed and implemented and as a result, areas considered unsuitable for electrode location can be identified.

In cases where no potential sites with suitable geophysical and geological characteristics can be found after the site exclusion process, it would be necessary to revisit the process and possibly adjust some of the exclusion parameters recognizing that there may be economic impacts.

4.2 Geophysical, geological and hydrological aspects of site selection

The effective resistivity of the soil may vary within three or four orders of magnitude between areas of different geological conditions and the resistivity distribution is therefore a critical parameter in the selection of electrode site.

The electrode must be located in a location where the resistivity of the soil material is low and relatively consistent so that sharing of current between electrode elements or electrode sections will not be too uneven. The resistance of the electrode to remote earth depends on not only the properties of the host material near the electrode, but also the resistivity of rock units away from the electrode. For example, an electrode placed in e.g. fairly thin low-resistivity soil cover underlain by high-resistivity rock will have high resistance.

The resistivity down to a depth that is comparable to the distance between the electrode and the observation point must be considered. If the underlying rock or geological strata exhibits high resistivity, the current will not rapidly disperse deep into the earth and problems with corrosion of buried infrastructure due to stray currents may occur at tens of km away from an electrode. .

Unfavourable conditions with high electric resistivity in the bedrock is common in areas dominated by solid crystalline rock (granite, gneiss or similar). Favourable conditions with low resistivity to significant depth may be found in certain geological environments like deep sedimentary basins, rift zones, areas with active volcanism and areas with graphite bearing rock.

For sea/shore/pond electrodes, the low resistivity of salt or brackish water will usually keep electric fields at low levels around the electrode. However, significant electric fields in the water can result if a sea/shore/ pond electrode is located in a shallow water environment underlain by solid, crystalline rock.

Electrode resistance, thermal effects and electro-osmotic effects are dependent on the soil material into which the electrode is installed. Unfavourable soil conditions may require large electrodes with large contact surface to the host material and will be more expensive. Careful selection of electrode site might therefore be cost saving.

4.3 Geoscientific desktop study and definition of candidate areas

The purpose of a geoscientific desktop study is to compile available geological and geophysical information into a regional model of relevant parameters for selecting candidate locations. Relevant information includes but is not limited to the following.

- Geological maps which are usually available at different scales.
- Deep geophysical measurements like magnetotelluric (MT) measurements. The image in Figure 5 shows a two dimensional interpretation of the variation of resistivity with depth along a given line derived from magnetotelluric data acquired around the Gerus electrode of the Caprivi Link.
- Airborne geophysical data which are available from some national geological surveys. Figure 6 shows results from helicopter-borne measurements at Caprivi, Namibia. The resistivity at approximately 15 m depth below surface is shown.
- Marine geological maps.
- Bathymetric information.

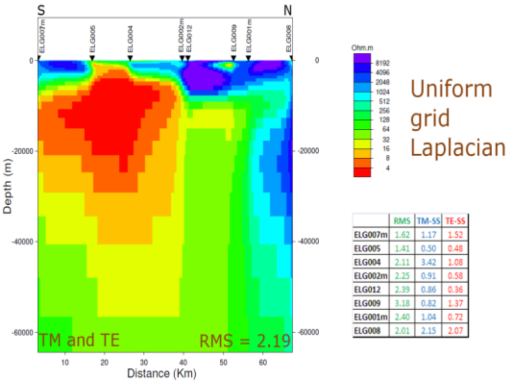


Figure 5 - MODEL BASED ON MAGNETOTELLURIC SURVEY [1]

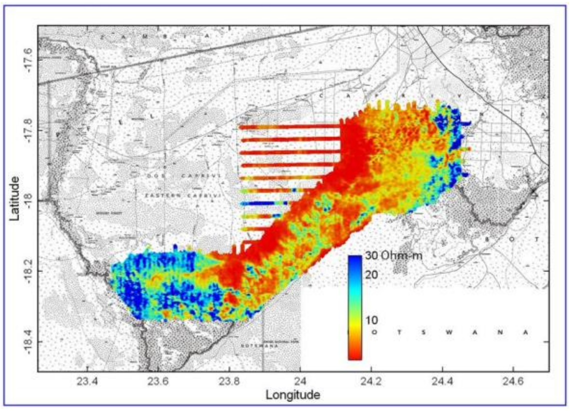


Figure 6 - MAP SHOWING HELICOPTER-BORNE GEOPHYSICAL RESULTS FROM CAPRIVI, NAMIBIA [2][3]

Information that is relevant for the site selection process should be extracted from the available sources of information. The result may be very detailed or quite coarse depending on the available information. The information should be presented in a desk-top study report. The report should point out areas where it should be possible to locate an electrode and where it would not be possible. The report should also include information about what information is missing for the next steps in the process.

4.4 First resistivity model

It is advisable to construct a tentative resistivity model of the ground based on the outcome of the desktop study. The complexity of the model will be a function of the available data. The resistivity of certain geological units might be completely unknown and values may be assigned based on the experience from other places with similar geological conditions. The model can be used to predict the magnitude of the electric potential and the electric field as a function of distance from a tentative electrode position. The predictions should be treated with great caution if the model is based on uncertain and/or inferred parameters.

4.5 Initial field investigations

The geoscientific desktop study might not give information about the resistivity at large depth. The desktop study and first resistivity model should indicate if such information is necessary for the site selection. A magnetotelluric survey should be carried out if that is the case.

Initial field investigations should also include site visit for geological reconnaissance mapping. The site visit should focus on parameters that are essential for the electrode function and construction. This will include rock and soil types, soil particle size, soil moisture, possible depth to ground water table, land access and constructability, environmental factors etc.

Initial field investigations for sea electrodes can include sonar or echo-sounding investigations of sea-bottom topography and morphology. It should also address possible restrictions for electrode cable routing.

4.6 Site selection

Candidate sites for an electrode should be selected in areas that have passed the site exclusion process and where appropriate geological conditions can be expected based on the geological desk-top study and initial field investigations. A number of candidate sites can be selected since some of sites may be disqualified later based on the results of detailed site investigations.

Trench based land electrodes should preferably be located in areas with shallow groundwater. Clayey soils should be avoided if the electrode will be used as anode, since problems with electro-osmosis might occur. Land electrodes based on vertical boreholes should be located in areas with fairly thick cover of alluvial sediments, permeable sedimentary rocks or similar. The groundwater should be at reasonably shallow depth to avoid the necessity of drilling deep holes. Drilling may also be complicated by unconsolidated sediments since holes might collapse.

4.7 Permitting, land acquisition, line servitudes

Detailed field investigations will in many cases require land owner and stake holder permissions. Many types of geophysical and geological investigations might therefore be limited to selected sites where such permissions have been arranged. The permitting process can take considerable time. It is therefore essential that the entire site selection process is started in good time so that the site selection will not become a matter of where the permits can be arranged quickly enough.

4.8 Detailed field investigations

Detailed site investigations with geophysical methods should be carried out in order to test if candidate sites fulfil the requirements for an electrode location. Testing of candidate sites on land might in some cases require boreholes and in some cases not. Electrode sites can be tested with DC resistivity measurements. Profile measurements with some kind of multi-electrode system will enable two- or three-dimensional modelling of the data. An example of the results from such a survey with around 10 m investigation depth is seen in Figure 7.

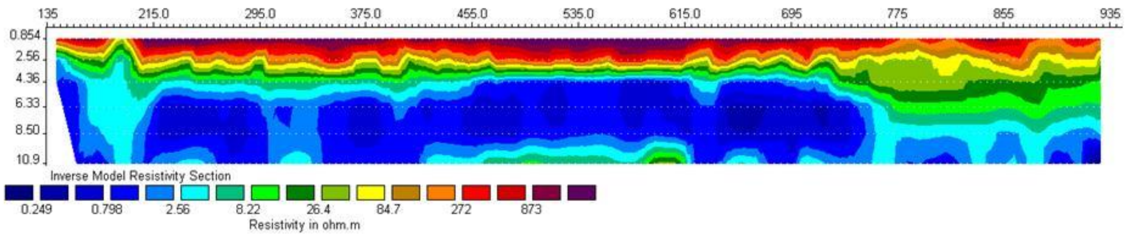


FIGURE 7- RESULTS FROM DETAILED GROUND RESISTIVITY PROFILE (COURTESY OF NAMPOWER)

Detailed field investigations for sea electrodes should investigate factors like sea currents, sea-bottom roughness and sea-bottom soil conditions. Morphological and geological investigations can include side-scan sonar, sub-bottom profilers and echo-sounders. Bottom conditions should also be investigated by divers and/or with underwater vessels and documented by camera. Soil sampling can be carried out with grabsamplers or boxcorers.

5. DESIGN CONSIDERATIONS AND PROCESS

Design of an electrode must consider the following aspects:

- Safety
- Physical design criteria and constraints
- Potential environmental impact
- Potential influence of electrode operation on other facilities

These aspects would be addressed in the design roughly in the sequence indicated above. As with site selection the process may need to be adapted or modified for individual designs. A conceptual flow chart of the design process is shown in Figure 8.

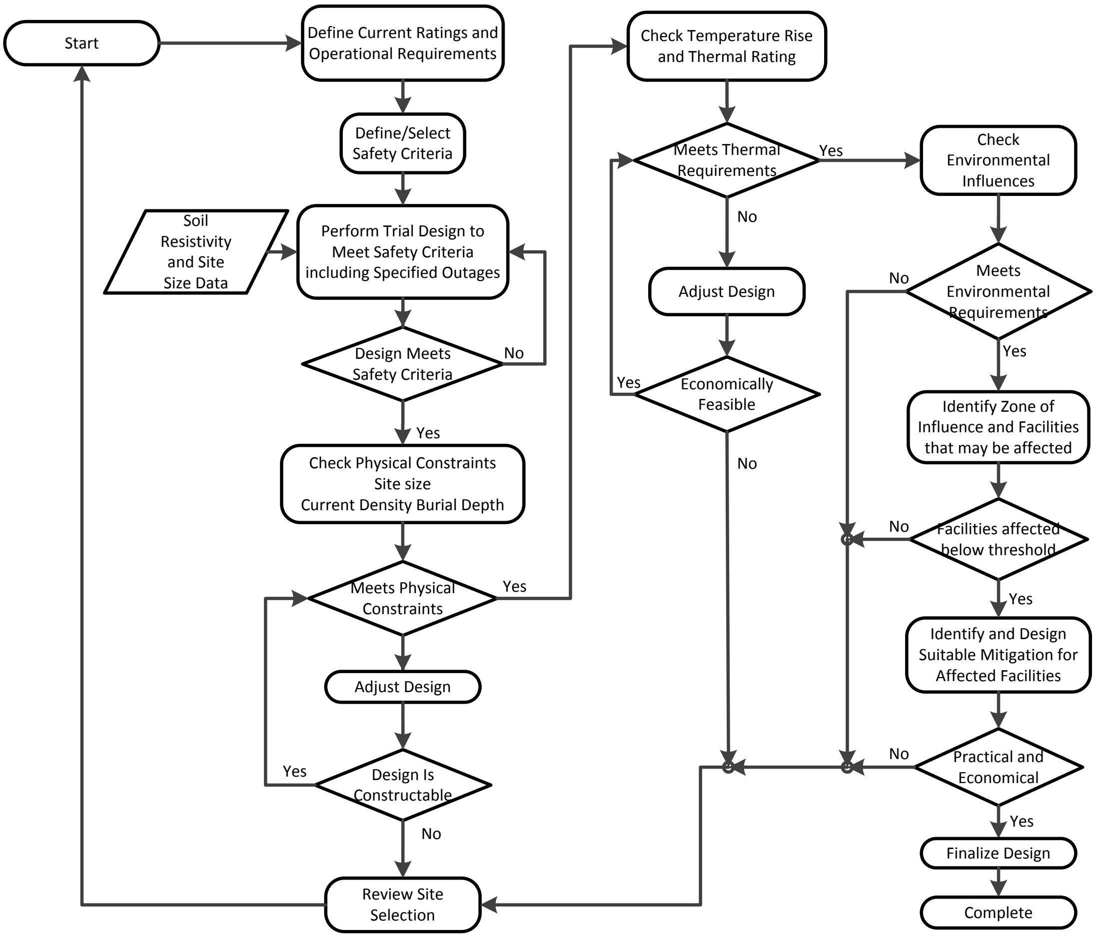


FIGURE 8 –CONCEPTUAL FLOWCHART OF ELECTRODE DESIGN PROCESS

5.1 Safety Criteria

The safety requirements of a ground electrode can be summarized in a single objective "the operation of the electrodes shall not result in unsafe conditions for people or animals either in publically accessible areas or within controlled areas accessible only to authorized maintenance workers". This general objective requires consideration of the full range of possible operating modes of the electrode and consideration possible conditions and facilities within the areas that can be influenced by the electrode in operation.

The operational conditions considered for safety fall into two categories:

(a) conditions which can persist for 10 seconds or longer which, for safety purposes, are considered to be continuous, and

(b) transient conditions which would persist for 10 seconds or less. In the case of a dc transient line fault the transient overcurrent would persist for only about 50 ms until the current line protection and current controller will reduce the fault current to zero.

The criteria for these two time frames are different since the tolerance of the human body to current is time dependent [4]. Single values of current for the continuous and transient limits rather than curves are used for convenience and simplification of design calculations. The single-valued limits are selected to provide significant margins to let-go current limits or heart fibrillation currents. The sensitivity of adults to dc current has been studied and tested but there is very little data concerning children. It is known that the threshold of perception and let-go currents are lower in women than in men and children are expected to be slightly lower than women.

The following voltages and voltage gradients are calculated when performing design calculations for electrode design:

- Step voltage
- Touch voltage
- Transferred potential
- Metal to metal touch voltage
- Voltage gradient in water (if applicable)

Step voltages approaching the limits would normally be confined to within the areas of the earth electrode sites. Of the above safety criteria, only two may extend for significant distances into publicly accessible areas:

- Transferred potential, and
- Voltage gradient in water

As the public cannot be protected from these effects by restricting access behind locked fences the calculated values need to be predictable and conservative and the means to mitigate them needs to exist, otherwise a new site may be needed.

Actual limits of safety are related to current flows in the human or animal body but the criteria most commonly applied in electrode design are voltages or potential gradients. The most limiting of the calculated values becomes governing for the design for safety purposes.

When calculating acceptable voltage criteria for electrode design it is necessary to make assumptions with respect to resistance of the body and the contact resistance between the body and the earth or energized object. There are some differences between IEC 60479 [5] in this regard but the IEEE calculation methodology has been most widely applied for electrode design.

Body resistance and contact resistances in series with the body resistance are as follows:

(a) Hand and foot or skin contact resistances to metallic structures are equal to zero.
(b) Glove and shoe resistances are equal to zero.
(c) The value of resistance of the human body can be approximated by a single resistance with a value of 1000 Ω. This value is used to represent the resistance of a human body from hand-to-feet and also from hand-to-hand, or from one foot to the other foot. (i.e. $R_B = 1000\ \Omega$)
(d) The contact resistance of a foot to ground is taken to be the same as that of a metallic disc representing the foot. The foot is represented as a circular plate with a radius "b" of 0.08 m. The resistance from each foot to ground (Rf) for soil surface resistivity (ρs) is given as

$$Rf = \frac{\rho s}{4b} = 3.125 * \rho s$$

The above assumptions are consistent with the assumptions made in IEEE Std. 80 [6] relating to safety in substation design.

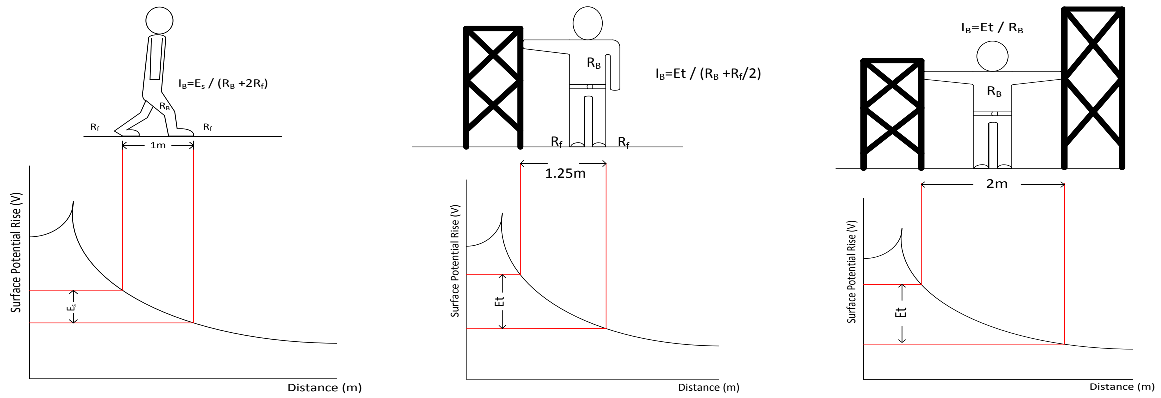
Step Voltage/Touch Voltage/Metal to Metal Touch Voltage

Step voltages/touch voltage should be limited to values that will not exceed the following criteria:

(a) The step/touch voltage in publically accessible areas under continuous operating conditions should not exceed a value that would result in body currents above the threshold of perception. (IBc<5 mA)

(b) The step/touch voltage during short time and transient operating conditions and transient faults shall not exceed a value that would result in body currents exceeding the lowest threshold of let-go-current. (IBt < 30 mA)

These values are fundamental limits related to human tolerance. The determination of step voltages, touch potential and metal to metal touch voltage corresponding to these criteria is illustrated conceptually in Figure 9. A similar diagram can be made for transferred potential and for voltage gradient in water.



$$Esc < IBc * (RB + 2 * Rf) = 0.005 * (1000 + 2 * 3.125 * \rho s)$$
$$Esc < (5 + 0.03 * \rho s)$$
$$Est < IBt * (RB + 2 * Rf) = 0.030 * (1000 + 2 * 3.125 * \rho s)$$
$$Est < (30 + 0.18 * \rho s)$$

$$Etc < IBc * \left(RB + \frac{Rf}{2}\right) = 0.005 * \left(1000 + \frac{3.125}{2} * \rho s\right)$$
$$Etc < (5 + 0.008 * \rho s)$$
$$Ett < IBt * \left(RB + \frac{Rf}{2}\right) = 0.030 * \left(1000 + \frac{3.125}{2} * \rho s\right)$$
$$Ett < (30 + 0.008 * \rho s)$$
$$Ett < (30 + 0.008 * \rho s)$$

$$Etc < IBc * RB$$
$$Etc < 5\ V$$
$$Ett < IBt * RB$$
$$Ett < 30V$$

(A) **STEP VOLTAGE** | **(B)** **TOUCH POTENTIAL** | **(C)** **METAL TO METAL TOUCH VOLTAGE**

FIGURE 9 – CONCEPTUAL ILLUSTRATION OF STEP VOLTAGE, TOUCH POTENTAL AND METAL TO METAL TOUCH VOLTAGE AND CORRESPONDING CRITERIA

<u>Transferred Potential</u>

Transferred potentials can be present on metallic objects or cables which are on the site and which may become grounded at one point and floating at another point. Metallic cables entering or leaving the site or metallic fences near the site can also pose a risk of transferred potentials.

The highest transfer potentials that can occur would be equal to the difference between the maximum and minimum values of ground potential on the site. The maximum relatively long duration transfer potential will occur at the 10-second short time overload current.

Transferred potential is a special case of touch voltage and thus the same body current limits and associated continuous and transient voltage limits would apply. However in this case the distance can be any unspecified value. Suitable design measures and electrical isolation or sectionalization of facilities must be applied to avoid dangerous situations.

5.2 Electrode Physical Design Constraints and Criteria

<u>Operating Duties and Project Life Cycle</u>

Electrode duties are based on the anticipated pole outage rates which result in the need for monopolar operation of the HVDC system, bipolar imbalance current under normal operation, load factors, and planned operating configurations of the HVDC transmission system. These duties result in loss of electrode element materials and may have cumulative corrosion impacts on the surrounding infrastructure and. The design of the electrode shall be such that the electrode elements shall be able to sustain operation over the life cycle of the project or shall be replaceable at regular intervals. Operating duties may be limited to lessen the impact on infrastructure in the electrode zone of influence or alternatively mitigation works may be applied to protect important infrastructure against the effects of electrode operation.

<u>Current density</u>

The current density of electrode element surface should be selected to avoid risk of electro-osmosis, migration of water molecules under an electric gradient for land, and to reduce chlorine selectivity for element in contact with saline water for beach and sea electrodes. A higher current density can be used for pond electrodes. Also a lower current density results in lower chlorine selectivity and the type of elements used will also have an influence.

A current density of less than 0.5 A/m^2 to 1 A/m^2 is recommended for land electrodes [1] and 6 A/m^2 to 10 A/m^2 for sea electrodes.

Thermal stability at specified current ratings

The current rating that is of primary concern for electrode thermal design is the continuous current rating. The durations of the short time overload current and transient overload current are too short to have any noticeable impact on the thermal rating of the electrode. Thermal stability of the electrode system needs to consider the time duration of service at maximum current levels to assure long term stable life of the completed systems.

Polarity- Anodic and Cathodic Operation, and Element Types

The polarity of a ground electrode is specified as a cathode, to which current flow from the earth, or as an anode, from which current flow into the earth. For a scheme where current flow direction through the earth return path remains the same, the grounding sites can be designed as an anode and as a cathode. In case the direction of current flow changes periodically, the grounding sites shall be reversible type having capability to operate as an anode and as a cathode.

The ground electrodes associated with a bipole scheme are reversible since the direction of bipolar imbalance and monopolar current under a pole outage current can reverse, and a monopole scheme may have reversible or single function ground electrode.

5.3 General Data Requirement for Design

Current Rating

The HVDC scheme current that passes through the ground electrode is the prime parameter by which a ground electrode is rated. The current passing through a grounding site is a function of the HVDC scheme design and its operational configurations. To ensure its electrical performance, the electrode must be sized adequately for the current while maintaining the electrode element current densities within the recommended limits. The operation and maintenance factors to be considered include maintenance on a subsection of the electrode during operation, and safety for access to electrode elements for inspection and maintenance.

The HVDC system currents (continuous, short-time, and transient) form the basis of the grounding site design. The ground electrode shall be designed to meet the safety requirements for the maximum transient electrode overcurrent.

Soil Physical and Chemical Properties

During the design of earth electrodes, the main physical properties of the soil on the electrode site should be measured in order to determine the electrical parameter model of the site, thermal properties of soil and evaluate the impact of the earth electrodes on the environment. The main properties of soil include resistivity, thermal capacity, thermal conductivity, highest natural temperature, moisture, depth to water table, type of soil or rock material, moisture content, depth to water table, electro osmosis and chemical properties.

5.4 Design methodology

Electrode design includes consideration of the following factors all of which must be within acceptable limits

(a) Electrode dc resistance
(b) Thermal stability at specified current ratings
(c) Design life based on corrosion
(d) Current density
(e) Current sharing between sub-electrodes
(f) Potential interference with other nearby facilities

Simulations

Direct calculations using analytical expressions are usually used for preliminary calculation of step potentials and current density at the electrode-soil boundary. However such methods are not sufficient if the soil in the immediate area of the electrode is not uniform. Programs are available which using numerical methods which allow the detailed modelling of soil structure near the electrode to establish the expected variation in step voltage or current density even in non-uniform soil.

In general, the soil resistivity structure would be modelled at three levels of depth based on:

- **Near surface** – hundreds of meters by means of electromagnetic soundings or large separation DC resistivity measurements;
- **Shallow** – tens of meters by means of DC resistivity measurements with short transmitter-receiver separations or shallow electromagnetic soundings;
- **Deep** – down to Moho (crust/mantle interface) by means of magnetotelluric measurements

Two kinds of soil resistivity structure can be constructed:

- Detailed and near-surface model – close to the electrode (up to two times its diameter) using the data form the shallow and near-surface surveys;
- Wide area model – covering all the interference area, by means of e.g. a layered model using the data form the deep survey.

The detailed modelling is required near the electrode elements to ensure that the design including the backfill material such as coke is adequately modelled to show the ground potential rise (GPR) and potential gradients near the electrode. Figure 10 shows an example of top layer soil resistivity modelled in an area within 250 km of the electrode.

Sensitivity cases including the outage of sub-electrodes, variable top soil resistivity representing seasoning variations and higher resistivity layers at deeper earth shall be carried out to establish a range of conditions that could occur based on differences in assumptions with respect to the extent and depth of regions of different resistivity. Example of calculated ground potential rise and potential gradient are shown in Figure 11, Figure 12 and Figure 13.

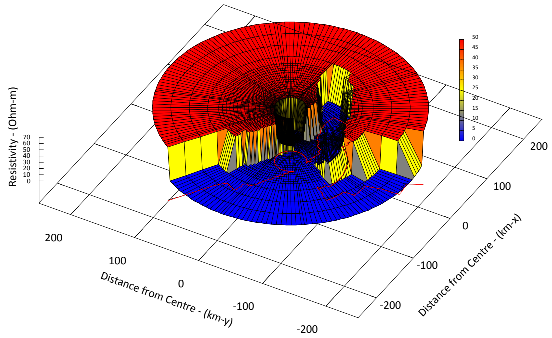


FIGURE 10 - EXAMPLE OF A TOP LAYER RESISTIVITY AS MODELED IN AREA WITHIN 250KM OF THE ELECTRODE

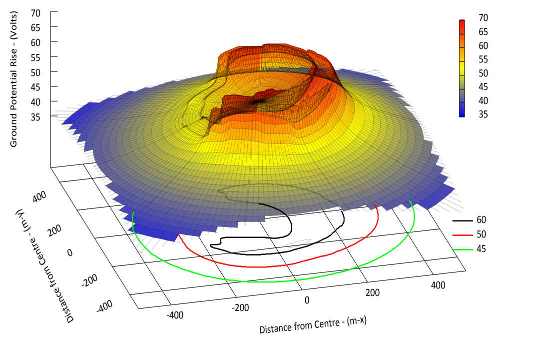


FIGURE 11 - EXAMPLE OF A LOCAL CALCULATED GROUND POTENTIAL RISE A SHALLOW DOUBLE RING ELECTRODE WITH ONE PART OF THE ELECTRODE OUT OF SERVICE

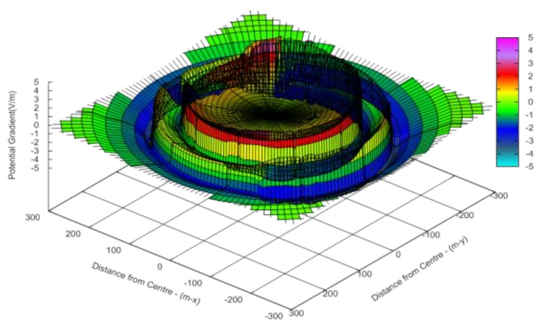


FIGURE 12 - EXAMPLE OF A LOCAL CALCULATED POTENTIAL GRADIENT OF A SHALLOW DOUBLE RING ELECTRODE

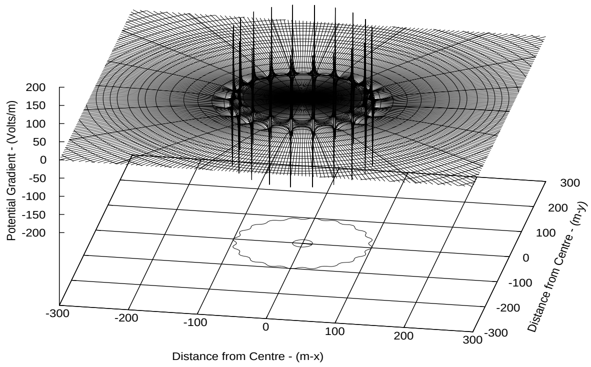


FIGURE 13 - EXAMPLE OF CALCULATED POTENTIAL GRADIENT OF A DEEP WELL ELECTRODE

Verification of Design

The design of electrode should be verified after the installation and during the commissioning of the HVDC system by carrying out electrode site measurements to confirm the electrode design meets the desired criteria and requirements and to demonstrate that the influence on other facilities is within acceptable limits. The electrode site tests would include measurements of

- Soil temperature and moisture
- Electrode resistance
- Step and touch voltage
- Ground potential rise
- Current distribution between sub-electrodes

The measurement results would be compared to the calculated and simulated design values. In general, the actual measurement results may never exactly match the design since there is always some uncertainty in the data used in the modelling process. However, they should agree within a within the range of the design values investigated in the sensitivities. If the measurements are significantly outside of the design range it could affects HVDC system operation and performance and also result in safety concerns, and unexpected mitigative work and cost.

6. IMPACT OF ELECTRODES AND MITIGATION OF ADVERSE IMPACT

There is no major difference between ground currents of AC systems, DC systems or lightning strikes to earth. In all cases current flows through earth and dissipates through the easiest path possible. Nevertheless, the environmental impacts and their area of influence are different. For AC grids, the main concerns relating to ground currents operation are safety aspects and operational problems. However, for HVDC ground electrodes the dc current would be injected into the earth for an extended period. Thus, the safety aspects need to be taken care of in the design but other non-immediate problems may appear. Impacts may include the following:

- Corrosion of buried infrastructure
- Saturation of grounded transformers
- Interference to communications systems
- Chemical reactions in water or soil
- Soil and groundwater heating near the electrode
- Transferred potentials near the site or on long metallic structures off the site

Assuming that ground current is not specifically prohibited by the regulatory framework, obtaining environmental approval requires careful consideration and description of both local and remote aspects of potential impacts.

Local impacts which would occur in the immediate area of the electrode can normally be minimised or mitigated by careful design of the electrode itself. However remote impacts which may occur within ten or more km from the electrode can normally be avoided or mitigated only by proper site selection, applying mitigation to important facilities, or in extreme cases by changing the site or severely constraining electrode operation.

Local aspects at or near the electrode site generally involve electrical safety or environmental release of chlorine gas or metals from the electrodes and thermal/heating considerations. Remote impacts may include corrosion or electrical interference with existing or new infrastructure (pipelines, railways, power lines, transformers and telecommunication) or impacts on electro-sensitive species.

At an early stage in the project both remote and local aspects can only be investigated by modelling. In the past the design process and investigation of impacts was hampered by lack of data and lack of adequate software to permit study of the potential impact in fine detail. Advances in soil resistivity survey methods and development of finite element software have now provided enhanced capability for study and exploration of sensitivities.

7. OTHER ASPECTS COVERED IN THE GUIDE

The guide for design of HVDC electrode also covers the following aspects

- The connection between the converter station and the electrode station which is usually referred as the neutral line or electrode line. Neutral lines can be built as overhead lines or using insulated cables for undersea or underground lines. Both electrode lines technologies are described.
- Auxiliary systems for electrode stations including the station service supply and monitoring of electrode station.
- Testing and commissioning associated with electrodes.
- Operation and maintenance of electrodes stations.

8. SUMMARY

Environmental concerns related to electrode operation have more prominent in recent years due to greater public awareness of potential impacts and tighter environmental approval processes and also a greater number of HVDC projects. While the environmental process can be challenging, the long-time successful operation of many existing electrodes indicates that the potential environmental impacts from electrodes can be reduced to tolerable levels or eliminated either by suitable selection of the electrode site for impacts remote from the electrode and by application of good design techniques if the impacts are near the electrode or on the electrode site.

Advances in tools for electrode site investigations and electrode designs design include

a) Magnetotelluric (MT), audio magnetotelluric (AMT) and airborne geophysical measurements (AGM) electrical resistivity tomography (ERT) soil resistivity survey and interpretation techniques.
b) Improved access to land use and facilities databases
c) Greatly improved modelling software using finite element software capable of very fine resolution in the area of the electrode while providing adequate resolution of very deep soil structure and structure of soil in three dimensions surrounding the electrode. This allows consideration of reasonable ranges in sensitivity in soil resistivity.

The guide is a collection of most recent techniques, processes and descriptions of software and procedures involved in site selection and electrode designs.

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SC B4: HV DC and Power Electronics
PS1: HV DC Systems and Applications

Operational Experience of India Bangladesh Interconnector, 1 X 500 MW HVDC BTB Link– A Key Milestone in Development of SAARC Grid

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In order to harness capacities and resources of SAARC Nations to address the growing energy needs in the region and for effective utilization of resources towards mutual benefits, formation of a strong SAARC grid is envisioned by the Stakeholder Countries. Presently, a number of interconnections exist between India & Nepal and India & Bhutan, which are being strengthened for mutual exchange of power. A milestone has been achieved in this direction with the commissioning of an asynchronous interconnection between countries India & Bangladesh, through 500 MW High Voltage Direct Current (HVDC) back-to-back terminal along with Bheramara (Bangladesh) - Baharampur (India) 400kV D/c line in September, 2013, enabling power flow of the order of 500MW from India to Bangladesh.

The paper elaborates the various challenges in the coordination between various stakeholders for smooth operation of the link. The major issues discussed in the paper includes

1) **Salient parameters of the project**
2) **Power Purchase Mechanism**
3) **Interfacing with load despatch centres of Bangladesh and India**
4) **Coordination between various stakeholders for smooth operation of the link**
5) **Operational Experience**
6) **Way forward**

Key Words : – SAARC – South Asian Association for Regional Cooperation,

Introduction

The Bangladesh economy has grown at about 6% per annum on average over the past five years, and the same level of economic growth is expected in the coming years.Rapid economic growth in Bangladesh is causing electricity demand to increase sharply as the country continues to industrialize and raise the living standards of its large population. In addition, there is a need for energy diversification as about 90% of the power sector generation capacity in Bangladesh is fuelled by domestically produced natural gas.

India is playing an active role in formation of a strong **SAARC grid** for effective utilization of resources for mutual benefits. Presently, various electrical interconnections exist with neighboring countries like Nepal and Bhutan with plans to further strengthen the interconnections for substantial power exchange across the borders.

Against the backdrop of a growing power demand in Bangladesh, and the vision of having a strong SAARC grid which would provide a platform to demonstrate the substantial economic benefits of enhanced regional cooperation and address the prevailing energy gap, an important step in the process of optimal and sustainable harnessing of regional energy resources was taken , when the interconnection of Electrical Grids between the India and Bangladesh was discussed during the visit of Indian delegation to Bangladesh from 22nd Nov. to 26th Nov., 2009. A memorandum of understanding (MoU) was signed in January 2010 between Government of India and Government of Bangladesh for bilateral Co-operation in the areas of Power Generation, Transmission, energy efficiency, Renewable energy, Consultancy services, Training & Development , Constitution of Steering Committee on Working Group and establishment of grid connectivity between India and Bangladesh. A Joint Technical Team from India and Bangladesh examined multiple options regarding the interconnection of the grid between the two countries keeping in view the technical & operational aspects as well as economical considerations, the scope of works for interconnection between India and Bangladesh grids was finalised which included:

- Establishment of 400kV switching-station at Baharampur (India) by looping in and looping out of Farakka-Jeerat 400kV Single circuit line (Fig. 1).
- Baharampur(India)– Bheramara(Bangladesh) 400kV Double circuit line
- Installation of 500MW HVDC back-to-back station at Bheramara (Bangladesh).
- Looping in and looping out of 230KV D/C Ishurdi-Khulna Line at Bheramara

The asynchronous HVDC Back to Back interconnection between the Indian and Bangladesh Grid was determined to be the appropriate solution as it facilitated to allow each country to have independent control and operation over its own national grid, ensure complete control on the power transfer between the two countries, to prevent faults in one grid to propagate in other grid, and to utilise the advantages which HVDC system provide through its dynamic controllers in riding through the AC system faults and helping the of AC system in damping the system disturbances. The contract for the HVDC project was awarded under International Competitive Bidding funded by Asian Development Bank (ADB) in March 2011 and 500MW power flow is being supplied to Bangladesh since December 2013.

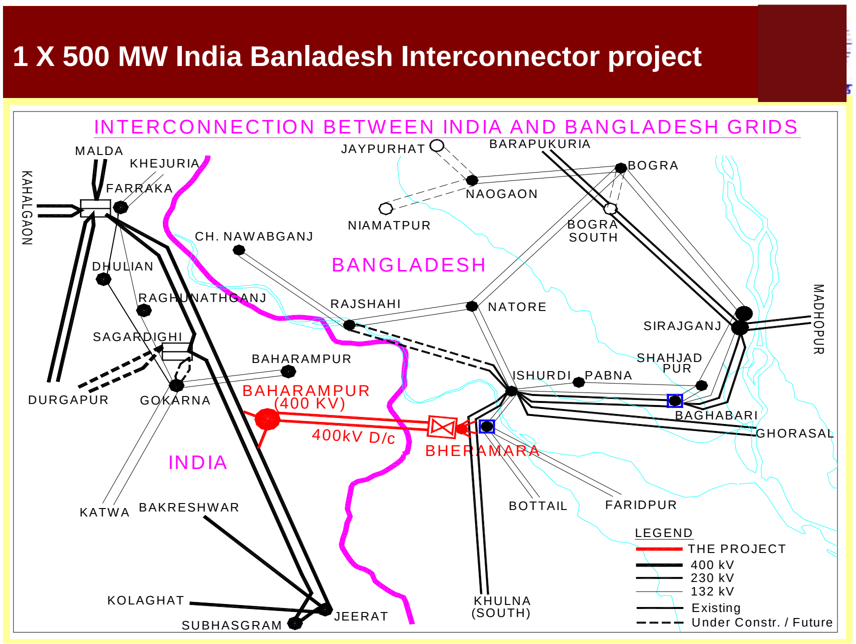

Fig.1

Salient parameters of the project

The HVDC Back to Back link comprise of one 12 pulse Block of 500 MW designed for Bi-directional power transmission. The Bangladesh back-to-back HVDC system has been designed for minimum short circuit levels of 1500 MVA on Indian side and on Bangladesh side to meet the performance requirements. The above short circuit levels are the minimum design values which take into account n-1 contingency in the network. With contigency on the Bangladesh network (i.e. outage of Bheramara-Ishurdi 230 kV line) the short circuit MVA contribution from the network reduces to 1000 MVA. Under this condition, Power limit on the Back to Back DC Scheme shall have to be applied.

Power Transmission Capacity

The Bheramara HVDC converter station when operating in Normal and Reverse power direction has a continuous power transfer capacity of 500MW defined at the ac inverter bus. The maximum continuous rating will be maintained up to dry bulb ambient temperature of 45 Deg C and within the specified range of AC system parameters at Bangladesh and India side. The Station is designed for 2 hour overload rating of 1.1 p.u. utilising the redundant cooling under specified AC system Conditions. Further , a five second overload rating of 1.33 pu over the nominal rating is available for providing support under dynamic conditions. The Fig. 2 and 3 below shows the Converter overload capability with and without redundant cooling.

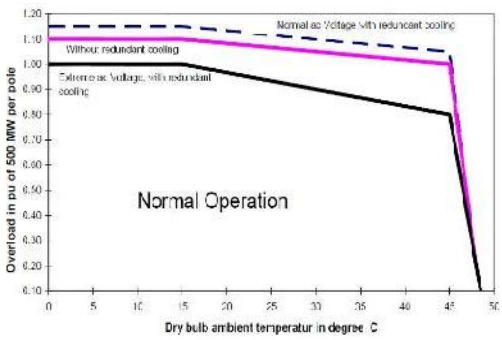

Fig 2

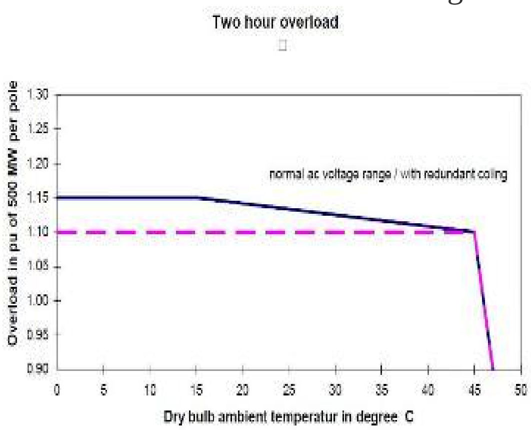

Fig 3

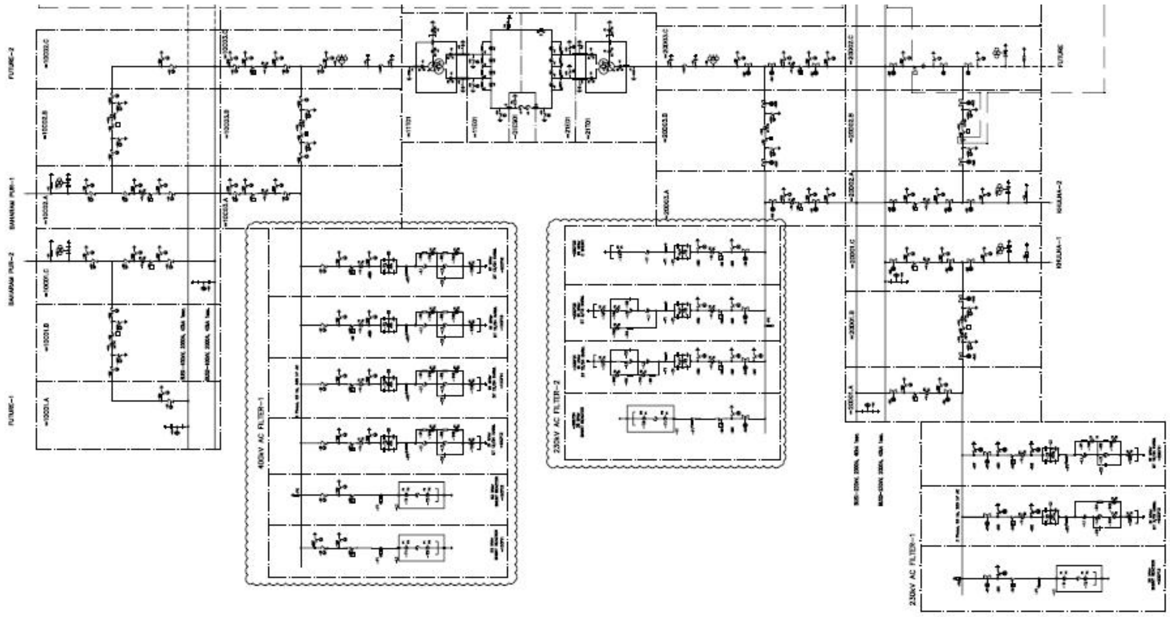

Fig 4 Single Line Diagram

Overview of Design Studies for HVDC station

The design studies for Bheramara Back-to-back HVDC project can be classified in three groups. The first group of studies are the basic design studies , like main circuit parameter , overvoltage, reactive power, insulation co-ordination, ac filter performance and rating studies, etc are required for finalisation of power circuit equipments for the HVDC system.

The second group of system studies, like the load flow and stability study, the sub-synchronous resonance and interaction study are carried out for analysis of the interconnected ac/dc system.

The functional and dynamic performance tests as the third group are studies which have been carried out for finalisation of control, protection and communication and which have been validated on Real Time Digital Simulator.

Main Data of the HVDC system

		Rectifier	Inverter
DC Power	MW	504.2	503.6
DC Current	Amp	3189	3189
DC Voltage	kV	158.1	157.9
Firing Angle-Nominal	Deg	16	
Extinction Angle- Min	Deg		17
Transformer Impedance	p.u.	0.16	0.16
Transformer Rating (single phase three winding)	MVA	201	201
Transformer Sec Voltage	kV	66.8	66.8
Converter Reactive Power	MVar	265	278

Reactive Power

The reactive power compensation elements have been designed to comply with the specified exchange requirements with the AC system as well as with the specified maximum voltage change after switching. The maximum size of subbanks of 91 MVAr.

The following reactive power supply and absorption equipment installed at the 400kV (India Side) and 230kV (Bangladesh Side) buses at Bheramara Station:

	India Side	Bangladesh Side
Total Filters (MVAr)	364	364
Total Shunt Capacitor (MVAr)	-	91
Total Shunt Reactors (MVAr)	2X63	2X35
Banks		
Number of Banks	1	2
Filter/Capacitor Subbanks		
Number of Subbanks	4	5
Largest Subbank (MVAr)	91	91
Type of ac filter sub-banks		
DT = double tuned 12 / 24	4 x 91 MVAr	2 x 91 MVAr
DT = double tuned 3/12	-	2 x 91 MVAr
C = Shunt Capacitor	-	91 MVAr

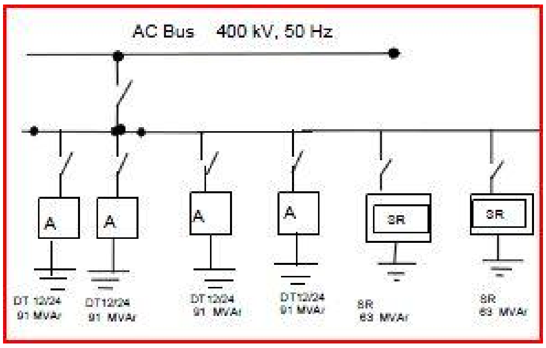

Fig.5 AC Filter Arrangement 400kV Side

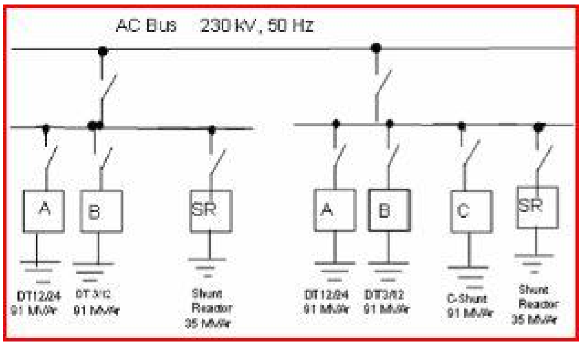

Fig.6 AC Filter Arrangement 230kV Side

Project Execution –Issues and Challenges

1. Scope of Execution

Powergrid Corporation of India Ltd (POWERGRID) and Power Grid Company of Bangladesh (PGCB) were assigned the execution of the transmission system related to project in the respective countries. The scope of work is summarized as below-

Indian Portion executed by POWERGRID

a) Transmission Line:
   - Baharampur(India) – Bheramara(Bangladesh) 400kV Double Circuit line , App 71 kms (Twin ACSR Moose Conductor)
   - Loop-in and loop-out of Farakka-Jeerat 400kV Single Circuit line at Baharampur (India) : App 3 kms

b) Sub-station:

Establishment of 400kV switching-station at Baharampur (India)

- 2 Nos of 400 kV line bays for loop-in and loop-out of Farakka-Jeerat 400kV Single circuit line
- 2 Nos of 400 kV line bays for Baharampur-Bheramara 400kV Double Circuit line.
- 1 No. of 80 MVAR Bus Reactor

Bangladesh Portion executed by PGCB:

a) Transmission Line

- Baharampur(India) – Bheramara(Bangladesh) 400kV Double Circuit line (Bangladesh Portion) : App 27 kms (Twin ACSR FINCH Conductor)
- Loop-in and loop-out of Ishurdi - Khulna 230kV Double Circuit line at Bheramara (Bangladesh) : App 5 kms

b) Sub-station

Establishment of 500 MW HVDC back-to-back station and 230kV switching-station at Bheramara (Bangladesh)

- Installation of 500 MW HVDC back-to-back Terminal.
- 4 nos of 230 kV line bays for LILO of Ishurdi -Khulna South 230kV Double Circuit line

2. Power Purchase Mechanism

One of the key challenges for success of the interconnector project was formalization of power purchase mechanism among the stakeholders at mutually agreed terms before commercial operation of the project. Out of the 500MW of the HVDC Back to Back Station Capacity, the first 250 MW has been facilitated by NTPC Vidyut Vyapar Nigam (NVVN). NVVN has been assigned the role of Nodal Agency for trading of power with Bangladesh. NVVN has signed an agreement with Bangladesh Power Development Board (BPDB) for supply of 250 MW power for 25 years from various central generating stations of NTPC from Indian central government's unallocated quota. The tie up of power supply was done on 28th Feb 2012 well in advance before commissioning of project.

PTC has signed Power Sale Agreement (PSA) with Bangladesh Power Development Board (BPDB) for supply of balance 250 MW power from the State Power Pool of West Bengal State Electricity Distribution Company Limited (WBSEDCL) on medium term basis (3 years) through International Competitive bidding process. The Power flow under the PSA has commenced from 3rd December, 2013.

POWERGRID has signed a Bulk Power Transmission Agreement with Bangladesh Power Development Board for payment of Transmission Charges for the above said system.

3. Communication Interface with load dispatch centre of Bangladesh and India:

Effective Telecommunication between the Load Despatch Centres of the two countries is a key to smooth operation of the India – Bangladesh Interconnecter Link.The Remote Control Interface (RCI) carries out data exchange between the Control & Protection system in the Bheramara Back-to- Back Converter Station, the Eastern Regional Load Dispatch Centre (ERLDC) in India and the National Load Dispatch Centre (NLDC) in Bangladesh. For data exchange, the international standard IEC 60870-5-101 is used for Eastern Region Load dispatch Centre (ERLDC) & National Load Dispatch Centre (NLDC), Bangladesh. Voice connectivity between India and Bangladesh control centers and Bheramara HVDC BTB station (Bangladesh) & 400kV Beharampur substation (India) is exclusive one and does not have any connectivity with other voice network at their ends.

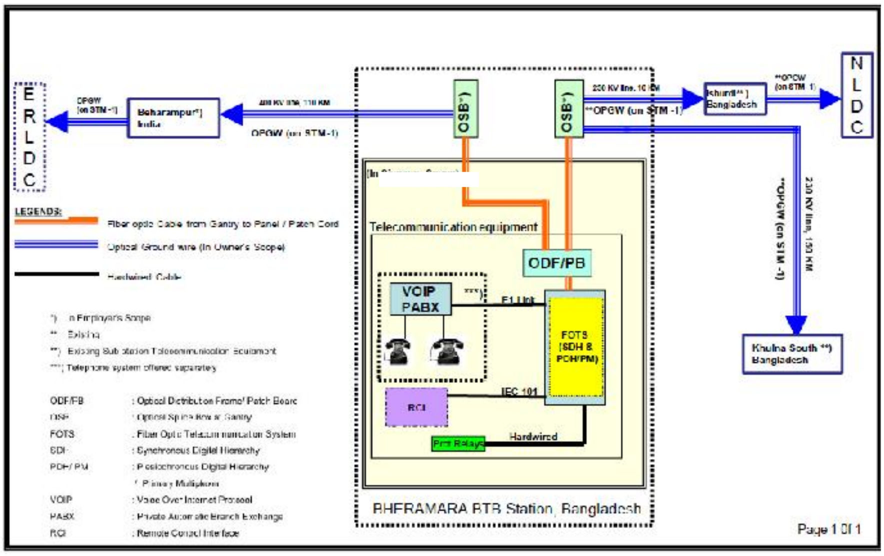

Fig 7 Telecommunication requirement for the interconnector project

4. Coordination among multiple stakeholders

Invitation for Bids for the HVDC System was notified on 28th Feb 2010 under International Competitive Bidding and the effective date of Contract was in July 2011. The project was successfully commissioned in Sept 2013 in a record time of 26 months. The project highlight is the close coordination between the multiple stake holders including the government, execution agencies, utilities, regulators, load dispatchers of the two countries. The successful implementation of the India Bangladesh Interconnector link is a result of concerted and coordinated efforts all stakeholders, which are summarized as under.

The vision of Governments of respective countries was realized through deliberation of Joint **Working Group**/**Joint Steering Committee** of the Officials of the two countries which facilitated the feasibility of the India Bangladesh Interconnector.

PGCB, the transmission utility of Bangladesh, implemented the Bangladesh portion of the subject project and **POWERGRID** executed the Indian portion of the system which required close coordination between the two utilities, especially in the execution of interconnection of respective portion of Baharampur-Bheramara 400kV Double Circuit line and interface related to tele-protection and tele-communication between Beharampur (India side) and Bheramara (Bangladesh side) Stations.

The project included first HVDC Station and first 400kV Transmission line in Bangladesh. POWERGRID, alongwith the exécution of the Indian portion of the transmission system, was assigned a consultancy assignment by PGCB for 1 x 500 MW Back to Back Station at Bheramara (Bangladesh) and related Transmission Lines (Bangladesh Portion) associated with Bangladesh – India Interconnector Project. The Scope of the Consultancy assignment included-

- Pre- award Engineering

- Finalization of Bidding Documents, Assistance in Tender evaluation
- Post Award Engineering
- Training of PGCB Engineers on HVDC BTB Station design and Tower and Transmission line Design along with on training at site)
- Construction Supervision

Being the first HVDC system in Bangladesh, special emphasis was given to the Capacity Building and Knowledge sharing to PGCB Executives pertaining to the HVDC system. PGCB executives were provided class room training as well as hands on site training at various HVDC establishments of India under the above said consultancy assignment. Also, the PGCB executives were given training on the Real Time Digital Simulator at POWERGRID, Gurgaon Office which helped in the understanding the dynamics of HVDC system and various aspects of AC – DC Interaction.

The land acquired by PGCB, app 120 Acres (Including the space for Future Block 2) required soil filling of app 4.0-4.5 meters before handing over to Contractor for execution of contract. Considering the scale of work and the time line of the project, it was a very challenging assignment. But the same was accomplished successfully by PGCB through the **Bangladesh Water Resource department** by a process of dredging from the nearby Padma River and the land was handed over in time to the Contractor in time which facilitated the timely execution of project.

BPDB was the sole buyer of the power on Bangladesh side. The tariff mechanism for generation and transmission is based on the methodology/regulations of Central Electricity Regulatory Commission (CERC), India. The agreement between the two countries in finalisation of the tariff mechanism shows the trust, willingness in achieving the shared vision, confidence among various institutions of the two countries which is key to the success of this project.

Another key aspect associated with the project was the commissioning of the telecommunication interface between the Bheramara HVDC BTB Station, National Load Despatch Centre (NLDC) Bangladesh, 400KV Baharampur Switching Station, India, Eastern Region Load Dispatch Centre (ERLDC), India, and National Load Despatch Centre (NLDC) India. This was achieved by close coordination **between Power System Operation Cooperation Ltd (POSOCO)**, a wholly owned subsidiary of POWERGRID which operates the Regional and National Load Despatch Centre of India, PGCB, NLDC-Bangladesh.

The above stakeholders are among a lot which contributed to the success of the project including Contractor of the HVDC package, Transmission line Contractors, various subcontractors/ agency involved in the manufacture of Equipments, erection testing and commissioning & logistics involved in the complete value chain of the delivery of project which helped in realizing the vision of the respective governments and **ADB** (Funding Agency)

5. Operational Coordination

The successful operation of the link was facilitated by finalisation of operational coordination protocols through extensive discussions by various agencies including Central Electricity

Authority (CEA), Central Transmission Utility (CTU), NLDC, NVVNL, PTC, POWERGRID from India Side and BPDB, PGCB from Bangladesh side including NLDC, Bangladesh. The discussions covered the issues related to Operation philosophy, system security aspects, protection coordination, operational liaison defining protocols for information exchange between the system operators, operating instructions, reactive power management, outage planning, recovery procedures and event information, scheduling and despatch information. The following coordination forums have been constituted to facilitate smooth operation of the HVDC link-

- Operation Coordination Group
- Protection Coordination Group
- Commercial Coordination group

These groups have members from the system operators, Transmission Owner and other stakeholders of both the countries. The operation coordinating group is scheduled to have quarterly meetings and the protection and commercial coordination meeting is to be held as and when required.

Operational Experience:

1 x 500 MW India- Bangladesh Interconnector Link has been in smooth operation since September 2013 and is generally running to the maximum utilisation up to the contracted power. The 500 MW Bheramara HVDC interconnector, being the single largest infeed to the west zone of Bangladesh system, has impacted the Bangladesh power system significantly in terms of frequency, voltage and line loadings. . The voltage profile in West Zone has also improved by almost 15-20 kV at 230 kV level. Imports through HVDC have also reduced load shedding and dependence on expensive liquid fuel.

No major equipment failure including Thyristor Valves/Valve Hall Equipments, Converter Transformer, AC Filters, Circuit Breakers, other AC/ DC equipments has been reported till date. Minor controls and telecommunication related issues have been promptly rectified at site. For enhancing the grid security, special protection scheme has been implemented on Indian side and Bangladesh side which results in the run back of power on the HVDC link under some specified conditions. In Bangladesh side, status of various outgoing feeders at near substation of Bheramara HVDC (Ishurdi and Khulna South) is transmitted to runback module in Bheramara control system through tele protection system for decision of runback. In Indian side, status of various incoming feeders connected at Bahrampur is also transmitted to Bheramara for same purpose. Based on significant changes in transmission network of both Indian & Bangladesh side, conditions of runback has been updated.

The following Fig 8 and Fig 9 give the energy and the power exchange on the Transmission link-

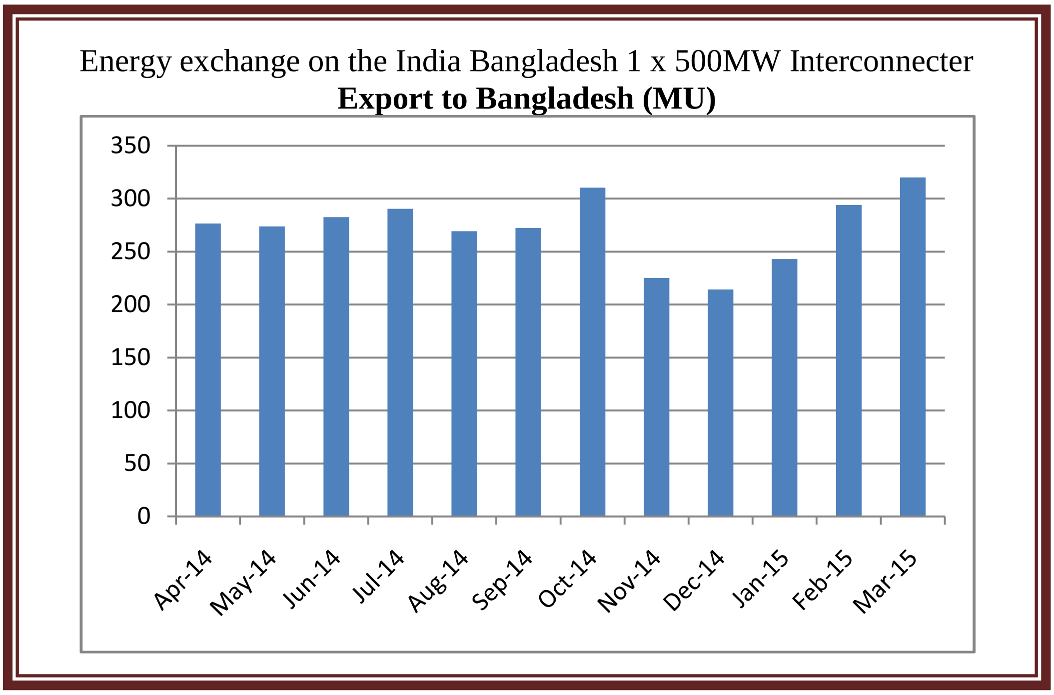
Energy exchange on the India Bangladesh 1 x 500MW Interconnecter
Export to Bangladesh (MU)
350
300
250
200
150
100
50
0
Apr-14
May-14
Jun-14
Jul-14
Aug-14
Sep-14
Oct-14
Nov-14
Dec-14
Jan-15
Feb-15
Mar-15

Fig 8

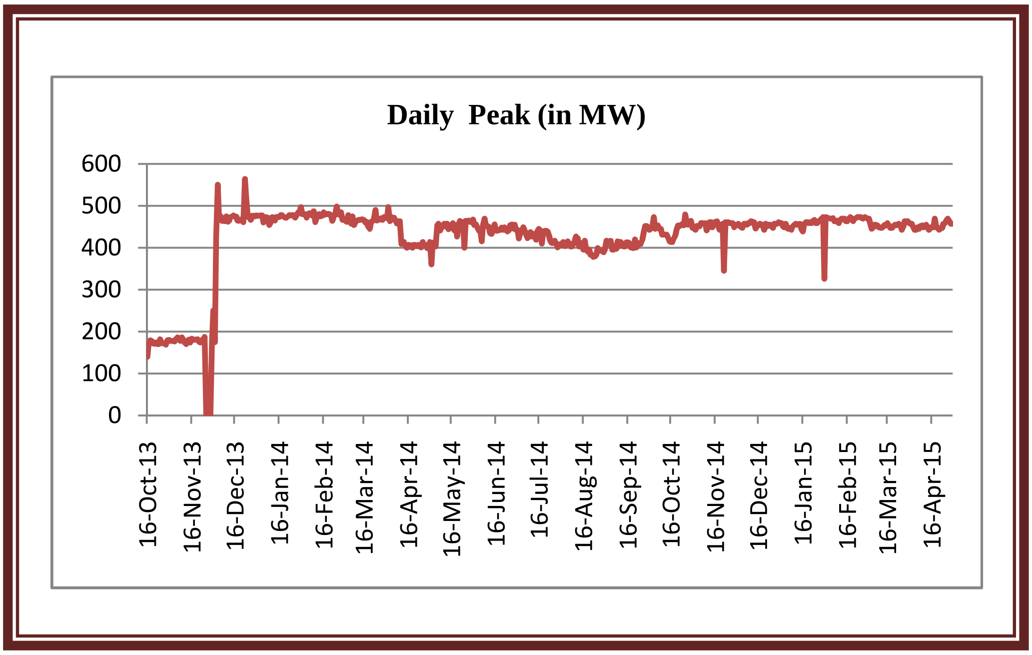
Daily Peak (in MW)
600
500
400
300
200
100
0
16-Oct-13
16-Nov-13
16-Dec-13
16-Jan-14
16-Feb-14
16-Mar-14
16-Apr-14
16-May-14
16-Jun-14
16-Jul-14
16-Aug-14
16-Sep-14
16-Oct-14
16-Nov-14
16-Dec-14
16-Jan-15
16-Feb-15
16-Mar-15
16-Apr-15

Fig 9

Way forward:

1x500MW HVDC BTB India Bangladesh Cross Border link is an example of realising the vision of cross border cooperation for mutual benefits, sustained inclusive economic growth through optimal utilization of power generation capacity in the South Asian region laying foundation of a vibrant SAARC grid in near future. The capacity building efforts have resulted in capacity building and information sharing regarding planning, development, operation, maintenance, and power exchange agreements between the two countries.

This has lead to discussions of feasibility of further transmission links and corridors to supply power between the two countries. Recently, an agreement has been signed between India and Bangladesh for a transmission line from Tripura to Eastern Bangladesh. Pre Award activities of Second Block of 500MW India Bangladesh HVDC BTB Interconnector is in process and ±800KV, 7000 MW, Rangia (India), Barapukuria (Bangladesh), Muzaffarnagar (India) Multi Terminal HVDC Link is under discussion. The synergies generated by the successful implementation of the 1X500 MW Cross Border Interconnector may be harnessed for further development of a strong and vibrant SAARC grid.

Acknowledgement

Authors wish to thank POWERGRID and PGCB for granting them permission to present the paper. Views expressed in the paper are of the authors only and need not necessarily be of the management of POWERGRID and PGCB.

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Employing SVC at weak LCC HVDC terminals and comparison with VSC HVDC

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SUMMARY

This paper studies system-level impact of an SVC connected to a LCC HVDC terminal, in particular in the context of weak AC systems. The real power flow is varied from zero to full power at each of the HVDC terminals and the system variables are observed when fixed capacitive support is applied and comparatively when an SVC is connected.

The SVC at the LCC HVDC terminal brings significant operating advantages, and in particular it can provide a cost effective means of assisting HVDC operation into a weak AC system. The SVC can be used in combination with the filter and reactive power banks associated with the LCC HVDC terminal to meet the total reactive power demand of the system.

The peak AC voltage at HVDC terminals connected to a weak AC system (SCR=2.5) can reach over *1.47pu* for load rejection, when fixed capacitors provide reactive power. The study shows that using SVC with a TCR dynamic rating of *0.335pu*, the peak AC voltage is limited to *1.16pu*. This also substantially improves stability margin and transient response.

The LCC HVDC with SVC is further analysed on PQ diagrams from the grid connection point. Comparing with PQ diagrams for similarly rated VSC HVDC and LCC HVDC converters With the addition of an SVC to the LCC it has a wider operating area at high powers compared to VSC HVDC, which may be welcome by grid operators.

KEYWORDS

HVDC, SVC, HVDC voltage stability, Maximum available power.

Introduction

The Line Commutated Converter (LCC) HVDC will experience a number of operating difficulties when connected to weak AC systems. Weak AC systems are classified as having SCR (Short Circuit Ratio) 2<SCR<3 [1]-[3]. In particular the inverter terminals experience more problems because of an increased risk of commutation failure. An important consideration is that of the overvoltage caused by the fixed reactive power support (for example AC harmonic filters), which can occur for sudden HVDC load rejection.

One of the possible solutions to these challenges is to install an SVC (Static Var Compensator) at the HVDC terminals, and several systems have been implemented [4],[5],[7]. The impact of an SVC on reducing commutation failure and transient voltage overshoots has been studied previously [6].

CIGRE has developed a new working group WG B4.64: “Impact of AC System Characteristics on the Performance of HVDC Schemes“, which has as one of the topics to be investigated the impact of reactive power support on the operation of LCC HVDC.

This paper reports on one of the WGB4.64 studies, where the goal is to examine the system-level benefits of connecting an SVC at a LCC HVDC terminal, such as; voltage profile, power flow and maximum available power. The paper also compares the operating curves with HVDC based on VSC (Voltage Source Converter) technology.

LCC Converter Reactive Power Switching

A LCC will both generate harmonic currents into the AC system to which it is connected and absorb reactive power, irrespective of operation as an inverter or a rectifier. The conventional, cost effective, method of removing the AC harmonics is to use shunt connected AC filters close to the converter point of connection. Such filters are usually interfaced to the AC system via a capacitor bank which, at fundamental frequency, will provide the reactive power needs of the converter. An efficient converter terminal design will maximise the size of each filter bank in order to minimise the harmonic impedance of each bank and minimise the number of switchable banks hence minimising cost and footprint. Reducing the number of switching operations also reduces the wear on the circuit breakers and hence the consequential maintenance needs.

The reactive power absorbed by a LCC is approximately linearly proportional to the real power transmission, hence, the higher the power transfer level the more AC harmonic filters/reactive power banks are energised in order to achieve the targeted reactive power exchange with the ac system [1], as seen in Figure 1.

The AC filter/reactive power banks are usually switched using AC circuit breakers which can take several AC system cycles to open and even more to close making them, in comparison to the speed of the power electronic systems, very slow. There is also an additional problem associated with switching capacitors in AC systems. When the AC breaker opens and the current extinguishes, as it passes through zero, the applied AC voltage will be equal to the AC peak voltage at that instance. Reclosing the AC breaker with such a trapped charge on the capacitor could result in excessively high currents flowing into the capacitor, potentially resulting in equipment damage. It is therefore normal practice to inhibit re-closing of a capacitor bank, after it has been opened, for a period of time in order to allow the stored energy within the bank to discharge. Reclose inhibit times are typically in the range of three to five minutes. Clearly, therefore, if the AC filter/reactive power bank is needed in order to meet the AC system steady-state requirements these banks cannot be opened in order to elevate the impact of dynamic events, without curtailing the transmission capacity of the link.

If the power flow through a LCC is suddenly interrupted its reactive power absorption will fall to zero. However, the AC filters/reactive power banks will remain connected to the AC system resulting in an overvoltage on the AC bus. Where the Short Circuit Ratio (SCR)[1] is 4.5 the peak voltage would reach approximately 1.1pu [2] whilst for a SCR of 2.0-3.0 the overvoltage would be approximately *1.4pu* [2]. This voltage rise would be transmitted through the system down to the distribution level where a high magnitude overvoltage lasting the duration of the HVDC recovery may not be acceptable. Equally, at the transmission level, such a high overvoltage may cause transformer saturation.

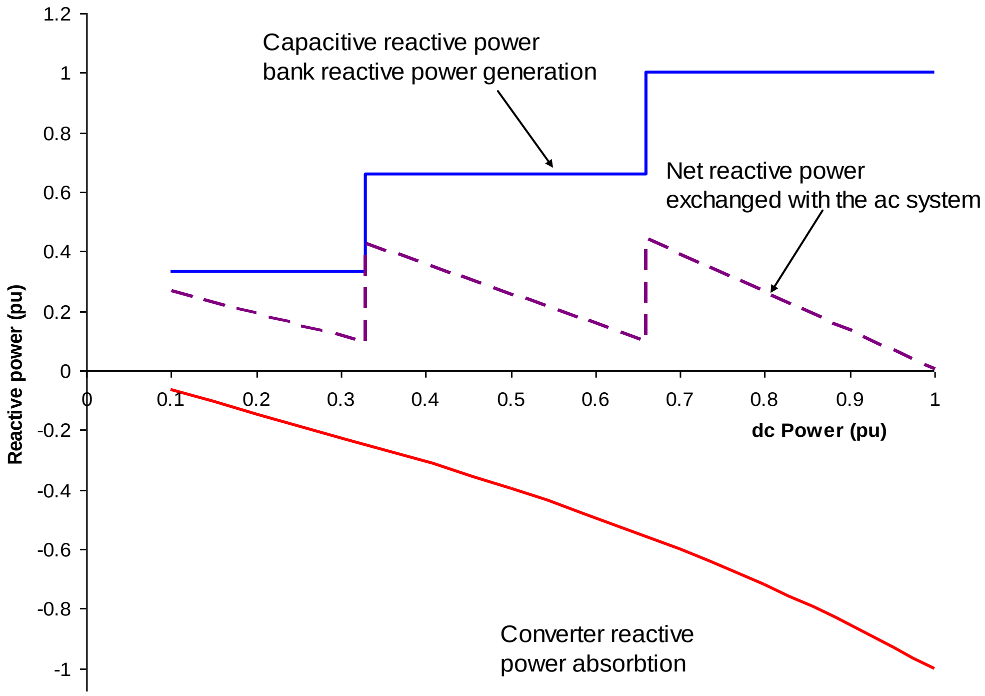

Figure 1: Increasing reactive power absorption and AC filter/reactive power bank switching for a typical LCC HVDC terminal.

A solution to this problem employed on a number of schemes [4], [5], [7] has been to use a Static Var Compensator (SVC), located at the HVDC converter station, to compensate for the potential overvoltage resulting from excessive capacitive VAr's. The primary requirement of the SVC is to provide short term overload reactive power absorption to compensate sufficiently for the AC harmonic filters in order to bring the AC overvoltage to within acceptable limits. However, having made the decision to investe in the SVC the SVC's steady-state rating can be used to optimise the overall HVDC + SVC reactive power solution further reducing or simplifying the switching arrangements for the shunt connected AC filters/reactive power banks.

Figure 2 indicates a typical 'static characteristic' [1] for a HVDC scheme and includes (purple dotted line) an indication of a *constant reactive power absorption characteristic*. This indicates that when the DC voltage collapses to a low value the reactive power absorbed by the converter is less than it is at *1.0pu* operation. However, as the scheme recovers, climbing up the static characteristic, it can be seen that during some period the converter absorbs more reactive power than it does at full power, hence, will tend to depress the AC voltage. This effect can lead to multiple commutation failures in a multi-infeed AC system where several electrically close LCC's are recovering from an AC system disturbance in parallel [8].

[1] Short Circuit Ratio is defined as the ratio of the AC system short circuit strength, at the converter AC connection point, to the real power being injected by the converter:

$$SCR = \frac{MVA_{sys}}{MW_{DC}}$$

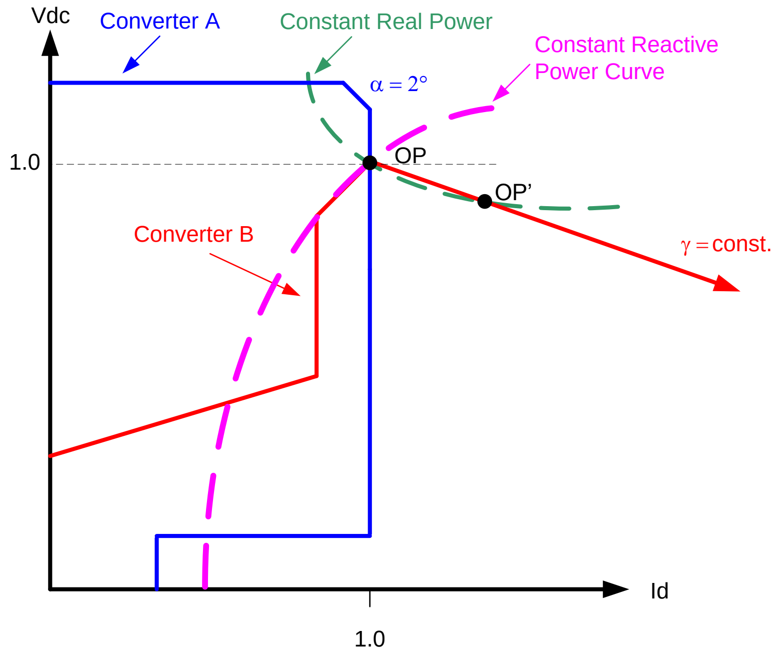

Figure 2: Typical LCC HVDC Scheme static characteristic indicating constant reactive power line

It is worth noting that an SVC consisting of a TCR or a TSC is effectively a thyristor based power electronic device, similar to the LCC. Response times of an SVC will therefore be commensurate with those of a LCC, not less than one cycle [5]. An SVC will therefore not mitigate against a commutation failure. The SVC's main function is to control the overvoltage resulting from the temporary loss of power transfer and to assist in LCC recovery.

HVDC with SVC – An illustrative example

Figure 3 shows a LCC HVDC terminal with an associated SVC, connected to an AC system given by series impedance. It is assumed that the magnitude of the remote voltage *Vs* is constant but its angle can change to accommodate power flow variation. The terminal bus voltage *Vg* has zero angle (coordinate frame position) but its magnitude can change as power flow is varied. A 1000MW HVDC system is considered connected to a weak AC system (SCR=2.5), and the data is given in Table 1. Converter requires around 550MVAr for inverter or 470MVAR for rectifier reactive power at full load (ignoring tolerances, measurement error, etc.), but it is necessary to add further capacitors to compensate for reactive power loss in the weak AC grid. The SVC system data is shown in Table 2. For comparison, full reactive power is supplied either by HV connected capacitor banks or by combination of capacitor banks and the SVC. When the SVC is connected 200MVAr is removed from the fixed capacitive support. The SVC is optimised for partial reactive power compensation to limit the voltage deviations below *16%*. When the SVC reaches the reactive limit the system will operate with fixed capacitors but the total reactive power will be smaller.

The following assumptions are made regarding HVDC voltage stability analysis [3],[6]:

1. No converter transformer tap changer action is considered (constant tap position) since tap changer operation is very slow.
2. No capacitor bank switching is considered (constant capacitive support) since switching hysteresis time does not permit rapid switching
3. There are no controls in the AC system (or they have no time to respond)
4. For the inverter study, DC current is an independent variable, which is assumed to be accurately controlled by the rectifier. The power flow is solved to reach a stable operating point for each value of DC current.

5. For the rectifier study, the control angle is an independent variable, while the inverter maintains constant DC voltage. The power flow is solved to give stable operating point for each firing angle and the points are connected to give the full operating diagram.

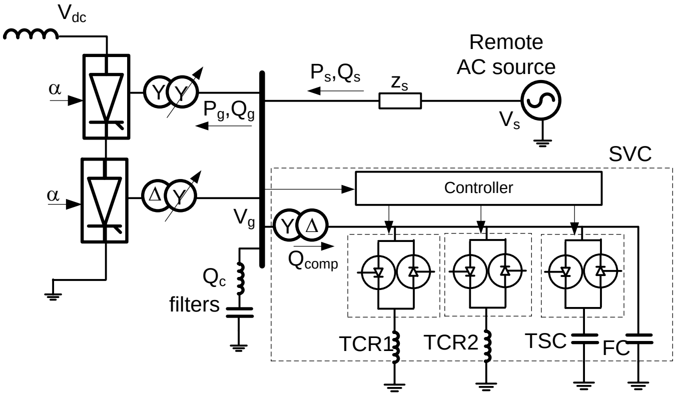

Figure 3. HVDC terminal with Static Var Compensator.

Table 1 HVDC test system

	Rectifier	*Inverter*
DC system power rating	*1000MW*	
AC system voltage	V_s*=415 kV*	V_s*=415 kV*
DC voltage (at inverter)	V_{dc}*=500 kV*	V_{dc}*=492 kV*
Transformer rating,	S_t*=1137MVA*	
Transformer impedance	X_{tpu}*=0.12pu.*	
Inverter operating mode	*Idc=const.*	*Vdc=const*
Nominal firing angle	α *= 15deg*	γ *= 20deg*[#]
Minimum extinction angle	γ*=15deg*	
AC system	*SCR=2.5, X/R=10*	
Reactive power supply	80% of Pdc (Qc=800 MVAr)	63% of Pdc (Qc=630 MVAr)

[#] Note: The inverter is designed to maintain the DC voltage constant for a voltage drop of 3% in the AC system.

Table 2 SVC parameters in the test case

Range on 400 kV bus	*+200/-335 MVAr*
Transformer turns ratio	*400 kV / 23 kV*
Transformer rating	*200 MVA, 12%*
Fixed capacitor	*53 MVAr*
TSC	*123 MVAr*
TCR	*2 x 235 MVAr*

Figure 4 shows the operating diagrams of inverter terminal of the test system. The capacitive support, and SVC rating, are selected sufficiently high to enable MAP (Maximum Available Power) marginally over the rated power. If fixed capacitors are used, it is seen that the AC voltage variation is excessive (around 33%) in case of low load. SVC brings benefits in terms of limiting AC voltage variation and maintaining extinction angle close to optimal. If the SVC controls AC voltage (SVC *Vg=const*) better responses are observed than if the SVC is in constant power factor (SVC *p.f=const.*) control.

Figure 5 shows the operating diagrams of rectifier terminal of the test system. In this case voltage variation is larger since the converter draws both active and reactive power from the AC grid. The AC voltage variation between minimal and maximal power, with fixed capacitors, is *47%* which would not be allowed in practice. With the SVC the maximal voltage variation is *16%*. It is also seen that HVDC with the SVC in unity power factor control cannot deliver full power, which is a consequence of the large resistive voltage drop in the weak AC system.

Operation of a VSC

VSC technology was first trialled for HVDC transmission only as recently as 1997 [3] and since this time it has gone through several iterations of technology. Early schemes used a simple 2-level converter utilizing PWM (Pulse Width Modulation) to synthesise the AC waveform. However, such converters suffered from very high losses and hence the topology was changed to a 3-level converter, again using PWM. Later designs then went back to a 2-level converter design but using a modified PWM known as Optimal PWM or OPWM. Using OPWM reduces the switching frequency of the converter and hence the losses but at the cost of increasing selected AC harmonics, which then require passive filtering.

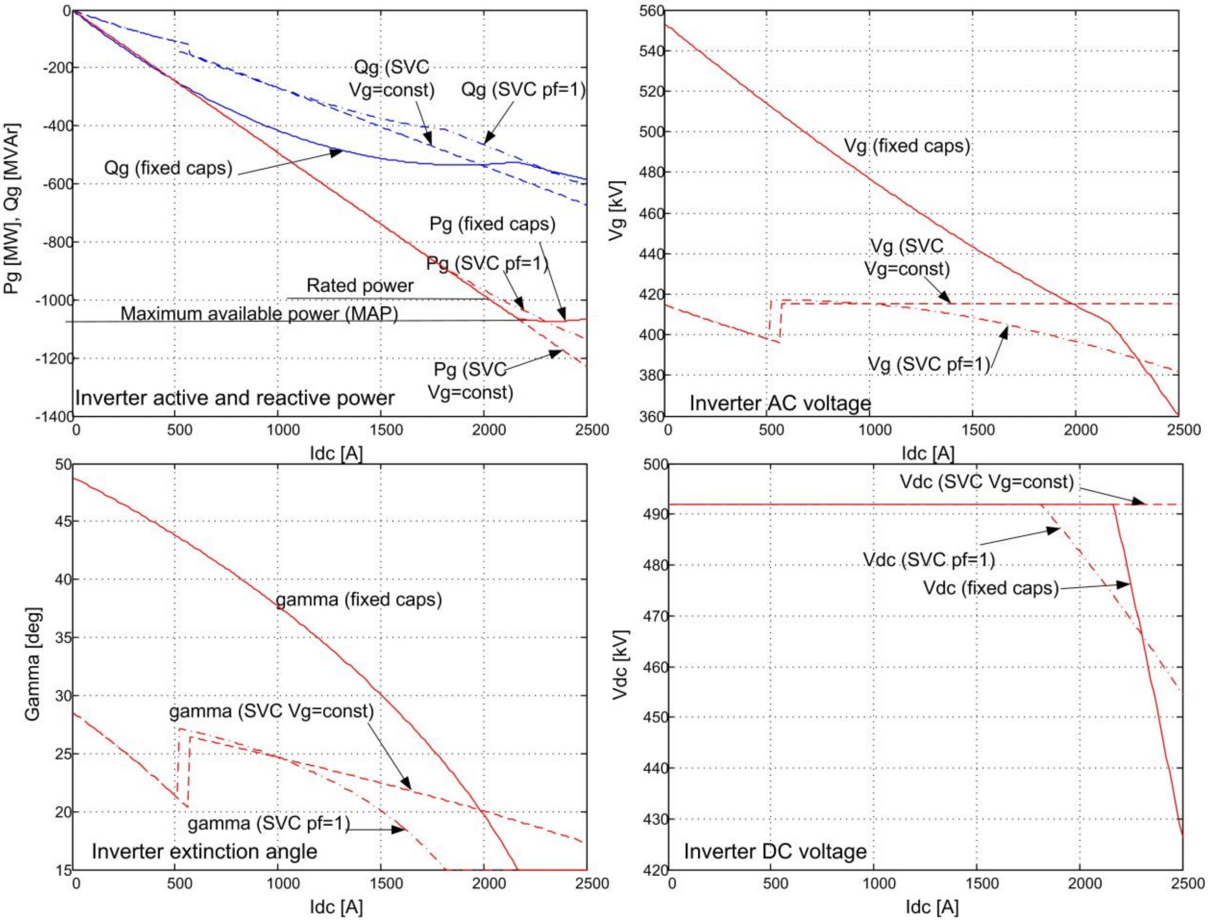

Figure 4. 1000 MW LCC HVDC inverter with +200/-335 MVAr SVC, operating curves as power transfer is increasing. Curves 'fixed caps' show operation with 630 MVAr capacitor, curves whilst 'SVC' use +200/-335 MVAr SVC, either in power factor control or Vg control mode.

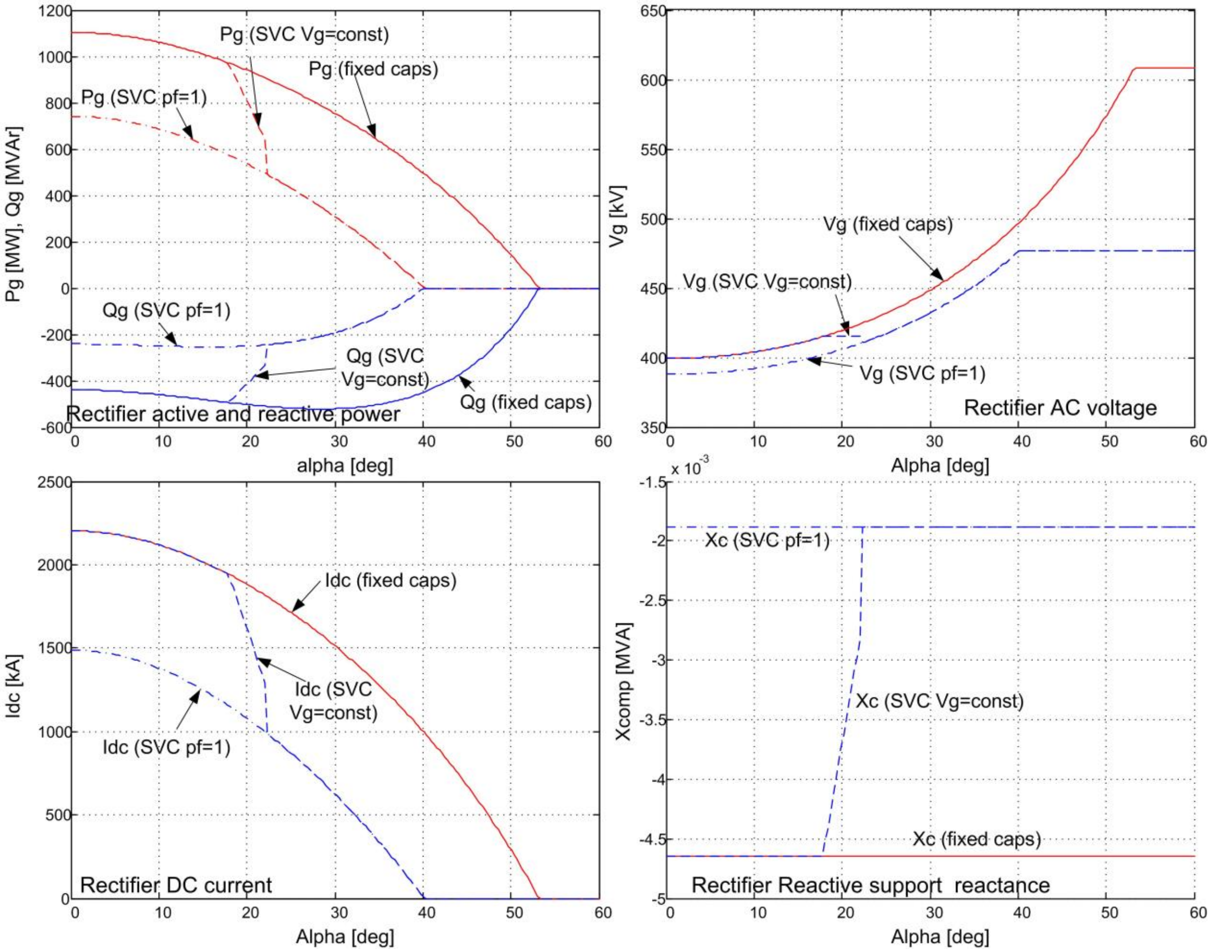

Figure 5. 1000 MW LCC HVDC rectifier with +200/-335 MVAr SVC, operating curves as power transfer is increasing. Curves 'fixed caps' show operation with 800 MVAr capacitor, curves with 'SVC' use +200/-335 MVAr SVC, either in power factor control or Vg control mode.

Today, the state of the art in VSC for HVDC is known as the Modular Multi-Level Converter (MMC), as shown in Figure 6. Unlike the earlier topologies of VSC the voltage used to synthesis the AC voltage does not experience large, rapid voltage changes, instead the secondary voltage waveform contains only small steps in voltage. These small steps are created by the individual switching of elements within the converter connected together in series in an arrangement known as a "chain-link" [9]. A single HVDC converter may consist of several thousand elements connected together. Included in each half phase of the VSC is a linear reactor, which provides control of the current in each phase during switching of the semi-conductor devices and acts to limit fault currents in to the power electronic converters.

The MMC can be either a 'full-bridge' or a 'half-bridge' circuit. The 'full-bridge' circuit is able to reverse the DC voltage. The full-bridge's ability to reverse the DC voltage means that the converter can produce a voltage which opposes the voltage driving the fault current on the DC side and hence stop it. However, in the case of, for example, a simple point-to-point DC submarine interconnection where a DC side fault will almost certainly be permanent and, hence, will necessitate tripping the DC connection, cost and loss savings can be realized by using the half-bridge circuit. The half-bridge circuit is comprised of only two IGBT's per sub-module but does require additional circuit elements to protect the circuit in the event of a DC side fault.

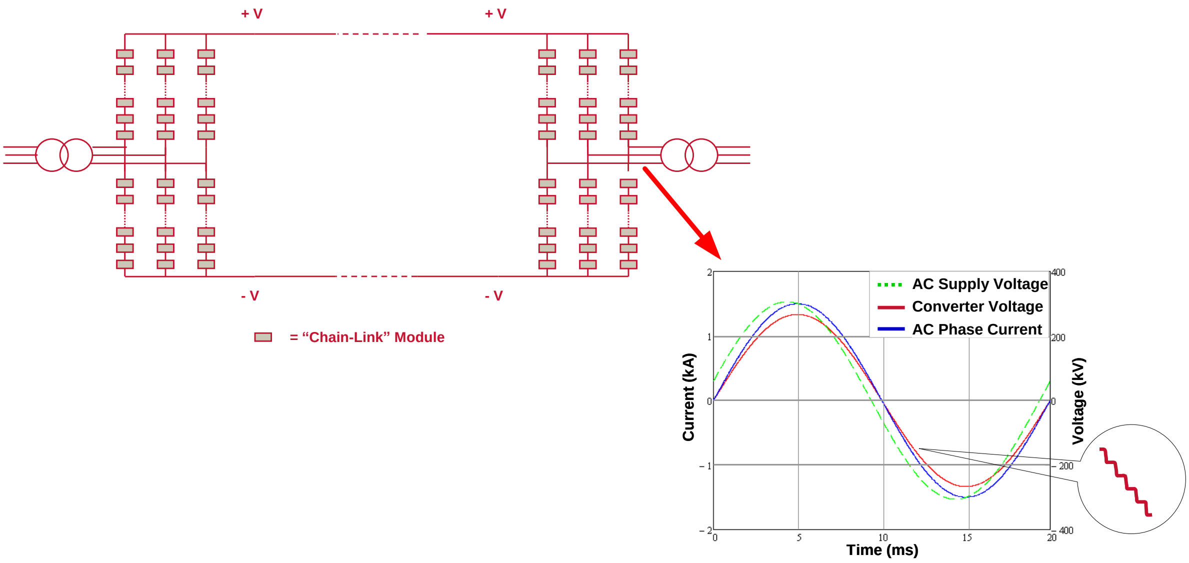

Figure 6: A typical Modular Multi-Level Converter (MMC)arrangement and output AC waveform

MMC Reactive Power Capabilities

The MMC operates as a four quadrant device, i.e. it is able import/export real power and import/export reactive power to the AC systems at both ends of the transmission link. The reactive power can be controlled independently at each converter station. If no power flow is required or possible, e.g. due to a cable fault, each converter station is able to operate as a STATCOM, providing reactive power support to the local AC system.

The multi-module converter current limit capability contour for the same AC system with SCR=2.5 is shown in Figure 7b). It can be seen that the reactive power export capability is limited by the control signal magnitude (essentially valve voltage limit). This limit varies with the AC system steady-state voltage. The reactive power import is constrained by the circuit current rating. The design of the converter must also respect the DC current limit imposed by the DC circuit (for example the DC transmission cable). The multi-level converter design can be adjusted to match customer requirements for real power and reactive power demand at the terminals of the converter station, or Grid Code requirements on operating power factor range. A converter based on the full-bridge circuit is less constrained in terms of capacitive reactive power output than the half-bridge circuit, and is able to deliver full capacitive reactive power output.

Comparison with VSC HVDC

Figure 7a) shows the PQ diagrams at the AC terminals for the test LCC HVDC with an associated SVC for the same system from Figures 4 and 5. This figure adopts PQ presentation in order to compare the operating area with VSC HVDC terminal. The discontinuity at zero active power occurs because of the different reactive power support needs when the HVDC is in rectifier and inverter modes.

The operating range for LCC+SVC is wider at high power operating conditions. In particular, at full active power (export or import), LCC HVDC with SVC has much wider operating range, which may, possibly, be further adjusted with the aid of a transformer tap changer.

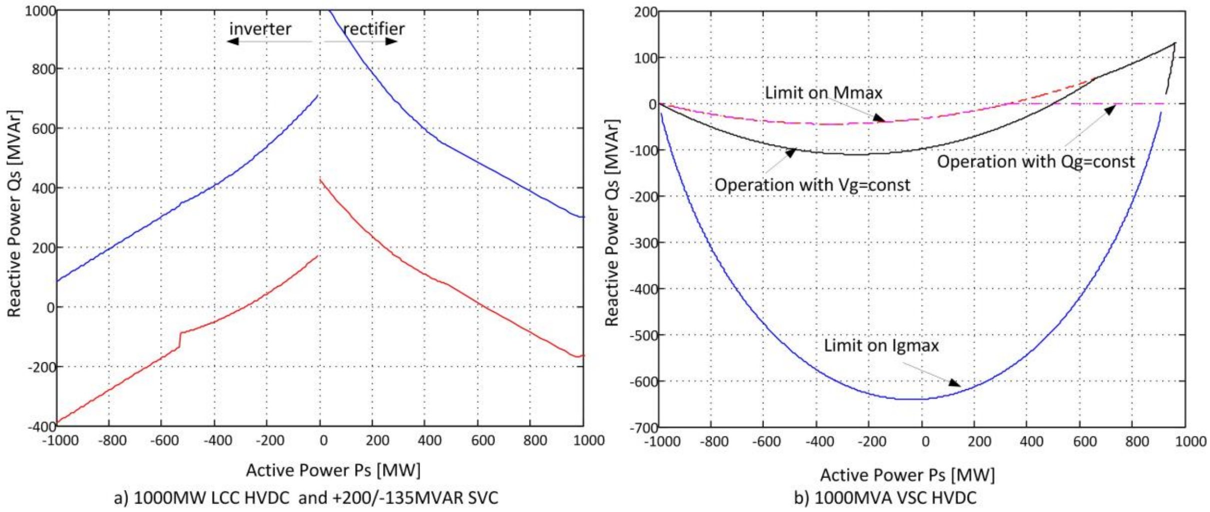

Figure 7. Comparison of PQ diagrams for LCC HVDC with SVC and VSC HVDC. SCR=2.5, X/R=10 (Positive power indicates power flow AC to DC)

Conclusion

An SVC at the terminals of a LCC HVDC brings operating advantages, and in particular it enables HVDC operation with weak AC systems. It equally helps maintain firm steady-state AC commutating voltage for both rectifier and inverter operation. The SVC rating need not necessarily equal full reactive power demand, in which case some overvoltage will remain for extreme load rejection cases. The power flow study with a SCR=2.5 and an SVC TCR rated for 0.335pu shows that worst case overvoltage is 1.16pu.

The comparison with VSC HVDC PQ diagrams reveals that LCC HVDC with SVC generally has wider operating area at higher powers, although VSC offers more flexibility at lower active power flow.

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HVDC AND POWER ELECTRONICS
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Study of AC/DC interactions and control strategy in Hami-Zhengzhou UHVDC project

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SUMMARY

In order to meet the demands of long distance bulk power transfer, UHVDC has gotten unprecedented development in China. Thus a large hybrid AC/DC power grid has been established and the influence between DC and AC system becomes a considerable problem. Obviously, due to the power grid pattern of strong DC system and weak AC system, the restriction between AC and DC system, especially in 750kV EHVAC and 1000kV UHVAC level, will greatly increase the risk of stability problems.

In this paper, the hybrid AC/DC system conditions and characteristics as well as the existing stability problems of Hami-Zhengzhou UHVDC are introduced firstly.

The sending end, Hami converter station, is an important part of the northwest China 750 kV power grid. It's also a node of 750kV AC power transmission channel which connects Xinjiang grid to Northwest China grid. At the beginning operation of this station, due to the lag of power resource construction, the dynamic stability, transient stability and voltage stability problem interweave together and cause unacceptable impact to the Qinghai-Tibet HVDC project, whose sending end is located at the northwest China Grid and the other end located at Tibet which is a typical weak receiving end. The other notable problem is the voltage instability of Haixi regional grid during the power rebalance caused by UHVDC blocking. This has become the main restricting to the DC transmission.

The receiving end, Zhengzhou converter station, which injects into the Henan power grid, is exposed to the synchronization stability problems of north-central China UHVAC power grid. The UHVDC pole block will lead to large scale of power flow transfer. This will cause the overload on the regional links, thus result in voltage instability at last.

To solve above-mentioned stability problems, a well-designed security and stability control systems (SSC), building a whole system together with SSC in other substations and power plants, are installed in both ends. In this paper, the configuration of security and stability control system and corresponding security control strategy are proposed. Based on the real-time digital simulator (RTDS) and the control and protection equipment applied on site, the UHVDC converter deblocking failure problem during operation is analysed, and the impact of the UHVDC control mode on voltage stability of AC system is also discussed.

KEYWORDS

UHVDC – SSC - Control Strategy - Voltage Stability – RTDS

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0. Introduction

Hami - Zhengzhou ±800 kV UHVDC transmission project, which is an 8000MW UHVDC project from Hami district of Xinjiang area that has large coal and solar energy to Zhengzhou in Henan province, the load center of middle China in the distance of 2210km, is the first UHVDC project for electricity delivering of Xinjiang province, also is the first DC transmission project of wind power and thermal power baling. It is the largest and longest UHVDC project in the world so far.

The rated operation voltage of AC bus in sending end, Hami converter station is 530 kV, where the power supply nearby, including 4 units of 1000 MW generator sets and 8 units of 660 MW generator sets, which will be put into operation in batches, connect to through the 500 kv lines. The 500 kV bus bars connect with the Northwest power grid by two 750kV transformers, whose capacity is 2100 MVA each. And there are 4 AC lines with 750kV in converter station, respectively connect to Hami substation and Hami south substation. Hami south converter station, which is used for electricity delivering of Xinjiang province together with the existing first 750kV AC power transmission channel which connects Xinjiang grid to Northwest China grid, the blue part shown in Fig. 1, is a node of second 750kV AC power transmission channel which connects Xinjiang grid to Northwest China grid, the red part shown in Fig. 1. It's also an important part of the Northwest China 750kV power grid.

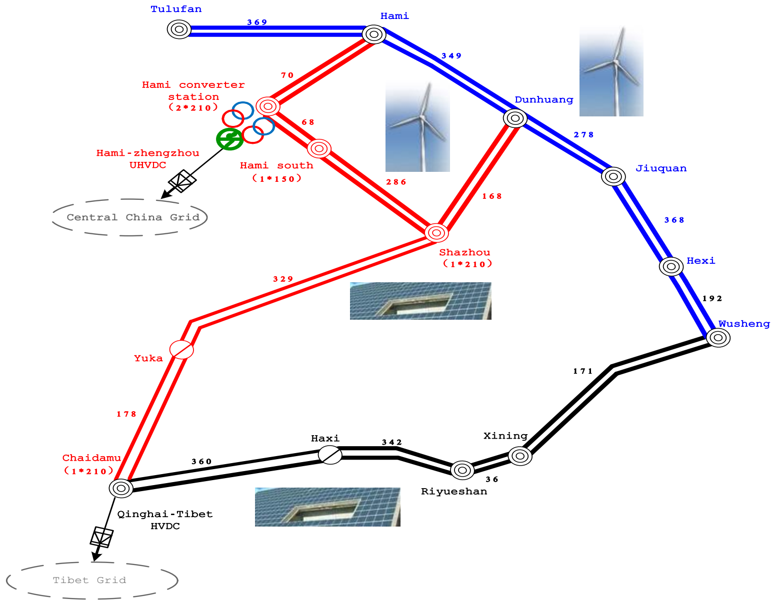

Fig.1 Schematic diagram of Hami converter station

The receiving end, Zhengzhou converter station, is connected to the Henan power grid with 6 AC lines in 500kV level. Respectively, each 2 AC lines are direct to Zhengzhou north substation, Guandu substation and Bianxi substation. The rated operation bus voltage in converter station is 525 kV.

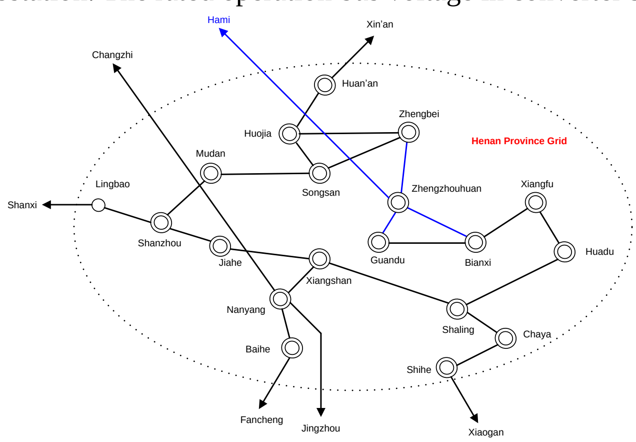

Fig.2 Schematic diagram of Zhengzhou converter station

1. AC system characteristics

After operation of the Hami-Zhengzhou UHVDC project, the characteristics of large-capacity DC, wind power and photovoltaic power in transmission channel from Xinjiang grid to Northwest

China grid and the weak receiving end for Qinghai-Tibet HVDC project, is very outstanding. At the beginning, due to the construction lag of power resource, the electrical connection between coveter station and main network is weak, where the short-circuit capacity is small [1]. In case the AC line nearby the converter station has fault or the DC pole blocks, it will cause transient stability and voltage stability problem and also it will endanger the operation of Qinghai-Tibet HVDC.

In addition, if N-2 fault occurs in the transmission line of the first 750kV AC power transmission channel which connects Xinjiang grid to Northwest China grid, the power will transfer to the second channel, whose transmission line is on the same tower with the first channel. The transmission distance of the second channel is more than 1200km， along which the power grid construction is weak. Also there is less power support and reactive power compensation and there are more switching stations in transmission channel. It cause unacceptable voltage sag, especially in 750kV Chaidamu converter station, the sending end of Tibet HVDC, as shown in Fig.3. With the operation of the power source project, the transmission power of Hami-zhengzhou UHVDC will increase fast, and the transferred power to the Northwest grid will also increase. Due to the weak network and small load base, thus for the Haixi power grid, which is in the transmission end of Qinghai grid, the electrical distance gets shortened with main network after the operation of grid interconnection project. The operation mode or the disturbance has a more obvious influence on Haixi grid. Thus voltage stability problem during the power flow transferring may occur.

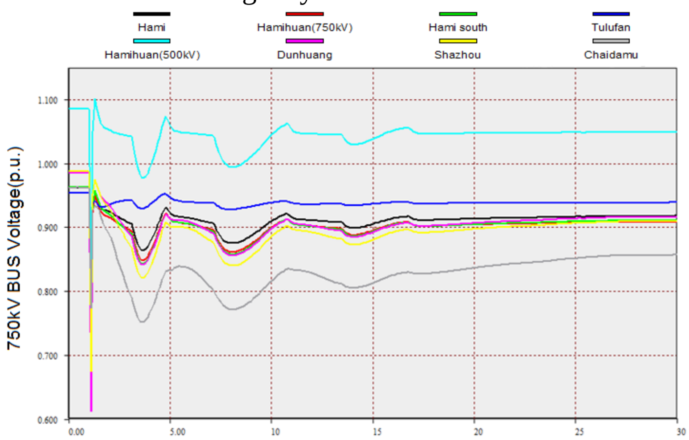

Fig.3 Schematic diagram of voltage dropping in second 750kV AC power transmission channel

Comparing with the sending end, Zhengzhou converter station is good for the large capacity power receiving because of the strong power grid and the close electrical connection. The issue to consider is the voltage problem of north-central China UHVAC power grid [2]. The UHVDC pole block will lead to large scale of power flow transferring. This will cause the overload on the regional links, thus result in voltage instability at last. Different with the AC/DC parallel operation, there no AC link lines between the Northwest grid in sending end and the Henan grid in receiving end. So the main control measures taken in receiving end is load shedding and power modulation.

2. SSC and control strategy

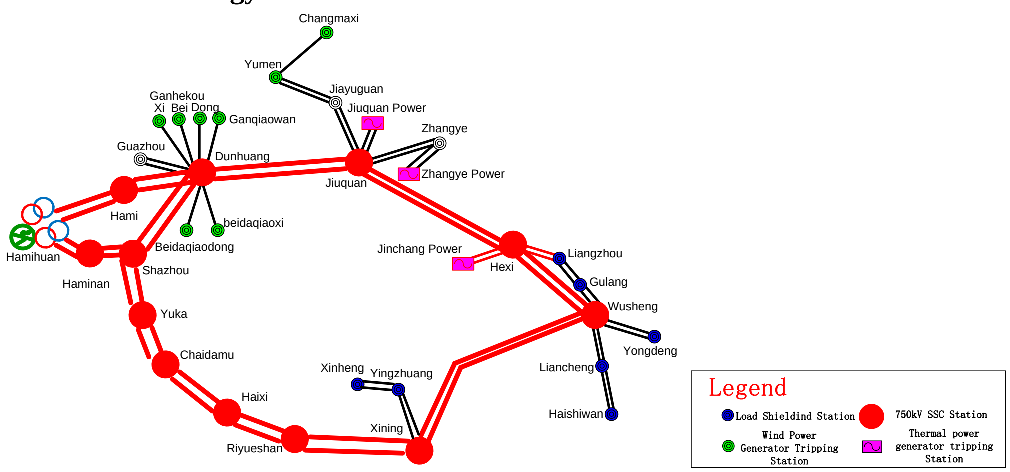

Fig.4 Configuration of SSC at sending end

To solve above mentioned stability problems, a well-designed security and stability control system (SSC), building a whole system together with SSC in other substations and power plants, are installed at both ends.

The configuration of SSC in sending end is shown in Fig.4. The main task of SSC in Hami converter station is sending the generators tripping order to SSC executing station in 500kV power plants and SSC master station for 750 kV power grid in Dunhuang station according to the 750 kV / 500 kV transformer fault information, 500kV power grid fault information, DC fault information and the operation status information of 750kV power grid, and also executing the emergency DC power modulation order from master station in 750 kV Dunhuang station.

For example, in the operation mode with 8 units of 660 MW supporting generator sets, in case of mono-pole blocking with 3700MW for Hami-Zhengzhou UHVDC, system instability will occur at sending end if no control measure is taken. The voltage of 750kV bus will decrease much more due to the lack of reactive power and the frequency instability of middle Tibet power grid appears because of the power fluctuation of Tibet HVDC. The frequency deviation of middle Tibet is more than 1 Hz. If taking the control measure of tripping 4 units of 660MW supporting generator sets, the frequency of middle Tibet grid can keep stable

In case of bi-pole blocking with 7400MW for Hami-Zhengzhou UHVDC, the impact of different control measures on system stability is more apparent. If the control measure of tripping 8 units of 660MW supporting generator sets and 350MW thermal power unit in Xinjiang is taken, the voltage can be stable, but the frequency instability of middle Tibet will occur. If the control measure of tripping 350MW thermal power unit in Xinjiang is replaced by tripping 400MW wind power unit in Dunhuang, the voltage and frequency both cannot keep stable. According to the system analysis and simulating calculation, in order to keep system stable, 8 units of 660MW supporting generator sets and 2 units of 350MW thermal power generators must be tripped. Also it can be found that tripping the thermal power unit is more effective for system stability.

In addition, in case N-2 fault occurs in AC line from Dunhuang to Jiuquan, due to the large amount of load shedding and generator tripping, the voltage of 750kV bus in Hami, Dunhuang, Shazhou and Yuka substation will increase significantly after SSC action. The highest rising voltage appears in Dunhuang substation, which reaches 100kV as shown in Fig.5.

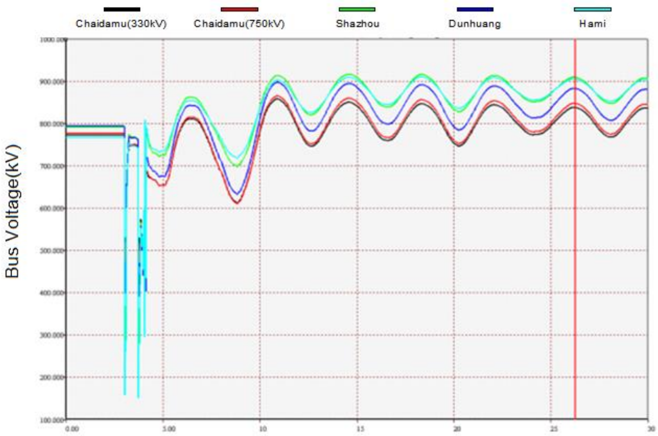

Fig.5 750kV bus voltsage curve in Northwest Grid

And the overvoltage can be restrained by adjusting the capacity of controlled reactor in Shazhou substation and the tap position of controlled reactor in Yuka substation.

On the other hand, SSC in Zhengzhou converter station sends the DC modulation order to Three Gorges master station and load shedding order to Henan master station and Hubei master station, according to DC fault information, operation information of UHVAC line from Southeast Shanxi to Nanyang, operation information of DC in Three Gorges areas and the operation status information of500kV power grid. The detail configuration of SSC in receiving end is shown in Fig.6.

The selected control points includes almost all converter station in Three Gorges area such as Longquan station, the sending end of Three Gorges-Changzhou HVDC, Tuanling station, the sending end of Three Gorges-Shanghai II HVDC, Yidu station, the sending end of Three Gorges-Shanghai HVDC, Jiangling station, the sending end of Three Gorges-Guangdong HVDC, Gezhouba station, the sending end of Gezhouba-Nanqiao HVDC. Also the control points are set in Jinping and Fulong converter station in Sichuan province.

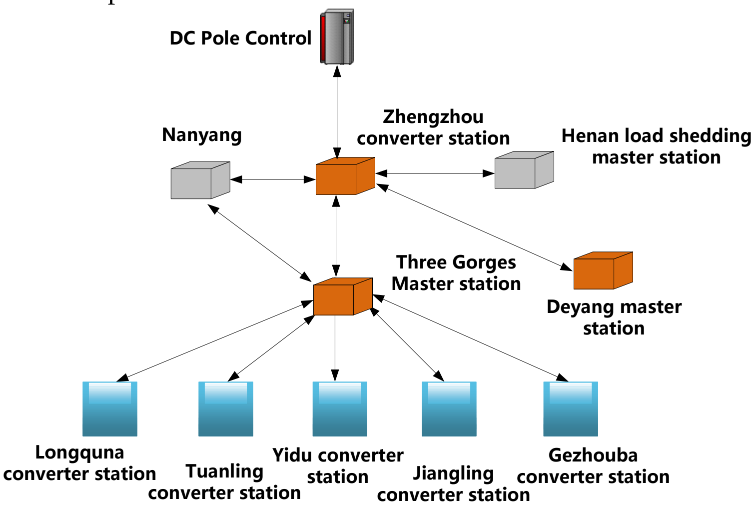

Fig.6 Configuration of SSC at receiving end

In operation mode 2013 with 5000MW power sent to south for UHVAC, when Hami-Zhengzhou UHVDC pole block, the power shortage in Central China Grid will be added to the cross-section of UHVAC according to the principle of inertia distribution, which will result in separating running for Northern China Grid and Central China Grid. In case of mono-pole blocking in operation mode with bi-pole low voltage converter running in 4000MW for Hami-Zhengzhou UHVDC, system can be stable. But if bi-pole blocking occurs, the control measure of load shedding in Henan for 1290MW, where the generators have governor or power modulation of HVDC in Three Gorges area for 1300MW must be taken.

To decrease the amount of load shedding in Henan province after UHVDC pole blocking, using the emergency power supporting of HVDC sufficiently, which the control measure of DC modulation is a priority is taken as the control principle of SSC at receiving end.

3. Research of the impact of the control mode of UHVDC on receiving end

According to the control object, the basic control mode of HVDC includes constant voltage (CV), constant current (CC), constant power (CP) and constant extinction angle (CEA) control. As a result, the four commonly used HVDC control mode [3] (C1-C4) for rectifier and inverter stations are as follow:

1) Rectifier CC and Inverter CV

In this kind of control mode, the DC current is maintained constant by the current controller at rectifier side, and the inverter work in constant voltage control mode to maintain a stable DC voltage. When the increasing load makes AC bus bar voltage dropping at the receiving end, thus the reactive power consumption is reduced at inverter side, which prevents voltage decline further and the voltage collapse.

2) Rectifier CC and Inverter CEA

Under this kind of control mode, the extinction angle at inverter side is adjusted to reference by extinction angle controller. When the increasing load makes AC bus bar voltage dropping at the receiving end, the change of reactive power consumption depends on the system operation status. But in general, the firing angle at rectifier side increases with extinction angle at inverter and the power factor of converter decreases with extinction angle, which results in the reactive power, absorbed from AC power grid increases accordingly and leads to the increase of harmonic current.

3) Rectifier CP and Inverter CV

In this kind of control mode, the power is kept constant by controlling firing angle at rectifier side. When the increasing load makes AC bus bar voltage dropping at the receiving end, the reactive power consumption will decrease. It is benefit for maintaining the voltage stability at receiving end.

4) Rectifier CP and Inverter CEA

Under this kind of control mode, when the increasing load makes AC bus bar voltage dropping at the receiving end, due to the decreasing of power factor at inverter side, the reactive power consumption at inverter side will increase. And this results in AC bus bar voltage dropping further, which is not helpful to the voltage stability.

In the actual projects, the CV and CEA both have applications. In generally speaking, for weak receiving end, the CV mode in inverter has a distinct advantage due to the less reactive power loss and higher stability margin. Furthermore, the larger extinction angle can be obtained in light-load condition and the reactive power consumption will increase, which is benefit for the reactive power balance in converter station.

Fig.7 shows the comparing results of static voltage stability margin of Henan power grid after Hami-Zhengzhou UHVDC project put into operation. It can be seen that the CV mode is good for system voltage stability at receiving end as we have analysed before and the C3 mode is the best in almost all typical power level.

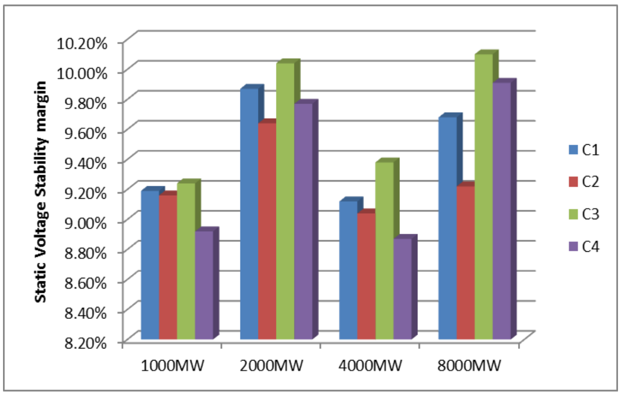

Fig.7 Compaing diagram of static voltage stability margin
(*Figure created by author from data in bibliography [4])

4. Research of the failure of converter deblocking

The series structure is used in UHVDC, thus the pole can operate not only in single converter mode but also in two converters mode, which can be changed on-line by converter deblocking and blocking. The converter deblocking on-line can be achieved by coordinate control of converter unit and the bypass switch paralleling [5]. Fig.8 is the schematic diagram of high voltage converter deblocking. When the current in high voltage converter V1 is equal to the operation current of low voltage converter V2, the current in bypass switch C4 is almost zero. At this time, the switch is opened and the pole runs in two converters.

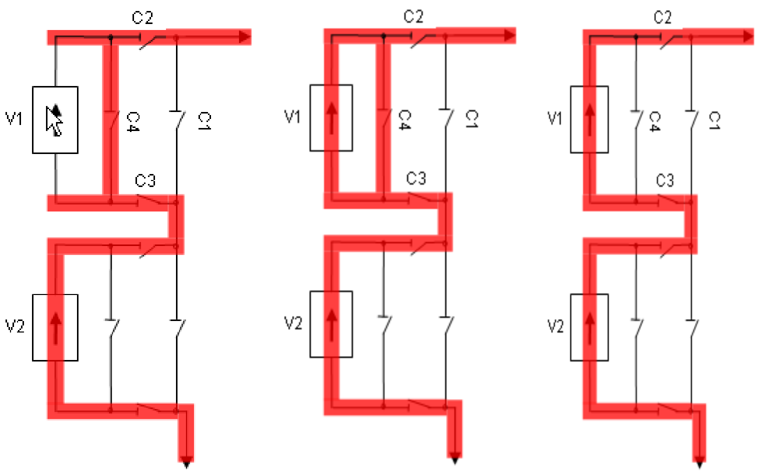

Fig.8 Sequence diagram of converter deblockong on-line

Because AC system at rectifier side of Hami-Zhengzhou UHVDC is weak, the failure of converter deblocking on-line appears. Fig.9 shows the wave record on site, which pole 1 was running in metallic return with low voltage converter deblocking in 2000MW. The system short-circuit was around 9kA, at a low level.

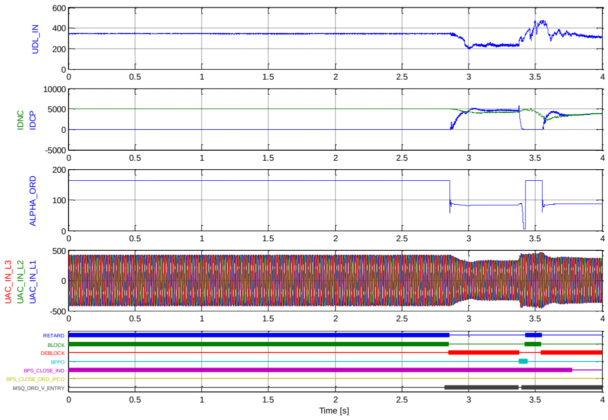

Fig.9 Failure of converter deblocking on-line in 2000MW on site

The similar result has been gotten by means of real-time digital simulator (RTDS) in case of same operation mode with short-circuit level in 7kA, which is shown in Fig.10.

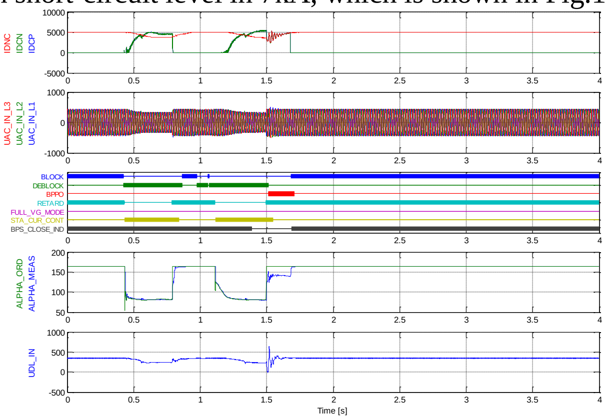

Fig.10 Simulate results of RTDS system in 2000MW

In case of the power level in 400MW, the converter deblocking on-line is successful. The result is shown in Fig.11.

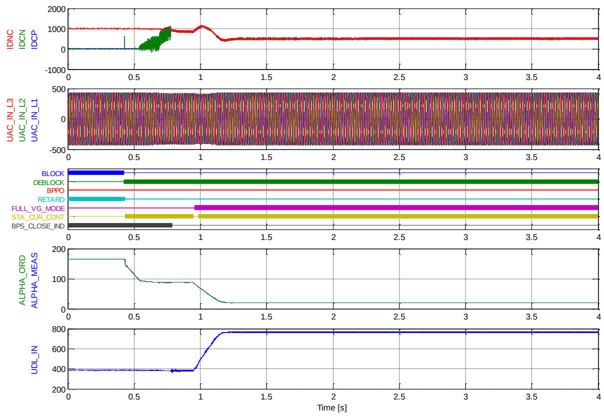

Fig.11 Simulate results of RTDS system in 400MW

It can be seen that the AC voltage at rectifier dropped obviously during the converter deblocking in high power level. This is due to the zero power deblocking mode adopted in Hami-Zhengzhou UHVDC as same as Xiangjiaba-Shanghai and Jinping-Suzhou UHVDC. In this mode large amount of reactive power will be required during converter deblocking on-line, which cause disturbance to the weak system. For example, in the running state described above the reactive power will increase to 1600Mvar, and this number is about 450Mvar before converter deblocking. To solve his problem, reducing the DC power before executing the operation of converter deblocking is suggested firstly. And the other way is adopting the small firing angle mode for converter deblocking on-line. In this mode the reactive power rush is small but the requirement of bypass switch is strict. The economic factor must be taken into account.

5. Conclusion and future work

With the rapid development of DC power transmission in China, the influence between DC, especially UHVDC and AC system becomes more complex. So how to use the control strategy to guarantee the safe and stable operation of AC/DC system and coordinated control for AC/DC system are becoming more and more important in UHVDC project.

This paper analyses the stability problem of both ends after the Hami-Zhengzhou UHVDC put into operation. The corresponding simulation results are given. In order to keep system stable, it is proved that SSC system is necessary, and the control strategy of both converter stations are researched in this paper. Of course, accelerating the construction of power at rectifier and strengthening the operation margin of AC link line of north-central China are both important for improving system stability.

In addition, studies have indicated that the impact of control mode of UHVDC on voltage stability at receiving end is great and the CP-CV mode is suggested. But in fact, which control strategy is used must take comprehensive consideration from the aspects of reliability, economy and so on.

The problem of failure of converter deblocking on-line is mainly caused by the weak AC system. The action of reducing the power is suggested in this case. Of course, changing the operation sequence and adjusting the relevant parameters also can be used. But this requires further studies to determine the impact of changing on system performance.

Researches of this paper can provide some references for the design and implementation of UHVDC project.

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Design aspect of ±800kV, 6000MW HVDC NER – AGRA Multi-Terminal HVDC Project (NEA800)

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SUMMARY

The ±800kV HVDC NER-Agra Multi-Terminal HVDC project shall transmit 6000MW from NER (North east region), ER (Eastern region) of India & Bhutan to major load centres of NR (Northern Region) in India over a distance of 1728km. This prestigious DC transmission project features several first of kind attributes in HVDC Systems. The project is being executed by JV of M/S ABB and M/s BHEL.

NEA800 consists of two rectifier terminal station and one inverter terminal station, where rectifiers with bipole configuration are located in Biswanath chariali in the state of Assam and Alipurduar in the state of West Bengal. The inverter station with double bipole configuration is located in Agra close to the National Capital Region.

Considering higher pollution levels at Agra, 800kV equipments and respective bus arrangement is built indoor (DC hall).

This paper highlights some major design features, studies and main components of the project including Converter Transformers, Thyristor Valve, smoothing reactors, control and protection systems, AC & DC filters, DC switches and multi-terminal feature, DC hall.

The following key considerations pertaining to the design aspects of NEA800 Multi-Terminal is covered:-.

1) Introduction 2) Converter station design criteria 3) Design Studies 4) Major equipment and technical features. 5) DC halls at Agra 6) Control and Protection System 7) Interstation telecommunication.

KEYWORDS

HVDC Design Aspects, Performance Requirements, Converter transformer, AC/DC filters, Thyristor valves, DC Hall, Control and Protection.
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1) Introduction

Power Grid Corporation of India Ltd., The Central Transmission Utility of India has taken up a high capacity ±800kV HVDC Transmission project consisting of ±800kV HVDC Line of 1728kM for interconnection of the North Eastern Region & Eastern Region of country with the major load centres of the country in NR/WR. As a part of the ±800kV, 6000 MW HVDC Multi-Terminal Project (NEA800), Rectifier and Inverter stations are being established (Refer fig-1A & 1B) at:

i) Biswanath Chariali (3000 MW) in Sonitpur district of Assam where power from NER would be pooled.
ii) Alipurduar (3000 MW) in West Bengal where power from Bhutan and its neighbourhood would be pooled.

The corresponding inverter Station is being established at Agra (6000 MW) close to the National Capital Region, which is connected to Northern and Western part of India through 400kV & 765kV AC Lines.
The proposed scheme shall facilitate strengthening of North Eastern- Eastern- Northern-Western transmission corridor for dispersal of power with reliability and security and effective utilization of right of way with low transmission loss.

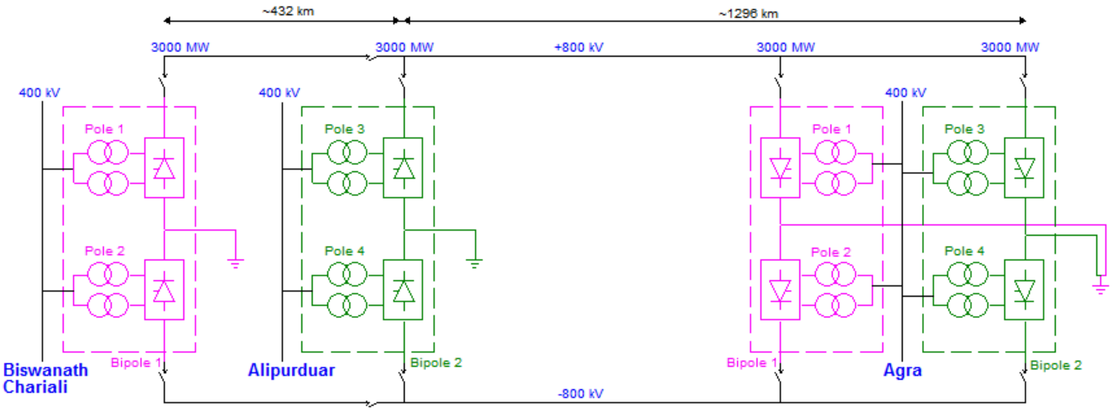

Fig-1A: Schematic Diagram of NEA800 HVDC Multi-Terminal

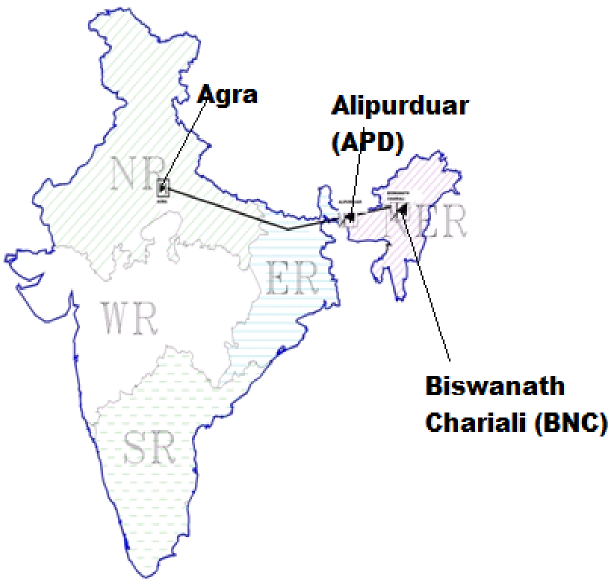

Fig-1B: NEA800 HVDC Multi-Terminal Link in India

There is huge potential in NER region to generate surplus hydro power; hence there is provision to add one more 800kV bipole in parallel to the existing bipole in each rectifier station to be able to handle 6000MW in future. A new Inverter terminal in Northern/ Western part of India along with new 800kV HVDC Line shall be envisaged during up-gradation of Rectifiers in future. Below figure 2 shows the present arrangement of NER-Agra and future scenario

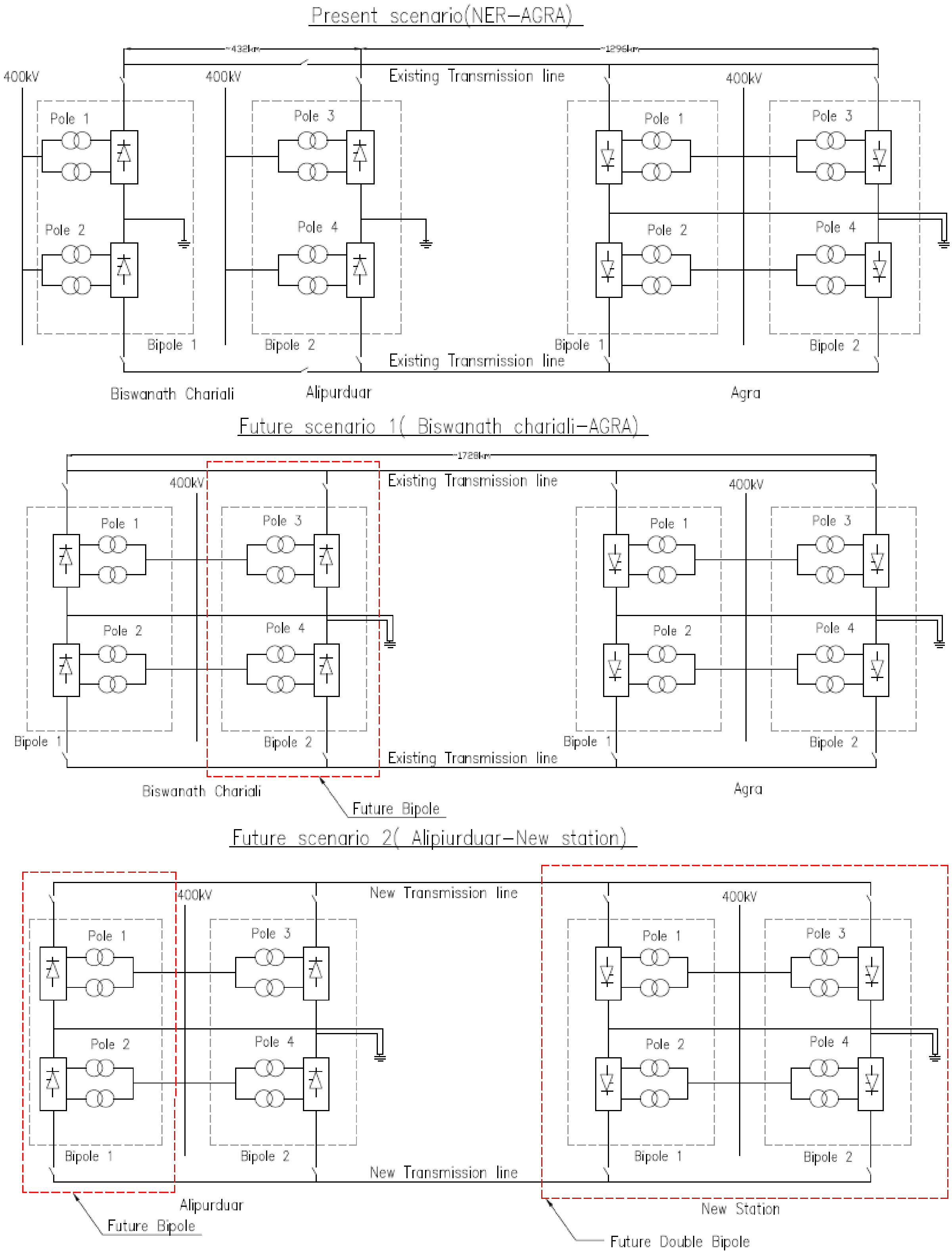

Figure 2

2) Converter Station Design Criteria

A. Power Transmission Capacity

The HVDC multi-terminal system is rated for a nominal power level of 6000 MW, with 3000 MW at each rectifier and 6000MW (including losses) at inverter end . All the rectifiers have nominal rating of 800kV and 1875A. The HVDC scheme can be operated in multi-terminal mode, bipolar mode and monopolar mode with ground return or metallic return. For maximum ambient dry bulb temperature of 40°C at rectifiers and 50°C at inverter, the converter stations are designed to transmit continuously full rated power without redundant cooling system in service. A continuous overload requirement of 33.3% has also been included for each converter. In case of outage of any converter, 33.3% continuous overload capacity can be used. All the series equipments are designed for 1.33 pu DC power (DC current of approximately 2500 Amps). Earth electrode stations are also designed considering the continuous overload capacity of the converter stations. Study has been performed considering future up gradation and configuration ,which includes insulation of neutral bus, energy range of valve arrester , tap changer range of converter transformer, control and protection design, layout and building arrangement.

The HVDC interconnection scheme is capable of continuous operation at any reduced dc voltage level from 800 kV down to 640 kV (80%). Although the normal power flow direction is from NER/ER to Agra, the HVDC system is designed to transmit power in the reverse direction also for point to point transmission i.e. from Agra to Biswanath Chariali only.

In case of DC line fault between Biswanath Chariali and Alipurduar section, DC fault shall be detected and discriminated leaving Alipurduar – Agra section to continue to transmit power within its capacity.

B. Performance Requirements

The maximum specified equivalent outage frequency (EOF= number of one pole outages x 1+ number of other pole outages x 1+ number of bipole outages x 2) is 10. The guaranteed energy availability per year of the each bipole during the three years availability guarantee period, considering both forced and scheduled maintenance outage is 97%. Maximum Forced outage unavailability is 0.7%. For overload availability requirement has been defined as 99.8%.

The maximum guaranteed annual failure rate of thyristor valve shall not exceed 0.2% per 12-pulse thyristor valve. The maximum guaranteed annual capacitor failure rate shall not exceed 0.15% except first unit failure.
Fast fault detection, effective repair and maintenance strategies as well as fault-tolerant control systems, redundancy, spare components and stringent quality assurance have been used in order to ensure the highest level of system reliability and availability with minimal downtimes.

Stringent flashover guarantee (Not more than 2 per station for outdoor DC Yard and zero for DC hall at Agra) with a provision of heavy penalty has been specified.
The performance requirements for dynamic response, reactive power exchange with AC system, overvoltage control, AC voltage distortion, equivalent disturbing current on the DC

side, radio interference and audible noise have been considered in the system design as per the limits stated in the Technical specification.

3) DESIGN STUDIES

The design studies for NEA800 HVDC project Multi-Terminal Project can be classified broadly into three groups.

First group consists of all studies which are required for dimensioning of equipments as per the technical specification of the project, viz. main circuit parameter study, overvoltage, reactive power, insulation co-ordination, AC/DC filter performance and rating studies, AC breaker, DC switches and interference studies.

Second group of system studies, like load flow, stability study, sub-synchronous resonance and AC equivalent, interaction with existing nearby converter stations (multi infeed) has to be studied and finalized before the start of functional test and dynamic performance study.

Third group of studies are the functional test and dynamic performance study for control, Protection and communication requirements.

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A. Insulation Co-ordination

This Insulation co-ordination determines overall arrester arrangement in the converter station have been followed as per the design philosophy of the CIGRE guidelines and IEC TS 60071-5 . In order to protect the installed equipment gapless ZnO arresters are used both on the A.C and the D.C side of the converter stations. The multi-terminal HVDC operation as well as future configuration with 6000 MW power transmission from Biswanath Chariali or Alipurduar is also considered in the insulation level design. AC bus arrester (converter transformers/filters) and neutral bus arrester rating has been finalised considering the future configuration. This shall be further coordinated as a part of up-rating scope at Biswanath Chariali or Alipurduar. Energy capability of valve arrester V1(top most valve, three pulse commutating group connected at pole bus potential) at rectifier has been dimensioned considering ground fault between valve and transformer bushing . Inter station communication delay between the rectifier is one of the key input for dimensioning the energy of top valve arrester(V1).
Air Clearance of the Valve hall and DC hall has been selected based on Engineering practices. In case live part is in proximity to two or more number of planes, additional clearance margin has been provided.

B. Overvoltage study

Abnormal A.C/ D.C side voltages, originating from the A.C/ D.C system, may appear on the converter buses and influence the converter operation and the equipment in different ways. Overvoltages of different characteristics, besides asymmetric voltages may also appear. In general, fundamental frequency overvoltages are considered for worst case load rejection of 6000 MW at Agra with the available reactive power compensation. The overvoltage have been investigated and coordinated by means of limitation and protection and suitably deciding component ratings. The intention is to coordinate the conditions within the range that can be controlled by protections and also compare with the region where arrester acts, i.e. within a few cycles of the initiation of the overvoltage.

C. Reactive Power management

The reactive power compensation elements have been designed to comply with the specified absorption and supply requirements .The size of sub banks at rectifier are of 125 MVAr and it can be switchable up to 1000 MW power transmission. Further from 1001 MW to 3000 MW 160 MVAr sizes filter/shunt compensation elements are available for switching at rectifiers. For inverter 200 MVAr sizes are available for switching between 1001MW to 6000MW. The necessary reactive power support is available at the rectifier station with redundant unit for 1.pu HVDC power transmission.
However, Reactive Power during overload shall be met by taking support from AC grid. At inverter end no reactive power support is required since they are connected to common 400 kV AC bus in the same location and overload for balance healthy converters are applicable only in case of outage of one of the converter.

D. Multi-in feed Interaction:

A study has been performed between the NEA800 HVDC Link and other HVDC links in vicinity by calculating the Multi-infeed Interaction Factor (MIIF) and Multi-infeed Effective Short Circuit Ratio (MIESCR). The study indicates the impact and sensitivity of the HVDC links in proximity to NEA800 HVDC link and identify links amongst them that have significant interaction with the new NEA800 HVDC link.

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4) Major Equipments and Technical features

A. Thyristor Valves

The NER-Agra ±800 kV UHVDC Multi-terminal project is designed based on the proven technology and the project experiences of other ±800 kV series systems. Here, classical configuration of one
12-pulse bridge per pole has been adopted with a very careful design of key equipments, such as, converter transformer, thyristor valves, Smoothing reactor etc. due to increased voltage and power stress.
Each 12-pulse thyristor valve is arranged in one individual valve hall. There are total eight valve halls (02nos. at each rectifier and 04 nos. at inverter) in this project. The valve towers (hanging structures) are arranged as double-valves, which are suspended from the ceiling of the valve hall. Hence, in each hall of one 12-pulse valve group there are six such towers.
All single valve functions in the 12-pulse bridge are identically dimensioned. Each complete single valve unit consists of a number of series connected thyristor positions, assembled in thyristor modules with intermediate reactors.

Fig-3, 800 kV Double valve structure of NER-Agra HVDC Project (under contruction).

Physically one single valve lies in multiple layers and have more than 100 numbers of series connected thyristors. The thyristor modules contain thyristors, voltage divider circuits,

Thyristor Control Units (TCU) and heat sinks. The modules and their components are fully interchangeable within the converter station. For this project, a 4 inch thyristor device is used. Thyristor valves are designed for indoor installations, air insulated and water cooled.
The cooling medium pipes are coming from valve cooling skid and the main header is running in valve hall at the top of double valve structure; from the main header of supply and return water pipe further distributed to each double structure and further branches out in each layer of valves and thyristor module. From the upper section, the supply and return pipes run down spiralling downwards around the structure. The potential of the cooling liquid in the pipes is controlled by means of electrolytically inert electrodes (platinum). The light guide channels are running vertically through the valve structure. The double valve structure is based on fiberglass reinforced epoxy rods, running vertically in the valve structure. This design is flexible enough to withstand all static and dynamic load conditions, including the seismic stresses specified for the project.
The main data of Thyristor valve is as under:

Description	Typical Thyristor arrangement
Number of Single valves per Pole	12
Number of single valves per structure	2
Number of double valves in station per pole	6
Number of thyristor levels per single valve	More than 100
Number of redundant thyristors per single valve	4

B. Converter Transformer

Converter transformer are manufactured as single Phase two winding oil immersed type ,considering the transport restrictions (dimensions, weight & transport facility , i.e.road, rail etc).Total 60 nos. of converter transformers shall be available to serve this project ,out of which 48 nos will be in service and 12nos. of the transformers as standby units divided equally in three terminals The line side (400 kV AC) transformer windings will be connected in star and neutral is solidly earthed. The valve side windings will be connected in star and delta with external bus arrangement between valve side bushings within valve hall.

Fig-4 800 kV Converter Transformer of NER-Agra HVDC Project (under contruction).
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The selection of on load tap changer range is adapted to the requirements of AC voltage variation range, reduced dc voltage operation, valve capability of operating at high firing angles and considering future up-gradation. The transformer leakage impedances were selected by considering key features (i) Permissible short-circuit current of the thyristor valve, (ii) Harmonic currents, and (iii) Reactive power consumption and optimized for rating and construction cost
A typical 3-D view showing the arrangement of converter transformers, Valve Hall and DC Hall at Agra has been indicated in Fig 5. The converter transformers are placed side by side for overall space optimization. The arrangement provides for replacement of the faulty transformer with in 72 hours which shall also be demonstrated at site.

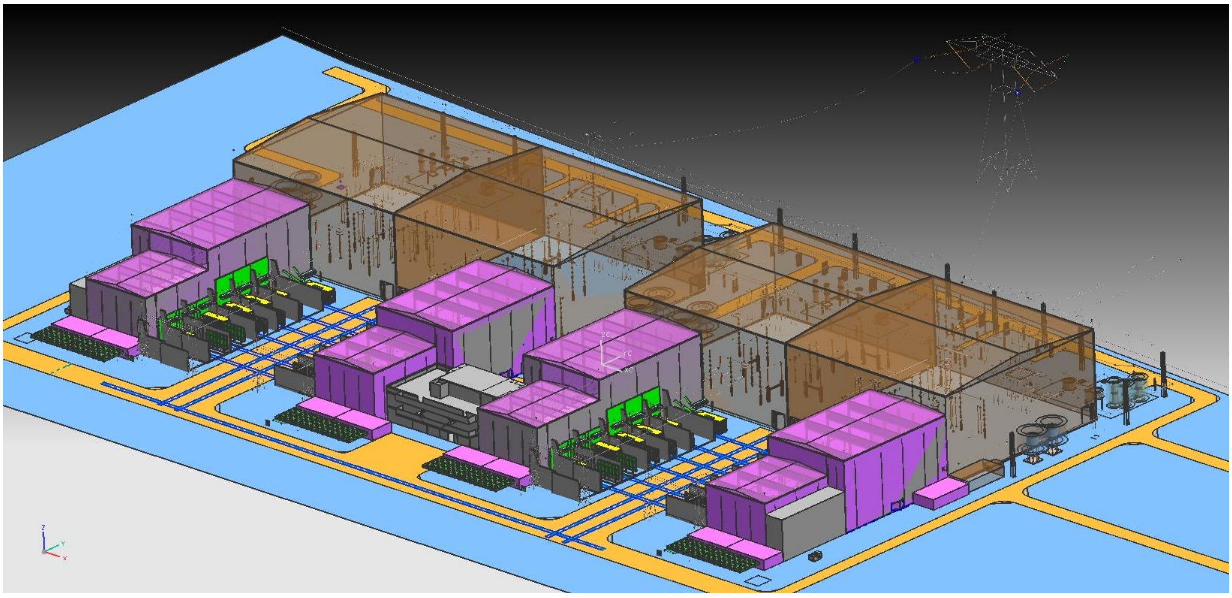


Fig 5: Typical 3-D arrangement of Converter Transformer Island, Valve Hall & DC Hall at AGRA

Major technical data of converter transformer is as follows:

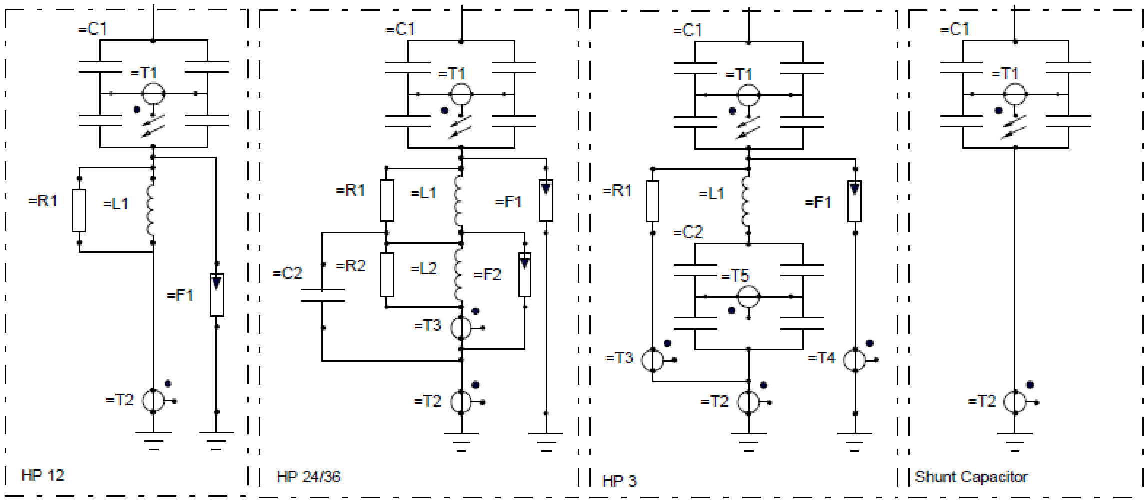
		AC Winding (Rectifier)/ Inverter	DC wdg. YY800 kV /YD 400 kV (Rectifier)	DC wdg. YY800 kV /YD 400 kV Inverter (Agra)
Rated Power	**MVA**	295.1/281.6	295.1	281.6
Voltage	**kV**	400/√3	333.9/√3	316.9/√3
Tap steps	**%**	1%, 35 steps each at rectifier (+28, -6) & at inverter (+26, -8)		
Shipping weight	**T**	~250 (YD) & ~300 (YY)		

C. AC Filters

Elements of AC filter and reactive power are so selected that between 0.1 to 1 Pu power transmission, they are capable of supporting the converter reactive power requirement and filtering of harmonics meeting the performance requirements as given below.

- Individual harmonic distortion Dn ≤ 1.0 %
- Total harmonic distortion D ≤ 4.0 %
- Total effective distortion Deff ≤ 3.0 %
- Telephone influence factor TIF ≤ 40
- Generator harmonic current content Ig ≤ 1.0 %
- MVAR per sub bank varies between 125 MVAR and 200 MVAR based on the power transmission and terminal.

In case of overloading upto 1.33 PU, rectifiers (Biswanath chariali & Alipurduar) shall require necessary additional reactive power from the grid (Corresponding to 4000MW active power), where as for inverter (Agra) no need for additional reactive power support as all the elements are connected to common 400kV bus.



Typical Configuration of AC Filters sub-bank at Terminals

D. Smoothing Reactors

The total inductance of 300 mH per converter is supplied by four 75 mH coils at rectifiers two each at HV bus and neutral bus. At inverter 2 no of 75 mH are located at HV pole bus inside the DC hall and 1 no of 150 mH coil is located at neutral bus in the open yard.. Various aspects has been considered for the limitation of high rate of rise of DC current during inverter voltage collapse and smoothing the ripple effect. Dry-type smoothing reactors have been selected for this project.

Special care has been taken during design due to High seismic zone at rectifier station. Coils of smoothing reactors are so placed to derive techno-economic advantage considering technically feasible installation. Half of the reactors are on the high voltage dc bus and the other half on the neutral bus. Additionally, for protection against lightning surge stresses from the dc lines, the coils installed at the 800 kV bus are directly protected with parallel surge arresters. The pole smoothing reactors have following main data:

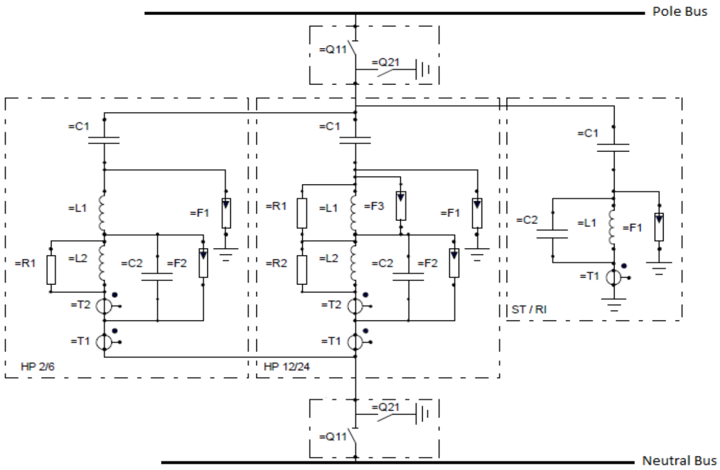
Fig- One coil Smoothing Reactor (75 mH ,2674 A) at Agra DC hall connected at HV bus (under construction)

E. DC Filters

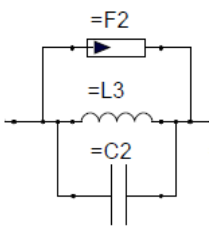
The DC filter design consists of one harmonic filter bank per pole. Each bank consists of three branches – a 2nd/6th harmonic branch, a high-pass 12th/24th harmonic branch and a single-tuned higher frequency harmonic branch to ground.

Filters are of similar nominal types at all converter stations, but differ to some extent in size, tuning and damping in order to provide the optimal matching to the different line impedances as seen from each station. Disconnect switches are provided to allow removal of a pole filter bank during operation.

Typical Configuration of DC Filter at Terminals



Blocking filter: A blocking filter (tuned LC circuit) has also been provided at Inverter end to block 50 Hz harmonic current originating from parallel AC lines. Typical blocking filters arrangement is as follows:



F. DC Switches

1) Parallel and De-parallel switch:
   The DC Pole High Speed Switches are used for the purpose of rapid reconfiguration of the main DC circuit of a HVDC station .for connecting or disconnecting from the pole bus by control and protection action of the converter connected in parallel. It is located in Pole bus.

2) MRTB and GRTS:
   The metallic return transfer breaker (MRTB) and ground return transfer breaker (GRTB) located in the DC yard of each rectifier station are designed to allow transfer from ground return operation to metallic return operation and vice versa up to DC currents for operation up to 1.33 pu overload without interruption of transmission. The

MRTB switches have been designed to commutate approximate full DC currents since opening of individual parallel pole opening is not exactly in the same instant. NBS, NBGS are rated based on individual converter rating as in line with normal bipolar HVDC scheme.

5. DC Hall at Agra

For the first time in the world 800kV UHVDC equipments and its bus work is being built indoor.
Here are few execution challenges for the engineer.

i) Installation of a gigantic structural building of the order of 70mx70mx35m overlooking Valve halls on one side and outdoor DC yard on other side without coloumns in between.
ii) Meeting stringent electrical clearance requirements inside DC hall, at 800kV DC level. Minimum Creepage distance of DC hall equipment is 30mm/kV.
iii) DC hall shall witness a positive air-pressure so as to keep dust and contamination out from critical equipments.
iv) Ventilation system design considering maximum ambient temperature in Agra as 50 deg C with a major heat generation from smoothing reactor above 450kW at 1.33 pu operation.
v) Ventilation duct geometry was selected considering corona discharge requirements and routing has been selected close to corners of DC hall floor level .

6. Control and Protection

The control and protection system of NER- Agra Multi-terminal UHVDC Project is based on the MACH2 (Modular Advanced Control system for HVDC) Platform . The design of the overall system is modular and flexible. The control functions are implemented as programmed modules in different processes operating in a multi-tasking environment. The system uses powerful industrial standard computers and standard serial and parallel communication buses.

Due to multi-terminal configuration, Operating conditions/ configurations are much higher than normal Bipole

The HVDC protection systems are based on a fully redundant concept .The protections are arranged into overlapping protective zones. Each fault case is detected by at least two protections with a limited protective zone.

The control system is divided in three hierarchical levels for the inverter (Agra) Station, Master, Bipole and Pole. For the rectifier (Biswanath Chariali/Alipurduar) stations, the control system is divided in two hierarchical levels Bipole and Pole. The control system on each level is primarily housed in two identical computer cubicles, where either of the computers can act as active or hot standby computer The computer cubicles used in this project are Pole Control and Protection cubicles, Bipole Control and Protection cubicles, Master Control cubicles, AC filter Protection cubicles.

Master control level, where the multi terminal related control is located. In this control level, there is a master computer cubicle, located at Agra, that coordinates between Biswanath Chariali, Alipurduar and Agra. Master Control facility is provided to control and co-ordinate the power flow from Biswanath Chariali & Alipurduar rectifier terminals to Agra inverter terminal. The station master controller is communicating with all the other control levels both within as well as between the stations; this to synchronize the control actions.

7. Inter station Communication

A Duplicated telecommunication system based on fiber optics is running along the DC-line for the purpose of control and protection. This link provides communication between all three converter stations .In addition, there is another redundant fibre optic link available for interstation telecommunication by using Powergrid existing Network.

8. CONCLUSION

This paper provides an overview of the converter station design aspect of the world's first ±800 kV UHVDC Multi-Terminal NER-Agra project.

This paper describes feature of the key feature of the multi-terminal Bipole link with some technical parameters of major HVDC equipments and also special consideration, design practices and engineering challenges in the overall converter station design.

ACKNOWLEDGEMENT

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MULTI-TERMINAL HVDC OPERATION SEQUENCE FOR ±800kV, 6000MW HVDC NER – AGRA Project (NEA800)

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SUMMARY

Power Grid Corporation of India Ltd. (POWERGRID) is constructing ±800kV, 6000MW NER-AGRA Multi-Terminal HVDC Project. The Rectifier terminal shall be at Biswanath Chariali (NER) and at Alipurduar (ER) while the inverter station shall be located at Agra (NR). This will be the first multi-Terminal transmission at 800kV DC voltage with 12- pulse converter. The other multi-terminal which are operating in the world are i) Nelson River, a double bipole (parallel converter) ii) SACOI- the Sardinia-Corsica-Italy three terminal tapped monopolar system, iii) Hydro Quebec/ New England, a three terminal bipolar.

Operation sequence in NEA800 Multi-Terminal scheme is more complex than that of a two terminal HVDC in the way that two rectifiers station at different location and associated inverters requires safe and reliable switching for all main circuit equipment taking part in power transmission. Besides this, an operator friendly procedure for smooth starting and stopping of the transmission and switching between various Control modes is an essential requirement.

In the NER-Agra HVDC Multi Terminal transmission system, two different control modes have been used, namely Master Control Mode and Separate Control Mode.In Master Control Mode the Master Control will automatically coordinate specific sequence actions among all three stations requiring coordination. In Separate Control all sequence orders has to be entered in each station and manually coordinated between the stations.

The paper elaborates the following key considerations pertaining to the operation sequence of NEA800 Multi-Terminal :-

1) Introduction 2) Multi-terminal operational concept 3) Requirement of Master Control
4) Master Control Mode (Multi-Terminal sequence) 5) Paralleling /De-paralleling
6) Pre-Charge of DC Line Section between Rectifiers i.e. Biswanath Chariali (BNC) & Alipurduar (APD) 7) DC Line Fault Scenario 8) Telecom requirement

KEYWORDS
Multi-Terminal, HVDC, NEA800, Master control, sequence, pre-charge

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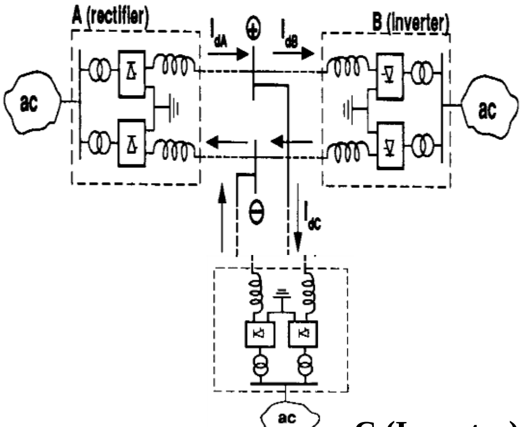
1. Introduction

In India, several hydropower plants are being constructed in the North Eastern region and Eastern region, where the abundant hydropower resources will be available in the next five to ten years. Beside this, our neighbouring country Bhutan is also exploring hydro power resources and surplus power have been planned to transmit to India. The most effective method to transmit a large power over a long distance range of 1500-1800 kM is through HVDC transmission which will be transmit this clean energy to the urban areas in Northern and Western Region of India. Since, all the hydro power generation shall come in phases and the associated HVDC line needs to pass through narrow area between India and Bangladesh (chicken neck area), it has been decided that a common HVDC Line shall be constructed at which DC power from different location can be pooled up and can be transmitted to NR & WR of India.

As a result, HVDC long distance transmission schemes with a transmission capability of over 6000 MW at a voltage level of 800 kV DC is being implemented with two nos. of Rectifier station located at Biswanath Chariali (NER), Alipurduar (ER) respectively and inverter Terminal shall be located at Agra (NR) which is connected through various HVAC lines to NR and WR regions of India. The total length of transmission line shall be 1728 kM (432 km from Biswanath Chariali to Alipurduar and 1296 kM from Alipurduar to Agra). Thus, it will be first multi-Terminal HVDC project at 800kV DC in the world.
To avoid the flashover in DC switchyard at the inverter location at Agra (NR) due to heavy pollution, 04 nos. Indoor DC halls have been constructed where all 800kV DC equipment and HV capacitor of DC Filters shall be located. The Scheme is having Eight number of 12 pulse Valve Group where two no of Valve Group each at two rectifier station and Four no of Valve Group are at One Inverter station at Agra.

2. Multi-Terminal Operational Concept

Multi-Terminal operational concept is different in comparison to Bi-pole control as it involves the transmission of power from different location of rectifiers to a common inverter station . Beside this, the most pronounced difference for a HVDC multi terminal scheme compared to a point-to-point two terminal HVDC system, is the requirement for selectivity. In case of a fault, the faulty equipment must be tripped with minimized impact on the healthy parts of the system.



C (Inverter)

Fig-1: A typical Multi-Terminal DC System with three terminals

Terminal A and B as shown in above figure (Fig-1)are connected in a typical two-terminal (Bipole) with a common current and voltage on each pole. The DC connection shown between Terminal C using a parallel connection at a common pole voltage with matching polarity makes the scheme a multi-terminal. Thus, more than one rectifier or inverter located at different location and connected with a common DC line makes the HVDC scheme as Multi-Terminal link.

A simplified basic multi-terminal scheme for 800kV NER-Agra HVDC Project with rectifiers (Biswanath Chariali and Alipurduar) and inverters (at Agra) connected to the same dc line with voltage has been shown below in figure-2.

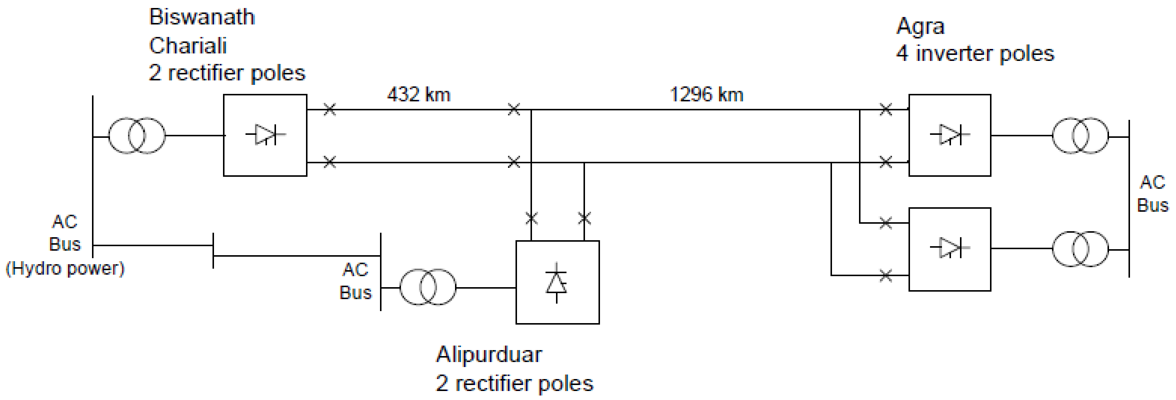


Fig-2: Basic Multi-terminal HVDC scheme of NEA800

At balanced bipolar operation both the converter connected to the +800 kV d.c. line and the converter connected to the -800 kV d.c. line are in operation at the same time, with a common shared bipolar power order; e.g. the Biswanath Chariali pole 1 and pole 2 will take half the power order each. Both operating at normal d.c. voltage level. The rectifier converters at each station will balance the ground current as close to zero as possible; i.e. Alipurduar and Biswanath Chariali. The inverters will also balance the current in-between the converter within each bipole, i.e. in-between pole 1 and pole 2 in Agra and in-between pole 3 and pole 4 in Agra. In case both the bipoles are in operation the two inverters connected to the same d.c. line will also balance the power between them. In case one converter is tripped, for any reason, during this operation mode, the other pole or parallel converter will automatically compensate, within its capability, for the lost power.

The control system for this multi-terminal scheme can be described in two levels:

a. Master control level, where the multi terminal related control is located. In this control level, there is a master computer cubicle, located at Agra, that coordinates between Biswanath Chariali, Alipurduar and Agra. The station master controller is communicating with all the other control levels both within as well as between the stations; this to synchronize the control actions.

b. Separate control sequence which is similar to normal bipole/ station control however multi-terminal task can be performed by manually co-ordination between stations. The details are described in coming sections.

3. Requirement of Master Control

When the parallel rectifiers/ inverters are located in different stations there is an increased need for coordination between stations regarding the sequences which involve more than one station. The sequences such as start/ stop of poles, co-ordination of current order, DC line sectioning during faults/ restoration, metallic/ ground return transfer and normal/ reduced DC voltage mode, power loss compensation involves more than one station and working telecom. To execute these sequences, requirement of Master control is essential. The master sequences controls the multi terminal HVDC scheme using the local station sequences in a coordinated manner. In NEA800, the master sequences are executed in the Agra station and all coordination is controlled from here through master control.

4. Master Control Mode (Multi-Terminal sequence)

While in Master Control mode the related Master HVDC Sequences are controlling the Multi Terminal HVDC scheme using the Local Station Sequences in a coordinated manner. The operator can access the Master HVDC Sequences (Multi-Terminal sequence) in the Operator Work Station via the Master HVDC Transmission Window. The Master Sequences are executed in Master Control Computer located in the Agra station. Here it may be noted that the access to this master control mode can also be taken at any of the rectifier end with telecommunication available. However, all the task of master sequence shall be executed through Master control computer located in the Agra station. In the Master Control necessary orders are entered and processed. Proper outputs are then sent from the Master Control to the control equipment in the respective stations where the orders are executed.
In this normal operating mode (called Master Control Mode) individual power orders for the respective rectifier station are used as input and dealt with in the Master Control.
The Master Control calculates and coordinates the corresponding current orders among all converters. Both steady state operation and temporary conditions are carried out by the Master Control.
The major control tasks performed by the Master Control are:

- Active Power Control (handling power orders, power ramping etc)
- Current order balancing/synchronization in between the converters along each DC-line
- Power loss compensation (all types)
- Coordinating DC-voltage reference (80 – 100 %)
- DC line sectioning

The Master Control is also involved in manoeuvring of the transmission system requiring coordinated action between converter stations.
To achieve all of the above, the Master control is equipped with:

- An Active Power Control (MAPC)
- Master sequences mainly dealing with Start and stop of the power transmission
- Changing configuration requiring action in more than one station

Master Active Power Control (MACP)

The Master Active Power Control (MAPC) is controlling power transmitted from each rectifier station. The multi terminal power is then determined by an individual Bipole Power Order for each rectifier station. The power level in a rectifier station is defined as the sum of the power from the two individual converters measured on the DC-side. If both converters in a station are operating in Bipole Power Control (BPC) mode the direct current between the converters shall be divided equally to eliminate electrode currents. The MAPC shall automatically maintain ordered power flow.

Power loss Compensation

Power compensation in the station will take place in both conditions whether the converter is manually stopped or tripped by protective action provided that the station previously was in bipolar operation. Similarly when the second converter in a rectifier station is manually started the MAPC automatically ramp up the power in the started converter while ramping down the power in the other converter until balanced bipolar mode of operation is achieved.
If a power reduction takes place below the ordered value in one of the rectifier converters the other converter in the same station will primarily compensate the power loss within its capability. Provided the power loss will not be fully compensated within the affected station secondarily the power loss can be compensated in the other rectifier station. Power compensation between rectifier stations can be enabled/disabled by operators. In addition, there is adjustable max limitation for the power compensation between the rectifiers.

Current order balance:

In a two terminal HVDC scheme only one terminal will determine the current and therefore there are very little requirements to distribute current orders.
Since, in multi-terminal system there are more than one converter that simultaneously control the current and therefore a central master control function is needed that calculates and distributes a current order to each converter so that the basic condition that the sum of all current orders (with signs) is always zero. For NEA800 link, the master controller will make sure that the sum of the rectifier current orders is equal to the sum of the inverter current orders. This is required to maintain the current margin at all operation conditions. Fig.-3 below gives the basic schematic for the function in NEA800 link. The K weighting factors in the feedback loops reallocate any current order imbalance according to predetermined criteria. Since, the inverter location is only at Agra for NEA800, common K factor named K_{agr} has been used at inverter. Different criteria can be selected according to DC system configuration, operating conditions. Due to multi-terminal configuration as many as 32 Operating conditions/ configurations have been envisaged for equipment dimensioning.

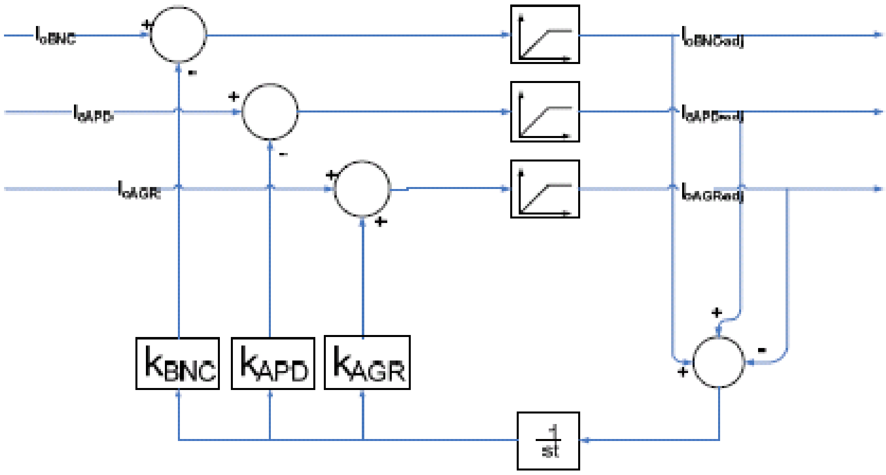


Fig-3: Current order balancing

Master Sequences:

Many of the normal manoeuvring procedures for the Multi-terminal transmission are controlled through the Master Sequences which are sub divided into two parts:

- Master Mode Sequences (MMSQ)
- Master Switch Sequences (MSSQ)

The Master mode Sequences (MMSQ) handle the following type of action:

- Coordinates start and stop of the converters of the first set of converters in two terminal operation
- Provides necessary interlocking if adding or removing converters(i.e. paralleling and de-paralleling) while operating converters on the same DC-line.
- Deals with necessary DC line pre charge between BNC – APD at start of converters in BNC while APD-AGR are operating on the same DC-line (details shall be covered in next section)
- Operator- or Protection initiated transfer between Normal-/Reduced DC voltage (details shall be covered in next section)
- Changeover between Master-/Separate Control mode.

Start/ Stop of Converter:

Starting a converter is always performed by De-blocking the converter at minimum direct current. Similarly manual ordered stop of a converter is finished by Blocking the converter from minimum direct current. Converters can be selected for start (or stop) by the Operator as shown below:

a) Start of first pair of converters belonging to the same pole line

Precondition**:** All converters blocked but at least one rectifier and one inverter are in RFO along the same pole line.

- It is possible to start any one (of the two) rectifiers in RFO together with one (of the two) inverters in RFO along the same pole line. This is similar to start up of a typical bi-pole scheme i.e. inverter shall be de-blocked first followed by rectifier. Figure-4, indicate that APD-Agra has been started in Bipole mode. Here, it is also possible to start only one inverter i.e. Agra-1 or Agra-2 or both inverter simultaneously.

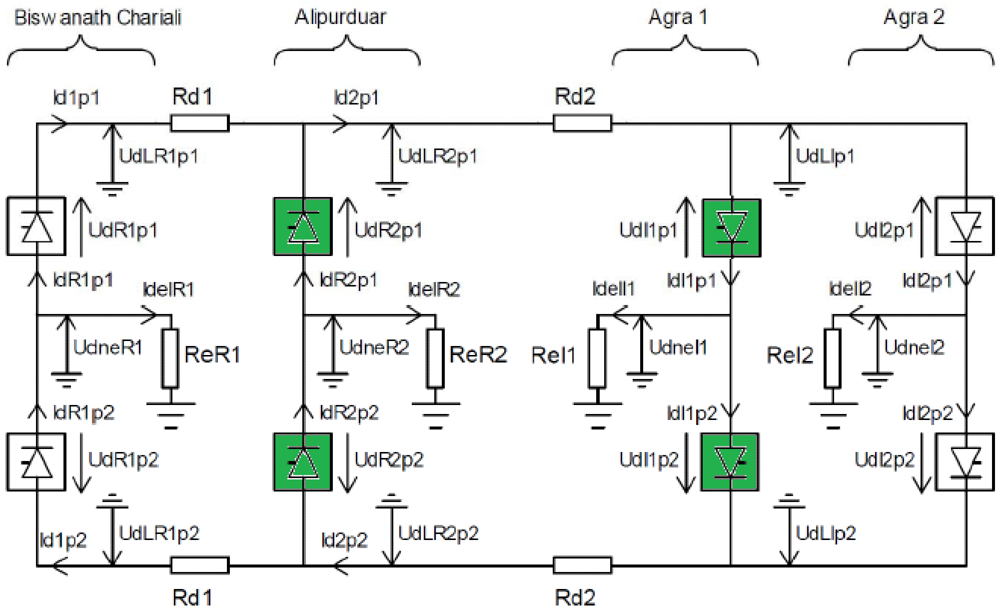


Fig-4: Starting of first pair of converter

b) De-blocking a converter (on an already operating pole line)/ paralleling procedure:

Precondition: One rectifier and one inverter along the pole line are in operation as also shown in figure-4.

It is possible to select and start the other rectifier or the other inverter along the same pole line. During start of a converter in BNC the DC-line between BNC and APD need to be pre-charged (approx. 95 % of DC Line voltage) while DC-line section between APD and AGR is used to transmit power in the same pole. The detail of pre-charging is covered in next section.

Initially, after De-blocking the converter, minimum direct current level (10 % of rated power) will flow.

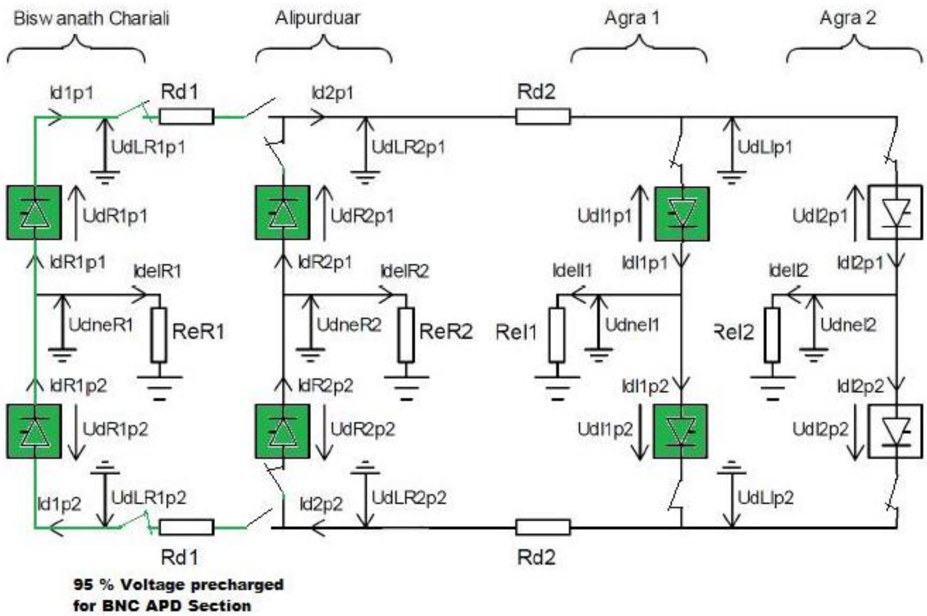


Fig-5: Paralleling sequence by pre-charge of BNC-APD Section

Similarly, if BNC-Agra are running at rated power, APD terminal can be directly connected after pre-charging up to 95% of DC voltage to already charged DC line after closing the DC Disconnector and HSS switch at APD.

c) Manual Blocking a converter (when operating with parallel converters on the pole line)/ de-paralleling procedure:
Precondition: Both rectifiers and/or both inverters along the pole line are in operation.
- It is possible to select and Block any one of the parallel converters. The selected converter is ordered to Block at minimum direct current. This will set the Blocked converter into RFO state.

d) Stop of the last operating pair of converters belonging to the same pole line
Precondition: One rectifier and one inverter along the pole line are in operation. It is possible to select and stop the operating converters at minimum direct current. This will first Block the rectifier followed by the inverter and set the selected converters in RFO state. At the inverter side the DC voltage is controlled according to the rated value referring to the rectifier terminals.

The Master Switch Sequences (MSSQ) handles:

- Coordination of transfer between Metallic- & Ground return mode.
- Coordination of the DC-line fault restart logic.

The above task can only be performed with Master Control Mode and a working Tele communication.

5. Pre-charging of DC Line section between Rectifiers Biswanath Chariali (BNC)-Alipurduar (APD)

The charging of the DC-line prior to connection to the remaining system will then minimize the disturbance in the APD – AGR transmission as well as ensure a healthy transmission line section between BNC and APD prior to connection. Pre change procedure for the DC-line section BNC – APD shall be as per following details:

Precondition:

a. The DC-line section between APD - AGR is energized and transmitting power.
b. In APD station the associated DC-line section is Isolated i.e. the Disconnector provided at APD end between BNC-APD Line section is in open condition & HSS is closed
c. The related converter in BNC is blocked.

Pre-charge procedure:

a. Start the Pre-charge sequence from the Master Control Access.
b. As soon as the converter is Ready for Operation (RFO) it is now possible to de-block the converter at BNC from Master Control Access.
c. The automatic sequence will pre charge the line up to 95 % of the direct voltage in the APD station from BNC. This will also help to check the healthiness of BNC-APD Line section.
d. The DC-Line section BNC-APD will automatically be connected by closing the DC Disconnector at APD followed by closing the high speed switch at APD

The converter will now automatically start at minimum power.

The pre-charge above can be made also without tele-communication between the stations (in separate mode) but then manual coordination between the stations are required.

Also note that if the intention is to only make an Open Line Test for the BNC-APD section (and not a pre charge before connection) that is considered as a local BNC sequence and can not be made from the Master Control Access.

6. Paralleling and De-paralleling Switch

As the multi-terminal HVDC scheme involves the transmission of bulk power at different location, a rapid paralleling and de-paralleling requirement is essential to inflict as little disturbance on the connected ac systems and to give the fast recovery for the healthy converter/ pole. It has been implemented by providing High speed paralleling and De-paralleling switches on pole side of each rectifiers and inverter end. The location has been indicated in Fig-2 above.

The paralleling and deparalleling switches consist of a simple breaker giving a isolation duty of approx. 2-3 cycles.

7. Scenario of DC Line Fault

a. DC Line fault between BNC- APD Line section:

The DC line protection consists of derivative protection as primary and level protection as back-up.A line fault between BNC & APD shall be detected by current direction seen by CT at APD end (DC Line protection). A coordinated order down shall be given at BNC and APD both in parallel converters.

In this situation, only full voltage restart attempt shall be initiated at BNC end. If restart attempt fails, BNC converter shall be isolated by opening HSS at both BNC and APD end. The APD- Agra power shall be restored with normal sequence.

b. DC Line fault between APD-AGRA Line section:

A line fault shall be detected by DC Line protection. To provide a coordinated action of the DC line protections in parallel rectifiers, whenever one of the DC line protections is activated it should trigger the restart logic of the own rectifier as well as the parallel rectifier. The first rectifier to detect the fault will be responsible to restart the transmission (full voltage re-start) and the other will follow.

8. Telecom Requirement

A working telecommunication is of prime importance for coordination of the multi-terminal HVDC system. This is due to the fact to decide the operating mode/ configuration after a fault/ disturbance or an outage. The unavailability of telecom may lead to pro-longed loss of converters connected to same pole line. During loss of one parallel inverter during high load, as the pre-fault dc current from the rectifiers will be quite high for the remaining inverter(s). In practice it is not possible to change the load without telecommunication. Even manual change of the load flow requires communication between the operators. In NEA800, the working telecom link (main & standby) alongwith HVDC overhead line and back up telecom link through parallel AC lines has been provided.

CONCLUSION

This ±800kV multi-terminal link shall transfer the bulk power from hydro generation centre of NER, ER and Bhutan to load centres of NR and WR with reliability and security. This will be first multi-terminal at ±800kV in the world with 12- pulse converter. The Multi terminal configuration of the link requires more coordination between the various stations than a normal bipole link. The number of operation scenarios is much higher than normal point to point bipole.

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Design and Operational Aspects ±800KV, 6000MW Champa-Kurukshetra Parallel HVDC Bipole System

Planning Study and Future Requirements for DC System

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SUMMARY

The Champa-Kurukshetra HVDC Bipole-I and Bipole-II of individual rating of 3000 MW with operating DC Voltage of ±800 kV have been awarded by POWERGRID in two stages. The HVDC line for the first ± 800 kV Bipole of 3000 MW with Dedicated Metallic Return (DMR) has been designed keeping in view both the Bipoles. The paper shall discuss the design and operational aspects of ± 800 kV, 6000 MW Champa-Kurukshetra Parallel Bipole HVDC link keeping in view the integrated operation of both bipoles.

In order to design system with provision of future bipole addition in parallel to another bipole at the power level of 6000MW, there are equipment zones in the AC and DC side of the station which shall have impact of future up-gradation. Particularly, the possible transient and dynamic overvoltages needs due attention while finalizing the rating of surge arresters and circuit breakers. Further the converter transformer tap changer range, DC commutating switches should be designed considering the contribution of parallel pole operation. The control and protection system shall also need to have coordination in terms of operational strategy, setting parameters for controllers and protections etc. The paper shall discuss the following aspects of the project, from the view point of parallel bipole of ±800 kV, 6000MW:

- Main Circuit Parameters and Insulation coordination design consideration
- AC and DC filter design consideration
- Possible Operational configurations with Parallel Poles
- Control and Protection Coordination between the two Bipoles
- Protection strategy for Dedicated Metallic Return (DMR) conductor with parallel poles.

Further, dynamic performance of both parallel bipoles under AC and DC side fault scenarios shall be coordinated. The simultaneous control action of both bipoles during ac side faults (1-ph and 3ph) for smooth and optimum recovery of HVDC link shall be decided by the Dynamic Performance Testing considering both bipoles.

KEYWORDS

Master control, DMR (Dedicated Metallic Return), Parallel Bipoles

1.0 INTRODUCTION

The scheme for the ± 800 kV, 6000 MW Parallel Bipole System is as per the Figure-1 given below. Each pole is rated for 1500 MW power with 1.1 pu continuous overload and 1.2 pu overload for two hours. Both bipoles share the same HVDC line and DMR conductor. The neutral of each bipole is connected to the DMR conductor (2 no. of twin lapwing conductors rated for 4000A approximately) with its own Metallic Return Transfer Breaker (MRTB).The commutation switches shall be rated considering the total overload current from two parallel poles and shall be capable to commutate the maximum current.

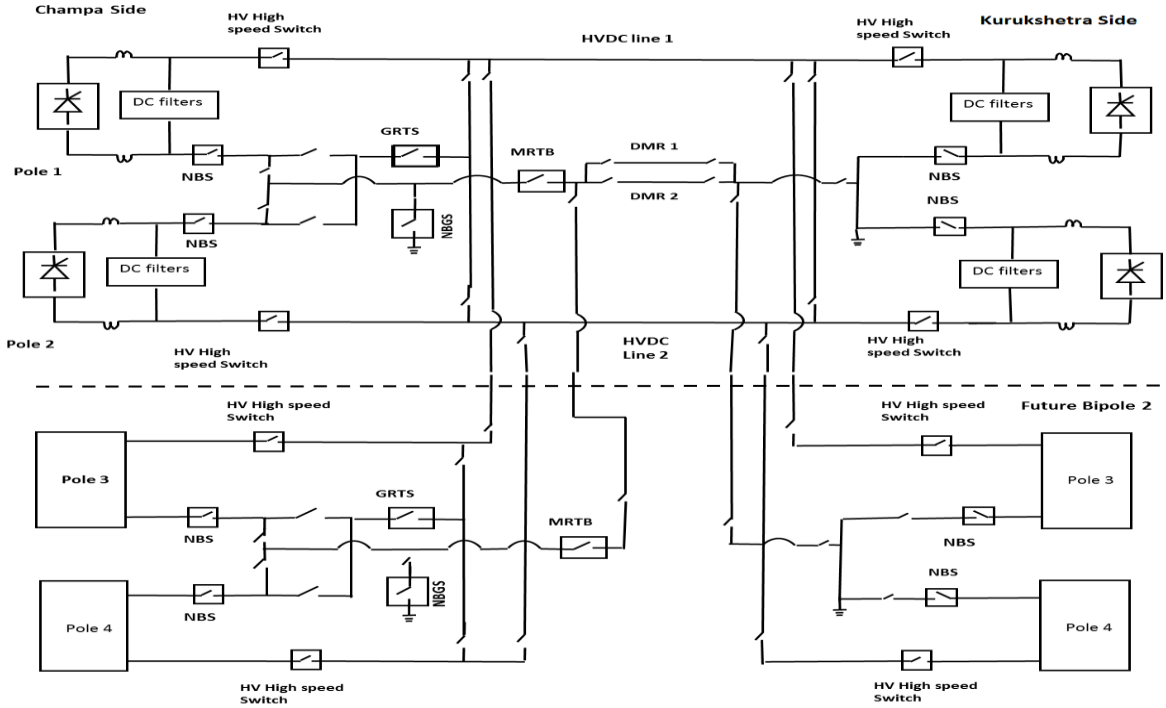

Figure-1 : Single Line Diagram

In monopolar operation, based on the selected return path, the operational configurations, for 3000 MW power system are defined. Some of the possible configurations are given in Table- 1 :

Configuration	Return Path
P1(or P2) // P3(or P4) Monopolar operation	return via DMR(1 and 2) // PMR
P1(or P2) // P3(or P4) Monopolar operation	with return via DMR (1 and 2) (In this configuration loading upto the rated current of DMR is possible due to DMR conductor rating limitation)
P1(or P2) // P3(or P4) Monopolar operation	return via DMR (1 or 2 only) // PMR
P1(or P2) // P3(or P4) Monopolar operation	return via DMR (1 or 2 only) (In this configuration loading upto the rated current of single DMR is possible due to DMR conductor rating limitation)
P1(or P2) // P3(or P4) Monopolar operation	with return via PMR only

Table – 1: Configurations for monopolar operation

2.0 Main Circuit Equipment Consideration for Future Up-gradation

The main circuit equipment design for the up-rating purpose:

a) Insulation Of Neutral Bus / DMR conductor

The maximum continuous operating voltage of the neutral bus connected to DMR conductor is selected based on maximum voltage drop in the DMR conductor. The configuration selected for this calculation shall be Monopolar DMR return with two parallel poles i.e. P1//P3.The maximum overload current of the two parallel valve groups (1 .2 pu overload 4500Amp) has been assumed for this operation mode. The arrester rating of Neutral bus arrestors in the station has been calculated based on the future up-gradation requirements.

b) Energy capability of Valve arrestor

With addition of another station in parallel to the existing rectifier station will not require high energy absorption capability for valve arrestors because the control and protection action will act much quicker as compared to a multi-terminal scheme. In a multi-terminal scheme where the rectifier station is at different physical location, the arrestor energy calculation shall consider the telecom delay for force retard of the parallel rectifier.

c) Tap-Changer Range of the Converter transformer

The selected tap-changer range for the converter transformer also takes into account parallel operation of the two valve groups. The tap changer range of first bipole is designed such that terminal dc voltages shall remain same with up-gradation to 6000 MW power flow. The converter transformer parameters are same for both CK-I and CK-II.

d) DC Current Measurement

The High voltage side DC current measurement on line side which is being installed during CK-I execution is rated for maximum operating current of 5000 Amperes considering future up-gradation.

3.0 CONTROL STRATEGY FOR PARALLEL POLES:

Congruent Pole Operation – The HVDC Bipoles are being implemented stage wise. The supplier of Bipole 2 could have been different from that of Bipole 1. To avoid the complex control design for Bipole2 and to minimise the modifications in the controls of Bipole 1, operation of each rectifier pole-inverter pole shall be congruent i.e.

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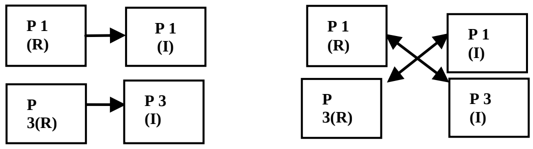

The following control strategy for parallel operation has been considered :

The two rectifier converters are controlling their DC current, the two inverter converters operating with commutation margin close to minimum value but an additional control loop is added into the inverter current control to balance the DC current between inverters.

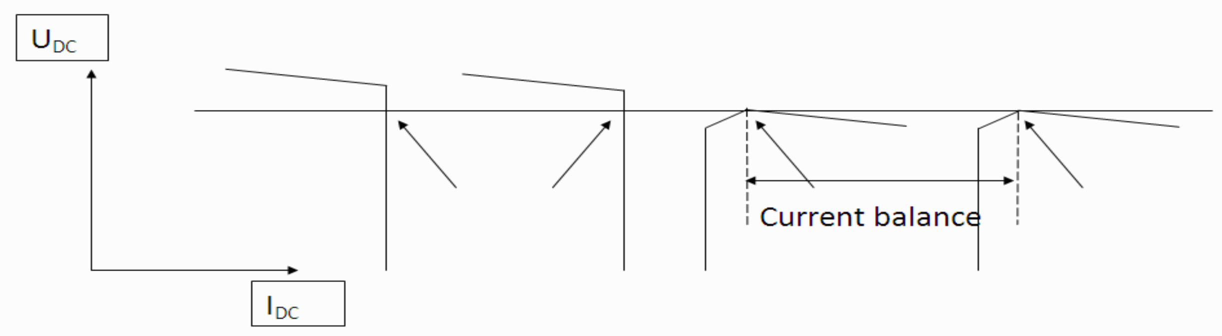

Figure 2 : V – I diagram for control strategy

Inverter Current Balancing Control : One of the most critical functions at the inverter is to dynamically control the currents in the two parallel converters so that each separate inverter current order is maintained while both inverters remain primarily in dc voltage control to ensure that the rectifier is operating at rated dc voltage or at reduced voltage if so ordered. During normal operation the Inverter Current Balancing control equalizes the direct current between the two parallel inverters connected to the same DC-line. The extinction angle γ is then kept constant to same values in both parallel converters. In case of a small unwanted difference of the measured direct current between the two parallel inverters would occur, it is equalized. The inverter that get a reduced d.c. current will get a slightly increased Gamma.

The current sharing between the converters in operation is handled by coordinating converter transformer tap changers action together with controlling extinction angles γ.

4.0 OVERALL CONTROL HIERARCHY FOR PARALLEL BIPOLES

The overall control hierarchy of parallel Bipole system for Champa-Kurkushetra HVDC Project shall be similar to two number of standalone Bipoles except the Master Control which exercise coordinated control action between the two Bipoles for some functions. The control signal coordination between the two bipoles and between Master Control and Bipole Controllers of Bipole1&2 is needed for integrated operation. The conceptual control signal coordination is as per the figure 3 :

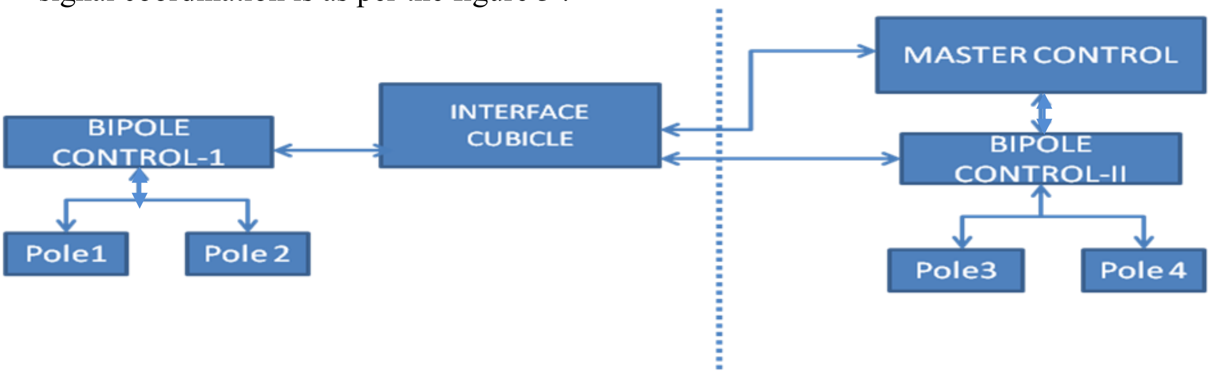

Figure 3 : Control Hierarchy for Parallel Bipole

5.0 STRATEGY FOR SPECIFIC CONTROL FUNCTIONS DURING INTEGRATED OPERATION OF BIPOLES

a) The Master Power order control (figure 4) will generate power order for each pole in steady state as well as for power compensation during pole outage /pole current limitation. In case of outage of one pole, the other pole of the Bipole shall go into overload and further the two poles of the other Bipole shall be overloaded. However this action is much faster and healthy poles will be power compensated typically in 80-100 ms

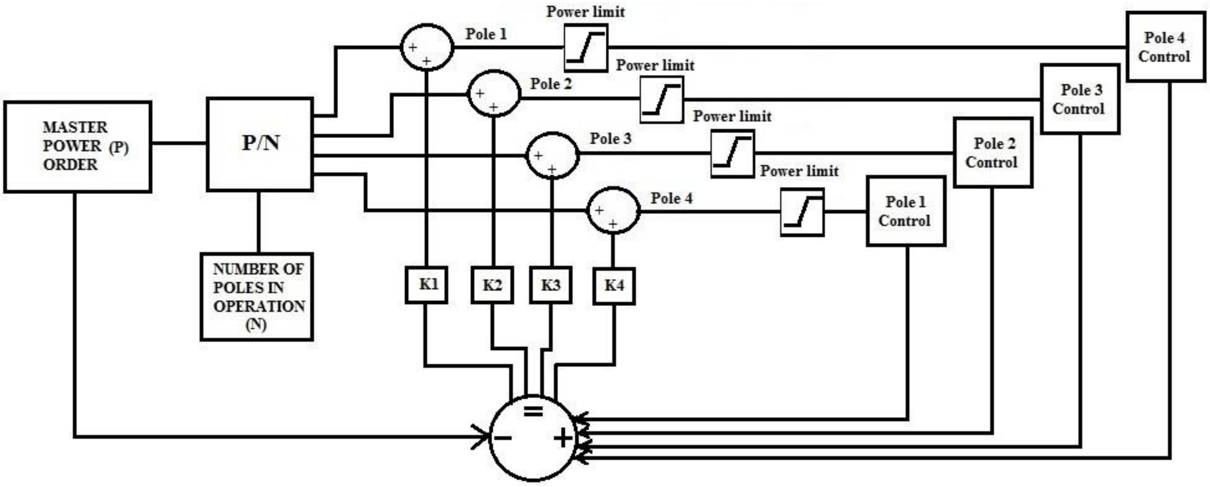

Figure 4: Master Power Order Control

b) Stability Modulation Functions

The stability modulation controls such as Frequency Control, Power Oscillation Damping and Sub Synchronous Oscillation Damping controls shall be implemented at the bipole level. The bipoles are expected to have these functions individually. This was proposed based on the fast control action of these auxiliary controls, as routing of these signals from Master control to the Bipole may cause unwanted time delays.

1. Frequency Control

The coordination for frequency control is at bipole level. The slope settings for the frequency controllers are to be coordinated for both the bi poles to avoid conflict during operation of both the bi poles.

2. Power Modulation Control and Sub Synchronous Oscillation Damping controller

New bipole shall have POD controller considering existing bipole and upgraded network . The two bipoles share the power oscillation damping and the gain is adjusted automatically according to the availability of pole / bipole and its ordered power. The implementation to be coordinated and should be carried out without conflict in both the bipoles. This principle is also applicable to sub synchronous control.

3. Runback/Run up Control

In case of outage of 400 kV/765 kV connecting lines to Champa and Kurukshetra HVDC station, power reduction may be required in HVDC power. This functionality is implemented in Master Control as various runback power levels. This is derived based on network studies carried out where various set of contingencies are considered. When ordered power cannot be transferred or evacuated due to network contingencies, Master Control shall execute runback levels and distribute the ΔP to poles of both the bipoles depending upon the availability of poles.

For Bipole-II, the Runback studies shall be based on the upgraded network with new network elements coming in Stage-II. The final runback levels for both bipoles shall be implemented in the Master control with runback power equally distributed to both the Bipoles.

c) Reactive Power Control Strategy

The Reactive Power Control (RPC) of respective bipoles perform the functions of Bipole level Filter switching based on rating and harmonic performance of each bipole. Each (RPC) is designed to meet the harmonic performance of its own bipole. However, both the Bi-Poles will exchange the information of filter switching and take care to prevent simultaneous switching of filters on both the bipoles.

The RPC function in Master controller monitors and controls the reactive power exchange with the AC system. It also reduces potential over voltages on the 400 kV networks by disconnecting or inhibiting connection of shunt capacitors or filters. Further it avoids self excitation of the generators by limiting the maximum amount of shunt reactive elements connected to the 400 kV bus-bars according to number of machines and network configuration.

In case of 400 kV bus sectionalizer open at Champa, Station level Reactive Power Control in Master Controller has a provision to select 'inhibit' master controller reactive power functions and individual bipoles shall take care the above mentioned functions.

d) <u>Control Sequences for Parallel Bipole Operation</u>

When an operation mode is selected from the Master Control screen of Operator Work Station (OWS), the command for the desired configuration shall be given to respective bipoles from Master Control. Pole level sequences such as valve hall DC disconnectors, valve cooling, ac side energisation etc. shall be carried out within individual Bipole. The configuration achieved i.e. ‘Ready Signal’ shall be exchanged by each Bipole control with Master control. If the configuration achieved in each Bipole are not matching ‘Invalid Configuration’ signal shall be generated on Master Control screen and further operation is not allowed.

6.0 PROTECTION STRATEGY DURING INTEGRATED OPERATION OF BIPOLES

6.1 Protection Classification Based on Effect on Parallel Pole

	Faulty Converter	**Parallel Healthy Converter**	**Remarks**
Non-SevereFault Eg:converter transformer faults, Asymmetry, DC overvoltage etc.	Block, trip and isolation from DC line (R)	No action (R)	Faulty converter is isolated from DC line
	Converter is forced to minimum gamma operation and block (I)	Gamma increase signal (I)	
SevereFault Eg: Valve short circuit, converter differential, station earth overcurrent etc.	Block, trip and isolation from DC line (R)	Order Down (R)	Faulty converter is isolated from the dc line and parallel converter is brought back.
	Converter is forced to minimum gamma operation and block (I)	Gamma increase signal (I)	

Note: R : Rectifier I : Inverter

Faults in a parallel bipole HVDC station can be classified based on the location, severity of fault and its impact on healthy pole. Faults in a converter permitting the parallel healthy converter to remain in operation while the fault is being cleared in the faulty converter is Non-severe Fault. A fault in a converter requiring block in the faulty converter and protective action in the parallel healthy converter can be termed as Severe Fault affecting the overall system.

The above strategy shall be applicable only when telecommunication is available between rectifier and inverter stations.

6.2 **DMR Protection Philosophy** :

An important aspect of this project is the Dedicated Metallic Return (DMR) Conductor. Since faults on DMR effects both bipoles, the DMR protection becomes important from the system availability and reliability point of view. There are dedicated DCCT's for both circuits of DMR on both sides of the link. Under the balanced bipolar operation only a small current flows through the DMR.

There is a line differential protection along with a backup DMR differential protection to detect faults on DMR conductor. In case of monopolar operation with DMR return, if there is a fault on DMR, the protective action shall be to connect the Pole Metallic Return Conductor by closing GRTS and isolate DMR by opening the MRTB switch, without affecting the operation and power flow in the link. Thus, the fault isolation shall be the first line of action.

If configuration change to fail then Neutral Bus Grounding Switch (NBGS) sequence shall come into operation. If fault is still detected by DMR protection function then tripping of the Pole shall be the last resort.

Open Circuit fault protection is also provided for DMR. When one of the DMR circuit opens in monopolar DMR return operation (PMR not available), an alarm is raised and the power is reduced automatically upto the capacity of one DMR conductor. When both the DMR circuits open, overvoltage protection at rectifier operates and trips the pole.

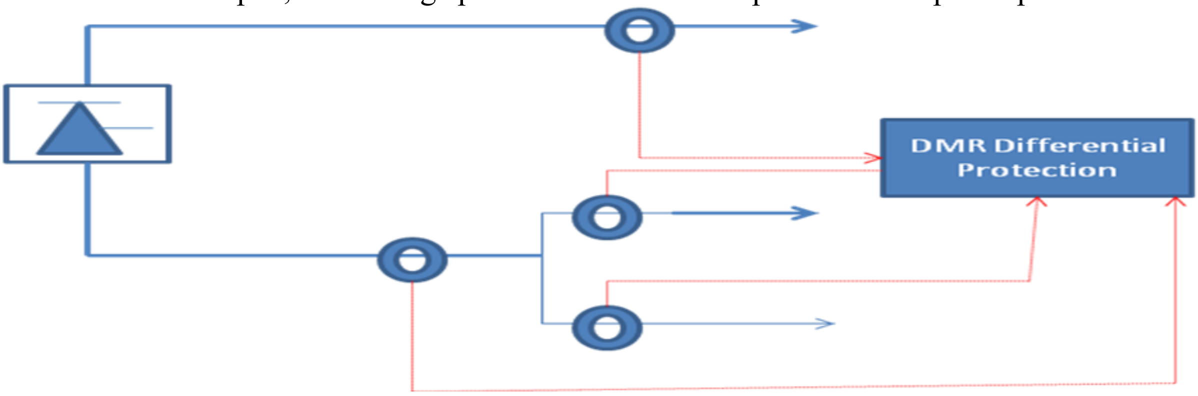

Figure 5: Conceptual diagram for DMR Differential Protection

Both bipoles shall detect the DMR or PMR fault independently and it is expected that each Bipole shall perform the same protective sequence.

6.3 **DC Line Protection Strategy for Parallel Pole Operation**

One Pole will detect the dc line fault on HV line1 or HV line 2 and will activate DC Line Fault sequence and the parallel Pole shall follow the POLE dc line fault sequence. The parallel Pole DC Line Fault protection shall be disabled and parallel Pole shall follow Pole when in the parallel operation. The settings of the de-ionization times and number of restart attempts should be the same in both bipoles. The DC line fault detection time shall be coordinated with the transportation delay of the telecom.

7.0 CONCLUSION

Champa –Kurukshetra HVDC system is a complex project with a parallel Bipole system (in two stages) at 800 kV DC voltage level with return current via same DMR conductor. Hence, from the utility perspective, it becomes very vital that the project requirements are well defined considering that both bipoles can be from different suppliers. Further, in order to avoid complications involved in integrating both systems, it was essential that overall design philosophy of the system which includes main circuit equipment design along with control and protection integration are well defined and kept simple.

Majority of station level control functions are coordinated by the master control and auxiliary functions which require fast control action have been coordinated between the two bipoles at bipole level. In order to achieve the defined functionalities it is important to carry out the integrated testing of controls.

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Champa Kurukshetra an 800kV HVDC Scheme – Design Considerations Related to Parallel Operation of Stage I and Stage II Schemes

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SUMMARY

Converters are usually connected with independent DC transmission lines and are only configured in parallel in the event of an outage of one of the DC transmission line circuits. However, in Champa-Kurukshetra HVDC transmission scheme two bipole converters are configured and operated in parallel to maximise the utilisation of the available infrastructure. In such a configuration availability of healthy converters, in the event of an outage of any equipment on the faulty converter is of prime importance. Therefore, equipment is introduced on the DC side in order to de-parallel a faulty parallel pole. Furthermore, facilities are provided to parallel or de-parallel poles when the link is already transmitting power. This is done with the help of an automated sequence and other measures allowing the smooth transition between circuit configurations. Additionally, it is possible to parallel and de-block the poles simultaneously by using a sequence which is described in this publication.

In the event of a converter outage or an equipment outage, the power is redistributed among the healthy poles in order to maximise the availability of power. Alongside other co-ordination functions, the master control is incorporated to implement these overarching functionalities for both bipoles.

Logistical issues regarding the staged commissioning of the scheme are also described.

KEYWORDS

800 kV HVDC, parallel converter, Champa, Kurukshetra.

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1. Introduction

Champa Kurukshetra is a 1305 km, ±800kV HVDC transmission corridor connecting the generation in Western Region at Champa to the load centre in the Northern region at Kurukshetra in India. The transmission scheme consists of two stages. Bipole-1 in stage 1 will deliver 3000 MW and it will be upgraded with Bipole-2 in stage 2 with another 3000 MW, increasing the capability of the link to 6000 MW. The link will share the same DC line to transfer the power in order to maximise the utilisation of existing infrastructure. The Champa Kurukshetra transmission scheme has a unique feature; it consists of a Dedicated Metallic Return (DMR) instead of Ground Electrode Return which is also shared between both the bipoles [1].

Further in this paper, special requirements in control and protection schemes incorporated in the converters to facilitate parallel operation are discussed. These include start-up and shut-down sequences, the control and protection strategy employed and the process of upgrading the 3000 link into a 6000 MW link with minimum interruption to the operational 3000 MW Link.

2. Start-up and Shut-down of the converters

Both the converters in the Champa-Kurukshetra link are identical, hence it is possible for the operator to first de-block any converter of Bipole 1 or Bipole 2. The paralleled converters can be blocked when in operation, and deblocked when paralleled offline, simultaneously with minimum stagger. It is also possible to block or de-block any one converter when scheme is already transmitting power (online).

Offline Paralleling/De-paralleling

Prior to de-blocking parallel poles simultaneously, the switchgears of both poles should be independently configured at the pole level connecting the poles to the DC line. Their operating configuration is validated by the master control. Following receipt of validation the poles are deblocked at minimum power one after another by staggering de-block. Once minimum power is achieved in the poles then power in both poles is ramped simultaneously. Similar staggered approach will be adopted when both the parallel poles are simultaneously blocked.

Online Paralleling/De-paralleling

To maximise the reliability of the scheme it is important that the parallel converters can be connected or disconnected by performing online switching. The particular sequences required to perform the connection of the parallel converter when one of the pole is already in operation are described below.

When one of the poles is already in operation, the inverter to be paralleled is connected before the rectifier. At each converter terminal the connect sequence is initiated at the neutral side followed by the HV side. Figure 1 illustrates the primary switchgear associated with the link.

The inverter end neutral pole connect sequence is completed which includes connecting neutral disconnectors, followed by closing the neutral bus switch (NBS). The inverter end is then deblocked, which is followed by HV pole connect sequence which connects the HV line disconnectors and the paralleling/de-paralleling high speed switch (HVHS). After the inverter is connected the associated rectifier end neutral connect sequence is completed which closes neutral disconnectors and the NBS. The rectifier end is then deblocked and pre-charged. The HV pole connect sequence is initiated automatically which connects the HV line disconnectors and the HVHS [2].

The sequence of actions to perform the disconnection of one of the parallel converters is described below. The parallel pole which needs to be blocked is first ramped down to the minimum power. The corresponding rectifier current is gradually reduced to zero and is then blocked. The rectifier is then disconnected from the DC line by performing the pole isolate sequence. The pole isolate sequence at the rectifier end will initiate opening of the HVHS and the NBS followed by the associated disconnectors. When the inverter end current is slowly extinguished the inverter is disconnected from the DC line by performing a pole isolate sequence similar to the rectifier end.

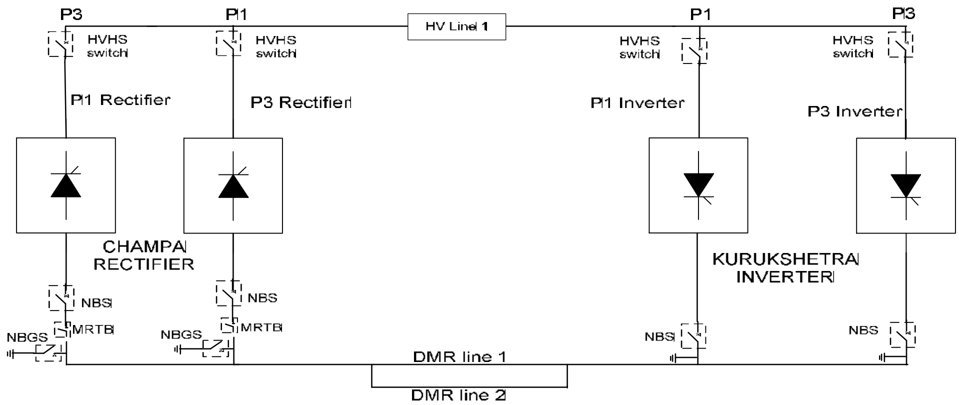

Figure 1 : Switchgear Configuration For Parallel Operation Between P1 and P3

3. Parallel Control Strategy

Similar to single bipole operation, in parallel mode the rectifiers will be in current control. The current flowing in the HVDC line is equal to sum of the currents of the parallel converters. The current orders for both the parallel rectifiers are normally evenly distributed. Uneven distribution of power in parallel converters is also catered for in the design. At the inverter end in parallel mode the two inverters will share voltage control. The current sharing between the two inverters will be managed by utilising an appropriate droop voltage characteristic. The tap changer control for parallel inverters, will maintain extinction angle of the respective inverters within the limits. When extinction angle of both inverters is in within the specified range, the tap changer control of both poles will be synchronised in order to maintain the DC voltage at the inverter end.

The simulated performance for uneven distribution of power between poles is shown in Figure 2. For the purposes of demonstration various actions such as tap-changer operation etc. are accelerated. X and Y in the plots refers to rectifier and inverter end respectively. In this scenario the power in one of the parallel poles (Pole 3) is ramped down to minimum power and the other pole (Pole 1) continues to run at nominal power as shown by IdcF and PdcF plots below. In order to share appropriate DC current between the two parallel inverters, a Current Balancing Control module is required at the inverter end; the balancing effort of which is shown in the plots as Ibal. This additional control loop automatically balances both the inverters by creating a dynamic droop between the two inverters. This current balancing control module is only activated when the poles are running in parallel operation.

4. Control Hierarchal Structure

The control functions are hierarchically distributed between the pole, bipole and master control. The pole and bipole control functions for a parallel converter scheme are similar to a typical bipole. The master control consists of functionalities which are required to co-ordinate the parallel bipoles. Since the two bipoles for Champa-Kurukshetra are being executed in stages, station control is provided in Bipole 1 to perform the station level functionalities. These functionalities will be superseded by the master control in stage 2 to allow incremental upgrade of the link.

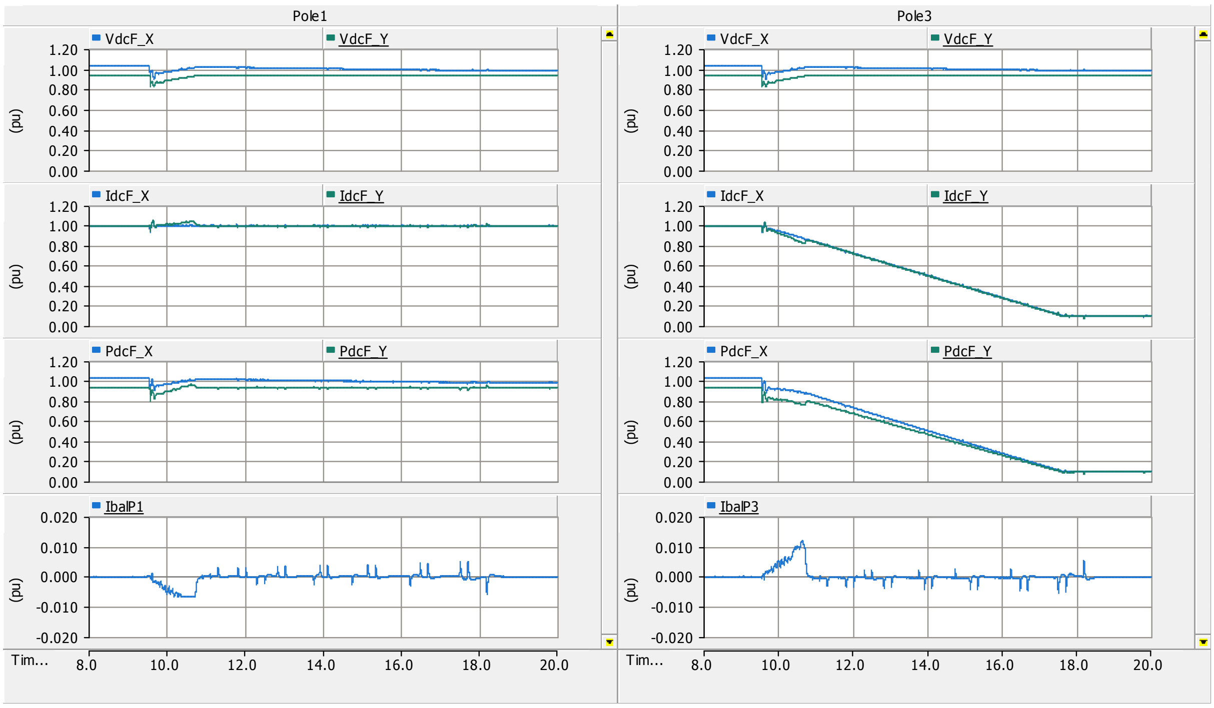

Figure 2: Un-balanced Power Distribution in Parallel Converters

In this link, at Champa end (rectifier) the bus sectionalizer connecting Bipole 1 and Bipole 2 is normally kept open and will only be closed in exceptional cases. The implication is that the bipoles may be connected to different AC networks at Champa end. If the bus sectionalizer is closed or the AC networks are closely coupled; in the event of a contingency in the network, the power of both the bipoles will be reduced together if found necessary. However, when the bus sectionalizer is open and respective AC networks are loosely coupled; in the event of contingency on one of the AC networks, power reduction if necessary, will be resorted to in the associated bipole while the other bipole will run up the power in an attempt to maintain the prefault total link power flow.

The bipoles are sharing the same DC and neutral line(s), therefore it is expected that parallel poles shall run in a similar configuration. Hence the selection of configuration is done at master level. The configuration of individual poles is achieved at the respective pole level and a check-back signal is sent to master control to ensure both the parallel poles are in same configuration before the poles are deblocked as described in section 2 above.

The power is distributed by the master control, among the poles in operation subject to the capability of the individual pole. When there is a loss of pole in the scheme the power is redistributed to the remaining healthy poles up to their loading capability with the aim of maintaining the pre-contingency power transfer to the AC system.

5. Parallel Protection Strategy

Faults are categorised into different severity levels in order to allow the resumption or continued operation of the healthy pole in order to maximise the availability of the converter in the event of fault on the parallel converter. Less severe faults permit extinction of the current in the faulty pole enabling isolation of the faulty pole from the DC line. Critical faults render continued operation of the remaining (healthy) pole unviable.

The control and protection philosophies are designed to be robust even in the absence of inter-station telecommunication between Champa and Kurukshetra. The inter-station communication is used judiciously to enhance fault detection and discrimination.

For severe faults at the rectifier terminal the faulty pole is blocked and the current of parallel healthy pole is extinguished temporarily allowing isolation of the faulty pole from the DC line. The less severe faults are cleared by extinguishing the current and isolating the faulty converter from the DC line without interruption of power transfer.

In case of critical faults at the inverter end where the healthy inverter cannot assist in the isolation of the faulty inverter, both the parallel poles will be blocked. For less severe faults at the inverter terminal the current will be transferred from the faulty pole to the healthy pole. The faulty pole will be isolated from the DC line.

In the event of DC line fault the DC line protection of the designated “first” parallel pole will detect the fault and perform co-ordinated restart attempts between both the parallel poles. When there is a DMR line fault the relevant protection will detect the fault and will operate on both the poles independently and perform similar protective sequence.

Figure 3 demonstrates a temporary fault on one of the poles. In this case the healthy pole continues operation and the faulty pole is blocked by the relevant protection. X and Y in the plots refers to rectifier and inverter end respectively.

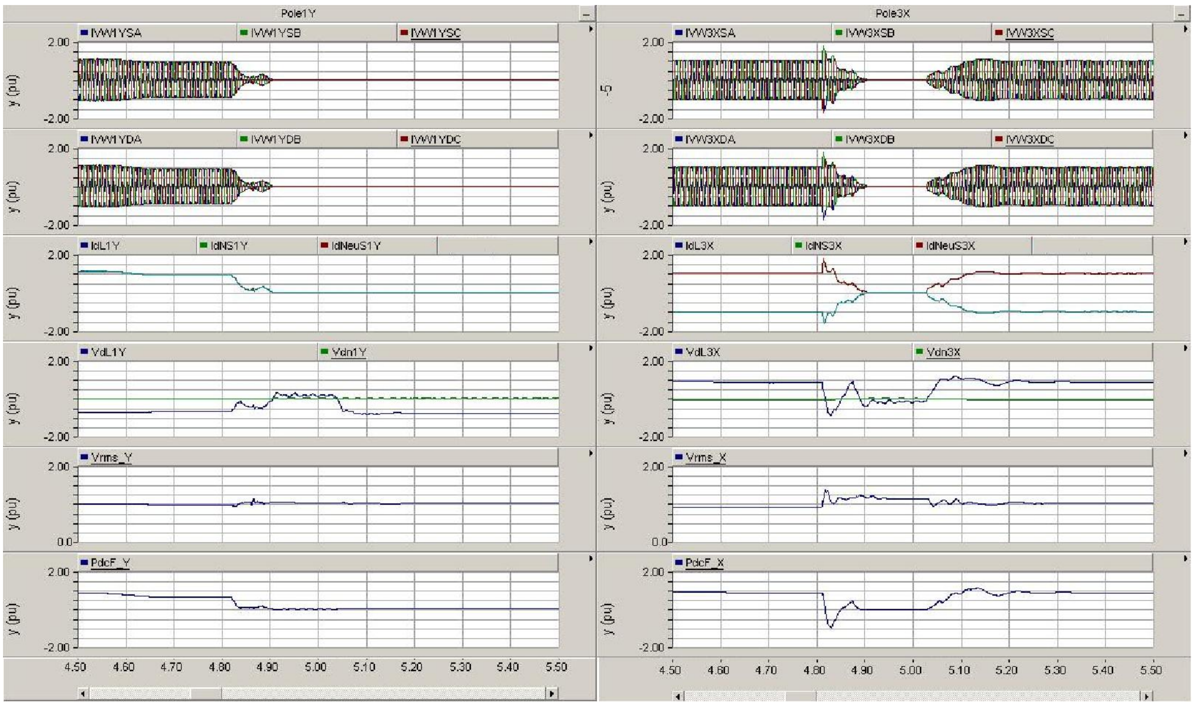

Figure 3 : Temporary Fault on One of the Parallel Poles

6. COMISSIONING

The Champa Kurukshetra 800 kV HVDC link will be commissioned in two stages. In the first stage, Bipole 1, presently under construction, will be commissioned allowing the transfer of 3000 MW of nominal power between Champa and Kurukshetra. In the second stage, Bipole 2, presently being designed, will be added in parallel with the existing Bipole 1, sharing the same DC line and the DMR Conductor, upgrading the link to 6000 MW nominal power. The design and construction of Bipole 1 and Bipole 2 aims to minimize the interruption of the operation of Bipole 1.

In Stage 1 the control and protection strategy has been devised to accommodate Bipole 2. Signals required for interface between both bipoles have been identified and made available for exchange between the two bipoles. The stations for both bipoles are adjacent and share the same line, therefore disconnectors have been provided in Stage 1 to allow future connection of Bipole 2 to the line without requiring shutdown of Bipole 1.

In order to minimize the shutdown of Bipole 1, a temporary arrangement is foreseen, to segregate one of the two available dedicated metallic return conductors, for Bipole 2 commissioning. Pole 3 or Pole 4 belonging to Bipole 2, will be commissioned on one HV line. At the same time Pole 1 or Pole 2, belonging to Bipole 1, will keep transferring power over the other HV line, Figure 4.

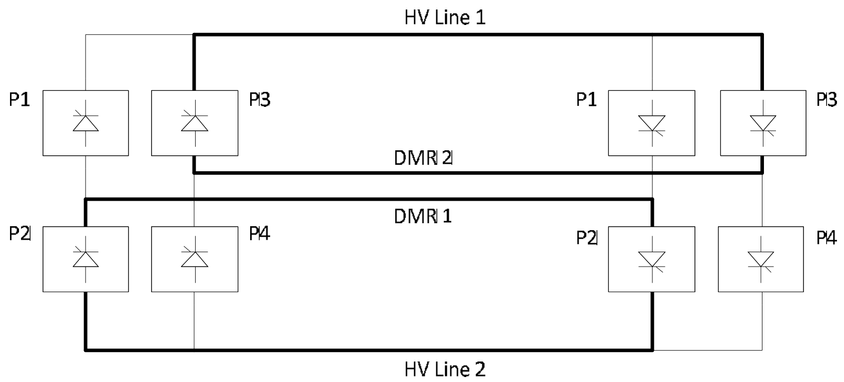

Figure 4 : Configuration of the DC circuit at Bipole to Commissioning Phase

7. CONCLUSION

Champa Kurukshetra HVDC is 6000 MW link connecting the Western region of India to the Northern region of India, where most of the load is present. Thereby, maintaining power transfer is of prime importance. To conclude, features are therefore designed to allow co-ordinated operation of the two parallel bipoles. These features also cater for contingent situation and staged approach to upgrade the link during commissioning.

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NEW HVDC CONTROL SYSTEM FEATURES IN NEW ZEALAND TO BETTER SUPPORT RENEWABLE GENERATION

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SUMMARY

New control systems on the recently upgraded New Zealand HVDC transmission system facilitate improved performance from an island electricity system with predominantly renewable generation. The recently completed Pole 3 HVDC project has replaced the 1965 Mercury Arc Valve converters and the 1992 hybrid link control systems. New control system features include automatic Roundpower operation with fast automatic deblocking and a continuous frequency keeping control using system frequency differences. These features provide improved network security through seamless transfer of inertia and dynamic power reserves. This paper will review the design of the new control features and provide the results of simulations and actual commissioning tests. The resultant improvement in grid system performance enabled by the new HVDC control systems will be revealed from analysis of an initial operating period.

KEYWORDS

HVDC Bipolar Systems - Design - Performance - Rating - Reactive Power - Roundpower - Control System - Frequency

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1. INTRODUCTION

NZ System

The New Zealand electricity supply system in 2014 provided 72% from renewable sources. The system has a total installed capacity of 9.9 GW. The generation mix was 55% hydro, 10% geothermal, 7% wind, 16% gas, 5% coal and 7% for others including co-generation. A market exists for the sale and purchase of electrical energy.

Market Operation

The New Zealand Electricity Market was established in 1996. Five major generating companies compete by bidding into a common half-hourly pool. Transmission and System Operator services are provided by Transpower New Zealand Ltd, a regulated business.

HVDC Configuration and History

The primary purpose of New Zealand's HVDC link is to transport hydro generation from the south island to the load centres in the north island with the HVDC transmission circuit partially comprising of an under-sea cable.

The 600 MW +/- 250 kV HVDC link was commissioned in 1965 using Mercury Arc Valve (MAV) converters and was at the time the largest long distance bulk power HVDC transmission system. In 1992 the existing transmission line was uprated to +/- 350 kV, a new line commutated thyristor converter Pole (Pole 2) was added and the existing MAV converters were modified to work in parallel as half-poles (Pole 1). In 2013 the MAV converters were decommissioned and a further 700 MW line commutated thyristor converter (Pole 3) installed. While 1400 MW of converter capacity is now available (with Pole 2 and Pole 3), transmission is limited to 1200 MW through limitations in the capacity of the HVDC submarine cables and reactive compensation plant. The NZ HVDC transmission system usually operates in a balanced bipolar mode with transfers of up to 1000MW.

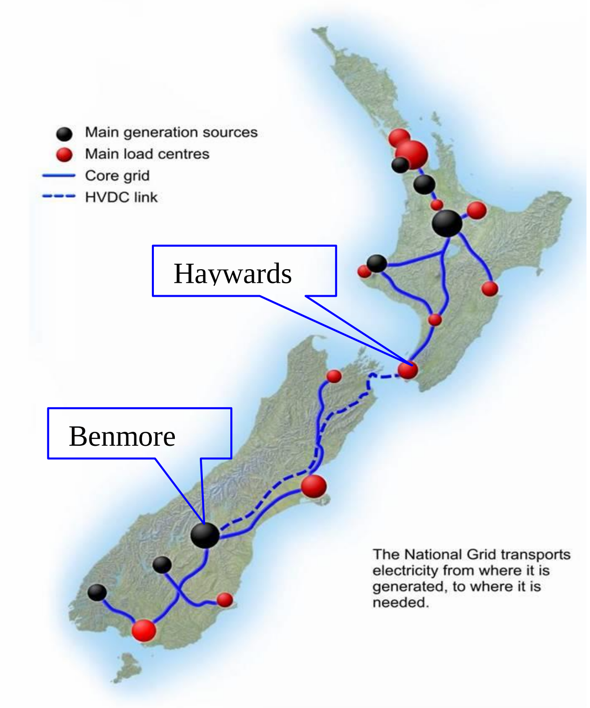


Figure 1 Picture of New Zealand showing location of HVDC converter stations at Haywards and Benmore

2. HVDC CONTROL FACILITIES

Roundpower

A new operating mode called Roundpower[1] was developed to avoid the market discontinuity created by the minimum transfer capacity of the line commutated converters (typically minimum power transfer is 10% of rated power, sometimes defined as Pmin). Roundpower mode also ensures that no delay occurs when changing the overall direction of power transfer from north to south and vice versa.

When Roundpower is selected there are three different operating modes; Bipole operation, Monopole operation and Roundpower operation. The Monopole/Roundpower transition level is set at 40 MW, and the Monopole/Bipole transition level is usually set at 200MW. Roundpower operation can be explained by the following automated sequence of power transfer direction reversal.

1. Starting in bipole operation above 200MW northwards, as power transfer is reduced towards zero (southward transfer) Pole 2 blocks and Pole 3 adjusts to maintain scheduled transfer.
2. Before Pole 3 reaches minimum transfer Pole 2 deblocks in the reverse direction with Pole 3 again adjusting to maintain scheduled transfer.
3. At zero MW transfer on both poles are operating at minimum transfer in opposing directions. At this point the DC current is also at minimum and a small loss penalty occurs due to the circulating dc current. These additional losses are not significant in the overall energy market settlement.
4. Continuing to move towards higher southward transfer when the transfer exceeds 50MW Pole 3 is blocked and Pole 2 maintains the scheduled transfer.
5. At 200MW southwards Pole 3 is deblocked and bipole operation in the reverse direction continues.

This sequence is illustrated in Figure 2. To prevent chattering and excessive blocking and deblocking 10 MW direction dependent hysteresis levels have been allowed at each of the bipole to monopole transition points and 12.5 MW at each of the monopole to Roundpower transition points.

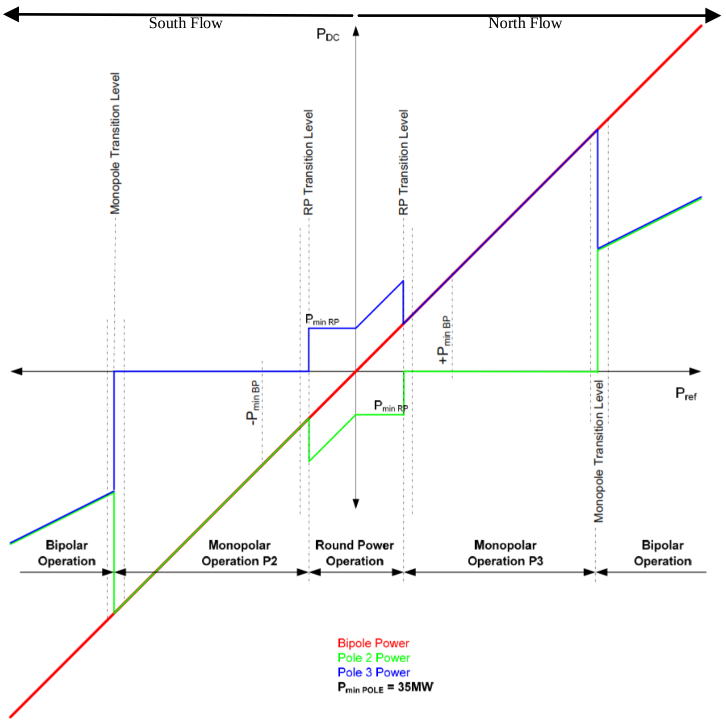


Figure 2 Roundpower operation diagram

In order to prevent excess voltage stress on the Mass Impregnated Non-Draining (MIND) submarine cables a 5 minute discharge time is enforced before deblocking is allowed with the opposite polarity. This restricts the ramp rate (25 MW/min) and roundpower transition levels ensuring that the 5 minute time is elapsed prior to the roundpower control requesting pole deblock in the opposite polarity.

During the period of monopolar operation in Roundpower mode the blocked pole is immediately available for fast deblocking if the operating pole trips. This enables the reserve risk for the connected ac grid to be the same as if in balanced bipole operation.

Frequency Stabiliser Control (FSC) and Spinning Reserve Sharing (SRS)

During the 1992 upgrade a special frequency control system[2] was developed to support the operating configuration of the New Zealand electricity market at that time. When commissioned this allowed separate dynamic reserve and frequency control arrangements in the North Island and South Island. This control system had two components. Firstly a fast acting Frequency Stabilising control (FSC) and secondly a slower acting Spinning Reserve Sharing (SRS) control. The FSC was tuned to respond within less than 1 second and wash out with a 30 second time constant so that it had no steady state impact on transfer. This has been successful both in improving small signal stability as well as reducing the initial magnitude of frequency fall in the predominantly hydro generation systems. Effectively this acts to share inertia between the connected systems. The SRS was tuned to take over from the FSC with a 30 second time constant only once the system frequency was outside a 0.2 Hz deadband. The deadband ensured that no steady state offset occurs while still enabling the transfer of spinning reserves between the islands when extreme frequency events occur.

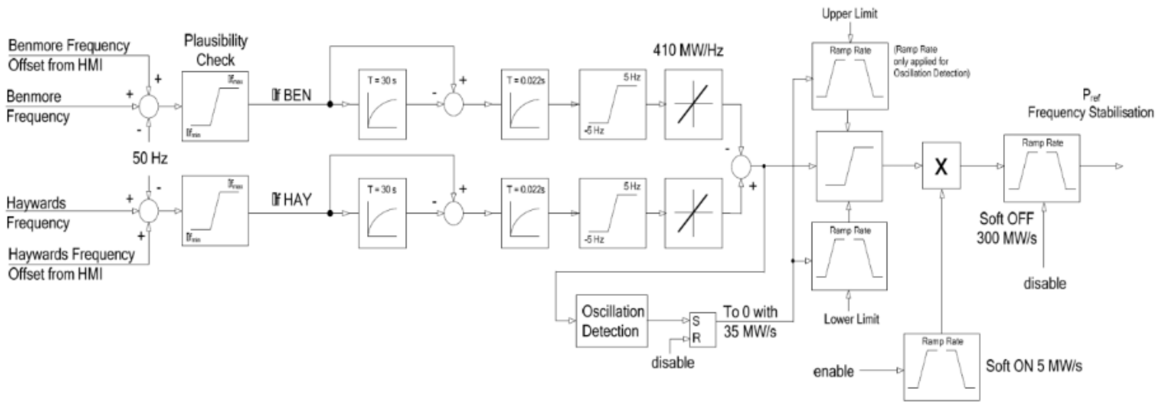


Figure 3 Frequency Stabilisation Control block diagram

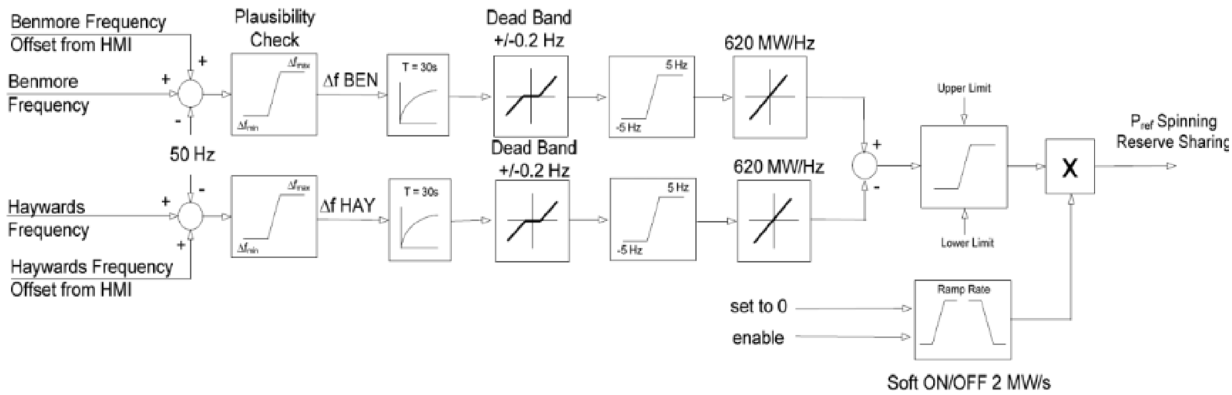


Figure 4 Spinning Reserve Sharing control block diagram

Frequency Keeping Control (FKC)

In order to enable a reduction in market operating costs and provide for increased competition in the provision of frequency keeping services, a revised approach to frequency control and reserves management is enabled by provision of a new Frequency Keeping Control (FKC). This was delivered as part of the upgrade in 2013 and enables the HVDC transfer to automatically track the generation dispatch in each island using system frequency differences. Both islands can now be operated as a single frequency control area, emulating the behaviour of an interconnected ac network. This allows generation to be used for frequency control irrespective of location within the network. It provides improved frequency keeping stability and for rapid transfer of reserves between the island without any deadbands. These modulation controls are also allowed to automatically reverse power transfer direction in conjunction with Roundpower operation.

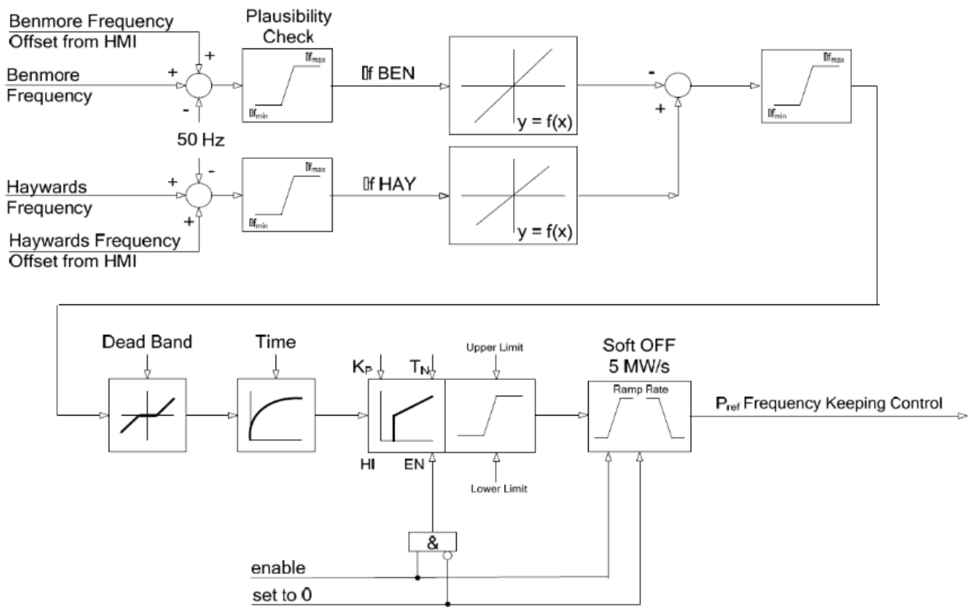


Figure 5 Frequency Keeping Control block diagram

Other Frequency controls

Additional frequency control functions originally developed for the 1992 upgrade have been carried over into the new Pole 3 project control systems. These are the Wellington over-Frequency Brake (WFB) and the Haywards Constant Frequency Control (CFC). The WFB is designed to prevent a high over frequency in the Wellington area (bottom of the North Island near Haywards converter station) if it becomes suddenly islanded from the rest of the North Island grid during northward power transmission. The CFC allows control of the Wellington area frequency to allow resynchronisation of the islanded section with the rest of the North Island grid.

3. SYSTEM MANAGEMENT AND DISPATCH CONTROLS

Transpower uses various system management and dispatch controls to facilitate secure real-time operation of the interconnected power system. These are described below.

Multiple Frequency Keeping (MFK)

Transpower operates a form of electronic AGC (Automatic Generation Control) called Multiple Frequency Keeping (MFK). The main functions of MFK are to compensate for non-ideal generator governors and maintain time error within acceptable limits. The controller structure is shown in Figure 6. The PI-I control path is turned off, since proportional control of the Time Error is equivalent to integral control of the frequency, but with the added benefit of having no integrator drift. The Tie Bias function acts to reduce the deviation from dispatch of the HVDC by adjusting the frequency keepers.

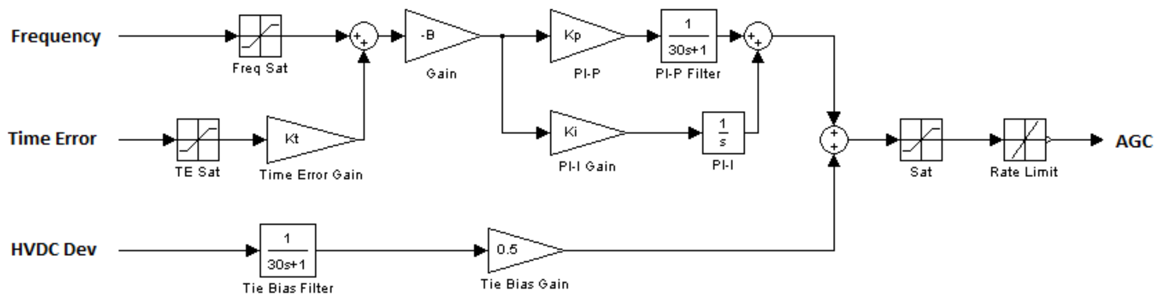


Figure 6 Block diagram of AGC and Tie Bias function

Automatic Pre-Solve Deviation (PSD)

All generators and the HVDC are redispatched automatically every 5 minutes in the Pre-Solve Deviation (PSD) process. This redispatch takes into account the generation, HVDC, and MFK deviation from dispatch, the updated forecast, and the time error.

Reserve Management Tool

The Reserve Management Tool (RMT) is a component of the market system that maintains post-event frequency within frequency bands set by the System Operator's Principle Performance Obligations. The RMT contains a dynamic model of generator governors and the HVDC frequency controls (it only calculates DC dynamic flows, AVR models are not included).

The RMT dynamic model is used to calculate the quantity of reserves required to cover the risk of a major generator or HVDC tripping for each half hour trading period. This quantity is passed to the Schedule Pricing and Dispatch (SPD) program to determine how much reserve needs to be scheduled to cover the risk of a major generator or HVDC tripping.

Inaccuracies in the model can lead to the wrong quantities of reserve being scheduled. In the worst case this could lead to the system frequency falling below statutory limits.

4. TESTING AND TUNING OF SYSTEM CONTROL AND DISPATCH PROCESSES

Tests During HVDC Commissioning

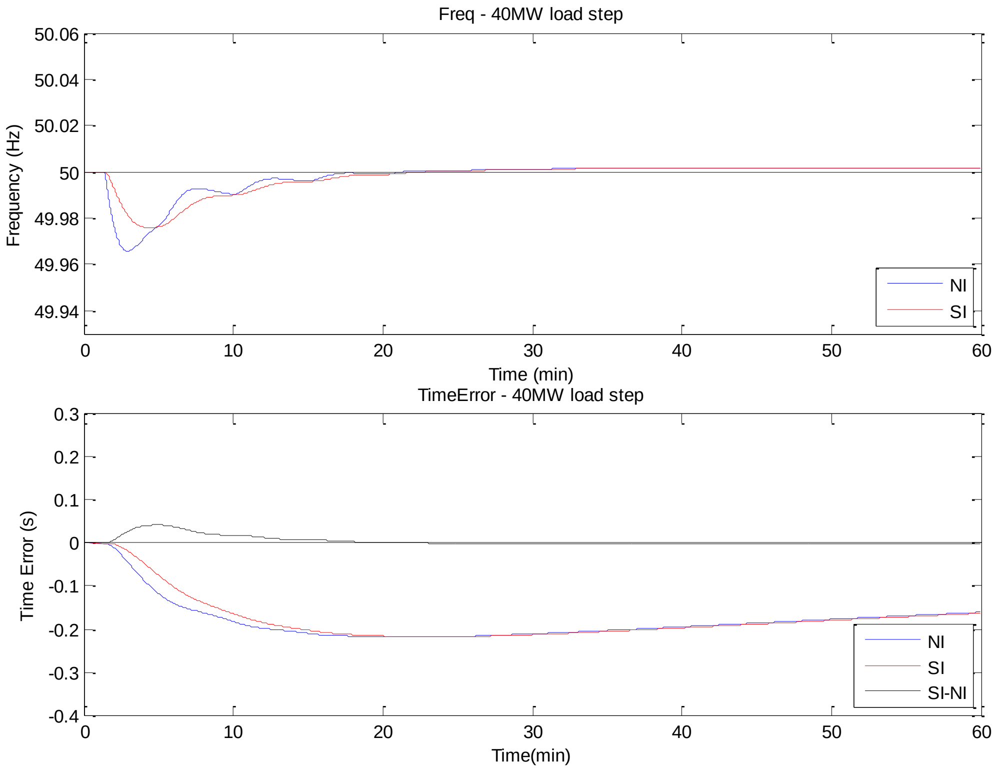
Tests were carried out during HVDC commissioning in late 2013 which demonstrated the control response of the new FKC control and provided a comparison to the existing FSC control. This was especially important for the System Operator, ensuring that RMT would continue to allocate the correct amount of reserves in the system.

The FKC control initially implemented had a gain bias which led to a deterioration in transfer from North to South Island during under frequency events. On the recommendation of the System Operator this bias was removed and the FKC control was then assessed to be equivalent to the FSC control. The only difference being additional filtering time in the FKC controls. The effects of this additional filtering time were found to be not significant.

Testing After Commissioning

After the commissioning of the new HVDC Pole 3 work commenced to integrate the new FKC and Roundpower into the system operations and dispatch processes, it was necessary to retune MFK and dispatch processes to achieve acceptable operation with the FKC control in service. At this time and for subsequent testing MFK was only available on a per island basis. In this situation it was important to ensure that only one island frequency was controlled with zero steady state error (i.e. a type 1 control system). FKC is also a type 1 control system and so it works to maintain the frequency of the other uncontrolled island with zero steady state error. If both island MFK systems were in operation with the FKC then they oppose each other in steady state and drift to limiting values as only two independent output variables exist (each island frequency). This then emulates the behaviour of an ac tie line. The disadvantage of this structure is that generation and load dispatch need to be accurately matched in each island, if not, similar to an ac tie line, the HVDC transfer will not be as expected (HVDC deviating from dispatch). This was corrected by improving the generation dispatch process and was not a malfunction of the FKC control.

To support these tests Matlab simulations were undertaken modelling the frequency response of the system, FKC control and MFK. Figure 7 below illustrates an example output from these simulations showing the combined action of FKC and MFK to a 40MW load step in the North Island. As steady state frequency control of a power system is an inherently slow process these simulations extend over 60 minutes.



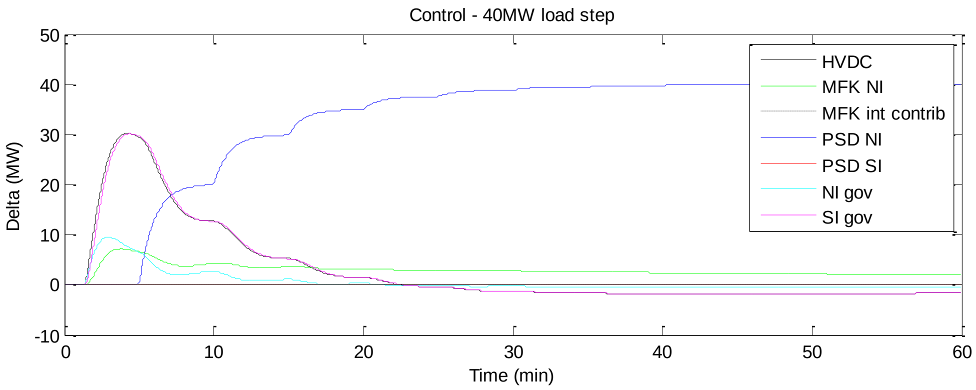


Figure 7 Example Matlab Simulation of FKC test

Results from Initial FKC Testing

Testing was undertaken between April and September 2014 to assess the impact FKC had on normal frequency management and dispatch processes. Tests were run with varying levels of procured frequency keeping from 75 MW (the standard procured quantity) through to 0 MW. Along with changes to the level of procured frequency keeping, tuning of the MFK and dispatch processes was also carried out.

All of the graphs below are normal distribution plots where the total area under the curve represents 100% of the time of the relevant test period. Figure 8 and Figure 9 provide data on system frequency deviation for a series of 24 hour periods. They show the change in frequency performance compared to the current state with no FKC (FKC off). In each case the overall performance with FKC enabled is dependent on the size of the frequency keeping band (FK band). For the North Island, all cases with FKC enabled are improved, with a tighter frequency performance in all test cases. For the South Island there is a small degradation in performance, however this was dependent on the test conditions and size of the FK band. With a 75 MW frequency keeping band the performance is very similar to when FKC is disabled and a band of 50 or 30 MW appears to have very similar results. In both islands it was noticeable that during tests of 30 MW FK band the results were quite different. This is attributed to different generation and system load variations during the tests.

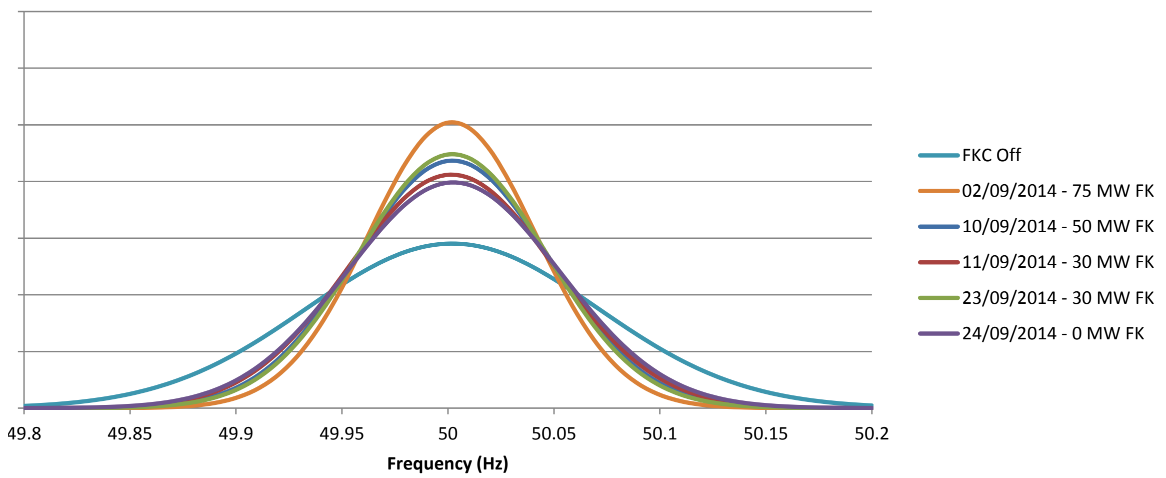


Figure 8 North Island Frequency Performance

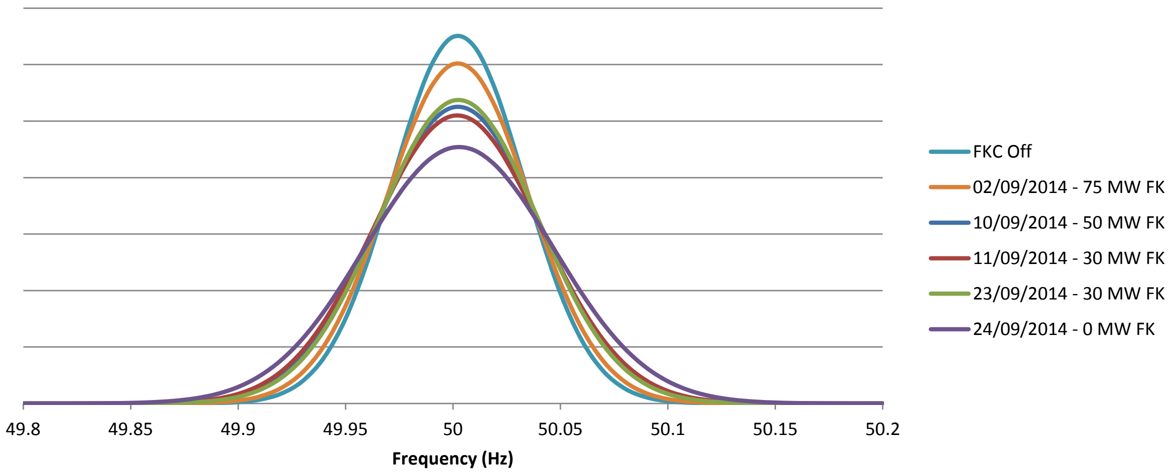


Figure 9 South Island Frequency Performance

An overall system comparison was also completed against the 30 MW tests. This took the frequency deviation (change from 50 Hz) weighted by the North Island and South Island loads to compare operation with FKC versus FSC. Results of this assessment are included in Figure 10 below and demonstrate an overall improvement in the system frequency performance with 30 MW of procured frequency keeping tests.

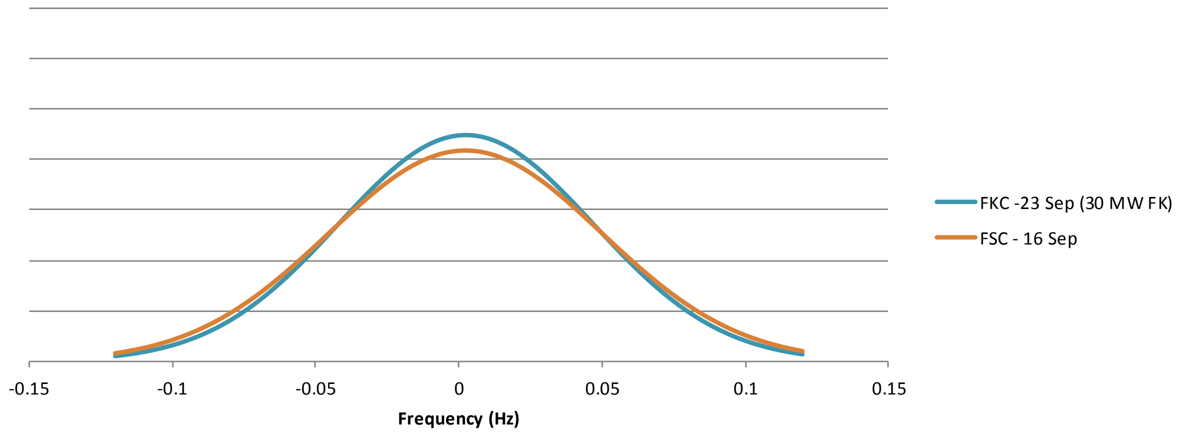


Figure 10 - Frequency Comparison for 30 MW FKC Test on 23rd September

Another consideration from these tests was the HVDC performance. With FKC active, the HVDC deviates from its dispatch setpoint dependant on the system frequency of the islands. This deviation from dispatch is considered in the assessment of system risk. As shown in Figure 11, the HVDC does tend to deviate from dispatch with FKC enabled.

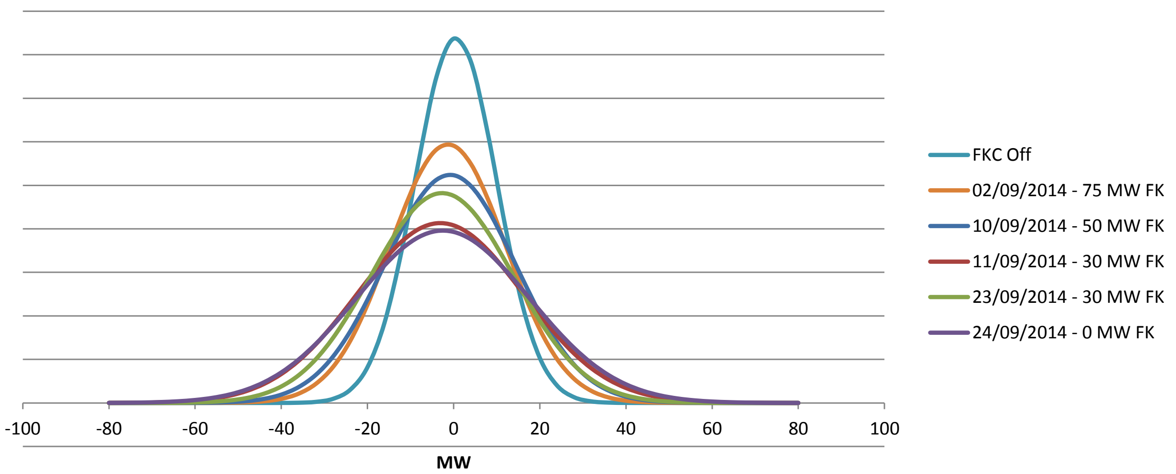


Figure 11 HVDC Off-Dispatch Performance

Overall the results demonstrate that with FKC enabled the system can be securely operated with a reduced frequency keeping band such that frequency, time error and dispatch can be managed within the System Operators obligations.

Frequency performance in the North Island showed improvement during all of the FKC testing and the South Island was observed to have a slightly degraded performance. This is expected as both islands are now acting as a single frequency system with the more regular and higher magnitude disturbances of the North Island network being mirrored in the South Island. Taking the existing (ie no FKC operation) North Island system frequency performance (ie the status quo) as a baseline, both the North Island and South Island systems demonstrated better performance than this baseline.

HVDC off-dispatch performance was degraded with FKC enabled when compared to having FSC enabled. This was expected as FKC continually responds to frequency changes to balance the two islands whilst FSC tends to wash out within 30 seconds. From the tests the off-dispatch performance has increased by approximately 40 MW.

The outcome of these tests was to commence a longer term system trial with 30 MW FK band selected. This will reduce the procured frequency keeping by 45 MW and so result in cost reductions for consumers.

Initial Results from FKC trial

Following the success of the tests described above, a long term trial of FKC commenced on 16th October and finished at the end of March 2015.

The trial allowed refinements to the dispatch process for the FKC control and to allow further testing of the appropriate level of frequency keeping quantities. The trial saw no significant operational or technical impediments to FKC operation and therefore from the end of March 2015 FKC is the normal mode of operation.

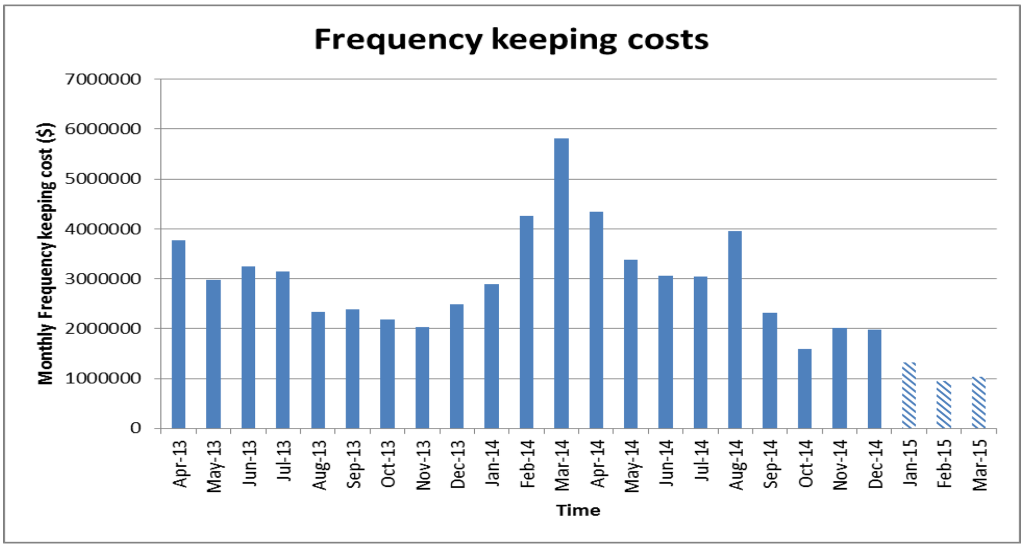
The trial showed that it would be technically feasible to rely on governor action alone for frequency control and not use a frequency keeping service. This technical change would need:

1) Increased governor action by Generators.
2) Improvements to the market system tools dispatch automation.

The Electricity Authority (New Zealand electricity regulator) has commissioned a work stream to address these actions.

The trial demonstrated the significant financial benefits of reducing the quantity of frequency keeping services purchased.

For technical reasons the trial was not fully in operation for November and December 2014. In the first three months of operation frequency keeping costs reduced by two thirds. If this trend continues then annual savings of $25 million are envisaged.



5. SUMMARY

Since commissioning the new HVDC controls have been operated in automatic Roundpower mode with Frequency Keeping Control. By interconnecting the frequency control process between the North Island and South Island the overall system frequency control has been improved and less capacity needs to be assigned to frequency keeping duty. This has resulted in a reduction in market operating costs.

In addition to providing for the fast transfer of inertia during major system disturbances, the new FKC control allows better use of flexible hydro generation from the South Island to balance the intermittent generation from wind farms in the lower North Island. During the trial testing period, in order to evaluate the improvement provided by the new FKC control, the quantity of generation (frequency keeping band) used by MFK to control system frequency was varied between 75MW and zero.

Additional work is being undertaken to assess how to best manage normal frequency with FKC in place with one option being to rely on faster economic generation dispatch. This is possible as the larger interconnected system with more generator governors acting under droop control is adequate to maintain system frequency within required limits and so the slower electronic market dispatch process can be used to manage time error.

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Practice of the First Five-Terminal VSC-HVDC Project

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SUMMARY

The ±200kV VSC-MTDC project is specifically designed to enhance the regional power grid, increase power supply reliability as well as integrate wind energy within Zhoushan Islands near the city of Shanghai, Southeast coast of China. The project has been put into commercial operation on 4th July, 2014. It connects five islands by submarine cable with each station rated power of 400MW, 300MW, 100MW, 100MW and 100MW respectively. The radial VSC-MTDC project adopts symmetrical monopole topology.

The system configuration including topology, main equipments, convert station layout and others are given in the report. The important parameters for both power grid and major equipments such as transformer, converter, reactor are provided for reference.

The VSC-MTDC model adopts 26 operating modes out of 27 theoretical modes. A black-start mode is also provided in case of main power grid black out. To achieve both flexible and reliable operation of the VSC-MTDC, a well-designed hierarchical control and protection system is equipped. Besides the system configurations, the control and protection strategy and their realizations are put forward in detail.

During engineering and factory test period, a large number of tests have been carried out to confirm the control and protection strategies. In the end of the report, the site commissioning process is discussed including test items and relevant methodologies. Also a brief of AC earth fault test, voltage control mode shift test, and the island only operation mode shift test are focused. In addition to that some site test results are also illustrated to show the performance of the five-terminal VSC-HVDC transmission project.

KEYWORDS

VSC-HVDC, Multi-terminal, System design, Control and Protection, System test

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1. Introduction

The Zhoushan five-terminal VSC-HVDC project, owned by the State Grid Corporation of China (SGCC) is located in Zhoushan Island in the southeast coast of China. The main AC power grid consists of the Dinghai Island power grid and the Shengsi Island power grid. Dinghai power grid connects to Zhejang Province power grid, the mainland of China by means of one double circuit 220kV AC links and three single circuit 110kV AC links. Shengsi connects to Shanghai power grid by a ±50kV HVDC links with submarine cable. Other 110kV AC submarine cable transmission is used to connect between Shengsi and Dinghai.

The rated DC voltage of Zhoushan VSC-MTDC project is ±200kV. Five converter stations are located at Dinghai Island (400MW, 220kV), Daishan Island (300MW, 220kV), Qushan Island (100MW, 110kV), Sijiao Island (100MW, 110kV) and Yangshan Island (100MW, 110kV). Connected by submarine DC cables, the five stations construct a radial multi-terminal topology. Figure 1 shows the geographical location and SLD of the Zhoushan VSC-MTDC project.

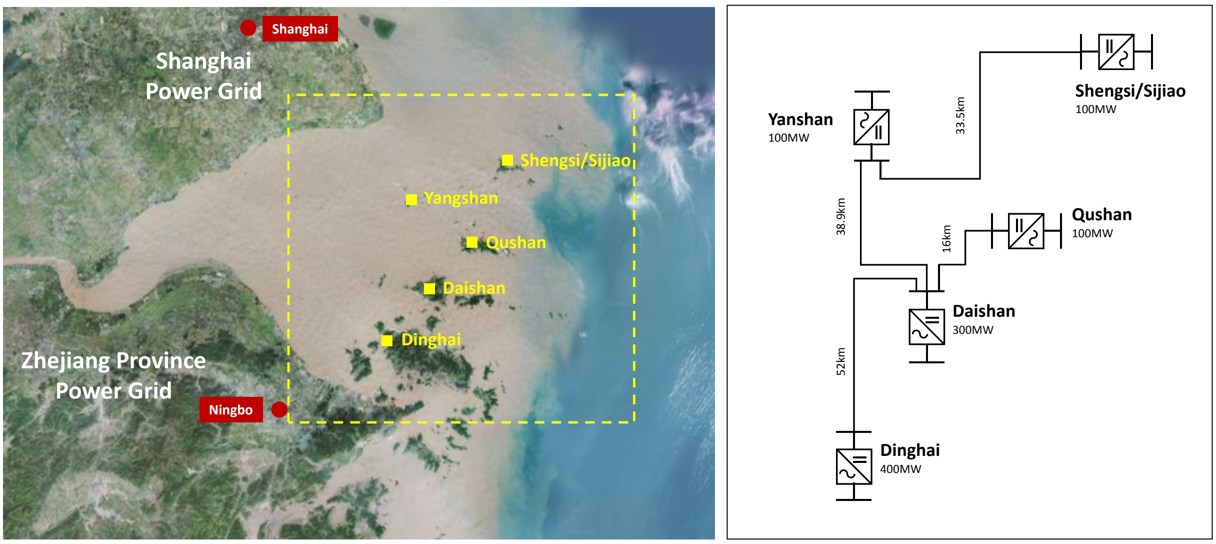

Figure 1. The geographical location and SLD of the Zhoushan VSC-MTDC project

The motivation that built a five-terminal HVDC link in Zhoushan is as follows:

- Enhance the regional power grid structure as well as increase power supply reliability by means of connecting five islands together and realizing bi-direction power flow control between them
- Adopt the wind energy within Zhoushan Islands (Qushan Island and Sijiao Island)
- Use of submarine cable

The Advantages of VSC-HVDC over Classic-HVDC are:

- Suitable for connecting to week AC systems/dead power source areas
- Small footprint than classical model
- Ability to enhance the system reactive power stability
- Easy for Black-start function

2. Major Components

Zhoushan VSC-HVDC project adopts the symmetrical monopole scheme. The main circuit diagram of Dinghai converter station is shown in Figure 2[1]. The equivalent AC network parameters are also given in Table I.

Table I AC network equivalent parameters

	Dinghai	Daishan	Qushan	Yangshan	Sijiao
AC System Equivalent Impedance(Ω)	2.045+j8.269	3.15+j11.459	2.694+j10.162	2.839+j11.865	6.633+j11.410

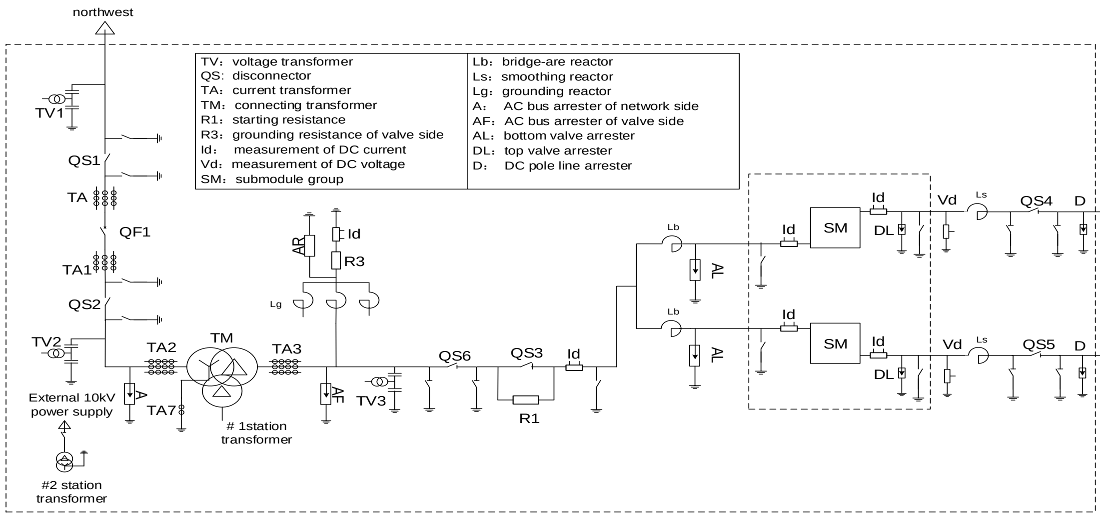

Figure 2. Main circuit digram of Dinghao converter station

The Converter

The heart of the VSC-HVDC system is the converter module which pumps the power to other stations. In this project, the three-phase bridge converter is based on the multilevel converter topology. Each converter has six converter arms and each converter arm consists of three valve towers of four levels. Figure 3 shows the layout of converter in the valve hall. For reference, the main parameters of the converter in Dinghai station are given in Table II.

Table II Parameters of converter (Dinghai Station)

Item	Parameters
Rated power	400 MVA
Rated DC Voltage	200 kV
Rated DC Current	1000 A
Fully controlled semiconductor	IGBT 3300V/1500A
No. of Modules per converter arm	250+20(spare)
Dimension	10090*2730*6934 mm

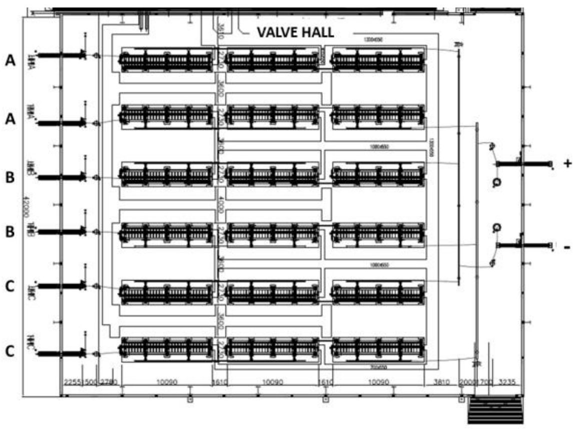

Figure 3. Layout of valve towers in the valve hall

The Reactor

Before the converter, the converter arm reactors are connected to provide the commutation reactance as well as to control the active or reactive power for DC transmission. The parameter of the reactor should satisfy the requirement of active/reactive power, circulating current suppressing, dynamic performance, over current limitation and harmonic current restrain. Major simulation studies are performed after theoretical calculation in order to verify the parameter under various operation conditions. The smooth reactors are included in DC side to limit the short-circuit current. The parameters for both AC/DC reactors are listed in Table III.

Table III Parameters of the bridge arm reactor and smooth reactor

	Dinghai	**Daishan**	**Qushan**	**Yangshan**	**Sijiao**
Converter Arm Reactor Inductance (mH)	90	120	350	350	350
Smooth reactor Inductance (mH)	20	20	20	20	20

The Coupling Transformer

The coupling transformer that connects the converter to AC system is normal type AC transformer and is more economical than the converter transformer used in conventional CSC-HVDC. The capacity of this transformer is determined by both the requirement of power transmission and the losses. Table IV gives the main parameter of coupling transformers in the Zhoushan project.

Table IV Parameters of the coupling transformer

	Dinghai	**Daishan**	**Qushan**	**Yangshan**	**Sijiao**
Type	3-phase 3-winding oil immersed Yn, d, d	3-phase 3-winding oil immersed Yn, d, d	3-phase 3-winding oil immersed Yn, d, d	3-phase 3-winding oil immersed Yn, Y, d	3-phase 3-winding oil immersed Y, Yn, d
Capacity (MW)	450/450/150	450/450/150	450/450/150	450/450/150	450/450/150
Rated Voltage (kV)	230/205.13/10.5	230/204.12/10.5	115/208.2/10.5	115/208.2/10.5	115/208.2/10.5
Rated Current (A)	1130/1267	879/984	603/333	603/333	603/333
Tap Changer	(+8/-6)*1.25%	(+8/-6)*1.25%	(+8/-6)*1.25%	(+8/-6)*1.25%	(+8/-6)*1.25%
Short-circuit Impedance(%)	15/50/35	15/50/35	14/24/8	14/24/8	14/24/8

3. Control Scheme

Under the normal operation mode, Dinghai station behaves as the only source and rest of the stations as receivers. In addition to the main operation mode, a total of 26 operation modes are designed for Zhoushan project to improve the operating flexibility and to maximize the advantages of VSC-MTDC. It automatically changes its control mode during any abnormal trip or temporary fault or maintenance. The control scheme is suitable for all designed operating modes.

Table V Operation modes

Category	**Operating station**	**No. of the modes**
Five-terminal	Dinghai、Daishan、Qushan、Yangshan、Siqiao	1
Four-terminal	Four converters of the Five	5
Three-terminal	Three converters of the Five	10
Two-terminal	Two converters of the Five except Yangshan-Sijiao	9
STATCOM	Work individually	1

A. Configuration of the Control Functions

A set of high performance hierarchical supervisory control and protection system of VSC-MTDC is equipped in each of five converter stations. Figure. 4 shows the main control functions that can be divided into four control layers.

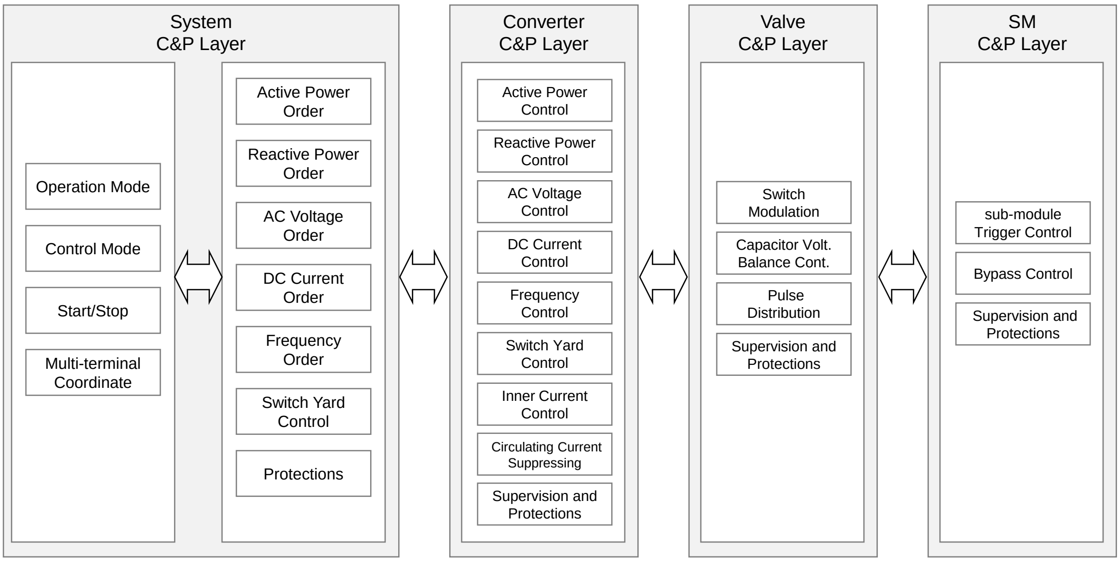

Figure 4. Configuration of control functions in Zhoushan project

1) Module Control Layer

These control functions are imbedded in the SM (sub-module) and are designed to control the SM individually.

2) Valve Control Layer

Valve control is the interface between system control and the SM control. It is mostly realized in the VBU (Valve Basement Control Unit). The main functions of this layer include voltage balancing, pulse distribution and modulation.

3) Converter Control Layer

Converter control is realized in the Pole Control and Protection system. The main functions of this layer include active power control, reactive power control, DC voltage control, AC voltage control, inner current control, transformer tap changer control, overload limitation and additional control to enhance the system stability.

4) System Control Layer

System control is realized in the Pole Control and Protection system. It is mainly responsible for receiving the operation order and sending it to the converter control layer. Besides this, the AC and DC switchyard control and the multi-terminal coordinate control functions are also included in this layer.

B. Control strategies

1) Smooth switchover strategy for DC voltage control

In a VSC-MTDC system, the converter station, which controls the DC voltage is the balance point of the active power and is very important for the stability of whole transmission system. If it loses the DC voltage control ability because of system failure or over-load, then another converter station acts immediately to take over the control rights and achieves a new balance thereafter.

In Zhoushan project, a dedicated communication network is built between the five converter stations which is mainly used for supervision. When the master station, which controls the DC voltage quits, the switch over strategies are as follows:

1. If the inter-station communication is effective, the master station will send a message to the first in order station to take over the DC voltage control right as soon as possible. At that time, the first in order station should be in power control mode and has the ability to take over. Otherwise, the second in order station will be informed by analogy.
2. If the inter-station communication is failure, when detecting the DC voltage deviations from the rated value, after a short time delay, the power control station will take over the voltage control right according to predetermined priority. The new master station, which takes over

the control right, will set the DC voltage order as the rated value or the current operation value to achieve a so called no-fluctuation switch over process.

2) Active pre-energizing strategy from DC side[2]

In VSC-HVDC, when starting a passive station that connects to an area without any power source, the converter needs to be pre-energizing from DC side and the SM voltage only can reach at half of its rated voltage. Using normal start/deblocking process, a large overload current will be triggered. The active pre-energizing strategy from DC side has been designed to solve this kind of problem. The detail process is as follow:
- Deblocking all the SM with capacitor on at one time
- According to setting period T_{set}, reduce SM to N/2 per arm with Δn at a time, where the N is the total number of SM with capacitor on in one converter phase

In Zhoushan project,
Δn=1, T_{set}=50ms

3) Online switchover from grid-connection to island

Once one or more stations change into island operation mode, the control system should immediately identify this and switch the control mode from grid-connection type to island type. In Zhoushan project, the variation of AC frequency in the AC side is used as the criterion to make the change over. The disturbing caused by three-phase grounding fault should be avoided during fault and fault-recovery period.

4. Site Test and System Performance

The site tests of three stages are performed before putting the project into operation. They include sub-system test, station system test and system test. The detailed test is given in table VI. The objectives of these entire tests are to verify the functional design & realization and to evaluate the system performance according to the pre-defined code and standards.

Table VI Site test list

Sub-system test	Station system test	System test
DC control and protection	Sequential control test	Initial operation test (multi-terminal and control priority switchover)
AC protection	Protection tripping test	Protection test
Primary equipment	VSC valve charging test	Redundancy switchover test
	Open line test	Stable state performance test
	STATCOM function test	Dynamic state performance test
		Operation configuration switchover test
		Auxiliary control test
		Black-start test
		Islanding test
		Overload test
		Disturbance test

Below some site test results are provide to show the performance of this five-terminal VSC-HVDC transmission project.

1) AC fault test

Figure 5 shows the wave-form for 1.2s single-phase grounding fault test in Dinghai. This test is designed to verify the AC low-voltage ride-through ability of the VSC-HVDC when AC fault occurs. In this case, A-phase grounding fault test is carried out by shooting a copper wire to phase-A of inject line of Dinghai station. From the test and wave-forms it is cleared that, the VSC-HVDC perfectly rides through and works proper after the AC fault.

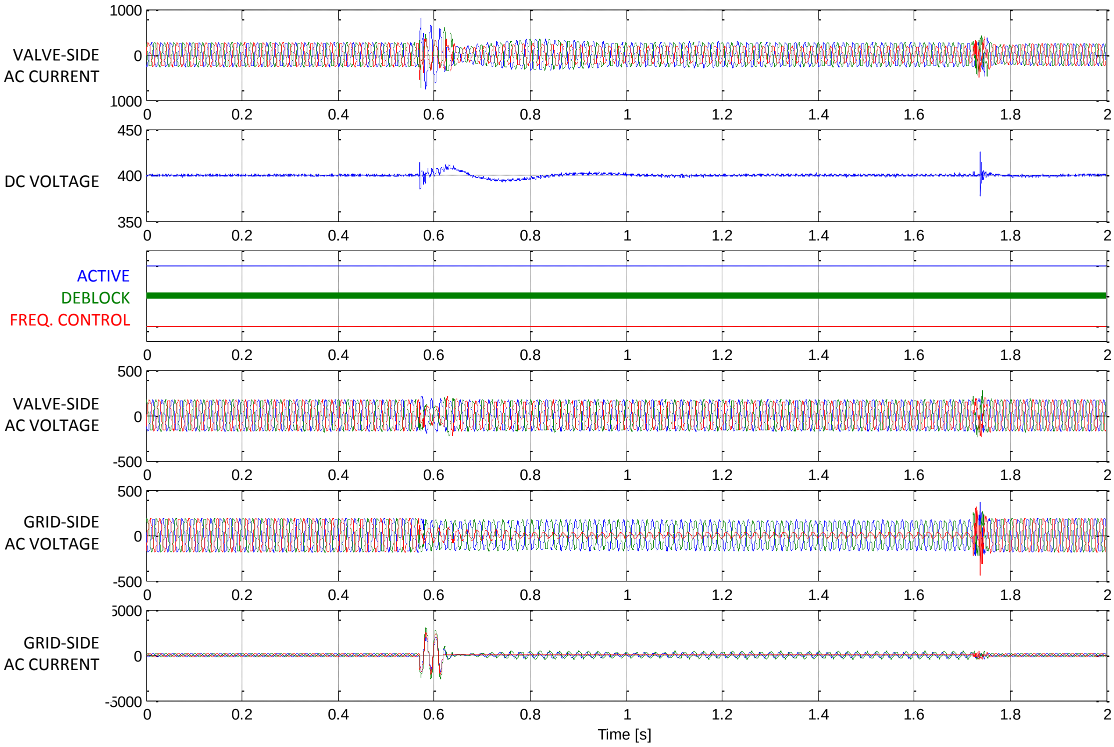

Figure 5. Site test recording of 1.2s single-phase grounding fault in Dinghai station

2) DC voltage control switchover test

DC voltage control switchover test is the most important test carried out at site. An overload fault in valve cooling system is simulated for Dinghai station in the following figures. Due to Dinghai station losing DC voltage control ability, the Daishan station takes over the control right according to predesigned control strategy. Figure 6 shows the wave form of Dinghai station at the very moment of switchover, while the Figure 7 shows the wave form of Daishan station at the same time. The test clearly shows that, the DC voltage control smoothly switchover from Dinghai to Daishan under load operation.

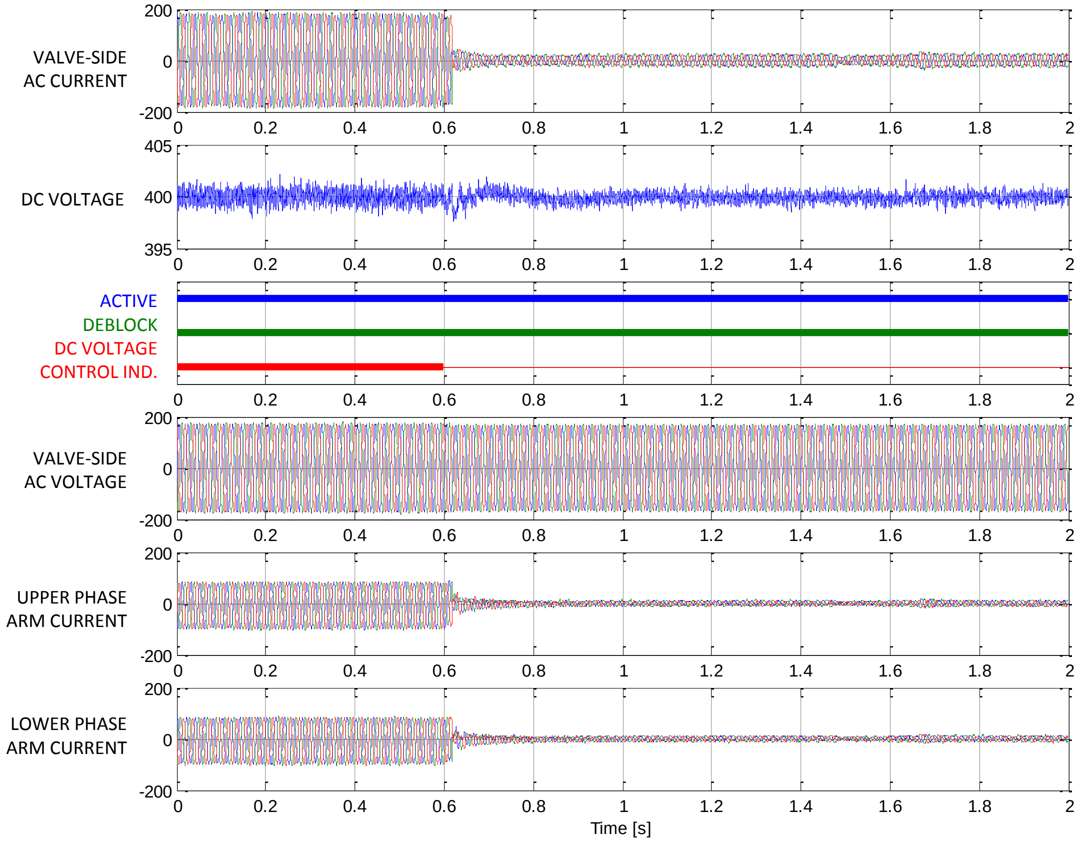

Figure 6. Site test recording of DC voltage control switchover (Dinghai station)

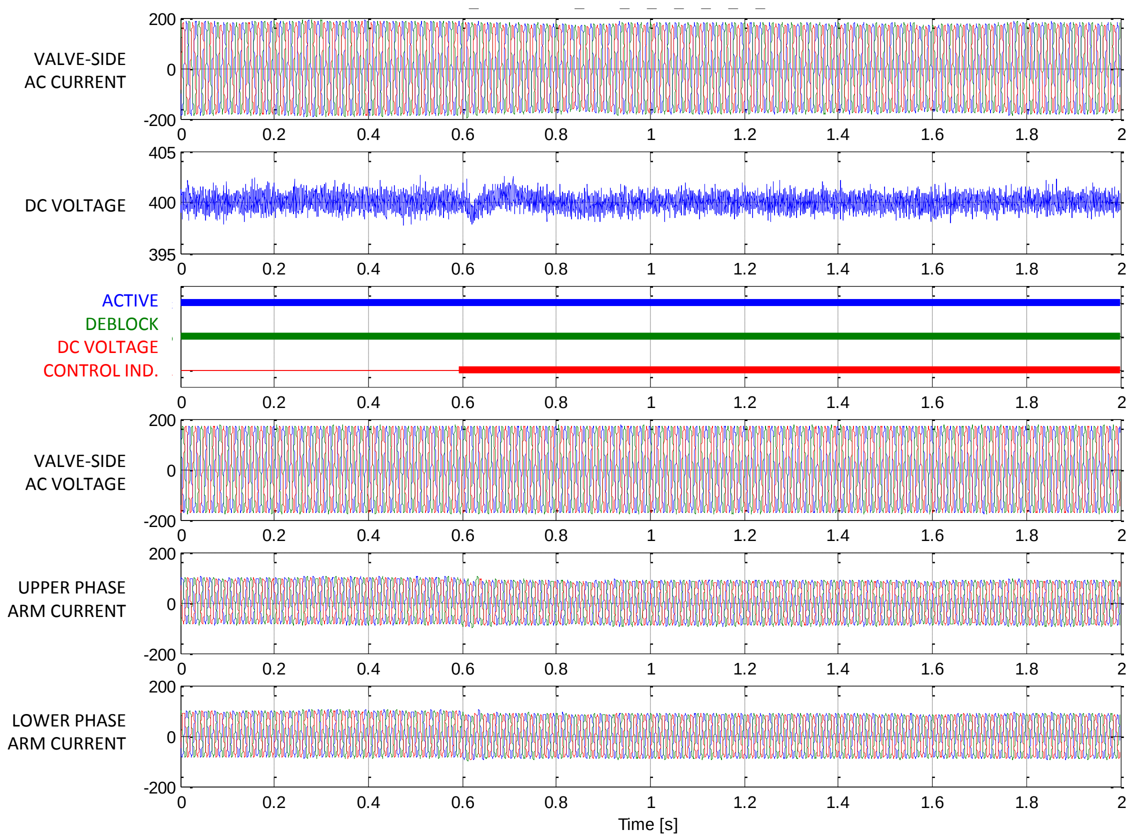

Figure 7. Site test recording of DC voltage control switchover (Daishan station)

3) *Active pre-energizing test*

During this test, the Daishan station acts as a passive station and is pre-energized by Dinghai Station from DC side. It deblocks all the SM with capacitor on and reduces one SM in upper and lower arms at every 50ms, until the sum of SM in one phase equal to 125. Figure 8 shows the site test wave-form for active pre-energizing. During this process, the voltages of capacitors are stably rising to the rated value. The pre-energizing has no impact to the DC system and has no overload current as well.

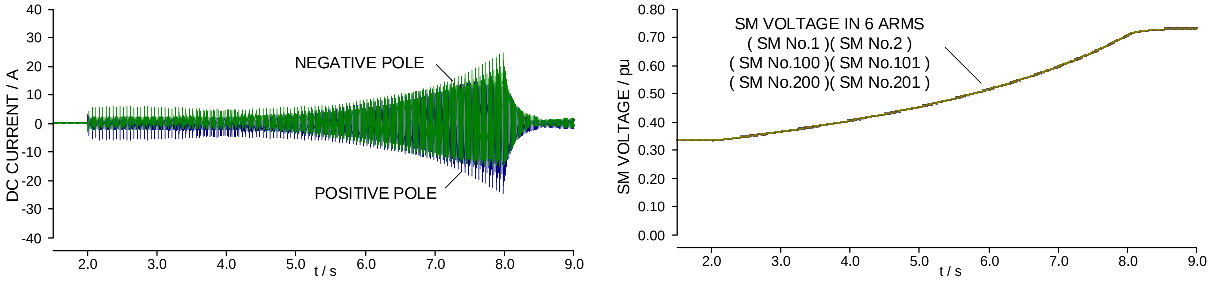

Figure 8. Site test recording of pre-energizing from DC side (Daishan station)

4) *Online switchover from grid-connection to island*

The test is carried out at Qushan station to check the feasibility of switchover. During this test, Dinghai station is in DC voltage control mode while Qushan station is in constant power control mode. When the AC grid is disconnected by means of circuit breakers, the control mode of Qushan station automatically changes to the island mode (constant AC voltage control mode or constant frequency control mode). Figrue 9 shows the wave-form at the switchover moment.

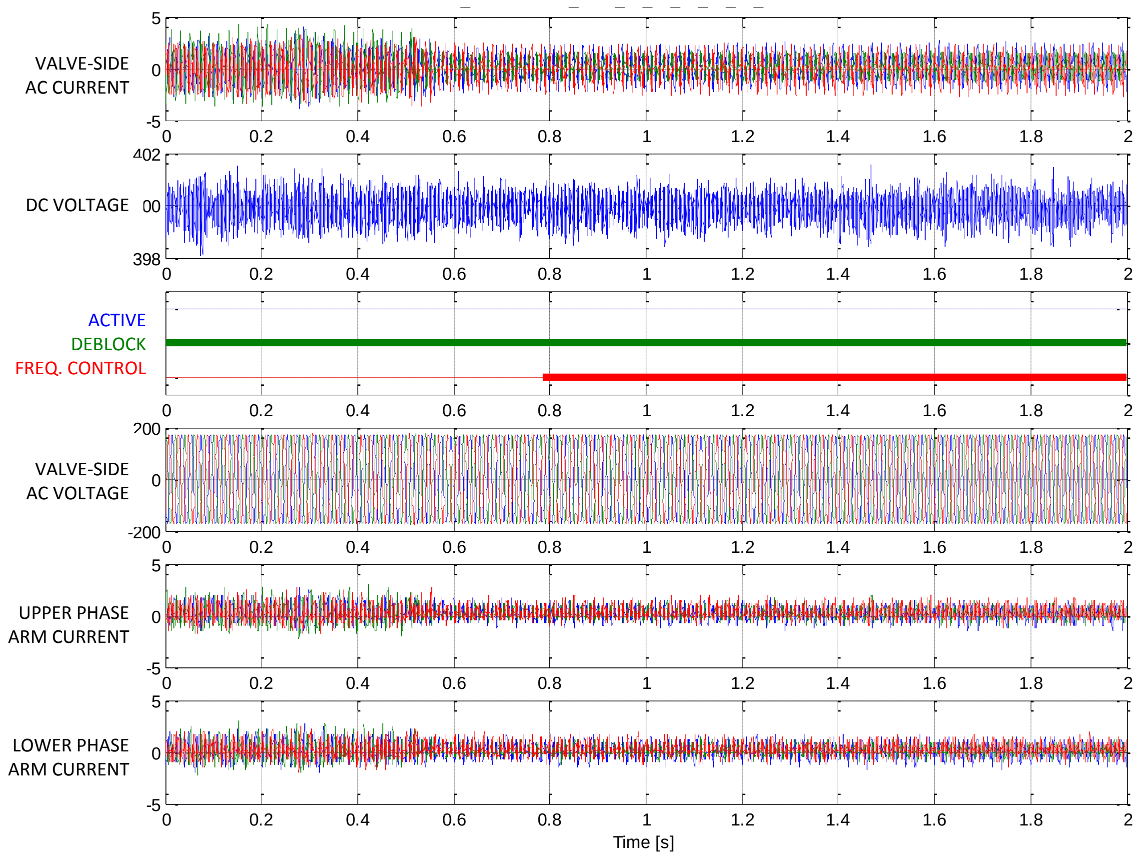

Figure 9. Site test recording of online switchover from grid-connection to island (Qushan station)

5. Conclusion

So far, VSC-HVDC is the most flexible and cutting-edge transmission technology in the world. The Zhoushan VSC-MTDC project with a collective power transfer capacity of 1000MW, ±200kV has been successfully built and put into commercial operation on 24th july, 2014. Presently, the performances of steady and transient state are fully meeting the technical requirements. It has the following advantages:

- Ability to control the AC voltage and frequency during ride through disturbances
- Fast system response and advance control technique with/without dedicated communication
- Enhanced power supply quality compared to classical HVDC

In this paper, based on the introduction of 5-terminal VSC-HVDC project, the system background and configuration, control strategies, site tests are given for reference.

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DC-to-DC Capacitor-Based Power Transformation

PS 1: Planning Study and Future Requirements for DC System

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SUMMARY

DC's role in power system delivery is growing to the point where system planners now envision high voltage dc grids as an overlay to ac systems in Europe and in North America for efficient coordination of loads and generation across wide areas. DC's growth at the end-use level has been even greater; in this case driven by dramatic growth in the use of electronics, new lighting technologies and likely to accelerate with growing vehicle charging load. This growth, both at the power delivery and power utilization level, has been achieved despite the lack of an efficient DC-to-DC transformer; one that would functionally parallel the magnetic transformer that propelled ac to early dominance in both delivery and utilization functions. This paper explores the prospects of capacitor-based transformation of power from one voltage level to another without an intermediate magnetically-based transformer. It considers the advantages and limitations of capacitive circuits widely used for that purpose at the electronics level, but also seeks to take advantage of the capabilities inherent in power-level thyrsitors and IGBT's within the bridge architecture of commonly used MMCs. The paper cites the criteria by which various capacitor-based schemes can be judged as well as means by which relatively smooth dc output and input wave-forms can be achieved within the limitations of what is basically a pulse-based energy transfer mechanism. The practical, multi-modular DC-to-DC capacitive transformer (MMDCT) configuration described is significantly less costly and more efficient than the present DC-to-AC-to-DC scheme and is capable of direct transformation of large levels of dc power from one voltage to another while making use of existing half-bridge IGBT architecture. The system requires no power controller and performs in a manner functionally equivalent to an ac transformer inasmuch as dc power transfer responds to voltage difference between terminals in a manner analogous to that in which an ac transformer responds to phase angle. Detailed PSCAD simulation example shows the proposed transformer's performance interconnecting two major dc

circuits with one another. Approximate cost estimates are included, relating the probably cost in relation to costs associated with conventional MMC bridges.

KEYWORDS

HVDC Transmission, DC-to-DC Conversion, Multi Modular Converter

INTRODUCTION

DC's roles in power delivery and in power consumption has grown significantly over the past several decades; driven by economics, innovation and changes in energy priorities. DC transmission, once used only for long distance point-to-point requirements has become an integral part of large AC networks and now promises to overlie those networks in Europe and North America. Furthermore the dramatic growth in electronic loads, LED lighting, and automobile charging load have suggested to many that at least a share of the power delivered to households and businesses should be DC.

DC's role has grown despite the lack of a DC equivalent to the AC transformer - responsible for AC's early leap to prominence. Transforming between HVDC voltage levels now requires first inversion to AC, magnetic transformation to a new AC voltage, then reconversion to DC. The importance of a more economic DC-to-DC transformation method, analgous in performance within a DC system to that of a magnetic transformer in an AC system, is now well acknowledged by system planners [1]-[4]. It is also reflected in an increasing number of publications directed to that goal [5]-[10].

Adapting to HVDC the capacitive transformation methods common at electronic levels is not easy. At very low voltages efficiency demands are more lenient, available switching devices different and insulation requirements less important. The authors' search for a high voltage capacitor-based DC transformer (DCT) suitable for applications, began with attempts to adapt those schemes to high voltage applications. A large number of capacitor-based transformations were first explored with simple energy exchange models; then with PSCAD representation to determine transient behaviour, switching demands, control issues, and compatibility with component architecture commonly used in LCC and VSC converter design. This work led to a design based in capacitor bypassing strategy that satisfied all the requirements felt necessary for a DCT effective for commercial introduction.

A more efficient DC-to-DC power transformer could serve a host of other purposes in the rapid growth of DC as a form of energy delivery, utilization, and even generation. Potential applications include:

1. Interconnection of HVDC lines of different voltages, grounding systems, or commutation mode (i.e. LLC to VSC).
2. Power flow regulation between HVDC circuits or within a DC grid
3. Voltage boost in long DC transmission lines
4. Wind farm and solar plant interconnection to DC grid
5. Economic taps of moderate power levels from HVDC lines
6. Industrial DC voltage conversion.
7. Residential & commercial load-serving equipment

PERFORMANCE REQUIREMENTS

An optimal DC-to-DC transformer (DCT) will perform within a DC system in a manner functionally equivalent to the way an AC transformer does in an AC system. However rather than a continuous magnetic transfer of energy from primary to secondary busses as possible with AC, a DCT must depend on discrete transfers of charge using capacitors, inductors and solid state switches. In order to be generally useful, it must:

a. Be capable of high MW ratings.
b. Have an efficiency comparable to Voltage Sourced Converters
c. Change power flow in response to changes in relative primary and secondary voltages *without a power control signal*. Need for such a signal would require very complex control interactions between the DCT and converter terminals of the effected DC lines.
d. Be capable of regulating flow by use of external controls just as an AC transformer does through tap changes.
e. Achieve bidirectional flow.
f. Result in relatively smooth input and output current without a large filtering burden.
g. Be modular in structure to reduce cost of manufacture, increase design carry-over from one project to the next, and provide interruption-free redundancy in the event of component failures.
h. Operate such that modules equally divide pole-to-ground voltage to minimize switching and insulation costs.
i. Provide primary and secondary fault isolation and accommodate both internal faults and faults on either terminal.
j. Be comprised of components already part of modern MMC-VSC, e.g. half-bridges or their equivalent. This will save time and cost in prototype prove-in, lower manufacturing cost, and provide reliability carry-over.

FUNDAMENTALS OF CAPACITIVE TRANSFORMATION

Based on the requirements cited above, the authors have explored and evaluated a wide range of capacitive transformation schemes and developed one that meets all of the requirements cited above. The proposed transformer scheme is based on a relatively simple series column of capacitive modules which is charged resonantly through a reactor from a primary bus and discharged resonantly through a different reactor to a secondary bus. Losses are minimized with soft switching by breaking connection with either bus at the first resonant current zero. A brief review of capacitive change principles will help in explanation of the MMDCT's operation and features.

The energy content in Joules of each pulse exchanged between a capacitor and source is:

$$\Delta E = \frac{1}{2} C \cdot (V_2^2 - V_1^2) \qquad (1)$$

Where V_1 and V_2 are the capacitor pre-and post-charge voltages respectively. In this case the pre- and post-charge voltages of the column are $(1-k)\cdot V_{dc}$ and $(1+k)\cdot V_{dc}$. Therefore equation (1) can be expressed as:

$$\Delta E = 2\cdot k\cdot C\cdot V_{dc}^2 \tag{2}$$

The MMDCT achieves transformation by alternately receiving a current pulse from one bus; then delivering a current pulse to another through the line switches (LS) as shown in Fig. 1 which also illustrates input and output current waveforms. The line switches must be bi-directional to allow the current flow both ways. To maximize energy exchange, the frequency characterizing both input and output charge exchange should be as high as practicable. Since the effective total capacitance of the columns differ between charge and discharge cycles, the reactors on each side of the MMDCT must be different if those frequencies are to be the same. If power output is delivered resonantly to or from the MMDCT with frequency of $f=\dfrac{1}{2\pi\sqrt{LC}}$, where C is the equivalent capacitance of the total capacitive column at the time of charge or discharge, then for a given pre- and post-discharge voltage on C;

$$P \propto k\cdot\sqrt{\frac{C}{L}}V_{dc}^2 \tag{3}$$

The current waveforms represented in Fig. 1 would obviously be challenging to filter to smooth DC. However if three or more MMDCT columns are placed in parallel and caused to generate equally spaced pulses, then in addition to smoothing both output and input waveforms, the compound MMDCT group increases its megawatt transfer capability proportionally. Fig. 2 illustrated this for three parallel MMDCTs each of which contributes overlapping current pulses offset by 120 electrical degrees at the charge or discharge frequency. Smoothing to that extent requires that charging and discharging frequencies be equal. Together they present a waveform with very low sixth harmonic ripple of the switching frequency and at the same time increase the power cited in (3) by a factor of three.

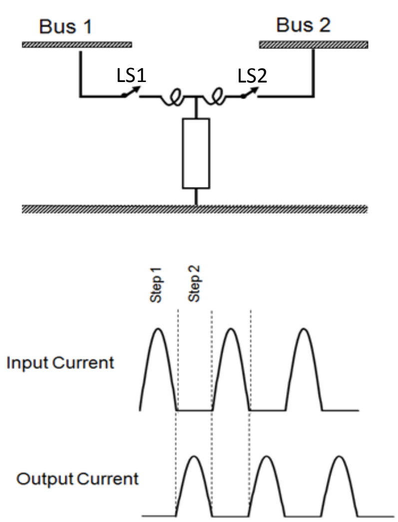

Figure 1 MMDCT transfer principles

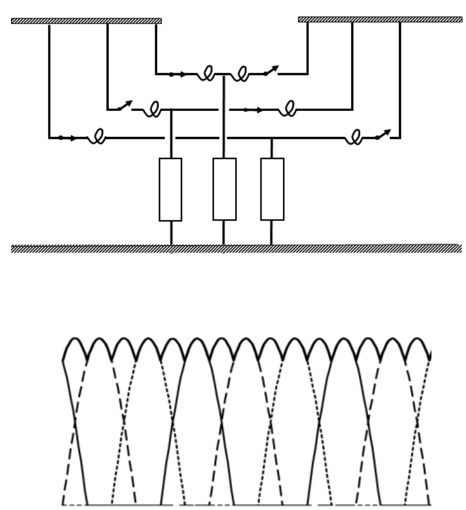

Figure 2 Parallel MMDCTs to smooth input and output waveforms

In practice, the line switches in each MMDCT operate in a complementary manner, i.e. when one is closed the other will always be open, thus always providing galvanic isolation between the two high voltage DC nodes. Since line switching occurs at current zero, a back-to-back thyristor may be a used to achieve higher ratings and lower losses.

A MULTIMODULE DCT (MMDCT)

Equation (1) illustrates that the *direction* of the energy transfer into or out of a capacitive column depends on the difference between the voltage to which it's previously charged and the voltage to which it is connected. Thus to affect transformation, a capacitive column must be configured to present to an input bus, through the complimentary inter-bus switches shown in Fig. 1 and 2, a voltage *lower* than the voltage of that bus and then, by reconfiguration, present to the output bus, a voltage *higher* than the voltage of that bus.

Suppose that the capacitive columns of Fig. 3 are comprised of n half- or full-bridge modules, as shown in that figure. Each such module contains a capacitor (C_{SM}) which can be electrically inserted into a column or bypassed and electrically removed from it. Thus at any given time capacitors in a column associated with m of the n modules can be bypassed while $n-m$ are electrically part of the series column. Assume further that $V_1 < V_2$ and n and m are selected such that the ratio $(n-m)/n$ is exactly equal to a voltage ratio V_1/V_2 and, further, that when connecting to higher voltage bus, all capacitors are in the circuit but when next connecting to lower voltage bus, m capacitors are bypassed. Therefore, the equivalent capacitance of the series column connected to low voltage and high voltage busses are $C_{SM}/(n-m)$ and C_{SM}/n respectively. A capacitive column is rated slightly higher than V_2 due to the voltage variations of the capacitors. The current flow amount and direction depends on the voltage and charge variations of the capacitors in each cycle.

Although the actual number of the bypassed capacitors must remain equal to m for a given voltage ratio, the bypass role must be rotated among the submodules in the column to balance charge and voltage variations. This is a commonly used charge equalization process called "sorting". Sorting in one half cycle of charging or discharging is well adapted to high voltage ratios. For low voltage ratios the bypass role can be rotated among capacitors from one cycle to the next so that, despite some variations in voltage, the voltage of all capacitors remains within reasonable and stable bounds.

Several characteristics of the MMDCT described above will be apparent:

- The MMDCT operates without a need for a power control signal.
- MMDCT has high eficiency. Basically the losses consist of the submodules and line switches conduction losses during the operation and the rotational submodule switching losses while the capacitive column is connected to the lower voltage bus. The line switching occurs at current zero, and no submodule switching occurs while the capacitive column is connected to the high voltage bus.
- Varying m during operation will allow the MMDCT to serve either as a means of flow control or of voltage boosting.

- Where an MMDCT is used to tie an LCC system to an VSC based system the MMDCT modules would simply make use of full bridge modules rather than half-bridges modules shown in Fig. 3.
- The number of capacitive modules provided in the column may exceed the number used in the process described above in order to be inserted to replace failed modules; thus increasing reliability.

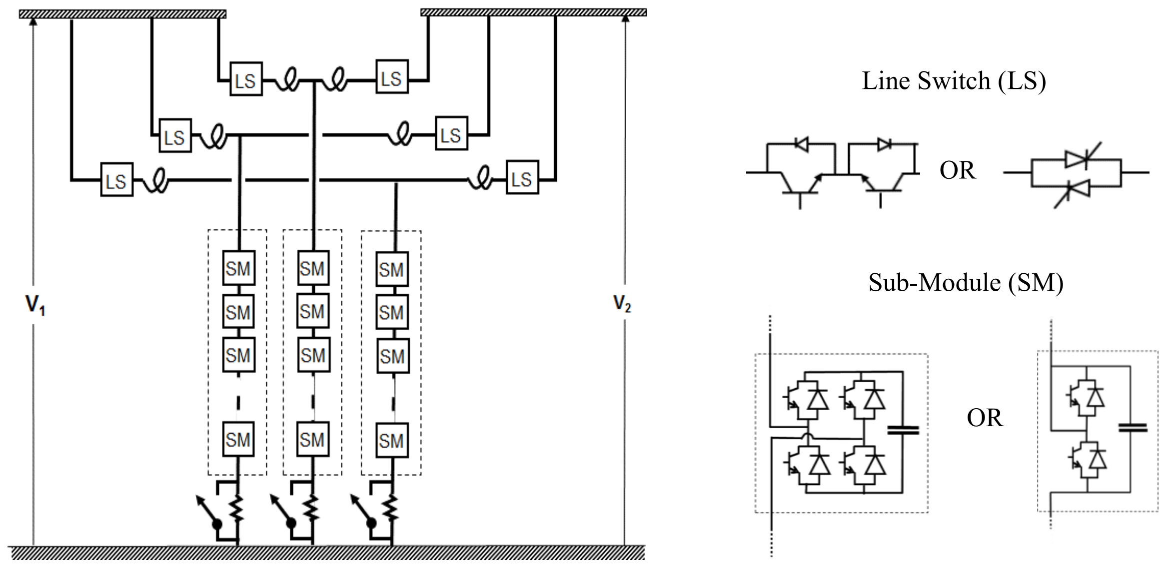

Figure 3 – Circuit diagram of the MMDCT. Options for line switches (LS) and sub-modules (SM) in capacitor column are shown

The capacitive filters at the terminals of MMDCT will effectively decouple the impact of the line impedance on the resonance frequency and it will also reduce the voltage and current ripples. Moreover if MMDCT connects two high voltage DC lines, the small current ripples generated by MMDCT will be filtered at the converter side by transmission line inductance.

MMDCT Performance Start-up and Power Changes

Assume that the MMDCT connects two DC lines with different voltages; each in VSC HVDC applications. Assume further DC voltage is controlled by the converter on the low voltage side of the MMDCT and the power is controlled by the converter on the high voltage side. Power flow in a DC line depends on the voltage difference between ends of the line and the line resistance. When the converter power order is changing, its voltage changes accordingly and thus controlling DC current flow.

During start-up the MMDCT column is charged by V_2 through a resistor temporarily in the circuit at the base of the column, to prevent an initial resonant over-shoot of capacitor voltage. Thus with all capacitors in the circuit at startup, each is charged to V_2/n. The resistor is then bypassed for normal operation. When power flow in both the lines linked by the MMDCT is zero, line voltage is equal to rated DC voltage over the length of each. Suppose that within the MMDCT column, m and n have been chosen with respect to the two nominal line voltages V_1

and V_2 such that at those voltages no power is transformed from one line to the other. Suppose however that the voltage on high voltage bus drops to *less* than V_2. Now connection of the column to that bus will cause a resonant charge transfer from the column to that bus reducing each capacitor's voltage to *less* than V_2/n. Then when $n-m$ capacitors are connected to the low voltage bus, charge will be transferred from that bus to the capacitor column. Since DC voltage is controlled to be constant by the low voltage side converter, current flow through the MMDCT will cause the low-side voltage to decrease too, thus keeping the ratio of voltages constant. With this process power is transferred from the low voltage bus to the high voltage bus. It is apparent that if the voltage on high voltage bus becomes *greater* than V_2, power will flow from the high voltage bus to the low voltage bus. Thus transformation of power between two high voltage nodes responds to variations in DC voltage of primary and secondary nodes based on system requirements without the need for a power controller.

MW TRANSFER CAPABILITY

According to (3) it is apparent that, for a given frequency and capacitor discharge ratio within a feasible range, power is maximized when the equivalent discharge capacitance is high and the discharge inductance is low, suggesting use of air-core reactors such as are used in wave-traps, the latter having inductance in the range of 200 mH. To minimize the capacitor size, the operating frequency has to be as high as possible. Once L and C are fixed, power flow is changed by rate of change of energy stored in the capacitors.

CASE STUDY: INTERCONNECTION OF TWO LARGE HVDC LINES

The foregoing MMDCT characteristics were modeled in detail using PSCAD software to assure operation in accordance with the principles and equations cited above. Fig. 4 illustrates MMDCT connection of two VSC HVDC systems, each using a symmetrical monopole configuration [11]-[13] . DC voltage is controlled by the LV converter, rated at ±320kV and real power is controlled by the HV converter, rated at ±400kV. The DC lines connecting the converters to the MMDCT are 200km on each side. MMDCT parameters for this case are listed in Table 1.

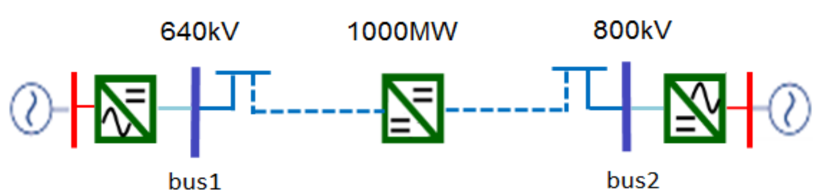

Figure 4 – Interconnection of two large HVDC lines via MMDCT

Table 1 MMDCT parameters

Rated power	1000 [MW]	HV inductor	0.024[H]
Primary voltage	640 [kV]	LV inductor	0.015[H]
Secondary voltage	800 [kV]	Maximum voltage deviation	10%
Sub-module capacitance	2600 [μF]	Cycle frequency	400 [Hz]
Number of sub-modules per column	400	Rated voltage of sub-modules	2 [kV]

Fig. 5 shows dc currents, voltages and power at bus1 and bus2. The figures illustrate a power exchange ranging from +1000MW to -1000MW. Note that the ripples that might otherwise appear on input and output currents of the MMDCT are effectively filtered by the line inductances and that the converter-side currents, shown in fig. 5, are smooth. Figure 6 and 7 shows input and output currents as well as the capacitor column voltage of each branch during power changes and steady state respectively. Fig. 8 shows a sub-modules capacitor voltage in one branch of the MMDCT. The capacitor voltage deviation at full power transfer is 10%.

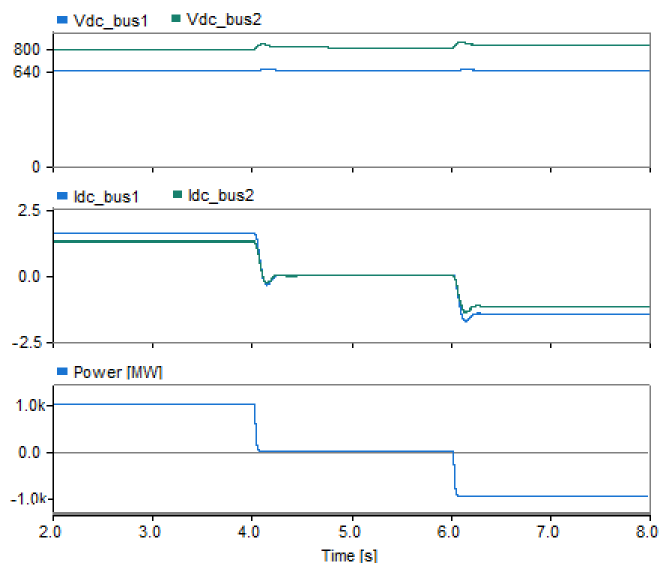

Figure 5 – DC voltage, current, and transmitted DC power at bus 1 and 2

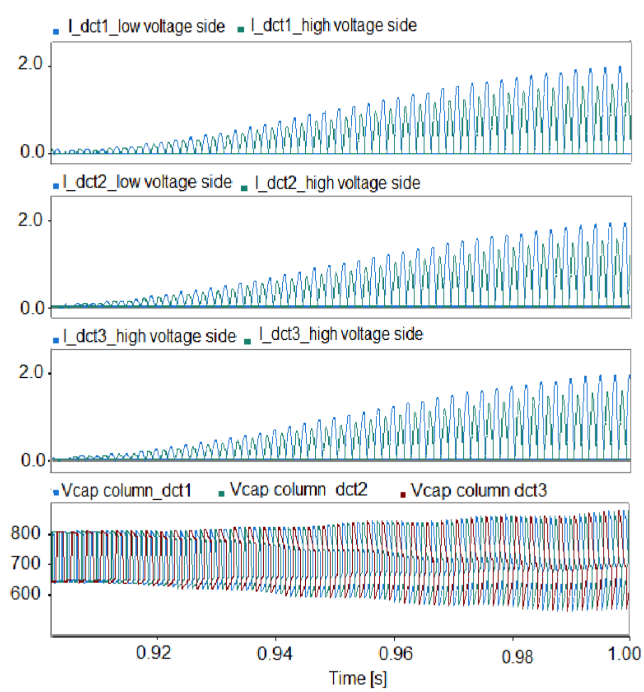

Figure 6 Input and output currents and capacitor column voltage of each branch during power changing from 0 to 1 pu

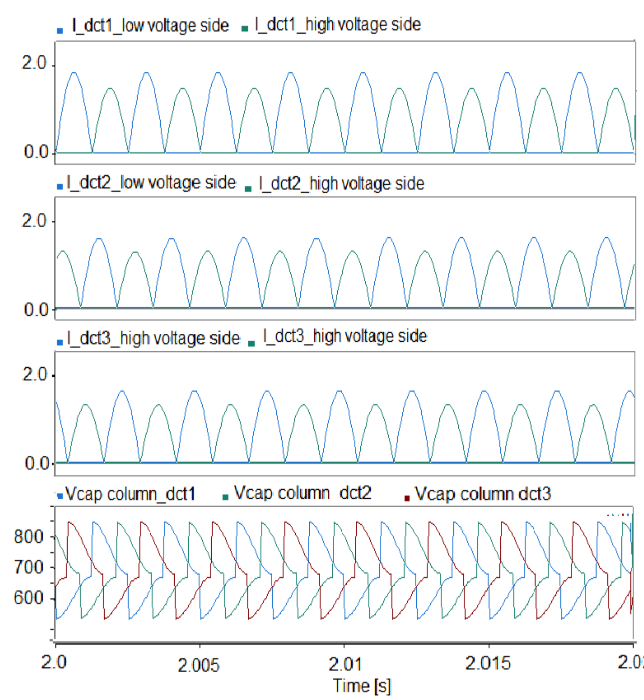

Figure 7 Steady state input and output currents and capacitor column voltage of each branch at 1 pu power transfer.

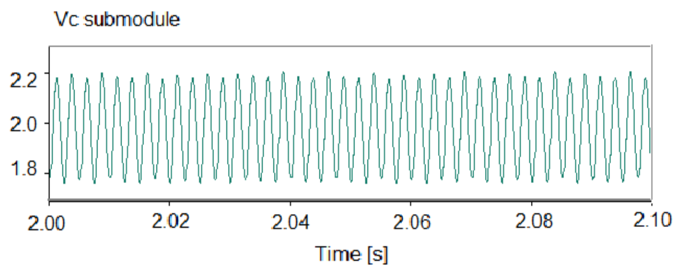

Figure 8 –The capacitor voltage of a sub-module in one branch of the MMDCT

COST CALBRATION

Estimated costs of an MMDCT can be derived by comparison with the components of a single MMC Converter of similar rating [13]. Cost benefits of the MMDCT accrue over a similar rated MMC converter. Important points of comparison are:

1. No transformer
2. Smaller capacitor size due to higher operational frequency
3. Half the number of valve arms but with a similar number of sub-modules in each of three column compare to the number of submodules in each of six valve arms in an MMC converter
4. No ac switchyard but possible minimal dc filtering
5. No external control for power flow
6. The additional equipments needed in an MMDCT compared with an MMC converter are:
    a. Six air core reactors
    b. Six bidirectional solid state switches which can be constructed of bidirectional thyristors
    c. Three resistors and by-pass switches for start-up which can be mechanical switches

Similar facilities an MMDCT will have compared to an MMC converter include a valve hall, sub-module cooling, auxiliary power, control and protection, civil works, project engineering and administration, small rated dc filters (one each side of the MMDCT)

CONCLUSION

The ability to economically transform energy between dc voltages will accelerate the development and usefulness of HVDC Grids and may expand dc's role in wind-energy and potentially in distribution to points of energy use. This paper shows that it is possible to build a capacitor-based dc-to-dc transformer that performs, within a dc system, exactly as a magnetically-based transformer does within an ac system except responding to voltage difference rather than phase angle difference. That transformation can, as with ac, be bidirectional and respond to system demands without a power control signal. In this scheme, existing, commonly-used components and substructures can support ratings in excess of 1,000 MW at an efficiency of approximately 98%.

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Adapting the controls of Rio Madeira HVDC transmission systems to improve the frequency stability of generators in Jirau and Santo Antonio power plants

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ABB	ABB	ONS	ONS
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SUMMARY

The Santo Antonio and Jirau dams on the Rio Madeira River are two very large hydroelectric plants located in the Amazon basin near the borders of Bolivia and Peru with combined generating capacity of 6600 MW. Jirau and Santo Antonio power plants were constructed with small reservoir, run-of-river design, using a large number of low head bulb type turbines with small power rating and low inertia. The generating stations are connected to a 500 kV AC collector system which operates asynchronously from the local AC power systems. A small portion of the electrical power is used to feed local load in the Acre-Rondônia 230 kV AC system which includes two state capitals of Porto Velho and Rio Branco, via two 400 MW Back-to-Back HVDC blocks, installed at Porto Velho. The surplus electrical power is transmitted to load centers in South-Eastern in Brazil over two 2375 km HVDC bipolar transmission lines. Each Bipole is rated 3150 MW/±600 kV.

A Master Control and Generator Station Coordinator has been provided to coordinate the power transmission on the two HVDC bipolar links and the two Back-to-Back converters based on the dispatch and generation capability of the Santo Antonio and Jirau power plants. The Master Control also coordinates various actions involving components installed in the two converter stations, including converters, harmonic filters, reactive power compensation, number of generators and outgoing lines, and also acts as a protection to avoid critical operating configurations that could result self-excitation of generators in the Santo Antonio and Jirau power plants, overvoltages or frequency excursion of the generators outside the acceptable range. Additional controllers have also been added to keep the frequency excursion of generators within the normal range during system disturbances involving a sudden drop in generation or reduction of power transmission. The Master Control thus provides fast open loop adjustment of major system parameters to ensure that the system is near an ideal operating point. However, the Master Control cannot influence the stability of the operation at a given condition. This is must be achieved by the coordinated actions of the DC converter controls and the turbine governor controls of the generating stations.

The initial operation of Rio Madeira HVDC transmission showed an unstable 0.15 Hz oscillation. Theoretical analysis and simulations indicated that the low head, especially during seasonal low water periods, increases the water time constant in the turbine governor controls making the machines inherently unstable when operating in against the constant load characteristic of the converters. Stable operation was achieved by modifying the load characteristics of the converters by adjusting the proportional gain of the frequency controller in addition to improvements in the governors at the power plants. This paper describes the adopted solution introduced in the Bipole 1 HVDC control system.

KEYWORDS
HVDC, Power transmission, Rio Madeira system, Hydro Power plant, Speed Governor, Constant load, Power oscillation.

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1. INTRODUCTION

Electrical power from the Jirau and Santo Antonio hydroelectric power plants of on the Rio Madeira River, near Porto Velho, is transmitted to load centers in South-Eastern in Brazil over two 2375 km HVDC bipole transmission lines. Each Bipole is rated 3150 MW / ±600 kV. The Rio Madeira collector system also transfers power into Acre-Rondônia 230 kV AC system that includes two state capitals of Porto Velho and Rio Branco, via two Back-to-Back HVDC blocks of 400 MW each, installed in the Rio Madeira collector substation in Porto Velho as shown in Figure 1.

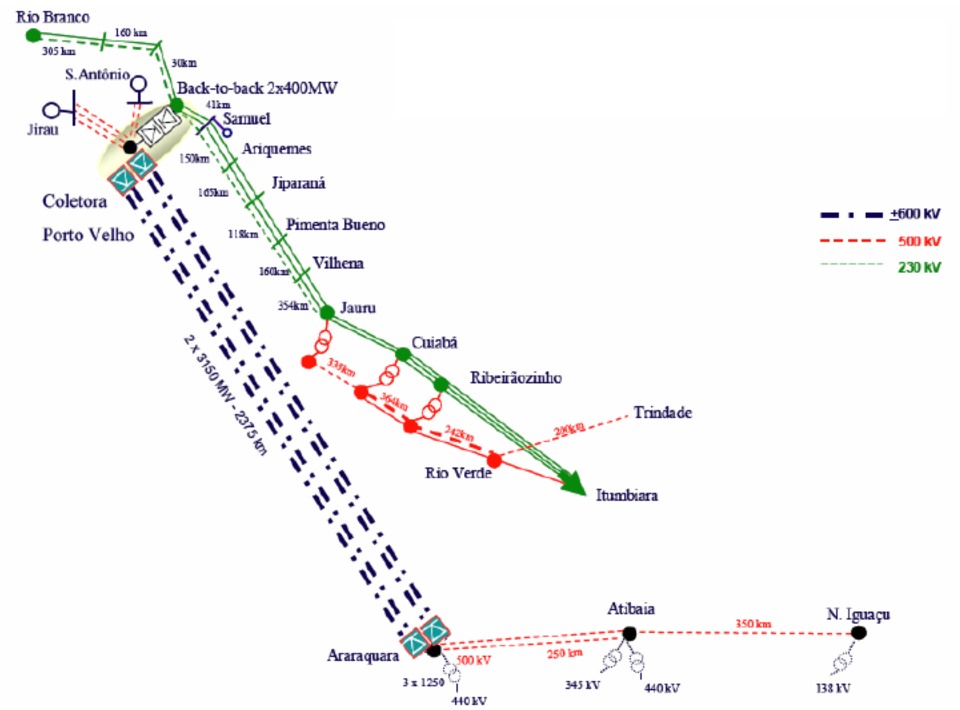

Figure 1: Integration of Rio Madeira power plants into the Brazilian electrical system using HVDC transmission systems

The Santo Antonio power station includes 44 generator units (total installed capacity of 3150 MW) and the Jirau power station includes 50 units (total capacity of 3450 MW). For environmental reasons, both power plants were constructed with small reservoirs, necessitating the use of run-of-river turbines. The low head bulb type turbines with small rating and low inertia have a considerable influence in the design of the controls of the HVDC transmission system. A fast Master Control to coordinate the transmission and generation and a suitable frequency controller are examples that will be described in the paper.

A particular characteristic of the Rio Madeira transmission system is that the generation was divided into several lots during the public auction. As a result, the lots are owned by a number of entities. Each entity has chosen its own generator supplier. Therefore, the overall system includes different designs for each of the lots which provided additional engineering challenges not only for the operation but also during the design of the controls.

One of these challenges is related to the frequency stability of generators in Jirau and Santo Antonio power plants. As the converters are seen by the generators as a constant load, this will impose special requirements on the design of the speed governor of turbines as well as on the design of HVDC controls. Controls of the HVDC transmission have a frequency range over which could have beneficial effects over the small-signal frequency stability of generators in Jirau and Santo Antonio power plants, in special for the low frequency governor related oscillations.

Experience obtained from initial operation of Rio Madeira HVDC transmission and confirmed in theoretical analysis and simulations shows instability phenomenon for the frequency oscillation associated with the interaction between turbine-generators and converters. A 0.15 Hz oscillation was observed in the operation and during tests. The instability was observed to be influenced by very large variations in the seasonal flow of the river, and variation of the water flow, available head, transmitted power and number of converters in operation.

Mitigation measures had to be introduced in the controls of HVDC converters in order to increase the damping for this mode of oscillation, and measures were also introduced in the speed governors of the power plants that are described in the paper. This paper describes the solution implemented in the controls of the HVDC transmission system and demonstrates that this solution will ensure satisfactory and stable operation of generators. The evaluation of the proposed solution was performed by simulation using digital tools, including frequency domain analysis tools, time domain transient simulation tools, real time simulators and finally system tests in the actual plant during commissioning.

2. THE RIO MADEIRA SYSTEM

2.1. The Santo Antonio and Jirau Generation Facilities and 500 kV AC Collector System

The Santo Antonio and Jirau dams on the Rio Madeira are very large hydroelectric plants located in the Amazon basin near the borders of Bolivia and Peru. The two plants have a combined generating capacity of 6600 MW. They are intended to supply electrical power to small local loads in the Acre-Rondônia area through the two Back-to-Back HVDC blocks of 400 MW each, and the energy surplus is to be transmitted through two long distance HVDC transmission links to the load centers in the southeastern state of São Paulo.

An important characteristic of the Rio Madeira generation is the run-of-river design of the turbines. The low head turbines and very small reservoir, using the natural range of water levels of the river gives the generating plants two special features. One is the use of bulb turbines of small rating and very low inertia; the other is the very large seasonal flow variations of the river, which affects the capability of power generation. These two main features had a significant influence in the detailed design of the transmission system.

The Rio Madeira generation complex includes the hydroelectric plants at Santo Antonio and Jirau. The generating stations are each connected to the Porto Velho converter station via three (3) 500 kV AC lines from Jirau and four (4) lines from Santo Antonio. The Santo Antonio plant is about 10 km away from the Porto Velho rectifier converter bus and Jirau is about 120 km away.

The HVDC transmission system and 500 kV collector system design has to take into account the large variations number of machines in the isolated generating collector system, from a maximum of 94 machines in operation to a minimum of twelve, or even fewer machines in operation at well below rated power. Master Control is introduced to handle the balance between generation and transmission during contingencies as one of key tasks.

Presently, Jirau includes a black start facility in some of generators units in order to initiate transmission against HVDC transmission (Back-to-Back or Bipole). When initiating the transmission with reduced number of generators a shunt reactor is used to compensate the charge of the AC transmission to Jirau. This will prevent self-excitation of the generators in Jirau. The reactor can be connected to any of the existent three transmission lines between converter station and Jirau power plant.

In the future the black start facility will also be available in some of the generators in Santo Antonio that will increase the operating flexibility of the system.

2.2. The Transmission System

2.2.1. The Back-to-Back Converter Station

Two Back-to-Back HVDC converter blocks of 400 MW each are used to connect the 500 kV Rio Madeira collector system to the Acre-Rondônia 230 kV network system. This decouples the 230 kV system from the 500 kV collector system and reduces the disturbances to the local system from the bulk power transmission links to São Paulo. This helps ensures reliable power transfer to the main load centers in Acre and Rondônia, including the two state capitals of Porto Velho and Rio Branco.

Capacitor Commutated Converters were selected for the two Back-to-Back blocks to avoid the use of synchronous condensers that had been planned to be installed at the 230 kV inverter converter bus to strengthen the Acre-Rondônia system, as the network is relatively very weak for the operation of conventional Line Commutated Converters. A Voltage Source type of Converter could be an alternative to the Capacitor Commutated Converters. This has been disregarded as the cost is considerable higher in a Back-to-Back configuration of converters.

2.2.2. The bulk power HVDC links

The bulk power system is comprised of the two ±600 kV bipolar HVDC links from Coletora Porto Velho to Araraquara 500 kV substation, each with a capacity of 3150 MW. The two Bipoles link the Rio Madeira 500 kV collector system and the main interconnected 500 kV AC network in southeast Brazil.

As part of the first Bipole (Bipole 1), a Master Control was installed to coordinate power transfer of the HVDC links and the Back-to-Back interconnections and the dispatch and generation capability of the Santo Antonio and Jirau power plants. The Master Control coordinates various actions involving components installed in the two converter stations, including converters, harmonic filters, reactive power compensation banks, number of generators and outgoing lines, and also acts as a protection to avoid critical operating configurations that may result self-excitation of generators in Santo Antonio and Jirau power plants, and overvoltages and frequency excursion of the generators outside the acceptable values.

3. DYNAMIC CHARACTERISTICS OF THE SYSTEM

3.1. Special Controls for the Porto Velho 500 kV AC Collector

Different types of turbines, generators and respective controllers (speed regulators and voltage controllers) have been used in Jirau and Santo Antonio power plants, with the result that these machines do not have identical behavior. For example, some groups of machines include turbines with 4 or 5 blades; three different types of voltage regulators have been used, and also different speed regulators. All these of these factors contribute to non-identical dynamic behavior between groups of generators.

In addition, all of the machine units feature run-of-river design, with very low head turbines due to very small reservoir, controlled in such a way as to not exceed the normal natural flood levels of the Rio Madeira River. The machines are bulb type turbines with very low inertia. Due to large variation in seasonal water flow, the system had to be designed to operate with a very large variation in the total number of machines in operation. Between wet and dry seasons, the number of machines in operation could vary from a maximum of 94 machines to minimum of 12 machines or even fewer in extreme low water conditions.

This very large variation in the total number of machines in operation and results in the need for coordination between the Bipoles, the Back-to-Back blocks and the generating stations, especially during abnormal conditions for the Rio Madeira system a major control function was need and included in high level hierarchy called Master Control. Main tasks for Master Control are to:

1) Optimize the re-distribution of the active power between Bipole 1 and Bipole 2 upon loss or limitation of HVDC transmission capacity below the transmitted power level in any of the Poles or Bipoles. Active power is also re-distributed from the Back-to-Back to Poles in operation upon reduction of the Back-to-Back transmitted power level due to loss or limitation of the Back-to-Back. This also may involve tripping of generators to avoid overspeed, to keep the equilibrium generation-transmission.

2) Balance the active power in the HVDC systems on the Porto Velho collector 500 kV AC bus with the total amount of generated power at Santo Antonio and Jirau. This means, ordering a so called “Runback” of the power transmitted in Bipole 1 and Bipole 2 in case of loss of generation or

collector transmission capacity. For similar reasons a Runback can also be ordered due to limitations in the amount of active power that can be received in the Araraquara inverter as a result of the network topology.

3) Avoid self-excitation of the generators in Jirau and Santo Antonio by limiting the maximum amount of shunt reactive connected to the 500kV busbars according to number of machines and network configuration.

4) Reduce potential overvoltages on the 500 kV networks by disconnecting or inhibiting connection of shunt capacitors or filters.

5) Balance and control the reactive power exchange between the HVDC converter stations and the corresponding network by operating the shunt capacitors or filters, while obeying the minimum filtering requirements of the two Bipoles or Back-to-Backs.

Moreover, an additional task included in the Master Control is the validation of the Operating Configurations when sharing equipment between the two Bipoles. For example: operating configurations as paralleling converter Poles, sharing an electrode, crossed operation and such status signals that are required to be exchanged between Bipoles.

3.2. Latency Time and its Countermeasure

As the HVDC transmission is the only load for the Jirau and Santo Antonio generating plants there needs to be coordination between the DC power order and the generator output. Balancing of generation-and load is a principal task carried out by Master Control together with Generator Station Coordination.

In case of a system or equipment failure affecting the power transmission or power generation the Master Control will act in cooperation with Generator Station Coordination to reduce the unbalance of generated and consumed active power.

If the HVDC capacity has been reduced (Pole or Bipole trip) the Master Control will quickly act by immediately provide a re-calculated value of the maximum amount of generated active power. The selection of generators to be tripped is made by Generator Station Coordination.

For the Master Control to issue an appropriate reduction of total transmitted HVDC power (called Runback) if generators are tripped, the total dispatched active power from all generators in service together with the number of generators in service are supplied to the Master Control.

Figure 2 below shows the main interfaces between Master Control and Generator Station Coordination.

Considering that the machines in power plants are relatively very small units compared to the transmission equipments, and particularly with very low inertia, they tend to accelerate or de-accelerate rather fast in case the balance generation-transmission is not quickly achieved. Because of this a good communication system between the generating plants and transmission system is required for a proper operation of the Rio Madeira. A fast and reliable communication between Generator Station Coordination and Master Control is necessary to balance generation and transmission in case of contingency. A delay in the communication system (latency time) between Master Control and Generator Station Coordination degrades the action to provide the open-loop correction to restore the equilibrium load-generation.

The Frequency Control included in the transmission also contributes to the balance between generation and transmission to reduce the excursion of the frequency during contingencies. In severe contingencies like outage of significant blocks of generation or transmission, it is necessary to quickly perform the power transmission reduction or cut of generation respectively performed by the open loop control included in the Master Control and Generator Station Coordination.

In Rio Madeira a low latency is used to reduce the impact on the system as it allows a fast open-loop correction. However, in the two possible scenarios listed below,

1) In case of loss of Pole or Bipole or even Back-to-Back block in the transmission system, and in this case it is required a fast removal of generating units in Santo Antonio and Jirau power plants without causing over-frequency of the remaining units,

2) In case of loss of significant blocks of generation and an order to run back the power transmission should be made quickly to prevent collapse of the voltage in the AC network and prevent the under-frequency of the remaining units,

the open-loop control action in the Master Control was found to be not a sufficient control measure to protect the generators and maintain the frequency within the tolerable deviation. The inherent latency time in the communication between Master Control and Generator Station Coordination and the margins resulted from the selection of generators to be tripped influence its performance. Therefore, the frequency controller in the HVDC transmission systems will then play the important role in both types of contingencies and, combined with the action from the high levels controller Master Control – Generation Station Coordination will help ensure the proper operation of the system.

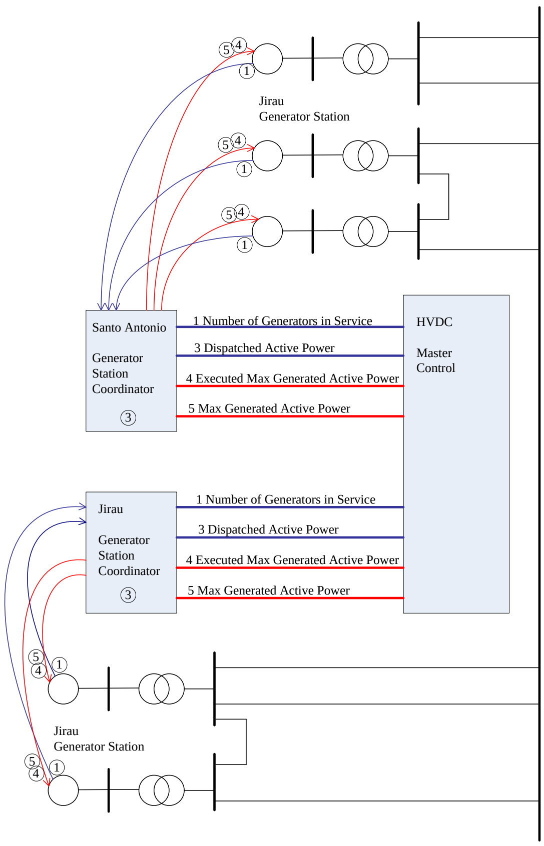

Figure 2: Main interfaces between Master Control and Generator Station Coordination.

3.3. Frequency Controls

The Frequency Control function included in the controls of the HVDC converters helps the relatively slow Generator Speed governors system to minimize frequency excursions during disturbances. The Frequency Control is based on proportional frequency control device in all four Poles. The Frequency Control measures the frequency deviation from nominal values and based on this deviation the regulator gives a power contribution to the Active Power Control in each Pole.

The integrating part of the Frequency Control is provided at a Bipole level in one of the operating Bipoles. It supports the primary frequency regulation of the 500 kV system in Porto Velho.

The Frequency Control on Porto Velho 500 kV side originally used in the Bipole 1 as shown in Figure 3 has the following main parameters:

- Integral part – time constant 10 seconds, and gain 1 pu MW (referred to Bipole basis, 3150 MW) / pu Hz (60 Hz basis). Through the supervision of Master Control the function can be activate or deactivated in the Operator Work Station.
- Proportional Part: Gain = 3 pu MW (referred to a Pole basis, 1575 MW) / pu Hz (60 Hz basis)

In the event of Back-to-Back is standalone operation (considering that either Bipole 1 or Bipole 2 may not be available) Frequency Controls is activated. In normal condition, having at least one Pole from Bipole 1 or 2 in operation, the Frequency Control is de-activated to prevent the interaction between the 500 kV network in Porto Velho and the fragile 230 kV system. The following parameters are used.

- Integral part – Gain 1 pu MW (referred to Bi-block basis, 800 MW) / pu Hz and time constants similar to that included in the Bipoles.
- Proportional Part: Gain = 1 pu MW (referred to block basis, 400 MW) / pu Hz (reduced gain)

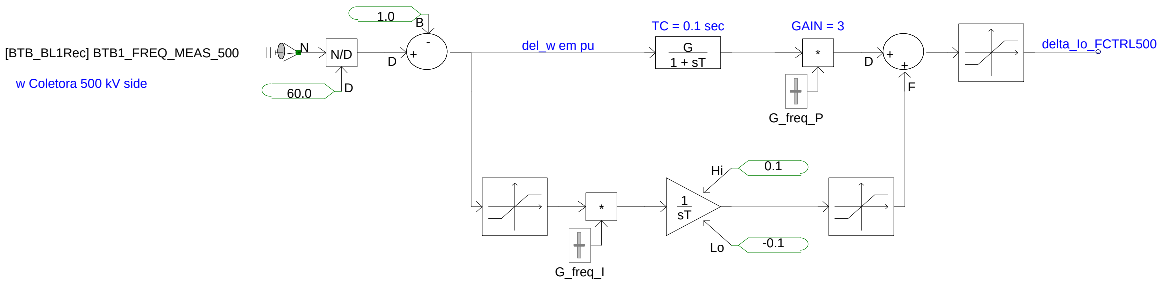

Figure 3: Frequency Control for the 500kV collector system implemented in the Bipoles and Back-to-Back

3.4. The influence of Weak Acre-Rondônia 230 kV AC network on the Stabilization of Jirau and Santo Antonio Machines

The power transfer from Jirau and Santo Antonio power plants to Acre-Rondônia network is made trough the Back-to-Back.

It should be noted that due to the arrangement conceived for the two power plants of Jirau and Santo Antonio leaded to adopt the Back-to-Back converter station to ensure reliable power transfer from the 500 kV Rio Madeira collector to Acre-Rondônia 230 kV system, taking the advantage of their asynchronous nature of the solution. This Acre-Rondônia network is characterized by long 230 kV AC lines (serving a distance that exceeds 1500 km), low generation and wide variation in loadings. The impedance of the network seen by the converter is influenced by variations in shunt compensation and the number of generators connected at the hydroelectric Samuel power plant, the closest major power generation in this network. The Samuel power plant is rated 250 MW, having in total 5 generator units. During wet season all the machines can be in operation, while during dry season there may be only two machines in operation, significantly reducing the strength of the network.

Because of the fragility of the 230 kV AC network, a major design consideration was to limit the actions from the Frequency Control of the Jirau and Santo Antonio machines to avoid the risk of collapsing the 230 kV network during normal swings of machines in Jirau and Santo Antonio. It should be noted that Frequency Control of the collector system by the Back-to-Back is only activated in stand-alone operation of the Back-to-Back. In normal operation, Frequency Control of the collector system is via the bipolar HVDC as long any one or more Poles of the bipolar systems is available.

The proportional part of the Frequency Control used in the Back-to-Back has also reduced gain as compared to gains used in the Bipoles to limit the interaction between the 230kV and the 500 kV AC collector system.

3.5. Interaction Between HVDC Transmission System and Generators in Santo Antonio and Jirau Power Plants

The controls of the HVDC transmission have a frequency bandwidth which can be effectively used to provide beneficial effects over the frequency stability of generators in Jirau and Santo Antonio power plants.

In the normal constant power control, the converters are seen by the generators as a constant load and would have a neutral impact on the damping of unstable oscillation mode of the turbine governors. However by engaging the frequency controller the constant load characteristic of the HVDC is modified to include a frequency dependent negative droop (frequency increase causes load increase and frequency decrease causes load decrease) which will increase the damping of the unstable mode.

Figure 4 shows an oscillogram made in the plant during the initial phase of operation of Rio Madeira system. The black curve is the network frequency; blue curve is the generated active power; green curve is the opening of distributor of the governor of the turbine; and red curve represents the opening position of blades of the turbine.

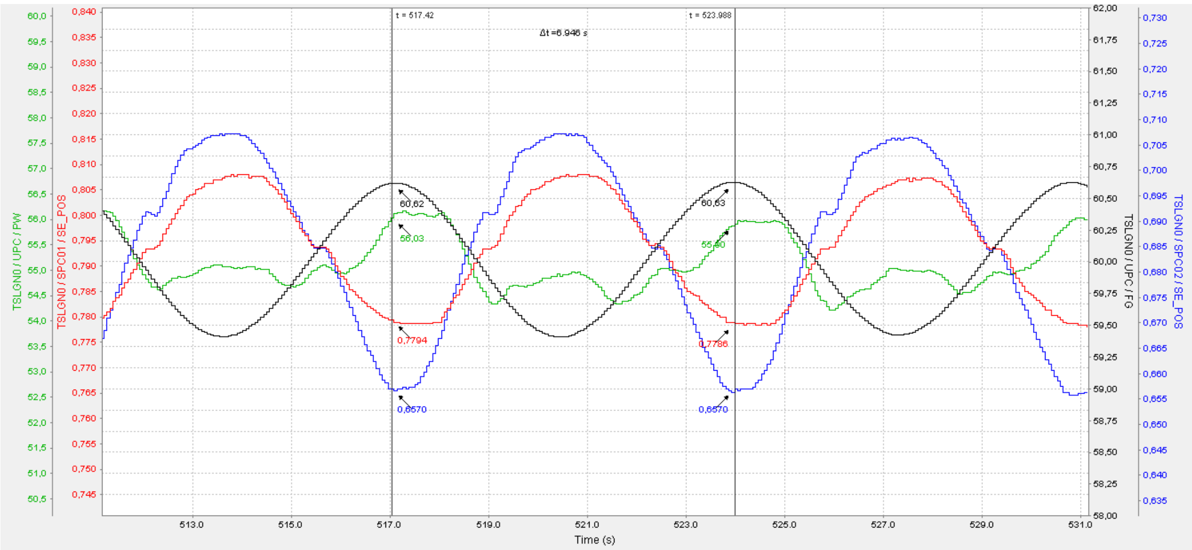

Figure 4: Oscillogram of oscillations observed during initial tests of the Rio Madeira system

The oscillogram shows there are low frequency (0.15 Hz) power and frequency oscillations in the network as seen by the measured frequency and power transmission associated with the interaction between turbine-generators and converters. The instability is influenced by variations in flow of the river, and variation of the water flow combined with head, transmitted power and number of converters in operation.

A theoretical analysis indicated that the oscillatory behavior observed in the plant is a characteristic of the bulb type of turbines used in Santo Antonio and Jirau power plants. Figure 5 shows a block diagram of the non-linear model of the turbine, where G is the position of the distributor, h is the net head, D is the damping, which is a function of the distributor position, and T_w is the water time constant.

An important characteristic of a bulb type of turbine, typical for run-of-river, is the low net head, which leads to relatively high values for the water time constant T_w. In Jirau and Santo Antonio plants, small reservoirs are used, which constrains the available head to the natural flood levels of river. Thus the net head can vary between the wet and dry seasons, affecting the water time constant T_w and consequently the response and the operating stability of the machines. The higher the net head h is the smaller is the water time constant T_w resulting a more stable condition for the machine. The impact of water level on the stability of the turbine-generators has been observed and confirmed in the real system at both Santo Antonio and Jirau power plants.

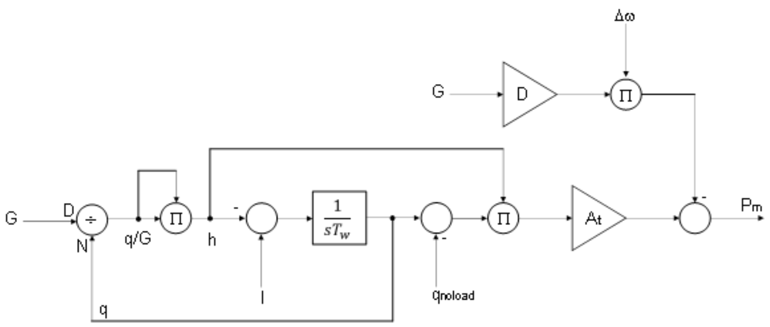

Figure 5: Non-linear model of the turbine

If a small signal theoretical analysis is performed using a simplified model of the governor of the turbine and a model of the HVDC represented by a constant power load seen by the machine, it is possible to draw the routes of the transfer function, as presented in Figure 6. It is clear that increasing the value of T_w which would make the natural oscillation mode more unstable.

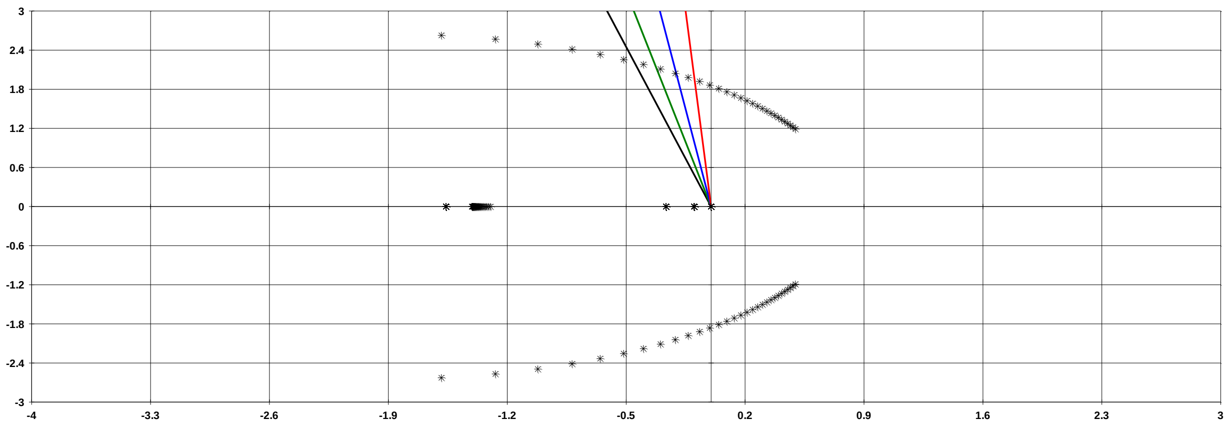

Figure 6: Geometric locus of the routs of the transfer function as function of T_w

The controls of HVDC converters were adjusted to increase the damping to this mode of oscillation. A Frequency Control included in the High Level controller of the HVDC converter changes the operating characteristics of the HVDC as constant power load by introducing a frequency dependent load component. Increasing the gain of the proportional part of the HVDC Frequency Control increases the damping of the mode while increasing the time constant of the integral part increases the damping as shown in Figure 7.

Based on the theoretical analysis and demonstrated in site tests it has been decided to increase the gain of the Proportional part of the frequency controller from 3 to 4 pu MW / pu Hz (pu MW ≡ 1575 MW and pu Hz ≡ 60 Hz) to increase the damping of the low frequency oscillating mode.

As a result of the variation of power generation capability due to seasonal flow variation of the river the number generators in operation in both power plants will vary. There are periods in which not many generators are in operation, and in the case of having only fewer machines the number of converters is also reduced when the capability of power generation is low. This normal operating strategy that is applied into the system has made possible to use a fixed parametric adjustment of the controls gains to provide sufficient apparent damping for different power transmission level.

In general the major portion of generated power is transmitted through the Bipoles. The required damping of the oscillating frequencies is provided by these converters. The Back-to-Back converters have normally the Frequency Control deactivated in this operating configuration. Having the Back-to-Back is stand alone operation against the generators, and then the Frequency Control is activated. Due to the fragility conditions of the Acre-Rondônia network it was necessary to use low gains in the control, and to avoid unstable operation additional number of generators was found to be necessary to have in operation, making them operating at reduced power.

Regarding the Integral Part of the Frequency Control it was not necessary to adjust the gain or time constant and these have been kept unchanged.

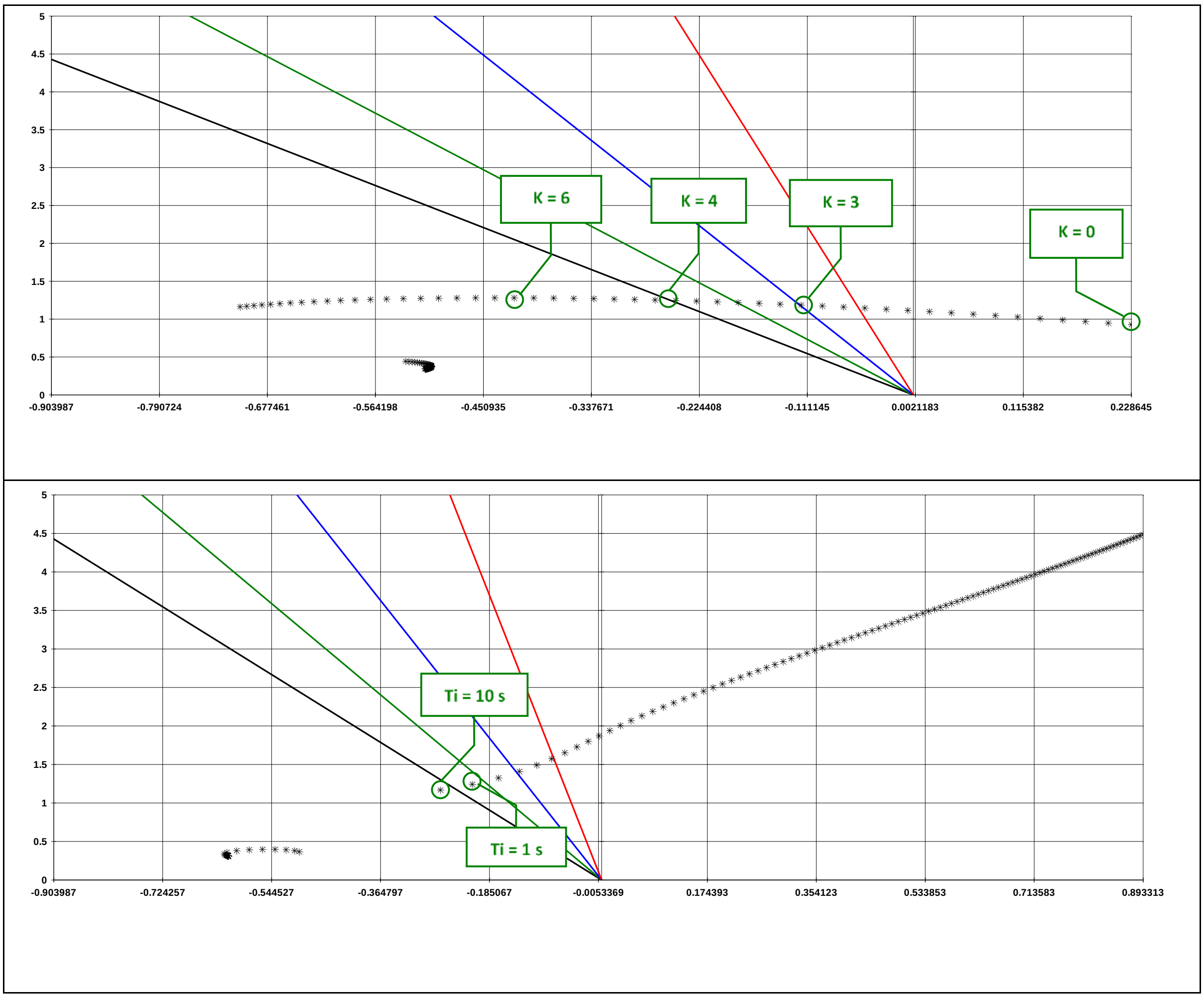

Figure 7: Influence of the Frequency Control in the damping of oscillating mode of the turbine-generator. Figure on the top: Oscillating mode as function of the P-Part gain of the HVDC controller; Figure on the bottom: a function of the I-Part and time constant, assuming constant proportional gain (P-Part = 4 pu MW / pu Hz)

Some measures were also introduced in the speed governors of the power plant in order to increase the damping for the low frequency mode of oscillation. Similar linear analysis has also been made to verify the influence of the gains of the regulator and the conclusion was that a lower proportion gain increases the damping to this mode of oscillation [3]. This has been made to complement the overall adjustment introduced in the system.

The evaluation of the performance has been made in the RTDS (Real Time Digital Simulator) where a replica of the controls of the Rio Madeira HVDC transmission system has been installed. Also, a model of the generators of the hydroelectric power plants of Jirau and Santo Antonio was also included. In Figure 8 is shown a test where Bipole 1 is transmitting nominal power, 3150 MW, and a fault is applied in one of the poles resulting a trip of this pole. As a result of the fault the following control actions take place:

- Use of the 1.33 pu overload capability (30 minutes) by the healthy pole;

- Master Control orders a reduction of 1055 MW in generation and an appropriate number of machines is cut by Generator Station Coordinators in Jirau and Santo Antonio

The purpose of the test was to demonstrate the overall stability of the system having introduced the changes in the converter controls and in the turbine governors. In that particular test case the influence of the Time Constant in the integral part of the Frequency Controller of the converters was under consideration. The result indicated very good stability condition of the system.

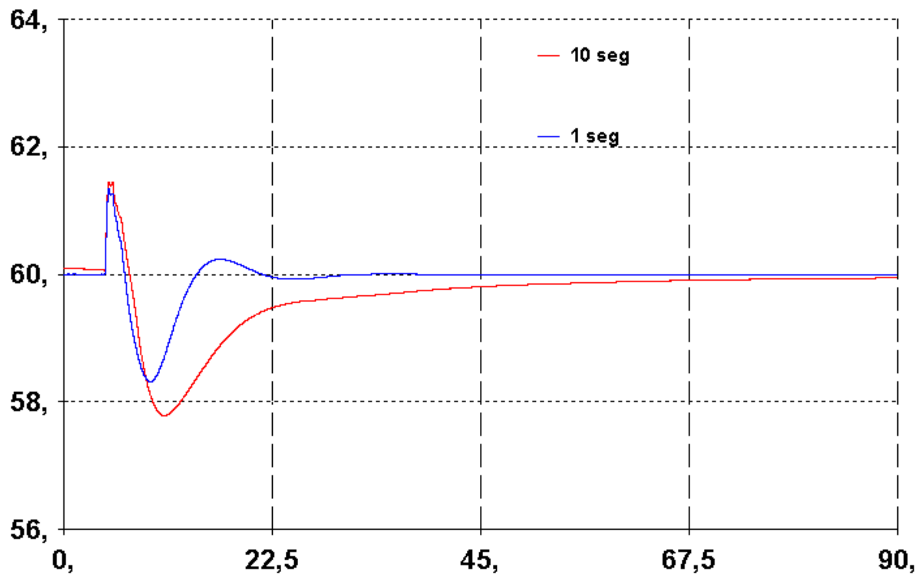

Figure 8: Test case made in RTDS to demonstrate an overall good stability condition of the system after applying the necessary changes in the controls of the converter and in the controls of the turbine governors of the generators. Contingency: loss of part of the HVDC transmission capability and consequent cut in the generation to reestablish the equilibrium generation-transmission

4. CONCLUSION

The Jirau and Santo Antonio power plants were constructed with small reservoirs, run-of-river low head bulb type turbines with small rating and low inertia. The collector system contains 94 generators, six 500kV lines, two bipolar transmission systems and two Back-to-Back converters as well as associated reactive compensation and filters. To help facilitate the operation of the system, a Master Control and Generator Station Coordinator were installed to coordinate converter station configuration based on the dispatches and transmission capability of both HVDC links and Back-to-Backs, and based on the dispatch and generation capability of both Santo Antonio and Jirau power plants. The Master Control coordinates various actions involving components installed in those two converter stations, including converters, harmonic filters, reactive power compensations, number of generators and outgoing lines. It also acts as a protection to avoid critical operating configurations that may result in self-excitation of generators in Santo Antonio and Jirau power plants, overvoltages and frequency excursion of the generators outside the normal values.

Besides these supervisory and protective features included in Master Control and Generator Station Coordinator to maintain balanced between generation and transmission, additional controllers have been added to keep the frequency excursion of generators within the normal range during system disturbances or sudden cut of generation or reduction of power transmission.

Thus, the Master Control provides fast open-loop adjustment of major system parameters to ensure that the system is near an ideal operating point. However, the Master Control cannot influence the stability of the operation at a given condition. This is must be achieved by the coordinated actions of the DC converter controls and the turbine governor controls of the generating stations.

Low frequency oscillations were observed in the system frequency and generator power during testing and initial operation. A theoretical analysis indicated that the instability could be traced to large reduction in seasonal water flow which reduced the available head at the power plants to the point where the turbine governors of the machines are inherently unstable when operating against a constant power characteristic of the HVDC systems. The studies also indicated that stable operation could be achieved by modifying the characteristics of the Frequency Control of the HVDC transmission systems to provide additional damping. The control parameters of the Frequency Controls were modified based on the analysis to mitigate the oscillation.

5. ACKNOWLEDGE

The authors express their sincere gratitude to Bruno Bisewski from RBJ Engineering Corporation from Winnipeg, Canada, for providing valuable comments and for reviewing this paper.

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Application of DC Breakers and Switches for the North-East Agra 800 kV HVDC Multi-terminal Project

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SUMMARY

This paper describes the application of breakers and switches on the d.c. side for the North-East to Agra 800 kV HVDC transmission project. As the project is a multi-terminal, bipolar transmission, with two rectifiers and two inverters per pole line, special consideration needs to be taken regarding switch configuration and sequences.

A multitude of operation configurations are possible; any of the rectifier(s) is able to operate with any of the inverter(s) of the same pole line, i.e. there are no dedicated rectifier/inverter pairs. The rectifiers are located in different stations (Biswanath Chariali and Alipurduar which are about 432 km apart) while the inverters are all located in Agra.

To ensure high availability, each converter need to be controllable as far as possible without interfering with the operation of the other converters. The connection and disconnection of the d.c. components in the transmission shall be fast, safe and independent of present operating configuration.

To achieve the above there are three main aspects to be considered that are specific for this project:

1. Converter to be connected to / isolated from d.c. transmission in a fast and reliable way with minimum disturbance to remaining d.c. network.
2. High voltage, high speed switches are subjected to a continuous voltage of 800 kV d.c. in this severely polluted area
3. Current stress of d.c. breakers/switches is dependent on configuration and manoeuvring sequence

The transmission system can be operated at nominal/full power with one converter out of operation as each converter is rated with a 33% continuous overload. To fully benefit from this capability the fault clearing sequence and isolation of faulty unit need to be quick and efficient.

Ultra high voltage across open switch in a polluted area is a challenge, especially as speed requirement doesn't allow to rely on traditional disconnectors, requiring a special solution.

The stresses of the switches are all dependent on location and use, very much different on pole (high voltage) compared to neutral. On neutral, a classic configuration of switches is chosen, however the stresses are dependent on operating configuration and chosen manoeuvring sequence. On pole, the operating voltage across switch and speed requirements sets the preconditions for the choice of configuration.

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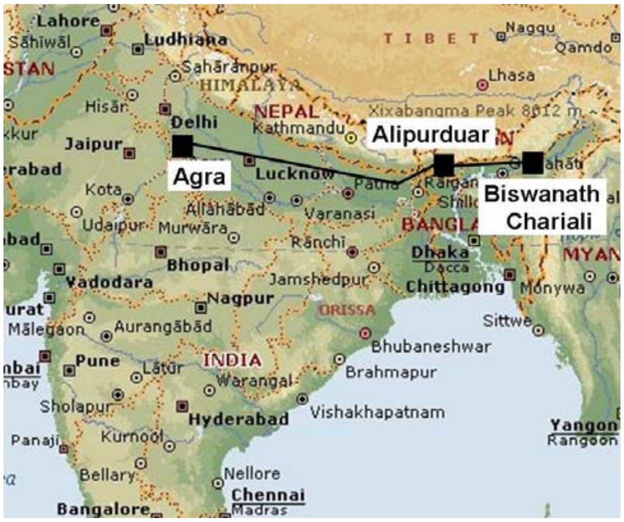
Further some aspects regarding manoeuvring sequences and how to ensure a current path when changing from ground return to metallic return and vice versa for the switches on neutral is discussed.

KEYWORDS

UHVDC – HVDC – Multi-terminal – Neutral – Breaker – DC Switch

1. INTRODUCTION

The UHVDC transmission from the North East region to Agra [1] is the first multi terminal operating at ±800kVdc in the world. It is also India's longest HVDC transmission, 1730km, and India's first at 800kV. A multi terminal and bipolar link transmitting 6000MW from two rectifier stations, Biswanath Chariali in Assam and Alipurduar in West Bengal**,** to one inverter station in Agra in Uttar Pradesh.



The four terminals, three converter stations, eight converters and three electrode stations are being commissioned during 2015 and 2016, ready to transmit 6,000 MW hydro power from the north-eastern parts of India to the region of Agra. Each converter has the capability of 33% continuous overload, i.e. 2000MW each, allowing for full power transmission also at an outage of one converter.

To fully benefit from this overload capability at an outage, the transition from one operating mode to another need to be smooth. A description of the switches and sequences needed is given in this paper.

2. DC YARD CONFIGURATION

The configuration of the d.c. yard shall allow for a smooth connection and disconnection of parallel converters, transition from ground return (GR) to metallic return (MR) and protective trip and disconnection of faulty converter or line with minimum of disturbances and power transmission loss.

The apparatus provided to fulfil the desired switching are shown in the below single line diagram.

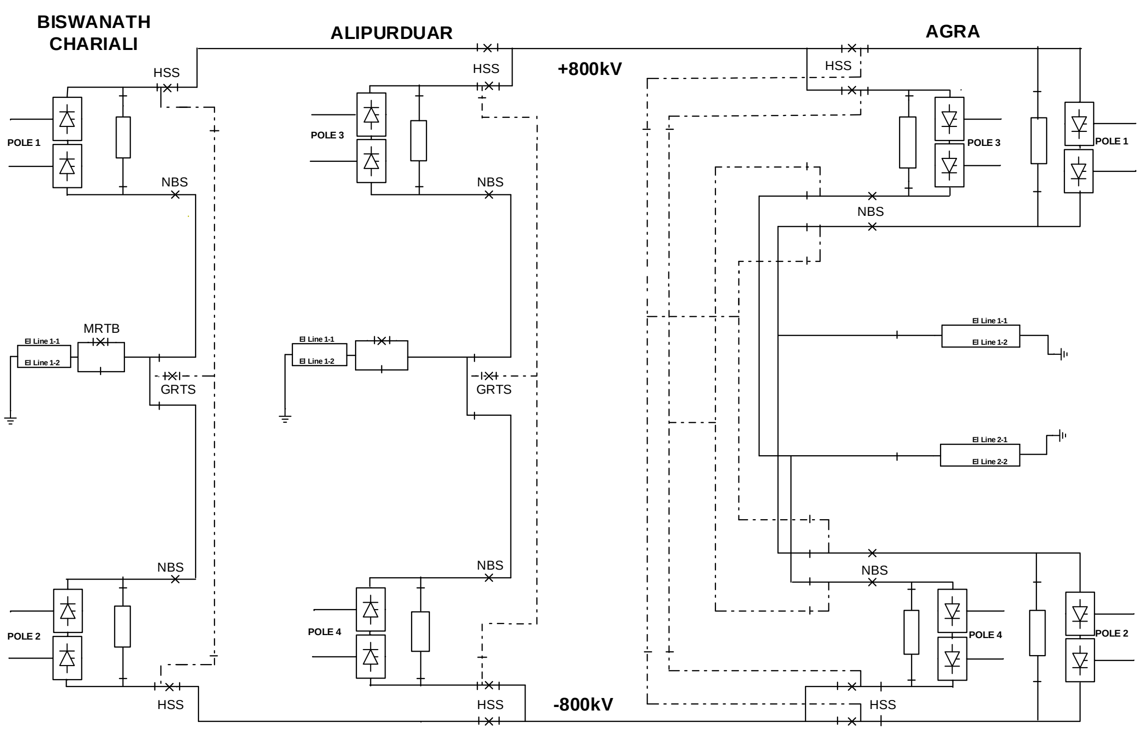


Figure 1 DC side overview of the multi terminal transmission

HSS – High Speed Switch, connects/disconnects the converter to/from the 800kV poles.
UHV disconnectors – for isolation of converter, d.c. line, d.c. filter or MR bus from the 800kV pole, which may still be in operation even though the converter is disconnected.
NBS – Neutral bus switch
MRTB – Metallic return transfer breaker, transferring current from electrode to metallic return path.
GRTS – Ground return transfer switch, transferring the current from metallic return to electrode line.

3. SWITCHES ON 800kV POLE

To connect/disconnect the converter from the 800 kV d.c. pole line, a combination of isolating disconnectors and fast acting high speed switches (HSS) are used. The HSS and disconnector are connected in the current path and may be subjected to full d.c. current and full d.c. voltage to ground in steady state.

The high speed switch allows for a safe connection to an energized pole line where the transmission is already in operation. It also enables a fast isolation of a converter or a faulty d.c. line between the two rectifiers, as soon as the current is extinguished by control actions, e.g. during a d.c. line restart action by the parallel rectifier.

Figure 2 High speed switch 800 kV (left) and disconnector800 kV (right, by courtesy of COELME) during factory testing

In a point to point transmission, the open disconnectors are not subjected to a continuous voltage of 800kV, as is the case in a multi-terminal transmission. The disconnectors are rated for 800kV d.c. across open contacts as well as to ground. The disconnectors are also serving as the HSS backup.

4. SWITCHES ON NEUTRAL

The d.c. breakers on the neutral are configured as in a classic point to point transmission, utilizing GRTS and MRTB in the rectifier stations [2]. However the imposed stresses on the d.c. breakers are dependent on the multi terminal configuration as the current from both rectifiers can be shared between the rectifier electrodes. Worst stress scenario is if Biswanath Chariali is operating in MR while Alipurduar is transferring from MR to GR. Then almost all current from both rectifiers will float through the GRTS, MRTB and electrode of Alipurduar to the electrodes of Agra. By completing the operating mode transition in Alipurduar before connecting Biswanath Chariali to MR, as is normally done, this worst scenario is avoided.

5. CONVERTER CONNECTION SEQUENCE

As easy as it seems there are some considerations that needs to be taken into account when connecting a converter pole to a d.c. line in operation. The ongoing power transmission is not permitted to be disturbed with this action and consideration also has to be taken to the voltage stress of the HSS.

When the d.c. line section Biswanath-Chariali to Alipurduar is connected to the operating transmission between Alipurduar to Agra, this section is pre-charged from the rectifier in Biswanath Chariali to approximate 90 % of the d.c. voltage. Seen from an apparatus design and system operation view this action is not required, however it will create less disturbances to the d.c. system, which is already in operation between Alipurduar and Agra, when the d.c. line section is connected.

6. CONVERTER TRIP SEQUENCE

To safely isolate a faulty converter requires a well-coordinated control and protection system. A close cooperation between the converter control and pole sequences is required in order to safely operate the d.c. switches. At trip of one converter the control system needs to extinguish the fault current before the isolation of the faulty equipment can be started. As soon as the current is below the design limit for the HSS of the faulty converter, opening is ordered and the power transfer can be resumed. At that instance the opening of the disconnectors, to achieve full isolation, is performed. The total transmitted power is resumed to pre-fault level, with a load flow rescheduled between the remaining converters (within their available overload capability levels). When the disconnector on each side of the HSS is opened the HSS will be closed again.

In the figures below the power transfer for all eight converters are shown at loss of one rectifier (Figure 3) and one inverter (Figure 4). Converters connected to the positive pole line is shown in the top of plots and converters connected to negative pole line in the bottom. The total time showed in the plots is 1 s.

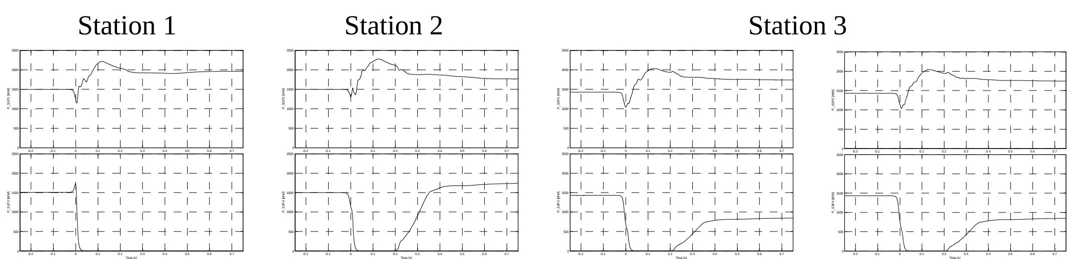


Figure 3 Trip of Biswanath-Chariali (rectifier) followed by isolation and system recovery.

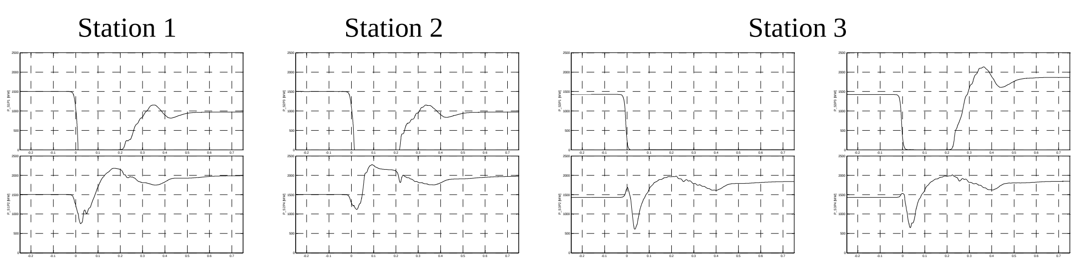


Figure 4 Trip of Agra (inverter) followed by isolation and system recovery.

7. TRANSFER BETWEEN OPERATING MODES

To avoid continuous current in the ground electrode when one pole in the multi terminal scheme is out of operation, the remaining pole can use the non-energized pole line as return path. As all transfer between ground and metallic return can be performed when the system is in operation there are some actions that needs to be considered:

- All switching needs to be coordinated between the three stations.
- Before opening of MRTB or GRTS a parallel current path needs to be secured.

Before starting the transfer to metallic return all the four converters related to the d.c. line to be used as metallic return conductor needs to be isolated from the system. The MR transfer sequence is prepared by connection of the MR transfer busses in Agra, Biswanath Chariali and Alipurduar. Agra will remain grounded through electrode or station ground, providing the transmission system grounding. After connecting the d.c. line to be used as MR in Agra, the system is ready to be transferred from ground return into metallic return operation.

Several different sequences for transfer of the two rectifiers to MR are possible (to start with Biswanath Chariali, or Alipurduar, or both at the same time). As described in chapter 4 above, the different sequences gives different stresses on the equipment and the proper sequence is implemented.

However, before allowing to open the MRTB, i.e. disconnecting the electrode, a parallel current path through the metallic return conductor should be secured. At some combinations of rectifier power levels, no current will flow in the metallic return path. Hence to be able to verify that there is a parallel current path and that the line is intact, the sequence is adopted dependent on the power level of the two rectifiers. The same type of considerations are taken when going from metallic return to ground return.

Below plot shows transfer from ground return to metallic return, starting with connecting Biswanath Chariali to MR line. As can be seen, the electrode current in Biswanath Chariali increases when connecting the station to MR, as part of return current from Alipurduar is taking the path through Biswanath Chariali electrode instead of MR line to Agra. In a point to point transmission the return current would be shared between GR and MR, decreasing the electrode current somewhat when connecting the MR.

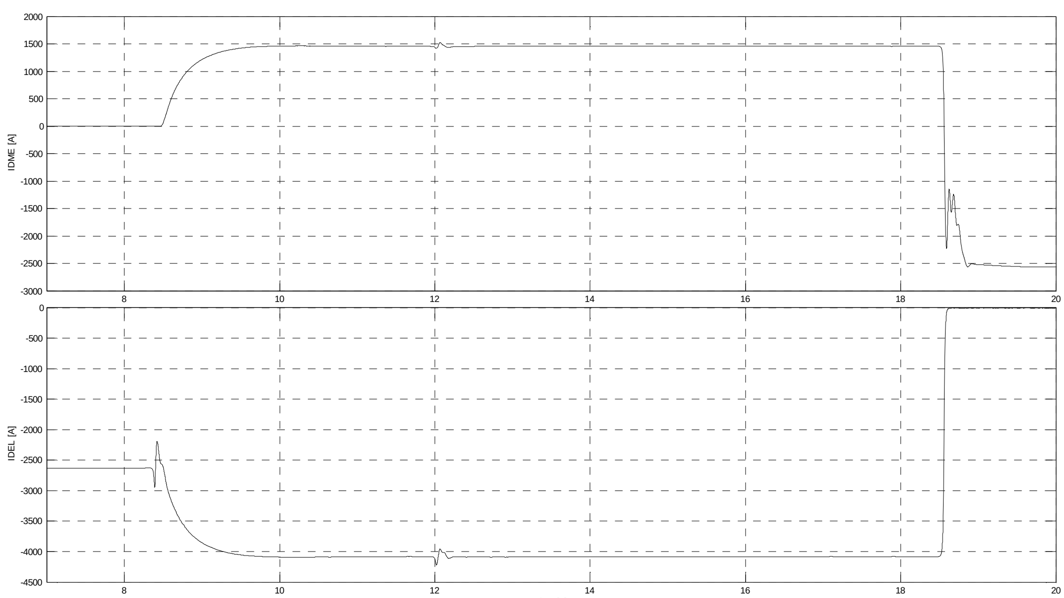


Figure 5 Transfer from ground return to metallic return in Biswanath Chariali when Alipurduar is operating in metallic return.

IDME – current in metallic return bus in station (upper plot)

IDEL – current in electrode lines (lower plot)

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North-East to Agra ±800 kV HVDC Multi-terminal Project – Overview of some results for multi-infeed studies

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SUMMARY

This paper presents a summary of the multi-infeed studies performed for the North-East to Agra 800 kV High Voltage Direct Current (HVDC) transmission project (NEA800). Transient over-voltages, commutation failure performance and a.c. fault recovery, harmonic interaction and control interaction [1] are covered.

In a power system fed by several HVDC transmission links, there could be a risk for negative interaction between the inverters, which must be investigated. In such a situation, disturbance at one HVDC converter may cause disturbances at other HVDC systems.

It is important to note that technically there is no inherent maximum number of HVDC links that may co-exist in a relatively congested electrical space [1]. However, as the density of HVDC links increases, the sharing of system short circuit level by all affected inverters may lower to the point where further HVDC development needs to be carefully studied. Thus it is important to perform a Multi Infeed study to know the degree of interaction between existing and newly included HVDC links.

The inverter station of North-East to Agra 800 kV HVDC transmission project (NEA800) is located in Agra in the Northern Region (NR) of India, which already has four other HVDC transmissions.

The initial Multi-Infeed screening study for NEA800 investigated the preconditions for the multi-infeed studies and analysed the impact of presence of other already existing HVDC links in vicinity to the new HVDC link at Agra. The investigation was done by calculating the Multi-infeed Interaction Factor (MIIF) and Multi-infeed Effective Short Circuit Ratio (MIESCR). The aim was to assess the impact of the HVDC links in proximity to NEA800 HVDC link and to identify links amongst them that have significant interaction with the new NEA800 HVDC link. The converter stations having MIIF more than 0.15 and/or MIESCR less than 2.5 are likely to have a higher degree of interaction with each other and thus further investigation is required [1].

As the HVDC converters consume significant reactive power, rejection of that reactive power due to a bi-pole block will induce an over-voltage at the inverter bus. If another HVDC link is in close proximity, then blocking of that link will also induce an overvoltage at the given inverter bus. If both links block simultaneously, the TOV experienced at the inverter may be higher than if only any

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individual link had blocked. It shall be noted that simultaneous blocking of the HVDC converters is considered as extremely unlikely.

The multi-infeed aspects of the northern region has been included in the Dynamic Performance Study (DPS) in order to investigate any harmful interaction with respect to power/voltage instability, control interactions and also commutation failure and a.c. fault recovery between the Agra HVDC terminal and the other existing links in the area which are in close electrical vicinity of each other and feeding power into the a.c. network in the Agra area.

Harmonic interaction and a.c. filter design is treated in studies presenting a.c. filter performance and rating. The conditions under which harmonic performance and rating are calculated which include other HVDC transmissions in the grid, thereby ensuring the design of any new HVDC converters and filters.

KEYWORDS

High voltage - HVDC - multi infeed - dynamic - performance - overvoltage - commutation failure - harmonics - interaction

1. INTRODUCTION

The inverter station of NEA800 is located in Agra in the Northern Region (NR) of India [2]. In this region there are already five other HVDC transmissions, referred as:

- Link – 1 (Ballia – Bhiwadi HVDC Link), 2500 MW
- Link – 2 (Mundra – Haryana HVDC Link), 2500 MW
- Link – 3 (Chandrapur – Padghe HVDC Link), 1500 MW
- Link – 4 (Vindhyachal Back-to-Back), 500 MW
- Link – 5 (Rihand – Dadri HVDC Link), 1500 MW

Geographical map of India with representation of the above HVDC links is given below,

Figure I: Geographical map of India with representation of the HVDC links considered

The following studies, covering the multi-infeed aspects, have been performed:

- Transient overvoltage effects.
- Commutation failure and a.c. fault recovery.
- Harmonic performance.
- Control interaction and power/voltage instability.

2. MULTI-INFEED INTERACTION FACTOR (MIIF) & MULTI-INFEED EFFECTIVE SHORT CIRCUIT RATIO (MIESCR)

An indicator based on the observed a.c. voltage change at one inverter a.c. bus for a small a.c. voltage change at another inverter bus provides a first level indication of the degree of interaction between two HVDC systems. This interaction factor is called the Multi-Infeed Interaction Factor and is defined mathematically as:

$$MIIF_{e,n} = \frac{\Delta V_e}{\Delta V_n}$$

Where,
ΔVe is the observed voltage change at bus ‘e’ for a small induced voltage change at bus ‘n’, for example 1% voltage change.

Inverter a.c. buses electrically far apart will have MIIF values approaching zero, while MIIF values approaching unity indicate a.c. buses that are very close. MIIF values above about 0.15 indicate the possibility of some degree of interaction [1].

The approach above is sufficient if the HVDC links are of similar capacity. In situations where one HVDC link has much greater power capacity than another, then MIIF values should be weighted by the HVDC power of the remote link and compared to the power of the inverter under investigation.

The performance of various components in a power system depends on the characteristic of the power system usually referred as “the strength of the system”. The strength of the system reflects the sensitivity of system variables to various disturbances in the operation of components connected in the system. Single infeed HVDC systems use a basic parameter called the Effective Short Circuit Ratio (ESCR) to assess whether or not the a.c. system into which the HVDC system is operating is sufficiently strong to support the operation of the HVDC system. In a multi-infeed context, this factor can be mathematically expressed as:

$$MIESCR_i = \frac{(SCC_i - Qf_i)}{Pdc_i + \sum_j (MIIF_{j,i} \times Pdc_j)}$$

where MIESCR is the multi-infeed definition of ESCR and the subscript j refers to all other HVDC links in electrical proximity. The converter stations having MIESCR less than 2.5 are likely to have a higher degree of interaction with each other and thus, will require detailed study of their interaction.

Peak load short circuit capacity of 28800 MVA and light load short circuit capacity of 27000 MVA has been considered for Agra. Shunt compensation of 3038 MVAr for peak load and 1609 MVAr for light load scenarios has been considered.

Below tables present the resulting MIIF and MIESCR for Peak load and Light load flow scenarios.

Table I : Peak Load Scenario, MIIF values for interaction with Agra

	Pdc (MW)	Delta Vj (pu)	Delta Vi (pu)	MIIFj,i	Pdcj * MIIFj,i
Agra	6000.0	0.0105	0.0105	1.0000	6000.00
Link - 1	2400.0	0.0056	0.0105	0.5333	1280.00
Link - 2	1766.0	0.0030	0.0105	0.2857	504.57
Link - 3	1500.0	0.0001	0.0105	0.0095	14.29
Link - 4	500.0	0.0006	0.0105	0.0571	28.57
Link - 5	1300.0	0.0014	0.0105	0.1333	173.33

MIESCR (Agra, Peak Load) = 3.22

Table II : Light Load Scenario, MIIF values for interaction with Agra

	Pdc (MW)	Delta Vj (pu)	Delta Vi (pu)	MIIFj,i	Pdcj * MIIFj,i
Agra	4000.0	0.0108	0.0108	1.0000	4000.00
Link - 1	2400.0	0.0057	0.0108	0.5277	1266.67
Link - 2	1766.0	0.0032	0.0108	0.2963	523.26
Link - 3	1500.0	0.0000	0.0108	0.0000	0.00
Link - 4	500.0	0.0010	0.0108	0.0926	46.30
Link - 5	1300.0	0.0015	0.0108	0.1389	180.56

MIESCR (Agra, Light Load) = 4.22

2.1 Conclusion from MIESCR Study

The multi-infeed interaction values for Agra HVDC link with other links 3, 4 & 5 indicated the remoteness of these links in the intervening influence in terms of infeed. Values below 0.15 suggested that they do not have any significant interaction with the NEA800 HVDC link at Agra. Thus, in both Peak load and Light Load scenarios, multi-infeed influence due to other HVDC links on the new HVDC link at Agra was analysed by detailed representation of the HVDC link at Agra, HVDC link 1 and HVDC link 2. Accordingly these three HVDC links were represented in detail in time-domain simulation for studying multi-infeed aspects in the Dynamic Performance study (DPS) performed for NEA800.

3. TEMPORARY AND TRANSIENT OVERVOLTAGES

As the HVDC converters consume significant reactive power, rejection of that reactive power due to a bi-pole block will induce an over-voltage at the inverter bus. If another HVDC link is in close proximity, then blocking of that link will also induce an overvoltage at the given inverter bus. If both links block simultaneously, then the TOV experienced at the inverter bus may be higher than then if only any individual link had blocked.

It shall be noted that simultaneous blocking of the HVDC converters is considered as extremely unlikely. Further as the filters will immediately be tripped in case of total blocking of the NEA800 transmission, the temporary over-voltage levels will rapidly be reduced to moderate levels.

Hence the more appropriate defining case for Temporary Overvoltage design is a fault driven simultaneous commutation failure. The same have been studied in the DPS study and plots from single and three phase fault close to Agra are found in Figure II to Figure VII below.

It may be noted that these over-voltages are without including the surge arresters in the model and that the plots show the over-voltages including harmonics. Thus the actual TOV will be lower than presented in plots.

In the study Multi-Infeed Investigation for NEA800, it is concluded that the MIESCR in Agra is 4.22 for light load and 3.22 for peak load. With such relatively high MIESCR, the expected maximum fundamental frequency temporary over-voltages are moderate, see CIGRE report [1], Figures 2-1 and 2-2, where it is given as maximum 20%.

1phase to ground fault, 200ms, less than 10% remaining voltage at AGRA inverter bus

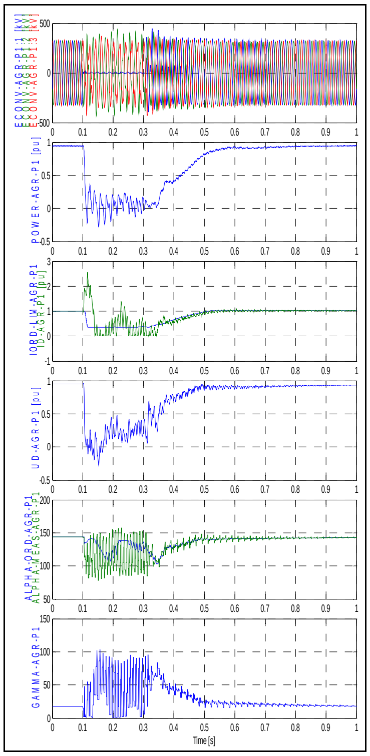

Figure II: Plots of Agra station

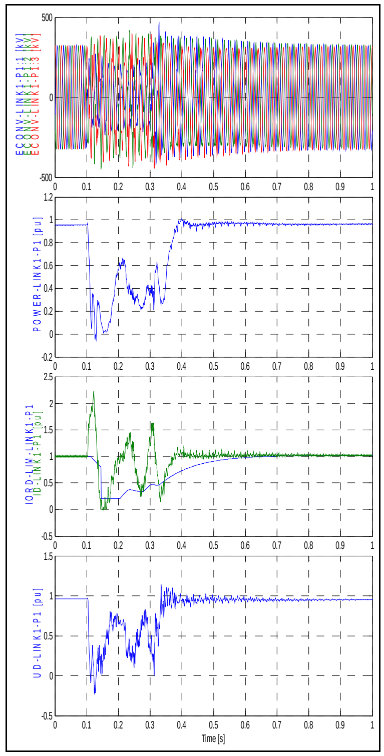

Figure III: Plots of Link -1

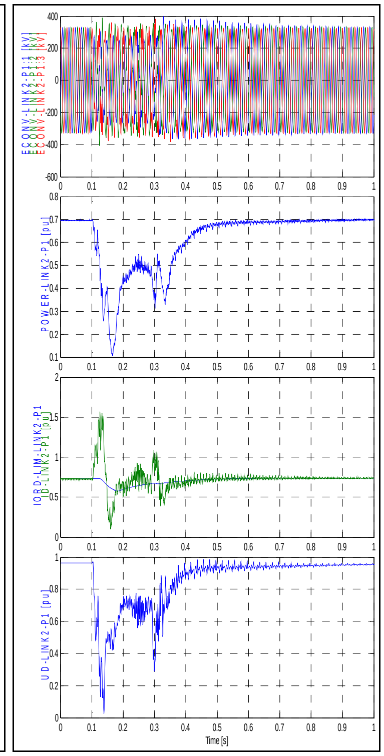

Figure IV: Plots of Link -2

3phase to ground fault, 100ms, less than 10% remaining voltage at AGRA inverter bus

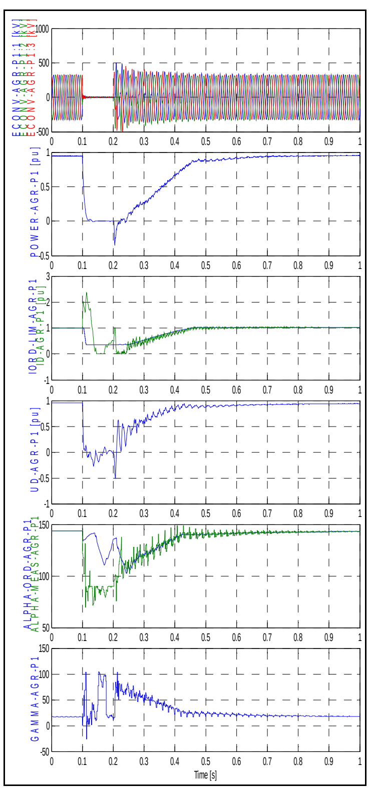

Figure V: Plots of Agra station

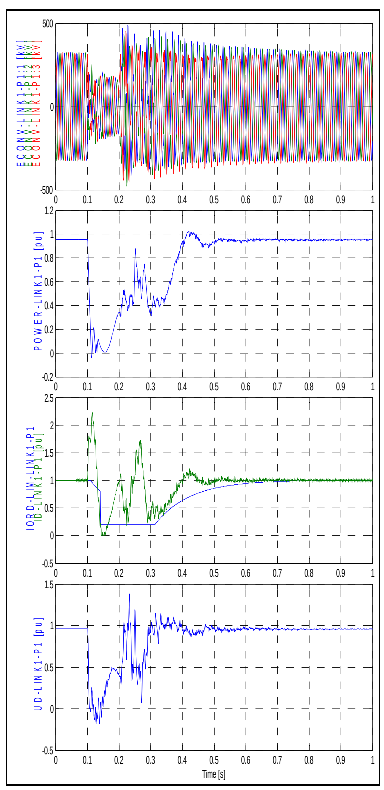

Figure VI: Plots of Link -1

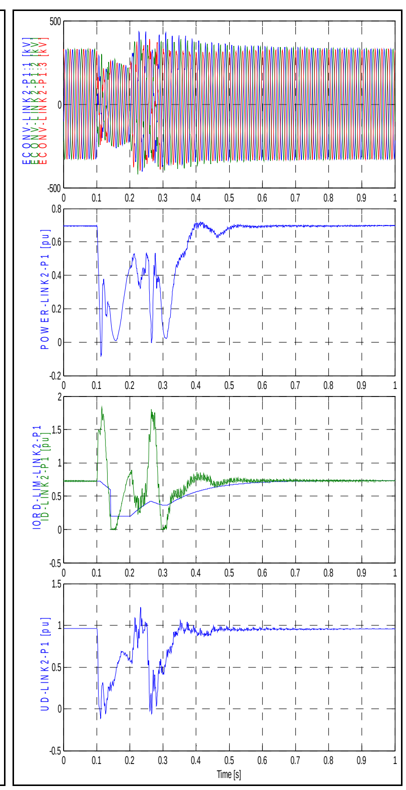

Figure VII: Plots of Link -2

4. COMMUTATION FAILURES AND AC FAULT RECOVERY

A detailed Dynamic Performance Study (DPS) has been carried out for the NEA800.

The inverter stations of the Agra, Link -1 & Link -2 are in close electrical vicinity of each other and feeding power into the a.c. network in the Agra area. In a power system fed by several HVDC transmission links, commutation failures at one HVDC converter may sometime cause commutation failures and following power interruption also in other HVDC systems.

AC network equivalents for normal operating conditions, i.e. peak load and light load conditions and also the performance of the other links (Link -1 & Link -2) have been considered in the optimization of NEA800 controls. These equivalents have been integrated with a detailed model of the NEA800 HVDC link. The DPS has been performed using PSCAD, an Electro Magnetics Transient Stability Program for simulation of e.g. power transmission systems.

In the presence of link -1 & link -2 feeding into the same area, a safe and stable operation of NEA800 has been verified when applying a.c. and d.c. system disturbances.

5. HARMONIC PERFORMANCE

The harmonic interaction and a.c.filter design is treated in different studies presenting;

- AC Filter performance calculations and results
- AC Filter steady state rating

The conditions under which harmonic performance and rating are to be calculated, are defined by the permissible harmonic distortion, the network harmonic impedance and the pre-existing harmonic distortion due to all other sources in the grid as given in the project technical specification.

The specified pre-conditions ensure that the design of any new HVDC converters and their filters considers the a.c. network properties and the existence of individual harmonic sources and filters elsewhere, which includes nearby HVDC station forming multi-infeed. Based on the above requirements the filter configuration is determined.

5.1 Low-Order Harmonic Filtering

With the given network impedance magnitude, it has been found necessary to include low-order filters, tuned to the 3rd harmonic, with a damped, high-pass characteristic. These filters are required in order to fulfil the harmonic performance requirements for individual distortion and total harmonic distortion.

The inclusion of the HP3 filter branches in the filter switching scheme eliminates any concern regarding possible resonance between the other a.c. filters and the a.c. network.

5.2 Filter Performance Results

The highest calculated individual distortion D_n, total distortion D_{tot}, effective distortion D_{eff} and telephone interference factor TIF at Agra are;

Table III: Harmonic performance levels

	D_{tot}	D_n	D_{eff}	TIF
Agra	4.0	1.0	1.5	40

Under normal operating conditions, the actual levels of the distortion parameters will be considerably lower than shown in the Table above. In particular, at the higher power levels additional shunt capacitors will also be connected, which will substantially help to mitigate the higher order harmonics.

6. CONTROL INTERACTION AND POWER/VOLTAGE INSTABILITY

While performing the DPS, the influences of small and large disturbances are investigated. During the analysis no tendency of power/voltage instabilities have been observed.

Furthermore, multi-infeed inverters with MIESCR of 2.5 or greater have a margin to allow for contingencies and possible heavily loaded a.c. system and will thus be typically PV stable, see Cigré report [1] clause 2.5.1.2.

The MIESCR factor for AGRA in the network with link 1 & 2 is calculated to be above 3.22.

The HVDC control system of NEA800 is carefully optimised considering the multi-infeed aspect to get stable restarts of the transmission with no commutation failures after faults. And also by considering stable recovery of the total system including link 1 and 2.

7. CONCLUSION

The HVDC links that can have some multi-infeed interaction with the NEA800 HVDC link were found to be links 1 & 2.

- The inverter stations of the Agra, Link -1 & Link -2 were included in the DPS study. The controls of NEA800 have been optimized for a safe and stable performance of the total system taking into account also the influence of the other links 1 & 2.
- Considering other HVDC's part of network seen from NEA800 inverter bus, while defining network harmonic impedance and pre-existing harmonics, there will be no adverse interaction of the harmonic filters at the NEA800 stations with the rest of the system. The a.c. filter design is well-suited to the specific conditions and requirements of the project and the calculated harmonic filtering performance is satisfactory.
- The most appropriate defining cases for TOV design have been studied without representing the surge arresters and the plots showing the over-voltages including harmonics have been presented. Multi-Infeed Investigation shows the relatively high MIESCR in AGRA for light load and peak load conditions, thus the expected maximum fundamental frequency temporary over-voltages are moderate as per CIGRE report, where it is given as maximum 20%.

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Early Investigations of Nelson River Pole 1 Thyristor Problem

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SUMMARY

This paper presents the early investigations into a unique thyristor redundancy problem with one of the three Nelson River Pole 1 valve groups at the rectifier end (Radisson), which first appeared in April 2009. Every time the valve group was blocked, the "Thyristor Redundancy Exceeded" (TRE) alarm was generated, which resulted in automatic isolation of the valve group from AC and DC sides and tripping of the converter AC breakers. It was discovered that the TRE alarm would disappear after the valve group was left de-energized for approximately 2 hours. It was possible to deblock the valve group without taking any other corrective action than just letting it cool down. The valve group would then operate normally till the next time it was blocked. The TRE alarm was generated again after the valve group was blocked. One of the initial troubleshooting efforts was to replace some thyristor level components (i.e., thyristors, gate units, damping resistors, DC grading resistors, etc.) at the locations indicated as failed by the Valve Base Electronics (VBE).

After investigations at the converter site without success, the equipment supplier was contacted for assistance. Following an internal analysis, the supplier indicated that the problem could be caused by uneven voltage distribution resulting from leaky thyristors (i.e., those exhibiting increased leakage currents) and the alleged faulty thyristors were actually healthy. This hypothesis was then verified to be correct by swapping thyristors. As a follow up, 14 thyristors were removed from the valve and sent to the thyristor supplier for testing, which included two thyristors that were indicated to be faulty by the VBE. The tests by the thyristor supplier proved that the two thyristors that were indicated to be faulty were actually healthy. At the same time the other 12 thyristors were found to exhibit increased leakage currents when heated to the operating temperature.

A detailed study on the thyristor leakage problem was subsequently conducted by Manitoba Hydro in 2013. It was discovered that there existed a significant number of leaky thyristors in all the valves in two of the three valve groups. This paper only presents the early investigations leading to the identification of the leaky thyristors as the cause of the thyristor redundancy problem. The results of the detailed study will be published in future papers.

KEYWORDS

Thyristor, thyristor leakage, leaky thyristor, Nelson River HVDC.

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1. INTRODUCTION

Nelson River Pole 1 consists of three 150kV 6-pulse Valve Groups (VG11, VG12 & VG13) as shown in Figure 1. The thyristor valves and controls currently in service were provided and installed by Alstom in replacement of the mercury arc valves during 1992 to 1993. VG11 and VG12 were commissioned first and VG13 a year later. There are 84 and 80 series-connected thyristor levels in each rectifier valve at Radisson and inverter valve at Dorsey, respectively. There are 3 redundant thyristors in each valve.

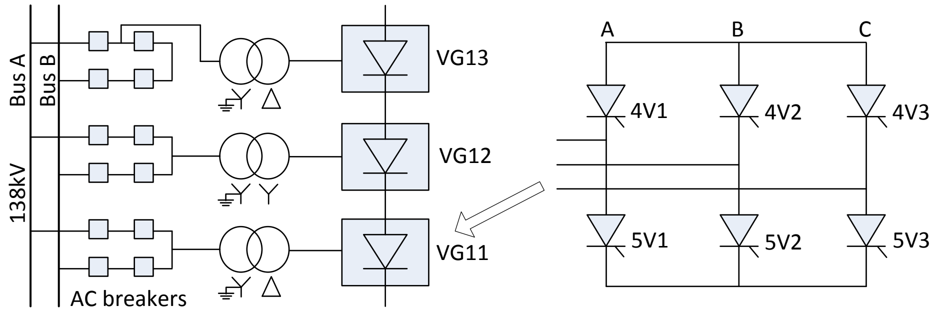


Figure 1. Nelson River Pole 1 valve groups at Radisson.

Starting from April 16, 2009, a considerable number of thyristor faults were detected consistently from certain locations (i.e., thyristor levels) in the two B-phase rectifier valves in VG11 (i.e., 114V2 and 115V2) at Radisson almost every time after VG11 was blocked, causing the thyristor redundancy to be exceeded and consequently the associated AC breakers to trip. One unique feature of these thyristor faults is that replacement of the associated components such as thyristors, gate units, etc. had no effect. This problem is referred to as the thyristor redundancy problem in this paper.

It was completely a mystery at that time as to what might have caused the thyristor faults. Lack of relevant information in the literature made the troubleshooting of the problem very difficult. Through approximately 3 years of investigations at the converter site with support from Alstom, it was found that the problem was caused by the leaky thyristors (i.e., those suffering increased thyristor leakage currents) in the two valves. A detailed study was subsequently conducted by Manitoba Hydro in 2013 on the thyristor leakage problem via thyristor voltage monitoring, computer simulations and leakage current measurements, which covered all Pole 1 valves including those at Dorsey.

This paper presents a review of the early investigations into the problem.[1] For convenience, some of the terminologies frequently used in this paper are defined as follows:

- *Blocked-state* — operating condition of a valve or thyristor in a VG after it is blocked (i.e., the firing pulses to the VG are blocked).
- *Deblocked-state* — operating condition of a valve or thyristor in a VG after it is deblocked (i.e., the firing pulses to the VG are released).
- *Databack signal* — a 4-bit data word (or pulse train) sent by the gate unit to the Valve Base Electronics (VBE) cubicle at ground potential.
- *Databack traces* — a series of databack signals.

2. DATABACK SYSTEM

Each Pole 1 valve has a dedicated thyristor level monitoring system, called databack system, in the associated VBE cubicle. The output data of the databack system (i.e., databack signals) are the only source of information readily available at ground potential on the status of each individual thyristor

[1] This paper is based on Manitoba Hydro HVDC Engineering Report “Nelson River Pole 1 Thyristor Problem” issued internally on May 11, 2014.

level. The databack information played a critical role in the investigations leading to the resolution of the thyristor redundancy problem.

The databack system in the VBE cubicle consists of opto-receiver subunits and databack subunits each comprising a decoder, an LED display driver and an LED display panel.

The gate unit at each thyristor level routinely sends serial data (i.e., databack signals) to the databack system via an optical fibre as long as the valve remains energized. Each databack signal is encoded in a 4-bit data word represented by a sequence of up to 4 pulses. The four bits, (1, 1, 0, 1), indicate thyristor healthy, thyristor conducting, Break-Over Diode (BOD) firing and power supply healthy, respectively. The first pulse (or bit) also serves as a receiver synchronization pulse and is always present with other ones (if any). A typical encoded databack signal is 1111 (code 1) or 1011 (code 2). The optical databack signals are received and converted to electrical signals (or serial data) by the opto-receiver subunit, and then decoded and processed by the databack subunit.

In a healthy valve in the deblocked-state, 4 databack signals (i.e., code 2 – code 1 – code 1 – code 2) are transmitted per cycle for each thyristor level as shown in Figure 2. The first databack signal is sent at the 60V-crossing near the beginning of the forward blocking period, the second at the start of conduction, the third at the 60V-crossing immediately following the start of conduction, and the fourth at 60μs after the start of conduction. Note that the 4th databack signal is code 2, where the thyristor conducting bit is cancelled although the thyristor continues to conduct. The time difference between the first 60V-crossing and start of conduction is denoted by T_{60VC}. Typically, $T_{60VC} = 0.53\ to$ 0.81 ms for the rectifier and $T_{60VC} = 8.82\ to$ 9.98 ms for the inverter.

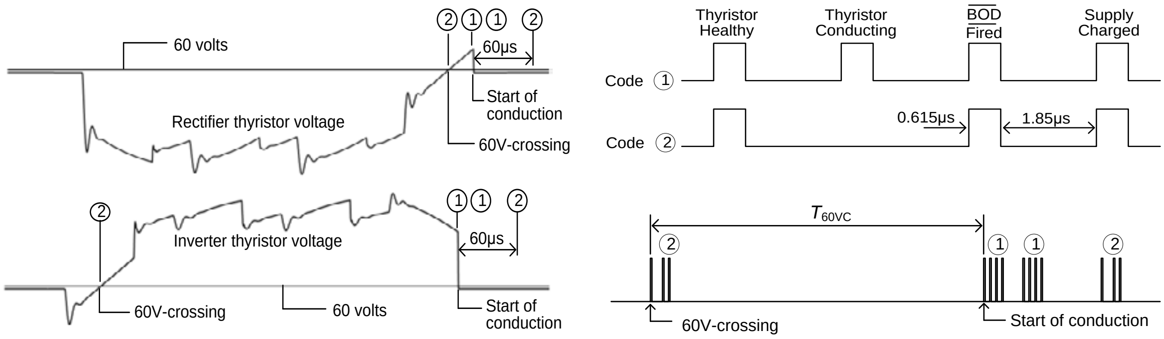


Figure 2. Databack transmission for one thyristor level in a deblocked valve. Note that the thyristor voltage waveforms are obtained through PSCAD simulations without considering the stray capacitances.

For a valve in the blocked-state, only two code 2 databack signals are transmitted per cycle for each thyristor level at the positive-going and negative-going 60V-crossings, respectively, as shown in Figure 3.

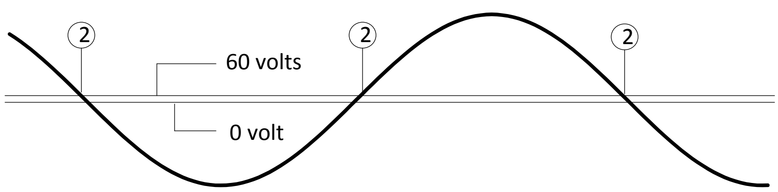


Figure 3. Databack transmission for one thyristor level after the associated VG is blocked and remains energized.

The gate unit is powered by the voltage across the associated thyristor. If the thyristor fails, its gate unit will lose power and stop transmitting databack signals. Thus, the VBE was designed such that if it has not received any databack signals from a thyristor level for 1 second, then the hardware timer on the associated channel will time out and a thyristor failure will be recorded and displayed in the front of the VBE although the loss of databack transmission can also result from the failure of other components such as gate units, optical fibres and opto-receivers. The VBE will read the thyristor failure which will then be passed to the Thyristor Fault Monitor (TFM). Four of such thyristor faults in one valve will bring up a “Thyristor Redundancy Exceeded” (TRE) alarm, causing the associated valve group and AC breakers to trip.

The databack signals for each individual thyristor level can be monitored with an oscilloscope or recorded with a logic analyzer from the corresponding Monitoring Point (MP) on the opto-receiver subunits in the VBE cubicle.

3. SYMPTOMS OF THYRISTOR PROBLEM

3.1. Thyristor Redundancy Problem

On April 16 in 2009, a TRE alarm was initiated from the B-phase valves (i.e., 114V2 and 115V2) of VG11 at Radisson following the blocking of VG11, causing the associated AC breakers to trip. The TFM reported 3 failed thyristors in valve 114V2 and 5 in valve 115V2, indicating that the thyristor redundancy was exceeded in valve 115V2. Over the next 4 years, the TRE alarm came up almost every time after VG11 was blocked, all initiated from the same valves. The number of thyristor faults (or failures) showed an increasing trend over the first 2 years and then stayed at approximately 20 as shown in Figure 4.

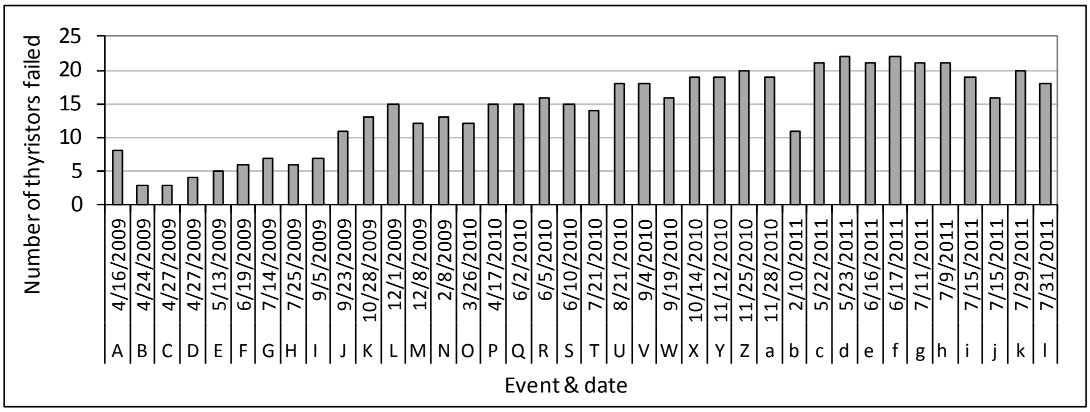


Figure 4. Total number of thyristors reported by TFM as failed in valves 114V2 and 115V2 at Radisson in each TRE event during April 16, 2009 to July 31, 2011.

These thyristor faults were consistently reported from the same locations, but at some of the locations they did not occur every time after VG11 was blocked. The timing of the thyristor faults is between 1.1 to 1.3 seconds after the firing pulses stopped.

These thyristor faults didn’t seem to be permanent as they were detected only after the valve group was blocked, disappeared by themselves some time (usually 1 to 2 hours) later and did not show up once the valve group was deblocked.

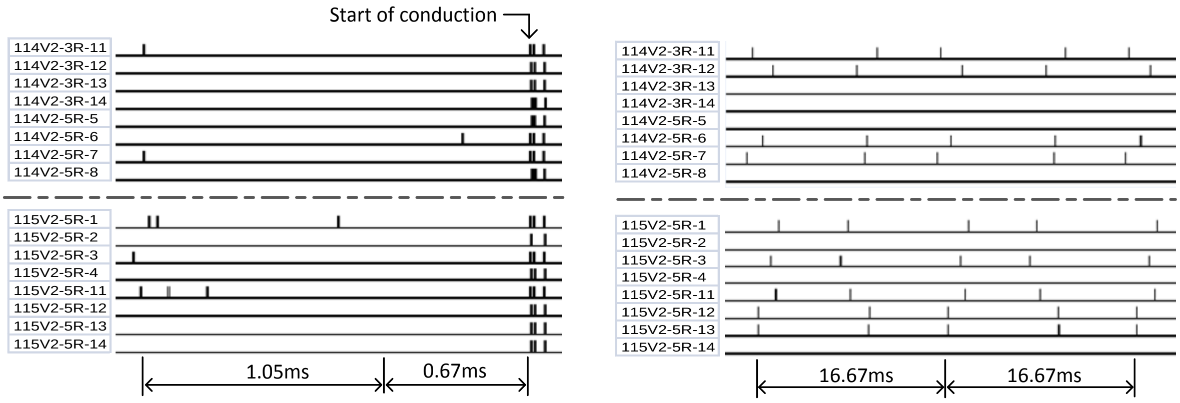
One of the early problem finding measures was to replace some thyristors reported by the TFM as failed, but the thyristor faults continued to show up after the blocking of VG11. This misled us into believing that the problem had nothing to do with thyristors.

3.2. Irregular Databack Traces in Valves 114V2 and 115V2 at Radisson

For a normal valve, databack transmission for all thyristors in the valve is expected to occur simultaneously with a small dispersion attributed to component tolerances. This, however, had no longer been the case with the VG11 B-phase valves at Radisson as discovered during the early stage of investigating the thyristor redundancy problem. Figure 5(a), for example, shows a snapshot of deblocked-state databack traces for 8 selected thyristors in valves 114V2 and 115V2 at Radisson, respectively. Five of the databack traces had one or multiple very early 60V-crossing signals (i.e., code 2 signals) with their first ones occurring approximately 1.72ms before the start of conduction, one had a late 60V-crossing signal only and the rest had no 60V-crossing signal before the start of conduction. Note that the 60V-crossing signals are normally present at 0.67ms before the start of conduction, which corresponds to the firing angle of 16 degrees. The databack traces taken later for all thyristors levels in the two valves indicated that the majority of thyristors in these two valves exhibited one or multiple early or very early 60V-crossings.

Figure 5(b) shows the blocked-state databack traces for the same thyristors, which were taken about 2 minutes after VG11 was blocked. Nine of the thyristors exhibited 60V-crossings scattered over a range as wide as 2.6ms (or 56 degrees) and 6 of them exhibited no 60V-crossing.

Comparison of Figures 5(a) and (b) revealed an interesting correlation between the databack signals before and after the blocking of VG11, which is that the thyristor levels without databack signals in the blocked-state are among those with missing 60V-crossings in the deblocked-state, but not vice versa. It was therefore believed that to find whatever had caused the irregular databack traces, especially the loss of databack signals, should lead to the resolution of the thyristor redundancy problem.



(a) Deblocked-state databack. ***(b)*** Blocked-state databack.

Figure 5. Two snapshots of databack traces for 16 selected thyristors in valves 114V2 and 115V2 at Radisson. One was taken when VG11 was deblocked and the other was taken approximately 2 minutes after VG11 was blocked.

What could cause the loss of databack signals? It could be anything other than the legitimately failed thyristors as they wouldn't result in databack signals absent only after the blocking of VG11. There had been no clue as to what might be the cause of the problem until it was identified in early 2012 with the assistance from Alstom as described in the next section.

3.3. Cause of Irregular Databack Signals

As the investigations continued, Manitoba Hydro decided to seek assistance from Alstom, the supplier of the Pole 1 valves. The focus then was turned back to thyristors that had been excluded as a potential cause in the first place.

After reviewing all the information, Alstom came up with a leaky thyristor theory that the irregular databack traces could result from a severe voltage grading imbalance which could be caused by the leaky thyristors that were presumably those exhibiting early 60V-crossings. This theory was proposed on the basis of a computer simulation using a very simple model consisting of 4 thyristors. According to this theory, the thyristors that were indicated as failed should be good ones. This explained why replacement of these thyristors had no effect.

To prove the leaky thyristor theory, a thyristor swap test was conducted at Radisson as guided by Alstom. It was found that the irregular databack traces followed the thyristors without changing their dispersion patterns and so did the thyristor faults. This clearly suggested that the irregular databack traces and thyristor level faults were somehow related to thyristors.

As a follow-up investigation proposed by Alstom, a total of 14 thyristors were removed from the Pole 1 valves and returned to the thyristor supplier for test and analysis, which included two thyristors indicated as failed and twelve exhibiting very early 60V-crossings. It was found that the 12 very early 60V-crossing thyristors exhibited increased leakage currents after a few hours in the hot blocking test and the other 2 thyristors exhibited good and stable characteristics in a blocking test. As of May 2012, there were 50 and 45 very early 60V-crossing thyristors in valves 114V2 and 115V2 in VG11 at Radisson, respectively.

The above findings suggested that the effect of leaky thyristors was the cause of the irregular databack signals and the cause of the thyristor redundancy problem.

However, there was still a lack of understanding of the meaning of the irregular databack traces and many questions remained to be answered. Subsequently Manitoba Hydro performed a detailed study on the thyristor problem via thyristor voltage monitoring, computer simulations and leakage current measurements. It was confirmed that the problem was caused by leaky thyristors. The details of this work will be published in future papers.

After the effect of the leaky thyristors was confirmed, 21 and 30 very early 60V-crossing thyristors were replaced in the two valves respectively in May of 2013. The thyristor redundancy problem disappeared afterwards and has never showed up since then.

4. CONCLUSIONS

The thyristor redundancy problem with the two B-phase rectifier valves in VG11 at Radisson was caused by the leaky thyristors. The thyristors reported as failed by the thyristor monitoring system were actually good ones and those exhibiting very early 60V-crossings were seriously leaky ones. There were more than 50% of such thyristors in each of the two valves. It was found later in the detailed study that these thyristors are all seriously leaky thyristors with a leakage resistance below 10kΩ at 300V, much lower than the dc grading resistance of 125kΩ.

Over the course of investigating the thyristor redundancy problem, it was found that the thyristor leakage problem was common to all valves in VG11 and VG12 at Radisson, not just limited to the above mentioned two valves.

The resulting voltage grading imbalance due to leaky thyristors led to a reduced safety margin for the valves during transient events. Although it was possible to operate the system in steady state with so many leaky thyristors, it was decided to replace all leaky thyristors to eliminate the risk of a complete valve failure due to transients.

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Nothing has been found from the existing literature regarding the unique problem presented in this paper.

Current status and development VSC-based HVDC technologies in power system of Russian Federation

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SUMMARY

VSC based HVDC System already widely used in electric power systems all over the world. In Russia scientific research and engineering works on creation of basic elements, systems and prospective technologies for VSC based DC Transmission System and STATCOM was started in 2003-2006. This paper provides a description of VSC projects which were held in Russian power system and its impact on system unavailability is also described. The major challenges and technical difficulties facing developers are analyzed. Priority aims regarding the future development of these applications in Russia and potential application fields are given.

One of the areas of R&D works was the development of reactive power compensator STATCOM, as a basic element for the development of VSC technology. From 2006 to 2010 series of works on design, development and implementation of STATCOM at Vyborg converter substation were carried out. The obtained experience in theoretical research, engineering, base technologies, equipment development and testing allowed to start developing of more complex projects of VSC based HVDC technology in the power range up to 200 MW.

At the end of August 2014 during the commissioning of Mogocha back-to-back VSC transmission test of one of two parallel VSC link was fulfilled. At the time when the back-to-back Mogocha interconnection was conceived, there were no electrical interconnections between the Far East and Siberia power grids. For the first time in the history Russian power system from Kaliningrad to Vladivostok has been fully connected and operated in "integrated" mode. AC networks to which Mogocha back-to-back VSC is connected, are characterized by low short-circuit ratio, prevailing traction load of the Trans-Baikal Railway and significant deviations of electric power quality. NPC VSC with 3 level topology occurred to be the best solution in relevant unique and adverse electrical conditions due to its dc voltage balancing abilities and independent control of active and reactive power. The most challenging task was to design a high voltage valve with series IGBT connection. Special bench test were carry out to proof a capability of design to withstand short circuit current through DC capacitor and IGBT valve. Complete control system was carefully tested through

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physical simulator in all modes of back-to-back operation. For future algorithms elaboration special digital simulation platform was developed and realized in HDL on high performance FPGA with time step 200ns. Considerable R&D progress in VSC equipment, IGBT valve design and advancements in testing technologies allows implementation of different HVDC projects in wide power range.

Nevertheless VSC-based HVDC technologies haven't yet been widespread in Russia. This can be explained by the fact that power grid interconnections are provided by powerful AC grid 330-750kV and due to absence of regions with distinct disproportion in power generation and consumption.

One of the possible future applications of VSC-based HVDC technologies is electrical power supply for small energy systems, which are isolated from Unified power system of Russia, located in the Russia's Far North and Far East, such as Yakutia, Chukotka, Magadan, Kamchatka and Sakhalin AC networks, Norilsk-Taimyr network. Another possible application area is power supply of cities (for example, Moscow) for increasing of reliability and short circuit current limitation.

KEYWORDS

VSC, STATCOM, Back-To-Back, Mogocha, Unified power system of Russia, short circuit current limitation, testing, commissioning

1.INTRODUCTION

HVDC transmission technologies have been widely developed and applied all over the world. In Russia R&D works for FACTS and equipment for FACTS was launched in 2003-2006. A series of static voltage compensators (SVC) and controlled shunt reactors (CSR) were commissioned into operation. The Russian's first CTATCOM demonstration project was developed from 2006 to 2010 and was commissioned into operation at Vyborg converter substation. Development was carried out in All-Union Electric Power Research Institute (VNIIE) under the leadership of Professor Valery Kochkin.

Full R&D cycle, including calculations of steady-state and transient processes, development and tasting of power equipment, control systems was organized. The obtained experience in theoretical research, engineering, base technologies, equipment development and testing and well established team allowed to start developing of more complex projects of VSC based HVDC technology in the power range up to 200 MW.

Mogocha VSC-based back-to-back for Trans-Baikal converter substation was developed from 2010 to 2013. Integrated testing of the equipment and commissioning were successfully completed in 2014-2015.

2.VYBORG STATCOM OPERATION HISTORY

The Vyborg back-to-back HVDC link, providing the asynchronous connection between power networks of Russia (330 kV AC voltage) and Finland (400 kV AC voltage), is in operation since 1981, consists of four parallel High Voltage Converter Unit (HVCU), each Unit has rated transmission capacity of 355 MW [1,2]. The first Russian's IGBT based STATCOM demonstration project was commissioned into operation at Vyborg substation in 2010. Its purpose was to provide reactive power and dynamic voltage support during transients in power grids of Russia and Finland.

The main objective for Vyborg STATCOM demonstration project was the accumulation of operating experience, regarding both reliability of the power equipment and its impact on the electrical networks. Besides it, STATCOM was considered as the basic unit for future FACTS.

STATCOM has 18 IGBT valves arranged in a three-level circuit topology, two series-connected capacitor banks on the DC side, three phase reactors, single-loop liquid valve cooling system, digital control and protection system, high-frequency broadband filter. The microprocessor control and protection system was designed and tested using the physical simulator. The IGBTs used in valves have a voltage rating of 2.5 kV, current rating of 4 kA. STATCOM has a rated dynamic reactive capacity of ±50 Mvar, AC line voltage rating of 15.75 kV and RMS phase current of 1840 A at nominal rating.

STATCOM system testing was performed in December 2011. The commissioning program included opetation with AC network having voltage rating of 11 kV and 15.75 kV. Typical tests were performed during converter operation: energization of the DC equipment, check that the DC voltage is controlled to its reference voltage, check hardware and software protection functions for DC voltage equipment. Load tests were performed for both generation and consumption modes. Performances of overcurrent valve protection, operation of cooling systems were checked. Tests were performed in manual control mode and automatic control mode both from automatic control system and Power Flow Controllers of converter substation. STATCOM dynamic performances were tested under operation in parallel with synchronous compensator. Transient time from consumption to generation mode and backwards was 0.2 s. Current harmonics were measured during 72 hours for various operation modes of STATCOM. The magnitudes of the current harmonics injected into AC grid 400 kV were evaluated.

System tests showed that STATCOM can be effectively used as a high-speed device for reactive power and voltage control together with the synchronous compensators, installed at the substation. However during 1st year of operation STATCOM showed bad reliability. The main problem was IGBT valves, which have low EMI noise immunity. Due to this drawback a lot of IGBT failed. In 2012 STATCOM was in operation for 2736 hours, there have been three forced outages: due to the faults in IGBT valve, to the failure in the cooling system of valves, and due to tripping of protection of DC side equipment. In order to improve the reliability of the equipment it was suggested to reduce the operational voltage from 15.75kV to 11 kV and after that failures of IGBT came to acceptable level.

3. MOGOCHA BACK-TO-BACK VSC

Mogocha back-to-back VSC was developed by a team of Russian scientists and engineers. This project embodies modern trends of VSC-based HVDC technologies, which are now widely used in the world. Full cycle of development (R&D), shipping, factory and system tests was fulfilled by Russian engineers.

Mogocha back-to-back VSC interconnects the Far East and Siberia power grids, nominal AC voltage 220 kV. Complete DC system, which is rated 240 MVA, consists of two parallel VSC links, nominal active power 200 MW. In the Mogocha VSC the IGBT valves are arranged in a three-phase three-level bridge, with converter transformer 220/38.5 kV.

Power link 220 kV Holbon - Mogocha - Skovorodino, interconnecting two power grids, is distant from the major power stations over a distance of 700 km and has a prevailing traction load of the Trans-Baikal railway. Consequently, AC networks to which back-to-back VSC is connected, are characterized by low short-circuit ratio and significant deviations of electric power quality. The presence of the back-to-back VSC has stabilized voltage at each interconnection point without additional means of reactive power compensation (Fig. 1).

A particularly important aspect is the possibility of voltage balancing. Electricity consumer with motor load, in particular oil pumping stations, located along power transit, have problems in operation of their equipment. Unbalanced and non-sinusoidal voltage leads to increased engine heating and wearing, interrupting the process at any tripping event. By using of voltage balancing algorithms in control system of back-to-back VSC Mogocha, it was possible to improve significantly the quality of voltage, which was noted by the main consumers. Results of commissioning tests has shown good transient behaviour of VCS during reclosure cycles (Fig.2), short-circuits in AC systems 220 kV, extremely unsymmetrical modes.

At the present moment works on relay protection and emergency control schemes of Power link 220 kV Holbon – Mogocha- Skovorodino for back-to-back mode are finalizing. The converters operate as VAR compensators and provide the AC voltage balance.

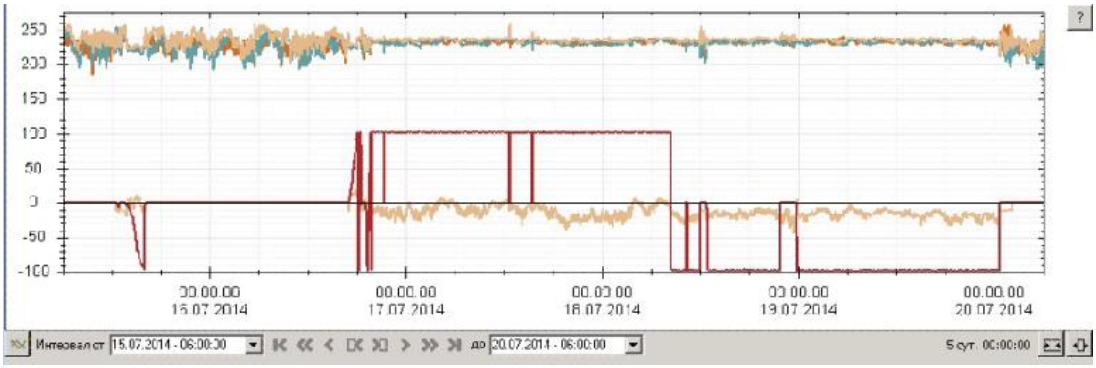

Figure 1 – Commision tests 72 hours, back-to-back operates in circular mode (top – RMS voltage 220 kV bus Uab,Ubc,Uca , bottom – red - P (MW) , yeallow –Q (Mvar)

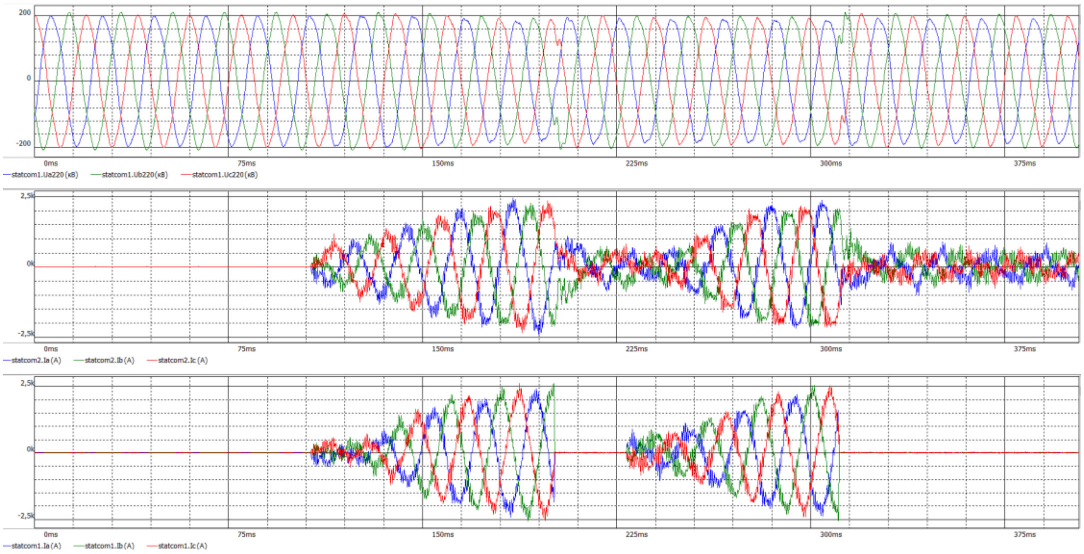

Figure 2 – Back-to-back behavior during reclosure cycle in circular mode, current protection setting of VSC1 reduced to 2.5 kA: top – phase voltage 220 kV Ua, Ub, Uc; middle – VSC2 phase currents; bottom – VSC1 phase currents

4. RESEARCHES AND DEVELOPMENT OF VSC EQUIPMENT

4.1. High voltage IGBT valve development

Before the development of converter equipment for Mogocha back-to-back HVDC was started, the maintenance and operation experience of VSC STATCOM, which is installed at Vyborg substation, were carefully studied. Based on this information the control system and IGBT drivers were drastically reworked. The control system was specially developed in modular type and provided a unified platform for control and protection for different types of high voltage converters, such as LCC, MMC, 3L-VSC and SVC. The latest advances in DSP and FPGA techniques was applied and implemented in the platform. This gives ultimate performance and exceptional reliability to create, debug, and run any algorithms in real-time mode. For Mogocha back-to-back it was developed and produced the set of 25 cubicles connected with each other with fiber optic. The control system is redundant – only one system active, while the other one is in “hot standby”. The control and valve protection system made with triple redundancy.

IGBT drivers were specially developed to have a high immunity to EMI. It supplied with power from a single IGBT cell when a voltage applied to IGBT valve. An intelligence system realized in drivers provides uniform distribution of voltage across valve IGBT cells in steady state and during transients. Data exchange between drivers and control unit based on fiber optic. Bandwidth of fiber channels and high speed data processing in valve control and protection unit allows commutate valve safely even if short circuit current through valve and DC capacitor occurred.

4.2 VSC equipment testing

When designing and developing of Mogocha VSC back-to-back special attention was paid to the testing equipment. A series of bench testing units for standard and factory tests of drivers, IGBT valves, assembled equipment and control and protection system were developed.

The entire amount of standard and factory tests of VSC equipment defined in IEC 62501 has been carefully analyzed and arranged as follows:

- bench tests of individual transistor cell, including testing of the dielectric strength, control the on /off functioning of transistor cell in both directions, as well as testing the proper functioning and parameters of control circuits, protection and alarm systems;
- assembly control of high voltage transistor valve (IGBT valve);
- hydraulic tests of IGBT valve;
- static high-voltage tests of IGBT valve;
- surge tests of IGBT valve;
- stress tests of IGBT valve;
- testing of valve device assembly.

Complete testing of developed control system was fulfilled to confirm all new technical solutions. All modules passed through series of factory tests and then everything was assambled and integarted in lab as in real project for full scale testing. For this purpose special bench testing unit containing the three-phase physical simulator of the VSC link, model of the adjacent AC grids and control panel were developed for full scale testing of control system. IGBT drivers of simulator were adapted for connection to the control system using fiber optics. Full cycle testing included analog measurment, control calculation and pulse firing were made on simualtor with scale 1 : 100.

4.3 Development of MMC technology

In some application fields the MMC technology has technical advantages. For carrying out rapid implementation of the MMC projects control system was developed and tested with physical simulator of the MMC [3]. Control system of MMC is based on the same hardware platform as back-to-back VSC and thus can be enlarged without restriction on protection or control.

Another field of concern is the development of real time digital simulators for MMC simulation. Digital simulator has advantages compared with physical simulators: lower cost, less development time, flexibility and more opportunities for implementation of operation modes of the converter and the adjacent networks. This simulator can be used both at the design stage and at the trial or commercial operation stages.

Digital model of the MMC with adjacent power grid was developed firstly in math equations and then realized on high performance FPGA in HDL. The experiments showed similar values in results obtained both on physical and digital models.

5. POTENTIAL APPLICATIONS OF VSC-BASED HVDC IN RUSSIA

5.1 General description of Russian Unified Power System

Russian Unified Power System (UPS) consists of 7 regional united power grids - Siberia, Ural, Mid-Volga, South, Central and North-West, which are interconnected with 220 – 750 kV overhead lines and East power grid.

In Russia there are a few isolated AC networks: Norilsk-Taimyr Power network, located in the Russia’s Far North on the Taimyr half island, several power networks located on the Far East: Chukotka, Magadan, Kamchatka and Sakhalin AC networks. There are some regions with low energy consumption located on the Far East and Siberia, having no central power supply.

Up to the present moment East power grid had no electrical interconnection with other power grids. Configuration of electrical network and location of generating sources in eastern part of Siberia power grid make impossible parallel synchronous operation of Siberia and East power grids.

AC network of Trans-Baikal area, located on eastern part of Siberia, is deficient, which impedes the full industrial development of the region, in particular the mining and metallurgical manufactures. Neighboring Amur AC network (East power grid) has energy surplus almost 2.5GW. Consumption does not exceed 1.5 GW, while the installed capacity of the Amur region is almost 4 GW.

Interconnection of East and Siberia power grids is necessary measure for increasing reliability of energy supply of Trans-Baikal railway and other consumes in Trans-Baikal and Amur region, providing technological connection of new consumers, enabling participation of economic agents of East power grid in total Russian wholesale electricity market. VSC Mogocha project is first step to interconnection of East and Siberia power grids.

5.2. Back-to-back VSC link Hani

Next step in the development of the VSC-based HVDC technologies is creation of back-to-back VSC on the northern power link between the Far East and Siberia power grids at Substation 220 kV Hani. The aim of this project is increasing reliability and transmission capacity of DC link connecting East and Siberia power grids. Power link is located along the Baikal-Amur Railway and the network parameters are similar to those at Mogocha. Thus, the preferred option is VSC back-to-back. Commissioning of VSC Hani is planned in 2019.

5.3. Power supply of isolated and passive AC networks

It was mentioned above that in Russia there are a few isolated AC networks located in Far East and Siberia where the cost of fuel delivery is very high. At the present time some options for connection of isolated AC networks to UPS of Russia are considering.

In particular, the connection of Norilsk-Taimyr power system to Siberia power grid in order to increase reliability of power supply, stimulate the development of new minefields and the construction of mining and processing plant, the development of social infrastructure is under study. Projects of long power transmission lines from the Kolyma hydroelectric power station in Magadan region for the power supply of Chukotka are also analyzing. Among the studied options for these purposes - cable and overhead HVDC power transmission using VSC technology.

5.4. Application of VSC-based HVDC technologies in networks of cities for increasing of reliability of power supply and short circuit current limitation

In electrical network of Moscow city there is a problem of limiting short-circuit current. One of the widely used measure for short-circuit currents limitation is sectionalizing of power system, which may cause malfunctions of the power supply as showed blackout in Moscow in 2005.One of the possible measures is power system sectionalizing with use of HVDC. In urban areas with lack of free territory design driver is substation overall dimension, which is key factor to select the modular multilevel VSC.

Researches performed by the Moscow institute "Energosetproject" have shown that installation of the back-to-backs with total capacity of 2000 MW at four points of Moscow power grid 220 kV and current-limiting device 40 ohms at 500 kV Substation Beskudnikovo will reduce the levels of short circuit currents to values not exceeding 63 kA. In this case Moscow power grid 220 kV will be split into three parts, interconnected with controlled HVDC back-to-back.

Without the use of current-limiting device at 500 kV Substation Beskudnikovo the problem of limitation of short circuit currents may be solved effectively by installation of the back-to-backs with total capacity of 2400 MW at five point of Moscow power grid 220 kV. In this case Moscow power grid 220 kV will be split into four parts, interconnected with controlled HVDC back-to-back.

CONCLUSION

The Mogocha Back-To-Back VSC HVDC allows to exchange power between isolated energy system of Siberia and East. It becomes the first HVDC installation based on VSC in Russian’s power grid. A lot of efforts were made by Russian scientists and engineers to bring this, relatively unique technology, to life. The main challenging task to create reliable IGBT valve with series IGBT connection was successfully accomplished. This task required creation of modular high performance redundant control and protection system which provides the platform for future VSC MMC applications.

Extensive tests and investigations in HVDC VSC technology continue to run in parallel with researches on impact of this technology on power grid, especially in proper coordination of conventional AC relay protections and HVDC protection. Current status of those development shows, that existing challenges have a great impact on total project cost and time. Some new projects still in feasibility study, and while the total cost of HVDC equipment continue to decline, the necessity to take into consideration technical and economic aspects for power grid companies, is challenging task.

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A Comparison between DC Fault Clearance Mechanisms for Multi-terminal VSC-HVDC Systems

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SUMMARY

This paper compares the DC fault clearing performance of multi-terminal VSC HVDC systems utilizing half bridge and full bridge converter technologies. For the half bridge VSC converters, the fast DC breakers are used to clear the fault and for the full bridge VSC converters, a controlled DC fault clearing mechanism proposed by the authors are used to clear the fault. The performance of the two technologies has been demonstrated using EMT (PSCAD) simulations. In terms of controlling the fault current, the controlling technique used in full bridge technology is as good as using the fast DC breakers with half bridge converters, the fault current can be reduced to safe limits in less than a millisecond after the fault is detected. Following that, the controller can bring the current close to zero within few milliseconds. For the three-terminal radial VSC systems, the faulted section can be detected in both of the technologies without using communication. The direction of the fault currents at the middle terminal is utilized for this purpose. Furthermore, it has been demonstrated that the restarting attempts can be performed for the three-terminal VSC system in both of the technologies without using communication. For the full bridge configuration, this is done without having any breaker operations (soft restarting). The full-bridge converters demonstrated similar performance in clearing a dc fault in a multi-terminal system. In cases where multiple restart attempts are required, the healthy portion of a multi-terminal system employing half-bridge converters and DC breakers can be restored quicker than a system employing full-bridge converters. However, the performance of the half-bridge configuration depends on how fast the DC breaker can operate, if the DC breaker operation takes longer, converters may need to be blocked and larger smoothing reactors may be required.

KEYWORDS

VSC HVDC, Full Bridge MMC, Half Bridge MMC, DC Fault Clearance, VSC Controller, Reclosing

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1. INTRODUCTION

Multi-terminal HVDC transmission systems based on the Voltage Source Converter (VSC) technology are being developed worldwide. The concept of a DC grid based on the VSC technology is also widely discussed and small DC grids may be realized in the near future. Clearing DC faults is a major concern for multi-terminal HVDC systems as the power transmission in all terminals is interrupted until the fault is cleared. In a multi-terminal application (and by extension in a DC grid) the faulted element is expected to be isolated in a short time and power transmission is resumed by the healthy parts of the system.

Full-bridge and half-bridge multi-module converter (MMC) technologies are commonly used in VSC HVDC systems. For DC fault clearance in multi-terminal systems, the half-bridge converters need fast DC breakers whereas the full-bridge converters have the ability of suppressing the fault current themselves. The common method used in full-bridge converters is to block the converter as soon as the fault is detected [1-3]. This brings the opposite polarity DC voltages momentarily at the converter DC terminals and hence extinguishes the fault current. Since the converter is blocked, it loses all its control abilities including the control of voltage or reactive power at its AC terminals. The authors have previously investigated the capabilities of full-bridge MMC converters especially in clearing DC faults. A new technique has been developed for controlling the DC fault current to zero without blocking the converter. More information on this technique can be found in [4]. When the DC fault is detected, a controller, which is combined with the low-level switching logic, controls the dc side voltage in order to bring the DC fault current to zero. The main advantage of this method is that the converters can continue operation in “STATCOM mode” without interruptions. This would be a huge support especially for weak ac grids.

This paper discusses how this capability of the full-bridge MMC converter can be utilized in a multi-terminal system. The fault performance of multi-terminal system consisting full-bridge converters is then compared to a system utilizing half-bridge MMC converters and DC breakers.

1. DC FAULTS IN MULTI-TERMINAL VSC SYSTEMS

During a dc fault (pole to ground in a bipolar system or pole to pole in a symmetrical monopole system), the module capacitors in both half and full-bridge converters can discharge producing very large dc currents. The rate of change of current can be very large and therefore fast detection and interruption of fault current is needed in order to protect the converters.

A. DC Fault Detection

In a multi-terminal system, one important issue is the selective fault detection. It is required to quickly determine the faulted section in order to clear the fault and to keep the rest of the system running. The interruption on the healthy lines and converters should be minimal. One method is to use the differential currents; however this involves the communication and the communication delay and reliability are major factors. Typically the fault current rises so quickly and it exceeds the protective levels of IGBT values within few millisecond. Usually, the communication delay is larger than few millisecond and therefore some way of fault current limiting logic is required to avoid converter tripping by valve overcurrent protection.

- Fault current control is limited in half-bridge converter applications. One way is to increase the DC smoothing reactor size to reduce the rate of rise of the current. Other way is to use a fast DC breaker with current limiting capability [5].
- One advantage of full-bridge converters is that it can control the fault current itself. The active fault current control logic described in [4] can be used to keep the maximum fault current within a pre-defined value.

In the three terminal radial applications, the faulted line can be detected without using current differential or the communication. When a fault occurs, the dc fault detection logic in all three stations will pick the fault and take appropriate actions to reduce the dc fault current. The direction of the fault current at the middle station is different depending on the location of the fault.

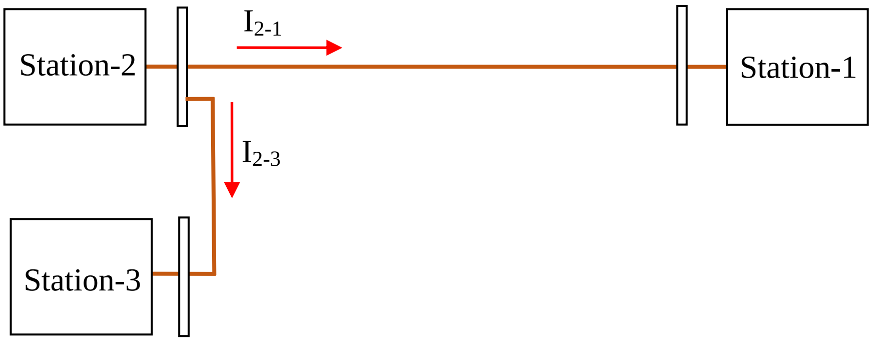

Figure 1: Identification of the faulted line

The middle station (Satation-2) is mainly utilized to identify the faulted section. For a dc fault in the system shown in Figure 1, the fault currents in the lines 2-1 and 2-3 at Station-2 are in opposite directions. The fault current always flows out of Station-2 into the faulted line. Therefore, the faulted line is identified by monitoring the direction of the line currents at Station-2. Once the faulted line is identified, it is disconnected from the system and the healthy part of the system is restored back to a new operating point determined by the dispatch center. If required, a few reclosing attempts can also be added.

A. Clearing DC Faults in Half Bridge Systems

There are two possible methods for clearing DC faults in point to point half-bridge VSC systems. One method is to block the converter once the fault is detected and then to open the AC breaker to stop the rising of fault current. When the fault current is dropped to a safe level, a mechanical DC breaker can be opened to isolate the faulted section. The other method is to use a fast DC breaker to isolate the faulted section. The requirement for blocking the converters depends on the operating time of the DC breaker. If the DC breaker can interrupt (or limit) the current before reaching the valve protective level, there is no need for blocking the converter. Furthermore, the size of DC smoothing reactor can be increased to reduce the rate of rise of the current and hence to allow more time for DC breaker to operate.
It is difficult to use the first method (i.e. AC breaker + mechanical DC breaker) for multi-terminal applications because of the need of blocking the converters and the longer fault clearing time. Therefore, the latter method was used in this study and the fast DC breaker configuration proposed in [5] was used.

A. Clearing DC Faults in Full Bridge Systems

One of the main advantages of the full-bridge converters over the half bridge is the ability to control both ac internal voltage and DC voltage independently (extra degree of freedom) over a full range of DC voltages. If required, the DC pole voltage can be reversed instantly by inserting the modules in the opposite direction while maintaining the ac voltage intact. The authors have shown in [4] how this ability can be utilized to control the dc fault current (Active DC Fault Current Control) without blocking the converters. When a DC fault is detected in one DC line section, the converters associated with that line section control the fault current to zero and high speed switches (HSS) or fast disconnects attached to the line section are operated to isolate the fault. The converters are switched back to normal operation once the HSSs are opened.

2. THREE TERMINAL TEST SYSTEM

EMT simulations using PSCAD was used to evaluate the performance of the DC fault clearance mechanisms of the full-bridge and half-bridge converters. The bipolar three terminal test system shown in Figure 2 was used in the studies. Each converter was rated for 1000 MW (i.e 2000 MW per station) and the rated DC voltage was 500 kV. As a worst case scenario, the ac system short circuit ratios were kept at 2.0. The DC voltage droop control proposed in [6] and [7] were used at all three stations. All the converters were controlling the terminal bus AC voltages individually. The converters were operated at the operating point given in **Table 1**.

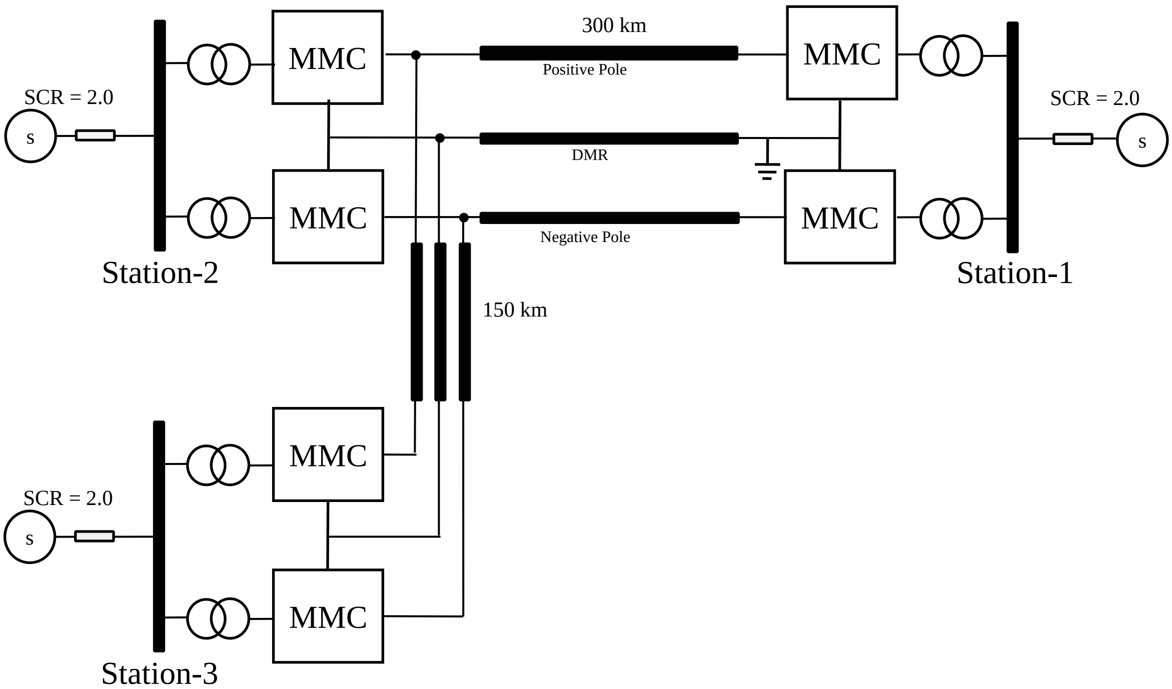

Figure 2: Three-Terminal VSC Test System

Table 1: Operating point of three terminal model

	DC Control			AC control	
	LRSP* (kV)	Pref (MW)/pole	Droop	Vac_ref (pu)	Droop
Station-1	500.0	1000	2%	1.0	1%
Station-2	481.9	600	5%	1.0	1%
Station-3	479.0	362	10%	1.0	1%

*LRSP – load reference set point

3. SIMULATION RESULTS

The performance of half-bridge and full-bridge converters in clearing DC fault in the three-terminal test system were compared against each other.

A. Temporary DC Faults

Figure 3 shows a comparison of the performance of the three-terminal system with half-bridge and full-bridge converters for a temporary DC fault on Line 1-2 close to Station-2.
The fault was detected using the local measurements of DC voltage and currents and their derivatives. At Station-2, where the fault was applied, the fault can be detected in about 2 ms and at the remote stations it takes up to 5 ms.

In the half bridge configuration, the fault was cleared by opening the DC breakers at all the stations without blocking the converters. The fast DC breakers used in this simulation takes about 1 ms to open after fault detection. Note that the reported DC breakers have a longer operation time, but in this analysis we used 1 ms to avoid blocking the converters. In order to keep the converter current within the protective level, it was required to use 100 mH DC smoothing reactors at the converters. Note that, this requirement is case dependent and needs to be determined through simulations/analysis. Once the fault was cleared, the DC breakers were closed and the system was restored back to its pre-fault operating point.

In the full bridge configuration, the active dc fault current control logic controlled the DC current to zero. Since the control logic can bring down the fault current within safe values (i.e. below rated DC current) in less than 1ms the full bridge configuration can be operated with lower DC smoothing reactor values (in this case, 20 mH was sufficient). However, for the comparison purposes, the same value as in half bridge configuration (i.e. 100 mH) was used in the simulation results presented. During the active fault current control, the high level controls were operated in the STATCOM mode. After the deionization time, the system was restarted by ramping up the DC voltages. Once the voltages were built up, each converter returned to normal operating mode. The building up of the DC voltage at each station indicates that the fault has been cleared and therefore, each station can be restored without any communication. That is, the high level controls are moved from STATCOM mode to normal (DC voltage droop control) mode and the power transfer is restored to the pre fault values.
The power transfer and the AC voltage support of the two configurations during the fault clearance is similar.

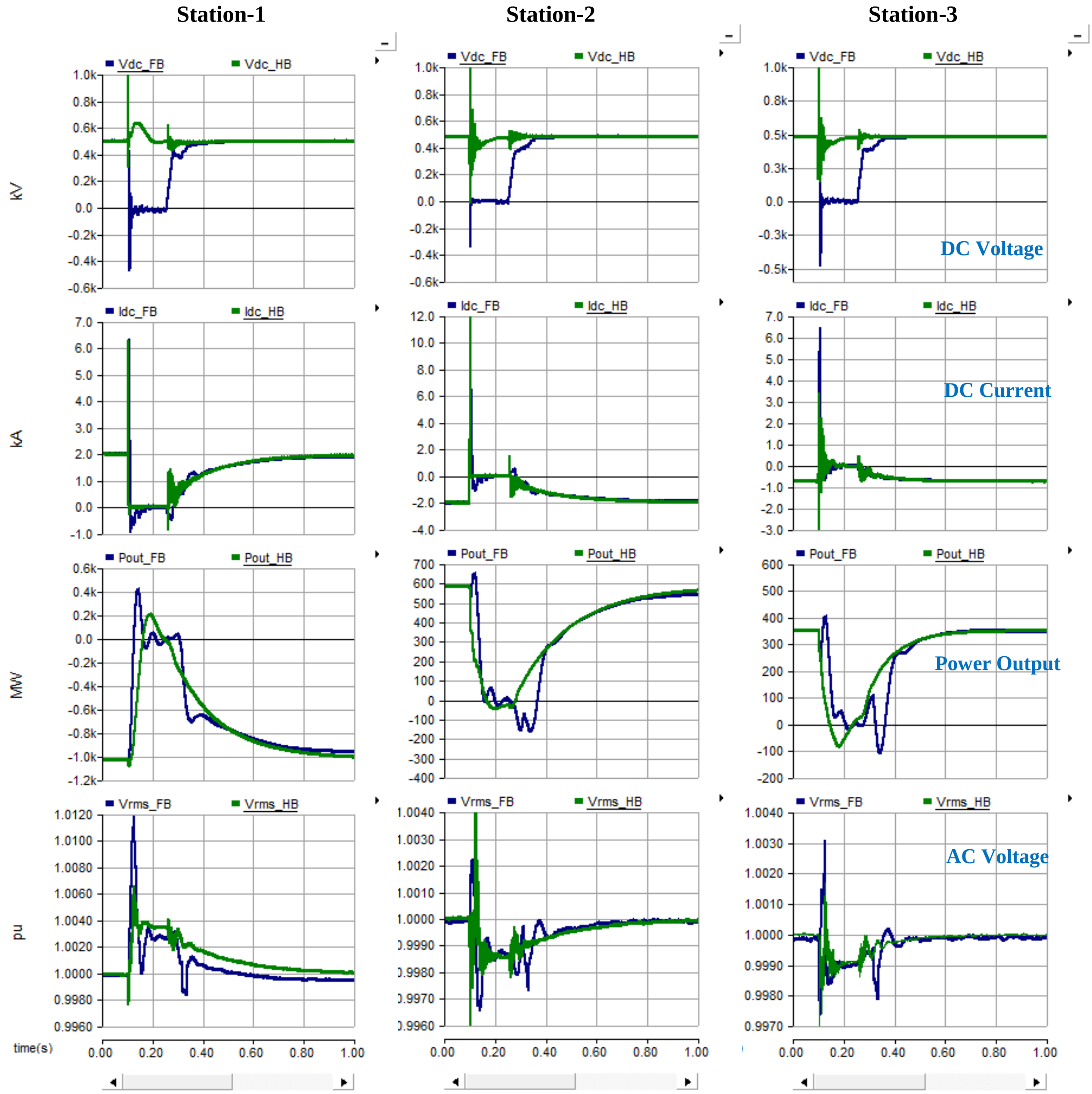

Figure 3: Performance of three-terminal VSC system for a temporary DC fault near Station-2 on the DC line from Station 1 to 2

B. *Permanent DC faults*

Figure 4 shows a comparison of the performance of the three-terminal system with half-bridge and full-bridge converters for a permanent DC fault on Line 1-2 close to Station-2. In this case three restarting attempts were considered. Note that the fast DC breakers may take considerable time to dissipate the energy stored before getting ready for the next operation. However, in this study, it is assumed that the fast DC breakers can re-operate after the deionization time considered.

As described in the temporary faults, the faulted section can be determined at Station-2. In half bridge configuration, the breaker reclosing times of Station-2 were set slightly lower than the others. During the first reclosing attempt, all the DC breakers are reclosed while monitoring currents. If the fault exists, only the DC breakers connected to the faulty line are tripped. Therefore, the second and third reclosing attempts are applied only for the faulted section. This was done through proper coordination of the current thresholds and reclosing timing.

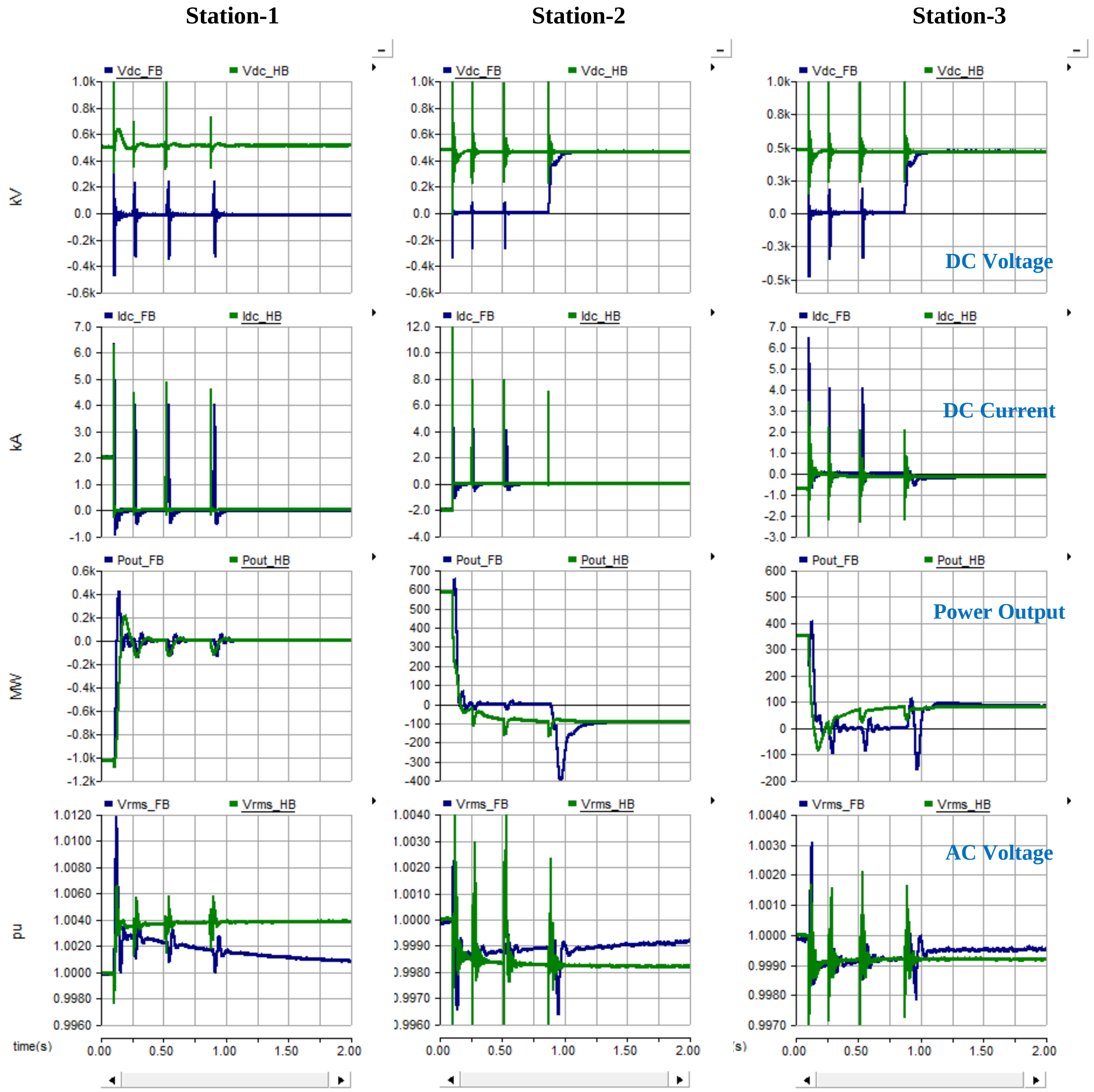

Figure 4: Performance of three-terminal VSC system for a permanent DC fault near Station-2 on the DC line from Station 1 to 2

The restating process is simpler in the full bridge configuration and it is done through controllers without any breaker operations (soft restarting). At each restarting attempt, the active current control logics at each station try to ramp up the DC voltage independently and the existence of the fault is detected by monitoring the current rise. After the second restart attempt, Station-2 opens HSS on the faulted DC line section. Therefore, in the third restarting attempt, the healthy section can be restarted. If the voltage is built up to the rated value the other station can switch into normal operating mode.

Both converter technologies demonstrated similar performance in reducing the fault current. The only advantage in the half bridge configuration is that the power transfer in the healthy section can be restored at the first restarting attempt.

4. CONCLUSIONS

The utilization of the controlled fault clearing capability of the full-bridge MMC converter in a multi-terminal system has been demonstrated. The fault clearing performance of multi-terminal system consisting of full-bridge converters has been compared to a system utilizing half-bridge MMC converters and fast DC breakers. The full-bridge converters demonstrated similar performance in clearing a dc fault in a multi-terminal system. In cases where multiple restart attempts are required, the healthy portion of a multi-terminal system employing half-bridge converters and DC breakers can be restored quicker than a system employing full-bridge converters. However, the performance of the half-bridge configuration depends on how fast the DC breaker can operate, if the DC breaker operation takes longer, converters may need to be blocked and larger smoothing reactors may be required.

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Research of the Control Strategies for the ±500kV Xiluodu-Guangdong Double-Circuit HVDC Project

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SUMMARY

The ±500kV Xiluodu-Guangdong HVDC transmission project is the first double-circuit project putting into operation in China and its rated DC power is 6400MW. This project is designed in a scheme that two DC circuits use common earth electrode, share primary equipments in AC yard and four DC transmission lines are erected on the same tower. In contrast to traditional bipole HVDC project, the double-circuit project need more complicated DC control system and control strategies. This paper focuses on the research of the control strategies for this project.

First, a well-designed hierarchical structure of the double-circuit DC control system is presented, as well as the control function configuration. Also a complete backup control scheme is introduced which increases the reliability of the control system.

Second, the double-circuit coordinate control strategies are researched carefully and the effective principles are presented in this paper. The main contents include the following aspects:

The total DC power coordinate strategy can ensure that DC power is assigned reasonably between two DC circuits under various operation modes. In case of emergencies such as pole trip, DC power can transfer rapidly between two DC circuits and the DC power loss can be reduced to minimum.

Power modulation can improve the performance of the whole AC/DC system. In double-circuit DC system, power modulation is designed as a double-circuit level function and it also need a coordinate control strategy between two DC circuits.

In this project, two DC circuits share the AC filters in AC yard to improve the utilization ratio of the equipments. The reactive power control strategy uses a kind of unified control way to ensure that the harmonic performance requirements are met and AC filters operate safely.

In this project, the current limit level of common earth electrode is designed according to traditional bipole HVDC project. The earth electrode current may reach almost twice the design level in some extreme cases, so the earth electrode current limitation function is required and it can reduce the common earth electrode current to the safety value quickly by an elaborate strategy.

Then, the island operation mode at the rectifier side is taken into account in this project and some special control strategies are required. It provides a close loop frequency control function to ensure frequency stability of the island AC system and an AC overvoltage control function to ensure the safety operation of primary equipments.

Research of this paper can provide some references for the design and implementation of similar projects such as ±800kV double-circuit UHVDC project.

KEYWORDS

Double Circuit HVDC - Coordinate Control Strategy - Common Earth Electrode- Island Operation

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0. Introduction

The Xiluodu power plant is the second-largest hydropower station in China and it supplies electric power to East China and South China. The ±500kV Xiluodu-Guangdong double-circuit HVDC project is the main channel from the hydropower plant to Guandong province in South China. The rated transmission power of this project is 6400MW and the DC transmission lines of each circut are about 1230 km long. This project is the first double-circuit HVDC project that has been put into commercial operation in China, it's completed in 2014 and works well until now.

The sending end is located in Zhaotong converter station of Yunnan province and the receiving end is located in Conghua converter station of Guandong province. The rated DC voltage is ±500kV and the rated AC voltage of each end is 525kV. To save investment and land resource, the project is designed in a scheme that two DC circuits use common earth electrode, share primary equipments in AC yard and four DC transmission lines are erected on the same tower[1].

Fig.1 shows the simplified one-line diagram of this project.

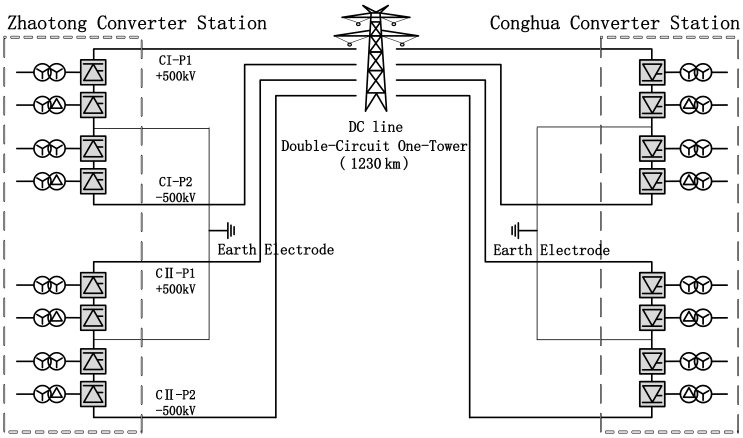

Fig.1 Simplified diagram of the ±500kV Xiluodu-Guangdong HVDC project

Compared with the traditional bipole HVDC project, the double-circuit HVDC project has huger transmission capacity. It needs more reliable DC control and protection system, also the control strategies are more complex. This paper focuses on the research of the control function configuration and control strategies for this double-circuit HVDC project.

1. Hierarchical structure and function configuration of the DC control system

Refer to the hierarchy principles for the DC control system in the IEC60633: 1998 standard[2] and the characteristics of this double-circuit HVDC project, several preliminary hierarchical structure schemes are listed and compared[3]. The final hierarchical structure scheme for this project shows in Fig.2.

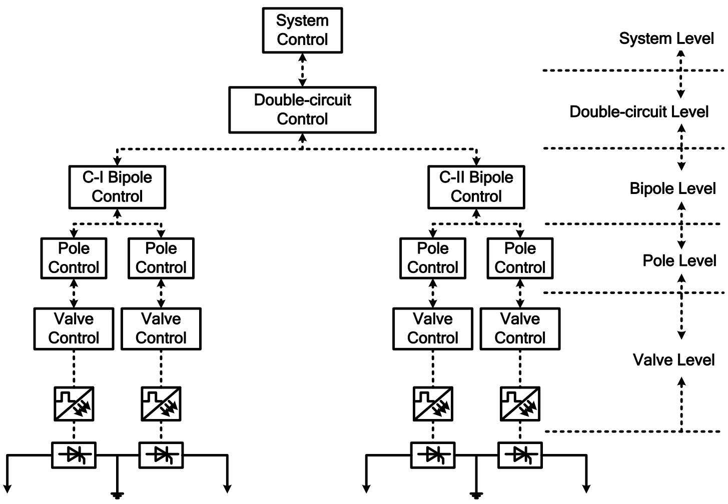

Fig.2 Hierarchical structure of the double-circuit DC control system

The double-circuit DC control system is divided into five hierarchical levels that include system level, double-circuit level, bipole level, pole level and valve level. System level is the top level and it handles the communication with the dispatching center. Double-circuit level is responsible for the overall and coordinate control functions. Bipole level is responsible for the bipole control functions related with one single-circuit DC system. Pole level and valve level are basically the same as the common bipolar system. This scheme has a clear hierarchical structure and relatively fewer information exchanges between different levels, also it considers the reliability requirements fully and embodies the characteristics of the double-circuit DC system better.

Because each pole has only one 12-pluse converter valve, the functions of pole level and valve level are configured into a same level equipment. Individual double-circuit level, bipole level and pole level equipments are configured in each converter station, also all level equipments adopt redundant configuration.

In the double-circuit level equipments, double-circuit DC power coordinate control function is used to coordinate the total active power and operation modes, power modulation function realizes the unified modulation control of the double-circuit DC system, reactive power control function realizes the unified control of the AC filters shared by two DC circuits, earth electrode current limitation function is used to monitor and control the common earth electrode current.

Considering the case that both the redundant double-circuit level equipments are lost, the double-circuit DC system will be unable to keep operating because the important functions are missing. To satisfy the reliability requirements of the double-circuit DC system, a complete backup control scheme is introduced and all the double-circuit level functions have backup in the lower bipole level. Table 1 shows the main control functions that are configured in the DC control system at different levels.

Table 1 Main control functions for the Xiluodu-Guangdong HVDC project

Control Level	**Main Control Functions**
Double-circuit Level	1. Double-circuit DC power coordinate control 2. Power modulation 3. Reactive power control 4. Earth electrode current limitation
Bipole Level	1. Mode control 2. Switch sequence and interlock control 3. Backup double-circuit DC power coordinate control 4. Backup power modulation 5. Backup reactive power control 6. Backup earth electrode current limitation
Pole Level (Valve Level)	1. Bipole power control 2. Pole power/current control 3. Converter firing control 4. Mode sequence control 5. Deblock/block sequence control 6. Overload limitation 7. Open Line Test 8. Tap changer control

2. Research of the control strategies for the double-circuit DC system

The Xiluodu-Guangdong HVDC project configures individual double-circuit level control equipments to realize the coordinate control of active power and reactive power. The double-circuit DC system can operate more flexibly by unified and coordinate control. In case of emergency, DC power can be transfered and reallocated between two DC circuits rapidly, thus the availability ratio and reliability of the whole system are higher than two separate single-circuit DC systems.

2.1 Double-circuit DC power coordinate control

In this project, two kinds of double-circuit DC power control modes are provided: joint mode and separate mode. In joint mode, the total DC power setting value is allocated automatically between two DC circuits by the double-circuit control system and the practical total DC power is maintained equal to the setting value. In separate mode, each DC circuit maintains its DC power equal to its own setting value.

In joint mode, the allocation of the total DC power considers every pole's DC voltage and operation status, etc. The basic strategy is that the allocated power of this circuit is in proportion to its total DC voltage (absolute value of pole 1 plus absolute value of pole 2). It can ensure that every pole's DC current is basically identical and the common earth electrode current is minimized. Meanwhile, synchronous start and stop of two DC circuits can be realized in joint mode.

Fig.3 shows the simplified block diagram for the double-circuit DC power coordinate control (C-I Radio and C-II Radio indicate the power allocation ratios of Circuit I and Circuit II respectively).

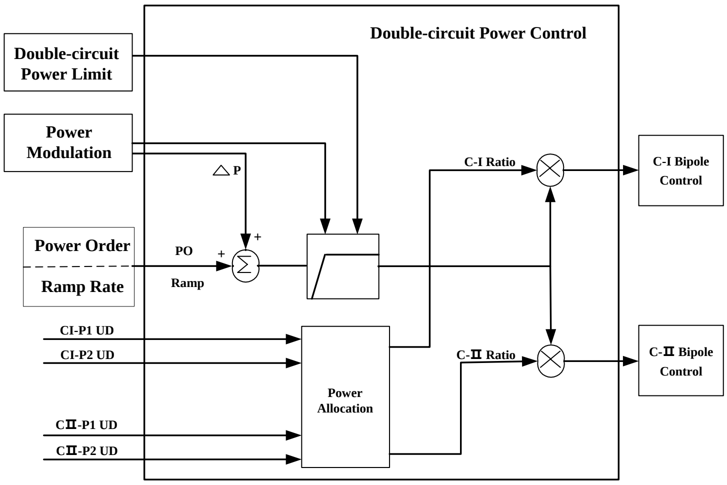

Fig.3 Simplified block diagram for the double-circuit DC power coordinate control

In joint mode, the double-circuit DC power coordinate control function can reallocate the total DC power automatically and reasonably according to the change of each pole's operation status. Factors that can cause DC power reallocation include: normal pole deblock and block, pole fault trip, power ramp, the change of power control mode, DC line fault recovery, the transfer between normal and reduced voltage operation, power or current limitation, etc.

Fig.4-a shows the test result that four poles start synchronously to the DC minimum power (0.1p.u.) in joint mode (OPN_CxPx indicates the operation status of each pole). It can been seen that each pole's changing procedure of the operation status and DC power is highly synchronous.

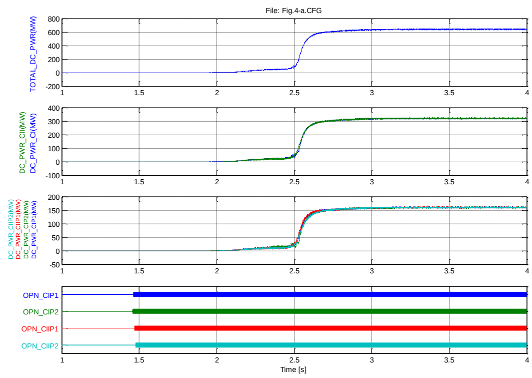

Fig.4-a

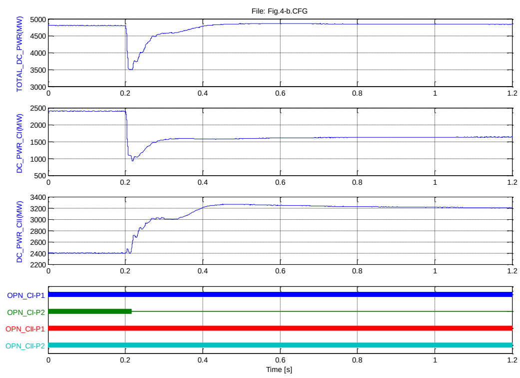

Fig.4-b

Fig.4 Test results of the double-circuit DC power coordinate control

Fig.4-b shows the test result in a case that four poles operate in joint mode and normal voltage, the double-circuit total DC power is 4800MW, then pole 2 of C-I is tripped. The total DC power is equally divided to both circuits and the DC power of each circuit is 2400MW at initial. After pole 2 of C-I is tripped, the loss of power is transfered to the other three poles evenly, the DC power of C-I is controled to 1600MW and C-II is controled to 3200MW at last.

It can been seen that rapid mutual support is provided between two DC circuits and the total DC power can recover to the pre-fault level quickly.

2.2 Power modulation

In this project, two DC circuits are linked to the same AC system and the stability control equipments are shared. The double-circuit level configures the interfaces to the stability control system and realizes the power modulation function. Considering the requirement of backup power modulation function, the stability control interfaces are also configured in the bipole level.

The major power modulation functions for this project include:

- Power runup / rundown
- Power limitation
- Frequency control
- Power swing damping control
- Low AC voltage limit power control

The power modulation function figures out the total modulation value and its allocation strategy is similar as the total DC power. One difference is that the allocation of power modulation value has nothing to do with the control modes and every operating pole can execute the power modulation value allocated. This strategy can ensure that every pole's DC current change caused by power modulation is basically identical in different control modes.

2.3 Reactive power control

In this project, the primary equipments in AC yard of each converter station are shared by two DC circuits. This scheme can perform better utility of the reactive power equipments and reduces the total number of the equipments.

The reactive power control takes a unified way to control the AC filter subbanks. The subbanks are switched on or off according to the operation status and total reactive power consumption of four poles. The reactive power control function is realized based on the reactive power strategy tables that are generated during the design of AC filters. In these strategy tables, the AC filter number requirements for the AC filter rating, harmonic filter performance and reactive power exchange are listed along with the change of the total DC power in different operation modes. One piece of strategy table corresponds to one or several operation modes.

Compared with the traditional single-circuit HVDC project, the operation mode combinations of the double-circuit HVDC project increase considerably. The Xiluodu-Guangdong HVDC project has 90 kinds of typical operation modes when considering normal voltage (100%), reduced voltage (80% and 70%), ground return and metallic return. So many operation modes will increase the number of reactive power strategy tables and the difficulty of the function implement. Thus an operation mode optimization strategy is adopted and the 80%-70% mixed voltage operation modes are all cancelled by a double-circuit voltage coordinate control strategy. The 100%-80% and 100%-70% mixed voltage operation modes are reserved. Table 2 shows the number change of the operation modes before and after optimizing.

Table 2 Operation mode number before and after 80%-70% mixed optimizing

Operating pole	**Operation mode number**	
	Considering 80%-70% mixed	**Not considering 80%-70% mixed**
One pole	6	6
Two poles	27	22
Three poles	36	22
Four poles	21	11
Total	90	61

Finally, this project provides 31 pieces of reactive power strategy tables for each station according to 61 kinds of operation modes after optimizing.

2.4 Common earth electrode current limitation

To save investment and earth electrode area, the common earth electrode scheme is adopted in this project. The earth electrode overcurrent level is designed the same as one single-circuit DC system, just equal to the overload value of one pole. Table 3 shows the current design level for the earth electrode.

Table 3 Earth electrode current design level for the Xiluodu-Guangdong HVDC project

Current level	**Current value**
Rated	1.0 p.u. (3200A)
3s overload	1.44 p.u. (4610A)

Long-term overload	1.22 p.u. (3903A)

With the common earth electrode, the total earth electrode current is determined by two DC circuits. In the extreme case that both the same polarity poles are tripped simultaneously, the earth electrode current will reach almost twice the design value. Too large current will cause serious detrimental impacts to the earth electrode safety, AC electric network and the surrounding environment. For this reason, earth electrode current limitation function is configured. When the earth electrode current exceeds the design level, the double-circuit control system will alarm and a request for DC power reduction will be sent out to decrease the earth electrode current to a safe level automatically.

The earth electrode current limitation function has two stages. When the earth electrode current measuring value exceeds 3s overload value, stage 1 will act immediately and decrease the earth electrode current below 3s overload value (80A as the dead band) by DC power reduction. When the earth electrode current exceeds long-term overload value more than 3s, stage 2 will act and decrease the earth electrode current below long-term overload value, then the earth electrode can operate continuously under this current level.

The DC power reduction value for each circuit can be calculated out in real time according to the limitation target value of the earth electrode, the operation status and DC power of each pole.

Fig.5 shows the test result in a case that four poles operate in joint mode and normal voltage, the double-circuit total DC power is 6400MW, then both pole 1 of each circuit are tripped (ID_CxPx indicates the DC current of each pole and IDEE indicates the common earth electrode current).

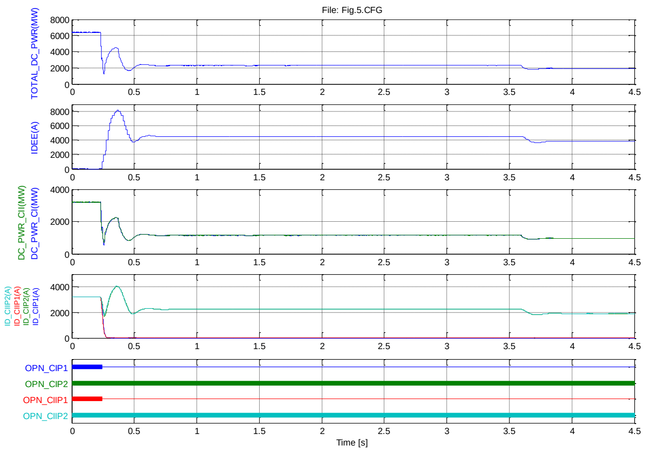

Fig.5 Test result of the common earth electrode current limitation

IDEE is approximately 0A at initial. When both pole 1 are tripped, IDEE reaches to an extremely large value (approximately 8180A), then it is limited to below 3s overload value (approximately 4530A) rapidly by stage 1 action. About 3s later, IDEE is limited to below long-term overload value (approximately 3820A) by stage 2 action once again.

It can been seen that IDEE is limited below the design level efficiently by the common earth electrode current limitation function, meanwhile the DC power reduction and the DC current change of each remaining pole 2 are highly synchronous.

3. Research of the control strategies for island operation

This project’s formal operation brings great impacts to the China southern power grid. To reduce the affect to the power grid safety in the cases such as pole fault trip, this project will adopt island operation mode at the sending end in some suitable conditions. Island operation can not only reduce the influences between the AC and DC system, but also improve the power transmission capability. Fig.6 shows the simplified diagram of the Xiluodu island system and the rated capacity of the generators equals 9×700MW.

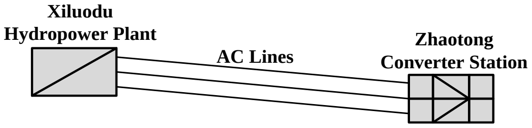

Fig.6 Simplified diagram of the Xiluodu island system

When island operation mode is adopted, the island ac system is relatively weak and it will face the problems such as system stability and overvoltage which are caused by AC or DC faults[4-6].

3.1 Frequency control

Research shows that a closed-loop frequency controller with appropriate parameters can better ensure the frequency stability of the island system. Fig.7 shows the transfer function diagram of the closed-loop frequency controller.

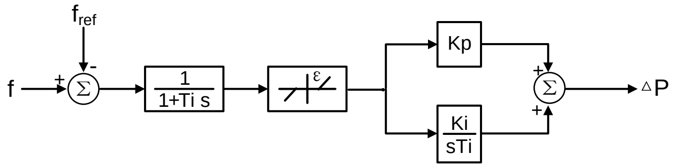

Fig.7 Transfer function diagram of the closed-loop frequency controller

Fig.8 shows the simulate results in a case that four poles operate in island mode, the double-circuit total DC power is 6400MW and nine generators are operating, then one generator is tripped (label 1 represents the result without the frequency controller and label 2 represents the result with the closed-loop frequency controller).

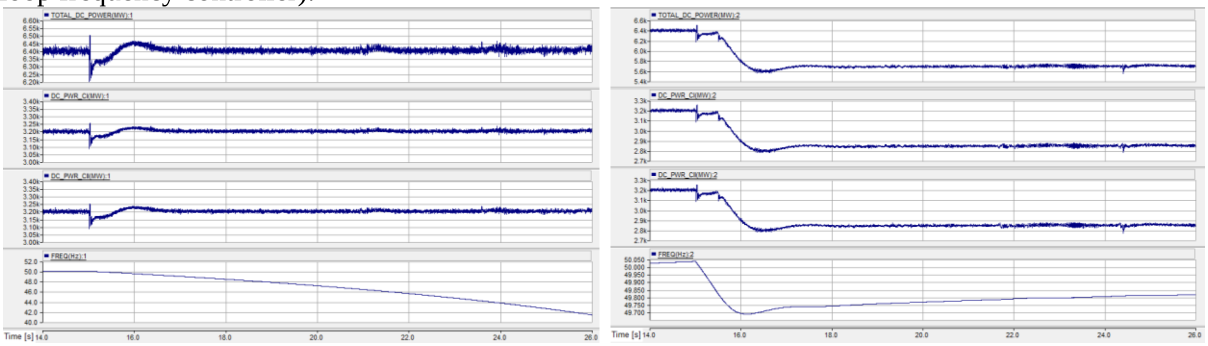

Fig.8 Simulate results of the frequency controller

After one generator is tripped, the total DC power remains unchanged and the island AC network frequency becomes lower and lower if no frequency controller works, the island system will lose stability if no other measures are taken. Conversely, when the closed-loop frequency controller works, the DC power of two DC circuits will decrease synchronously and the island AC network frequency can recover to the control range gradually.

It can been seen that the closed-loop frequency controller can ensure the frequency stability of the island system effectively.

3.2 AC overvoltage control

If four poles are blocked by faults simultaneously in island operation mode, an extremely serious AC overvoltage problem will appear because of the situation that all the AC filters are connected to the generators with noload AC lines[7].

Research shows that appropriate AC overvoltage control strategies can restrain the overvoltage level of island system effectively. The main control strategies for this project include:

1) Different time delays are configured to different overvoltage levels. When the AC voltage reaches the corresponding overvoltage level and the time delay is fulfilled, the AC filters will be switched off quickly in sequence.

2) When the AC voltage reaches an extremely high level, an order switching off all the AC filters simultaneously will be executed.

3) During the pole fault blocking period, the strategy putting off the trip of the converter transformer breaker can restrain the transient overvoltage level to some extent. The reason is that the converter transformer core will saturate in the role of overvoltage, the magnetizing current will increase and the reactive power comsumption will increase.

Fig.9 shows the logic diagram of the AC filter switching off strategies. Ulim is the overvoltage limit level (Ulim4> Ulim3> Ulim2> Ulim1) and T is the time delay (T4< T3< T2<T1).

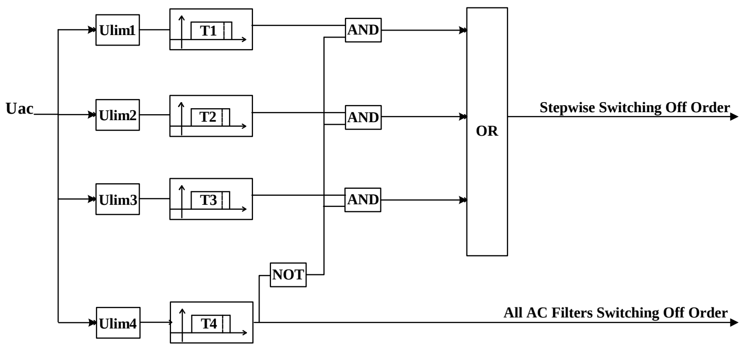

Fig.9 Logic diagram of the AC filter switching off strategies

Fig.10 shows the simulate results in a case that four poles operate in island mode and the double-circuit total DC power is 6400MW, then four poles are blocked simultaneously (label 1 represents the result without the AC overvoltage control strategies and label 2 represents the result with the control strategies). The metal oxide arresters (MOA) are considered in the simulate model and the AC overvoltage per-unit value is 550kV.

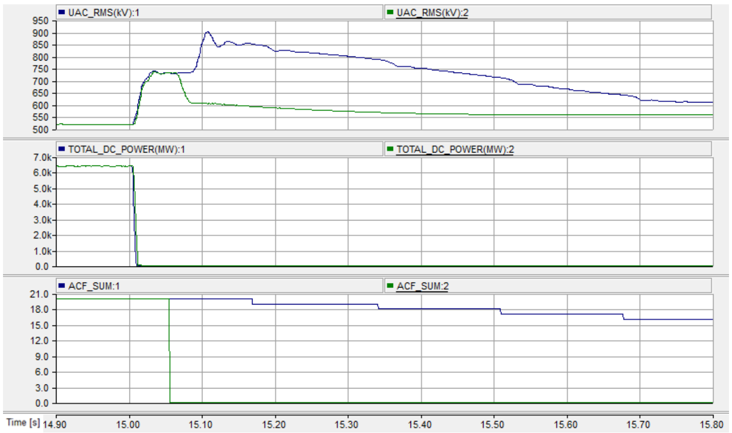

Fig.10 Simulate results of AC overvoltage control strategies

The AC voltage rms(UAC_RMS) peak value reaches approximately 901kV (1.638 p.u.) without the AC overvoltage control strategies. Conversely, the AC voltage rms peak value is reduced to approximately 736kV (1.338 p.u.) with these AC overvoltage control strategies.

It can been seen that the AC overvoltage control strategies proposed before can restrain the AC overvoltage level of the island system effectively.

4. Conclusion

This paper presents the research results of the control system configuration and control strategies for the ±500kV Xiluodu-Guangdong double-circuit HVDC project.

The hierarchical structure and function configuration scheme of the double-circuit DC control system not only embodies the characteristics of the double-circuit DC system, but also fulfill its high reliability requirement. The double-circuit DC coordinate control strategies and island operation control strategies for this project are also researched detailedly and the test results given out confirm the efficiency of these strategies.

Research of this paper can provide some references for the design and implementation of similar projects such as ±800kV double-circuit UHVDC project.

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Effect of Mutual Coupling of Parallel AC Lines on ± 800kV HVDC Lines: A Case Study for ± 800kV, 3000 MW Champa - Kurukshetra HVDC Link

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SUMMARY

Due to growing network of high voltage lines, the existence of HVDC lines and HVAC lines in close corridors is highly probable scenario. In Indian power system network, there are numerous HVAC lines running parallel or close by HVDC lines. The induction from these HVAC lines may cause problems in the smooth operation of HVDC links. The induction could be due to either capacitive coupling and/or inductive coupling.

±800 kV, 3000 MW Champa-Kurukshetra HVDC Bipolar link is being under execution is intended to export power from Champa generation complex in Western Region to Kurukshetra, Northern Region. The HVDC line length has been considered as 1305 km length. As the HVDC line passes through the Northern and Western regions, where large number of 400kV and 765 kV high voltage lines are present, the possibility of severe inductions is a matter of concern.

In this paper, the induction from parallel 400 kV double circuit and 765 kV single circuit AC lines on the 800 kV Champa - Kurukshetra HVDC line is estimated using PSCAD simulation. The effect of various operating conditions/configurations and other parameters on the induction are also considered in the simulation.
If higher values of induced currents are found; it will be necessary to take mitigation measures such as transposition of AC lines, blocking filter in DC link and DC control system modulation etc.

KEYWORDS

HVDC, Electro-magnetic Induction, PSCAD, CIGRE bench mark model.

1. INTRODUCTION

When an AC transmission line runs parallel to DC transmission line, capacitive as well as inductive coupling exists between the AC and DC lines. This can result in induced voltage and current on both ac and dc lines. In steady state a fundamental frequency component (50Hz) will be induced on DC line and a DC component in the AC lines. From HVDC link design point of view this fundamental frequency component may affect converter transformer due to DC offset. The dc component offsets the flux to cause saturation of the converter transformer and thus generation of harmonics [1]. The fundamental frequency component may induce harmonics through converter operation which needs to be considered in AC and DC filter design.

The electromagnetic coupling between lines primarily depends on following :

- Distance between ac and dc lines.
- Length of coupled sections
- Soil resistivity
- Transposition of ac line

Further induced voltages and currents on dc line may be influenced by power flowing on ac line, impedance of converter transformer and terminating impedance as seen by the dc line.

The fundamental frequency induction from HVAC lines is evaluated through PSCAD simulation. A model for ±800kV, 3000 MW Champa - Kurukshetra Bipole was developed in PSCAD from the HVDC CIGRE bench mark model for HVDC[2]. The HVDC system parameters are in accordance with the project specifications. The HVDC line consists of two Pole Conductors and two Dedicated Metallic Return (DMR) Conductors. The Pole conductors carry pole current at Pole voltage and DMRs are used to carry unbalance current during Bipolar operation and return current during monopolar operation. The 400 kV Double circuit and 765 kV single circuit towers are modelled with minimum conductor to conductor separation from HVDC line. The details of HVDC, rectifier AC system and inverter AC system is given in table 1.

Rated Power	3000MW	Nominal alpha	13.5 degree
DC System Voltage	± 800kV	Nominal gamma	18 degree
Rated DC current	1875A	AC system frequency	50 Hz
AC voltage at Champa	400kV	AC Voltage at Kurukshetra	400kV

Table 1 : Details of HVDC and AC system

3. PSCAD/EMTDC MODELING

The HVDC bipolar system with converter transformers, ac harmonic filters, DC harmonic filters, smoothing reactors, DC line with Pole conductors and Dedicated Metallic Return (DMR) conductors are modelled in PSCAD as shown in figure 1 and 2 with project specific parameters. The ac sources are represented as voltage sources behind short circuit impedances at Champa (Rectifier) and Kurukshetra (Inverter) end. The HVDC Controls from the CIGRE benchmark model are employed in the Champa-Kurukshetra HVDC link model.

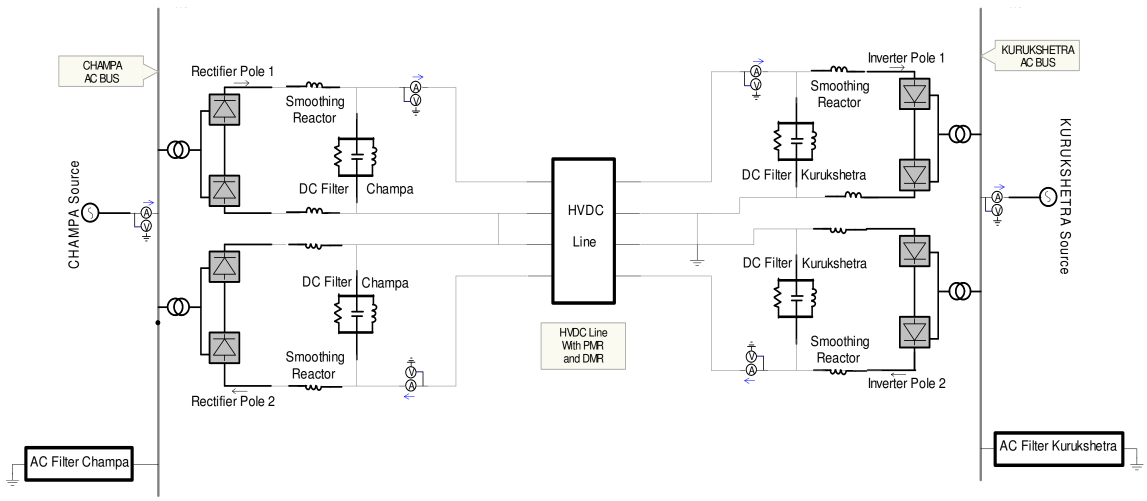


Figure 1: Champa - Kurukshetra HVDC Bipole model in PSCAD

The HVDC tower is modelled as two separate towers with zero horizontal spacing between them as shown in figure 2, since PSCAD doesn't allow modelling of different conductor types on the same tower. The Pole conductors are hexa ACSR lapwing and DMR conductors are twin ACSR lapwing and their details are given in figure 3.

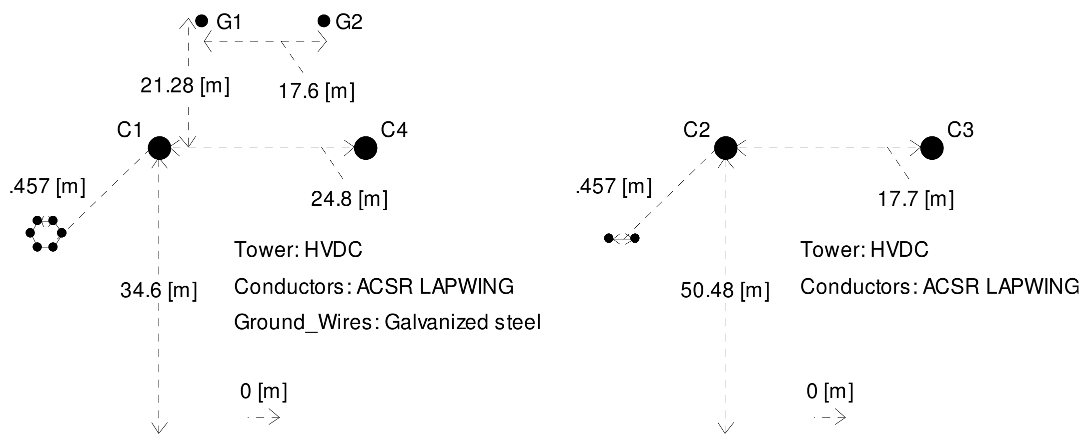


Figure 2 : HVDC Bipole tower modelled in PSCAD

Data Entry Configuration	
Data entry method	direct
Path to conductor library file	C:\home\user\pscad\lir
Conductor style is	solid core
Conductor Properties	
Name	ACSR LAPWING
Outer radius	0.01487 [m]
Inner radius	0.0 [m]
Total number of strands	19
Total number of outer strands	12
Strand radius	0.003 [m]
DC resistance (entire conductor)	0.03583 [ohm/km]
Relative permeability	1.0
Sag (all conductors)	14.916 [m]
Sub-Conductor Bundling	
Total bundled sub-conductors	6
Bundle configuration is	symmetrical
Sub-conductor spacing	.457 [m]
Bundle graphic is	visible

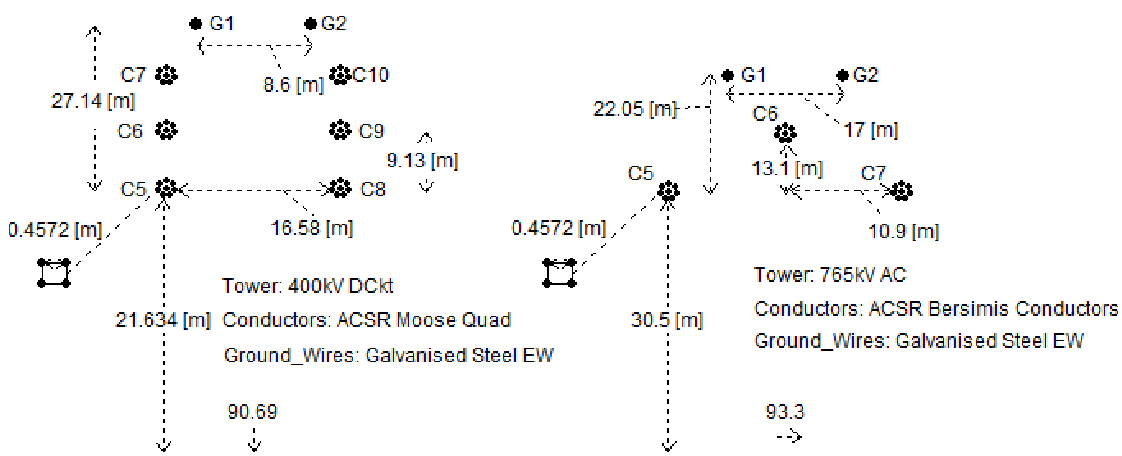
Pole Conductor details

Data Entry Configuration	
Data entry method	direct
Path to conductor library file	C:\home\user\pscad\l
Conductor style is	solid core
Conductor Properties	
Name	ACSR LAPWING
Outer radius	0.01487 [m]
Inner radius	0.0 [m]
Total number of strands	19
Total number of outer strands	12
Strand radius	0.003 [m]
DC resistance (entire conductor)	0.03583 [ohm/km]
Relative permeability	1.0
Sag (all conductors)	14.916 [m]
Sub-Conductor Bundling	
Total bundled sub-conductors	2
Bundle configuration is	symmetrical
Sub-conductor spacing	.457 [m]
Bundle graphic is	visible

DMR Conductor details

Figure 3 : Pole conductor and Dedicated Metallic Return conductor details in PSCAD

The 400 kV double circuit and 765 kV single circuit parallel AC lines are modelled in accordance with the tower and conductor configurations used in general. Their representation is shown in figure 4 and 5.



400kV Double Circuit Tower

765kV Single Circuit Tower

Figure 4 : 400 kV D/C and 765 kV S/C tower modelled in PSCAD

Data Entry Configuration	
Data entry method	direct
Path to conductor library file	..\conductor.clb
Conductor style is	stranded
Conductor Properties	
Name	ACSR Moose Quad
Outer radius	0.015885 [m]
Inner radius	0.0 [m]
Total number of strands	61
Total number of outer strands	24
Strand radius	0.001765 [m]
DC resistance (entire conductor)	0.01388 [ohm/km]
Relative permeability	1.0
Sag (all conductors)	12.8 [m]
Sub-Conductor Bundling	
Total bundled sub-conductors	4
Bundle configuration is	symmetrical
Sub-conductor spacing	0.4572 [m]
Bundle graphic is	visible

400kV Conductor Details

Data Entry Configuration	
Data entry method	direct
Path to conductor library file	..\conductor.clb
Conductor style is	stranded
Conductor Properties	
Name	ACSR Bersimis Conductors
Outer radius	0.017525 [m]
Inner radius	0.0 [m]
Total number of strands	49
Total number of outer strands	20
Strand radius	0.002285 [m]
DC resistance (entire conductor)	0.010605 [ohm/km]
Relative permeability	1.0
Sag (all conductors)	14.84 [m]
Sub-Conductor Bundling	
Total bundled sub-conductors	4
Bundle configuration is	symmetrical
Sub-conductor spacing	0.4572 [m]
Bundle graphic is	visible

765kV Conductor Details

Figure 5 : 400 kV D/C and 765 kV S/C conductor details in PSCAD

The coupling between HVDC tower and AC tower is represented by specifying the horizontal separation between the centres of both towers. The separation from outer conductor of AC line to HVDC line is 70m which is minimum separation and a conservative consideration. The induction due to 400 kV Double circuit and 765 kV single circuit are measured separately.

4. CASE STUDY

A. Objective

The Technical specification for Champa-Kurukshetra HVDC link takes in to account the possible AC line inductions. For estimating impact of parallel AC line induction, it mentions :

"As per initial survey there is 50 Km of parallel untransposed 765 kV and 50 Km of parallel untransposed 400 kV AC D/C line (with loading up to thermal rating) with the HVDC line within a radial distance of 70 meters. For 765 KV S/C thermal loading may be assumed as 2800 MW and for 400KV quad single circuit line as 1600MW"

Based on the above, it is necessary to take in to account of presence of both 400 kV double circuit and 765 kV single circuit lines to determine the worst possible induced current. Also taking in to account the future extensions involving parallel AC lines in excess of 50 kilometres, a set of cases were run with parallel 100 kilometre lines.

The induced currents were measured at the DC line and neutral side for all the cases.

B. System operating configurations

Champa-Kurukshetra HVDC Bipolar system with dedicated metallic return may operate in any of the following operating configurations in Bipolar mode:

- Bipolar with two DMRs.
- Bipolar with single DMR.

During Monopolar operation, if the Pole conductor of the other pole is available, it may operate with Pole Metallic Return (PMR) in parallel with DMR. Therefore, considering all combinations in monopolar operation, the following are possible operating configurations :

- Monopolar with two DMRs.
- Monopolar with single DMR.
- Monopolar with two DMRs and single PMR.
- Monopolar with single DMR and single PMR.
- Monopolar with single PMR.

C. Variation due to other factors

The variation of induced current due to other factors [3][4][5][6] like ground resistivity, horizontal separation of AC lines from HVDC tower, loading of the parallel AC lines, location of parallel AC lines from the rectifier end and transposition of AC lines are considered for the different operating configurations of Champa -Kurukshetra project.

5. RESULTS AND DISCUSSIONS

Influences of the following parameters on the peak value of induced fundamental current in the HVDC lines have been simulated and analysed :

A. Ground resistivity

The induced current was found to increase slightly with increase in ground resistivity. The induced current measured at the inverter end in normal bipolar operation with two DMR conductors increased from 0.5 A to 1.02 A when the resistivity was varied from 100 Ohm meter to 3000 Ohm meters thus increase in ground resistivity doesn't have significant effect on the induced currents. The ground resistivity of 300 Ohm meters was chosen for both Champa and Kurukshetra stations in the simulations.

B. Horizontal separation of AC line from HVDC line

The induced current in the HVDC conductors was found to decrease with increase in separation of the parallel AC line from the HVDC line. The induced current measured at the inverter in normal bipolar operation with two DMR conductors decreased from 2.03 A to 0.44 A when the horizontal separation was varied from 100 meters to 400 meters. The maximum induced currents are observed when separation between HVDC tower and AC tower is least i.e. 70m.

C. Loading of parallel AC line

The induced current as expected is higher when the loading of parallel AC line was higher. Variation of induced current with line loading measured at rectifier side of pole 1 in bipolar operation with two DMR conductors due to 765kV AC line in parallel for 50km length is shown below. Both the 765kV line and 400kV double circuit lines were loaded up to their respective thermal loading limits of 2800 MW and 1566 MW. For estimating the highest induced current in the remaining configurations, the maximum loading for 400kV double circuit and 765kV single circuit are considered.

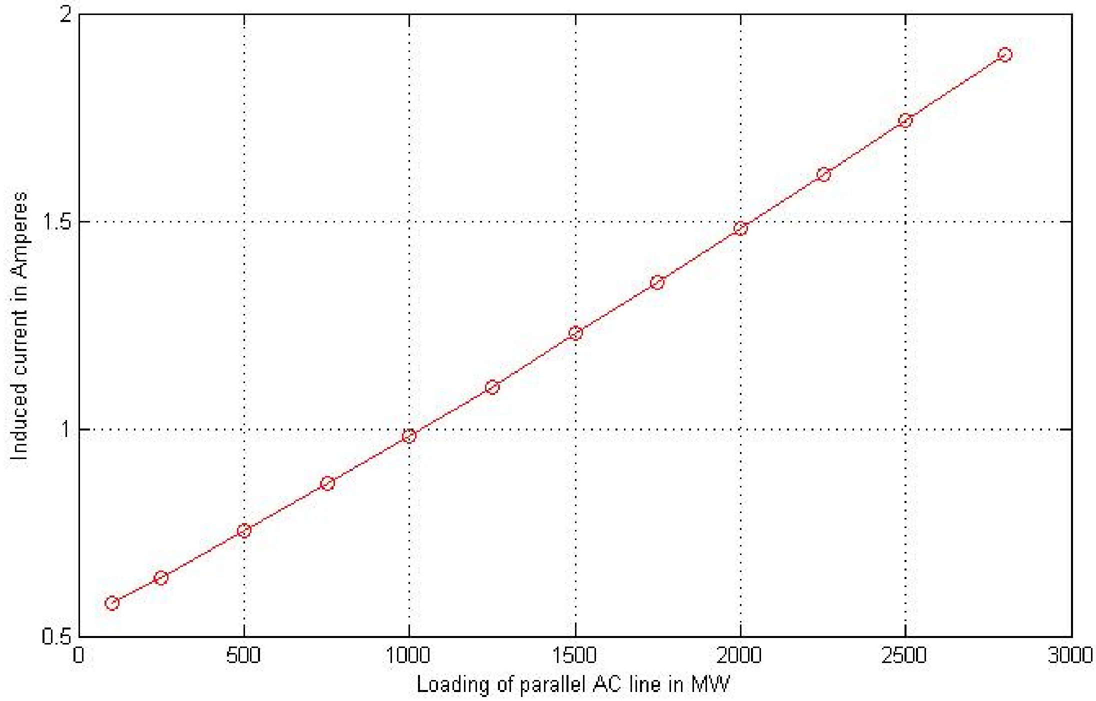


Figure 5 : Variation of induced current measured at rectifier DC bus pole 1 with parallel 765kV AC line loading

D. Location of AC line

The location of parallel line is changed from rectifier end to the inverter end for all the operating configurations to observe the highest induced current. The plots shown below corresponds to maximum induced fundamental current due to parallel 400kV and 765kV AC lines, which is observed at the neutral bus of HVDC in monopolar operation with pole conductor and two DMR conductors in parallel. The induced current variation follows a sinusoidal pattern with peak observed between the midpoint of the line and inverter end.

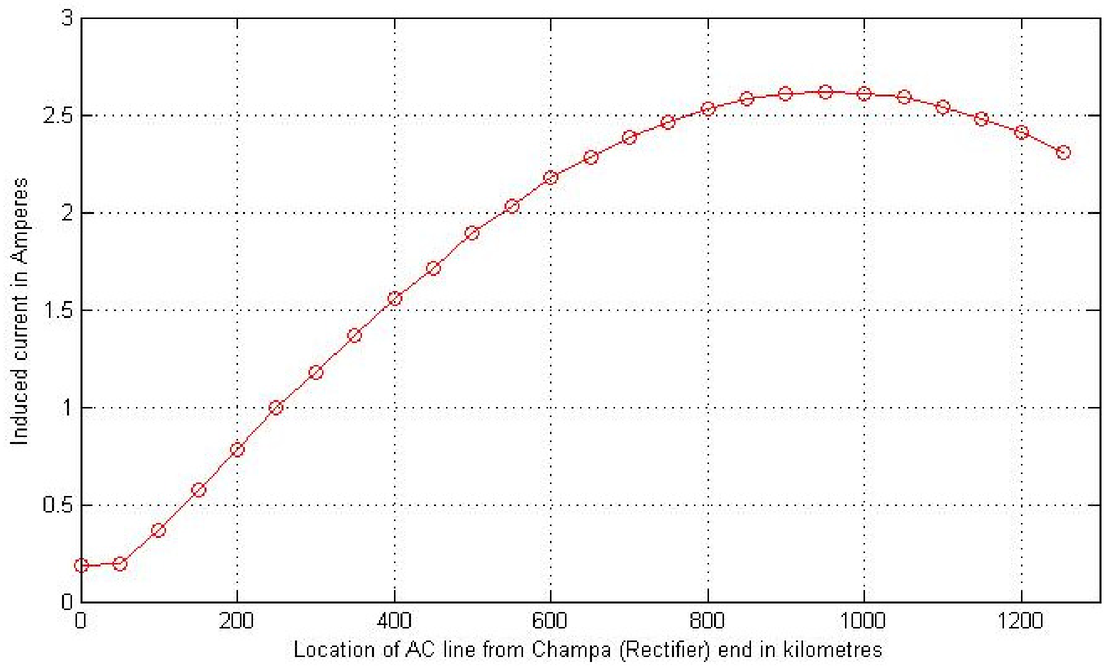


Figure 6 : Variation of induced current measured at neutral bus at Kurukshetra with parallel 400 kV AC line location

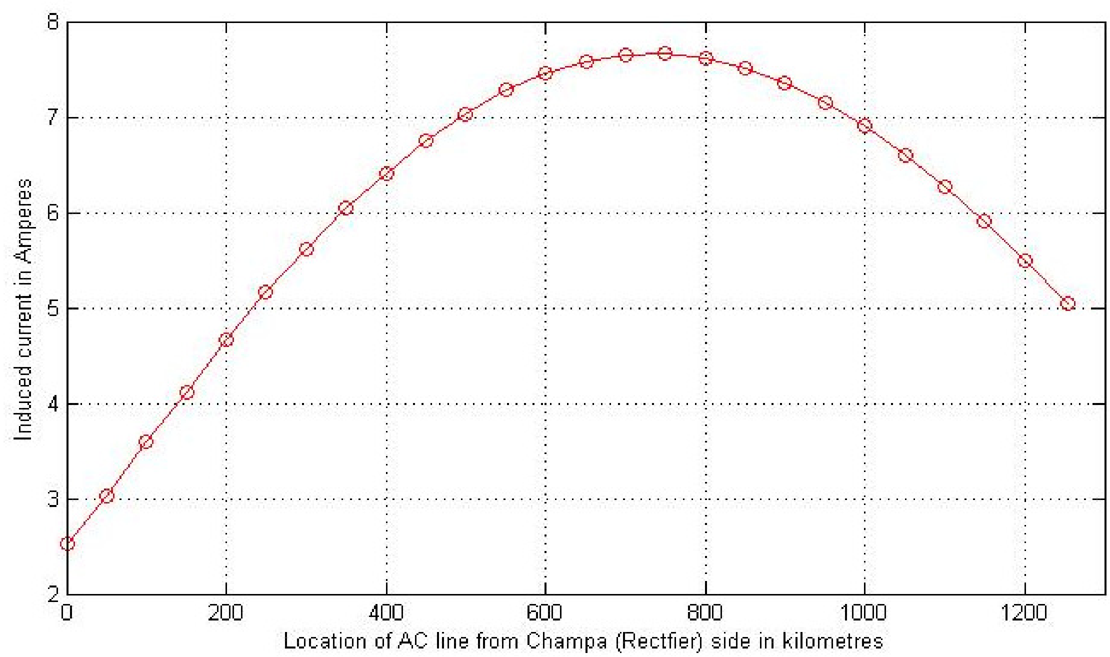


Figure 6 : Variation of induced current measured at neutral bus at Kurukshetra with parallel 765 kV AC line location

E. Different operating configurations of HVDC

Induced current measured for different operating configurations of Champa-Kurukshetra bipolar link with AC lines in parallel is shown in the table 2.

Operating configurations	765 kV single circuit line	400 kV double circuit line
	50 km	50 km
Bipolar with single DMR	5.53A	1.78 A
Bipolar with two DMRs	4.78A	1.55 A
Monopolar with single DMR	5.88A	1.83 A
Monopolar with one DMR and PMR	6.85A	2.33 A
Monopolar with two DMRs	6.01A	2.08 A
Monopolar with two DMRs and PMR	7.66A	2.62 A
Monopolar with PMR	5.94A	2 A

Table 2 : Induced current for different operating configurations with parallel AC line

A similar set of cases were done for parallel AC lines of 100km length and the pattern of peak value of induced currents followed the same as that for 50km AC lines with an increase in magnitude of around 97% . So, the induced fundamental current increases drastically if the length of the parallel ac lines increases.

F. Transposition of AC lines

The above cases when rerun with ideal transposition option available in PSCAD, the induced currents observed are very negligible.

The induced fundamental current in the HVDC line will result in dc and second harmonic component in the secondary of converter transformer.

5. MITIGATION METHODS

The mitigation methods to reduce effect of coupling include transposition of AC lines, blocking filter in DC link and DC control system modulation. However DC control modulation to limit induced current is generally not followed as it has limitation on modulation amount and it may produce non characteristic harmonics.

6. CONCLUSION

In the paper the induced currents have been estimated from parallel AC lines on Champa-Kurukshetra HVDC line. The impact of various factors which affect this phenomenon have been studied by PSCAD simulations. Based on the results, for Champa Kurukshetra HVDC project the following conclusions are arrived :

1. *Operating configurations*
   The induced current is found to be relatively higher in monopolar operating configuration. The highest induced current in the HVDC line was observed for monopolar configuration with two DMR conductors and pole conductor in parallel in the return path. The induced currents for a parallel AC line section of 50 kilometres is 7.66A for 765kV line and 2.62A for 400kV line.

2. *Separation*
   The induced current is higher when the AC lines are near to the HVDC line and it decreases as the separation increases.

3. *Line loading*
   The induced current increases linearly with increase in the line loading. For conservative estimation, thermal loading of both 400kV and 765kV lines are considered which results in highest induced currents.

4. *Resistivity*
   Resistivity has negligible influence on the induced currents and increase slightly with increase in earth resistivity.

5. *Location of parallel AC line from rectifier end*
   The peak value of induced current is significantly affected by the location of parallel AC line. The variation follows a sinusoidal pattern with their maximum values observed at different locations for different operating configurations of HVDC.

As per reference paper [1] one percent (1%) and above level of fundamental frequency current would cause a noticeable impact upon system performance. For the range of 0.1 % and 1 % the impact would depend on the design of the converter transformers and control and protective functions.

Worst possible induced currents on HVDC line for 50km parallel section of both 400 kV and 765 kV is 10.28 A (arithmetic sum of peak value of induced currents for 400 kV and 765 kV) which is 0.55 % of rated DC current and well below 1% level.

The induced dc current in the valve windings is given by the formula [1] :

$$I_{dc} = \left(\frac{\sqrt{3}}{\pi} \right) I_{50}$$

Where :

I_{dc} is the dc current in the valve.
I_{50} is the peak induced fundamental current in the HVDC line.

Based on the above equation, the maximum DC current through the valve windings comes to be 5.67A. The converter transformer valve windings for this project are designed for 10A dc. Therefore, the maximum DC current in the valve winding of the converter transformers from the induction is well below the proposed limit of 10A dc. In addition the converter transformers are designed to carry 30 A DC through neutrals on primary side. However to take care the uncertainties and unforeseen parallelism of AC lines along the route of DC lines a blocking filter is proposed to be kept in the neutrals of converters at Kurukshetra end. With these precautions, the performance of the +/- 800 kV Champa Kurukshetra HVDC transmission link is expected to be not effected by the specified parallel AC lines.

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Feasibility Study for 6000MW Raigarh(Chattisgarh) - Pugalur (Tamil Nadu) - Trichur (Kerala) HVDC Transmission

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SUMMARY

The long distance HVDC transmission links are most optimum solution for bulk power transfer from remote generation to load centres. A number of ±500 kV bulk power HVDC links are in operation and some ±800kV HVDC links are under execution in Indian power system. As per the approval of Ministry of Power, an HVDC link shall be established to export 6000MW power from Raigarh near Kotra generation complex to the beneficiary states of Tamil Nadu and Kerala. Various generation/IPPs such as Jindal, GMR, Lanco etc are coming up in Chhattisgarh(Western Region). Out of the total 6000MW generation in Raigarh complex, Tamil Nadu has a share of 4000MW and Kerala has a share of 2000MW. Considering technological complexities involved with such bulk power long distance HVDC projects, previous experience and time constraints for this project, POWERGRID shall execute this transmission scheme. The possible HVDC Transmission scheme shall be selected based on technical and economical feasibility of various options considering various factors. The options of various HVDC configurations have been evaluated with due consideration to

- Right of Way issues (ROW), foot print area of converter station.
- Power control flexibility (Active and Reactive) and system constraints.
- Present and future additions of large renewable generations in Tamil Nadu(TN).

The options which have been evaluated to select a HVDC scheme for the 6000MW transmission system are based on the following factors:

- Muti-terminal configuration with Parallel Bipole configuration or Single Bipole with series converter topology
- Two separate HVDC links, one between Raigarh-Pugalur (6000MW) and another HVDC link between Pugalur-Trichur(2000MW)
- The interconnection between Pugalur and Trichur via overhead line, overhead + underground HVDC cable due to right of way constraints in Kerala
- In case of two separate links, selection between Line Commutated Converter (LCC) or Voltage Source Converter(VSC) technology for the 2000MW link between Pugalur to Trichur considering Right of Way and system considerations.

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In all the possible options an 800kV HVDC line shall be constructed between Raigarh and Pugalur. However there is Right of Way (ROW) issue for HVDC line between Pugalur(Tamil Nadu) and Trichur(Kerala). Hence underground cable may be feasible due to anticipated ROW issues. The second option of Series Multi terminal configuration has some operational restrictions i.e. the power requirement of two constituents may not be met simultaneously and operation of both inverters are interdependent. The third option seems to be a better one with inherent VSC HVDC advantages as compared to LCC in terms of use of XLPE cable instead of costly MI cable, minimize interaction between two tightly coupled HVDC converters, dynamic voltage regulation and reactive power control to mitigate the problems associated with large renewable generation, minimum requirement of short circuit strength, smaller footprint area, black start capability etc.
The return path for DC current for 6000MW Raigarh-Pugalur Bipolar HVDC link has been envisaged via a Dedicated Metallic Return conductor instead of ground return to mitigate the issues and uncertainty with soil resistivity. The paper shall present an analysis of each of the above possible options with due consideration to all factors (technological, environmental etc.) and presenting the optimum HVDC scheme solution.

KEYWORDS

Master control, DMR (Dedicated Metallic Return), Joint FST (Factory System Testing), interaction

I INTRODUCTION

The scheme has bulk power of 6000MW which is to be transmitted over a long distance of around 1850 km between Raigarh to Pugalur and around 250 km between Pugalur to Trichur.
Therefore, HVDC is the obvious choice for transmission technology due to its techno-economic advantages. Further, the dc voltage level has been selected at 800 kV because of following reasons:

- Lower line losses
- Previous experience of 800kV DC links with Multi-terminal as well as Parallel Bipole configurations.

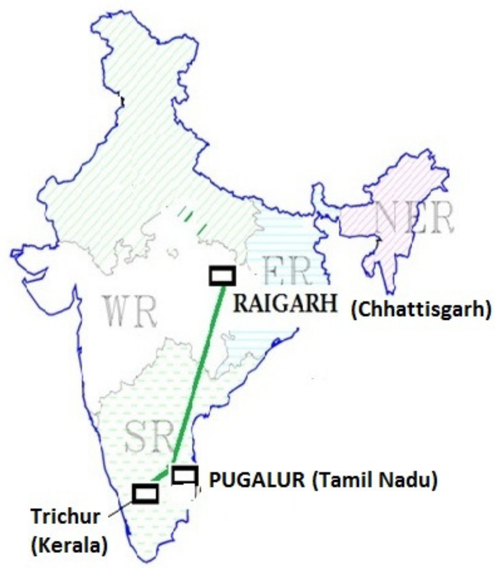


Fig 1:Map of India showing Chatttisgarh, Tamil Nadu and Kerala

The scheme has generation in Chattisgarh (Jharkhand) and the beneficiary states are Tamilnadu and Kerala. During the planning of the scheme based on HVDC, various configuration options were evaluated. The HVDC link options considered before finalizing the scheme have been discussed in the paper. Each scheme option was evaluated from technical and economical considerations.

II HVDC SCHEME OPTIONS:

The options which have been evaluated to select a scheme for the 6000MW transmission system are discussed below:

Option-1:

±800kV Parallel Multiterminal configuration using Line Commutated Converter technology with Rectifier at Raigarh(6000MW) and Inverter-1 at Pugalur(4000MW) and Inverter-2 at Trichur (2000MW)(Fig:2)

The scheme has high reliability and availability. A large number of operating configurations are possible in monopole with DMR/PMR return. During planning stages, it was deliberated that it may be possible that the entire 6000MW of generation would come in one stage or generation is available in two stages of 4000MW and 2000MW. Based on this, the multi-terminal scheme can be of two types with different converter ratings:

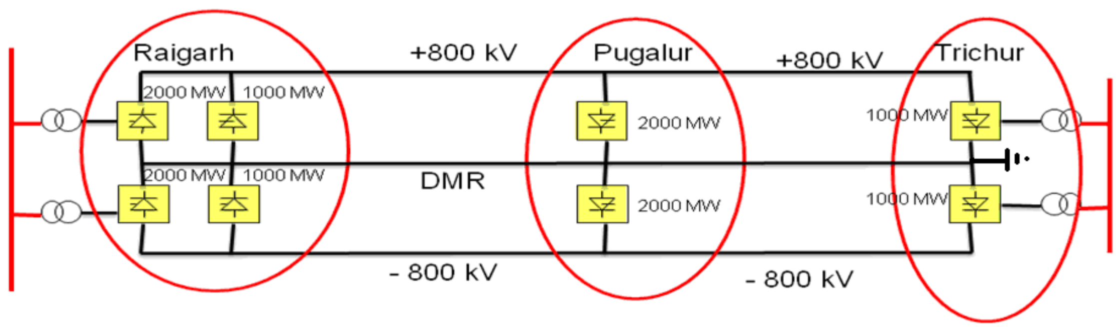


Fig:2 Two stage option of 4000MW + 2000MW: Multiterminal with rectifier converter of 2000MW and 1000MW

The other option of converter rating could be each converter of 1500MW :

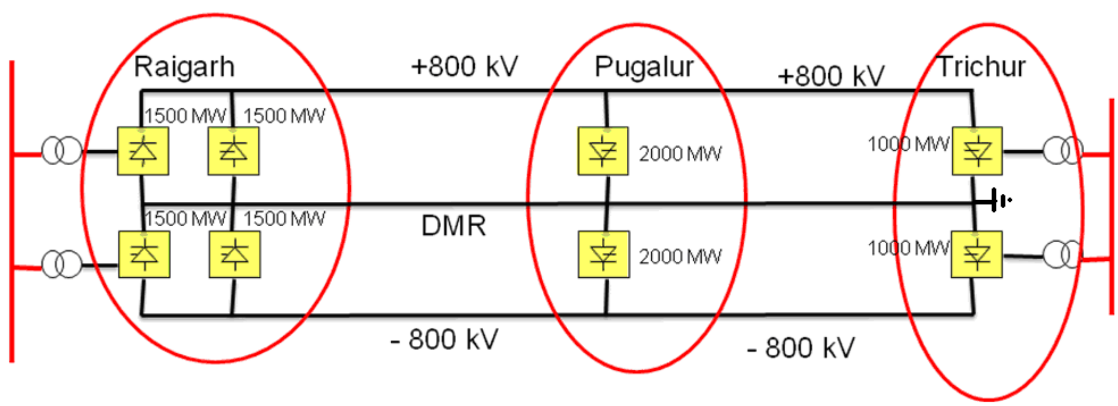


Fig:3 Single stage option of 6000MW:Multiterminal with rectifier converter of 1500MW each.

In both the options, the voltage rating of HVDC transmission line between Pugalur and Trichur shall be at 800kV. Due to acute ROW problems in Kerala state, construction of 800kV transmission scheme between Pugalur and Trichur which require a ROW of 70 m is not possible. Therefore, above options are not considered further.

Option 2:**Series Multiterminal Configuration** :

±800kV Series Multiterminal configuration using LCC technology with Rectifier at Raigarh (800kV,6000MW) and Inverter-1 at Pugalur(533kV,4000MW) and Inverter-2 at Trichur (266 kV,2000MW) with HVDC line at ±800kV level between Raigarh and Pugalur and at +/- 266kV between Pugalur and Trichur.(Fig:4)

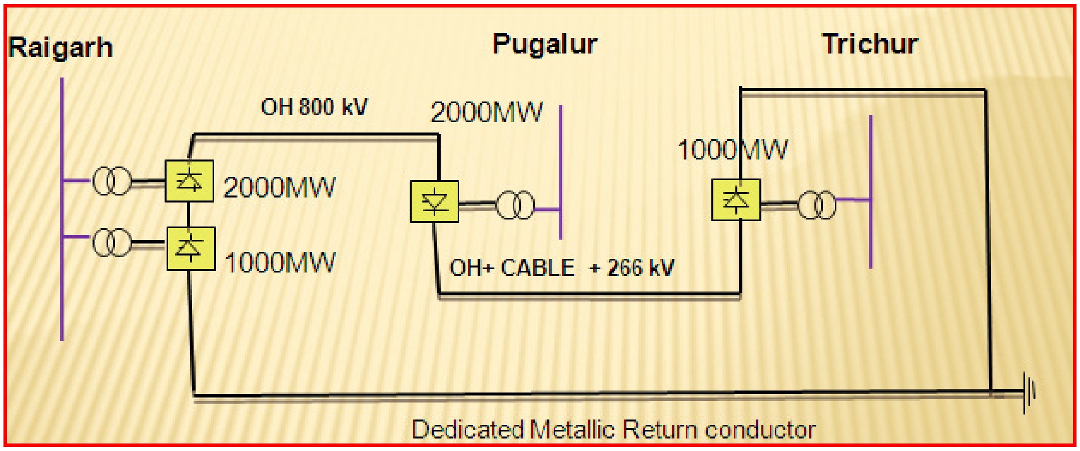


Fig 4: Series Multi Terminal HVDC Scheme (Note: 1.one pole of the bipole has been shown for simplicity. 2. Similar arrangement shall be made for other Pole).

a)Suitability of Series Converter Scheme

The severe Right of Way (ROW) problem in the state of Kerala demands a low DC voltage entry into that state. With Series Multi terminal configuration, Rectifier at Raigarh planned at 800kV, 6000MW, Inverter-1 at Pugalur at 533 kV, 4000MW and Inverter-2 at Trichur at 266 kV, 2000MW. The HVDC line between Raigarh and Pugalur operate at ±800kV level and between Pugalur and Trichur operate at +/- 266 kV. At the outset, this option seems better suited for this project as the HVDC line between Pugalur and Trichur is at low DC voltage of +/- 266kV requiring less ROW compared to +/- 800kV DC line in parallel multi terminal configuration.

Also series configuration has the following advantages:

- No need of reversing switches for reversal of power.
- Faulty Converters can be simply short circuited and rest of the HVDC link can operate at reduced voltage and reduced power.
- Transmission link between Pugalur and Trichur would be a combination of underground cable (80 km) + OH line (170 km) at 266 kV HVDC. The cost of transmission will be cheaper for both underground cable and OH line as the selected voltage is low (266 kV).

b)Main Circuit Analysis for Series Multi Terminal Scheme

There are no series connected multi-terminal HVDC projects in the world in commercial operation. Therefore, no prior experience of the series connected system is readily available. In view of this, study was carried out to analyze operating conditions and viability of series connected system. A main circuit study was carried out to work out the preliminary dc voltages, dc currents, tap changer design, reactive power consumption, operating firing angle ranges etc. In series configuration, the power flow is controlled by varying the DC voltage across each converter since the DC current is same for all the terminals. Therefore, a huge voltage change is required for moderate power changes. The two inverter terminals fall in two different states which have their own power demand at any given time. The worst case scenario occurs when one state demand is at maximum and other state demand is at minimum.

The possible scenarios are

(i) Pugalur operating at maximum power of 4000MW and Trichur operating at minimum power of 200MW
(ii) Pugalur operating at minimum power of 400MW and Trichur operating at maximum power of 2000MW

When both inverters are operating at rated power the DC voltage and current for Pugalur are 533.33 kV, 3.75 kA and that of for Trichur are 266.66 kV, 3.75 kA.
For scenario (i)Pugalur operates at 533.33 kV,3.75 kA and Trichur operate at 26.66 kV, 3.75 kA, whereas for scenario (ii)Pugalur operates at 53.33kV,3.75 kA and Trichur operate at 266.6 kV,3.75 kA.

Here also there are two options considered (i)a variable rectifier DC voltage (ii)Fixed rectifier DC voltage at 800kV. For variable rectifier DC voltage, the rectifier DC voltage is the sum of inverter DC voltages as shown in Table I

Rectifier voltage varies with power order (Option-1)				
Inverter-1 (MW)	Inverter-2 (MW)	Inverter-1 Voltage(kV) Current(kA)	Inverter-2 Voltage(kV); Current(kA)	Rectifier side voltage (V1+V2) kV
2000	1000	533.33;3.75	266.66,3.75	800
200	1000	53.33;3.75	266.66;3.75	320
2000	100	533.33,3.75	26.66;3.75	560

Table 1

For 800kV fixed rectifier DC voltage, both inverters have to be designed for higher DC voltages as mentioned in the Table II which is not economical. Therefore the option of fixed rectifier DC voltage is not further been analysed.

Rectifier voltage fixed at 800kV (Option-2)				
Inverter-1 (MW)	Inverter-2 (MW)	Inverter-1 Voltage(kV) Current(kA)	Inverter-2 Voltage(kV); Current(kA)	Rectifier side voltage (V1+V2) kV
2000	1000	533.33;3.75	266.66,3.75	800
200	1000	133.33;1.5	666.67;1.5	320
2000	100	762,2.625	38.1;2.625	560

Table: II

For variable rectifier DC voltage option further analysis has been carried out. From the Table I, the DC voltage change for Pugalur and Trichur are in the range of 480kV and 240kV approximately. To operate the inverter 1 at rated power (4000MW) and inverter 2 at minimum power (200MW) or in other extreme case to operate the inverter 1 at minimum power (400MW) and inverter 2 at rated power (2000MW), the tap changer range required for the inverter which is operating at minimum power is 950 % or 760 no. of taps with a tap step of 1.25%. This may cause practical difficulty in the design of such large tap changer range.

To explore the possibility to control the DC voltage with firing angle further main circuit analysis calculations have been carried out and results are as per Table III

SN	Power:Pugalur (%)	Power:Trichur	Firing angle (deg) Pugalur	Reactive power Pugalur(MVAR)
1	10% (200MW)	100% (1000MW)	**75.5**	**1660**
2	70% (1400MW)	100% (1000MW)	**15.2**	**884**
SN	Power Trichur (%)	Power Pugalur	Firing angle (deg) Trichur	Reactive power Trichur(MVAR)
1	10% (100MW)	100% (2000MW)	**75.5**	**830**
2	70% (700MW)	100% (2000MW)	**15.2**	**442**

Table III: Assessment of Firing Angle and Reactive Power requirement (on per pole basis)

c)De-Merits with Series Multi-Terminal System :

- High reactive power requirement, high firing angles impose higher stresses on the thyristors & associated snubber circuit components and surge arrestors connected across thyristors. The similar results observed at Trichur also. Therefore, using firing angle for DC voltage control is also not a viable option.
- With available range of tap changers upto 34 taps in normal converter transformer and firing angle range of 13 deg to 17 deg, it is seen that the power flow in the HVDC link operation is possible only with fixed power ratio between Pugalur and Trichur to meet the demands of both states simultaneously. The results has been tabulated in Table 4.
- Power control of both inverters is inter-dependent and the band is very limited i.e. desired power demand may not be achieved for two states simultaneously. Losses remain high even at low power levels when other inverter operates at high power as dc current remains high.
- Any permanent fault at Pugalur or Trcihur would also lead to outage of corresponding rectifier pole at Raigarh. When one converter is out of service, the other converter operates at its rated DC voltage which is system point of view a low DC voltage and with full DC current. It results in high line losses.
- Any transient DC line fault between two inverters / AC side fault at Trichur will affect the power transmission of 4000MW link between Raigarh-Pugalur.

Power at Trichur(MW)	Minimum Power possible at Pugalur(MW)	Max. Power possible at Pugalur(MW)
1000	1600	2400
500	800	1200
Power at Pugalur(MW)	Minimum Power possible at Trichur(MW)	Max. Power possible at Trichur(MW)
2000	800	1200
1000	400	600

Table IV

This scheme is not considered due to above mentioned limitations. Despite its drawbacks, the series Multi-Terminal system is well suited to certain applications. These applications include systems that will usually operate at full power and systems that have two main converter terminals with small intermediate taps between the main terminals. The series system should be seriously compared with the parallel system for these applications.

Option 3:±800kV, 6000MW Parallel Bipole between Raigarh and Pugalur using LCC technology. Another HVDC link based on Voltage Source Converter (VSC) technology of ±320kV, 2000MW between Pugalur and Trichur. (Fig : 5)

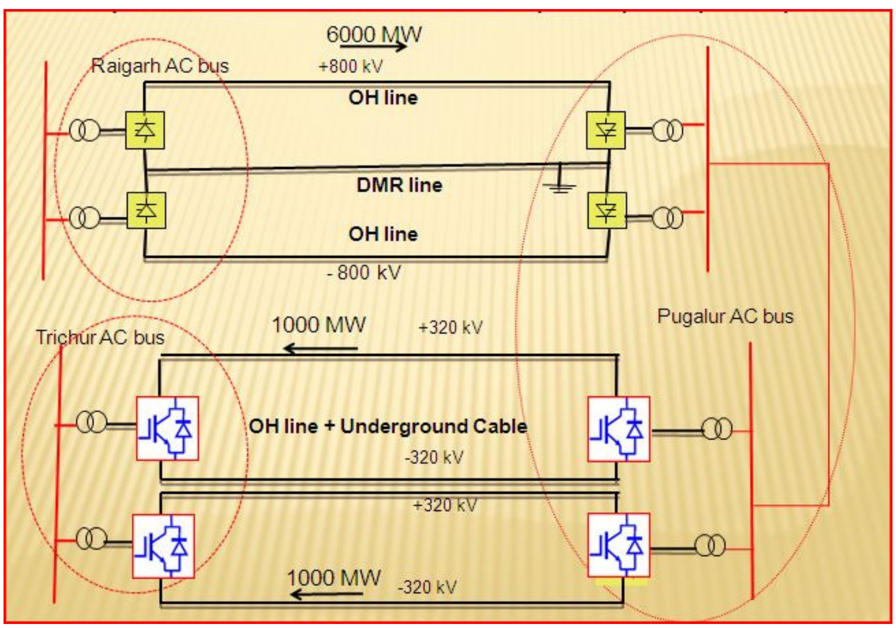


Fig :5 Two Separate Links One LCC + One VSC HVDC Link

There are two separate HVDC links with one link evacuating the total power of 6000MW from Raigarh to Pugalur and another independent link shall transmit 2000MW(share of Kerala) from Pugalur to Trichur. The first HVDC link shall be 800kV, 6000MW with two bipoles in parallel with each bipole of 3000MW.The second HVDC link shall be ±320KV, 2000MW VSC link.

a)Reason for Selection of Voltage Source Converter (VSC)

The choice for second link was based on the Right of Way issues in Kerala, as 800kV DC line tower is not feasible in the 80 km stretch of Kerala. Further there are other benefits with VSC technology. The options available for the second link are below :

Scheme	DC Line	DC Cable	Reactive power requirement	Foot Print area
500kV, 2000MW LCC Link	500kV DC line clearances	500kV underground MI cable	No dynamic voltage/reactive support to Trichur AC system which is comparatively weaker than Pugalur AC bus.	Larger foot print area for converter station
320kV 2X1000MW VSC Link	Existing 400kV dc tower design and same Right of Way can be utilised.Smaller towers will require lesser right of way	320kV Extruded XLPE cable required which is cheaper than MI type cable used for LCC	Dynamic Reactive power support at Pugalur and Trichur	Lesser foot print area for converter station

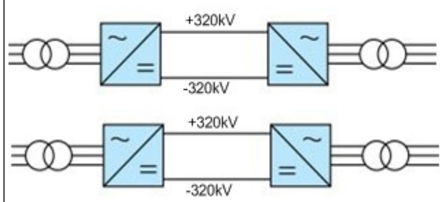
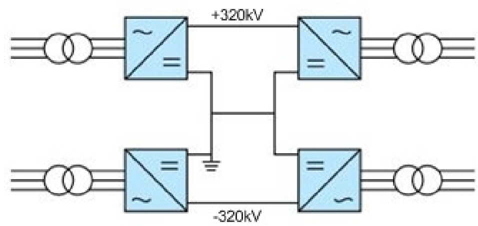
- If two LCC (Inverter-6000MW+Rectifier-2000MW) converters at same AC bus at Pugalur may result in Dynamic interaction between two system which may have impact on performance.
- If one LCC (Inverter-6000MW)+VSC(Rectifier-2000MW) with dynamic support capability) shall have better system performance in case of contingencies or disturbances without impacting both the HVDC system simultaneously.

Further the cost of VSC terminal has also decreased over the last decade and the switching losses have also gone down.

b)General Aspects of the Pugalur-Trichur VSC Scheme

The VSC scheme shall be at 320kV with 2000MW power transmission capacity. It will be based on modular multilevel based converter topology. . The transmission medium shall be combination of overhead line (around 170 km) and underground cable(around 80 km).The commonly used schemes for VSC HVDC system are Bipolar and Symmetric monopolar configurations. In Bipolar scheme, either ground return or a dedicated metallic return can be used. The comparison of both schemes with modular multilevel converter considering a transmission voltage of 320 kV and power transmission capability of 2000MW is given in Table V.

Table V:

Parameters	Symmetrical Monopole scheme	Bipolar scheme
Scheme layout		
Current	Current-1000MW/640kV =1.5625kA	Current-1000MW/320kV=3.125kA
Converter requirement	No need of parallel converters	Converter current limitation is about 1.5kA. For 1000MW, parallel converters to be used to meet higher current demand (3.125) kA. Also due to limitation of current rating of cables, multiple runs are needed.
Number of cable runs	Single run of two + 320 kV and two -320kV underground cable. Total no. of runs for cables= 04	Two runs of +320kV and –320kV cable each. Along with two runs of low voltage return cable. Total no. of runs for cables=06
Transformer	Normal Transformer	Converter Transformer
Grounding	High Impedance grounding such as Star grounding reactor.	Solid grounding

The feasibility of either of the configuration is under evaluation and shall be finalized in due course.

III CONCLUSION

In all the three options, an 800kV HVDC line shall be constructed between Raigarh and Pugalur. The first option of Parallel Multi terminal HVDC link at 800 kV is not feasible due to ROW requirement of 800kV DC line between Pugalur to Trichur. The second option of series configuration has major operational restrictions i.e. the power requirement of two constituents may not be met simultaneously and the operations of both inverters are interdependent. However, the third option with two independent links (LCC-6000MW + VSC-2000MW) with underground cable between Pugalur and Trichur seems to be better option as there would be minimum interaction between the two links, DC line fault in one link has minimum effect in other link. Also, VSC uses cheaper XLPE cables compared to costly MI cables required by LCC and VSC has advantage of dynamic voltage regulation and reactive power control to mitigate the problems associated with large renewable generation, minimum requirement of short circuit strength, smaller foot area, black start capability etc

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Development of 20MW MMC VSC HVDC Transmission System for Windfarm Interconnection

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SUMMARY

Technology development regarding MMC VSC HVDC transmission systems has been accelerating over the past few years. In particular, a number of MMC HVDC projects for the purpose of windfarm interconnection have been increasing considerably. In order to accommodate new demand in the market, Hyosung Corporation developed a MMC HVDC transmission system. This paper presents the results from the development project of MMC VSC HVDC transmission system in rating of 20MW.
The first part of this paper deals with the developments of MMC and its arm(valve) controller. A converter arm is composed of 12 half-bridge submodules, including 2 submodules as redundancy. One arm controller is based on a newly developed PSC PWM algorithm. Different from existing PSC PWM methods, the developed method can control AC/DC modulation and DC capacitor voltage balancing, including redundancies. Thus it can continue to operate until all of the redundancies are exhausted.
The second part of this paper deals with testing and evaluation of the control & protection system in the developed HVDC system using the HILS technique. The testing and evaluation were conducted by using RTDS as a real time simulation platform. In order to bring the HILS environment closer to a real life system, the MMC arms(valves) are modelled with CHAINV5 MMC arm(valve) models provided in the RTDS system. The valve models in the simulation are interconnected with arm controllers using GTDI & GTDO, and interface cards. The actual IEDs, HMI computer, and TFR server integrated with an IEC61850 data network are also included in this HILS system testing and evaluation.
The third part reports the results from HILS testing and evaluation. The results show the excellent operation of MMC VSC HVDC control system.

KEYWORDS

MMC VSC HVDC, MMC Control, Hardware In Loop Simulation, Real-Time Simulation, RTDS

1. INTRODUCTION

The Modular Multilevel Converter(MMC) system is a promising VSC(Voltage Source Converter) application in electric power systems, such as HVDC and STATCOM. The system can carry all the benefits of the VSC application in a transmission level system, which would be the ability of controlling active and reactive power independently, and generating an AC sinusoidal waveform. The output waveform can be made very close to a pure sinusoidal wave, minimizing or eliminating the requirement for harmonic filter. Furthermore, higher speed of control opens new possibilities in AC transmission applications.
This paper presents the development and testing of the 20MW MMC VSC HVDC transmission system for windfarm interconnection. The first section of this paper explains the development of MMC and its arm(valve) controller. In the developed system, the converter arms are composed of 12 half-bridge submodule(SM)s, 2 of which were installed as redundancy. Newly developed Phase-Shifted Multi-

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Carrier(PSC) PWM algorithms can lay a firm foundation for satisfying the necessary performance of the system. Being different from existing PSC PWM, the method can control AC/DC modulation and DC capacitor voltage balancing, with redundancy in the arm SM number being considered.

The second section presents a method of testing and evaluation of the control & protection system with the Hardware In-the-Loop Simulation(HILS) technique. RTDS(Real Time Digital Simulator) played a key role in this environment. The simulation environment enables testing and evaluation of control and protection in true close loop manner, the same as in the real system. In order to make the HILS environment closer to a real system, the MMC arms(valves) are modelled with CHAINV5 MMC arm(valve) models and they are linked with arm controllers using GTDI & GTDO cards, interface boards which work like a SM controller, and fiber optic cables. With this composition, the protection function of the arm & SM controllers was verified. The functions include important elements such as forced SM outage as well as corresponding controller reaction.

In addition to the testing and evaluation of core function of the controller, the communication in the controller was brought into the HILS environment with RTDS. The communication in the controller is based on an IEC61850 data network standard. The ability of handing the necessary communication in terms of the standard was an important factor, and was successfully satisfied by RTDS as well. Additionally, the IEDs(Intelligent Electronic Devices), HMI(Human & Machine Interface) computer and TFR(Transient Fault Recorder) server are also included in testing under this HILS system configuration.

Lastly this paper presents the testing results. It shows the outstanding operation of MMC VSC HVDC system in HILS testing and evaluation, such as active & reactive power control and starting up from black out circumstance at the one end of the system.

2. MMC ARM CONTROLLER

In the application of MMC, based on a half bridge SM topology, N+1 voltage levels can be generated by the positive and negative arms in which N SMs are series-connected. In order to cope with anticipated SM failure, redundant SMs are added in addition to the basic number of SMs. In order to operate the system with N+M SMs per arm, the DC capacitor voltage of the N+M SMs must be maintained to Vdc/N at all times, and the N SMs must operate normally with M redundant SMs.

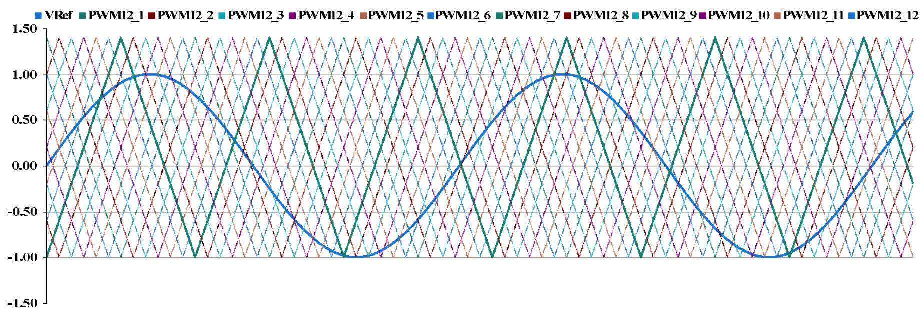


Fig. 1 Proposed PSC PWM method (N=10, M=2)

The maximum peak value of carrier : $1 + \frac{2M}{N}$ (1)

The minimum peak value of carrier : -1 (2)

The frequency of carrier : $\frac{N}{N+M} \times f_{carrier}$ (3)

If the Near Level Control(NLC) method is employed as the low level control of an arm, the implementation of the system, including redundancies, can be relatively easy. In contrast, conventional PSC PWM method cannot control these redundant SMs easily. In order to generate N+1 level voltage in the method, N phase-shifted carriers have to determine the switching state of N+M SMs. To engage M redundant SMs while switching, the N carriers must be rotated among the N+M SMs. This control method creates an increase in the switching frequency because the carrier is continuously shifted. Consequently, the shifting the switching state is also simultaneously changed.

In order to solve this problem, we propose a new PSC PWM method, as shown in Fig. 1. Different from the conventional approaches, the triangular waveform of carrier signal is not symmetrical to zero, and its magnitude and frequency are dependent on the number of faulted redundant SMs. The equations (1)~(3) present the maximum peak value and the minimum peak value of the triangular waveform of the carrier. In the developing system, having 12(=N+M) SMs including 2(=M) redundancies per an arm, the peak value of carrier will be 1.4, 1.2, or 1.0 and its frequency will be 167Hz, 182Hz, or 200Hz when none, one or two redundant SMs fail respectively. [1]
In the proposed method, the implementation becomes easier because each SM is associated with only one carrier. In addition, N+1 level output voltage can be generated without any carrier rotation thus this new approach can eliminate unnecessary switching, which might occur when the carrier is shifted. The proposed PSC PWM algorithm is implemented in the developing MMC VSC HVDC transmission system.[1]

3. RTDS MMC MODELING

The model proposed in [2] has been the basis of the real time testing environment for the development. An MMC valve contains a reactor and potentially hundreds of SMs connected in series. Fig. 2 shows the topology for one half-bridge SM, which consist of two IGBTs with anti-parallel diodes and a capacitor, and the surrogate network of the MMC circuit composed of the SMs.
Three states exist for a half-bridge SM: blocked (T1 and T2 are OFF), inserted (T1 is ON, T2 is OFF) and bypassed (T1 is OFF, T2 is ON). The surrogate network modifies the topology of the valve to reduce the computational burden on the processor. The surrogate network consists of three sections: the reactor section, the blocked SM section and deblocked SM section. The section each SM will be included will be based on the external gating signal controls. The half-bridge surrogate network topology in Fig. 2 shows a valve where two SMs are blocked, two are inserted and two are bypassed.

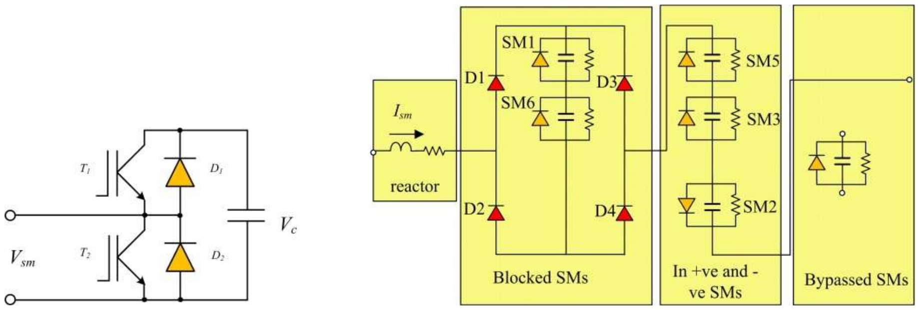


Fig. 2 A half-bridge submodule and its surrogate network

Since all SMs in a valve are connected in series, the diodes in each blocked SM will switch synchronously with all other blocked SMs. As a result, diodes D1 and D2 in the network are enough to assure proper switching for all blocked SMs. Also, the MMC valve current will flow through one diode/IGBT in each half bridge SM and therefore diodes D1 and D2 can represent the forward voltage drop and turn ON resistance for all IGBT/diodes in a valve. Regardless of the number of SMs, the surrogate network only consists of 2 switched elements in a half-bridge converter valve which significantly reduces the computational load. The capacitor of each deblocked SM will be included in either the “In +ve SM” or “Bypassed SMs” section and depends on the external gating signal. If the SM is bypassed than the capacitor is omitted from the circuit and the capacitor will discharge through a resistor which is placed in parallel across the capacitor. The capacitor voltage of a real SM cannot charge to negative voltage due to the anti-parallel diodes. The surrogate network topology models this by placing an upwards directed diode in parallel across each capacitor. However, the parallel diode does not need to be modelled as a switching element since the purpose is only to prevent the capacitor voltage of the SM to go to negative voltage and can be accomplished by forcing the capacitor voltage and the history voltage source of the Dommel capacitor to zero.

4. CONTROL & PROTECTION SYSTEMS

The single line diagram in Fig. 3 presents the 20MW MMC VSC HVDC system which was being developed. As previously noted, each arm in the system was built upon 12 half-bridge topology based SMs, and 2 among those 12 were included for the purpose of redundancy. The DC voltage in the system is ±12kVdc.

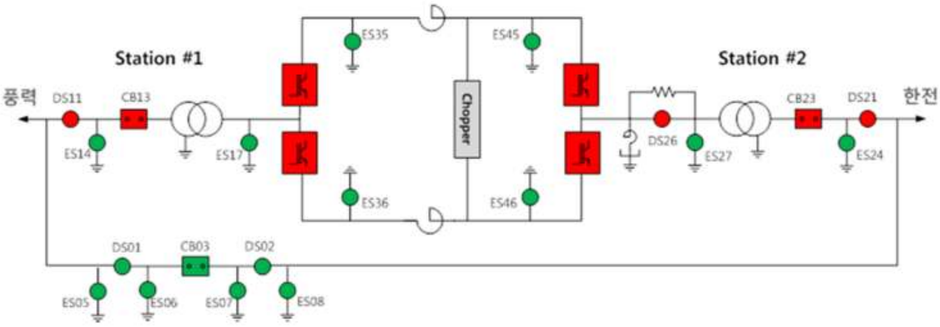


Fig. 3 Single Line Diagram of 20MW MMC VSC HVDC

This back-to-back MMC HVDC system connects Hankyoung windfarm with the 22.9kV AC power system in Jeju Island, Republic of Korea. Even though the system is a back-to-back style, an extra reactor was inserted at the DC side to emulate the behaviour of cable at the DC side. In addition, a chopper at the AC side converter implements the necessary fault ride-through capability in the wind farm system. Besides, the AC bypass routes at both sides of the converters ensure continuous electric power system operation under unexpected circumstances during the installing and the operation of the system.

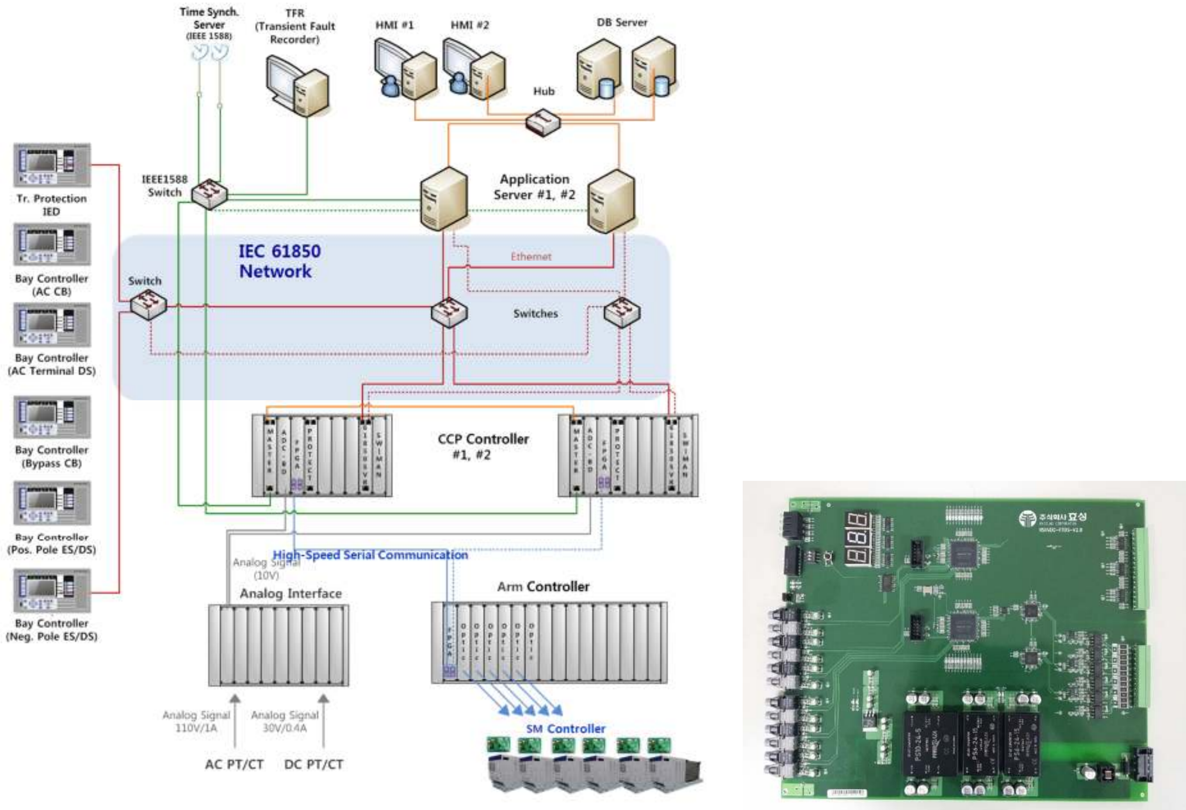


Fig. 5 Control & Protection System of 20MW MMC VSC HVDC, and Interface card connecting RTDS with Arm controller

The control and protection system in the HVDC system is depicted in Fig. 5. The system includes the arm controller, a converter control and protection system, the application server, and HMI. The IEDs for the AC/DC yard facility and bay controller also participate in the operation of the HVDC system. The communication network between the individual devices in this control system is based on IEC 61850 standard protocols.

RTDS played a very important role in the development and testing of the entire system in Fig. 5. Testing and evaluating it using the real power stack and system are unrealistic due to various reasons such as safety concerns and the associated cost. In order to ensure the maximum fidelity in the real time simulation, the positive arm and negative arm in the single phase system were represented by CHAINV5 MMC models in RTDS model library, and the MMC arms model in the RTDS simulation is interfaced with the external arm controller through GTAO and GTDI cards.

In order to interconnect the MMC simulation model with the arm controller, the extra interface card is developed with the same electronic components with the SM controller. The SM DC capacitor voltage values in the real time simulation are exported as analogue voltage signal from the terminals of GTAO cards. This voltage is converted into digital data at the interface card and transferred to the arm controller. At the same time, the gating command signals from the arm controller are translated into on/off signals on the terminals of the GTDI card, which drives the switching state of SMs in the MMC arm model. One interface card can take care of up to 6 SMs. The arm controller side of this card is identical to the optical communication interface between a physical SM and controller, enhancing the fidelity of close loop testing. Furthermore, this fidelity allows for a more realistic simulation of failure in communication, such as a malfunction in a communication component.

All other necessary simulation quantities necessary for the system control and protections, were produced as analogue voltage values through GTAO cards. The output from IEDs and bay controllers, usually on/off signals for circuit breakers and disconnect switches in the AC and DC yard, were coming back to the real time simulation in RTDS through an HV panel. Those AC/DC yard facilities, which were the subject of the IED and bay control output commands, were also part of a real time simulation case in RTDS.

5. SIMULATION RESULTS

5.1 MMC Arm Controller

Fig. 6 presents the RSCAD model of MMC circuit and the RTDS simulation environment for testing a single phase MMC bridge system. If the output AC voltage phase of the right side single phase MMC system leads the output from the left side, then the power which is supplied from DC power supply flows from right side to the left side. This incoming AC power to the left side of the system is rectified as DC and the resulting DC power is brought back to the DC power supply. In this way, a large scale AC power circuit, a back-to-back single phase MMC system in this case, can be evaluated with a relatively small DC power capacity. This way of testing was utilized for the HILS environment, as well as a real physical experiment set. [3]

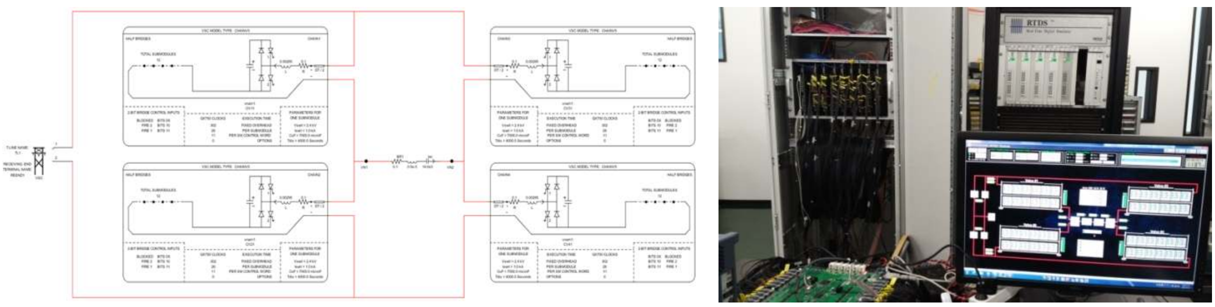


Fig. 6 RSCAD Model & RTDS Set for MMC Test Circuit

Fig. 7 shows the HILS result using the test set in Fig. 6. As explained previously, it is controlled by arm controllers based on the proposed PSC PWM algorithm and connected with GTDI and GTAO card using the interface card. Around 0.287 sec, one SM at the positive arm of the left side MMC circuit is outage by the external fault switch at its interface board, and then the SM is by-passed. However the test circuit can continue its normal operation with other remained SMs.

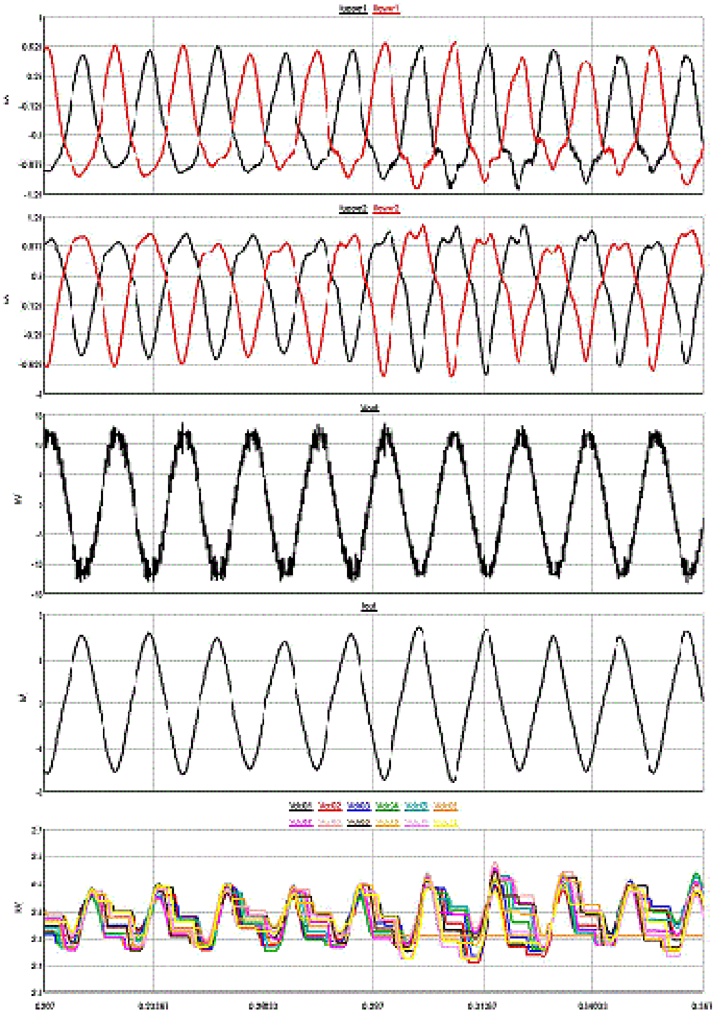


Fig. 7 Arm currents of (a) left and (b) right side of MMC circuits, (c) AC voltage, (d) AC current, and (e) SM capacitor voltages

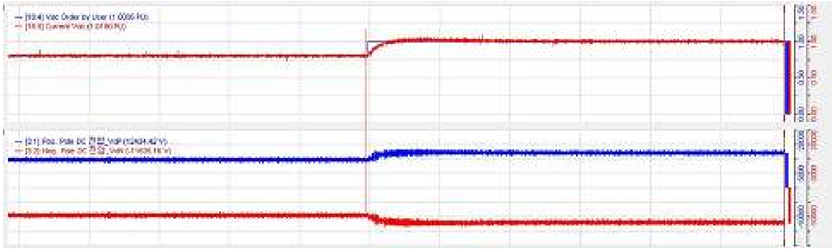
5.2 Control System of MMC VSC HVDC

Fig. 8 shows the HILS results using RTDS for the control system of the 20MW MMC VSC HVDC transmission system in Figs. 4 and 5. The figures are captured from the TFR and all of commands are generated by the HMI computer.

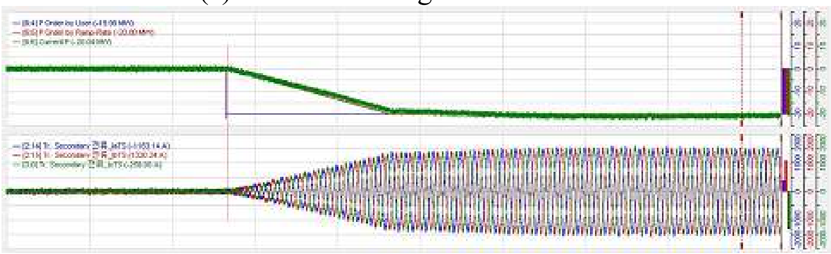
Fig. 8(a) shows the operation of the AC side converter (Station#2 in Fig. 4) in DC voltage control mode. When DS21 and CB23 turn on, the SM capacitor voltage and the corresponding DC side voltage begin to rise as a result of the operation of the bridge as a simple diode rectifier. The charging current comes from the transformer and initial charging resistors. Once the DS26 turns on, the next controlled charging of the DC capacitor initiates. The bridge can then start the DC voltage control mode operation. The DC voltage at converter at the other side, Station#1 in Fig. 4, depends on the DC voltage established by the AC side converter. Once the initial charging stage completes, two switches, the DS11 and the CB13 are turned on. Only then does the operation of the converter begin to establish the AC voltage at the wind farm side. The AC voltage is necessary for starting up the individual wind turbines in the wind farm.

Fig. 8(b) presents the flow of real power from the operation of wind turbines. The power flows from the wind farm AC system to the MMC converter at the wind farm side, Station#1 in Fig. 4. In the figure, it can be noted that as the amount of real power grows from the wind farm side, the current flowing through the converter also becomes larger.

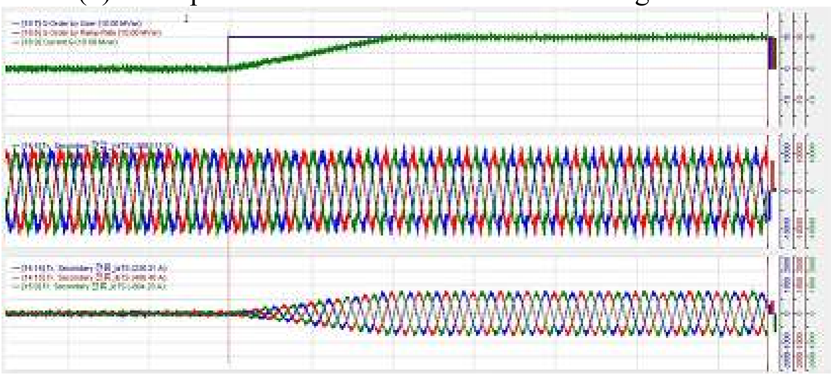
The reactive power control at the AC side converter is presented in Fig. 8(c). When the reactive power order was raised from 0 MVAR to 10 MVAR, the converter starts to inject the corresponding reactive power current into the AC system while the real power does not show any change.



(a) Vdc control of grid side converter



(b) Star-up of windfarm side converter & wind generation



(c) Reactive power, AC terminal voltage, and AC current output of grid side converter

Fig. 8 HILS results for 20MW MMC VSC HVDC transmission system

6. CONCLUSION

The paper presented the results from the development of the 20MW MMC VSC HVDC transmission system. The real time HILS testing by utilizing RTDS has been able to contribute to the quick and successful testing and evaluation of the developed system. The arm controller employs a low level control based on newly developed PSC PWM. In order to ensure the closest proximity between the HILS testing environment and real system in the actual field deployment, an interface card, identical to the SM controller, was also developed and utilized in order to communicate between the real-time MMC arm models and the arm controllers during the testing and evaluation. Furthermore, in order to test and evaluate the system control & protection, the simulated analogue signals from the real time simulation were used in the controllers and the other protective devices such as IEDs and its response was brought back to the real time simulation through digital interface cards without GTNET cards in RTDS. In addition, the available protocol in GTNET card enabled proper testing of the control & protective functions communication based on IEC61850 data protocol.

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Compact Gas Insulated Systems for HVDC applications

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SUMMARY

During recent years the requirements on high-voltage transmission systems in Germany have changed tremendously. The grid connections of large, decentralized regenerative energy sources (in particular offshore-wind plants in the North Sea) have altered the requirements on the transmission networks towards long-distant, high capacity transmission lines. At the same time, measures are necessary to stabilize and control the network voltage and frequency, in order to ensure the same high power quality supply. Modern HVDC technology such as half- and full-bridge converter systems provide advantages, compared to the established 3-phase AC transmission equivalents, thanks to their strongly reduced operational losses and their ability to support the grid via supply of reactive power. With the same conductor cross-section the DC transmission technology allows the transport of more electric power at lower losses. For ±320 kV DC application on offshore HVDC platforms a compact gas-insulated switchgear was developed. This new type of switchgear allows a reduction of up to 95% space for the switchgear, resulting in total HVDC platform size reduction of approximately 10%.

Figure 1 depicts a size comparison between an air- and a gas insulated DC converter pole for ±320kV, taking into account the required air clearances within the switchgear room as well. The development of compact gas-insulated systems for HVDC application requires the consideration of several physical mechanisms, which are negligible in conventional AC switchgear. Various effects such as the accumulation of electrical charges within insulating materials and on its surface occur during the presence of high DC voltage. Further, the dielectric stress in the insulation system is different from the transient to the stationary case. Non-linear material properties and their dependence on e.g. humidity and temperature challenge the development of gas-insulated DC systems and respective testing procedures. Suitable testing procedures are introduced in this paper, including DC polarity reversal tests, superimposed voltage tests as well as long term tests with combined

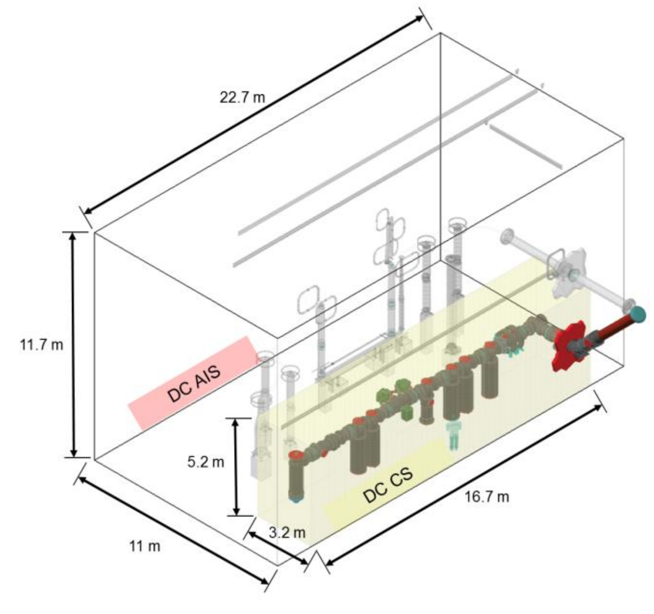

Figure 1: Size comparison between a ±320kV AIS and GIS DC pole

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thermal and electrical stresses. The functionality and reliability of a new developed compact ±320 kV gas-insulated system under realistic, challenging conditions has been confirmed. Further development in gas-insulated DC technology also investigates the development of high speed disconnector switches for the use in multi-terminal arrangements. Using gas-insulated technology, the multi-terminal switching station can be as compact as a conventional 420kV GIS substation building.

KEYWORDS

High speed Disconnector – DC GIS - DC CS – HVDC - Gas-Insulated – Switch – Multi Terminal

IMPORTANT ASPECTS FOR DC INSULATION

The development of compact switchgear for HVDC systems requires the consideration of several basic physical phenomena, which are negligible in conventional AC insulation systems. Various mechanisms (Figure 2) such as the accumulation of electrical charges on the surface and within insulating materials occur during the presence of high DC voltage, initially indicating a capacitive field distribution, which finally results in a resistive field distribution along the insulation system in the stationary case. The time constant of the field transition is mainly influenced by the insulator geometry and its material. Further, the non-linear material properties and their dependence on humidity and temperature challenge the development of gas-insulated DC systems and respective testing procedures.

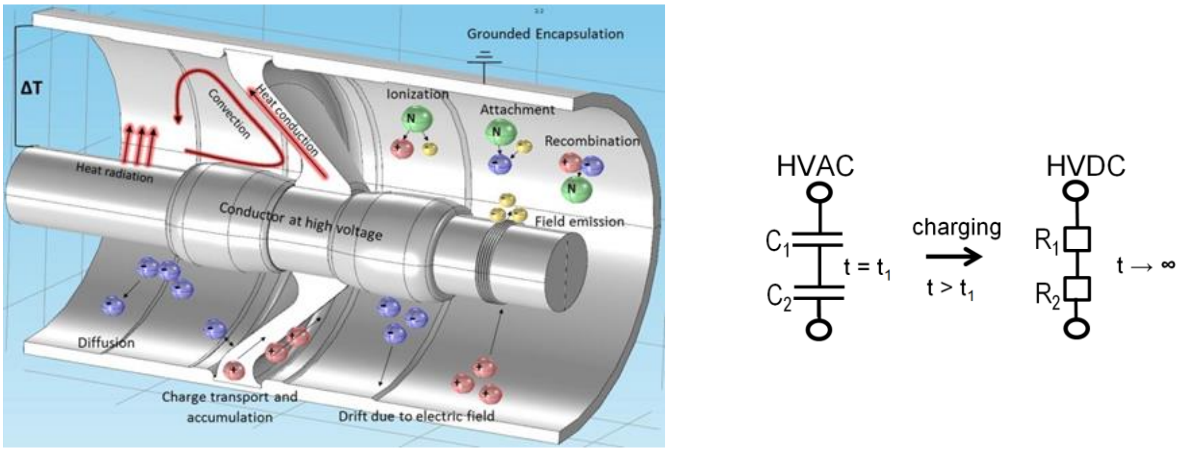

Figure 2: Physical mechanisms in gas-insulated systems and principle of the transition from capacitive to resistive field distribution after application of a high DC voltage at instant t_1.

FIELD DISTRIBUTION AT DC VOLTAGE

Directly after application of a high DC voltage, a capacitive field distribution along the insulator is formed depending on the capacitances, analogous to AC voltage stress. After a particular time, depending on the material properties and the geometry, the field distribution transits into a stationary resistive field distribution. This capacitive-resistive field transition [1] is accompanied by the accumulation of charges along the surface and within the bulk of the insulator [2]. Contrary to the capacitive field distribution, which is dominated by the permittivity of the material, the resistive field distribution is determined by the conductance of the materials used. Further, the material's conductance is strongly non-linear and dependent on e.g. temperature as well as humidity [3]. An example is given in Figure 3.

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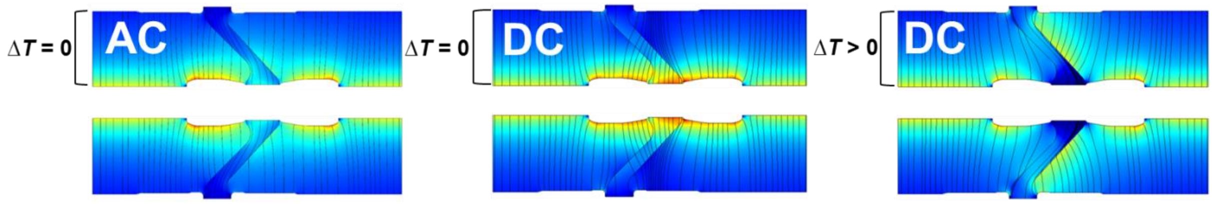

Figure 3: Exemplary depiction of the electric field strength and field lines of a conical insulator with AC voltage (left), DC voltage (middle) and DC voltage with a temperature gradient between conductor and enclosure (right, ΔT > 0).

RIP INSULATION TECHNOLOGY

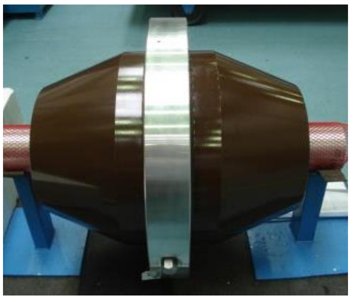

Figure 4: Design of a new RIP insulator for compact gas-insulated systems

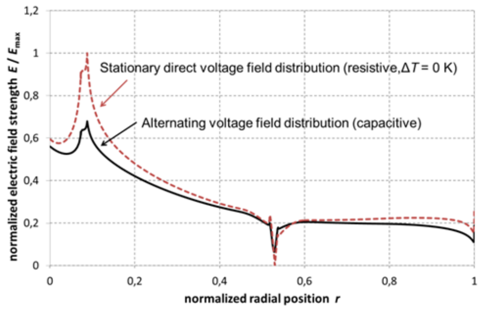

Figure 5: Electric field distribution along the RIP-insulator at AC and DC voltage

The Resin Impregnated Paper (RIP) technology is state of the art for outdoor bushings, especially for wall and transformer bushings, designed for AC and DC applications, at voltage levels up to 1100 kV. The today available field experience after more than 30 years in service confirms the excellent long term behaviour of RIP material and the suitability of the applied design.

RIP insulation is based on a special impregnated paper, with embedded metallic foils to ensure a uniform electric field distribution in the bulk and on the surfaces of the insulating body. Resulting from the conductive layers, the capacitive electric field distribution under AC or impulse voltage conditions differs only slightly from the resistive field distribution under DC conditions, including charging and discharging [4]. To benefit from the well-known reliability of RIP insulators under DC conditions, the design was adapted for the application in a compact, gas-insulated system (Figure 4). The electric field distribution along the insulator geometry is shown in Figure 5. The insulator design was optimized for a fast transition from the initially capacitive to the stationary resistive condition, without significant differences between the AC and DC electric field distribution. Note that the peak in electric field strength at position r < 0.1 results from discretization problems during FEM calculations.

The effects of the embedded conductive layers on the electric field distribution are shown in Figure 6. The foils ensure a uniform field distribution under AC and DC conditions, especially in the case of a temperature gradient between high-voltage conductor and housing, as it is typical for the application in compact gas-insulated systems.

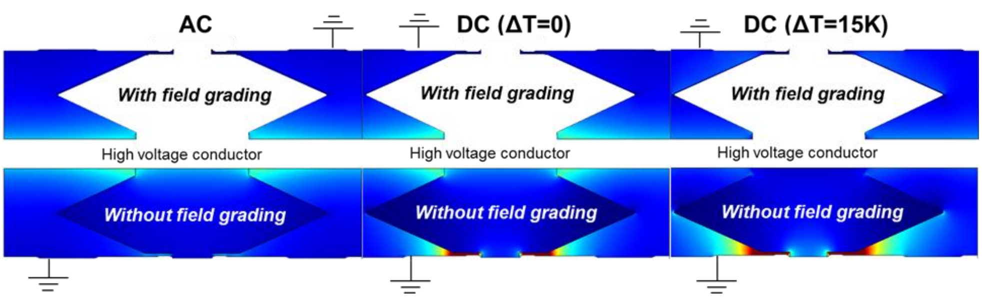

Figure 6: Electric field-distribution of a RIP insulator with (top) and without (bottom) field grading foils

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PRODUCT DEVELOPMENT OF A COMPACT GAS-INSULATED DC SYSTEM

Based on the RIP insulator technology, a new ±320 kV DC gas-insulated switchgear (DCCS –DC compact switchgear) of a modular design was developed. Typical functionalities are included in the different modules, e.g. disconnectors, earthing switches, surge arresters, voltage and current measurement devices (RC voltage divider / zero flux sensor) and interface modules to cables and overhead lines. Figure 7 gives an example of a typical configuration for a ±320 kV DCCS bay to connect a converter station to an outgoing cable.

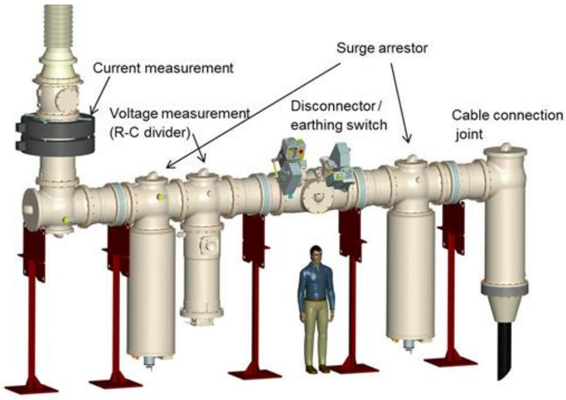

Figure 7: Exemplary bay of a ±320 kV DCCS switchgear with modules for current and voltage measurement, disconnector and earthing switches, surge arrester and cable connection modules

TESTING OF GAS-INSULATED DC SYSTEMS

Gas-insulated systems for AC applications have become common standard during the last decades. The insulation requirements and testing procedures are standardized since several tens of years, with only little differences worldwide. The commercial availability of HVDC-GIS started recently; therefore insulation requirements, adequate testing procedures and field experience with GIS for HVDC applications are very limited. In general, the existing standards for AC systems, e.g. IEC 62271-203, can be applied for some aspects, but have to be adopted for specific DC insulation requirements and different insulation coordination aspects to simulate real in-service conditions including adequate margins, ensuring a reliable transmission system performance. Table 1 gives some examples of different requirements, concerning testing.

Table 1: Examples of different testing requirements for AC and DC GIS

AC GIS	**DC GIS**
AC voltage tests	DC voltage tests
Impulse voltage tests	Impulse voltage tests
	Superimposed tests with DC and impulse voltages
Long term performance	Long term performance; charging effects, also at temperature gradient
PD measurement @ AC	PD measurement @ DC

Since the capacitive field-distribution applies instantly at AC stress, short testing durations such as 1 min are sufficient for AC switchgear testing. On the contrary, with DC stress the capacitive-resistive field distribution takes longer and varies between minutes and months, dependent on the insulating material and the insulator design. This results in longer and design-dependent test durations at DC voltage stress. Additional challenges are polarity-reversal tests, since in some HVDC arrangements (LCC, full-bridge technology) a polarity reversal is possible.

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In case of AC switchgear, realistic overvoltage strains can be simulated during testing with standardized lightning and switching impulse tests. The insulation coordination and the subsequent test voltages can be determined according to e.g. IEC 60071 and typical levels are standardized in the respective apparatus standards. For DC gas-insulated systems, a different approach is necessary. The test should simulate the real in-service conditions, which means the superposition of the stationary resistive field (DC voltage) with impulse voltages, taking effect via the capacitances of the insulation system. The superposition (Figure 8) necessitates complex test circuits to protect the DC and impulse generators against each other, using dedicated capacitors, resistors and spark gaps. A description of appropriate testing circuits is given e.g. in [5].

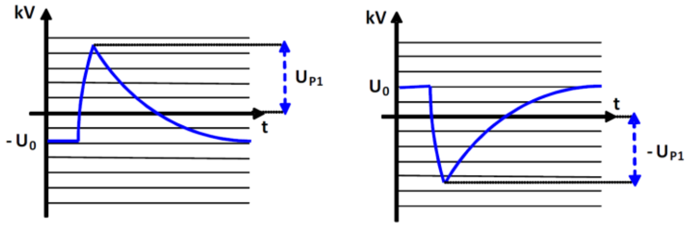

Figure 8: Schematic representations of superimposed DC + impulse test voltages [6]

The calculation of the test voltage values for DC gas-insulated systems is also based on the insulation coordination principle. The values are determined for the individual HVDC systems and not standardized today. Surge arrester protection levels are differing. Slow-front overvoltages are not resulting from switching operations, but mainly from earth- and converter-failures.
Partial-discharge (PD) measurement is a well-established measure to detect insulation failures within AC equipment and is an integral part of high-voltage testing. At DC voltage, the missing phase correlation of PD pulses leads to substantial problems in the interpretation of PD measurement results and is part of ongoing research activities. The distinction between noise and partial discharge signals is an important aspect. With fully encapsulated DC generators the suppression of external noise is possible and this helps to support the research activities as well as tests for practical applications [7].
Since typical insulation or installation failures in gas-insulated systems can be sufficiently detected by AC PD measurements, the implementation of AC tests with PD measurement for type, routine and on-site tests is recommended, also for DC systems.
The development and evaluation of appropriate testing procedures for gas-insulated DC systems is the main scope of the new Cigré Working Group JWG D1/B3.57 „Dielectric testing of gas insulated HVDC systems".

Table 2: Dielectric type tests of the ±320 kV DC Compact Switchgear (DC CS)

Test	Test voltage	DC pre-stress
DC voltage test with PD measurement	±504 kV DC ±630 kV DC	60 min 120 min
Lightning-impulse voltage test (LI)	±1175 kV LI	-
Switching-impulse voltage test (SI)	±950 kV SI	-
Superimposed voltage test DC + LI	±336 kV / ∓1175 kV	120 min
Superimposed voltage test DC + SI	±336 kV / ∓950 kV	120 min
Polarity reversal test	±420 kV DC ±630 kV DC	90 / 90 / 45 min 90 / 90 / 45 min

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TESTING OF THE NEW ±320 kV DCCS

The new gas-insulated switchgear for ±320 kV rated voltage has undergone numerous dielectric tests, to reproduce realistic operational stress in an appropriate manner. Beside polarity-reversal tests with DC pre-stress, tests with DC voltage, lightning and switching impulse tests, especially superimposed voltage tests have been carried out (Table 2), in order to prove the new insulation system. The duration of the pre-stress with DC voltage has been chosen in order to grant stationary, resistive field distribution in presence of DC charge accumulation, as it is under in-service conditions of the gas-insulated system. All tests were passed successfully, proving the functionality of the gas-insulated DC system. Beside the dielectric testing, several mechanical tests such as temperature-cycle tests, temperature rise tests and power tests have successfully been passed (Figure 9).

Figure 9: Examples of type test setups for dielectric, temperature-rise and power tests

LONG TERM TESTS ON GAS-INSULATED DC SYSTEMS

In addition to the tests given in the prior chapter, long term investigations have been carried out to simulate the functionality of the new switchgear under realistic operational stress with long-term effects. The emphasis was the practical investigation of the thermal influence on the electric field distribution on and in insulators in combination with relevant dielectric stress occurring in operation. Different load scenarios to create temperature gradients in the insulation system of the switchgear have been applied, by using a current induction to heat up the system. In addition to the load cycles of the long term investigation, polarity-reversal tests as well as DC voltage tests superimposed with impulse voltages were undertaken. The dielectric long term behaviour of RIP insulators is well known from operational experience with outdoor bushings. Since more than 30 years gas-insulated wall bushings using RIP technology are in operation with DC voltage up to ±800 kV, not showing significant aging appearances. As further proof, the new DC insulators were investigated in a long term test, amongst more than 100 other insulation devices using different materials under increased test voltage. No insulator failure occurred within the 15.000 test hours up to now. The long term investigations therefore proof the negligible aging behaviour of the RIP insulation system under the presence of high DC voltage.

FUTURE DEVELOPMENTS FOR MULTI-TERMINAL SOLUTIONS

Further developments of gas-insulated DC solutions aim at the realization of compact, high speed switches for HVDC multi-terminal stations. Here, dedicated high speed switches are required to separate a faulty line from the remaining system. With Full Bridge Voltage-Sourced-Converter (VSC) technology, the DC-circuit breaker function and respective ability to counteract on DC fault currents is included in the converter, hence no additional DC breaker is required for this duty in the DC switchyard. When designing such switches, possible residual DC currents have to be taken into account. Full Bridge VSC together with high speed disconnectors provide significant benefits compared to DC circuit breaker solutions in that they are cheaper and are considerably more compact. The increase in compactness is even higher using gas-insulated switches. They can either be integrated

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in a gas-insulated DC switchyard, or be installed as stand-alone switches in dead tank design. A dead tank switch would further allow integrating additional functions into the switch such as DC current measurement or disconnector- and earthing switches. In order to develop aforementioned switches, realistic assumptions must be made based on future applications scenarios, since the technical requirements of the switches vary in dependence of the spatial dimensions of a HVDC Grid, it´s predominant line design (i.e. whether overhead- or cable lines are predominant) as well as the capabilities of the converters used in a HVDC Grid.

CONCLUSIONS

To meet the demand of HVDC energy transmission with compact DC systems, a gas-insulated ±320 kV DC switchgear was developed and type tested. The design of compact DC insulation requires the consideration of several physical effects. Using the RIP technology, a dedicated insulator type for the gas-insulated system was developed and the operational safety of the system has been proven. The new insulator is suited for AC and DC voltages. Today, testing requirements for compact gas-insulated DC systems are not standardized and part of ongoing research activities. With numerous simulations, investigations and tests the functionality of the first commercially available ±320 kV DC Compact Switchgear (DC CS) has been proven. An outlook was given on further size reduction potential for HVDC multi-terminal stations and DC switchyards using dedicated high speed switches.

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HVDC AND POWER ELECTRONICS
INTERNATIONAL COLLOQUIUM

& STUDY COMMITTEE B4 AGRA, INDIA 2015

Aspect of High-Speed Protection for VSC-Based HVDC Grids

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SUMMARY

HVDC grids can provide an economically competitive and technically feasible way of exchanging power between geographically spread regions and power networks that may be even asynchronously connected. This paper discusses certain design aspects of protection schemes for a VSC based multi-terminal HVDC grid. A modular multilevel converter (MMC) based four-terminal dc grid connected via cables in a symmetrical monopole configuration is considered in this study.

When a fault occurs in a VSC based dc grid, uncontrollable fault currents can continuously flow through the anti-parallel diodes in the converter switching modules and fault currents can rapidly rise to a very high level due to the low impedance in the grid. A protection scheme will therefore have a very short time to detect and isolate the faulted segment before the high currents could damage the expensive converter equipment. Conventional protection schemes that rely on end-to-end communication may therefore be too slow for dc grids.

Isolating cable faults on a dc grid without affecting a larger section of the transmission network can be challenging. A protection scheme that could identify and isolate only the faulted segment in a dc grid within the shortest possible time will have the minimum impact on the dc grid and the associated ac system.

Due to the extremely short time available for isolating the faulted segment, high-speed fault detection and fault current interruption are key considerations in protection scheme design. In the proposed scheme, the rate of rise of the fault current is used for detecting a fault and identifying the fault location while dc breakers are considered for isolating the faulted segment. The paper investigates different phenomena that may have an effect on the proposed scheme such as changes in the dc grid configuration, the cable lengths, size of the current limiting inductors and connected ac system network strength at terminals.

KEYWORDS

HVDC, HVDC Grid, VSC MMC, Grid Protection, DC breaker, Fault Identification

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1. INTRODUCTION

A HVDC grid can provide an economical solution for exchanging power over a large region and also provide a method for improving stability in the connected power network. A dc grid would provide many advantages compared to comparable ac networks such as flexibility, security and low capital and operating costs. HVDC grids become particularly attractive in offshore transmission schemes due to the issues associated with long ac cables [1]. Voltage sourced converters (VSC) have become the technology of choice for implementing HVDC grids due to their flexibility in changing the direction of power flow. A HVDC grid, especially in places like Europe, is expected to consist of mainly submarine and underground cables. With the improvements in voltage and power ratings of VSC and dc cables over the years, developing a HVDC grid will soon become a reality [2].

When a fault occurs on a VSC based dc grid, uncontrollable fault currents can continuously conduct through the anti-parallel diodes in the converter switching modules and fault currents can rapidly rise to a very high level due to the low impedance in the grid. The fault current withstand capability of converter modules is very low, typically twice the converter full load rating current. A protection scheme will therefore have a very short time to detect and isolate the faulted segment before the high currents could damage the expensive converter equipment. Therefore, conventional protection schemes that rely on end-to-end communication may not be fast enough to detect faults on a dc grid.

A dependable protection scheme is essential for maintaining the stability of a dc grid. The protection scheme must detect a fault condition and isolate the faulty equipment from the grid quickly. Isolating a faulted cable segment on a VSC based HVDC grid without affecting a major part of the transmission network can be challenging. Different techniques can be used to remove fault current from the grid. For example, fault current can be interrupted by opening all ac feeds to the dc grid. Although cable faults are rare to occur, this approach could have a major impact on the stability of the associated ac system and the reliability of the dc grid. Another approach is using full-bridge converters with fault current blocking capability at each node of the grid. The faulted segment can be removed using switches while the converters at each node have blocked. This approach will also interrupt the power flow in the grid completely and therefore may impact the stability of the connected electrical network.

A protection scheme that could identify and isolate only the faulted segment in a dc grid within the shortest possible time will have the minimum impact on the dc grid and the associated ac system. Therefore, the authors believe that an approach involving high speed fault detection combined with dc breakers will provide the best solution for isolating a faulted segment in a large dc grid [3][4]. Since it is more economical to design these breakers with relatively low fault current interruption capability, reactors are used along with the breakers to limit the rate of rise of the fault currents.

Ref [5] describes a high speed fault detection method based on the initial rate of change of fault currents in a multi-terminal VSC based dc grid. In this method, the initial rate of change of fault current is used for determining the protection settings at each location. The initial rate of change of fault current is linked with the size of the reactors installed. When the grid expands, these reactors may have to be replaced to limit the initial rate of rise of the fault current or the settings of the protection system may have to be modified according to the new values.

This paper re-evaluates the results of [5] to develop a strategy to identify required changes to the settings of the protection scheme and the impact of the size of the reactor on these settings when the dc grid configuration and the connected ac network change.

2. PROTECTION SCHEME

The simulation results of ref. [5] demonstrated that by evaluating the initial rate of rise of fault current at each cable terminal on a dc grid, a fast and accurate method for detecting faulted cable segment can be developed. The ability of this protection scheme to operate without any communication between conversation stations is a main advantage.

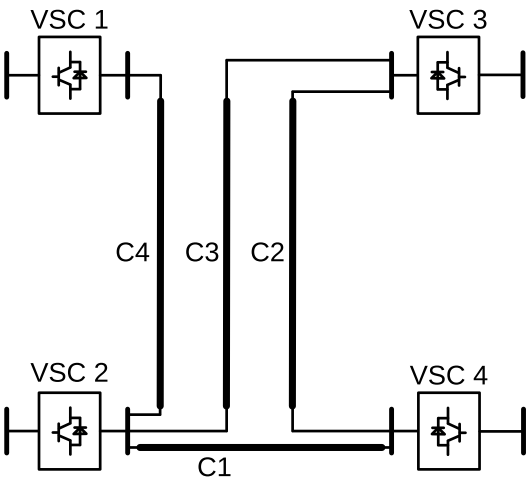
When a fault occurs in the grid, the initial high currents are due to the discharge of the dc cables onto the fault. The simulation results in [5] showed that the initial rate of change in current at each end of the faulted cable segment are relatively high compared to the rates of change in current on healthy cables. The results of this study also showed that when a fault occurs, the healthy cables close to the faulty cable also experience a rate of change in current. Therefore, a threshold level had to be defined for each cable segment to accurately identify the faulted segment by protection at each converter station. Considering positive pole to ground faults, negative pole to ground faults, and pole to pole faults along the length of each cable, some preliminary threshold limits were defined for protection at each converter station for the test network considered.

In this paper, the approach to determining settings in ref [5] are revisited to develop a strategy to identify required changes to the settings of the protection scheme and the impact of the size of the reactor on these settings when the dc grid configuration and the connected ac network change.

3. STUDY MODEL

In this study, a four-terminal VSC based HVDC grid is developed in PSCAD for initial simulations. The voltage and current waveforms are analyzed during different faults to identify transients that could be used for identifying faults and faulted segments. The four-terminal grid is then extended to five terminals and the waveforms are analyzed to identify variations in transient waveforms when the dc grid configuration is changed.

The schematic diagram of the four terminal grid configurations are shown in Figure 1. The dc grid model consists of four converter terminals which are connected to each other using four cable paths. The connected ac networks are represented by their simplified equivalents.

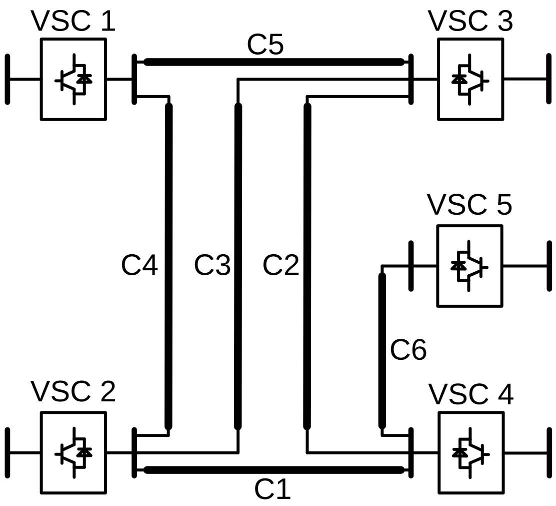


Converter	Power Rating (MW)	Voltage Rating (kV)
VSC 1	500	±320
VSC 2	1000	±320
VSC 3	1000	±320
VSC 4	500	±320

Cable Name	Length (km)
C1	70.0
C2	80.0
C3	30.0
C4	20.0

Figure 1: Four terminal VSC based HVDC grid model

The schematic diagram of the five terminal grid configurations is shown in Figure 2. The dc grid model consists of five converter terminals which are connected to each other using five cable paths.



Converter	Power Rating (MW)	Voltage Rating (kV)
VSC 1	500	±320
VSC 2	1500	±320
VSC 3	1000	±320
VSC 4	500	±320
VSC 5	500	±320

Cable Name	Length (km)
C1	70.0
C2	80.0
C3	30.0
C4	20.0
C5	40.0
C6	150.0

Figure 2: Five terminal VSC based HVDC grid model

The power rating of each converter is shown in each figure. Modular multilevel converter (MMC) based symmetrical monopole VSC configuration is considered in these models. In this study, 200 sub-modules are assumed in each phase of the MMC converter. Instead of simulating each converter module, the MMC's are represented by a time-varying Thévenin's equivalent as described in reference [6]. This model is mathematically equivalent to a detailed model, but is computationally more efficient.

The length of each cable segment is shown in each figure. The cables are modelled using PSCAD frequency dependent phase model. Each cable terminal consists of a 100 mH reactor to limit the maximum rate of rise of the fault current to about 3.5 kA/ms for a fault close to the terminal in a 320 kV dc system, when operating at a 10 percent maximum overvoltage [3].

The power flow between VSC terminals in the HVDC grid is regulated using a control system. The control system consists of a central master controller and local terminal controllers at each converter terminal which either controls ac voltage or reactive power and dc voltage or active power at each location. The control set points assigned for each converter terminal are given in Table 1.

Table 1. HVDC set points

Converter Terminal	Operating Mode	Set Point 1	Set Point 2
VSC 1	Inverter	Real Power = 500 MW	AC Bus Voltage = 230 kV
VSC 2	Inverter	DC Voltage = 640 kV	AC Bus Voltage = 230 kV
VSC 3	Rectifier	Real Power = 1000 MW	AC Bus Voltage = 138 kV
VSC 4	Rectifier	Real Power = 500 MW	AC Bus Voltage = 138 kV
VSC 5	Rectifier	Real Power = 500 MW	AC Bus Voltage = 138 kV

In this control arrangement, the control parameters can be locally selected depending on the system requirement. A phase locked loop (PLL) is used to synchronize the converter output voltage waveforms with the ac grid.

4. SIMULATION RESULTS

Simulations were carried out considering positive pole to ground faults, negative pole to ground faults, and pole to pole faults at different cable locations in the dc grid. Several case studies were performed to investigate the impact of the rate of change of initial fault current transient for several dc grid configurations and ac network strengths. Only a limited number of simulation results are presented in this paper.

Case Study 1:

A negative pole-to-ground fault was applied at 0.1 s at the midpoint of cable C1 of the model shown in Figure 1. The rate of change of currents computed for each negative pole cable segment in the dc grid is shown in Figure 3.

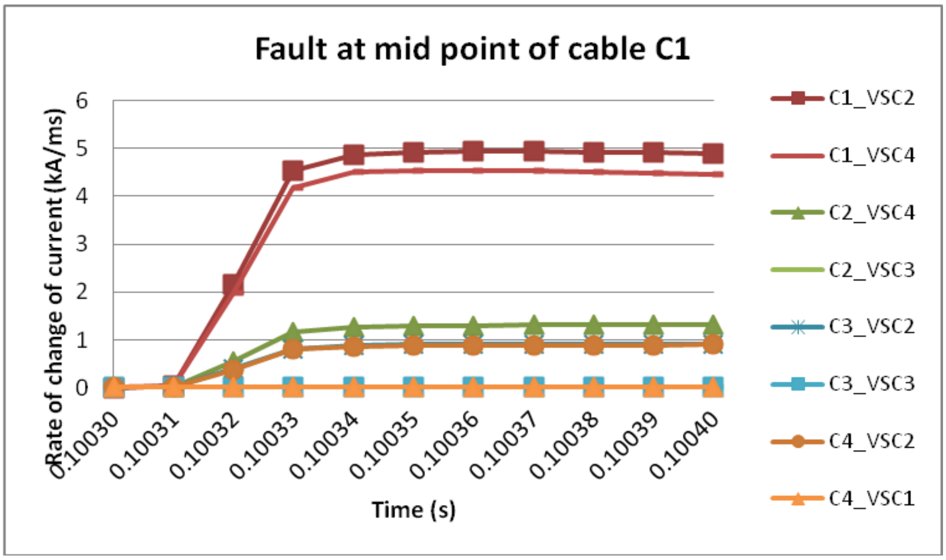


Figure 3: Rate of change of branch currents for a ground fault at midpoint of cable C1

When the fault is applied at the middle of the cable, both ends of the cable detect the change of current with a 0.31 ms time delay as shown in Figure 3. The initial rates of change of cable currents reach to about 5.0 kA/ms and 4.5 kA/ms at the two ends of cable C1. The initial rates of change of cable currents at the ends of healthy cables are significantly smaller than that of the faulty cable. This example shows that the a cable fault around the midpoint can be identified using the initial rate of change of current at the two ends of the cable within 0.35 ms after a fault occurs.

Case Study 2:

In this case, the dc grid configuration shown in Figure 1 was modified by adding a 40 km long cable between the converter terminals VSC1 and VSC3. Similar to Case Study 1, a fault was simulated on cable C1 and the rates of change of currents were computed.

Case Study 3:

In this case, a new 500 MW converter terminal VSC5 was connected to terminal VSC4 dc bus using a 150 km long cable C6 to form the dc grid configuration shown in Figure 2. A fault was simulated on cable C1 and the rates of change of currents were computed.

Figure 4 shows the rate of change of branch current for the faulted cable (C1) for case studies 1, 2 and 3. As shown in the figure, the initial rates change of cable currents are around the 4.5 kA/ms and 5 kA/ms at the two ends of the cable for all three dc configurations considered. The results show that the grid configuration changes did not have a major effect on the initial rate of change of fault current transients.

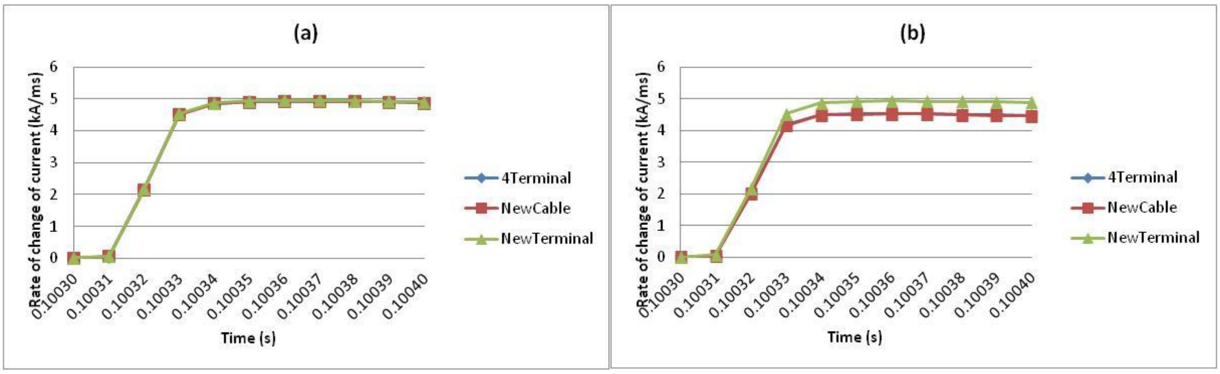


Figure 4: Rate of change of currents for a ground fault at midpoint of cable C1; (a) VSC2 end and (b) VSC4 end

Case Study 4:

In this case, ac system strengths at two of the converter stations, VSC1 and VSC3, were modified as given in Table 2. Faults were simulated on cable C5 for the dc grid system shown in Figure 2 with different ac system strengths given in Table 2.

Table 2: SCR values for ac networks

SCR	VSC1	VSC3
SCR1	9.61	2.02
SCR2	4.73	2.02
SCR3	4.73	4.04
SCR4	9.61	4.04

The rates of change of fault currents calculated using the currents measured at the two ends of cable C5 are shown in Figure 5 for different ac network SCR values. The results show that the ac system strength does not seem to have an effect on the initial rate of change of fault current.

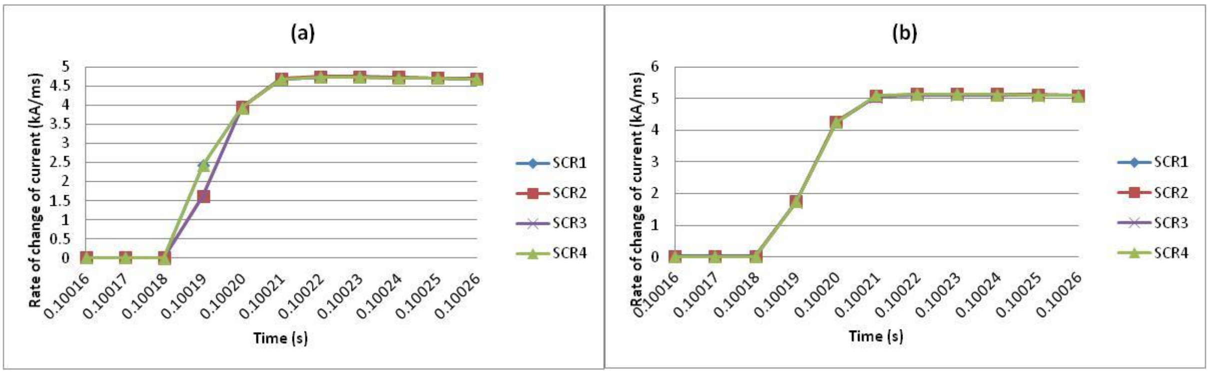


Figure 5: Rate of change of currents for a ground fault at midpoint of cable C5; (a) VSC2 end and (b) VSC4 end

Case Study 5:

In this case, the size of the reactor at each end of the cable terminals was modified. Faults were simulated on cable C5 for the dc grid system shown in Figure 2 with different reactor values. The rates of change of fault currents calculated using the currents measured at the two ends of cable C5 are shown in Figure 6 for different reactor sizes. The results show that the size of the reactor has a direct effect on the initial rate of change of fault current.

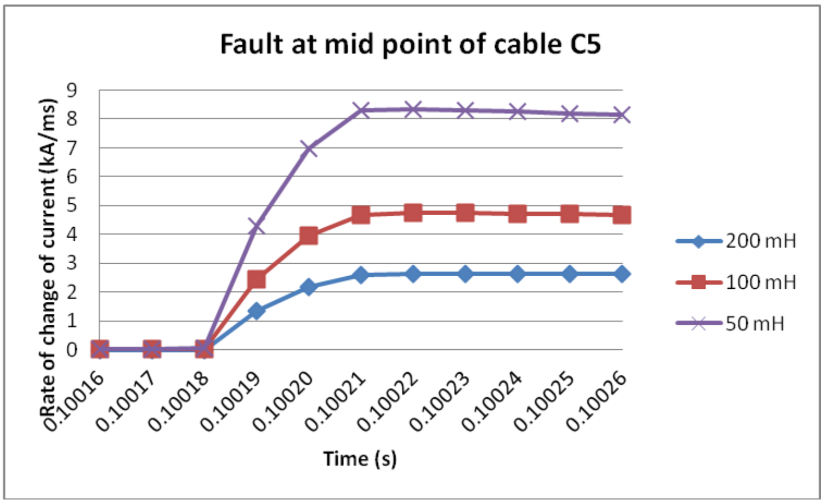


Figure 6: Rate of change of currents for a ground fault at midpoint of cable C5 for different reactor sizes

5. DISCUSSION

In this paper, a dc fault identification method based on initial rate of change of fault current was analysed for a multi-terminal VSC HVDC grid. A detailed model of the dc grid was developed in an electromagnetic simulation program to analyze the characteristic behaviour of initial cable currents during different faults. The simulation results showed that the initial rate of change in cable currents provides a fast and accurate method to identity the faulted cable in a dc grid without communication between conversation stations.

The results of the investigation showed that different phenomena such as changes in the dc grid configuration, the cable lengths, size of the current limiting inductors and connected ac system network strength at terminals did not have a major effect on the proposed fault identification method.

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Series Hybrid DC Converters with a Current Source Converter and a Voltage Source Converter

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SUMMARY

Commutation failure, which is a very frequent dynamic event in the line-commutated converter (LCC) high-voltage direct current (HVDC) inverters, can deteriorate the availability of HVDC links and thus affect the performance of the power system. Most commutation failures are caused by voltage reduction due to ac system faults or the increasing dc current due to the inverter faults. The current source converter (CSC) consumes a large amount of reactive power in the commutation process. Continuing developments in semiconductors and the voltage sourced converters (VSC) transmission technology are likely to make VSC transmision atractive in an increasing number of applications. VSC transmission has a number of technical features that are superior to those of LCC HVDC schemes and make it especially atrractive for the following characteristics: feeding into passive networks, transmission to/from weak ac systems, enhancement of an ac system. The ability of the dc grid to overcome a dc fault is one of the major challenges: when a fault occurs in the dc grid, it is not possible to force the dc current and voltage to zero and to restart the grid after the fault disconnection.

In this paper, series hybrid dc converters with a CSC and a VSC are proposed. The hybrid HVDC system constituted by the hybrid dc converters, which overcomes some drawbacks of the LCC HVDC and the VSC HVDC, has more advantages for fault toleration. For ac system faults in the inverter, the VSC can supply the constant or higher voltage to suppress the increasing direct current and to lower the effect of commutation failure in the CSC. For dc grid faults, the CSC in the inverter can block the large reversing fault direct current caused by the VSC. Besides, the VSC can supply a large amount of reactive power for the CSC.

KEYWORDS

high-voltage direct current (HVDC), current source converter (CSC), voltage source converter (VSC), hybrid dc converter, commutation failure

1. INTRODUCTION

Most HVDC schemes in commercial operation today employ line commutated thyristor valve converters [1]. In a line commutated converter, the commutation is carried out by the ac system voltage. This brings inherent difficulty in continuing reliable commutation at very weak ac system voltage, e.g., during ac system faults. Its technical capacity, combined with its economic advantage and low operating losses, make the line commutated converter based HVDC (LCC HVDC) a practical solution for enlarging or enhancing power system interconnections [2]. The converter performs the energy conversion between ac and dc. It usually has a 12-pulse arrangement, in which two 6-pulse brdges are connected in series on the dc side.

Continuing developments in semiconductors and the voltage sourced converters (VSC) transmission technology are likely to make VSC Transmision atractive in an increasing number of applications [3-4]. VSC Transmission has a number of technical features that are superior to those of LCC HVDC schemes and make it especially atrractive for the following characteristics: feeding into passive networks, transmission to/from weak ac systems, enhancement of an ac system.

Hybrid HVDC transmission is a new concept in the HVDC transmission. The LCC of the current source converter used as a rectifier and the SCC of the voltage source converter used as an inverter is proposed in [5-6]. The hybrid system can operate stably and return to steady operation after short time faults in the ac grid. The ability of the dc grid to overcome a dc fault is the major problem. Hybrid converter HVDC transmission is a new hybrid transmission system for connecting two ac systems [7]. It demonstrates the superior performance of hybrid converter based HVDC transmission systems with respect to increased stability and teminal ac voltage control. However, it cannot feed into passive networks and reverse the power as the CSC can only conduct current in one direction.

In this paper, series hybrid dc converters with a CSC and a VSC are proposed. Combining the advantages of the LCC HVDC and VSC HVDC, the hybrid HVDC constituted by the series hybrid dc converters can minimize the effect of commutation failure, block the fault current in the dc grid fault and transport to/from weak ac systems. Besides, it can feed into passive networks and reverse the acitve power with the bypass switches.

2. SERIES HYBRID DC CONVERTER TOPOLOGIES

2.1 Current source converters and voltage source converters

Starting with fundamental network theory, one can distinguish two basic electrical energy source types: the current source (CS) and voltage source (VS). All dc/ac power conversion systems are designed to act either as a current source converter (CSC) or as a voltage source converter (VSC). The CSC can only conduct current in one direction while blocking voltage in both polarities. The switches in CSCs normally have bidirectional voltage blocking or reverse blocking capability. This allows the direct control on phase angle and magnitude of the ac current by a proper switching control strategy. Therefore, power reversal in CSC-based systems is achieved by reversing the polarity of the dc voltage.

The presence of a VSC that maintains a given voltage across its ac terminal irrespective of the magnitude or polarity of the current flowing through the source. Therefore, by controlling the phase angle and magnitude of the ac voltage through the switching methods, the converter acts as an inverter or rectifier, with lagging or leading reactive power. The switches in VSCs normally have bidirectional current conducting or reverse conducting capability. This allows the power reversal in VSCs by controlling the dc current direction while the dc voltage has a fixed polarity.

2.2 Series hybrid DC converters

In this paper, four series hybrid dc converter topologies are proposed, as shown in Fig. 1. Four series connection modes are as follows: the cathode of the CSC connected to the negative of the VSC, as shown in Figure 1(a); the anode of the CSC connected to the positive of the VSC, as shown in Figure 1(b); the cathode of the CSC connected to the positive of the VSC, as shown in Figure 1(c); the anode of the CSC connected to the negative of the VSC, as shown in Figure 1(d). In addition, the bypass switches (S1), the bypass disconnection switch (S2) and the connected disconnection switches (S3, S4) are used to increase the redundancy of the system.

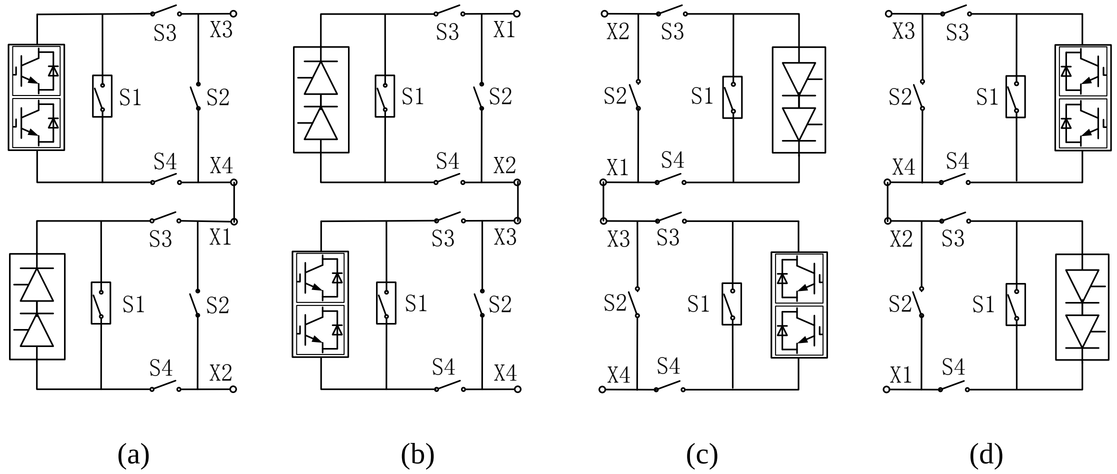


Figure 1: Four series hybrid dc converters

The CSC is constituted by a series-connected 6-pulse group or a series-connected 12-pulse group. One general feature for CSCs is the external short-circuit fault tolerance. This is because the large energy-buffering inductors in CSCs can limit the fault current rise, and the switches in CSCs normally have bidirectional voltage blocking capability. The most commonly used semiconductor devices in CSCs are thyristors. The main problem of this kind of converter is the commutation failure, most of which is caused by ac bus voltage disturbances.

The VSC is constituted by a two-level converter, a monolithic multilevel converter or a modular multilevel converter (MMC). A two-level converter utilizes only one dc level to create an average equal to the reference voltage in each switching cycle. Therefore, the switching loss and the total harmonic distortion (THD) are relatively high. On the other hand, multilevel converters are able to synthesize a stair case waveform using several independent dc voltage by capacitors or separate sources. Several types of monolithic multilevel converters have been proposed based on different structures of a dc-link voltage to generate staircase output voltage levels [8-9]. The neutral-point-clamped (NPC) [10], and flying capacitor (FC) [11] topologies are widely known in industrial and high-power application. However, lack of optimum power utilization and extra complexity in converter structure and control are the drawbacks of the proposed methods for transmission applications. During the last decade, modular multilevel converters (MMC) have shown a break through and have made their way to commercial high-power applications. Modularity, in general, refers to a technique to develop comparably large systems by combining smaller subsystems.

The building-block cell is the basic unit of any MMC configuration which can basically be either a dc/dc or a dc/ac power converter. The basic forms are as follows: harf-bridge commutation cells, full-bridge commutation cells, mixed commutation cells, asymmetrical double commutation cells, cross- or parallel-connected commutation cells, clamped-double commutation cells, FC commutation cells and NPC-type commutation cells. Half-bridge commutation cells are the simplest structure to generate a unipolar output voltage by chopping its dc-link voltage. Switch needs to provide bidirectional current flowing and unidirectional voltage blocking. The first group of MMC which corresponds to the first idea of modular converters for an HVDC application is constituted by half-bridge commutation cells [12]. This topology addresses, low losses, low switching frequency, slightly above the fundamental frequency, voltage scalability due to the simple cascading of identical cells, negligible ac filters due to the synthesized pure sine voltage waveform and mechanical simplicity. Since VSCs are not inherently fault-tolerant converters, controlling the converter when subject to internal faults such as dc short-circuit faults or converter ac bus faults is challenging. Different dc and ac circuit breaker solutions have been proposed in order to prevent the converter feeding the short-circuit faults.

The series hybrid dc converter, which connects one end of the CSC to one end of the VSC, as shown in Figure 1, can effectively prevent commutation failures and suppress dc fault current. For ac system faults in the inverter, the VSC can supply the constant or higher voltage to suppress the increasing direct current and to lower the effect of commutation failure in the CSC. For dc grid faults, the CSC in the inverter can block the large reversing fault direct current caused by the VSC.

3. OPERATION PRINCIPLE AND MODES OF SERIES HYBRID DC CONVERTERS

3.1 Operation principle

The topologies in Figure 1 (a) and (b) can be applied to the rectifier, while the topologies in Figure 1 (c) and (d) can be used in the inverter. The CSC system contains a CSC converter, a bypass switch (BPS), a bypass disconnection switch (BPI) and two connected disconnection switches. The VSC system contains a VSC converter, a bypass switch (BPS), a bypass disconnection switch (BPI) and two connected disconnection switches.

In the normal operation, the CSC and the VSC are connected to the HVDC transmission by the two connected disconnection switches, respectively. The BPS and the BPI are disconnected. When the CSC has a fault, the CSC can be out of operation by retard, connecting the BPS, connecting the BPI, disconnecting the two connected disconnection switches. Then the CSC is isolated from the HVDC system. When the fault disappears, the CSC can be in operation by connecting the two connected disconnection switches, disconnecting the BPI and BPS. When the VSC has a fault, the VSC can be out of operation by jumping the ac switches, connecting the BPS, connecting the BPI, disconnecting the two connected disconnection switches. Then the VSC is isolated from the HVDC system. The VSC is difficult to put into operation online even if the fault disappears.

In the LCC HVDC transmission, commutation failure is easily occurs when there is a fault in the ac grid of the inverter, such as one-phase-grounding fault. There are two reasons: The first one is that the ac grid in the inverter cannot supply the normal commutation voltage; The second one is that the commutation margin is reduced by the increasing direct current. In the HVDC transmission constituted by the hybrid dc converters, commutation failure is minimized as the VSC can supply the voltage to suppress the increasing direct current.

In the VSC HVDC transmission, which is constituted by a two-level converter, a monolithic multilevel converter or a modular multilevel converter (MMC) with half-bridge commutation cells, the ability of the dc grid to overcome a dc fault is one of the major challenges. When a fault occurs in the dc grid, it is not possible to force the dc current and voltage to zero and to restart the grid after the fault disconnection. In the hybrid dc converters for the inverter in Figure 1 (c) and (d), when a fault occurs in the dc grid, the dc current is close to zero as the CSC can only conduct current in one direction.

In the normal deblocking process, the CSC and the VSC in the inverter can be deblocked at the same time first. Then the CSC and the VSC in the rectifier are deblocked. In the normal blocking process, the CSC and the VSC in the rectifer can be blocked at the same time first. Then the CSC and the VSC in the inverter are blocked.

3.2 Operation modes

There are four operation modes for the series hybrid dc converters:

Mode 1: Both the CSC and the VSC connected in series with the HVDC system exchange the active and reactive power;

Mode 2: Only the CSC connected with the HVDC system exchanges the active and reactive power, while the VSC bypassed by the switches supplies the reactive power.

Mode 3: Only the CSC connected with the HVDC system exchanges the active and reactive power, while the VSC bypassed by the switches blocks.

Mode 4: Only the VSC connected with the HVDC system exchanges the active and reactive power, while the CSC bypassed by the switches blocks.

In mode 1, The VSC can supply the reactive power for the CSC, which consumes a large amount of reactive power in operation. When it feeds into passive networks, the VSC in the inverter and rectifier can be deblocked first, and then the CSCs in the rectifier and inverter are deblocked, respectively.

In mode 2, the CSC can reverse the power by reversing the voltage. The VSC can supply the reactive power for the CSC.

In mode 3, the reactive power required by the CSC should be supplied by the ac filters. The operation modes are similar to those of the LCC HVDC.

In mode 4, the VSC can reverse the power by reversing the current. The operation modes are similar to those of the VSC HVDC.

When the series hybrid dc converters operate in mode 1 and mode 2, the VSC can supply reactive power for the CSC. The var compensator can be reduced. For topologies in Figure 1 (c) and (d), when the ac grid has a fault in mode 1, the VSC can provide direct voltage to avoid commutation failure of the CSC caused by the increasing direct current. When the dc gird has a fault in mode 1, the CSC can block the large reversing fault direct current.

4. CONTROL STRATEGIES FOR THE SERIES HYBRID DC CONVERTERS

4.1 Control strategies for the CSC and the VSC

In a LCC HVDC transmission, all converters are given a basic closed loop current controller. In a regular two terminal transmission, the rectifier end is normally controlling the current while the inverter is controlling the voltage. This is done by subtracting a current margin (the magnitude of which is normally 10% of nominal current) from the current order in the inverter. Thus, the effective current order in the inverter is lower than that of the rectifier. Since the closed loop current controller tries to establish ordered current, the controller in the inverter end will increase its firing angle in order to lower the current on the HVDC transmission. It will increase alpha until it reaches the maximum allowed. This means that the inverter will output full voltage since direct voltage is a function of $\cos(\alpha)$.

The converter firing control of the CSC contains three parts: the current controller, the voltage controller and the gamma controller, as shown in Figure 2. Since the normal current control in the inverter will force the firing angle to its maximum due to the current margin, the simplest way to get the inverter to operate at AMAX (Inverter Alphamax Control) [13] is to set the maximum output from the current control amplifier. This is done by subtracting a current margin from the current order in the inverter.

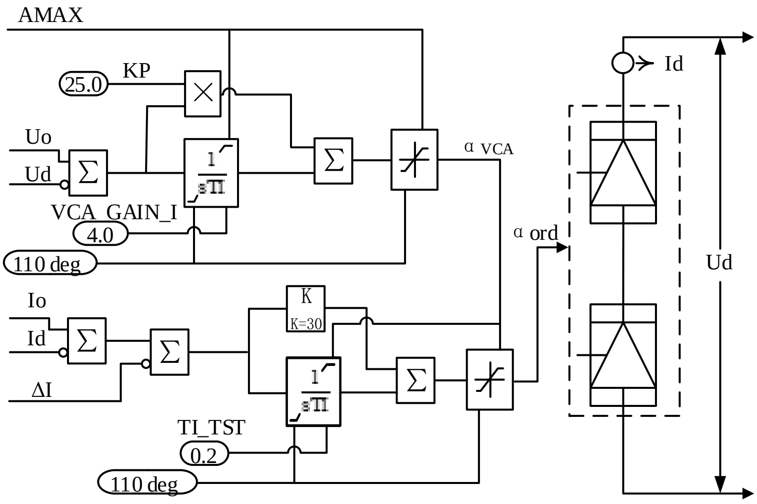


Figure 2: The CSC firing control block diagram.

In a VSC HVDC transmission, an independent control of active and reactive power, the capability to supply weak or even passive networks and lower space requirements are some of the advantages. For the two or three-level technology, the converter voltage, created by the pulse-width modulation (PWM), is far from the desired sinusoidal voltage. It needs ac filters to achieve an acceptable waveform. For the modular multilevel converter (MMC), both the size of voltage steps and the related voltage gradients can be reduced or minimized if the ac voltage generated by the converter can be selected in smaller increments than at two or three levels only. It is possible to separately and selectively control each of the individual power modules in all phase units. The two converter arms of each phase unit represent a controllable voltage source. The total voltage of the two converter arms in each phase unit equals the dc voltage, and by adjusting the ratio of the converter arm voltages in one phase unit, the desired sinusoidal voltage at the ac terminal is achieved.

The overall control structure of the MMC is shown in Figure 3. The outer power, outer voltage and inner current controllers are standard systems which generate the reference of inner converter voltage reference u_d^* and u_q^*.

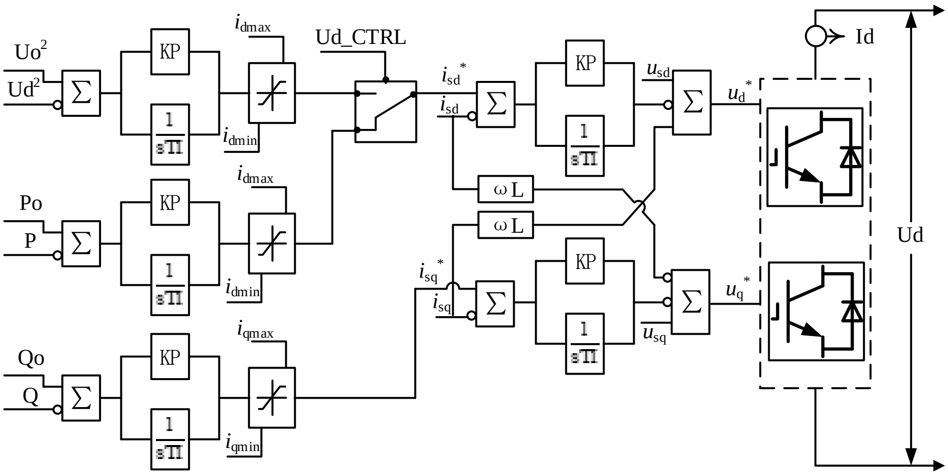


Figure 3: The VSC firing control block diagram.

4.2 Control strategies for the hybrid dc converters

For topologies in rectifier (Figure 1 (a) and (b)), the current control or the power control is adopted to the series hybrid dc converters. For details, the current control or the power control is applied to the CSC while the voltage control and the reactive power control are applied to the VSC.

For topologies in inverter (Figure 1 (c) and (d)), the voltage control is adopted to the series hybrid dc converters. For details, the constant gamma control or the voltage control is applied to the CSC while the voltage control and the reactive power control are applied to the VSC.

5. SIMULATION AND EXPERIMENTAL RESULTS

5.1 Simulation model

The control strategies for the hybrid dc converters are implemented in the control and protection unit of Ultra HVDC (UHVDC), which is called PCS-9550 in NR Electric Co., Ltd. The UHVDC system is modeled by the RTDS (Real-Time Digital Simulator) device. A bipolar UHVDC transmission constituted by the hybrid dc converters is shown in Figure 4. The hybrid dc converters are arranged in a series-connected 12-pulse CSC group and a MMC group, respectively. The MMC is connected in series by half-bridge commutation cells. The actions in preventing commutation failure and dc fault are verified in the UHVDC system.

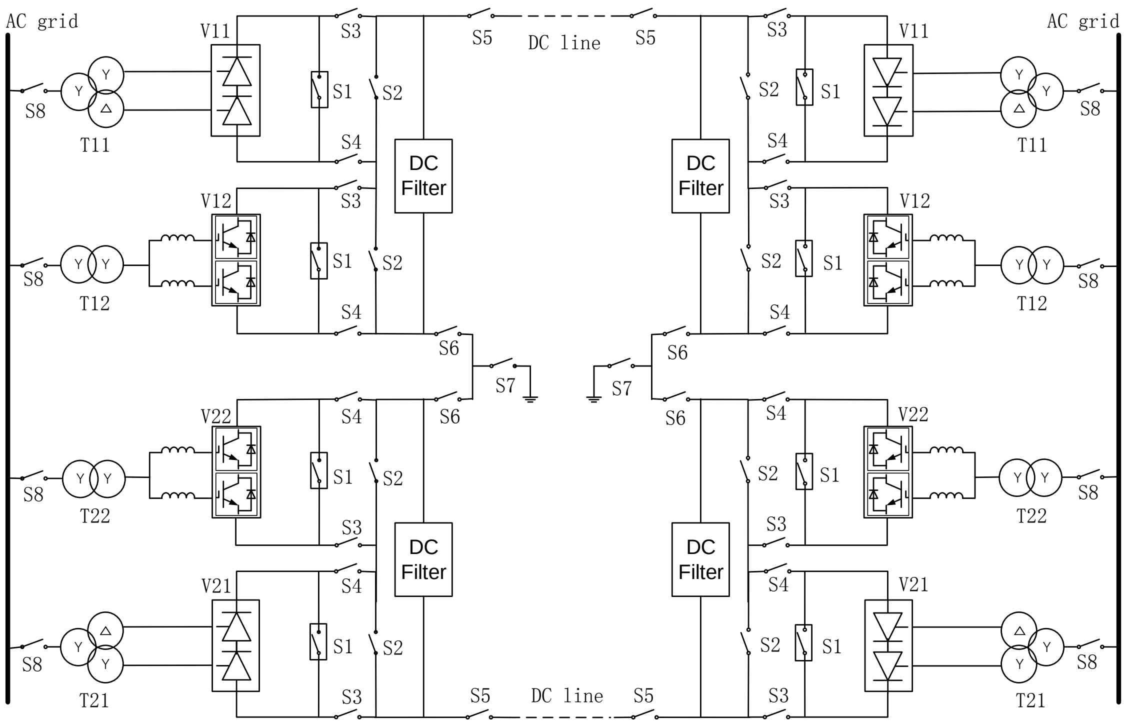


Figure 4: Simulation model in RTDS.

As shown in Table 1, the rated bipolar power is 8000 MW and the rated voltage is ±800 kV. In this section, the test results of the hybrid HVDC are compared with a LCC HVDC, which has the same rated power and voltage.

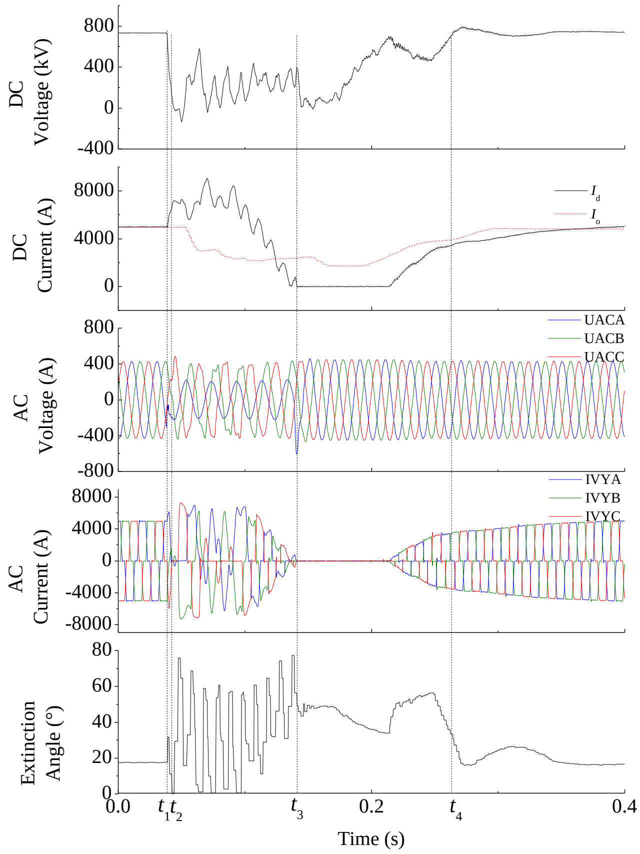
Table 1: Operation parameters of the UHVDC

Parameters	Values
Rated bipolar power(MW)	8000
Rated direct voltage (kV)	±800
Rated direct current (A)	5000
Rated no load direct voltage of CSC (kV)	215
Gamma reference of CSC(°)	17
d_x of CSC	0.1
Rated direct voltage of VSC (kV)	400

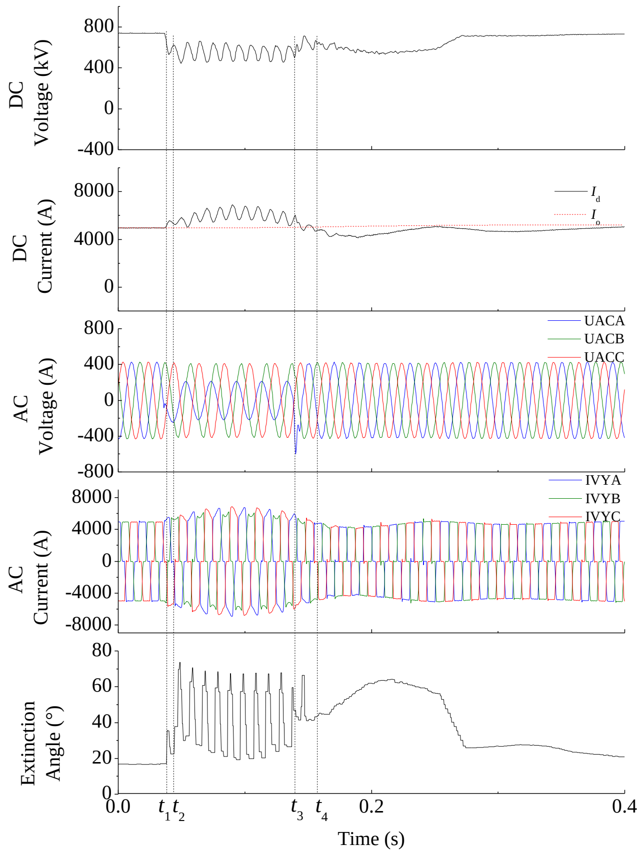
5.2 AC faults in the inverter

In the LCC HVDC, when the ac grid in the inverter has a fault, such as one-phase-grounding fault, the CSC cannot commutate normally for the ac voltage waveform distortion and the increasing dc current. The results of the CSC for a 5 Ω single-phase-ground fault in the 500 kV ac grid are shown in Figure 5 (a). At time t1, a single-phase-grounding fault occurs and the voltage of Phase A becomes smaller. The direct voltage of the two series CSCs decreases rapidly and the direct current starts to increase. The overlap angle increases as the current increases and the margin of commutation is greatly reduced. As a result, at time t2, the extinction angle is less than the Gamma Min and commutation failure of the converter occurs. Then continuous commutation failure occurs. At time t3, the single-phase-ground fault disappears and the converter resumes normal operation. At time t4, the dc power is restored to the normal value.

In the hybrid HVDC constituted by the hybrid dc converters, when the ac grid in the inverter has a fault, such as one-phase-grounding fault, the voltage of the CSC will rapidly decrease, while the voltage of the VSC does not change. The results of the CSC for a 5 Ω single-phase-grounding fault in the 500 kV ac grid are shown in Figure 5 (b). At time t1, a single-phase-grounding fault occurs and the voltage of Phase A becomes smaller. The direct voltage of the hybrid dc converter decreases slowly and the direct current starts to increase. The overlap angle does not increase so much as the current little increases. At time t2, commutation failure of the CSC converter does not occur. At time t3, the single-phase-grounding fault disappears and the converter resumes normal operation. At time t4, the dc power is restored to the normal value.



(a)



(b)

Figure 5: Test results of CSC in 1.0 p.u. for a 5 Ω grounding fault in the 500 kV ac grid. (a) LCC HVDC. (b) Hybrid HVDC.

The dc voltage and dc current for a 5 Ω grounding fault are drawn in the Ud/Id characteristic diagram again, as shown in Figure 6. Obviously, the direct voltage and direct current in the LCC HVDC change larger than that in the hybrid HVDC.

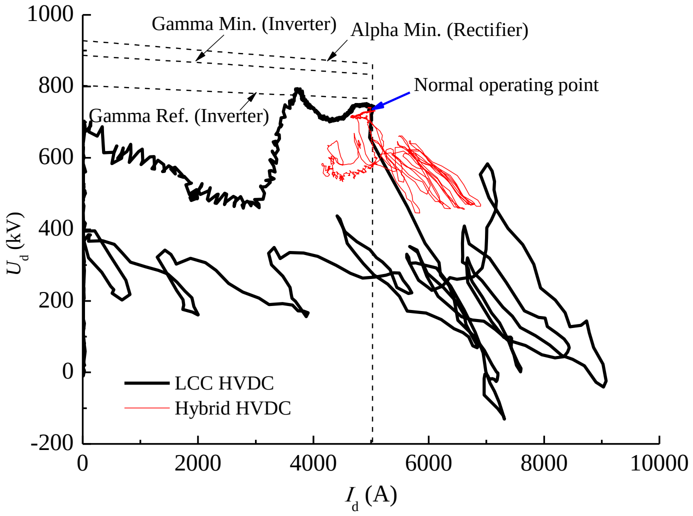


Figure 6: Ud/Id Characteristic in 1.0 p.u. for a 5 Ω ground fault in the 500 kV ac grid.

The comparison of dc power between the LCC and hybrid HVDC is shown in Figure 7. The dc power has a greater oscillation in the LCC HVDC than that in the hybrid HVDC.

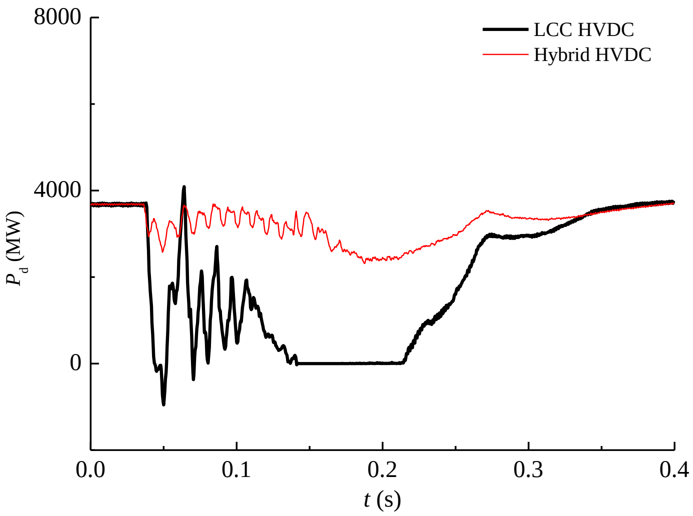


Figure 7: DC power in 1.0 p.u. for a 5 Ω ground fault in the 500 kV ac grid.

5.2 DC faults in the inverter

When the dc line has a fault in the hybrid HVDC, the CSC in the inverter can block the large reversing fault direct current. However, the CSC in the rectifier cannot block the large positive fault direct current. If the VSC in the rectifier is constituted by the harf-bridge commutation cells, which is adopted in this experiment, a large direct current will be produced and the hybrid HVDC will be blocked. If the VSC in the rectifier is constituted by the full-bridge commutation cells, the hybrid HVDC can continue to run after the fault disappears. The results of the CSC for a metallic grounding fault in the dc line are shown in Figure 8. At time t1, a fault in the dc line occurs and the direct voltage starts to decrease. At time t2, the direct current decrease to zero. At time t3, the direct voltage becomes to zero. The VSC in the inverter can continue to supply the reactive power for the ac grid.

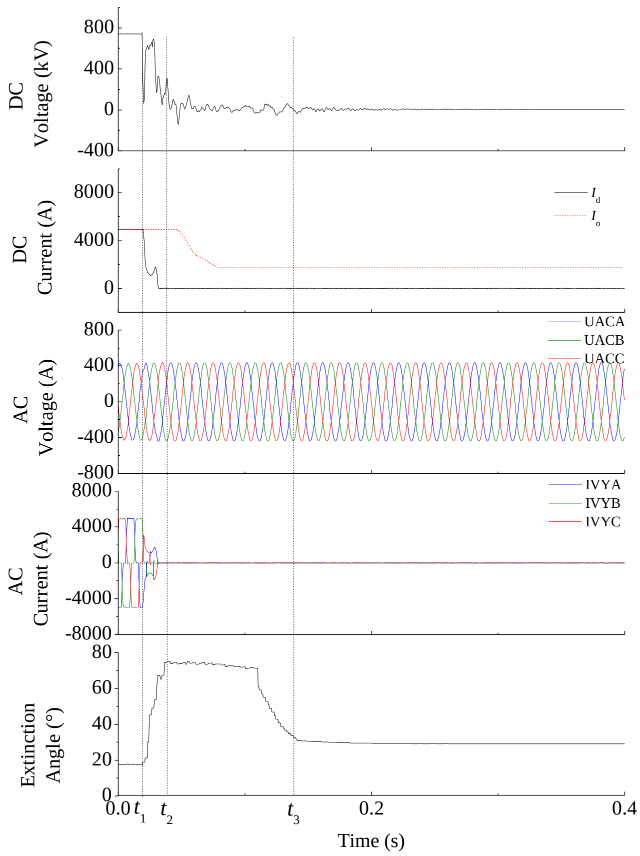


Figure 8: Test results of CSC in 1.0 p.u. for a metallic grounding fault in the dc line.

6. CONCLUSIONS

Series hybrid dc converters with a CSC and a VSC are proposed in this paper. Comparing to the LCC HVDC and the VSC HVDC, the hybrid HVDC system constituted by the hybrid dc converters has more advantages for fault toleration. The hybrid dc converters can minimize the effect of the commutation failure and block the reversing fault direct current. The great dc power oscillation is eliminated and the dc power transmission capacity is improved.

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Hybrid STATCOM Systems Based on Multilevel VSC and SVC Technology

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SUMMARY

Hybrid STATCOM systems based on multilevel Voltage Source Converters (VSC) is the newest member of the FACTS family of grid-optimization solutions and improves the efficiency of transmission systems, increasing the power transmission capacity as well as reducing the risk of voltage collapses and power outages. Combining the technologies of multilevel VSC and thyristor based SVC will optimize the FACTS system resulting in robust, secured and reliable grid operation; reliability, under- and over-voltage performance, TOV at fault clearing, speed of response, losses.

Besides the STATCOM and its VSC converter, the Hybrid STATCOM system consists of TSCs and/or TSRs to reach the required power rating. The VSC will be used for continuous control, TSCs and TSRs for offset. The use of mechanically switched devices (MSCs and/or MSRs) to offset the operating range is limited to applications with comparably low dynamic requirements. The design of the Hybrid STATCOM system is uniquely tailored to perform reliably at all times, combining simplicity and versatility. Chain-link multi-level topology allows for simple configuration of power circuits, while Pulse Width Modulated (PWM) power converters enhance their robustness. The result is an unrivalled combination of performance, user-friendly design and dependability.

STATCOM and Hybrid STATCOM systems based on multilevel VSC technology is particularly well suited for application in fast growing networks and in weak grids where harmonic resonances at low-order harmonics are challenging for the classical SVC concept. In addition, STATCOM and Hybrid STATCOM systems open up for improved performance of Line Commutated Converter (LCC) HVDC applications.

This paper presents the innovative design that makes Hybrid STATCOM systems particularly suitable for power grids facing a variety of challenges. The paper also discusses different configurations for Hybrid STATCOM systems, functional requirements applicable for transmission systems including considerations regarding footprint, reliability and dynamic performance. Reliability constraints for STATCOM topologies based multiple converters are compared to topologies using one single converter. Finally, STATCOM systems are discussed for improved operation of the LCC HVDC.

KEYWORDS

STATCOM, Hybrid STATCOM, Voltage Source Converter (VSC), Multi-level converter, Thyristor Switched Capacitor (TSC), Thyristor Switched Reactor (TSR), Line Commutated Converter HVDC

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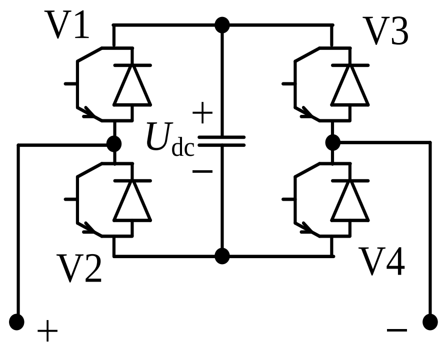
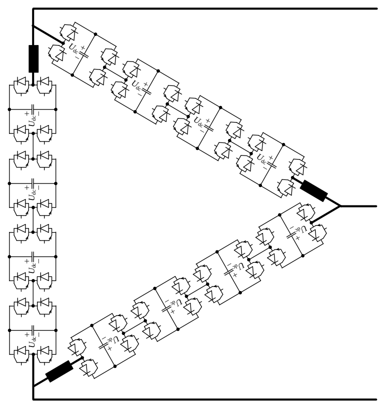
Introduction

For many years, STATCOM installations made use of 2- and 3-level converter schemes [1]. For this type of installations, typically a low-order harmonic filter was installed to prevent the harmonics generated by the STATCOM from negatively impacting power quality on the grid. Recent advances in the technology (i.e. the development and use of multilevel converter technology) have helped to eliminate the need for low-order harmonic filters in most multilevel VSC based STATCOM applications [2].

The new multilevel chain-link converter technology is built up by linking a number of H-bridge modules in series to form one phase leg of the VSC branch, Figure 1(a) shows a single H-bridge. Each cell module consists of four IGBT positions, each featuring an IGBT module with a corresponding gate unit, and a DC capacitor. Figure 1(b) shows a configuration in which four H-bridge modules make up each of the three phase legs. The IGBTs will be controlled to achieve +Udc, 0 or –Udc on the H-bridge terminals, similar to the voltage from a 3-level converter. For the case with 4 modules connected serially as in Figure 1(b), there are 9 possible voltage levels: 4 in the positive direction, 4 in the negative direction, and a zero-voltage, depending on how the IGBTs are switched [2].



(a) single H-bridge with IGBTs



(b) 3-phase chain-link of H-bridges

Figure 1: Multilevel chain-link converter with H-bridges

ABB solution for the new multilevel chain-link converter technology, i.e. SVC Light is shown in Figure 2. Pulse Width Modulation (PWM) is utilized with an effective switching frequency in the tens of kHz range, providing a smooth output voltage waveform on the AC-side; therefore there is no need for low order of harmonic filtering. In addition, each valve converter H-bridge module is operated with low switching frequency per cell, enabling low switching losses. The number of the connected H-bridge modules depends entirely on the required power rating. The sum of all individual power module voltages will form the terminal voltage and drives the output current from the converter. Additional modules may be required depending on requirements for harmonic distortion and overvoltage ride-through.

The converter system shown in Figure 2 has two sub-modules per phase, each containing four full bridge cells where each cell holds four IGBT units with associated gate units and one set of DC-capacitors. Each IGBT is inside of a modular housing which is made up of a number of sub-modules of enhanced Press-Pack type semiconductor chips which have passed rigorous failure mode and safety tests.

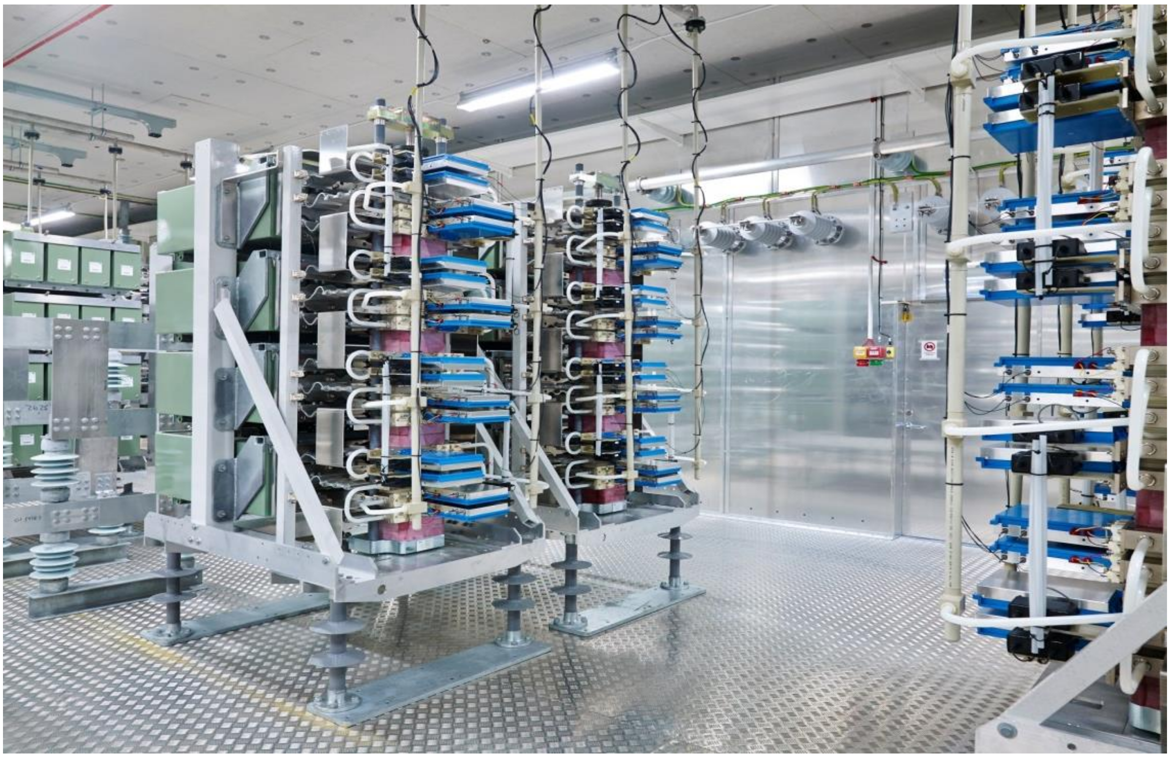


Figure 2: VSC bridge principle configuration showing four cells per phase.

Thanks to simplicity in configuration, requiring a minimum of components, the multilevel concept for SVC Light is modularized. Compared with the previous versions, the new multilevel technology offers a greater flexibility and wider dynamic range as a result of enabling modular and scalable design of the converter. The concept enables a high degree of prefabrication and in-factory testing, leading to enhanced product quality and an overall reduction of project execution time. If dictated by application requirements, the concept is excellent for Hybrid STATCOM solutions.

STATCOM and Hybrid STATCOM topologies

STATCOM systems come in a wide range of topologies. The pure STATCOM installation has a symmetrical operating range. However, very often asymmetrical operating range is required. This requires the VSC converter to be offset.

Besides the STATCOM and its VSC converter(s), the Hybrid STATCOM solutions consist of TSCs and/or TSRs to reach the required power rating. The VSC will be used for continuous control, TSCs and TSRs for offset. There will be no limitations in number of TSC switching operations. The VSC size is optimized to give bump less (smooth) switching of TCR and TSC branches, utilizing Vernier Control over the full dynamic range. The use of mechanically switched devices (MSCs and/or MSRs) to offset the operating range is limited to applications with comparably low dynamic requirements in terms of reaction time and consecutive number of switching operations.

STATCOM or Hybrid STATCOM systems for transmission applications normally make use of a power transformer between the power grid and the medium voltage (MV) busbar. The voltage on the MV bus is typically in the range of 20-30 kV irrespective of the voltage level on the mains. A normal transformer turn ratio is 400/25 kV. This large ratio results in very high short circuit currents on the MV bus, frequently in the range of 50-90 kA (rms symmetrical).

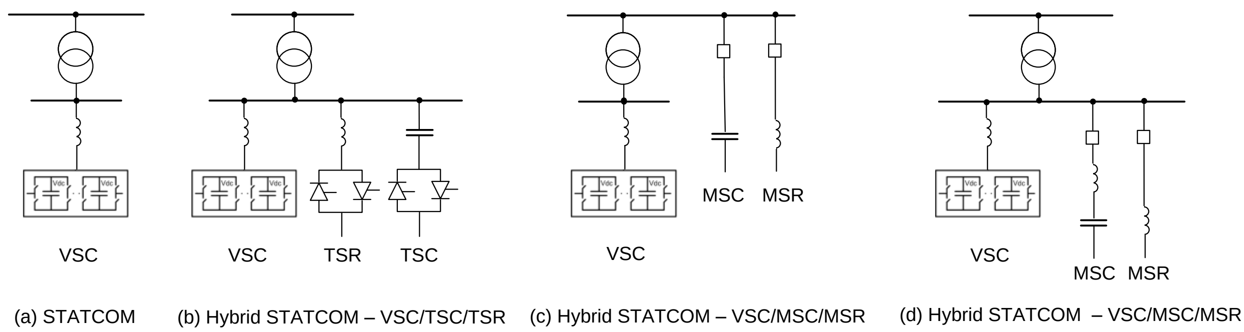
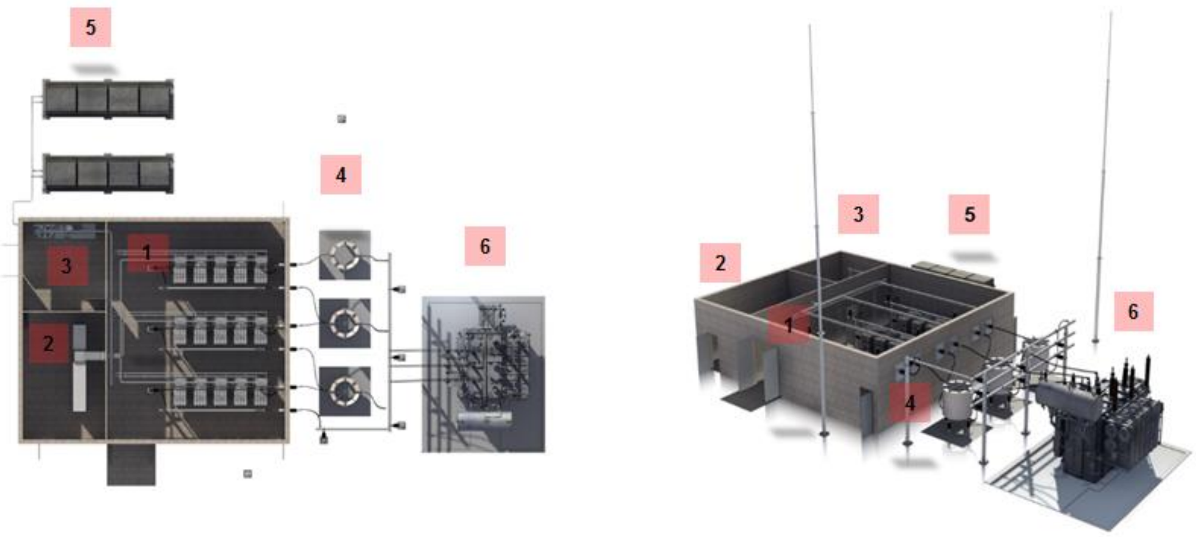


Figure 3: STATCOM and Hybrid STATCOM topologies

Although external breaker switch devices (MSC and MSR) are relatively simple and fairly economic, they come with some disadvantages which have to be taken into consideration in Hybrid STATCOM solutions. These are (a) Hybrid STATCOM solutions using mechanically switched branches (MSC and MSR) are limited to applications with comparably low dynamic requirements in terms of response time, (b) the obvious discharge time of MSC banks of several minutes before re-energization, (c) the overall limited number of switching cycles of a circuit breaker reducing the overall flexibility of the installation and (d) the limitation in short circuit capability of circuit breakers.

A Hybrid STATCOM topology based on VSC, MSC and MSR blocks may not be very suitable for voltage control applications in transmission systems experiencing frequent disturbances. STATCOM systems designed with small hysteresis (<<20%) and/or short time delays between the VSC and the device to be switched will result in large number of switching operations, i.e. high stress on the circuit breakers (CB) and requirements for CB maintenance will increase. For such system, it is essential that the breaker switched devices, i.e. MSCs and MSRs are only to be used for steady state base load. It must be controlled in a way so that switching is minimized. The number of allowed circuit breaker operations for this type of STATCOM system is typically in the range of 2000 to 3000. The number of allowed circuit breaker operations is significantly reduced compared to the number of operations for a standard substation breaker (8000 to 10000 operations) due to high capacitive breaking current required for this type of application. It is recommended that breakers are provided with controlled switching concepts. Mechanically switched reactors (MSR) may also create DC offset to the system voltage imposing risk of saturation of CTs and power transformers. Further, the short circuit capability of the MSC and MSR circuit breakers (CB) must be coordinated with the short circuit current on the connecting MV bus. For some applications the short circuit current capability of the circuit breakers is a limiting factor in the design of the STATCOM system.

Thanks to simplicity in modular multilevel STATCOM technology, requiring a minimum of components, the required footprint of an installation is small. Furthermore it enables a high degree of prefabrication and in-factory testing, leading to an overall reduction of project lead times and enhanced product quality. A typical SVC Light layout is shown in Figure 4 below.



1. VSC valve room
2. Control & Protection room
3. Pump room
4. Phase reactors
5. Heat exchangers
6. Power transformer

Figure 4: STATCOM layout

Harmonics

In a fast growing and rapidly changing power system environment, robust design of harmonic filters and FACTS devices is a challenge. Today, harmonic filters in classic SVC installations are optimized to the known grid topology and may be less efficient after a few years' time. This has to be handle by Utilities many times already at specification stage, i.e. requirements for split TCRs and/or increased number of SVC branches [4] or open up technical specifications for new FACTS technology with lower harmonic generation compared to TCR based SVC solutions.

The usage of a MMC Voltage Source Converter (VSC) based STATCOM and Hybrid STATCOM solutions for generating the reactive current have low harmonic generation and thereby reduced number of branches, i.e. harmonic filters of low-order is not required [2]. The elimination of low-order harmonic filters will result in less possible resonances with the network. This means that STATCOM and Hybrid STATCOM solutions are less sensitive and dependent on network conditions. Harmonic filters in classic SVC installations, is a weak point, as their performance depends entirely on the network harmonic impedance [4].

STATCOM and Hybrid STATCOM solutions based on MMC technology can also be designed for load balancing without installing 3rd harmonic filters if using active filtering. Third harmonic filters need to be installed for load balancing SVCs.

Overvoltage Ride Through

For overvoltage conditions in the transmission system, an SVC has superior performance as compared to a STATCOM with similar size. This is due to the fact that the reactive power output of an SVC varies with the square of the voltage (i.e. as voltage increases, the Mvar output increases quadratically). For a STATCOM, as voltage increases the reactive power output increases linearly.

However, if a TSR branch is added to the topology to create a Hybrid STATCOM solution, the solution can take advantage of the inherent ability of the reactor to consume reactive power during overvoltages.

Typically, most power utility applications for FACTS devices include an overvoltage profile for which the device must remain in service at full inductive conduction without blocking and/or tripping. Classic SVC's for transmission grids are typically required to operate at least up to 1.3 p.u. with full blocking capability. For some utility projects TCR valves shall be fully controllable up to 1.5 p.u. primary voltage. Overvoltage ride through capability for classical SVC is discussed in IEEE 1031-2011 [4], where the below overvoltage profile is given.

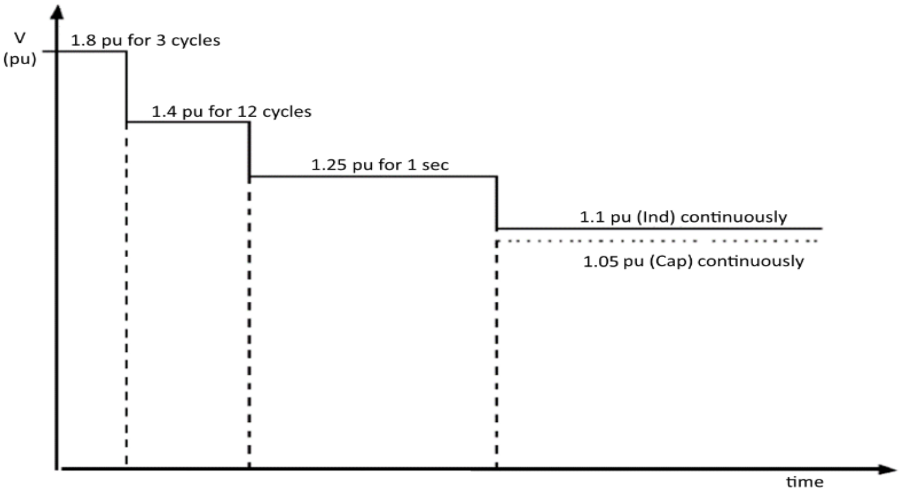


Figure 5: Example of system overvoltage profile (Source: IEEE 1031-2011)

Although this overvoltage profile is intended for use when specifying SVCs for transmission system applications, the same should be valid for STATCOM applications since they are intended to be operated in the same network, i.e. same over voltage ride through requirements applies for SVCs, STATCOMs and Hybrid STATCOM solutions. Hybrid STATCOM solutions involving switched capacitor branches requires sufficiently high blocking capability to successfully switch out caps at high voltage, e.g. system recovery.

STATCOM systems shall be designed to remain in service during operation in overvoltage conditions such as this is that the device should not block or trip but rather provide full inductive output in order to ensure that the grid voltage is stabilized. This requires that the STATCOM to be sized appropriately (i.e. the number of series-connected valve modules should be increased) in order to accommodate an overvoltage ride-through requirement. This has been the design philosophy for classic SVC installations for decades and so should also apply for STATCOM and Hybrid STATCOM systems.

Dynamic Performance
Combining the advantages of multilevel STATCOM technology with thyristor based SVC technology will optimize the performance of the Hybrid STATCOM system.

Under-voltage performance - at under-voltage conditions, the STATCOM inherently has superior performance and provides more VAR compared to the classic SVCs with same power rating, i.e. during under-voltage the STATCOM reactive power output linearly decreases, whereas the reactive power from the classic SVC decrease with the square of the voltage.

Over-voltage performance - for over-voltage conditions, the thyristor based SVC technology naturally gives more power than solutions with pure STATCOMs. The mature SVC technology is well proven and has excellent performance and operational experience at overvoltage conditions.

Speed of response - The speed of response of the Hybrid STATCOM solution based on VSC and thyristor switched technology is fast over the full operating range. No limitations in switching of branches as for the hybrid solution based mechanically switched devices.

Performance during single phase faults - the dynamic performance during single phase faults will be improved with the Hybrid STATCOM solution based on TSC technology, i.e. full dynamic range can be used for voltage support during fault conditions.

TOV performance at fault clearing – Hybrid STATCOM systems based on multilevel VSC and TSC technology can be designed with fast TSC blocking developed for classic SVCs to improve voltage recovery and avoid overvoltage at fault clearing [6] [7] [8]. No VSC power is required to balance the AC capacitors in the TSC(s), i.e. the complete VSC can be efficiently used to control the system voltage at fault clearing. In Hybrid STATCOM system with mechanically switched capacitors (MSC), MSCs may be connected at fault clearing and the power system will have to absorb the reactive power generated by the AC capacitors. Consecutively the VSC size has to be increased in Hybrid STATCOM systems based on MSC technology to have same TOV performance at fault clearing as the Hybrid STATCOM system based on thyristor switched elements. Fast TSC blocking is illustrated in Figure 6. From the figure it can be seen that the Hybrid STATCOM system designed with fast TSC blocking responds fast to combat voltage overshoot. Overvoltage with Hybrid STATCOM based on MSC devices results in overvoltage close to 1.5 p.u. voltage.

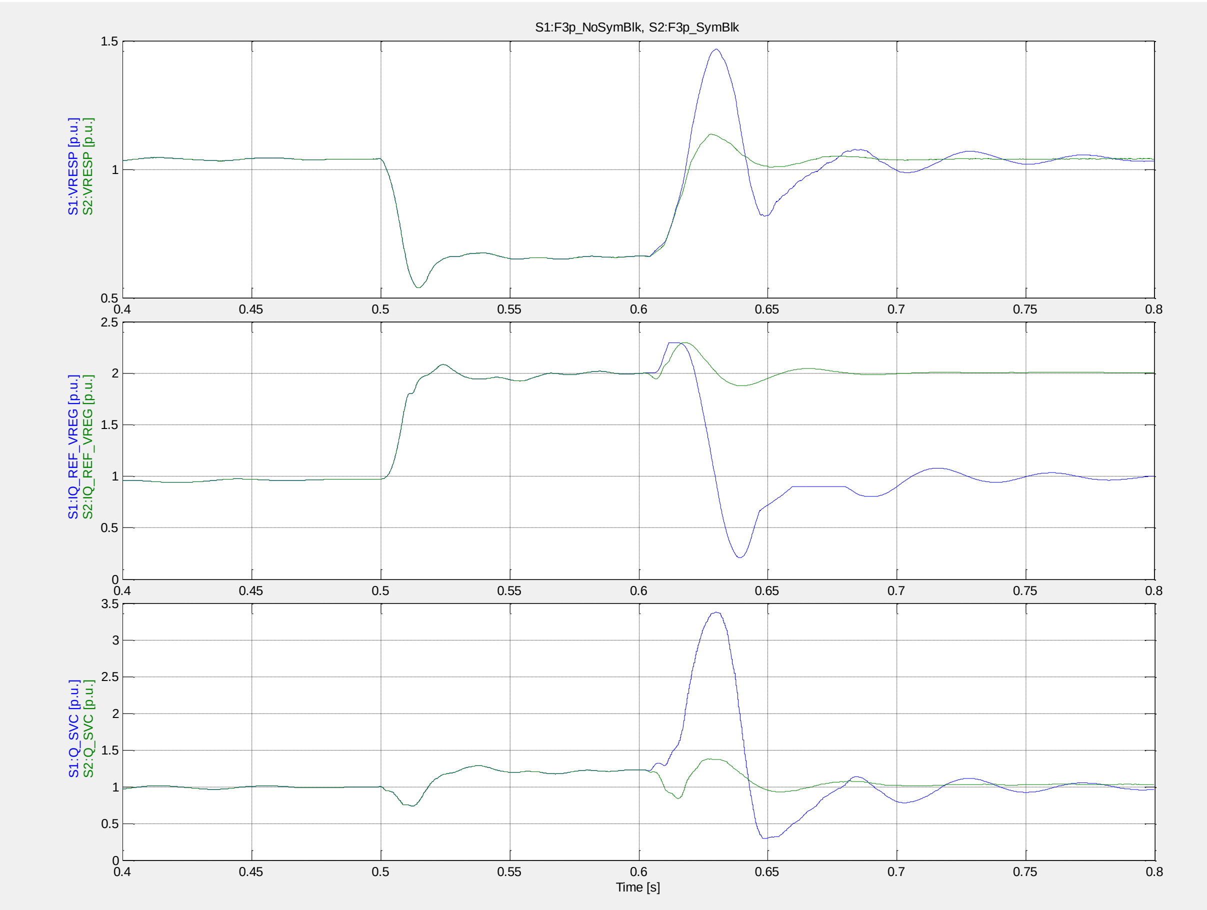


Figure 6: Hybrid STATCOM with and without fast TSC blocking

STATCOM and Reliability/Availability

The well proven concept of Static Var Compensator (SVC) has been used in transmission systems since the 1970s. As the STATCOM technology now makes its way into transmission applications it is of interest to make the comparison with the SVC from a reliability-availability perspective in how to address these requirements from a Utility specification point of view. Looking at since long time established requirements for transmission system SVC units, it is reasonable to take a look at how the STATCOM relates to reliability and availability numbers typically found in Utility company specifications.

First, establishing the definition of the reliability and availability concepts is pertinent. Reliability is driven by the number of forced outages of the STATCOM, Hybrid STATCOM or SVC system. It is a measure of the readiness to operate when called for and can be quantified as the number of forced outages over a defined period of time, typically number of failures per year. Typically no more than two (2) forced outages per year are allowed. Availability is driven by the operational time lost due to downtime, given as the percentage uptime of the total time. Typical numbers range from 98 – 99 % for transmission applications; 99% (forced) and 98% (forced and scheduled). By these definitions it is evident that reliability and availability is entirely different. It is important to address both when specifying the equipment. This to avoid situations with units subject to frequently tripping when called for to operate. Such units tend to show decent availability as long as they are re-energized after every trip. Their value to system support is however questionable.

By the definition given here, reliability requires equipment introduced for redundancy purpose to basically be on line, its purpose being to avoid outage. This is the purpose of having dual cooling pumps, redundant control systems etc. where seamless transition from the active to the standby system is achieved by design. This type of auxiliary and control equipment is more or less the same whether STATCOM, Hybrid STATCOM or SVC and the same criteria therefore applies.

It is in the main circuit of the two technologies the main differences is found. The STATCOM can be of different topologies as can the classical SVC. The STATCOM can comprise anything from a single Voltage Source Converter (VSC) alone to VSC and harmonic filters and/or switched capacitor and reactor banks, including any combinations of the latter two. Switched banks can be either mechanically or thyristor switched depending on design and application. The well-known Vernier controlled classical SVC can be configured of combinations of Thyristor Controlled Reactors (TCR), Thyristor Switched Capacitors (TSC) and harmonic filters. Looking at availability and reliability, larger multi branch transmission SVC units to an extent have inherent capability of providing partial availability, the word partial referring to reduced dynamic range being available when the unit is re-energized. A STATCOM can of course be designed to emulate this property by splitting the VSC capability into smaller fractions. This can however have detrimental effect on the overall availability and reliability as more equipment is introduced, more subsystems are required etc. Even though classical SVC units exist where “off-line redundant” branches are used to provide 100 % dynamic range also at N-1 branch outage conditions, these are rare. To achieve the same for a STATCOM a fully rated stand by VSC unit would be required. This being said, it may still be beneficial to split a VSC in two blocks to achieve partial availability or consider SVC partial availability with one or more branches out. The benefit of this is however far from obvious looking at it from a system perspective.

The dynamic range of dynamic shunt compensation, be it a STATCOM or an SVC, is driven by reactive deficiency in the system during identified specific dynamic events. Often there are different categories of events, either large events prone to rapidly turn into voltage collapse situations (category A), or smaller local events (category B) that may eventually lead up to more serious situations. The category A type is in most cases not met by partial availability. Standby branches of sufficient rating to sustain the required dynamic range are necessary. Category B events may or may not be covered by partial availability. There are obviously category B events more severe than others and it is recommended to look closely if partial availability is merited for such events before a decision is made. This will have impact on the size of the individual VSC block and as vendors tend to standardize on VSC block size this may have impact on the number of VSC blocks required. Consequently this may well differ between vendors.

For the Multi Modular Converter (MMC) concept, also referred to as the chain-link topology, redundancy is handled by introducing converter levels, or cells in addition to what the rating requires. This can be compared to redundant thyristor levels in a thyristor valve where a faulty level fails shorted. At an MMC cell fault it is either internally or externally bypassed and the VSC seamlessly continue operating.

STATCOM and LCC HVDC

STATCOM and Hybrid STATCOM systems have a lot to contribute to the operation of the classical Line Commutated Converter HVDC (LCC HVDC). Line Commutated Converters have two properties where a STATCOM can be of obvious use. LCC HVDC terminals consume reactive power from the network and they generate harmonics. It is perhaps the combination of said LCC properties that present the operational challenge, where a sufficient portion of reactive power and harmonic filtering is required while maintaining system voltage control. This combination of requirements presents difficulties during weak network conditions.

Here a STATCOM or Hybrid STATCOM system can help mostly by providing voltage control and managing reactive resources such as capacitor banks. In a weak network there is a likely conflict between harmonic performance and voltage control. The harmonic performance requires a certain portion of shunt filter banks connected, but this may not always work well with the system voltage control where the capacitive banks tend to push the system voltage upwards. Here the STATCOM or Hybrid STATCOM system can control the voltage such that the required amount of filters can be in operation to meet the harmonic distortion limits without the system voltage criteria being violated. In addition it can be used to manage reactive resources in terms of mechanically switched capacitor and reactor banks by having this type of control invoked in the STATCOM control system. It will also act to eliminate voltage steps caused by bank switching often seen when hysteresis based switching schemes are used. This again, is more prone to cause issues in weaker systems rather than stronger. With the voltage dynamically controlled filter and capacitor banks steps can be of higher rating, possibly enabling reduction of the number of banks required.

Depending on the HVDC configuration in terms of number of terminals, there may be reduced mode operation modes meriting STATCOM active filtering capabilities. Although potentially useful there are limits imposed by rating and the VSC control priorities. Active filtering is effective for lower frequencies up to approximately the 9th order harmonic. Most likely it would be useful during reduced mode operation where six pulse characteristic harmonics are present, which may allow for reduction of filters tuned to harmonics only present during relatively rare operating conditions. If there is intention to use active filtering it is of importance to note that it may require additional rating depending on the dynamic rating of the STATCOM required to meet requirements on voltage control. It also helps in reducing the number of switching operations, which have positive impact on system reliability and in expanding the maintenance intervals.

The perhaps most important aspect of STATCOM and Hybrid STATCOM operation to a classical HVDC is its action during commutation failures. Commutation failures are often caused by dips in the terminal voltage caused by system faults. Recurring commutation failures result in loss of power transfer. With a significant amount of capacitor banks in operation on the inverter side overvoltages of significant levels can develop as a result. This calls for rapid compensation and sufficiently rated the STATCOM or Hybrid STATCOM can be used to mitigate the overvoltage by absorbing sufficient amounts of the surplus reactive power during this type of events. If this is the intent and purpose of the STATCOM or Hybrid STATCOM, the rating will depend heavily on the overvoltage condition. To be noted is that most STATCOM vendors allow the VSC to block and trip during overvoltage events, rendering the STATCOM useless for this type of operation. To be of use here the STATCOM and Hybrid STATCOM system has to be intentionally rated to operate during these events. Coordination of the STATCOM system and the HVDC inverter controller implanted is a STATCOM based supplementary control function can be very useful to control this type of phenomena, whereas the initial cause of commutation failure, i.e. undervoltage caused by system faults, can be counteracted by the STATCOM or Hybrid STATCOM system dynamics in the capacitive range.

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Challenges in Renewable Energy Resources and Role of VSC-HVDC Technology in Integration to Grid

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INDIA

SUMMARY

The paper presents the challenges in integration of renewable energy resources to grid, and also discusses VSC-HVDC technology as one of the techno-economical options to overcome the integration challenges. Today, the world is facing rapid depletion of conventional energy resources like fossil fuels, thereby challenging us to look into more unconventional and sustainable renewable energy resources. Renewable energy exists over wide geographical areas, as compared to other energy sources, which are concentrated in limited areas. Development and utilization of renewable energy is resulting in significant energy security, environmental and economic benefits. Worldwide different countries have conducted studies to measure their potential in renewable energy to meet their present and future demands. But renewable energy is intermittent in nature, which makes it difficult to accurately schedule the power generation from a renewable energy source. Further these resources have limited generation (3-4 MW per wind turbine), and this would normally feed a very limited area. Therefore, a cluster of wind-turbines are used over a wide area in the sea in off-shore wind generation. The power from each wind turbine is brought to a pooling station using submarine cables and then further transmitted to onshore grid stations/load centres using VSC-HVDC transmission link. Nowadays, the VSC-HVDC has attracted more attention due to its beneficial features such as 1) independent active and reactive power control; 2) VSC-HVDC system can feed islanded and passive networks; and 3) there is no commutation failure problem. This has encouraged many power technology companies to focus their vision on development of VSC-HVDC especially in the application of renewable energy resource's integration to grid.
This paper investigates challenges faced while integration of various renewable energy resources into grid and the suitability of VSC-HVDC to overcome various technical challenges. In the conclusion of paper, future prospects to further improve the technology shall be discussed in brief.

KEYWORDS

Renewable Energy Resource, Wind Power, VSC-HVDC, Grid Integration, Cable

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1. INTRODUCTION

The installed renewable energy capacity globally is approximately 1,560 GW (including hydro power) in 2013. Renewables, excluding hydro, collectively grew to an estimated 560GW in 2013 from 85GW in 2004, which is a fivefold increase in less than 10 years. Globally, solar PV accounted for about 139 GW of renewable power capacity 2013 as compared to 2.6GW in 2004 and wind power capacity was 318GW till 2013 as compared to 48GW in 2004 [1].

Out of the above mentioned renewable energy sources; wind power generation has been growing rapidly in recent years. This increase of renewable energy resources in power grids, it is becoming an increasingly challenging task for grid operators to maintain power quality, which has resulted in the implementation of strict grid codes. Since grid codes differ from country to country, compliance to the same involves a lot of discussions between grid operators, wind farm developers, manufacturers and others.

This paper discusses issues in integration of renewable energy to the power grid and proposes VSC-HVDC as a most optimal and techno-economically feasible solution. Section – 2 of this paper focuses on common grid code requirements that have to be followed by renewable power producers. This paper deals with the requirements of wind power to discuss about the topic of grid integration. The advantages of VSC-HVDC over LCC-HVDC are discussed in Section -3 of this paper. The role of VSC-HVDC as a solution to comply with the strict grid codes is discussed in Section – 4.

2. ISSUES OF INTEGRATION OF RENEWABLE ENERGY RESOURCE

2.1 Reactive Power Capability

In order to keep the voltage of power system within the desired grid limits, reactive power is required to be balanced in the grid. In conventional power generation, this is done by Automatic Voltage Regulator (AVR) which controls the excitation of synchronous generator, which further controls reactive power absorption or generation at the AC bus, thereby controlling voltage. PV based solar power is designed with unity power factor and the characteristics of output power depends on inverter design. It does not contribute at the time of fault or any transient condition. Solar PV system is designed to supply real power only and it does not consume any reactive power. However in case of wind energy, since wind turbine generator has got a rotating mass, any kind of disturbance on AC grid will be impacted by wind power generation.

In earlier times when, the proportion of wind energy to conventional energy in an AC grid was not significant, the wind farms were allowed to trip whenever there used to be a fault or disturbance in the AC grid [2]. The conventional generators through their AVR used to take care of reactive power requirement to support the voltage profile of AC grid. This used to avoid cascaded tripping of generators which otherwise might have resulted in a black-out of the grid. But with increase in contribution of wind power in AC grid, reactive power requirements of wind farms have to be supported locally instead of absorbing reactive power from grid. Therefore adherence to the grid code requirements is also mandatory for wind power producers.

Figure 1 shows an example of the reactive power control demands defined in the UK grid code specified by National Grid [2].

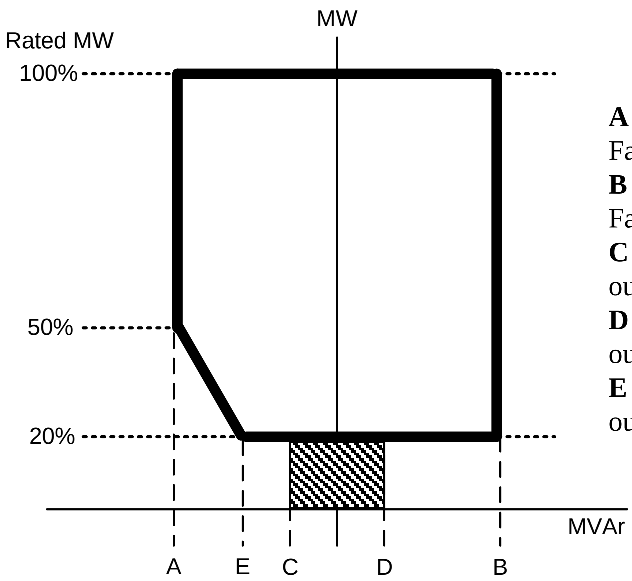

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Figure 1 : Reactive power requirements in the UK grid code specified by National Grid [2]

2.2 Frequency Regulation

In case of conventional power sources, frequency control is usually done in three levels in order to achieve the same frequency throughout the grid as well as meeting the power demands [2]. The primary level controls frequency of a single generating unit to maintain the frequency and power balance whereas secondary level uses an automatic generation control unit to control output of one or more generators. The tertiary level reschedules the power station output to control power and frequency balance at grid level.

For a power system with larger wind power generation sudden frequency change will result in significant active and reactive power variations. Since wind generators have rotating masses these will also contribute to AC grid inertia. In an event of fault or any other disturbance on AC grid, the wind generators will be forced to reduce the active power to AC grid in order to achieve fault ride through capability. The reduction in active power in this case will require reducing the frequency of wind power generator at a high rate which will produce excessive stresses on the turbine-generator. Further, as a result of this added complexity in dynamic behaviour of the AC grid, it will also raise issues for other power sources like PV based solar power generation. Since PV system is connected to AC grid through a power electronic device (inverter), it does not impact the inertia of the AC grid. In order to maintain frequency some extra measures will have to be adopted. Considering that a number of renewable power generation sources must be connected to the grid, the implementation of primary and secondary level control of frequency is very complicated as various renewable energy technologies have different dynamic impact on AC grids. This further complicates operation of grid when both renewable power and conventiontional power generation are operating in synchronism [3].

As an example, Grid code requirement for the EON Netz (Germany) are shown in Figure 2. The operation scenarios for different grid parameters are shown.

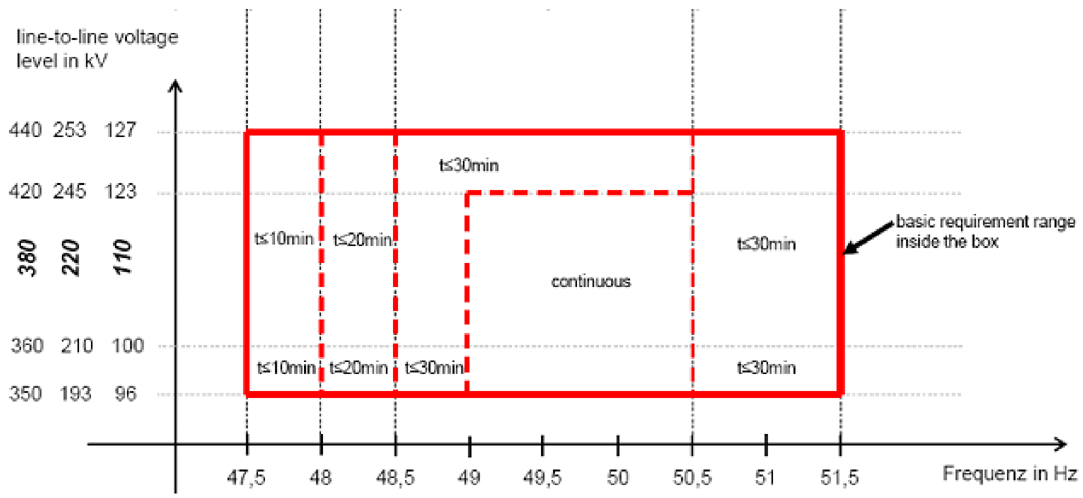

Figure 2 : EON Netz (Germany) tolerance requirements against variation in grid frequency and grid voltage [2]

2.3 Fault Ride-Through capability

In the event of a fault in the ac network, large overcurrent and power swings can stress the generators both during the fault and after its clearance. The conventional generators are designed to cope up with these stresses and are also equipped with effective AVR and frequency governor technology. This can help the generators to continue to be connected to the network during faults as well as help regain normal operating conditions of the grid system after clearance of the fault [4].

For wind turbine generators one of the most difficult requirements is the capability to ride through a fault. As discussed in the previous sections that, the wind turbine generator experience severe stresses due to disturbance in AC grid. As per the Grid codes in the event of fault, the wind farms are not allowed to trip rather they are required to be online and provide fault ride through support even when the AC grid voltages drop drastically. Figure 3 shows a typical wave shape of fault ride through capability curve where tripping is not allowed when magnitude of voltage drop and its duration are above the shaded area.

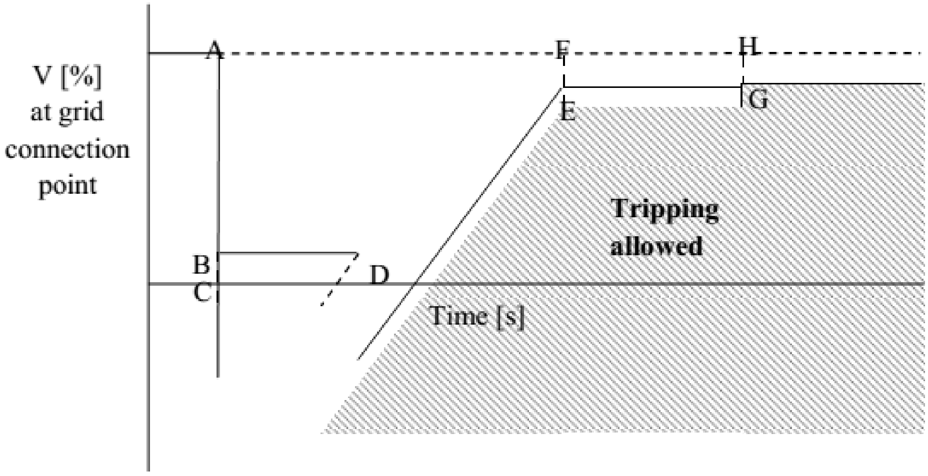

Figure 3: Typical shape of Fault Ride through Capability plot [2]

3. VSC-HVDC OVER LCC-HVDC AS A SOLUTION

Figure 4shows a typical VSC-HVDC schematic. It consists of two VSCs together with transformer, reactors, dc capacitors for each station, DC cable and Dynamic Braking System (DBS). A typical fault ride through scheme is shown in Figure 4 where the DBS enables to decouple both the poles temporarily in case of any transients due to fault.

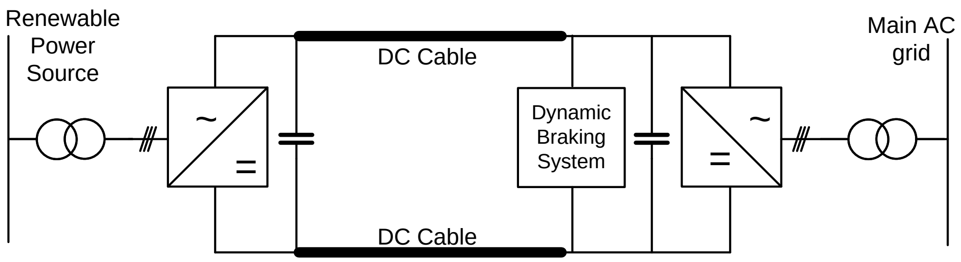

Figure 4: Typical VSC-HVDC schematic.

4. VSC HVDC AS A SOLUTION TO INTEGRATION OF RENEWABLE ENERGY RESOURCES

4.1 Reactive Power Capability

Reactive power capability of a VSC is determined by current rating of the switching devices, DC voltage rating and steady state stability limit. When a VSC converter is connected to AC grid, reactive power injection or absorption will depend on the magnitude of voltage level of converter and AC grid. If the VSC voltage magnitude is higher than AC grid voltage, then VSC injects reactive power i.e. it is in capacitive mode of operation. In the same way if VSC voltage magnitude is lower than AC grid voltage, then VSC absorbs reactive power i.e. it is in inductive mode of operation. The PQ capability diagram shown in Figure 5 shows all four quadrant operation can be performed with VSC. Focussing on reactive power capability, it can be seen that as the grid AC voltage decreases, the reactive power capability increases. A VSC transmission system can instantly take any operating point within the capability curve. A thorough look shows that with proper design criteria of maximum dc voltage and maximum dc current the capability curve can comply with reactive power requirements specified in most Grid codes.

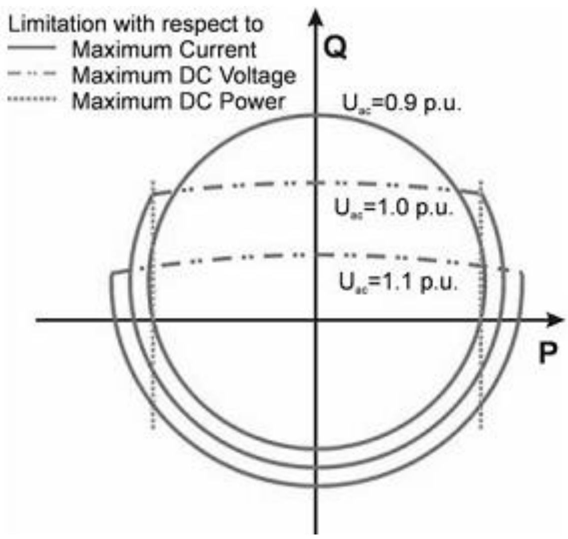

Figure 5 : A basic simplified PQ diagram [5].

4.2 Frequency Regulation

During any fault or disturbance, the active power export from VSC to the grid can be reduced to zero. This results in availability of excessive power at DC link. This excessive power can be dissipated using DBS [6]. Therefore wind power generators can continue generating rated power at same frequency for an intermittent time, without facing any severe stresses due to sudden change in power at AC side. This will allow the wind power generators to slow down at much less pace thereby obtaining a smooth frequency regulation as well as better power oscillation damping. Further wind turbine generators will not be required to be designed for different power changes with respect to different grid codes, which will be economically beneficial as standardized design solution for wind turbine generators can be obtained.

4.3 Fault ride through capability

VSC-HVDC can sustain quite severe faults or disturbances because of its fast switching capabilities and smooth control system. It can also control the fault current to a desired value within the range of semi-conductor current carrying capability [7]. During a fault, the AC grid bus voltage drops drastically as well as significant reduction of power at AC grid is also experienced which further requires reactive power to support the grid voltage. The AC side VSC has to reduce power feed to AC grid without hampering the operation of wind farm side VSC. Therefore, the surplus power produced in dc link due to undisturbed operation at wind farm side converter will be dissipated through DBS as discussed in section 4.2.

During fault condition, the grid side dc can be charged using some power out of the excessive power generated at dc link. This makes grid side VSC capable of supporting reactive power requirement at AC grid to maintain the voltage. Once the fault gets cleared, the wind farm and AC grid can again be connected through dc link. This allows wind farm to keep generating power continuously without getting tripped. In this way the VSC can provide fault ride through capability without stressing the wind turbine generator.

4.4 Other Benefits of VSC HVDC System

Since VSC based HVDC has capability of decoupling the main AC grid from the Renewable power generation, there are various other advantages apart from obeying the Grid code requirement.

The power quality characteristic also gets decoupled in a sense that voltage flicker or energization transients on any side grid do not get reflected to other side grids.

- In case of phase unbalance on any one side grid, will not have any ill-effects on other side grid as this can be taken care through switching capabilities.

- Since grid compliance can be obeyed by VSC-HVDC on behalf of renewable power, there is a window of opportunity to standardize these renewable power production products

- Renewable power efficiency can be increased by letting VSC of renewable side modify the AC frequency depending on availability of resources.

- When renewable power system gets connected to an existing AC grid through AC lines it might happen that short circuit current rating of the AC grid might exceed its present design limits. In this case VSC-HVDC solution can be used as it can also limit the short circuit current contribution to AC grid thereby reducing the risk of exceeding the short circuit current rating of AC grid.

- Black Start capability: This is a unique facility of VSC-HVDC which can be used to start the wind farm. The grid side converter is connected to AC grid, which charges the DC storage capacitor. This further energizes the wind farm side converter, thereby charging the wind power side grid. Once stable voltage and frequency is obtained the wind farm side can be connected to the bus.

CONCLUSION

Recent trends in power system show that the penetration of renewable energy is increasing day by day. This has introduced new challenges in terms of integration with AC power grids. The challenges exist in wide variety of fields like from Reactive power control issue to Fault ride through capability. This has resulted in strict grid code requirements that are to be followed by wind turbine generator manufacturer. In order to reduce such problems, HVDC solution has been discussed in this paper. It has been found that specifically VSC transmission system plays a vital role in integration of renewable energy resources in grid. VSC transmission comes with an advantage like, independent control of active and reactive power, better transient and dynamic stability. Capability of VSC to decouple the rectifier and inverter system and let both sides operate independently has been a great advantage as a solution for the integration issue. In this way the VSC-HVDC takes over the responsibility for grid code compliance from renewable energy resource. However, there is further room for development of VSC technology as DC grids based on VSC-HVDC are starting to be planned. With multiple distributed power sources of various kinds it might be required to make a DC grid of its own and then integrate it with AC grid.

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Challenges in Renewable Energy Resources and Role of VSC-HVDC Technology in Integration to Grid

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ALSTOM T&D India Limited
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SUMMARY

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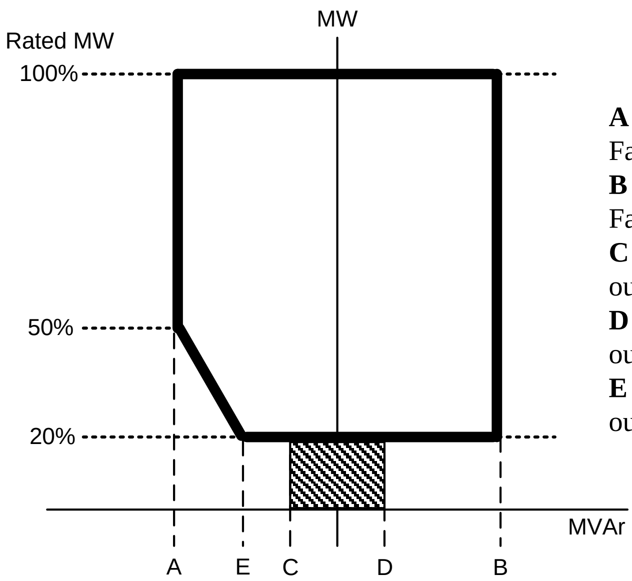

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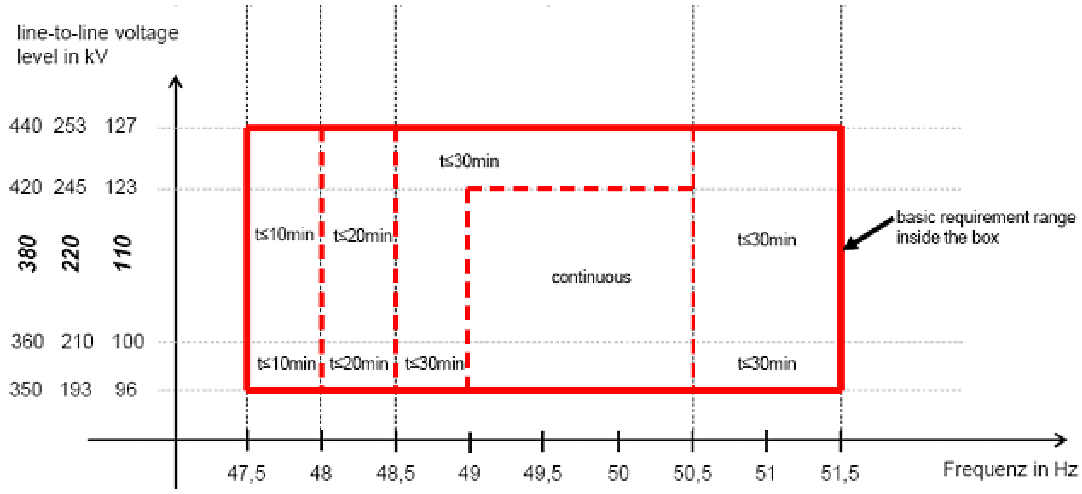

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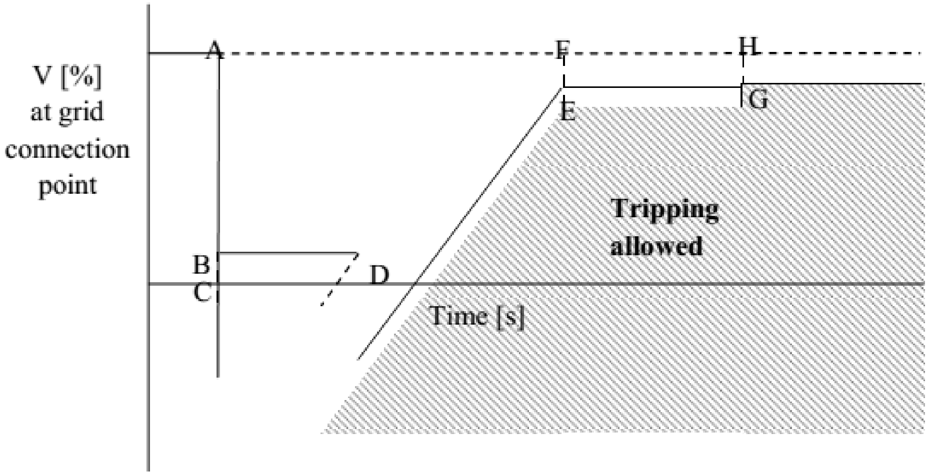

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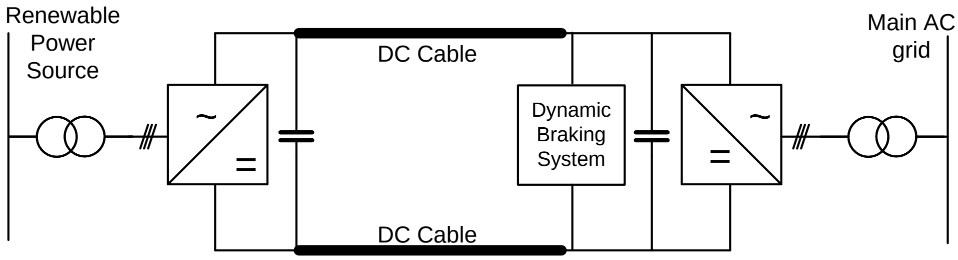

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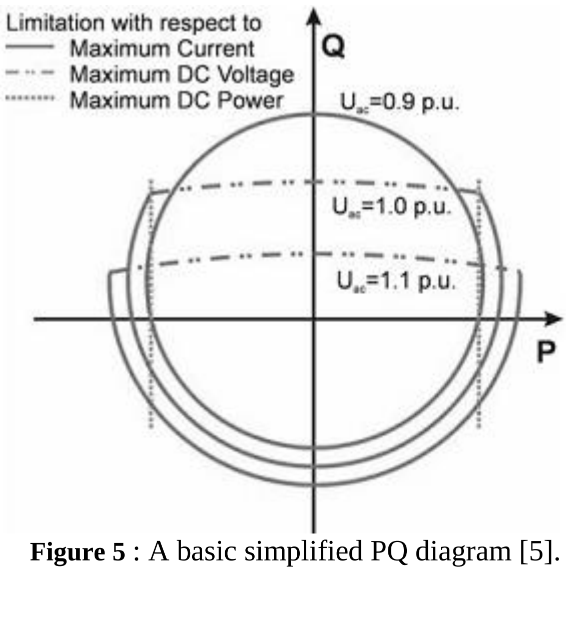

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Study on Steady state and Transient over voltages in Hybrid Multiinfeed HVDC system on RTDS

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SUMMARY

In developing countries to meet the energy demand long HVDC transmission lines are planned to the load centers. This resulted in two or more HVDC links terminating to close electrical proximity forming multiinfeed HVDC systems. The phenomena of concern for multiinfeed HVDC systems are Transient Over Voltage (TOV), Commutation Failure including Fault Recovery, Harmonic Interaction and Power Voltage Instability and Control Interactions.

The application of Line Commutated Converter (LCC) HVDC systems is proven technology. Where as in recent years installation of HVDC systems with Voltage Source Converter (VSC) technology are increasing due to its controllability, compact modular design, ease of system interface and low environmental impact. The hybrid multiinfeed HVDC system, with one HVDC link being LCC and other link being VSC will appear in future grids, which bring new challenges in operation and control of these systems. This formation is also possible if one of the existing HVDC system of multiinfeed HVDC system is upgraded or replaced with VSC technology.

Simulation studies have been carried out to study the dynamic performance of the multiinfeed HVDC links of LCC-HVDC and VSC-HVDC under varied network conditions. The study primarily investigated the (i) Dynamic performance (ii) Multi Infeed Effective Short Circuit Ratio(MIESCR) (iii) Steady state over voltages (ii) Transient over voltage of two systems for different Short circuit Ratios. The results of the studies are described in the paper.

KEYWORDS

LCC-HVDC, VSC-HVDC, Multiinfeed, RTDS, Multi Infeed Effective Short Circuit Ratio, Steady state over voltages, Transient over voltages

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1. Introduction

Because of the concentration of major load centre in a given geographical location in the country and their long distances from the generation source, the planned HVDC links have their inverters in close proximity. The over voltages in multiinfeed HVDC system when two LCC-HVDC are feeding the same ac network was well reported in Ref[1]. The steady state over voltages and Transient over voltages in a multiinfeed HVDC system when three HVDC links are involved was reported in Ref[2]. In these references the HVDC links considered are having line commutated converters. In this paper the Hybrid multiinfeed HVDC system if one of the link is VSC-HVDC and other link is LCC-HVDC is studied. Dynamic performance, MIESCR, steady state and transient over voltages in Hybrid multi-infeed HVDC systems are studied

The multiinfeed HVDC systems considered for the study are

System1: Multiinfeed HVDC System with line commutated converter HVDC systems LCC1_HVDC and LCC2_HVDC feeding AC network

System2: Multiinfeed HVDC System with voltage source converter based HVDC system VSC1_HVDC and line commutated converter HVDC system LCC2_HVDC feeding AC network

LCC1_HVDC and LCC2_HVDC systems are monopole CIGRE HVDC bench mark system of 1000MW. VSC1_HVDC system is 300MW system. The rectifier and inverter AC voltages of all HVDC systems are 345kV and 230kV respectively. Both inverters of HVDC systems are connected by a transmission line of 100km

System simulation is carried out on Real Time Digital Simulator(RTDS) which has accurate models of LCC with a time step of 50μsec and VSC with a time step of 2.5 to 5μsec. LCC controls are modeled in detail with current control at rectifier and extinction angle control at inverter. VSC-HVDC controls to maintain the DC voltage and DC Power constant through the HVDC link are implemented.

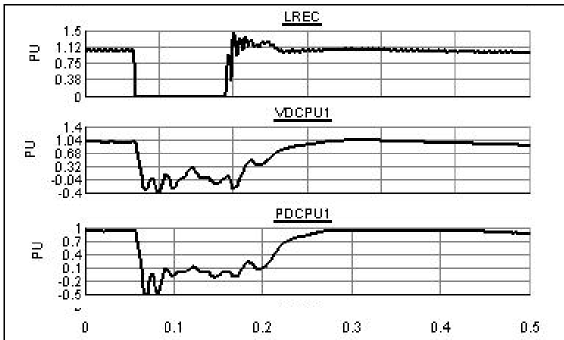
2. Simulation of Multiinfeed HVDC systems on RTDS:

2.1 Modeling of LCC1_HVDC and LCC2_HVDC Systems:

The first CIGRE HVDC benchmark system[3] is a mono-polar 500-kV, 1000-MW HVDC link with 12- pulse converters on both rectifier and inverter sides. AC filters are added to absorb the harmonics generated by the converter as well as to supply reactive power to the converter. AC system at Rectifier and Inverter in RTDS is modeled as balanced sinusoidal three phase infinite bus voltage of 345kV and 230kV respectively behind impedance. The source impedance at rectifier and inverter is modeled as RRL type. DC system parameters are 500kV and 1000MW.

Control of the converters is modeled by setting the firing angle α of the thyristor valves with respect to the AC system voltage. The rectifier's firing angle is chosen so that the DC current is maintained at set-point and the inverter's firing angle is chosen so that it's extinction angle γ is maintained at set point. Measured values of DC current and extinction angle are provided to regulators whose output is the rectifier and inverter firing angle respectively. The DC current set point is altered depending on the DC power requirements for the system. Instead of directly entering the DC current set point sometimes the DC power order can also be entered. VDCOL is the control circuit which handles the reduction of the current order based on either the DC voltage or inverter AC bus voltage is also modeled. Inverter controls are equipped with both a constant extinction angle controller and current controller. Under normal conditions the current controller’s output is not used. However, if the DC current error is greater than a predetermined amount the inverter’s current controller is used rather than the extinction angle controller’s output.

Dynamic performance of LCC1_HVDC System is studied for a fault at inverter and rectifier. The controls modelled are found satisfactory and the system is recovering for these faults. Figure 1 and 2 shows the recovery of AC voltage, DC voltage and DC power for a 3 phase to ground fault at inverter and single phase to ground fault at rectifier.



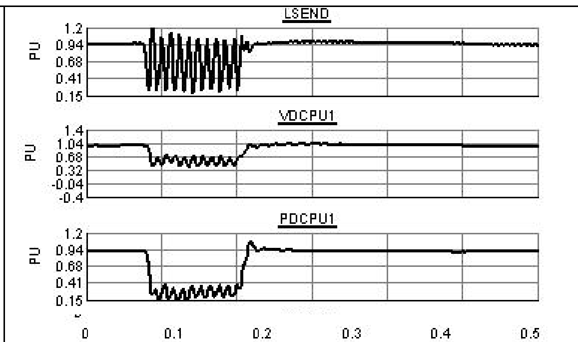


Figure 1: AC voltage, DC voltage and DC power for a 3 phase to ground fault at inverter	Figure 2: AC voltage, DC voltage and DC power for a Single phase to ground fault at rectifier

2.2 Modeling of VSC – HVDC System:

The voltage source converter HVDC system as is simulated[4]. The rating of the VSC HVDC link is 300MW, +/- 180kV. Rectifier side AC system considered is 345kV and inverter side AC system is at 230kV.

The circuit inside the “DCLINEL” box is simulated in small time step simulation and interfaced to the main circuit through small time step interface transformer. The rectifier side circuit consists of the interfacing transformer, smoothing reactor, VSC Bridge and the DC line. The inverter side simulation is the mirror image of this. Switching devices are represented as an RC branch with small C in the “OFF” state and as a small L branch in the ON state. In order to adopt the valve to the impedances of the simulated network, the usual peak switched voltage, the usual peak switched current and a damping factor δ are specified in the simulation.

Among the multilevel VSC configurations, the multi-level Neutral Point diode clamped Converter (NPC) has been widely accepted for applications in high power. As compared with the other prevalent multi-level converter topologies the NPC converter uses a fewer number of capacitors and switches per phase to synthesize the desired output voltage levels. One of the advantages of VSC-HVDC system using PWM technology is, it is possible to independently control the active power and the reactive power. The RSCAD has vast library of control system components from which, the outer loop DC controls based on ref [5] are implemented to control the VSC-HVDC link. The voltage margin method for interchange of power control was applied to the DC voltage control block and the active power control block in the terminal controller. The voltage margin is defined as the difference between the DC voltage references of the two terminals for the purpose of active power interchange between terminals.

The DC voltage and active power controller implemented in RTDS for VSC-HVDC. The VTD and VTQ generated through the controller are used to generate the sinusoidal modulation signal. This sinusoidal modulation signal is compared with a high frequency triangle wave. When the value of the triangular wave exceeds that of the modulation signal then IGBT switch will be turned on. Conversely, when the amplitude of the triangular wave is less than that of the modulation signal IGBT will be turned off.

Dynamic performance of VSC1_HVDC System is studied for a fault at inverter and rectifier. The controls modelled are found satisfactory and the system is recovering for these faults. Figure 3 and 4 show the recovery of AC voltage, DC voltage and DC power for a 3 phase to ground fault at inverter and single phase to ground fault at rectifier.

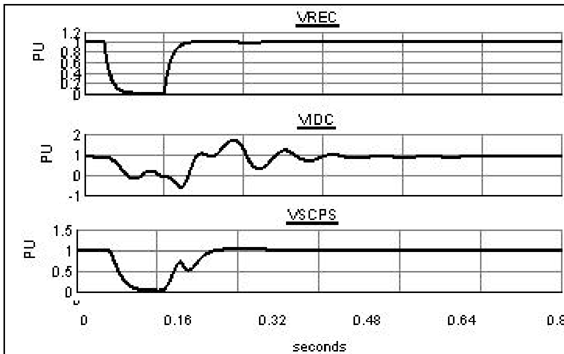


Figure 3: AC voltage, DC voltage and DC power for a 3 phase to ground fault at inverter

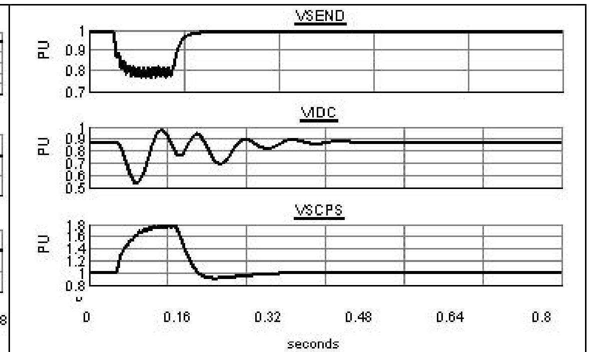


Figure 4: AC voltage, DC voltage and DC power for a Single phase to ground fault at rectifier

2.3 Simulation of System1:

In System1, LCC1_HVDC system and LCC2_HVDC system are connected by a transmission line of 100km at the inverter ends as shown in Figure 5 forming Multiinfeed HVDC system.

2.4 Simulation of System2:

In System2, VSC1_HVDC system and LCC2_HVDC system are connected by a transmission line of 100km at the inverter ends as shown in Figure 6 forming Hybrid Multiinfeed HVDC system.

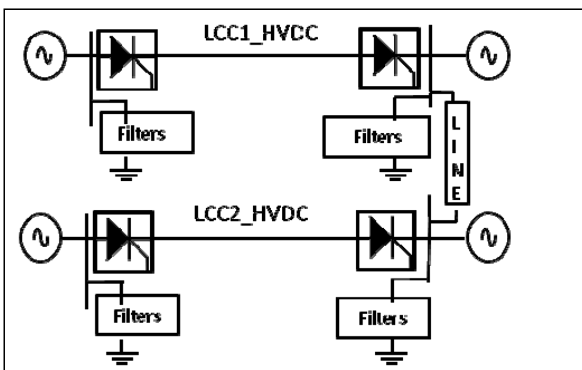


Figure 5 : Simplified Single line diagram of System1

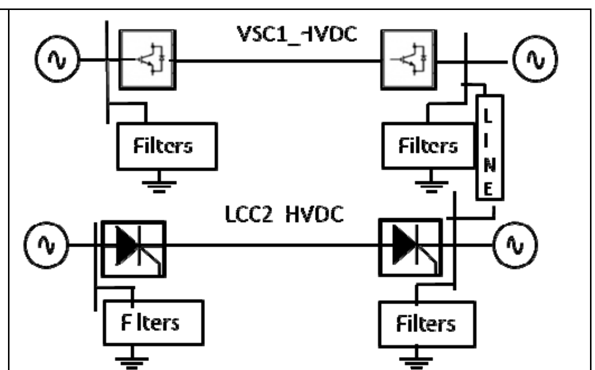


Figure 6 : Simplified Single line diagram of System 2

Studies are carried out for System1 and System2 to see the effect of VSC_HVDC system the context of Multiinfeed system

3.0 Studies carried out:

3.1 Dynamic performance of System1: Dynamic performance of multiinfeed HVDC System1 is studied for its dynamic performance for fault at inverter1 and inverter2. As both systems are identical the recovery pattern of both systems are also same of 3phase to ground fault at inverters. Figure 7& 8 show the AC voltage, DC voltage and DC power for this contingency.

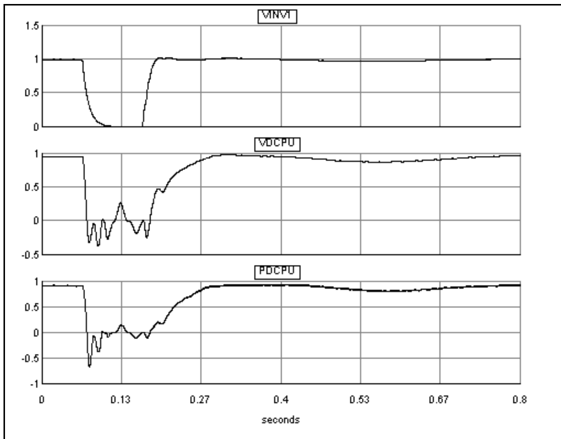


Figure 7: AC voltage, DC voltage and DC power for a 3 phase to ground fault at inverter of LCC1_HVDC

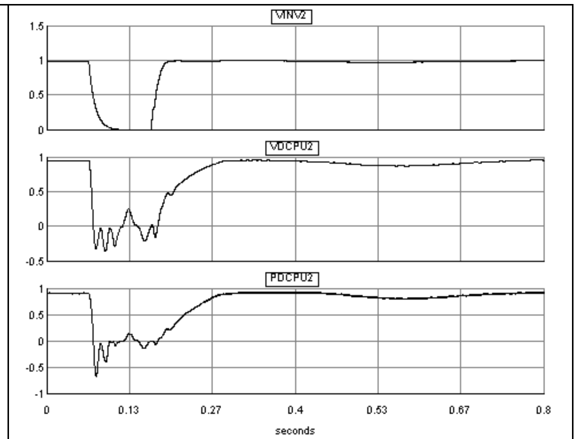


Figure 8: AC voltage, DC voltage and DC power for a 3 phase to ground fault at inverter of LCC2_HVDC

3.2 Dynamic performance of System2: Dynamic performance of Hybrid multiinfeed HVDC System2 is also studied for 3phase to ground fault at inverter1 and inverter2 for a duration of 100msec. The recovery of VSC1_HVDC system is happening around 0.4 seconds after the fault is cleared. The recovery of LCC2_HVDC system is after around 0.2 seconds.

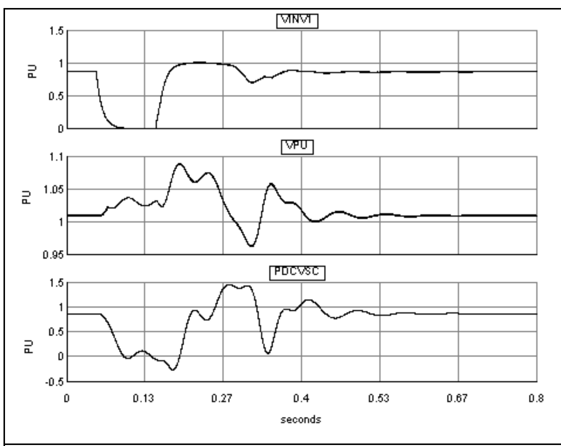


Figure 9: AC voltage, DC voltage and DC power for a 3 phase to ground fault at inverter of VSC1_HVDC

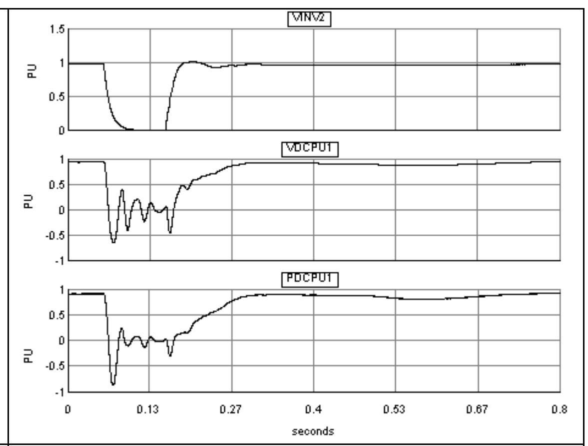


Figure 10: AC voltage, DC voltage and DC power for a 3 phase to ground fault at inverter of LCC2_HVDC

System1 and system2 are stable for the AC faults at inverter Buses. These two systems are further analysed to find the amount of interactions in each system

3.3 Multi Infeed Effective Short Circuit Ratio (MIESCR) for system1 and system2

The useful indicators that indicate the expected level of performance in a HVDC link are Short Circuit Ratio(SCR) and Effective Short Circuit Ratio(ESCR) of AC systems when HVDC links are widely separated. This index is extended to multiple infeed HVDC by the so called Multi Infeed Short Circuit Ratio (MSCR) and Multi Infeed Effective Short Circuit Ratio (MIESCR)[6]. MIESCR is given by

$$MIESCR_i = \frac{SCC_{MVAi} - Q_{filteri}}{P_{dci} + \sum_{j=1,\, j\neq i}^{k} MIIF_{j,\,i} * P_{dcj}}$$

where,

$MIESCR_i$ = Multiple Infeed Effective Short Circuit Ratio at inverter 'i'
SCC_{MVAi} = Short Circuit Capacity at inverter 'i'
$Q_{filteri}$ = Total MVAR of the filter at inverter 'i'
P_{dci}= DC Power of the link 'i'
$MIIF_{ji}$ = MIIF of the inverter 'j' with respect to inverter 'i'
P_{dcj} = DC Power of the link 'j'

Here Multi Infeed Interaction Factor (MIIF) is a parameter for estimating the degree of voltage interaction between two systems and is defined for converter 'i' to converter 'j' by by

$$MIIF_{ji} = \frac{\Delta V_j\,\%}{1\%\, voltage\ change\ in\, V_i}$$

This is essentially the ratio of voltage changes at the two converter buses following an inductive fault induced voltage reduction of 1% at the ac bus bar of converter i.

The SCR at inverter for CIGRE HVDC bench mark system is 2.5. MIECER is calculated for varying SCRs LCC2_HVDC.

Table 1: MIESCR values for System1

SCR at inverter of LCC1_HVDC	SCR at inverter of LCC2_HVDC	ESCR at inverter of LCC1_HVDC	ESCR at inverter of LCC2_HVDC	$MIIF_{21}$	$MIIF_{12}$	$MIESCR_1$ at LCC1_HVDC	$MIESCR_2$ at LCC2_HVDC
2.5	5.0	1.79	4.29	0.468	0.601	1.22	2.68
2.5	4.5	1.79	3.79	0.608	0.582	1.12	2.40
2.5	4.0	1.79	3.29	0.555	0.572	1.15	2.10
2.5	3.5	1.79	2.79	0.527	0.650	1.17	1.69
2.5	3.0	1.79	2.29	0.554	0.696	1.15	1.35
2.5	2.5	1.79	1.79	0.608	0.480	1.12	1.21
2.5	2.0	1.79	1.29	0.391	0.609	1.29	0.80

In a similar way MIESCR values are computed for System2 when LCC1_HVDC link is replaced with 300MW VSC1-HVDC link

Table 2: MIESCR values for System2

SCR at inverter of VSC1_HVDC	SCR at inverter of LCC2_HVDC	ESCR at inverter of VSC1_HVDC	ESCR at inverter of LCC2_HVDC	$MIIF_{21}$	$MIIF_{12}$	$MIESCR_1$ at VSC1_HVDC	$MIESCR_2$ at LCC2_HVDC
2.5	5.0	2.5	4.31	0.407	0.513	1.10	3.70
2.5	4.5	2.5	3.81	0.363	0.654	1.17	3.15
2.5	4.0	2.5	3.31	0.787	0.842	0.72	2.61
2.5	3.5	2.5	2.81	0.874	0.732	0.67	2.28
2.5	3.0	2.5	2.31	1.144	0.918	0.55	1.79
2.5	2.5	2.5	1.81	0.472	0.377	1.01	1.61
2.5	2.0	2.5	1.31	1.088	1.222	0.57	0.94

It is interesting to observe that in the above Tables 1 and 2, a dramatically different value of MIESCR is obtained compared to ESCR. Even though ESCR1 is constant MIESCR1 is varying dependent on the values of $MIIR_{21}$ computed. In Table 1 and Table 2 ECSR values are more than the MIESCR values. Based on the lower MIESCR values HVDC system may be embeded in week system but ESCR gives a wrong indication of stong system. MIESCR calculated for System1 and system2 shows the same index can be used for Hybrid Multiinfeed HVDC systems to find the effective short circuit ratio.

3.4 Steady State Over Voltages :

Monopole or bipole outage of HVDC link, with full shunt compensation in place, will lead to over voltages at the HVDC terminals. The steady state over voltages after the contingency are represented in Figures 11 and 12 below. The studies show that the over voltage at the inverter buses following the contingency are high. This is largely due to reactive power surplus generation by the filters on the AC side. The contingencies carried out are outage LCC1_HVDC and LCC2_HVDC one at a time for System1; outage of VSC1_HVDC and LCC2_HVDC one at a time for System2.

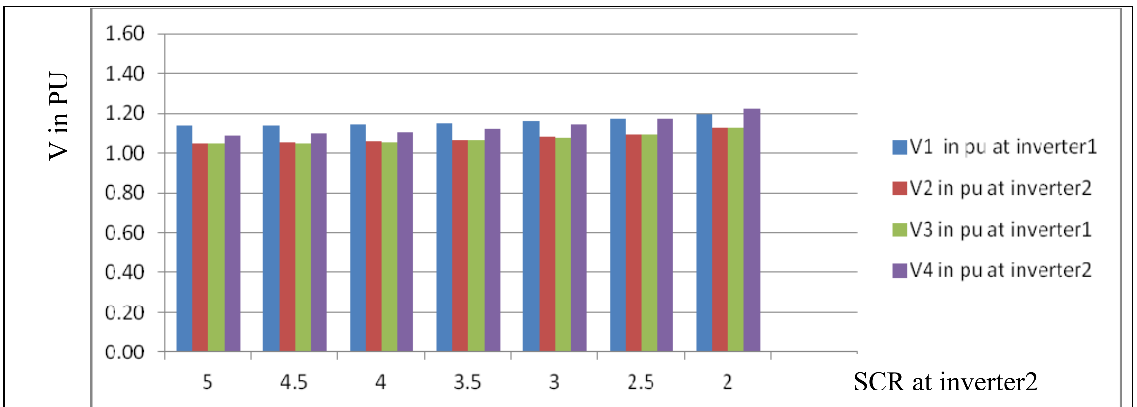


Figure 11: Steady state over voltages for System1

In Figure 11, V1 and V2 are steady state over voltages for outage of LCC1_HVDC and V3 and V4 are state over voltages for outage of LCC2_HVDC. It is observed that over voltage is high at the inverter bus whereever pole outage is present in the System1 configuration.

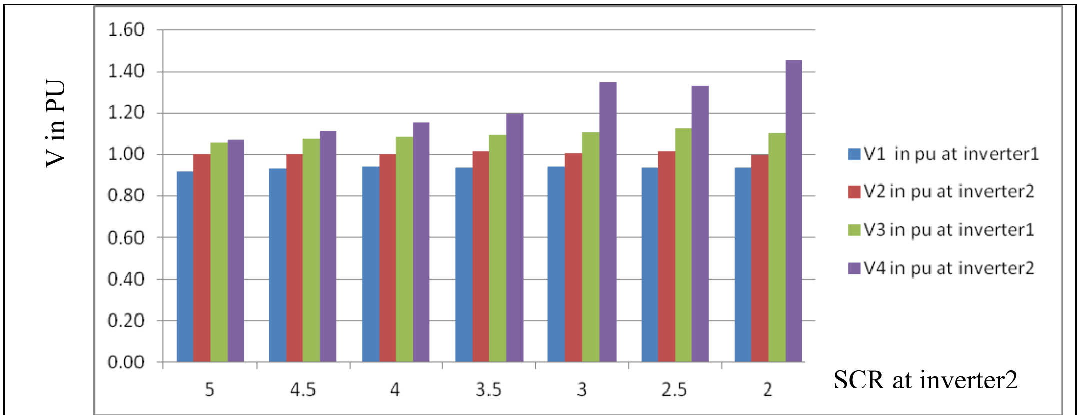


Figure 12: Steady state over voltages for System2

In Figure 12, V1 and V2 are steady state over voltages for outage of VSC1_HVDC and V3 and V4 are state over voltages for outage of LCC2_HVDC. It is observed that over voltages for the outage of VSC1_HVDC are less as the MVAR rejection is less. However for the outage of LCC2_HVDC steady state over voltage is as high as 1.4pu for SCR of 2.0.

3.5 Transient Over Voltages :

An important criterion in the design of an HVDC links is the permissible transient overvoltage at the ac terminals of the converter station. The overvoltage influences the ratings of the station equipment both on the ac and dc sides, and affects the ac network. Three phase-to-ground fault at the AC buses, one at a time with the fault clearing time of 100ms is created at inverter1 and inverter2 for system1 and presented in Figure 13. Similarly TOV for system 2 are presented in Figure 14. It is observed that Transient over volatges are more for System1 compared with system2.

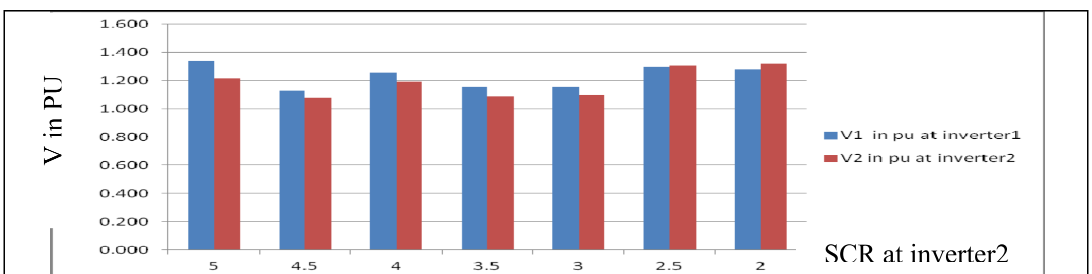


Figure 13: Transient over voltages for System1

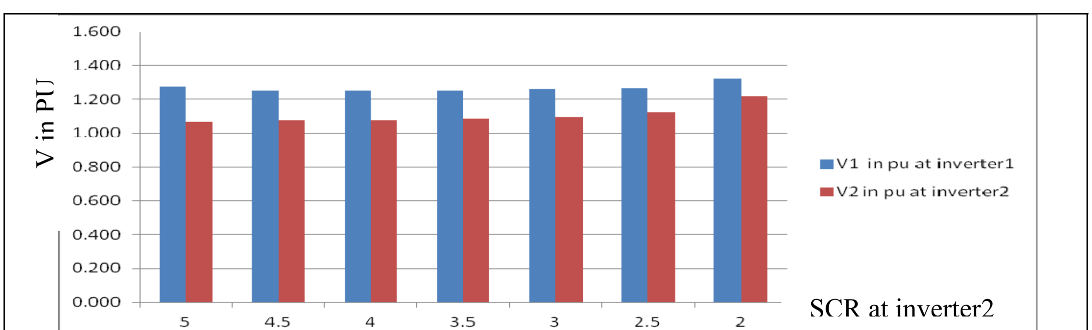


Figure 14: Transient over voltages for System 2

4.0 CONCLUSIONS:

In this paper the stuides are carried out for two multiinfeed systems one with line commutated converter HVDC systems and other with voltage source converter based HVDC system and line commutated converters. Both systems are modelled in detail on RTDS and steady state and transient performance of the systems are analysed.

The AC fault recovery time of VSC HVDC system is twice the fault recovery time of LCC HVDC system for the modelled controls. MIESCR which is applicable for Multiinfeed HVDC system is computed for both the systems and found that this concept can be extended for Hybrid multiinfeed HVDC system.

From the Steady state and transient over volatges are computed for both systems it is found that these are less for Hybrid multiinfeed system. However like in conventional multiinfeed sytems Steady state and transient over volatges are high for lower MIESCR values.

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Real-time simulation studies to investigate series power tapping options in CIGRE HVDC benchmark model

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SUMMARY

Line commutated converter (LCC) based high voltage direct current (HVDC) stations are normally used to transmit bulk power via HVDC transmission lines/ cables over long distances. However, the use of a small power rating, series tapping converters to feed power to a local AC grid/ load located somewhere along the HVDC transmission route has been a topic of research for quite some time.

In this paper, three series tapping options are presented having different system level control schemes. Of these three series tapping options presented, it is discussed that having a series tapping converter working in tandem with an alternate power source (to the local AC grid, say a diesel generator (DG)), is needed to have a fixed power tap to the local AC grid and a feasible rating of the series tapping converter for varying HVDC line current values. This series tapping arrangement, which has a voltage source converter (VSC) based converter topology, is studied, through real-time simulations, by connecting it to the HVDC LCC benchmark model.

Sequence of events are first presented to energize and start-up (connect the series tapping converter to HVDC line) the series tapping converter followed by a validation through real-time simulations. In the proposed sequence of events, it is ensured that the bypass switch across the series tapping converter does not need DC current breaking capability. Further, three series tapping converter faults are studied and a mitigation sequence for these faults are evolved, ensuring that there is a minimal impact on the series tapping converter and the main station converter. These fault mitigation strategies are further validated through real-time simulations.

KEYWORDS

Real-time simulation, series tapping converter, fault mitigation, energization

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1. Introduction

Line commutated converter (LCC) based high voltage direct current (HVDC) stations are normally used to transmit bulk power via HVDC transmission lines/ cables over long distances [1], [2]. Situations might however arise, where there is a need to provide power to a local AC grid/ load centre (which is of a relatively small power rating as compared to that of the HVDC stations), located somewhere along the HVDC transmission route. To address this issue, a small power rating converter connected in series with the HVDC transmission line has been a topic of research for quite some time [3], [4]. This series tapping converter, being connected in series with the HVDC transmission line, carries rated DC line current, but, is of a small voltage rating since the power provided to the local AC grid/ load centre is quite small as well. Further, this series tapping converter normally, has no control over the DC transmission line current, but varies series DC voltage injected into the DC transmission line so as to feed desired amount of power into the local AC grid/ load centre [3], [4]. Figure 1 shows a typical arrangement of a series taping converter connected to a HVDC LCC based monopole link.

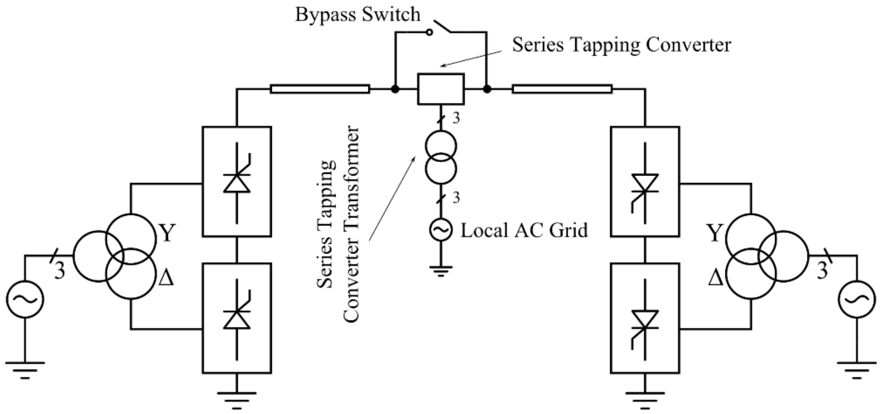

Figure 1: Typical arrangement of a series tapping converter

This paper implements a series tapping converter, in the CIGRE LCC HVDC benchmark model [5]. Real-time simulation cases are run for various system control philosophies and the converter level control philosophies of the series tapping converter. Further, real-time studies are also done to demonstrate the energization and connection of the series tapping converter with the HVDC line. The proposed method in this paper ensures that no DC current breaking capability is required for the bypass switch. Finally, three series tapping converter fault cases are studied and an effective mitigation strategy is further evolved so as to minimize the effect on the main station converters and the series tapping converter.

2. Series Tapping Converter Topology and Inner Controls

System level controls (outer controls) of the series tapping converter will be explained in the next section. This section meanwhile first discusses the choice of series tapping converter topology, and further discusses its converter level controls (inner controls). For the purpose of this paper, a voltage source converter (VSC) based topology is used for the series tapping converter.

This VSC based series tapping converter topology as shown in Figure 2, has two converter stages. The DC-DC converter performs only one function of maintaining the DC-link voltage at a constant value. If power is consumed by the local AC grid, DC link voltage drops. Therefore, to maintain this DC-Link voltage at a constant value, the DC-DC converter injects a voltage in series with HVDC line such that required amount of power can be fed back to the DC-link capacitor and hence local AC grid. The AC-DC Converter transfers this power into local AC grid. The AC-DC converter just has to control AC side direct and quadrature axis currents to control real power and reactive powers fed into this local AC grid.

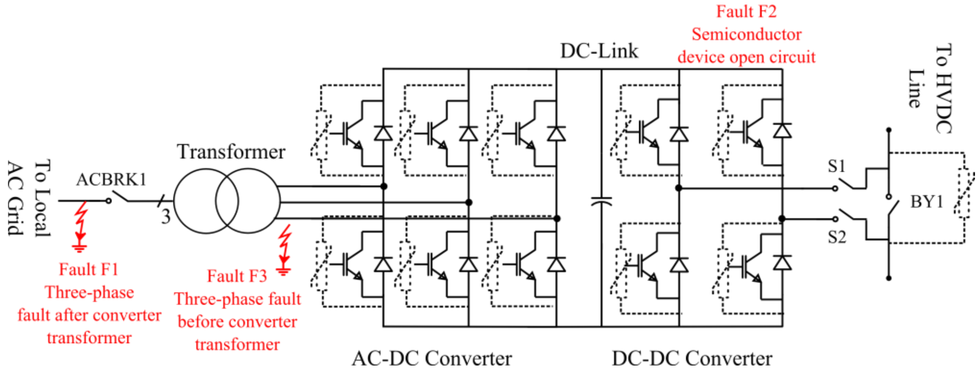

Figure 2: Topology choice for the series tapping converter along with associated switchgear and protection equipment

3. System control philosophies for the series tapping converter

The overall system control philosophy of the series tapping converter, dictates means of tapping power to a local AC grid. This, will be the top level control philosophy, which will be added ahead of the inner converter controls as explained in the previous section. Three system control philosophies were studied as part of this paper and the main conclusions of the same are presented below:

a. Series tapping converter feeds available power to local AC grid

In this system control philosophy, tapping converter DC link voltage is fixed to a particular value. Therefore, when HVDC line current reduces from its nominal value, power tapped by the series tapping converter and fed into the local AC grid is also reduced appropriately. The main drawback of such a scheme is the non-availability of a fixed power at the local AC grid, which is not acceptable in most cases.

b. Series tapping converter feeds a fixed power to the local AC grid

In this system control philosophy, when there is a reduction in the HVDC line current, the DC link voltage of the series tapping converter needs to be increased appropriately. However, as a result of this, the voltage rating of the series tapping converter and hence semiconductor device count in the series tapping converter will also increase significantly. Hence such a scheme will not be a very cost effective scheme from the series tapping converter's perspective.

c. Series tapping converter works in tandem with an alternative power source

To achieve an economically viable series tapping converter option, with the assurance of constant power availability at the local AC grid, series tapping converter needs to work in tandem with an alternate power source. That is, the series tapping converter is maintained to have a fixed DC link voltage, and hence a fixed voltage rating, and feeds available power to the local AC grid (as explained in Scheme a.). However to ensure that a constant power continues to be fed to the local AC grid, an alternate power source, say a diesel generator (DG), is connected to the same local AC grid. This DG supplies the deficit in power in case the main HVDC line current reduces from its rated value. Real-time simulations are presented in Section 6 to validate this power sharing in the event of HVDC main line current reduction.

4. Energization and Start-up of Series Tapping Converter

To perform its desired function, the series tapping converter needs to be energized first and then connected to the HVDC line. These processes of energization and start-up of the series tapping converter are explained in this section.

The series tapping converter is connected to a local AC grid via the series tapping converter transformer and a local AC breaker, ACBRK1. The first step is to close the local AC breaker (ACBRK1). Once ACBRK1 closes, the AC-DC converter acts as a diode bridge rectifier and charges the DC link capacitor. Once the DC-link capacitor is charged, voltage across it can be used to energize all gate units in both converters of the series tapping converter. Now that the series tapping converter is energized, the next step is to connect it to the main HVDC line and start tapping power from it. In this paper, this process is referred to as the start-up process and is accomplished in the following manner.

a. The isolators, S1 and S2 are first closed to connect the series tapping converter with the main HVDC line. However, the main HVDC line current continues flowing through the bypass switch, BY1, across the series tapping converter.
b. One option to divert current away from the BY1 into the series tapping converter is to directly open BY1 at rated DC line current. However, this means that BY1 will need rated DC current breaking capability. Such a requirement will increase the cost of BY1 and hence the series tapping converter arrangement as a whole significantly. To circumvent this problem, the DC-DC converter of the series tapping converter is first controlled in manner so as to divert main HVDC line current into the series tapping converter, i.e., away from BY1. Once current through BY1 reaches zero, it can be opened quite easily at the current zero crossing.

This completes the process of energization and start-up of the series tapping converter. Now, normal control functions of the DC-DC converter and AC-DC converter may presume. As can be seen, the proposed method of start-up does not require DC breaking capability in BY1. Real-time implementation results are presented in Section 6 validating the same.

5. Fault studies on the series tapping converter.

This section presents the mitigation sequence involved for three faults. It is assumed that all faults are permanent (or for a long duration). Therefore, re-closure is not attempted. The protection equipment required for the series tapping converter along with the three-faults considered in this paper are illustrated in Figure 2.

Fault F1 is a three-phase to ground fault at the local AC grid. The mitigation sequence for this fault is presented below:

a. The fault is sensed by an over current trip in the transformer winding current. Sensing this overcurrent, semiconductor devices of the AC-DC converter are gated low. This stops the series tapping converter from feeding this fault. AC breaker can also open now to electrically isolate the fault location from the series tapping converter.
b. DC-DC converter of the series tapping converter can continue functioning as usual. Since semiconductor devices of the AC-DC converter are gated low, power drawn by the series tapping converter to the HVDC line also reduces to a very small value (only pertaining to DC-DC converter losses).
c. Further to this, if required, the series tapping converter can be completely isolated from the main HVDC line by closing the bypass switch, BY1, blocking semiconductor devices of the DC-DC converter and opening isolators, S1 and S2.

Since power supplied by the series tapping converter is a very small fraction of the main station HVDC power, the effect on the main station due to this fault will be very small.

Fault F2 is a semiconductor open circuit fault due to device gate driver failure of the series tapping converter. This fault causes an open circuit in the main HVDC line and will affect the main HVDC power flow if left unattended. The mitigation sequence described below should avoid such a condition.

a. This fault is sensed by an overvoltage across the series tapping converter. The first step is to block all semiconductor devices and give a close command to the bypass switch, BY1.
b. During this period (until the bypass switch closes), the voltage appearing across the series tapping converter increases rapidly. Hence to prevent the same an arrestor across the DC terminals of the series tapping converter will be required.
c. This arrestor limits voltage across the series tapping converter, for the period until which the bypass switch, BY1, closes. Now the isolators S1 and S2 can open to completely isolate the series tapping converter form the main HVDC line.

The above mitigation sequence ensures that the series tapping converter is safe and there is no interruption in the main HVDC power flow. Real-time implementation results are presented in the next section validating the same.

Fault F3 is a series tapping converter terminal to ground fault before the series tapping converter transformer. The series tapping converter transformer serves a very important purpose of HVDC voltage isolation from the local AC grid. Therefore, a fault at the location as illustrated in Figure 2, takes out this capability of the series tapping converter transformer and is hence a very severe fault, both from the perspective of the series tapping converter and the main HVDC stations. Since the effect of this fault has an unintended severe effect on the main stations as well, the mitigation sequence, presented below, takes into account both the tapping converter effect and the main station effect.

a. To sense this fault, a quantity by the name *Idiff,* defined as the difference of current entering the tapping converter (say current through S1) and leaving the tapping converter (say current through S2) is continuously monitored (i.e. $Idiff = |Is1 - Is2|$). A large value of this current means that Fault F3 has occurred.
b. The first step is to block all semiconductor devices of the series tapping converter and close the bypass switch, BY1.
c. This does not isolate the fault location. Moreover, the main stations continue seeing this as a pole to ground fault and the series tapping converter valves are stressed to the main station voltage, thus requiring arrestors across all positions as shown in Figure 2.
d. One option to cope with this fault is to allow the main station to continue with its fault mitigation sequence. This will also mean that due to a fault at the tapping converter (which is less than 5% of the main station power rating), the entire main HVDC power transfer is also interrupted.
e. If this scenario is not desired, another option is to open S1 and S2, and isolate the tapping converter from the main HVDC line, once the bypass switch, BY1 closes. This means that simple isolators cannot be used for S1 and S2, and they will require DC current braking capability. Further, these switches will also need to open quite

quickly (within a few milliseconds), or else the main station will begin with its fault mitigation sequence.

It might seem that the need for DC breakers at S1 and S2 is a large problem from the cost perspective. However, it should be noted here that the occurrence of such a fault is very rare. And it might still be fine to allow the main stations to stop transmitting power in such a rare occurrence, than on investing in DC breakers for S1 and S2.

6. Real-time implementation results and discussions

Real-time simulation of a series tapping converter on the CIGRE HVDC benchmark system were performed on a 16-core real-time simulator. The software tool used for the real-time simulation studies was Hypersim [6]. In the HVDC LCC benchmark model, the main station power rating is 1000 MW. A series tapping converter of 30 MW (around 3 % of rating) with a DC link voltage rating of 15 kV is considered in this real-time simulation.

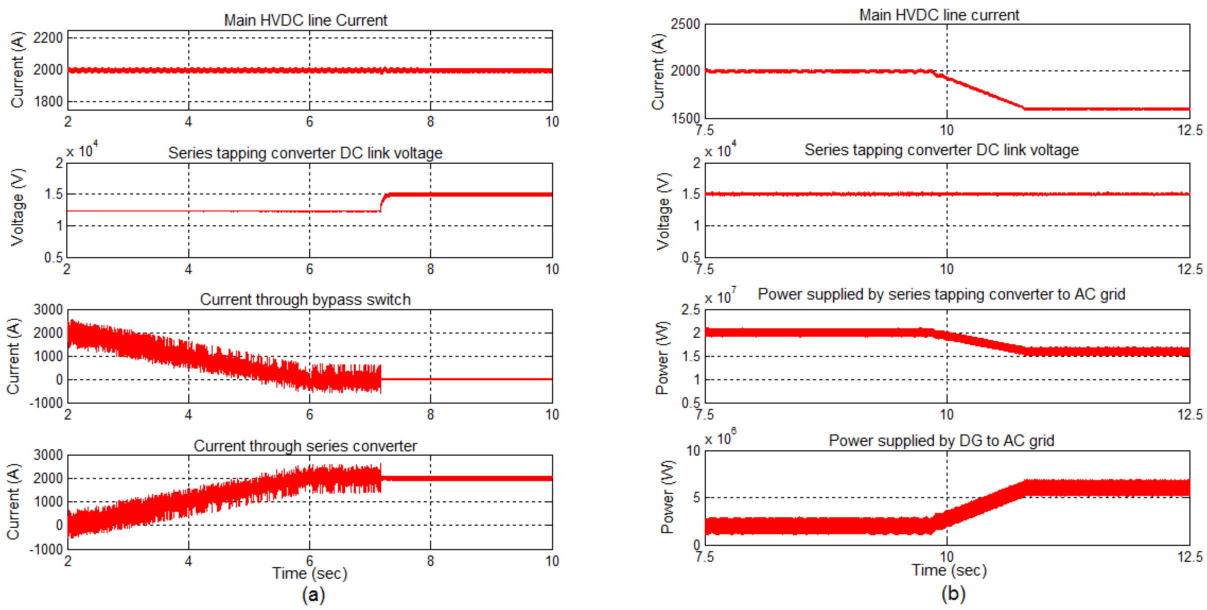

Figure 3: (a) Start up sequence used for the series tapping converter (b) results showing power sharing between series tapping converter and DG for a reduction in main HVDC line current

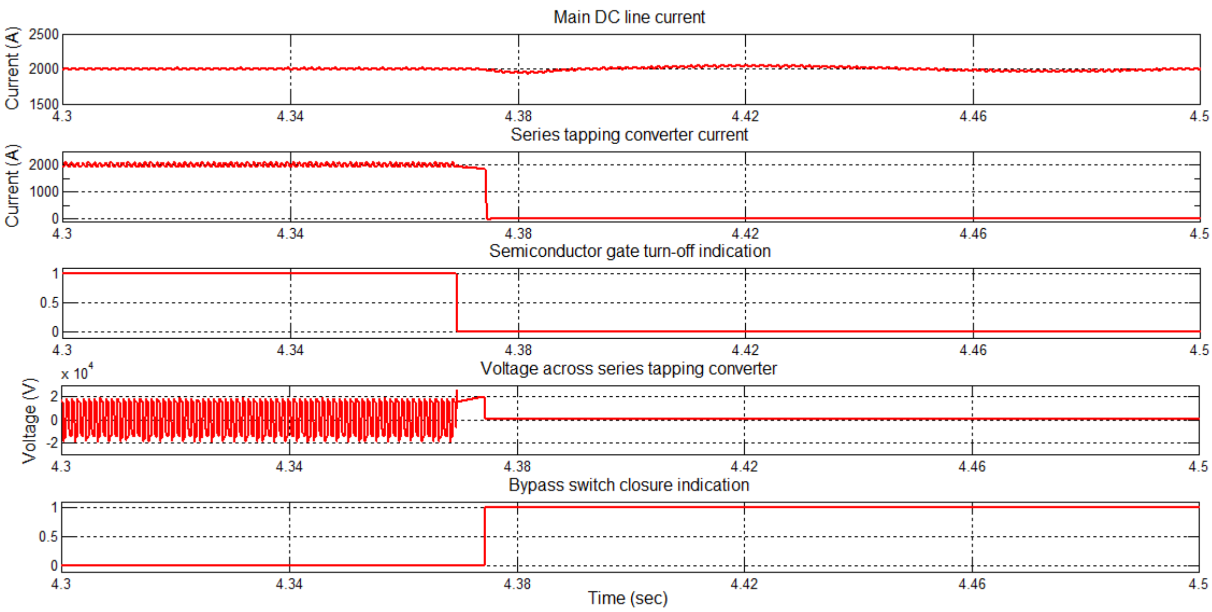

Figure 4: Real-time simulation results indicating successful fault mitigation for Fault F1

Figure 3 (a) shows the process of energization of the series tapping converter. As can be seen from the figure, the main HVDC line current is slowly diverted away from the bypass switch, BY1. The bypass switch opens at current zero and hence no breaking capability is required for this bypass switch BY1. Once this step completes, the series tapping converter continues with its normal control objectives. Figure 3 (b) shows the process of power sharing between the series tapping converter and the DG in cases when the main HVDC line current reduces in magnitude. It should be noted here that due to this, a constant power is always fed to the local grid without the need for overrating the series tapping converter.

Figure 4 shoes the occurrence of Fault F2 at the series tapping converter. This is a gate drive failure of the series tapping converter and has an impact on the main station power flow as well (if not mitigated). Various steps of the evolved mitigation strategy (see Section 5) such as, arrestor blocking momentary overvoltage followed by bypass switch closing for fault isolation, take place to ensure that the tapping converter is safe and there is minimal impact on the HVDC main station power transfer.

7. Conclusion

Series tapping can be used to tap power from a long distance HVDC based transmission system. This paper presented a VSC based series tapping converter which works in tandem with a diesel generator to provide constant power to a local AC grid, independent of the HVDC line current condition. This series tapping converter arrangement was connected to the CIGRE LCC HVDC benchmark model and various aspects of the series tapping converter, pertaining to energization, control and protection were studied with the help of real-time simulations.

An energization and start-up sequence was proposed for the series tapping converter. This proposed start-up method was validated through real-time simulations to show that no DC breaking capability for tapping converter bypass switch is needed. Also, three faults at the series tapping converter were studied. Effective mitigation strategies were evolved to ensure that there was minimal impact on the HVDC main station power flow, and the series tapping converter was well protected. The proposed fault mitigation strategies were further validated through real-time simulations.

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Application of VSC HVDC Technology for Metro City In feed

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SUMMARY

The positive industrial growth along with the rapid urbanization has resulted in increase of per capita energy consumption of electricity in urban areas of India. This has over loaded existing available transmission infrastructure. The present internal generation facilities for the cities are not adequate to meet the growing load demand. By virtue of being in boundaries of the congested cities, addition or expansion of existing generation or installation of new generation is generally difficult owing to various constraints like environmental consideration, land availability etc. Thus city's additional power requirements can only be met through the interconnecting lines from grid sub-stations located outside the city boundaries. These interconnecting transmissions corridors were built decades ago and are becoming critically loaded. In some of the metros, the n-1 redundancy requirements of planning criteria are already lost. In order to relieve the existing critically loaded transmission network, various probable options need to be explored and implemented in swiftly.

There is need to add or augment the bulk power transmission corridor which can meet the additional power requirement of the metros. Generally, most of the high voltage grid substations are located far away from the densely populated cities.

Most of the metro cities are geographically surrounded by sea, forest, creeks, protected tree zones of mangroves, ports which brings additional challenges to build EHV transmission corridor. Following are some of the options available for building bulk power transmission corridors for cities explained with benefits and constraints.

1. **Construction of new EHV Transmission Lines**
   Benefits: - Bulk power injection
   Constraints: - Non Availability of dedicated ROW, Cities surrounded by sea, reserved forest, creeks
2. **Enhancing of existing transmission line conductor Ampacity by High Ampacity conductor**
   Benefits: - Use of existing tower infrastructure

Constraints: - Higher execution time, Outages availability, loss of n-2 and probable load shedding

3. **Underground EHV AC cable connectivity**
   Benefits: - Very small Right Of Way
   Constraints: Mvar generation, voltage instability, need of reactive power compensation
4. **Underground dc cable connectivity**
   Benefits: - Controlled power flow and system stability, Smaller ROW
   Constraints: Need converter stations, High Cost

Line Commutated Converters (LCC) and Voltage Source Converters (VSC) are used for dc transmission. The LCC type is used for bulk power transmission, connectivity of two asynchronous grids. The limitations of LCC technology are requirement of higher short circuit ratio, Harmonics generation, additional reactive power compensation, lack of black start capability. These limitations of LCC technology can be overcome with Voltage Source Converters technology. VSC provides independent control of active and reactive power flow, minimum filter requirement and no reactive power compensation due to multi modular converters technology and four quadrant operation of converters. Black start capability offered by VSC can be very beneficial in the city like Mumbai, wherein the generation stations are limited to 1 or 2.

Summarising, this paper discusses various mode/options for bringing bulk power in the metro cities with their merits, constraints, feasibility for implementation and operational aspect. The most suitable and feasible option is voltage source converters based HVDC system.

KEYWORDS

N-1- redundancy, Voltage- stability, ROW, Reactive-power-compensation, Black-start, LCC, VSC, EHV-cable, Footprint

1 INTRODUCTION

Mumbai is India's one of the largest city (by population) and is the financial and commercial capital of the country. It is the nerve centre of capital markets, financial services, and manufacturing, playing a crucial role in the growth and development of the Indian economy. Its nodal location in terms of land, sea and air connectivity, both national and international, adds to its value as a leading industrial and commercial centre. It has attracted a large number of national and multinational firms since a long time. It is the home to major financial institutions like Reserve Bank of India, Bombay Stock Exchange, etc and important infrastructures like Airports etc. The key sectors contributing to the city's economy are finance, gems & jewellery, leather processing, IT and ITES (Information Technology enabled Services), textiles, and entertainment. This has resulted in infrastructural development in all aspects like Real Estate, Roads, Transportation and aviation facilities, Electricity and other utilities on larger pace in a decade time.

Apart from its social benefits, electricity is also a driving factor in the overall development of economy. Electricity is the Oxygen of economy and life blood of growth. Transportation facilities like Local train network, Metros, and Monorails which commutes nearly 7.5 millions of commuters and Mumbai Airports which facilitates Domestic and International aviation services need to be supplied with 24 X 7 uninterrupted quality power.

Mumbai being densely populated city, the city started to grow vertically within the confined boundaries. This has resulted in concentrated load growth in various small pockets. Thus construction of high rise commercial and residential building has increased electricity demand multifold.

Generally the cities' electricity demand is met in two ways, one by internal generation capacity & second through the import of electricity from the grid interconnecting sub-stations. On account of various environmental and social constraints, the expansion, augmentation or addition of new generation facility is difficult in the city boundaries, resulting in critical overloading of the existing interconnecting transmission lines which were constructed decades ago & losing of n-1 redundancy requirement.

Thus to bring additional power to city, there is need to build a bulk power transmission corridor which will provide reliable and secured power connectivity to cities and suffice the increasing load growth in highly populated area with higher load density.
Typical metro city like Mumbai which is surrounded by Arabian Sea from 3 sides and reserved national park on north side, the issue of bulk power Injection from outside city becomes more critical. Some of the critical challenges to construct new transmission infrastructure are listed below

- Lack of land availability (Very high cost of land)
- No dedicated ROW for Transmission Lines
- Environmental challenges like forest, sea, creaks, mangroves
- Stricter statutory norms and regulation

Various options to build interconnecting transmission network and its challenges are described below.

2 OPTIONS CONSIDERED FOR BUILDING OF BULK POWER TRANSMISSION CORRIDOR

Following are the options which can be implemented to address the issue of bulk power injection in Mumbai city,

- Up-gradation and Enhancing the Transmission Line Ampacity
- New 220/400kV Overhead lines
- Underground 220/400kV AC Cables
- HVDC interconnection

2.1 Up rating Existing conductor

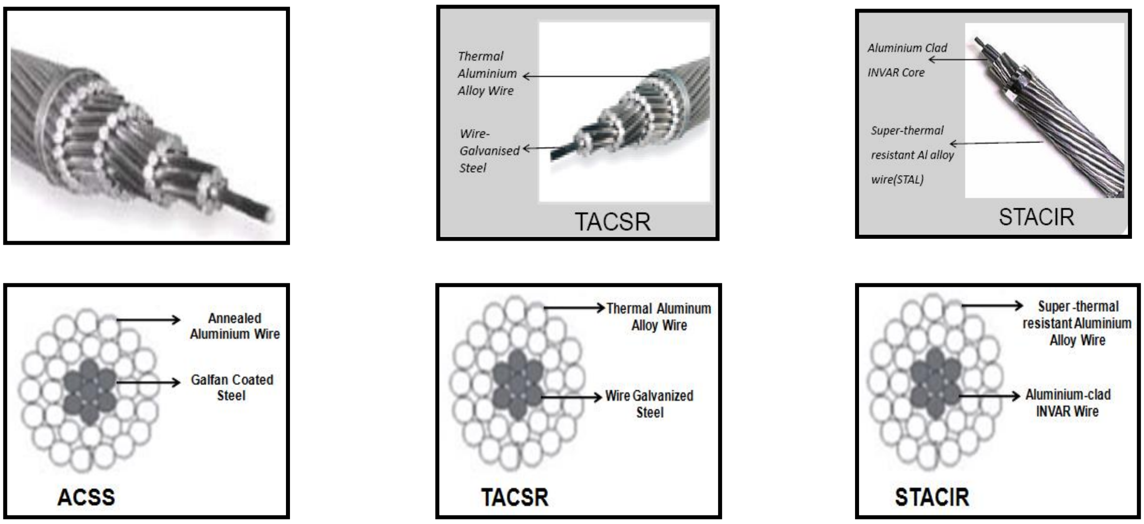


Figure 1- High Temperature Low Sag conductors

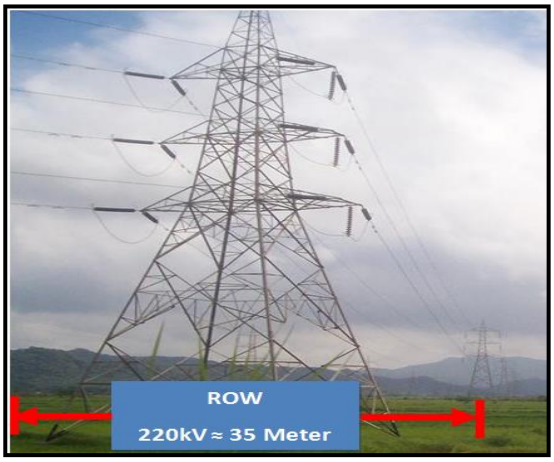
Up rating of the existing transmission line conductor with High Temperature Low Sag (HTLS) i.e high ampacity conductor is one of the alternatives to bring bulk power in Mumbai. The advantage of replacement of existing transmission lines conductor with high temperature conductors is that the line’s thermal rating can be increased with minimal modification of existing transmission line structures.

Maximum continuous operating temperature of HTLS conductor is up to 250^0C. Thus this conductor can be operated continuously without loss of tensile strength. The current carrying capacity can be doubled as compared to the conventional conductors. The additional benefits are

a) Low thermal elongation rate
b) Same or lower outside diameter
c) Same or lower resistance

The up rating of conductor uses the existing available tower infrastructure and same ROW without reconstruction and modification. For replacement of existing conductors with HTLS conductors, special conductor hardware (Clamps and connectors etc) are required which can withstand the high continuous operating temperature. During execution of this work, sufficient care needs to be taken to avoid damage to the conductor and hardware accessories. Although there would be benefits like building additional transmission capacity, but obtaining outages of interconnecting transmission lines for longer period, which are already overloaded is difficult. Even after the incremental increase in power corridor capacity, the n-1 redundancy cannot be achieved for criteria like single line failure or double circuit tower failure. Further this would be an adhoc measure in the near future & a separate scheme would be required to be formulated as a permanent solution.

2.2 New 220/400kV Overhead lines



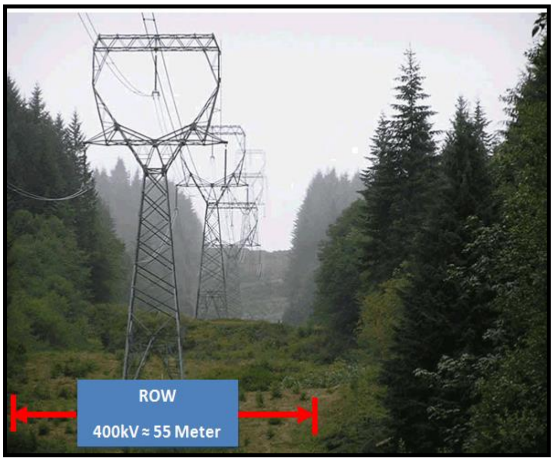


Figure 2- Typical ROW requirement for Overhead Transmission Lines

Figure 3- Present Mumbai Urban Transmission scenario

Construction of new 220 or 400kV transmission lines to bring additional power in Mumbai city is depends on various factors like availability of right of way, project approvals from local authorities. Generally the Right of Way requirement for 220kV & 400kV are in the range of 30-35 and 50-55 meters respectively. As clearly shown in above pictures construction of roads, bridges and buildings has left no continuous corridor of required size. Hence construction of new 220/400kV overhead lines is unfeasible option in Mumbai scenario.

Figure 4- Geographically distributed Power Injection points for Mumbai city

AC transmission system power is flow governed by sending and receiving end voltage, Phase angles and reactance of the transmission line. Thus injection of power directly at desired load centres may not be possible. Presently additional power requirements of the city is sufficed through power from Eastern, Central and northern corridors. Various load flow studies carried out to check the feasibility for bringing additional power through central corridor. The study results revealed that, addition of transmission line is not able to bring desired power through central corridor. AC power flow is governed by Phase angle of the sending and receiving end nodes. This angle cannot be controlled but it depends on the power balance at source point. The changes in the power generation or load demands also govern the power flow in AC lines. Thus the injection of power at desired load centre is not possible merely by constructing AC EHV transmission lines. The loop flow is also one of the constraint which leads to undesired loading of transmission network, resulting in the overloading of only one corridor creating an overall bottle neck in interconnecting system. Detailed network load flow studies indicates that with introduction of new dc line operating in parallel with existing ac lines, the overloading of the ac lines is reduced considerably. The new dc interconnection can be used to control active and reactive power dynamically.

2.3 Underground 220/400kV AC Cables

Figure 5- Typical ac cable construction

Figure 6- Cable Execution Constraints

Major grid substations are located at around 90-100 kM outside Mumbai, far away from the city load centres. Underground ac cable generates capacitive reactive power (Leading Mvar’s). Mvar generated by cable is governed by capacitive reactance and load current. Typically for 220kV cable system it is 3 Mvar/kM of circuit length. Active power flow through cable is restricted on account of current drawn for generation of Mvar. Additionally the ambient air temperature, ground temperature, depth of laying, type of laying, soil resistivity and multiple cable in close vicinity have the considerable impact on reduction in cable ampacity. Generation of additional Mvar in cable system may results in overvoltages in network & lead to disturbances in entire system. For every 50 kM a voltage controlling Flexible AC Transmission (FACT) devices for reactive power compensation may be required to control the likely over voltage situation. More numbers of such intermittent compensation station would be required if the circuit length is greater than 50kM. Availability of land for installation of these reactive compensation stations would be difficult in city like Mumbai. Non availability of dedicated underground corridor for laying of EHV cables make them more susceptible for damage and faults due to various activities like excavation or maintenance by other utilities in same corridor. Thus the introduction of HVAC cable is effective only for the short distance transmission. Considering the above mentioned aspect the option of laying new underground 220kV/400kV cable from long distances is not feasible for city like Mumbai. Hence the option of new underground 220/400kV AC cable options for grid interconnection is not feasible for city like Mumbai.

AC cable is very complex in terms of construction and operation. The sheath bonding system is critical in design and operations, which dictates the capacity of cables. There are three types of cable sheath bonding namely Single point bonding, Double point bonding and cross bonding. Following is the comparison based on merits and demerits of each type

Sr No	Type of Bonding	Merits	Demerits	Constraints
1	Single Point Bonding	Simpler, Less Maintenance	Standing voltage at open end	Higher voltage across sheath may damage the sheath
2	Double Point Bonding	Simpler, Less Maintenance	continuous circulation of sheath current results in cable de-rating and reduced life of cable	Required to design oversized cable to compensate de rating, XLPE insulation degradation
3	Cross bonding	Zero circulation current, Improved ampacity and life of cable	Complex design, required routine check and maintenance	Require specially designed sheath voltage limiters, link boxes. Require routine check and maintenance of these SVL, Link boxes etc

Table 1- Comparison of cable bonding system

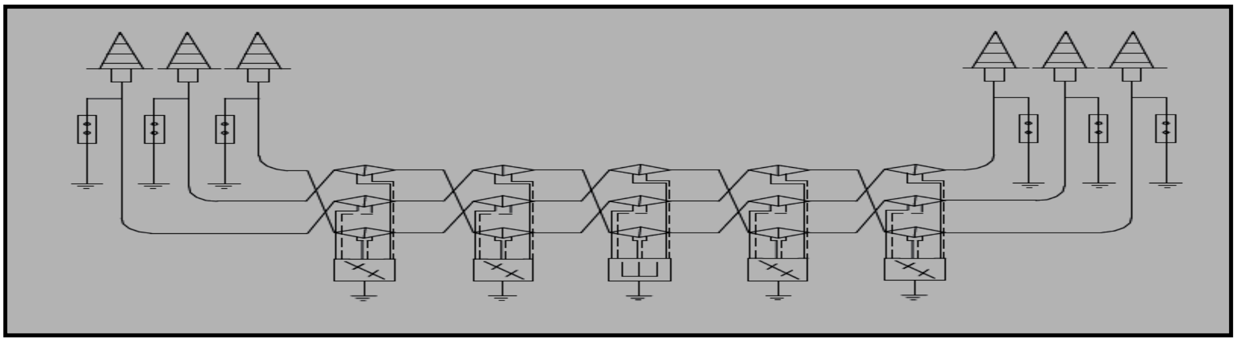


Figure 7- Cable cross bonding system

2.4 HVDC Interconnection

High Voltage Direct Current Transmission seems best feasible option for bringing bulk power into cities considering following technological advantage

- Bulk power transmission
- Controlled power flow
- Stability improvement
- No need for intermediate reactive compensation station as required with ac cable
- Smaller Size cable requirement as compared to ac cable
- ROW can be shared with other utility

There are two technologies available in HVDC cable systems i.e Line commutated converters (LCC) or Current source converters & Voltage source converter (VSC). The above mentioned technology is explained as under

2.4.1 Line Commutated Converters (LCC)

Line commutated converter's operation depends on line voltages of the system to which the Converters are connected. LCC technology is more preferred for the bulk power transmission. Considering metro cities applications it shall not be preferred solution due the constraints as mentioned below.

- High reactive power compensation requirement at Converter Terminal stations.
- Large space requirement due to additional reactive power compensation equipments
- Requirement of strong & stiff grid i.e Short circuit ratio higher than 2.
- Larger harmonic filter requirement
- Output with Harmonics Generation leads to additional filter requirements
- Lack of Black start capabilities required during the grid restoration
- Cable construction is complex as compared to XLPE cable used for VSC technology

2.4.2 Voltage Source Converters (VSC)

Voltage source converter uses solid state devices like Insulated Gate Bipolar Transistor (IGBT) with controlled Turn-on and turn-off capability for its operation. These converters are self commutated converters and do not depend on the voltage of the ac system.
Basically it works as a voltage source behind the converters or the generator without inertia. This works as a virtual generation without inertia located inside the city. The dc capacitor connected across the converter acts a source of voltage. The operation of VSC converter is fully controlled by Pulse width Modulation techniques and presently multi level topology.

The VSC Converter operation provides better quality of AC power due to its advanced switching techniques and multi level topology, which leads to reduced harmonics generation and hence reduced requirement of filters and thereby saving of space. The VSC Converters are having excellent 4 quadrant operation for exchange of Active & reactive power independently. Because of its operational characteristic it won't require any reactive power support. Additionally it can support the grid by delivering or absorbing the reactive power during fault & overvoltage contingencies respectively.
Cities are having small generation, which results in lesser short circuit ratio. The VSC advanced control system enables to connect the VSC HVDC system to the weak grid which is having the short circuit ratio less than one. Thus VSC is the best option for similar type of cities with limited internal generation. In the recent past the converter and cable rating are reached to one GW level and 320kV respectively, which enable us to meet the bulk power requirements.

3 BENEFITS OF VSC BASED HVDC SYSTEM

3.1 Unique black starts capabilities.

Mumbai being critical load center for the growth of the country, the restoration of grid in case of Cascade tripping, major grid disturbance and blackouts is critical. The blackstart facility in the VSC technology can support the important load in the event of grid disturbance.VSC technology can meet generator station power requirements for auxiliary lightups with its black start capability. Thus restoration of generation station is much faster compared to other counter type.

3.2 Short circuit ratio requirement

Short circuit ratio requirement for VSC HVDC system is minimum. The advanced VSC Controls enables the faster voltage recovery of ac system during system fault. The conventional LCC based HVDC is susceptible to commutation failure, when the connected ac system is subjected to faults. Unlike ac interconnection, dc interconnection offers isolation between two ac networks. DC links does not increase short circuit current level due to advanced control system and fault isolation. In conventional ac system, addition of any grid element like interconnecting lines results in increased fault level at respective bus.

3.3 Flicker control

Considering the critical load centers in Mumbai, quality of supplied power must be ensured. Most of the equipment, instrument loads in commercials premises are sensitive to voltage sag and swells. During such abnormal voltage condition they get affected and fail to operate. One of the cases is mentioned below, where the fault at EHV network resulted in marginal voltage dip in downstream network i.e distribution. Two of the instances are mentioned below

a) Tripping of 220 KV Grid Line on 06/11/2014 has resulted in voltage dip of 42.52% at the RInfra 220kV Substation thereby proportionate dip at 11kV and 0.415 V level.
b) Tripping of 220kV Grid line on 17/10/2014 has resulted voltage dip of 15.43% at 11kV Network of Reliance Infra.

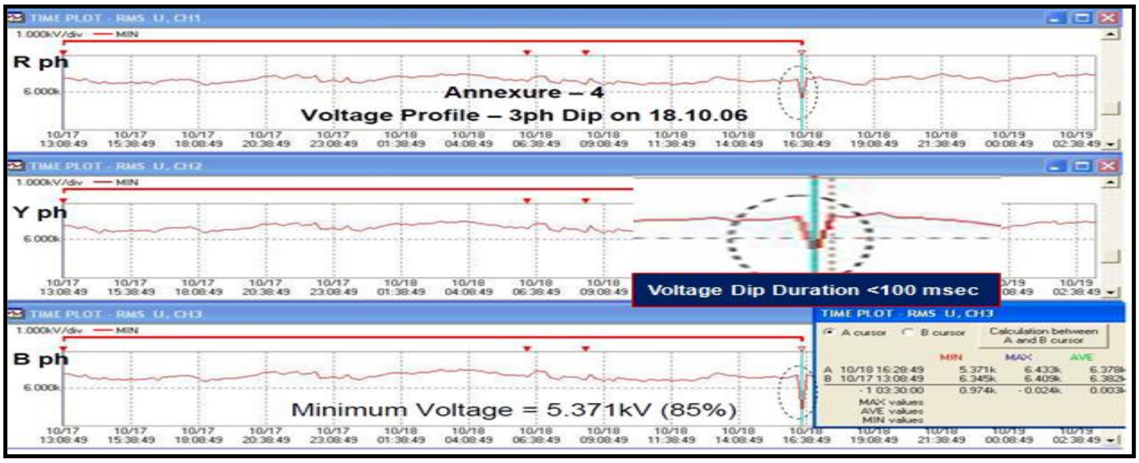


Figure 8- Voltage profile at 11kV network during 220kV system fault

VSC HVDC will provide dynamic support of reactive power during the fault duration to improve the system voltages. Additionally it can support the grid by delivering or absorbing the reactive power during fault & overvoltage contingencies respectively.

3.4 Reduced reactive power compensation requirement

LCC HVDC system requires at least 0.3-0.5 pu of reactive power support during its operation. This reactive power requirement is met through harmonic/reactive power filters. In VSC HVDC, Converter are having excellent 4 quadrant operations which allows independent exchange of Active & reactive power. For VSC technology no such reactive power compensation requirement exists.

EHV Transmission substation in the cities is connected with underground EHV cables. These cables may generate the capacitive Mvar which results in the overvoltages in the connected substations. Thus to limit these overvoltage's to permissible level, localize reactive power compensation in terms of Static Voltage Compensator (SVC) or STATCOM is required. The VSC HVDC with its excellent 4 quadrant operation and control system can be used to absorb the excessive Mvar in the network and maintain voltages within permissible limits and avoid the requirement of FACT devices.

In coming future, transmission network inside the cities shall be more of EHV underground cable. As explained under 2.3, these cables network would generate substantial quantity of capacitive Mvar and which may create overvoltage situation during off peak hours. To avoid these overvoltages, devices like SVC and STATCOM would be required. The inherent feature of VSC can be used to control the overvoltages through a 4 quadrant operation.

3.5 Availability of DC Cable for Power Transmission

In VSC HVDC, the power flow reversal is effected with reversal of line current not voltage polarity. This has allowed use of simpler cable design thus require lighter cable with higher drum length and hence reduced cable joints and maintenance. With dc cable operation, no additional Mvar is generated and need of reactive power compensation at intermediate location hence additional space and cost requirements can be avoided. Less dielectric losses, ageing, permitted higher field strength for insulating materials are added benefits compared to ac cables.

3.6 Supports to power system with Advanced VSC Controls

In the interconnected ac systems, system problems like transient in-stability and power oscillations can occur if the interconnected ac systems are weak. In such cases the VSC HVDC links in parallel to the interconnected lines can be used to stabilize the ac system. Further it can be also to used to control the power flow through the various ac interconnections making them to operate at optimum loading. The 4 quadrant operation of VSC HVDC system allows the independent Active and Reactive power flow. The active and reactive power can be controlled rapidly as per grid stability requirements. These controls allow VSC HVDC system faster recovery after various system fault contingencies.

3.7 Compact size and quality power

On account of Reduction in harmonic/reactive power filters requirement reactive power compensation requirement in addition to its modular setup. Further there is no requirement of dc side filters which reduces footprint requirement by almost 30 to 40% compared to LCC. Thus this application provides better solution to metro city where availability of land and exorbitant price is a major factor.

3.8 Lesser environmental impact

Most of the equipments in the converter stations are enclosed in buildings which results lesser noise pollution. Due to reduced filter requirement, the additional noise generated by filters during operation can be avoided. This allows us to accommodate the VSC Station in lesser footprint and hence impact on environment is further reduced.
No special ROW is required for cable, thus impact on environment is reduced. The cables used in VSC HVDC does not contain oils or other toxic elements. The magnetic and electric fields emitted by VSC dc cable are negligible. It does not harm living marine organisms. Due to it’s design, the cable does not emit electrical Fields. The magnetic field from the cable is negligible. The resultant magnetics field induced in two cables is very negligible, if laid together and carrying current in opposite direction. All the above aspects indicates that, VSC technology has very less effect on environment. The inherent noise level of the VSC system would be lesser than the LCC system which suits city like application.

4 EXECUTION CHALLENGES

4.1 Construction at Converter Terminal Station

a) Height constraint and FSI limitation
There are many restrictions related to height of structure and beyond some limits indoor construction is getting restricted by utilization of floor space index etc.

b) 66 statutory approvals (44 before work commencement and 22 during and after construction)
Special norms for project inside cities as compared to the remotely constructed project, much permission are required to be obtained from statutory authorities before commencements of work, during and after completion of work.

c) Conveyance limitation for Heavy equipment transportation
Heavy traffic, congested roads bring more challenges and restrict the movements of vehicles for heavy equipment. Also the movement of construction vehicle is limited and permitted for shorter period.

d) Project Sites surrounded by Residential habited area
Being surrounded by the habitant area working hours are restricted which may require longer timelines for the completion of projects.

4.2 Construction of dc cable system

a) No dedicated corridor for utility
In city, no dedicated corridor is available for laying of utilities network. This adds more challenges during execution and adhering to project timelines.

b) Presence of multi utility at lower depth
The EHV cables need to be laid at higher depth being more prone to excavation. As mentioned in Fig 4, there is plethora of cables and other utilities (gas, water, sewage, low tension cables etc) at lower depth. This adds further challenges for laying of HDPE pipes and making space for jointing.

c) Permissions only during non rainy season (Oct-April)
Mumbai being Traffic prone city and congestion on roads, the local statutory authorities do not allow excavation and laying of cables during rainy season.

d) Excavation permission in phase manner across the route
The permission allotted for excavation and other activities are also given in part of the route. Thus it brings additional challenges for HDPE pipes laying, matching, and pulling the cable inside HDPE pipes.

e) Permissions are generally granted only at night
The unloading of drum, movement of construction vehicle (RMC) for concreting, movement of cranes causes heavy traffic congestion and thus allowed for work only during night hours.

f) Period for cable laying
Granting of permission from local authorities for excavation and cable laying takes longer times. This activity further reduces actual laying time and impacts project completion timelines.

Figure 9- Execution constraints in Mumbai

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Application of Superconducting Fault Current Limiter in Multi-terminal HVDC Systems

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SUMMARY

Over recent years, HVDC transmission is recognized as a viable means of transmitting power over long distances. There are a number of point to point HVDC links in India and many world-wide. The interconnections of DC systems forming Multi Terminal HVDC (MTDC) systems, will definitively improve the system operation and reliability. However, these networks suffer from the disadvantages that there is no zero crossing of the DC fault current, which makes circuit interruptions difficult. One of the solution in this direction is the application of superconducting fault current limiter (SCFCL). The SCFCL can be technically and economically viable alternative, for the problems encountered in MTDC system operation.

The upcoming multi terminal UHVDC system in India, is +/-800 kV, 8000 MW converter capacity, including a 2000 MW redundancy, and transmits clean hydroelectric power from North East Region to the city of Agra, a distance of 1728 km. For this UHVDC system, the reliability and availability of the system is extremely important. The damaging effects during and after any fault needs to be minimized and the faulty equipment needs to be quickly and safely isolated from the healthy system. The possible solutions are simple isolators, high speed switches and HVDC circuit breakers. These are either very slow or expensive. The present proposition of the application of SCFCL, with its ultra-fast switching capacity, is one such promising device for multi terminal applications. A detailed simulation study of upcoming MTDC system, involving resistive type SCFCL, is carried out here. The results obtained for different transient conditions are indicative of the usefulness of the SCFCL in the upcoming MTDC system.

KEYWORDS

HVDC, MTDC, Super conducting fault current limiter, transient analysis, ± **800 kV,** UHVDC.

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1. OVERVIEW

High Voltage Direct Current (HVDC) technology has been in operation for more than 60 years now. It is gaining in importance within the existing power grids due to its advantages compared to conventional AC transmission for bulk power transmission over large distances. There is a vast expansion of HVDC technology due to the increasing demand for electrical power and rapidly growing electrification. Hence a number of high capacity long distance HVDC systems are in operation and/or planned. The interconnection of a number of AC systems is known to form a flexible network. Naturally, this concept has been extended to the interconnection of HVDC systems also. These HVDC interconnections are termed as multi terminal HVDC (MTDC) systems. The potential applications of MTDC systems are in the

- Bulk energy transfer from cheap energy sources to remote load centers
- Efficient wheeling of power
- Interconnection of several AC systems with different frequencies
- Improvement in the stability highly loaded AC systems.

Whereas the interconnection of AC systems does not pose any serious problems, for the case of MTDC systems, one has to overcome several specific difficulties. In the early stages, the lack of simple and field proven HVDC circuit breakers was a major hurdle in the development of MTDC systems. Also, these systems require a well-coordinated and complex control system for their successful operation.

Various researchers have been working on different aspects of MTDC operation [1-5]. The result of which is the first MTDC system in the form of a tap at Corsica on the existing Sardinia Italy HVDC link, in 1991[6]. The two-terminal HVDC system between Quebec and New Hampshire was built in 1986 which connected the asynchronous power grids of North-East US and Quebec. In 1990 two more converter stations were added to the existing two-terminal HVDC system. In 1992 another terminal was added to this MTDC system [7].

The next multi terminal HVDC system in India, to be commissioned in 2016, is +/-800 kV, 8000MW converter capacity, including a 2000 MW redundancy, and transmits clean hydroelectric power from North East Region to the city of Agra, a distance of 1728 km[8]. One Rectifier station in Biswanath Chariali (in North Eastern Region), second one in Alipurduar (in Eastern Region) and Inverter station at Agra (in Northern Region). This is shown in Fig.1.

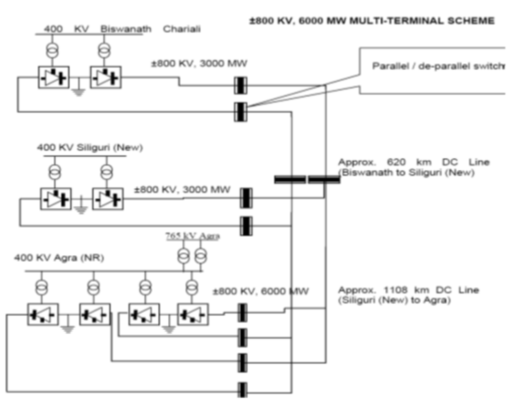

Fig. 1. NER-Agra MTDC system configuration [Courtesy www.sari-energy.org]

For this multi-terminal UHVDC system, the reliability and availability of the system is extremely important. The damaging effects during and after any fault needs to be minimized and the faulty equipment needs to be quickly and safely isolated from the healthy system. Further, the MTDC system heavily depends upon the telecommunication of current orders between various stations, control configurations and protection methodologies adopted. This MTDC system may also have an impact on the satisfactory operation of the nearby multi infeed system, involving Balia-Bhiwadi link and Rihand- Dadri line.

The CIGRE working group in [28] has outlined the technical feasibility of 800 kV HVDC applications. This includes converters configurations, ratings, transformer ratings, ground electrodes, reactive power compensation and requirement, control and protections, line lengths and losses, etc., for it to be a successful technology in operation. The separation of line or converters during a fault can be achieved through simple isolators or high speed switches. However, these are very slow and may take few seconds. The isolation can also be done by HVDC circuit breakers [9]. The major difficulty here is the investment cost. In addition, these circuit breakers need to be designed for increased insulation levels because of the presence of the counter voltages of the breaker. Considering that UHVDC system insulation levels are already very high, any alternative that overcomes this problem needs to be looked into seriously. The present proposition of the application of **superconducting fault current limiter (SCFCL),** with its ultra-fast switching capacity, is one such promising device for multi terminal applications.

With the upcoming multi terminal UHVDC system, the SCFCL is expected to work very efficiently controlling the fault currents, without the dependence on expensive HVDC circuit breakers. Here, it is aimed to carry out a detailed study of upcoming MTDC system, involving SCFCL, in the PSCAD/EMTDC environment. This study is expected to give insight into the usefulness of SCFCL in the upcoming MTDC system in India.

2. SUPERCONDUCTING FAULT CURRENT LIMITER

A Fault Current Limiter (FCL) basically offers high impedance to fault currents, thus bringing the current to a low value, in a short time. The SCFCL will be in super conducting state, with zero resistance, during normal operation and transfers to normal operation (offering high impedance) during fault conditions. The SCFCLs have distinct advantages over conventional FCLs, especially in high voltage networks. It provides an ultra-fast transition from superconducting to normal state and is self-operating and repetitive in nature. Further, during normal operation, the resistance being zero, the losses will be negligibly small.

Basically there are two types of SCFCLs, a resistive SCFCL and an inductive SCFCL. The resistive SCFCL is simpler in design and consists of an active superconductor element connected in series with the circuit to be protected. On the other hand, an inductive limiter uses the principle of magnetic coupling between the superconductor element and the protected circuit. The major advantage of resistive SCFCL is the simplicity of principle of operation and construction and hence lower cost. However, the main drawback can be the heat dissipation in the SCFCL, during fault. Various protective devices are suggested, in the literature, to prevent the damage to the SCFCL. Factors which favour the inductive SCFCLs are the absence of electrical connections between the superconducting elements and the circuit to be protected, lower voltage drop across superconducting element during fault condition and the possibility of making high temperature superconducting coils in the form of rings and cylinders.

The resistive SCFCL is found to be more suitable for power system applications. This is because the operation of the resistive type is simple to understand, can be easily connected in series-parallel combinations, reduces the time constant of the aperiodic component of the fault current and can also make the system less inductive. A number of studies concerning material aspects, types of SCFCLs, prototypes and testing have been carried out in detail in [10-14]. A number of high temperature superconducting (HTS) materials working at 77K have been suggested for power system applications. Of these, Bi2212 is the most robust material and artifacts with large surface area can be produced. This means that for the same critical current the critical current density of the FCL can be made higher and hence a Bi2212 made FCLs can have higher ratings.

Further, various researchers in this field, have come up with the concepts, studies and field testing of SCFCL devices for transmission level voltages. The matrix SCFCL module which is obtained by connecting series-parallel combinations of the basic SCFCL elements and the detailed study along with field test results, are outlined in detail, in [15-17]. It can be observed that the application of SCFCL in HVDC systems has received very limited attention. Some of the conceptual details and test details are explained in [18] and [19]. The experimental and test results demonstrated the current limiting capability of matrix SCFCL in dc system including the different values of shunt resistor, to limit the heat and temperature across superconducting FCL [20 and 27]. The basic dynamic modeling and simulation of resistive SCFCL is explained in [21-22]. Based on this model, a detailed study of the application of resistive SCFCL in a conventional two terminal HVDC system, is carried out by the present authors [23-24]. This study was further extended to voltage source converter (VSC) based HVDC systems where dc line fault plays a crucial part. The SCFCL was successfully integrated and the performance of the VSC-HVDC system was evaluated [25-26]. These results have augmented the effectiveness of resistive SCFCL in controlling the dc current during line faults.

3. MATHEMATICAL MODEL OF SCFCL

When the current density in the high temperature SCFCL exceeds the critical value, an electric field develops across the FCL. The electric field thus developed at any instant depends upon the current density in the SCFCL and the temperature of the FCL. This nonlinear *E-J* characteristic and its dependence on temperature forms the basis for the modeling and simulation of SCFCL. The *E - J* characteristic, exhibited by all HTS materials, consists of 3 parts, viz : flux flow state, superconducting state and normal resistive state, as shown in Fig. .2.

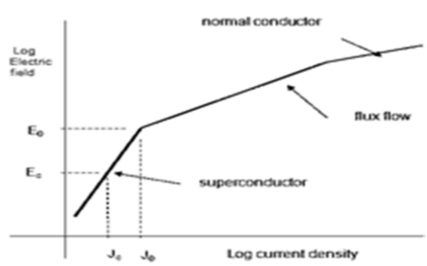

Fig. 2. E-J characteristic of HTS material

1) ***Superconducting state***

In this state, the HTS material is in the superconducting state. The current density across SCFCL is below the critical value and consequently the electric field across it is very small. The electric field is given by

$$E(J,T) = E_c \left[\frac{J}{J_c(T)} \right]^{\alpha} \qquad \ldots\ldots\ldots\ldots\ldots\ldots \quad (1)$$

Here, J_c (T) is the critical current density, T is temperature of the superconductor, E_c corresponding electric field, and J is current density of Bi2212 material. The quantity J_c (T) is temperature dependent and this dependence, obtained experimentally, is taken to be,

$$J_c(T) = \frac{J_c(77)(T_c - T)}{(T_c - 77)^{1.8}} \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (2)$$

with temperatures expressed in the units of K. Here, T_c is the critical temperature of the superconductor.

2) ***Flux flow state***

The HTS material enters this state when the current density across it exceeds a value represented by J_0. In this state, because of higher value of the current density, the electric field across the FCL starts picking up and the FCL develops resistance. Because of this resistance, the temperature increases. This increase in temperature causes a further increase in electric field across the FCL. This is self-enhancing process and it continues until the temperature of FCL exceeds a critical value known as critical temperature. At this point, the HTS material enters the normal resistive state. During this phase the electric field is given by,

$$E(J,T) = E_0 \left(\frac{E_c}{E_0} \right)^{\left(\frac{\beta}{\alpha}\right)} \frac{J_c(77)}{J_c(T)} \left(\frac{J}{J_c(77)} \right)^{\beta} \qquad \ldots\ldots\ldots\ldots\ldots \quad (3)$$

3) ***Normal resistive state***

In this state the normal conducting properties of the HTS material are exhibited. Here, the electric field across FCL is linearly proportional to both current density and the temperature of the FCL and is given by,

$$E(J,T) = \rho(T_c) \frac{T}{T_c} J \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (4)$$

where, ρ is the normal resistivity. For bulk Bi2212 material, the parameters J_c (77), ρ, α, β at 77K depend upon the material processing condition and falls in the following range:
$10^7 \le J_c \le 10^8$ A/m^2, $0.1 \le E_0 \le 10$ mV/cm , $100 \le \rho \le 2000$ μΩ-cm, $5 \le \alpha \le 15$, $2 \le \beta \le 4$
These parameters have to be chosen carefully because they bring about a marked difference in the behavior of FCL. In all the three states mentioned above, the heat diffusion equation of the HTS material is given by,

$$C \frac{dT}{dt} = E(J,T)J \qquad \ldots\ldots\ldots\ldots\ldots\ldots \quad (5)$$

where, *c* = specific heat of Bi2212 which is again temperature dependent.

Modeling the behavior of FCL involves the following steps. Knowing the cross sectional area and current flowing through the superconductor, calculate the current density in the SCFCL at each instant and compare the electric field E(J,T) with E_0. When E(J,T) ≤ E_0, SCFCL is in the superconducting state and when E(J,T) > E_0, , SCFCL enters the flux flow state. SCFCL continues to be in flux flow state till $R_{FCL} \leq R_n$, where $R_n = \rho(90)Ln/S$ and Ln and S are length and area of cross section of the superconducting material. When $R_{FCL} > R_n$, the FCL is in normal state and offers maximum resistance to the flow of current. The electric field, voltage drop, temperature and resistance of the SCFCL are calculated at every instant. The SCFCL model described here, is simulated in MATLAB and verified and validated by considering a typical test setup. The details of this are available in a previous paper [25] by the present authors and a part of it is reproduced above for the sake of clarity.

4. APPLICATION OF SCFCL IN MULTI TERMINAL HVDC SYSTEM

The ±800kV UHVDC Multi Terminal System (referred as NER-Agra) is being constructed, with 6,000MW as its rated capacity and with an overload capacity of 33% over shorter period of time. It has two rectifier stations, one located in the North Eastern region in the state of Assam (Biswanath Chariali), and second one 432 km apart from this in Eastern region in the state of West Bengal (Alipurduar). The inverter station with two terminals in parallel is located in the Agra region, distance is 1296 km from the nearest rectifier station. Each 800 kV converter is configured as single 12-pulse converter. Figure 3 shows the schematic diagram of the NER-Agra MTDC system.

The simulation and dynamic analysis of this MTDC system is done in the PSCAD/EMTDC environment. The SCFCL model is developed in MATLAB and interfaced with the MTDC system and the various transient conditions are studied to understand the effectiveness of the SCFCL on the performance of the MTDC system. In the present work, the required rating of matrix SCFCL module is 800 kV, 3.75 kA to be used in MTDC system. This is obtained by connecting a number of lower rated SCFCLs in series-parallel to make up the required voltage and current ratings. Each SCFCL component is rated for 10.5 kV and 2.8 kA. In order to obtain 800 kV, 3.75 kA, seventy six (76) such components are connected in series. This SCFCL module is tested and validated according to the data and results available in [21]. Other system details are described in appendix I.

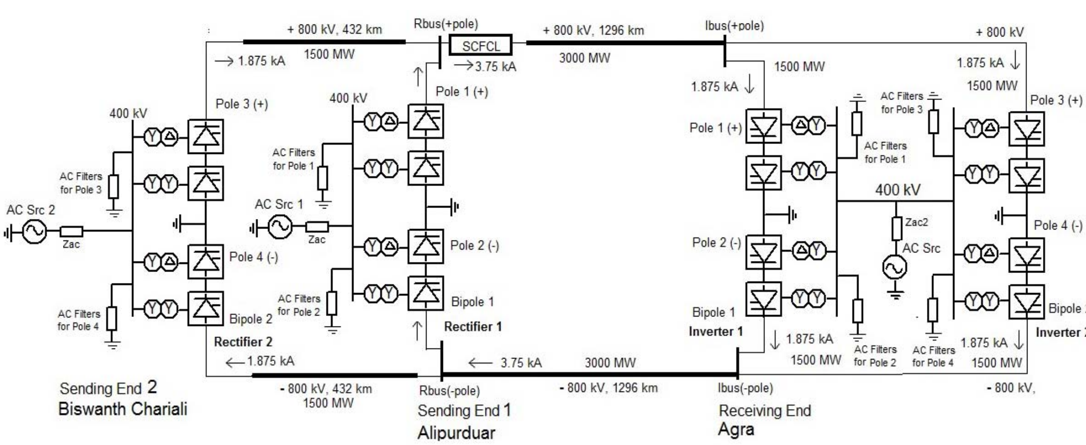

Fig. 3. Schematic diagram of NER-Agra ± 800 kV, Multi-terminal HVDC System.

The control strategy adopted here is the current margin method. This is basically an extension of the control philosophy in two terminal HVDC system. One of the converter station controls the voltage while the remaining stations operate current controlling terminals. Current commands (I_1, I_2...) having an algebraic summation equal to current margin ΔI, as given in Eqn.(6), are sent from control station to the respective converter stations.

$$\sum_{j=1}^{n} I_{j\,ref} = I_{margin} \qquad \ldots\ldots\ldots\ldots\ldots \quad (6)$$

Rectifier currents are considered to be positive while inverter currents as negative. The station having lowest ceiling voltage (V_{do} Cosα or Cosγ_n) controls the line voltage. This station is normally, one of the inverters operating at constant extinction angle. The other three converters operate in constant current mode. The control characteristics of the system are shown in Fig.4. The current at the voltage controlling station is algebraic difference of current demand and the current margin. If the ceiling dc voltage at one of the stations, operating on constant current drops, then that station would become the voltage controlling station and its current would decrease by the current margin.

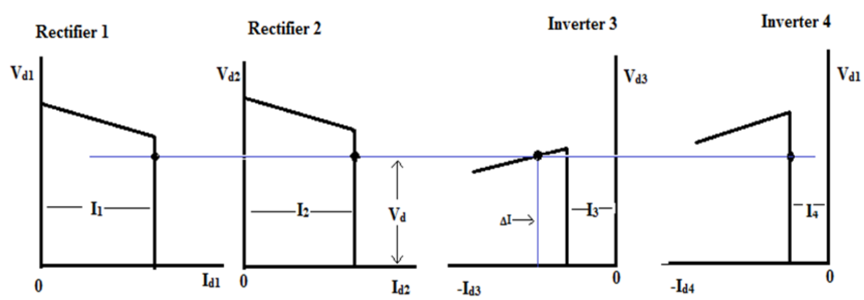

Fig. 4. Current Margin Method of control for MTDC system

Satisfactory operation of MTDC system also requires a reliable central Current Reference Balancer (CRB) that operates at all time. This requires reliable two way communication between a central station and each converter station. Under steady state condition, Rectifiers R1, R2 and inverter I2 operate in constant current control, inverter I1 operates in voltage control (CEA) mode. VDCOL is included in all the converter stations. A current margin of 10% is included for inverter1 which is acting as voltage controller (CEA).

5. NUMERICAL RESULTS AND DISCUSSION

In order to investigate the performance of MTDC system with SCFCL, various steady state and transient conditions are simulated. After establishing satisfactory steady state behavior different transients such as single line to ground fault on inverter ac bus, three phase to ground fault on inverter ac bus, dc line to ground fault at positive pole of inverter dc bus and dc line to line fault between the midpoints of 1296 km dc lines. Are simulated with and without SCFCL in the system. For the present study the SCFCL is placed on the rectifier side, in series with dc line as shown in Fig. 3.

Steady State Operation

Figure 5 shows the steady state dc voltage and dc current at rectifier 1 and inverter 1 response and the total power transmitted in the modelled MTDC system. System reaches its rated values i.e. ±800kV and 1.875kA after 0.75 sec from start-up. Total power of 6000MW is received at the inverter stations. In all the cases simulated here, the time step chosen for the simulations is $\Delta t = 50\mu s$, which is sufficient to notice the behavior of SCFCL, which provides ultra-fast transition from superconducting state to normal state.

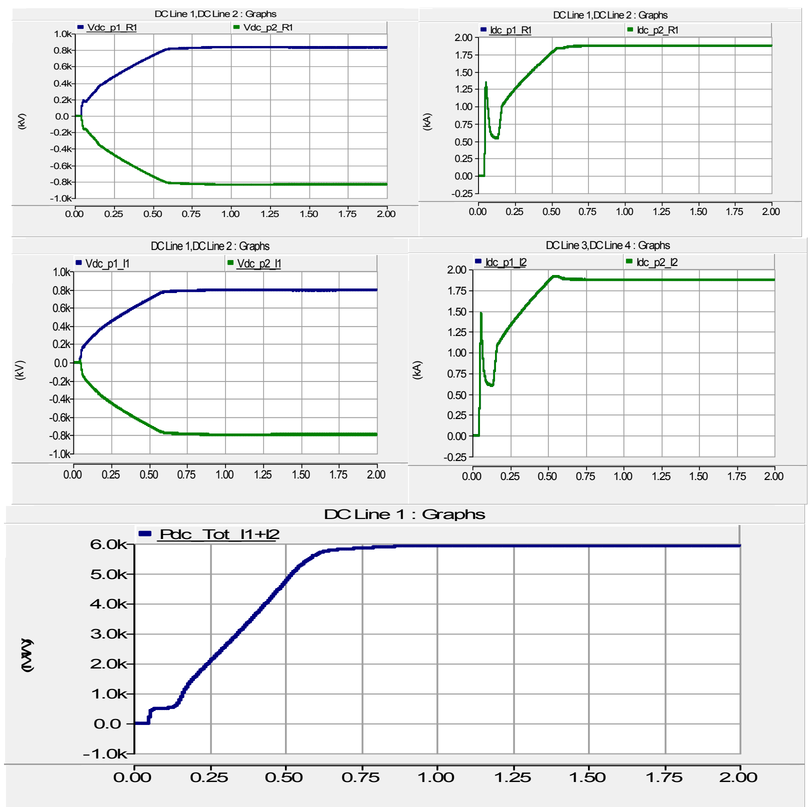

Fig. 5. Steady state performance of MTDC system

Single line to ground fault on inverter ac bus

A single phase to ground fault is created at the inverter AC bus at t=1.2 sec with fault duration of 0.06sec. As both the inverters are connected to a single AC bus, the effect of fault is same on both the inverters (I1 and I2). The various voltages and currents are indicated in Fig.5. Without the SCFCL, the dc voltages at all converter terminals drop to a lower value and the line current increases from 3.75kA to a peak of 7.8kA at the rectifier and nearly 9.8kA at the inverter end. . As soon as the fault is detected, alpha control will be activated to operate the rectifier at higher alpha to reverse the pole voltage, hence dc current. Commutation failure prevention function advances the firing angle alpha to its minimum limit of 110˚ in order to increase the extinction angle to prevent consecutive commutation failure during the recovery. Alpha order at rectifier increased to maximum value of around 140˚ to decrease the increase of dc current. Technically, both converters operate as inverters to discharge the line as fast as possible to extinguish the dc current. The VDCOL increases the current to nominal value after the removal of fault.   After the fault, the recovery is smooth without any hitches.

What is crucial here is the peak value of dc current at all the terminals which needs to be clipped before it causes damages to other equipment. With the inclusion of SCFCL in the circuit, the voltage and currents are modified drastically. The peak value of the dc current is clipped from 7.8kA to 5.2kA at the rectifier and from 9.8kA to 8.0kA at the inverter, in less than half cycle. This quick action of SCFCL is helpful in reducing the damage to equipment and also in preventing the commutation failure at inverter. A comparison of the values with and without SCFCL, helps in understanding the effect of SCFCL and hence the improvement of the overall system performance.
During the fault, the SCFCL enters the normal state and HTS material develops heat across it and this must cool down, in order to regain superconductivity. The time taken by SCFCL device to return it to superconducting state is known as recovery period and it varies from few milliseconds to seconds [H]. In the present study recovery period is taken to be 250 msec. It is also seen here that the recovery, with SCFCL, is better than that without.

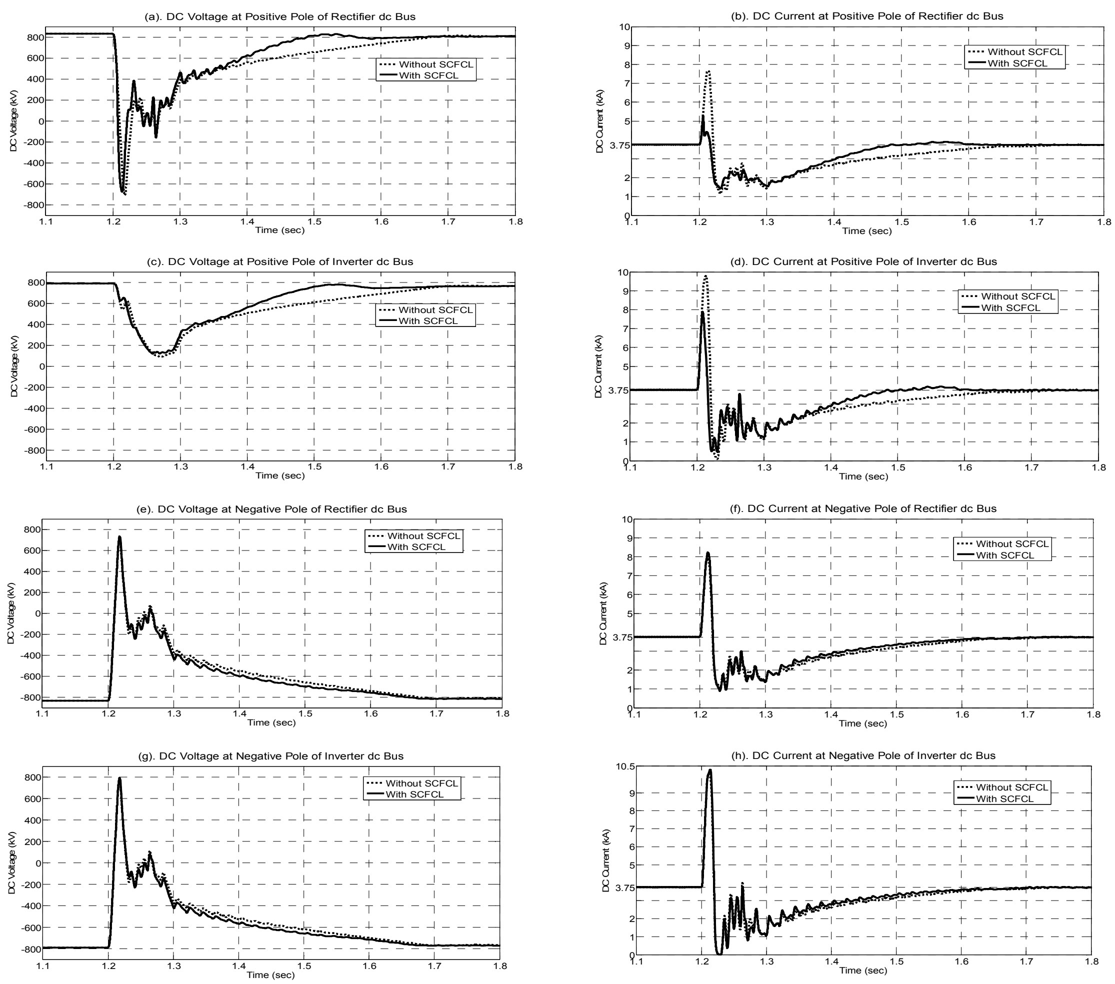

Fig. 6. Single line to ground fault at inverter ac bus (from 1.2 sec to 1.26 sec)

There phase to ground fault at inverter ac bus

A comparison of dc voltages and dc currents, for a three phase to ground fault at the inverter ac bus with and without SCFCL is as depicted in Fig. 7. The voltages and currents are much disturbed and also the peak here is much higher than that for single phase fault, reaching a peak of 10.4 kA at inverter pole. SCFCL clips this peak to 5.5 kA in less than half cycle.

An important thing to be noted here is the current in the other pole. With SCFCL in pole 1, the pole 1 currents are controlled while current in the other pole remains same. This necessitates another SCFCL to be included in the other pole also.

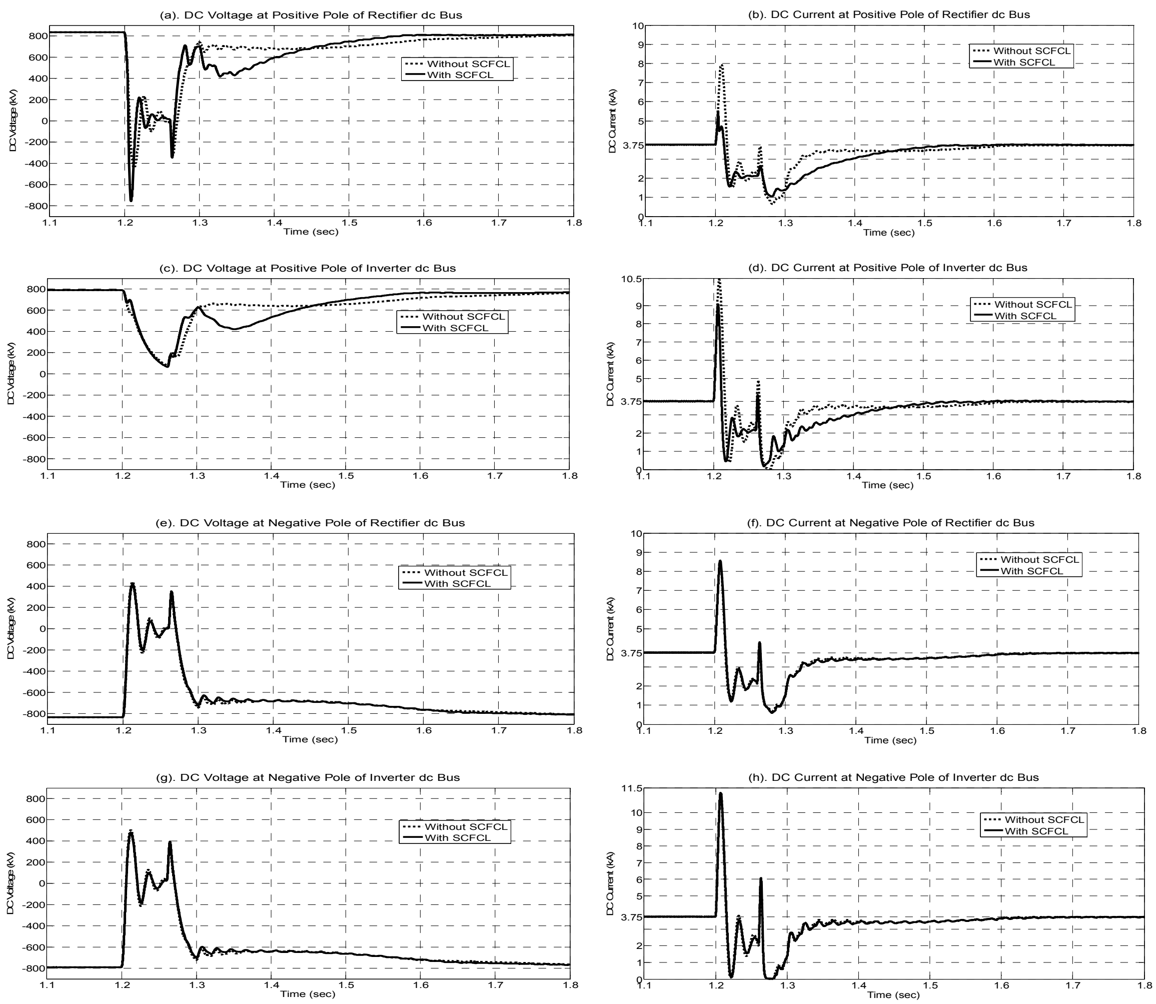

Fig. 7. Three phase to ground fault at inverter ac bus (from 1.2 sec to 1.26 sec)

DC line to ground fault at positive pole of inverter dc bus

The dc line to ground fault is initiated at 1.2 sec for a duration of 0.06 seconds. Immediately after fault, the current rises to about 8.0 kA at rectifier and 11.0 kA at inverter. The rise is very sharp. Also, it falls down to a low value very quickly, without the SCFCL. Including the SCFCL brings the peak value down from 8.0 kA to 4.0 kA at rectifier and 11.0 kA to 7.8 kA at inverter terminal. The recovery is much faster with SCFCL at both rectifier and inverter. The healthy pole currents voltages are hardly affected by the fault, in both with and without SCFCL case.

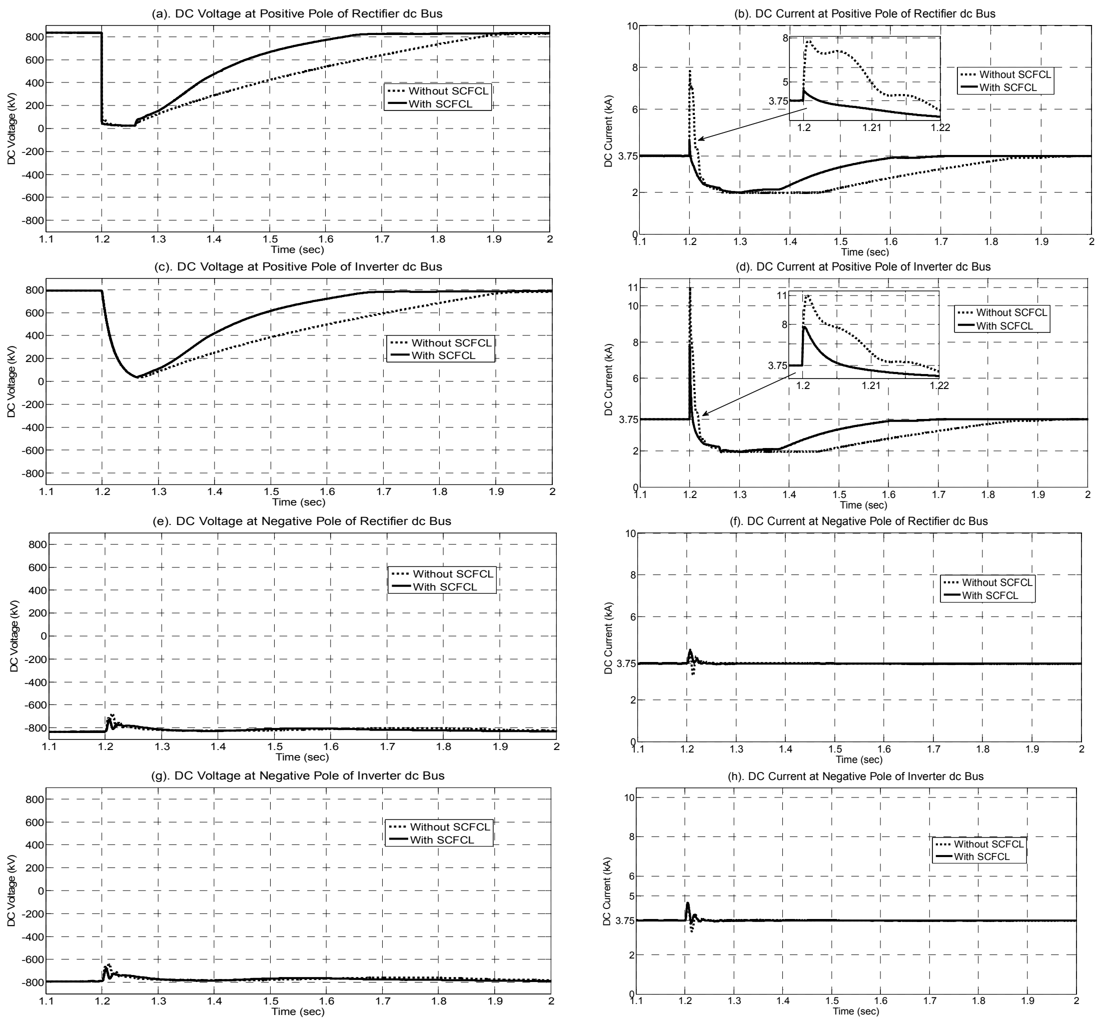

Fig.8 DC line to ground fault at positive pole of inverter dc bus (from 1.2 sec to 1.26sec)

DC line to line fault between the points of 1296 km dc lines.

The results of this fault is depicted in Fig. 9. A plot of voltage and currents at different points in the MTDC system indicate that this case is much more severe that the dc line fault described earlier. On the other hand the recovery seems to be smoother in both the cases, with and without SCFCL.

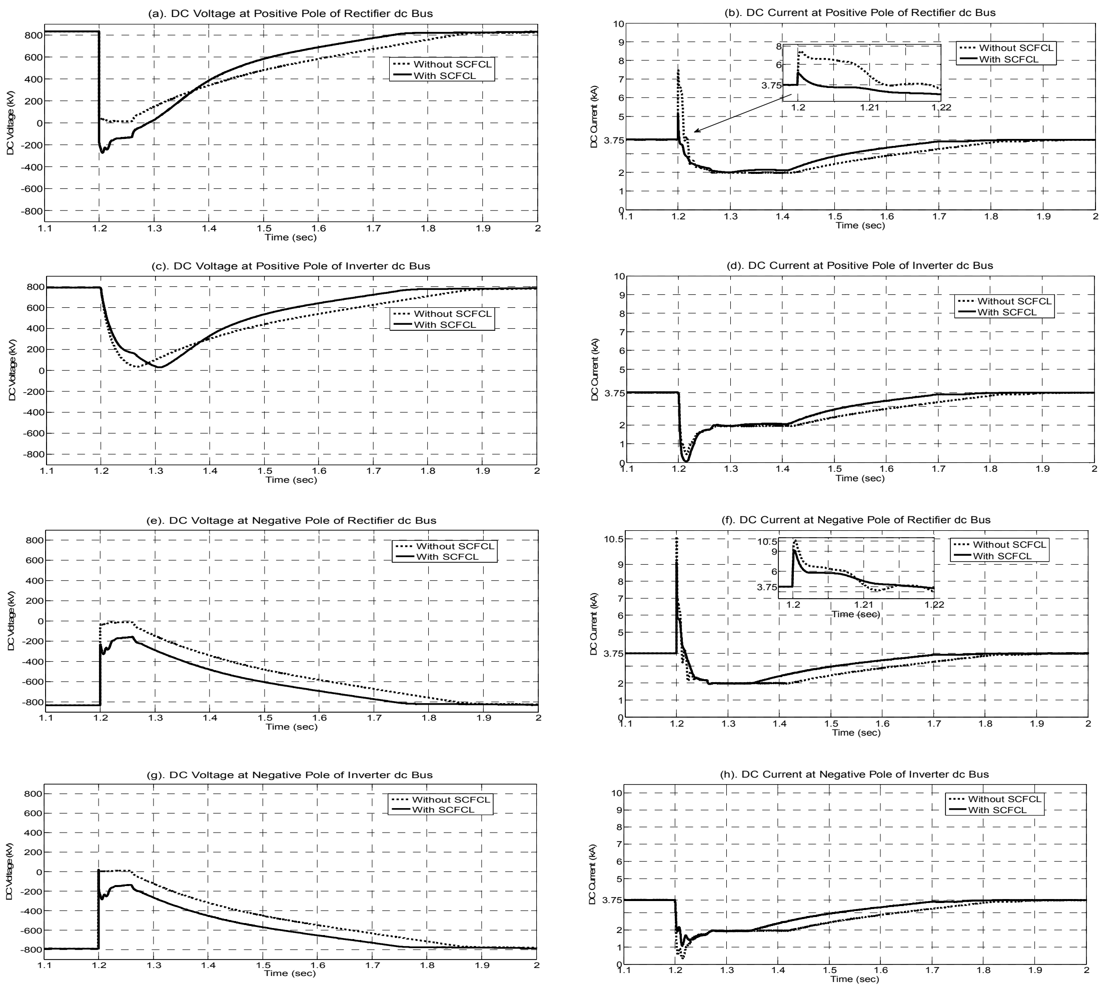

Fig. 9. DC line fault between the mid points of 1296 km lines (from 12 sec to 1.26 sec)

6. CONCLUSION

This paper has described the simulation results of the upcoming MTDC system in India. In the 4 terminal, parallel connected system, the fault currents increase to a very high level, without any protective devices, indicating a need for protective device to reduce the maximum currents. The performance of MTDC system with SCFCL at the rectifier, shows that the currents at the faulted poles are clipped to a smaller value within half a cycle, to a lower value. A more detailed study of MTDC system with SCFCL, taking care of the actual data, the controls adopted and protection systems considered is essential to come with conclusive remarks on the application of SCFCL in MTDC systems.

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Appendix I

Table 1 Control parameters of MTDC system.

Parameters	Rectifier 1	Rectifier 2	Inverter 1	Inverter 2
α	20.23˚	20.37 ˚	142.32 ˚	142.24 ˚
γ	-	-	15.19˚	15.47˚

Appendix II

SCFCL parameters

Un = 10.5 kV, In = 2 kA, both RMS values

T = 77 K, Tc0 = 90 K, Jc77 = 1.5E7 A/m^2

E0 = 1 V/m, Ec = 1.0E-4 V/m, Length = 20 m $\alpha = 4$, $\beta = 2.5$,

S = 0.34E-4 m^2 , ρ 7E -6 Ω-m, Lfcl = 0.4e-6 H, Rsh = 6 ohm.

Appendix III

System Ratings 6000MW, +/-800kV, 3.75kA (Bipolar MTDC System)								
AC system details								
Parameters	Rectifier side 1		Rectifier side 2		Inverter side 1		Inverter side 2	
Vs (kV)	425		425		375		375	
f (Hz)	50		50		50		50	
SCR	$4\angle 84^\circ$		$4\angle 84^\circ$		$4\angle 75^\circ$		$4\angle 75^\circ$	
Zs (Ω)	13.33		13.33		6.66			
Vbus (kV)	400				400			
Reactive Power compensation (MVAR)	1800		1800		1800		1800	
Converter Details								
	Rectifier side 1		Rectifier side 2		Inverter side 1		Inverter side 2	
	+Pole	- Pole	+ Pole	- Pole	+ Pole	- Pole	+Pole	- Pole
Transformer rating (MVA)	900	900	900	900	900	900	900	900
Xt (p.u)	0.18	0.18	0.18	0.18	0.18	0.18	0.18	0.18
Primary voltage (kV)	400	400	400	400	400	400	400	400
Secondary voltage (kV)	340	340	340	340	340	340	340	340
DC line parameters								
	Dc line 1		Dc line 2		Dc line 3		Dc line 4	
Line length (km)	1296		1296		432		432	
Line resistance (Ω)	11.66		11.96		3.86		3.86	
Ld (H)	1.2		1.2		1.2		1.2	

Segmentation with DC Transmission to Avoid Wide Spread Network Collapse

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SUMMARY

Segmentation allows regions linked only by HVDC to operate asynchronously (or synchronously through use of HVDC controls) under normal conditions and have frequencies diverge when one region experiences equipment failures. Through HVDC controls, adjacent supporting regions provide automatic assistance to a failing region without overstressing the supporting regions. Low frequency in the failing region results in under frequency load shedding only in that region where it is most effective. This process may avoid collapse of the failing region but should a failing region collapse, others remain healthy.

Segmentation of existing grids can provide great increases in transfer capability while substantially improving bulk grid reliability. This concept is more than simple insertion of back-to-back converters along boundaries that create asynchronous islands. It includes conversion of many existing AC transmission lines to HVDC and the use of simple unique local HVDC controls that enhance all of the traditional services of an AC grid while increasing transfer capability and reliability.

Studies have been completed on the efficacy of segmentation on large portions of both the Eastern and Western US Interconnections. These studies simulate known events that pose a high risk of cascading and blackout and show that they are made harmless. Dramatic transfer capability improvements are also demonstrated with some transfer limits tripled.

What has been learned from these North American studies is that where large system wide blackouts have occurred causing billions of dollars of loss to the economy, is that if segmentation had been in place such blackouts would have been prevented. Consideration of this important conclusion is that applying segmentation to Europe, China, India and Africa will prevent wide area blackouts compared with having such areas completely synchronized with AC transmission interconnections.

KEYWORDS

Segmentation – Blackout - System collapse - DC link - Voltage sourced converters - Cascading outage - AC interconnections - DC interconnections - HVDC converters

1. INTRODUCTION

Present AC electric grid systems can operate with increased transmission capacity and improved robustness by segmenting regions with HVDC transmission and back-to-back voltage sourced converters. Segmentation technology improves grid utilization and reliability by eliminating stability constraints, avoiding cascading outages, and by precise inter-regional and inter-sector control of power flows. An illustration of a segmented grid with interconnecting DC transmission systens is represented in Figure 1.

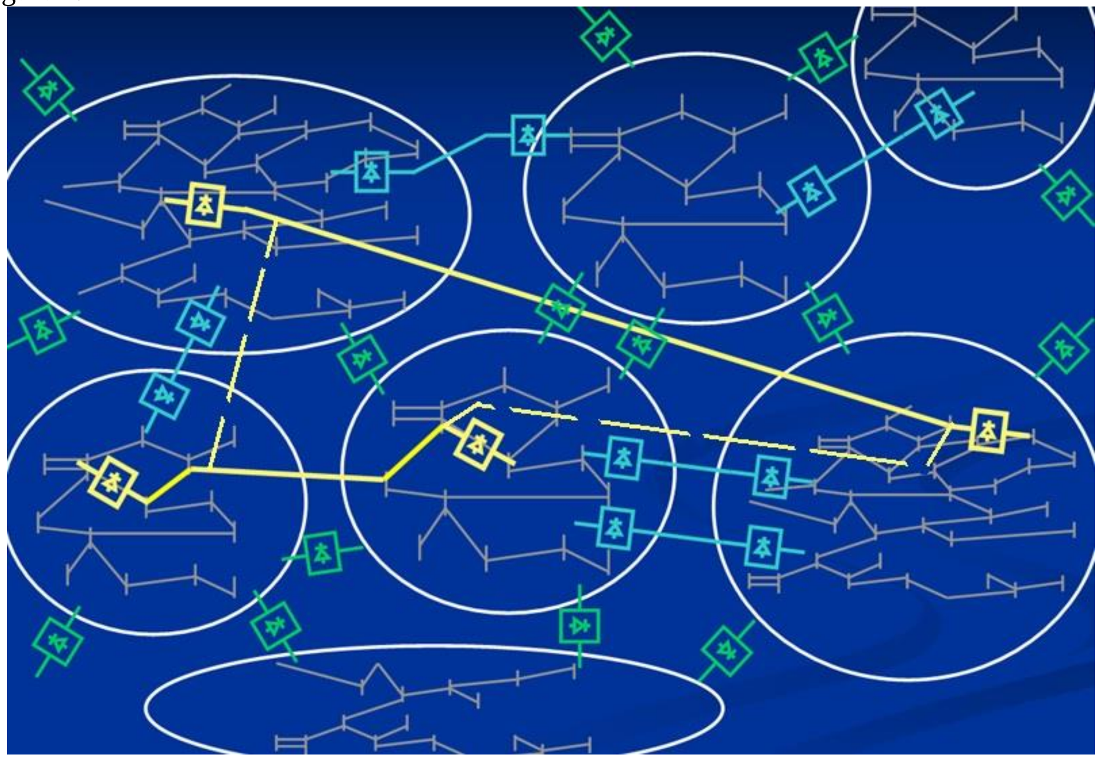

Figure 1. How a segmented AC grid is constructed through back-to-back DC converters (green), AC to DC line conversions or new DC Lines (light blue) , and long distance HVDC lines or DC grid (yellow)

The major breakup of the US and central Canada power system during Northeast Blackout in 2003 was a surprise. A power system that had seemed invulnerable collapsed leaving millions of people and businesses in the dark and with high societal costs. Many of the World's major blackouts would have been avoided or limited had segmentation through HVDC technology been in place.

To ascertain the benefits and cost effectiveness of segmentation, a joint study was undertaken by DC Interconnect (DCI) and the Electric Power Research Institute (EPRI). The study included examining the effectiveness of segmentation had it been in place in the US and Canada in 2003 when the Northeast Blackout occurred. Reliability improvements were assessed by examining the dynamic performance of the US and Canada grid before and after segmentation.

2. SEGMENTED SYSTEM OPERATION

There will be several types of controls required for DC links. Included will be Energy Management Systems (EMS) based controls for dispatch, dispatcher controls for manual operation, and local controls. Local controls will be critical to good dynamic response to disturbances and are the focus of this investigation.
The loss of generation problem is more onerous and is the basis of the following discussion.

The DC link controller must also operate in concert with automatic generation control (AGC) systems found in individual utility or Independent System Operator (ISO) operated EMS. Because AGC systems do not respond in the time frame being examined in this investigation, they are not modelled in the simulations presented herein. However, integration of DC links with AGC systems will be straight forward. In most cases an AGC system will adjust in-sector generation to restore frequency and DC link power to initial settings just as is done today to restore frequency and tie-line flows. However, having control over DC link power opens the door to the possibility of not restoring tie flows, but taking them to some new level that provides relief for the contingency that occurred. For instance, a line outage near a converter might result in a thermal constraint that could be addressed by reducing the power setting on the nearby converter. The potential for DC links to assist with contingencies and emergency conditions near converters or elsewhere in a sector is very large.

3. A STUDY WITHOUT AND WITH SEGMENTATION

The joint study intent was to introduce the segmentation concept and demonstrate the feasibility of using it to prevent cascading disturbances and network breakdown. Voltage sourced converters (VSC) were applied in the study to maximize benefits they can bring to segmentation. This was accomplished by modelling sets of four example segments in the Northeast Blackout area of the Eastern Interconnect. These segments are depicted in Figure 2 where Figure 2(a) has the Eastern Interconnect with its existing AC tie lines between the segments and Figure 2(b) has the tie lines between the same segments converted to DC links.

The local DC link controls in the DC link case are straight-forward. The controls increase power flow in the direction from the segment with higher frequency to the one with lower frequency with a gain or droop that is shown by analysis to be responsive and steady state stable. The maximum change in power at each DC link is determined by analysis of the thermal and voltage support capability of the segments on both sides of each DC link.

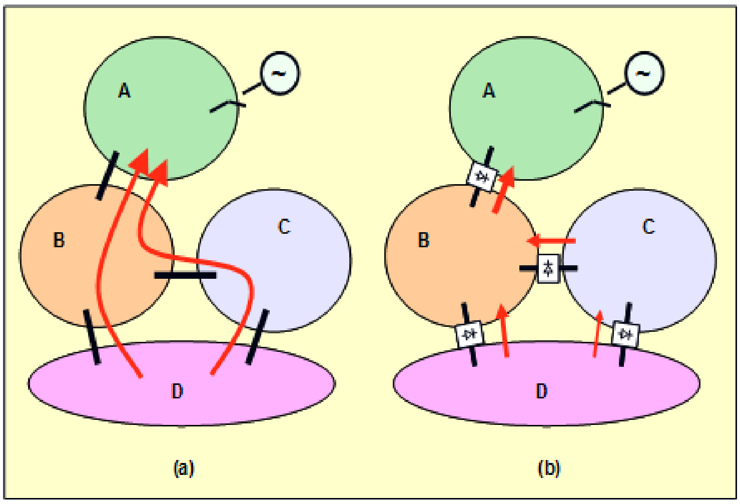

Figure 2: The Eastern Interconnect divided into four segments with (a) the segments are connected through the existing AC ties and (b) the same segments interconnected by DC links.

The three A, B and C segments in Figure 2 are connected to the much larger outside world segment of D. The initiating event consists of a large-scale loss of generation, 2700 MW, in segment A. This generation loss is 1100 MW beyond planning and operating criteria. The red arrows in Figure 2 denote the power flow from segment D when the generators in segment A trip out of service. This disturbance was applied to a 2011 model of the Eastern Interconnect with only AC and again with DC links added. The results showed the system is initially stable but tie flows are excessive by 1100 MW. Line flows exceed line ratings by twenty to forty percent of line rating and AC line trips occur as shown. Significant voltage excursions also occur with those line trips

Although the system with AC ties is initially stable, it is in an untenable state. The high reactive losses have caused voltage regulators to push generator excitation well above rated value. Voltage collapse is thus temporarily avoided. However, about twenty seconds after the disturbance, excitation limiters will begin pulling excitation down to rated levels and voltages will fall. When voltages drop sufficiently, motors will stall and initiate a grid breakup. Alternatively, if the low voltage spreads widely enough, breakup will result directly from steady state or oscillatory angular instability.

The first line trip was at seven seconds. Additional frequency excursions occur, loading on remaining circuits increases, and voltages fall further. While a more realistic load model (including induction motors) would likely have resulted in immediate instability, the model again shows the system continuing without instability. However, a second line trip at fourteen seconds results in immediate angular instability and grid breakup.

With the AC ties are replaced by DC links, the power flow between segments B and C is increased toward segment A by local HVDC controls as the frequency of segment A drops. The increases are limited to levels that are safe for the AC line thermal ratings and available voltage support in segments B and C. The increased power flow toward segment A results in some drop in frequency in segments B and C. This drop in frequency in turn pulls some power from segment D into segments B and C, again, limited by the DC link controls to a level that is safe for all three segments. In this manner, segment A receives the maximum support that segments B, C and D can safely provide. If this support, combined with spinning reserve in segment A is not sufficient to arrest the frequency decay in segment A, load shedding will occur in segment A. All load shedding thus occurs in the segment that experiences the generation shortage and is more effective than in an all-AC segment where under frequency load shedding occurs over a wide area (if the system is stable).

While the initial DC link loadings were below DC link ratings and safe AC system loadings in our example, the DC link controls allow normal condition DC link loadings to reach DC link ratings or levels that are at the safe limits in the AC systems. In cases where some or all DC links are maximally loaded before a generation loss disturbance occurs, those DC links will not respond to a drop in frequency and load shedding alone, in the system experiencing the frequency drop, the load and generation will balance.

This study of the Eastern Interconnect in Canada and the U.S.A. indicates that segmentation will improve grid reliability.

4. ECONOMIC JUSTIFICATION OF SEGMENTATION

Segmenting a grid involves significant investments similar to some of the competing technologies. To address an apparently common perception that segmentation is prohibitively expensive DCI has estimated the investment requirements for segmenting the Eastern Interconnect in North America based on preliminary design scenarios and estimated to be up to $25 billion. Based on this one Northeast Blackout in 2003, the range of societal costs is estimated to be between $6.8 billion to $ 10.3 billion [1]. The power grid in Western North America (the Western Interconnect) which is asynchronous to the Eastern Interconnect requires up to $5.4 billion to effectively segment. When the significant grid power outages listed in Table 1 are reviewed, there are six in the Eastern Interconnect and three in the Western Interconnect over a period of 47 years. There is apparent increase in the frequency of occurrence, perhaps due to increasing weather events and loading conditions.

Every power outage or blackout causes large economic loss to those affected. For losses in the distribution systems because of bad weather, distributed generation or microgrids are anticipated to improve reliability. For cascaded outages of the main transmission system, segmentation will improve reliability.

By accounting for the benefits of preventing cascading (based on historical blackout events in the Eastern Interconnect and the Western Interconnect), increased available transmission capacity (ATC), market benefits, and changes to system losses, our studies have found that contrary to industry perceptions, segmenting North America’s grids can indeed be cost effective. Moreover, the increases in retail rates needed to pay for the required investments are quite modest (less than 2 percent).

Further work is required to optimize segment boundary locations and refine the associated costs and benefits.

Table 1: An incomplete list of major grid blackouts [2]

Date	Location	Duration	No. Impacted	Cause
Oct 2012	Eastern US & Canada	2 weeks	8.2 million	Hurricane Sandy, floods, downed lines
July 2012	Northern India	2 days	Hundreds of millions	Overloads and repeated collapses
June 2012	Midwest & eastern US	7 to 10 days	4.2 million	Wind storm
Oct 2011	Northeast US	Up to 10 days	3 million	Early snow
Sept 2011	California & Arizona	12 hour	2.7 million	Hot weather loading, plant out for maintenance, technician error
Aug 2003	London, UK	½ hour	250,000	Two cables failed
Aug 2003	Northeast US & Ontario	Up to 4 days	50 million	Overloads, inadequate tree trimming, operators lacked coordination
June 1998	Canada & north central US	Up to 19 hours	52,000	Line tripped in Minnesota from lightning, Midwest separated
July 1996	US west coast	Several hours	2 million	Overloaded line in Idaho followed by cascading line and generation trips
Aug 1996	US west coast, Canada	6 hours	7.5 million	Inadequate tree trimming followed by cascading outages
Dec 1982	US west coast	Several hours	5 million	High winds knocked over 500 kV tower and cascading followed
July 1977	New York City	26 hours	9 million	Tower failures from lightning, cascading outages
Nov 1965	Northeast US and Ontario	13 hours	30 million	Transmission cascading due to incorrect protection setting

However, wide spread developing electric power systems such as in China, Africa and India have an advantage in costs. The national or continental transmission planning strategies can incorporate segmentation as their system grows giving an overall cost advantage over segmenting a large established power system such as the Eastern Interconnect. For example, a well-planned segmented transmission system in Northern India most probably would have minimized the wide spread blackouts from overloads that occurred in July 2012.The segmenting DC links would themselves not overload as their controls always limit the maximum power the collapsing AC system demands, thus acting as a buffer to the neighbouring segments. This was evident in the August 2003 North East Blackout which affected the U.S.A and Ontario when neighbouring Quebec remained relatively unaffected because of its DC tie lines to the Eastern Interconnect.It does not require too many large system blackouts to justify any added cost of segmentation but there are additional market benefits to include. For example, simply reducing congestion through increased transfer capability will improve market operation. However, additional market benefits will obtain from a reduction in inadvertent flows and loop flows that make conformance with schedules difficult and complicate grid operation through very complex scheduling and settlement protocols and procedures.

When a segment does collapse to a power outage, modern VSC links to that segment can provide black start capability to reduce its total outage time.

5. CONTROLS FOR SEGMENTING DC LINKS

Three control regimes are necessary in a segmented grid. They include:

- Power controllers on each DC link;
- Central control to provide routine updates to the power controller settings (gains and power limits); and
- Central control to adjust the distribution of interchange power among the DC links following an emergency to prepare for possible additional contingencies.

Only the power controllers on each DC link need to respond during emergencies

The second control regime provides routine ongoing updates to the HVDC controller settings to accommodate changes in sector operating conditions and scheduled power transfers and assure the ties are ready to provide support across sector boundaries without jeopardizing reliability in any supporting sector.

The third control regime is the usual "adjustment" that occurs following a contingency. Adjustments typically involve phase angle transformer adjustment, changes in generation dispatch, start-up of combustion turbines and similar operator activities. Generally these adjustments are expected to occur within 30 minutes following a contingency. In a segmented system, DC link power controller settings provide an additional and powerful adjustment. Adjustments may be needed to remove circuit overloads that are allowed to result from DC link response to contingencies as well as to correct overloads that result from intra-sector contingencies. The DC links have a significant advantage over other adjustments in that changes can be made relatively quickly thus reducing the risk associated with exposure to an additional contingency.

A frequency-based DC link controller is designed to operate in concert with generator governors. This is done by designing it to respond to frequency excursions with a time lag that approximates that found in typical generator governor and turbine controls. Also, just as generator governor droop settings determine how generators will share a needed change in power output, a droop setting in the DC link controllers determines how the DC links share a needed power change with the generators as well as among the DC links. For example, loss of generation in a segment will cause frequency to drop in that segment. Generators within that segment will respond, as will the DC links. In most situations the goal will be to let in-segment generators cover as much of the shortage as is practicable, with the DC links contributing as necessary to avoid or limit under frequency load shedding.

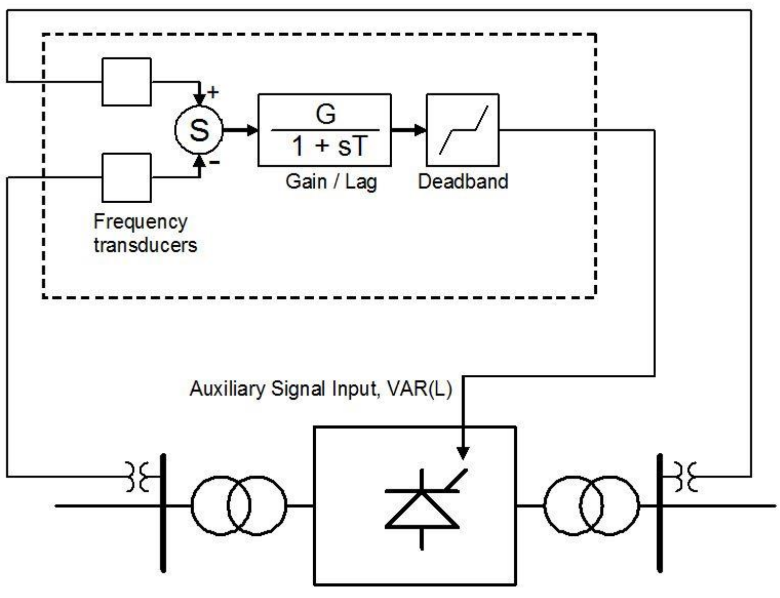

Figure 3: Basic elements of a DC link frequency controller

In Figure 3, frequency on each side of the DC link is measured and the difference is passed through a lag function acting as a low pass filter to delay response to share the burden of frequency control with affected generators in that system and other parallel converters. The dead band prevents the converters from responding to small routine minute to minute variations in frequency.

Segmentation requires no significant new hardware or control technology. The only missing piece is the controller and this is a very minor piece that can be readily programmed into existing HVDC digital control hardware. Remote adjustment of HVDC controls is also a mature technology and can easily accommodate the needed adjustments.

There may be a reason to require a national DC grid to be synchronized. This does not prevent segmentation. DC interconnections forming the segmentation can operate as synchronous links with the advantage that if a segment requires support, the DC link just runs up and continuously provides its maximum power in continuous support. When the frequency of the distressed segment returns to rated frequency, the DC links will again lock into synchronism [4]. A simplified control diagram of how synchronization with a DC link is presented in Figure 4.

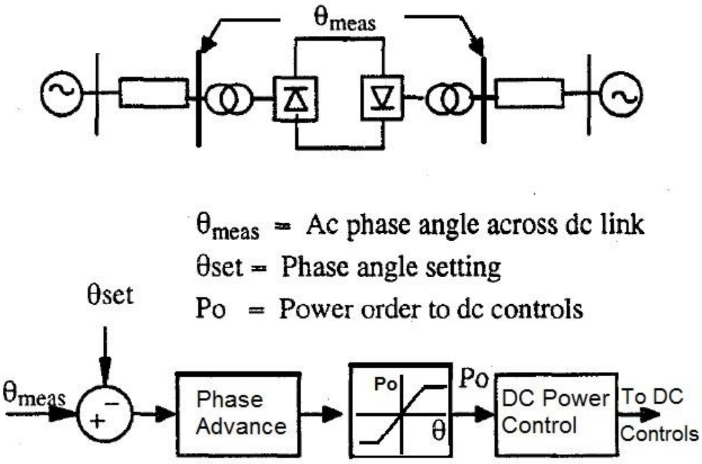

Figure 4: Basic representation of controlling a DC link to provide synchronization between two AC power systems

The System Operator can set the steady state power flow through the θset input signal. The difference signal between θset and the measured phase angle θmeas signal is phase advanced for control stability to offset the latency in the measuring of θmeas and provide system damping.

6. ADDITIONAL BENEFITS FOR SEGMENTATON

The two key benefits of segmentation are a virtually complete freedom from large-scale blackouts and large increases in transfer capability between ac sectors. The increase in transfer capability is generally available with little or no new transmission construction beyond conversion to HVDC.

6.1 Reliability

Segmentation improves grid reliability by preventing disturbances within a sector from cascading to adjacent sectors. In each sector of a segmented system, DC link capacity is designed and operated so that failures in adjacent sectors cannot propagate from sector to sector.
The ability to use the DC links to regulate power flow and make prompt corrective changes in power flow across a sector enhances reliability within each sector.

With intra-sector reliability improved there will be fewer cascading events. And, when cascading events do occur, they will be limited to a single sector. This compounding provides substantial reliability improvement.

6.1 Total Transfer Capability Benefit

The increase in total transfer capability provided by segmentation obtains from several mechanisms including:

- Removing angular stability constraints;
- Conversion of AC circuits to HVDC;
- Maximizing use of local spinning reserve;
- Routing power to maximize AC grid use;
- Reducing or eliminating loop and inadvertent flow; and
- Local controls (remedial actions schemes).

6.2 Stability

Regional stability constraints are generally well known and include both first-swing or “transient” stability limits and oscillatory or “dynamic” stability limits. In some locations removing remaining stability constraints will contribute to new transfer capability. Also, any increase in transfer capability associated with conversion of ac transmission lines to HVDC will be free of stability constraints.

6.3 Conversion of AC Transmission to DC Transmission

Conversion of ac circuits to DC can significantly increase the transfer capability of existing transmission lines. Depending on the DC technology, increases of 200 percent or more are possible.

6.4 Spinning Reserve

The improved utilization of intra sector spinning reserve can provide very large transfer capability increases. In every AC electric power grid, a disturbance that removes generation from the system results in inertial and then governor response at generators throughout the synchronous AC power grid.

In a segmented grid, controls on DC links allow frequency to drop in the sector that experiences a generation loss so that spinning reserve in that area will pick up a majority and if desired all of the generation loss. The DC links can provide backup to the local spinning reserve where DC link capacity is reserved for that purpose or is otherwise available. Where the generation loss is large and the DC links do not have idle capacity that can be activated to help, under frequency load shedding in the affected sector will balance load and generation. While load shedding is never desirable, it is preferable to the cascading that can occur when excessive power flows across ac ties and causes voltage or angular instability. A side benefit of the occasional minor frequency excursions is identification of generators that are not responding to frequency as they should.

6.5 Loop and Inadvertent Flow

DC links also solve the problem of regional loop and intermittent flows. Some loop and inadvertent power flows will still occur within sectors, but the opportunities for either are greatly reduced. To the extent DC links are placed in paths that are experiencing loop or inadvertent power flows, those flows will no longer be troublesome.

6.6 Selecting Segment Boundaries

Cost is a major issue with segmentation. It is expected that often the least costly boundary will provide substantial benefits and have a high benefit to cost ratio.

Market operation benefits are likely to be greatest when an HVDC boundary falls on a political boundary. However, reducing congestion and gaining a means to control and measure power flows and provide AC voltage support will be advantageous from a market standpoint wherever the HVDC boundary falls.

7. CONCLUSIONS

This paper demonstrates the benefits of segmentation using HVDC in large AC grids that are predominantly used all over the world. AC grid segmentation using HVDC not only reduces the cascaded system wide blackouts but also increase the overall power transfer capability of the entire grid. The results from the case studies of Eastern Interconnection and Western Interconnection of the North American Power Grid were presented in this paper, which clearly demonstrate the feasibility and benefits of the segmentation concepts. Though there are additional costs associated with the segmentation, but the benefits seem to outweigh the costs.

Based on the results of this study, those responsible for development policy for their respective wide area power systems being established around the world should seriously heed these conclusions. The extensive blackouts happening to very large synchronous grids all too frequently are unacceptable and pose serious financial and national security risks. Segmentation is proven to be a robust solution to minimize this risk.

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Reliability Evaluation of VSC-HVDC

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SUMMARY

Wind power is currently the fastest growing and the most competitive renewable energy in the world. Due to the intermittent and stochastic nature of wind power and the increasing integration of wind farm, the impact of wind farm on power system is more and more serious. To tackle this problem, one widely-used technique is VSC-HVDC (Voltage Source Converter-High Voltage Direct Current). The reliability evaluation of offshore wind farm VSC-HVDC system is very important. This paper focuses on the development of reliability evaluation on VSC-HVDC. Using Sequential Monte Carlo Simulation method, the states of all the components are simulated. Numerical studies are applied on a multi-terminal VSC-HVDC system. The results from the numerical studies demonstrate the effectiveness and feasibility of the proposed method.

KEYWORDS

Multi-terminal, VSC-HVDC, reliability evaluation, wind power

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1 INTRODUCTION

Wind power is currently the fastest growing and the most competitive renewable energy in the world. Compared with onshore wind energy resource, offshore wind energy resource is with the benefit of more abundancy, lower turbulence intensity, larger speed, and more stablity of the wind direction.

Due to the intermittent and stochastic nature of wind power and the increasing integration of wind farm, the impact of wind farm on power system is getting serious. To utilize this wind power and transmit it to the onshore land, the Voltage Source Converter-High Voltage Direct Current (VSC-HVDC) is considered to be a good technique. This technique is not only suitable for small capacity (several MW) power transmission, but also suitable for the large capacity power transmission (hundreds MW). Meanwhile, it is also suitable for the asynchronous interconnection between power grids.

For transmitting the offshore wind power, compared to the AC grid connection and the traditional HVDC system, VSC-HVDC has the following advantages:

1)No problem with reactive power compensation;

2)Independently control the active and inactive power;

3)High switching speed and low harmonic level.

At present, many countries all round the world are in the research and development of offshore wind grid-connected system based on VSC-HVDC system: from the early Danish Tjaereborg demonstration project to the recently German Borkum West wind power project, offshore wind farms based on VSC-HVDC technology has entered the stage of large-scale application. In August 2008, the State Grid Corp of China carried out a demonstration VSC-HVDC project called Shanghai Nanhui VSC-HVDC demonstration project. And in March 2011, it was successfully put into operation. Literature [1] has introduced the basic situation of the project, including the operation mode and power transmission range, which provides technical support and operation experience for wind farm integration in China.

In view of the rapid development of VSC-HVDC technology and demonstration projects, the reliability evaluation of VSC-HVDC system is very important. At present, the research of VSC-HVDC system reliability model is based mainly on the existing established methods of traditional HVDC reliability model, which includes: state enumeration method, Markov method. According to the main functional structure of VSC-HVDC system, it can be divided into several subsystems (such as valve subsystem, transmission line subsystem). By establishing the two state models (normal or failure state) for each subsystem, and making the state combination, the whole VSC-HVDC system reliability model can be obtained. Literature [2] studied the reliability evaluation model of HVDC transmission system with a tapped VSC-station, and analyses the influence of VSC-station on the reliability of traditional HVDC power. Through the method of model combination, literature [3] established the equivalent model of VSC-HVDC system.

The above mentioned literature has done important contribution to the development of VSC-HVDC system reliability, but further consideration are needed to incorporate the following factors in the reliability evaluation of VSC-HVDC, such as the consideration of multi-terminal systems, the output intermittency of wind power, etc.

Therefore, this paper mainly focuses on the development of reliability evaluation of VSC-HVDC system considering not only multi-terminal configuration of VSC-HVDC system, but the output intermittency of wind power. In the evaluation process, a variety of component failure impacts are included, such as the transformer, valve, DC transmission line, and so on.

2 SEQUENTIAL MONTE CARLO SIMULATION METHOD

Although the state enumeration method can evaluate the reliability of VSC-HVDC system, the model is not applicable if the influence of wind power intermittency is included. Since if the wind power output is small, while the VSC-HVDC system is in derated operation state due to component failure, and the available transmission capacity is greater than the wind farm output, obviously, the failure state of VSC-HVDC component should not be included in the reliability evaluation. Taking the impact of wind farm output intermittency into account, consideration should be given to the coordinated evaluation of wind power and VSC-HVDC system.

Sequential Monte Carlo simulation is a simulation method performed in a time sequence. It uses the state duration sampling method to simulate system state and the transition process. It is a duration distribution based probability sampling method which is divided into the following steps:

Step 1: Initialize the state of all components. Usually it is assumed that all components are in normal states.

Step 2: Sample the duration of each elements in a sequential order.

For different states, such as normal or repair process, they can be assumed to follow different probability distribution. For example, the state duration of the exponential distribution is given as following:

$$D_i = -\frac{1}{\lambda_i} \ln R_i \tag{1}$$

where R_i is the uniformed random number of component i over U [0, 1]. If the current state is normal, then λ_i is the failure rate of component i, and if the current state is outage state, λ_i is the repair rate of component i.

Step 3: Repeat the Step 2 over the simulation time, and record all the sampling results of components at each state (the transfer process of each element in a given time are shown in Figure 1.

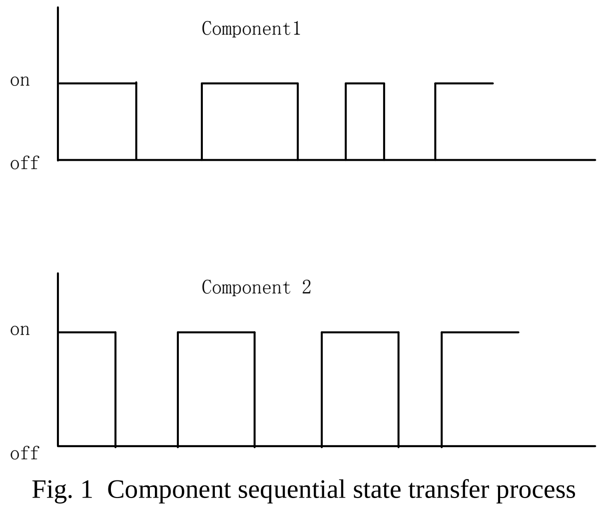

Fig. 1 Component sequential state transfer process

Step 4: Combine the transfer processes of all elements and form the chronological system state transition process, as shown in Figure 2.

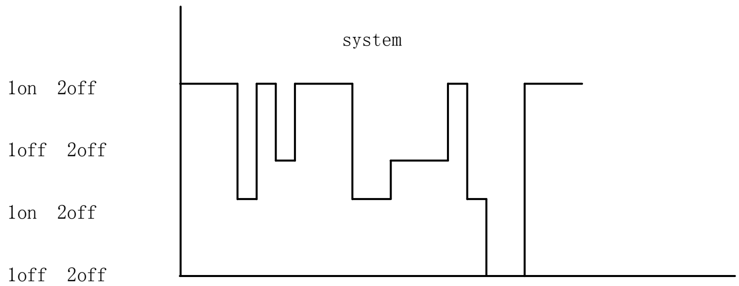

Fig. 2 System sequential state transfer process

Step 5: Calculate the reliability indices by conducting the system analysis for each different system states.

Three general reliability indices are given as below :

$$P_f = \frac{\sum_{k=1}^{M_{dn}} D_{dk}}{\sum_{k=1}^{M_{dn}} D_{dk} + \sum_{j=1}^{M_{up}} D_{uj}} \tag{2}$$

$$F_f = \frac{M_{dn}}{\sum_{k=1}^{M_{dn}} D_{dk} + \sum_{j=1}^{M_{up}} D_{uj}} \tag{3}$$

$$D_f = \frac{\sum_{k=1}^{M_{dn}} D_{dk}}{M_{dn}} \tag{4}$$

where P_f, F_f and D_f are the probability of system failure, frequency and average duration, respectively; D_{dk} is the duration of the outage state k; D_{uj} is the duration of the normal state j; M_{dn} and M_{up} are the times of the failure state and the normal state in the simulation period, respectively.

Hence the key of sequential Monte Carlo simulation method lies in the generation of the system state transition process, once this step is completed, index calculation is relatively simple. The essence of this method is to build the transfer process of normal and failure system.

3 THE OUTPUT OF WIND TURBINE GENERATOR (WTG)

3.1 Wind power model

Wind power model is a basic research of the influence of large-scale wind power integration on power system. The accuracy of the model and the parameters will directly affect the accuracy of following simulation. The relationship of the wind speed and wind power output of WTG is not linear. In the standard air density condition, the relation curve of wind power output and wind speed is called the standard power characteristic curve of WTG, as shown in figure 3.

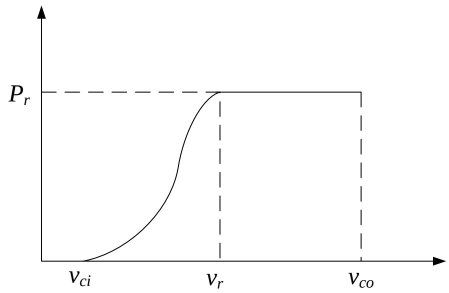

Fig. 3 Curve of WTG power output

It can be described by Equation (5) :

$$P(v)=\begin{cases}0 & 0\le v<v_{ci}\\ P_r\ (A+B\times v+C\times v^2) & v_{ci}\le v<v_r\\ P_r & v_r\le v<v_{co}\\ 0 & v\ge v_{co}\end{cases}\tag{5}$$

where P_r is the rated power output of WTG; v is the wind speed; v_{ci}, v_R, and v_{co} are the cut-in, rated, and cut-out speed of WTG; A, B, and C are the coeffiecients of the output model, calculated as following:

$$\begin{cases}A=\dfrac{1}{(v_{ci}-v_r)^2}\left\{v_{ci}(v_{ci}+v_r)-4v_{ci}v_r\left[\dfrac{v_{ci}+v_r}{2v_r}\right]^3\right\}\\ B=\dfrac{1}{(v_{ci}-v_r)^2}\left\{4(v_{ci}+v_r)\left[\dfrac{v_{ci}+v_r}{2v_r}\right]^3-(3v_{ci}+v_r)\right\}\\ C=\dfrac{1}{(v_{ci}-v_r)^2}\left\{2-4\left[\dfrac{v_{ci}+v_r}{2v_r}\right]^3\right\}\end{cases}\tag{6}$$

3.2 Outage model of WTG

WTG structure is relatively simple, and the maintenance time is short. The maintenance can be arranged at the time of low speed or no wind, so it will not be considered in reliability analysis. From this point of view, the nature of WTG and the traditional generator is the same, so the reliability model of traditional unit can also be used for WTGs. The model contains the normal state and outage state, and the state transition diagram is shown in figure 4.

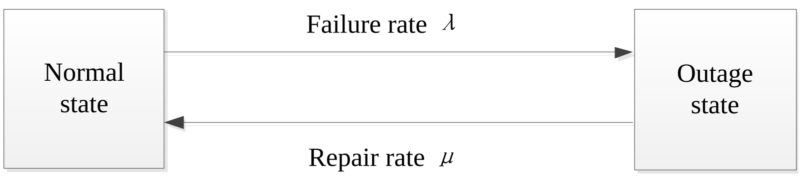

Fig. 4 The model of two states of WTGs

4 RELIABILITY INDEX

At present we always refer to traditional HVDC reliability index to evaluate the reliability of VSC-HVDC system, such as energy unavailability. But for VSC-HVDC system to transmit offshore wind power, the intermittency of wind power should also be included into the reliability index. Therefore, new indices are defined to describe this influence.

According to the CIGRE 14-97 "PROTOCOL FOR REPORTING THEOPERATIONAL PERFORMANCE OF HVDC TRANSMISSION SYSTEMS" and code for statistical reliability standard DL/T 989-2005-main reliability indexes of HVDC system are:

1) The energy unavailability (EU)

$$\mathrm{EU} = \mathrm{E}(\sum EOT_i) / \text{study interval} \tag{7}$$

In the equation, EOT_i is the equivalent outage time of the outage time i in a year. It is numerically the proportion of actual outage time T_i in which the system is at a derated capacity, i.e., $EOT_i = T_i$ = (1- capacity available during the outage / system rated capacity).

2) The energy availability (EA)

$$\mathrm{EA} = 1\text{-}\mathrm{EU} \tag{8}$$

When VSC-HVDC is used as an transmission system to transfer offshore wind power, there will be some new operating conditions due to the intermittent nature of wind power: if the wind speed is low, and the output is relatively small, though the VSC-HVDC is in derated state due to component failure, but wind power is still able to be transmitted by the VSC-HVDC system, and with no losses of power. In such a case, the failure should not be included in the reliability index.

3) Forced outage rate of terminal

Since the VSC-HVDC system (single converter configuration) does not have the conception of monopole outage or bipole outage, i.e., any failure of the component will result in the outage of the whole system. Meanwhile, considering the configuration of multi-terminal system, a new index called forced outage rate of terminal is designed in this paper. This index is shown as:

$$FOR_{Term} = \frac{\lambda}{\lambda + \mu} \cdot \mu \tag{9}$$

where FOR_{Term} is the forced outage rate of a terminal. Usually, if there is no DC breaker installed in the VSC-HVDC system, the outage rates of all the terminals are identical.

5 FLOW CHART

The flow chart of the proposed algorithm is as following.

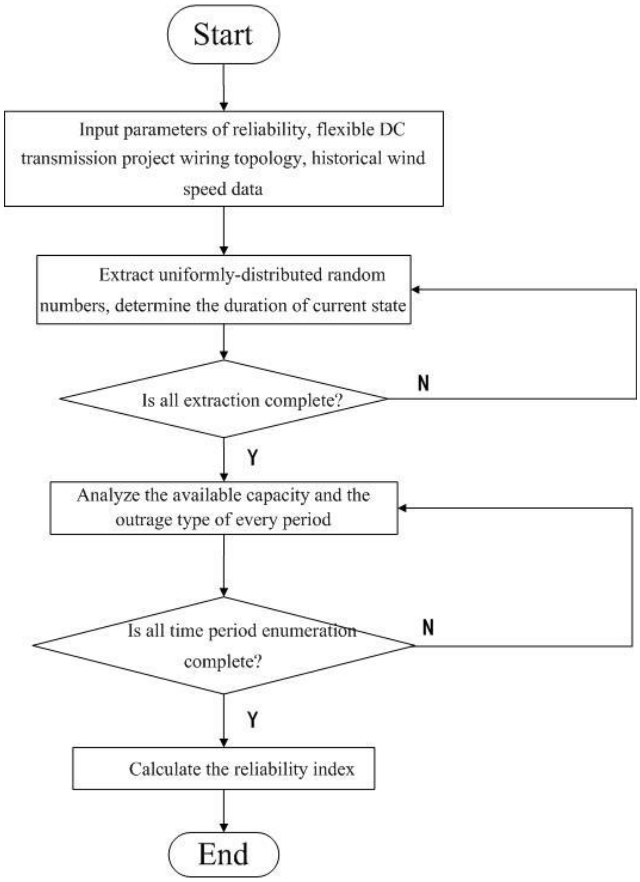

Fig. 5 Flow chart of the algorithm

6 CASE STUDIES

To demonstrate the effectiveness and feasibility of the proposed method, numerical tests are applied on a multi-terminal VSC-HVDC system.

The VSC-HVDC system is used to transmit the wind power to the mainland grid system. Due to the reason that the WTGs in this wind farm are located dispersively, the VSC-HVDC system has been planned to have two sending terminals (Sending Terminal 1 and Sending Terminal 2) and one receiving terminal (Receiving Terminal). The capacity of these two sending terminals are 50MW and 100MW, respectively. The capacity of the reveiving terminal is 200MW, which means that the VSC-HVDC has a redundant capacity of 50MW. The utilization of this redundant capacity is due to the consideration of future expansion of the system. Figure 6 gives the diagram of this VSC-HVDC system.

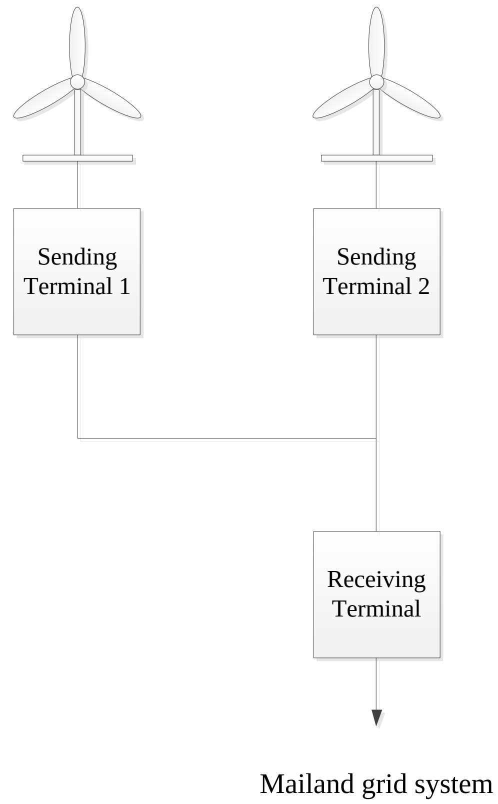

Fig. 6 Diagram of the multi-terminal VSC-HVDC system

Because the reliability evaluation adopts sequential Monte Carlo simulation method, we choose the sequential wind speed model. The wind speed stachastic data are from Referrence [4].

The configuration consisting of the main components of one terminal in the VSC-HVDC system is shown in Fig. 7. The reliability parameters of these main components are as listed in Table 1. The tranmission distances between Sending Terminal 2 and Receiving Terminal and between the Sending Terminal 1 and the Receiving Terminal are assumed to 100km and 50km, respectively. No DC breakers are configured in this VSC-HVDc system.

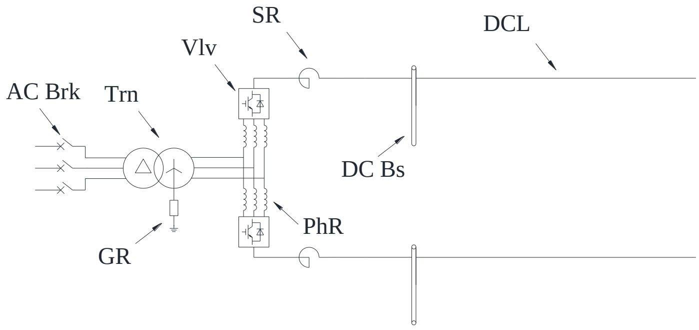

Fig. 7 Configuration of main components in one terminal of VSC-HVDC system

TABLE 1 COMPONENT RELIABILITY PARAMETERS USED IN THE EVALUATION OF THE VSC-HVDC SYSTEM

Components or subsystems	Failure rate (occ. / yr.)	Repair time (hr.)
Transformer (Trn)	0.0675	462
Valve (Vlv)	0.0116	27
AC Breaker (AC Brk)	0.0010	24

DC Line (DCL)	0.14/100km	4
Phase Reactor (PhR)	0.0047	7
Smoothing Reactor (SR)	0.0035	5
Ground Resistance (GR)	0.0010	2
DC Bus (DC Bs)	0.0060	3
Station Control	0.00053	3
System Control	0.000061	2

Note : 1. Station control and system control are secondary equipments, and do not drawn in Figure 7.
2. The failure rate and repair time of WTG are essential in the following study. They are assumed to be 0.073 occ. / yr. and 135 hr., respectively.

6.1 Results of the reliability evaluation of the VSC-HVDC system

The results of the reliability evaluation for the VSC-HVDC system are shown in Table 2.

TABLE 2 VSC-HVDC SYSTEM'S BASIC RELIABILITY INDEX

Index	Value
Energy availability	99.15%
Forced outage rate of Sending Terminal 1	0.513 occ. / yr.
Forced outage rate of Sending Terminal 2	0.513 occ. / yr.
Forced outage rate of Receiving Terminal	0.513 occ. / yr.

It can be seen from Table 1, the energy availability of the VSC-HVDC system reaches as high as 99.15%, which is better than the traditional HVDC system. This is mainly because that the transmission distance of the VSC-HVDC system is short, and the components in the system are less than the traditional HVDC system, which also result in a reduction of the likelihood of forced outage. In addition, the rated total capacity of sending terminals (150MW) is smaller than the rated capacity of receiving terminal (200MW). This redundancy of capacity configuration in the receiving terminal is also beneficial to improve the energy availability of the system.

It can also be seen from Table 1 that the forced outage rates for all of the three terminals are all 0.513 occ. /yr. This is due to the fact that for this tested VSC-HVDC system, there is no DC breaker installed in it, which means any component in the system fails will result in the outage of the whole system. Only after the system is at a power-off state, the switcher disconnects the terminal that failure component is located at, the remaining two terminals can operate in a normal state. In other words, the forced outage rates of all the three terminals are affected by the failure of any single component.

But if a multi-terminal VSC-HVDC system has DC breakers installed, the forced outage rates of the terminals may be different.

6.2 The influence of intermittency of wind power output on the reliability of the VSC-HVDC system.

The influences of intermittency of wind power output on the reliability of the VSC-HVDC system are explained in Table 3 and Table 4. Table 3 gives the available capacity distribution of the VSC-HVDC system without considering the intermittency of wind power. Table 4 gives the available capacity distribution of the VSC-HVDC system considering the intermittency of wind power.

TABLE 3 AVAILABLE CAPACITY DISTRIBUTION OF THE VSC-HVDC SYSTEM WITHOUT CONSIDERING THE INTERMITTENCY OF WIND POWER

The available capacity	Probability	Frequency
1.00	0.9891	0.403
0.67	0.0036	0.144
0.33	0.0036	0.109
0	0.0037	0.155

TABLE 4 AVAILABLE CAPACITY DISTRIBUTION OF THE VSC-HVDC SYSTEM CONSIDERING THE INTERMITTENCY OF WIND POWER

The available capacity distribution	Probability	Frequency
1.0	0.9936	3.371
0.5~1.0	0.0061	4.313
0~0.5	0.0032	1.028
0	0.0000	0.000

It can be seen from Table 4 that, when considering the intermittency of wind power, the probability of available capacity distribution of the system is better than the one without considering the intermittency of wind power. This can be explained as following: since the wind speed is stochastic and volatile, and this stochastic and volatile wind speed will result the change of wind power. Suppose that when a component in the VSC-HVDC system is outage and this will result in derated system state. However, at the same time, if there is no wind or the wind speed is small, so the power output of wind farm is zero or small. And the remaining capacity of VSC-HVDC can still transmit the wind power to the load demand side. In this case, when considering the intermittency of wind power, the component does not result in the power transmission congestion, so the failure of this component does not contribute the derated capacity of the VSC-HVDC system. In other word, when the wind power is less than the remaining capacity of the VSC-HVDC, the failure of the component does not result in the reliability index of unavailibility. For instance, if a component in Sending Terminal 1 fails, so this will lead Sending Terminal 1 outage. And the remaining capacity of the VSC-HVDC system still operates. At this time, the remaining capacity of the system is 100MW. If the wind power at this time is smaller than 100MW, e.g., 40MW, hence the wind power is not hindered. Then the whole VSC-HVDC system can be seen as normal.

It can be observed in Table 3 and Table 4 that the frequencies of capacity states in Table 4 are all greater than the ones in Table 3. This is the reason that the wind power changes dramatically, and lead the capacity states change a lot than the ones in Table 3.

For better comparison, the availability capacity distributions of two cases (without considering wind power and with considering wind power) are listed in Table 5. For the case of without considering wind power, the discrete availability capacity is allocated to the corresponding interval.

TABLE 5 COMPARISON OF THE VSC-HVDC SYSTEM'S AVAILABLE CAPACITY BETWEEN WITH/WITHOUT CONSIDERING WIND POWER

Available capacity distribution	Without considering wind power		Considering wind power	
	Probability	Frequency	Probability	Frequency
1.0	0.9891	0.403	0.9936	3.371
0.5~1.0	0.0036	0.144	0.0061	4.313
0~0.5	0.0036	0.109	0.0032	1.028
0	0.0037	0.155	0.0000	0.000

6.3 Influence of the failure of WTG on the reliability of the VSC-HVDC system

To research the effect of the failure of WTG on the reliability index. The expanded test is conducted under that case of ignoring the failure of WTG. The compared results are shown in Table 6.

TABLE 6 ENERGY AVAILABILITY DISTRIBUTION WITH CONSIDERING OF WTG FAILURE

Available capacity distribution	Considering the failure of WTG		Without considering the failure of WTG	
	Probability	Frequency	Probability	Frequency
1.0	0.9936	3.371	0.9923	3.238
0.5~1.0	0.0061	4.313	0.0074	4.144
0~0.5	0.0032	1.028	0.0003	1.006
0	0.0000	0.000	0.0000	0.000

It can be seen from Table 6, when considering the failure of WTGs, the available capacity distribution is better than that of without considering the failure of WTGs. This is mainly because when considering the failure of WTGs, the output of WTGs is getting worse and the blocking probability of wind power is getting smaller, which will result the reliability of the whole VSC-HVDC system is better.

7 CONCLUSIONS

Conclusions can be drawn from the analysis of the reliability evaluation of the tested HVDC system.

The energy availability of the VSC-HVDC system amounts to 99.15%, which is better than the traditional HVDC system. It is mainly because that the transmission distance of the VSC-HVDC system is short, and the components in the system are less than the traditional HVDC system. In addition, the redundant capacity of receiving terminal is also beneficial to improve the energy availability of the VSC-HVDC system.

The forced outage rates for all of the three terminals are all 0.513 occ. /yr. This is due to the fact that for this tested VSC-HVDC system, there is no DC breaker installed in it, which means any component in the system fails will result in the outage of the whole system.

When considering the wind power, the available capacity distribution of the VSC-HVDC system is better than that without considering wind power. This is the reason that when considering the wind power, not all the failures of the system will contribute the unavailable capacity of the system.

When the failure of WTGs is neglected, the available capacity distribution of the tested VSC-HVDC system is worse than that the failure of WTGs is not neglected. This is due to the fact that when the failure of WTGs is neglected, the wind power is larger than the case that the failure of WTGs is not neglected, and this larger wind power will create more unavailable capacity states of the system when doing the Monte Carlo simulation.

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System Recovery Ancillary Service provided by VSC-HVDC in Transmission Network

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SUMMARY

HVDC systems based on the Voltage Sourced Converter (VSC) technology can provide a variety of network stabilizing functions which were not available with the Line Commutated (LCC) HVDC systems. A unique functionality of VSC-HVDC systems using Forced Commutated Converter (FCC) is the ability of operating in an islanded network where VSC-HVDC is the only power source or is in charge for the network voltage and frequency control. This functionality allows the VSC-HVDC converter to provide System Recovery Ancillary Service (SRAS) during the restoration of an AC transmission network after a Black Out.

The variety of possible network restauration scenarios is very high so that not all possible network configurations can be tested. To define a method for a general verification of the SRAS capability provided by a VSC-HVDC system during AC network restauration, an understanding of the restauration process and the critical aspects for VSC-HVDC systems operating under this conditions is required.

This paper gives an overview of the process to restore operation of the VSC-HVDC system without relying on the external electric power transmission network (Black Start), followed by the description of the requirements, coordination and sequential procedure by which network restoration is performed (SRAS). Considering the high variety of network configurations and network elements which can occur during a network restoration, a generic test environment is proposed which is based on the SRAS relevant network elements and can be parameterized according to specific AC network requirements. The generic test environment allows the SRAS capability verification of a VSC-HVDC system without the need for complex and time consuming network studies.

KEYWORDS

Black Start, Black Out, SRAS, VSC-HVDC, FCC

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1. INTRODUCTION

After a total and unintended loss of electrical power in a transmission network, commonly known as Black Out, the network restoration process has to be started. The requirements, coordination and sequential procedure by which network restoration is performed are described as System Recovery Ancillary Service (SRAS). Gas- and Hydroelectric power stations are the preferred sources for SRAS in the conventional network restoration due to the flexible control and fast ramp up times.
HVDC systems based on the Voltage Sourced Converter (VSC) technology are capable to operate in an islanded network where VSC-HVDC is the only power source or is in charge for the network voltage and frequency control. The functionality of islanded network operation allows the application of the VSC-HVDC converter in the SRAS mode. The SRAS mode of the converter is considered as finished when the primary controls of VSC-HVDC converter is switched to active and reactive power control and the voltage/frequency control is done by generators of thermal power plants.
In the following clauses the network restauration process and a method for SRAS capability verification is presented.

2. VSC-HVDC Black Start

The network restauration is started with the black start of the VSC-HVDC converter station. A black start is the process of restoring a power station to operation without relying on the external AC electric power transmission network. The black start process can be considered as finished when the converter transformer is energized. For VSC-HVDC applications, Black Start is mainly the energisation of the converter station that is not directly connected to the AC network, but through the DC network.
The steps of the VSC-HVDC Black Start process are presented in Figure 1.

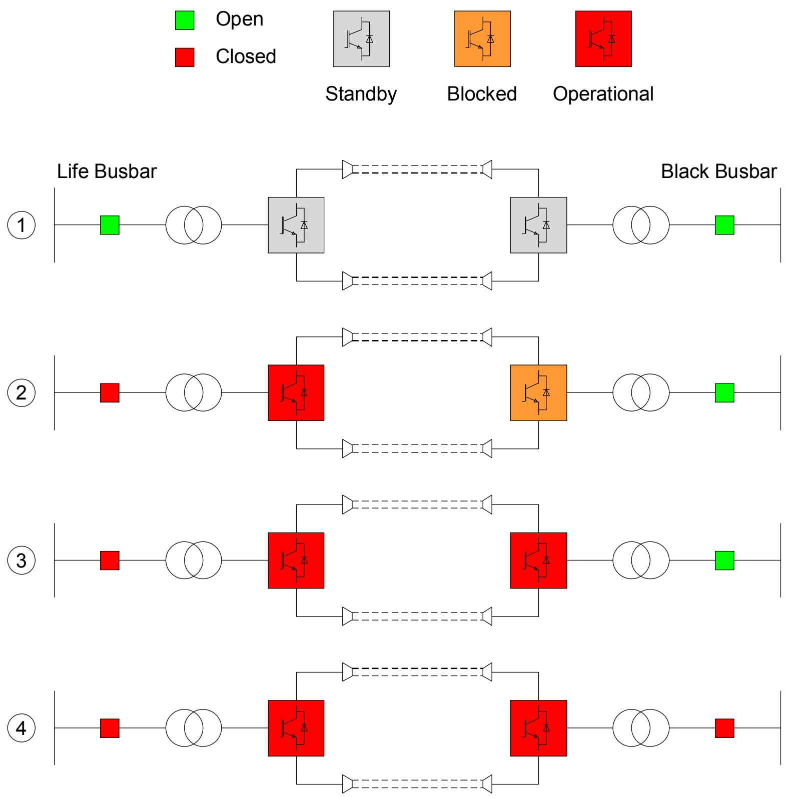

Figure 1 : Black Start Sequence

In initial state, the de-energized VSC-HVDC System is in Standby mode and the AC circuit breakers are open (1). The converter at the life busbar is connected to the network and is energized from the AC side, the converter at the black busbar is then in blocked mode (2). During the energisation of the first converter, the remote converter is charged through the DC side. After the charging process is finished, the remote converter is deblocked and changes into operational mode (3). After the energisation of both converters the AC circuit breaker to the black busbar can be closed (4). The energisation of the busbar closes the black start process and is the first SRAS delivered from the converter.

3. Network Energisation Strategy

During SRAS mode, power is drawn from a remote and strong network connected via the HVDC system (life network according to Figure 1) to the network that has to be restored. With this "bottom up" method of network restauration, the network energisation capability is defined by VSC-HVDC characteristics.

Two general strategies for network recovery are possible using the VSC-HVDC SRAS:

- Collective Network Energisation
- Sequential Network Energisation

Collective Network Energisation, which can be also described as "soft start", is a process where the elements of the network (e.g. lines and transformers), that have to be energized, are connected to each other prior to the application of the voltage. Then the complete network is energized using a defined voltage ramp. The voltage ramp definition depends on the disturbances caused by switched elements (e.g. traveling waves on transmission lines, inrush currents of transformers, etc.) and by the protection systems of the network. The collective network energisation can be used e.g. for initial offshore wind park energisation.

Sequential Network Energisation is a process where the individual elements of the black network are energized sequentially. Transformers, transmission lines, loads, etc. are switched to operational voltage/frequency level following a predefined sequence.

The Collective Network Energisation can be used for the initial energisation only. After the voltage/frequency level has been established, the process of connection additional elements to the network can be considered as Sequential Network Energisation.

The Sequential Network Energisation is more prevalent and has more aspects that have to be considered, such as transient effects. In the following clauses the Sequential Network Energisation is presented. The aspects considered can also be assigned to the Collective Network Energisation process.

4. Sequential Network Energisation

The Sequential Network Energisation can start after the Black Start of the VSC-HVDC system is finished as described in clause 2. The network elements are then connected sequentially to the converter bus bar. The evaluation of the Sequential Network Energisation process can be done by monitoring of voltage and frequency changes in the AC network. For a successful network restauration, the connection of the network elements must not cause a voltage and frequency disturbance outside the specified limits, and the VSC-HVDC System should not trip.

The SRAS capability depends therefore on the network elements connected to the bus bar of the converter. The selection of the network elements to be used for the SRAS capability verification can be generally done by two approaches

1. Simulation of the network restoration based on the real network data
2. Simulation of the network restoration based on the generic model

The first approach is based on the network simulations studies where the interaction between HVDC system and AC network is analyzed. The advantage of this study is the verification of the SRAS capability for the AC network of interest. Unfortunately, this approach has some significant drawbacks. During project execution, only a limited number of network restoration scenarios can be tested. Therefore, a general statement about the SRAS capability cannot be made. In case of new network restauration scenarios, the verification of the SRAS capability has to be repeated. Another drawback is the converter modeling during the SRAS mode. Network simulation studies are done in RMS type models in order to enable the simulation of extended AC network. The RMS type model and the simulation time step might not be sufficient to cover all the relevant functions in the SRAS mode. Therefore, for a reliable analysis of the SRAS capability, an EMTP type model is required.
With the application of an EMTP type model, only a limited AC network can be analyzed. In order to cover all the relevant network elements of a network restauration process a generic network model has to be applied.

4.1 Generic network model

The main purpose of the generic network model application is not to create a network model that can be applied for all VSC-HVDC converters and AC networks, but to create a network topology of relevant network elements. The network elements are then parametrized according to the VSC-HVDC system capability and to the AC network configuration. A network topology which covers the most relevant elements for SRAS analysis is presented in Figure 2.

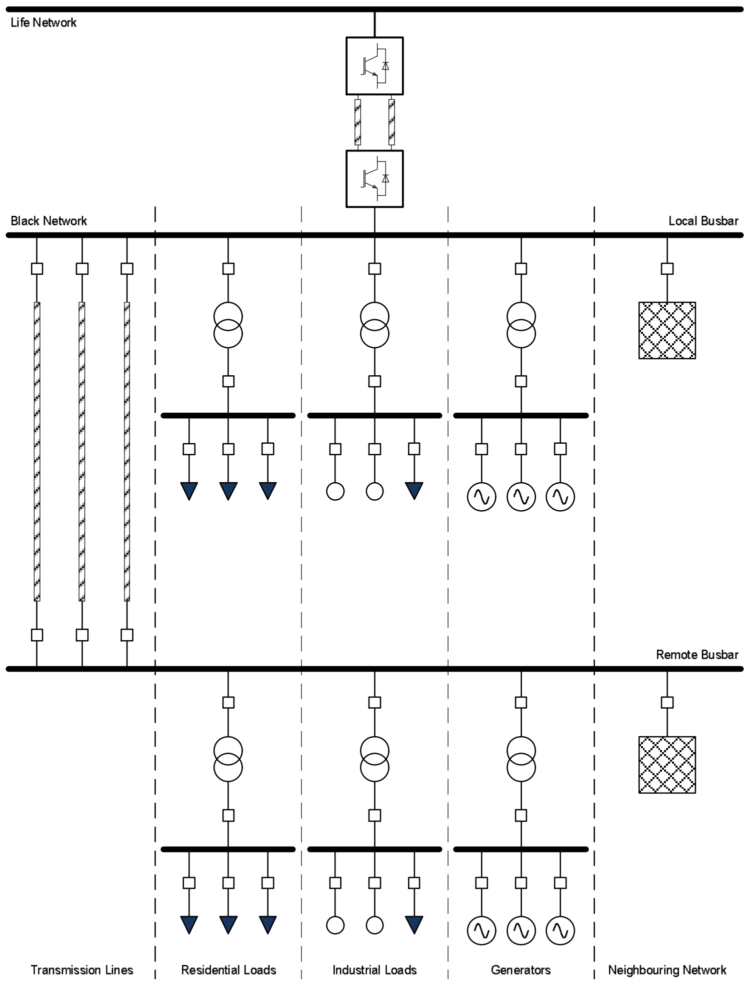

Figure 2 : Generic network topology for SRAS analysis

The main elements considered in the generic network topology are transmission lines, transformers, domestic loads, industrial loads, generators and remote networks. The topology considers especially the connection of the network elements to local and remote busbars to cover transient effects. In the following clauses, the main elements and their relevant parameters are presented.

5. Definition of parameters for the SRAS capability evaluation

5.1 Voltage and frequency disturbance definition

The connection of AC network elements to an existing non-ideal voltage source will cause voltage and frequency disturbance in the network. The maximum disturbance allowed in the AC system depends on the connected loads and might change during the AC network restauration process. Assuming that the load shedding protection can be activated at a network frequency of $f \leq 49$ Hz in a 50 Hz network, connecting elements should cause a frequency change of $\Delta f \leq 0.8$ Hz [1]. The final definition of the voltage and frequency disturbance has to be done by AC network operator and specified as design criteria for SRAS.

5.2 Transmission lines & transformers

The connection of unenergized transmission lines cause steady state and transient effects, which must not cause a disconnection of the VSC-HVDC system. Transient effects depend on the transmission line type (OHL, cable), configuration (mast type) and transmission line length. Therefore, different transmission line configurations should be considered in the SRAS verification. For German AC power grid, the line distances of 50km, 100km and 350 km and Danube configuration is representative [2]. The transient effects relevant during the energisation are switching overvoltages, travelling waves and resonances (incl. Ferroresonances). After decay of the transient effects, the reactive power demand of the transmission line has to be provided by the VSC-HVDC system, which must have sufficient reactive power capability.

Transformer connection causes, in the first step, AC network stress by inrush currents. The inrush currents themselves depend on the pre-magnetization, time point of connection and the transformer size. In comparison with the SRAS provided by conventional generators, the overcurrent capability of a VSC-HVDC system is limited. Therefore the connection of transformers can cause a high voltage drop in the AC network if the inrush currents are not limited by other measures such as point on wave switching. The limitation of voltage drop, might limit the capability of transformer connection in the SRAS process.

Transformer connection also changes the total network AC network impedance. In an AC cable network, the connection of transformers can initiate harmonics, which can cause the destabilization of the AC network. Since the destabilization of the AC network also depends on the converter control, the full evaluation has to be done with the full converter control modeling in a small time step (< 1 ms).

5.3 Loads definition

Power consumption of elements connected to the network during Sequential Network Energisation ranges for the existing network recovery strategies between 5 MW and 30 MW. The upper limit of a power consumption block should be 10 % of the power supply station and is limited to 100 MW. Generally, resistive, capacitive and inductive loads are connected. Domestic and industrial loads are mostly inductive. Typical power factors are $\cos\varphi = 0.9$ for domestic and $\cos\varphi = 0.85$ for industrial loads [3]. The definition of the loads must also take into account that the reactivation of the loads after a system Black Out might cause significantly higher power consumption than before the load (“Cold Load Pick-Up) [4].

Special stress to the VSC-HVDC systems is created by motor loads. Motor loads are usually responsible for 60% of the loads in an electrical AC network. The majority of the motor loads (app. 95%) are provided by asynchronous machines. Depending on the motor size and the ramp up strategy, initial motor currents can be in the range 6-8 p.u. of nominal motor currents. Therefore, the maximum load definition cannot be done by power block definition only, but has to take the initial currents into account in case a high motor power is installed.

5.4 Synchronising Additional Generating Units

Additional generating units are connected to the network using the same procedures as under integrated network condition. The generator is accelerated and a synchronising relay is controlling frequency and voltage produced by the generator to obtain the required synchronism with the network. The connection of additional generators requires control settings coordination between the VSC-HVDC and the generators to create the desired load sharing. During generator synchronisation the VSC-HVDC should not trip, nor do cause voltage or frequency disturbances outside the specified limits. For the modelling of the additional generator units connection, a full VSC-HVDC converter generator control has to be used.

5.5 Re-Synchronising the Network to the Remote Networks

The re-synchronisation is a switching event that establishes a connection between a life but yet islanded network and the integrated network. The re-synchronisation is done with a circuit breaker equipped with a synch-relay. To allow these relay to work properly the frequency and voltage deviation across the open breaker has to be within certain range which is defined by AC network and the AC circuit breaker. Typical values are in the range of 100-200 mHz.
After the connection to the integrated network, SRAS mode of the VSC-HVDC system is considered as finished.

6. CONCLUSION

For the evaluation of SRAS capability with VSC-HVDC systems a generic network-topology with specific network elements was presented. The network-topology has to be parametrized based on the AC network configuration which has to be restored after a Black Out. The relevant parameters for the network elements were presented and default proposed.
The SRAS verification with the generic network-topology provides a general evidence of the SRAS capability with VSC-HVDC systems and ensures that all the relevant aspects of the network restauration process are considered.

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A Novel Control Strategy for MMC-HVDC Connected to Passive Networks

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SUMMARY

Modular Multilevel Converter Based VSC-HVDC（MMC-HVDC）has great application prospects for power in-feed of passive networks, such as city center, distributed islands, offshore gas platforms, etc, because of its control flexibility. In this case, the key task of MMC-HVDC is providing stable AC voltage for passive networks. Output voltage feedback control in synchronous frame is generally adopted, to achieve zero steady error and fast dynamic performance. However, when considering large amount of harmonics introduced by switching devices and non-linear loads in some passive networks, the conventional control strategy may not be satisfactory. The various-order harmonic current flowing through arm buffer inductors will severely distort the output voltage waveform, and the abstraction and suppression of harmonics in synchronous frame could be onerous tasks.

This paper firstly introduces the circuit configuration and operation mechanism of MMC-HVDC connected to passive networks. A generalized mathematical model for MMC-HVDC is deduced. On this basis, analysis of arm buffer inductors designing process based on per-unit value is carried out, which reveals the relationship between the harmonics current and the output voltage THD. To improve the output voltage quality, a novel control strategy with parallel resonant controllers in stationary frame is proposed. The resonant controller has nearly infinite gain at the controlled frequency, which ensures zero-steady-state-error tracking of sinusoidal-wave reference, without coordinate transforming. On the other hand, the parallel structure can suppress the selected-order harmonic, to improve the quality of MMC-HVDC power supply. The parameter designing criterion for the parallel resonant controllers is also discussed. The results show that due to the inherent characteristics of MMC-

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HVDC, the parameter designing process is quite simple. Moreover, it is possible to suppress all the integer-order harmonics content within the control frequency.

A 49-level MMC-HVDC model is established in Matlab/Simulink. The passive network to be fed contains a large rectifier load. The 5^{th}, 7^{th}, 11^{th}, and 13^{th} harmonics are selected to be suppressed with the proposed control strategy. The simulation results show that smooth sinusoidal output voltage is obtained and the parameter designing process is quite simple.

KEYWORDS

Modular Multilevel Converter, Passive Networks, Buffer Inductor, Parallel Resonant Controller, Harmonic Suppression

I. Mathematical Model of MMC

The structure of MMC-HVDC connecting passive networks is shown in Figure 1. Each phase of MMC contants an upper arm and a lower arm, between which are buffer inductors. There are *N* submodules in the upper and lower arms, respectively. Each submodule consists of a storage capacitor, two IGBTs and two antiparallel diodes, to form a half-bridge circuit. u_{Uj} and i_{Uj} are the voltage and current of the upper arm of the j(j=a，b，c) phase. u_{Lj} and i_{Lj} are the voltage and current of the lower arm of the j phase. u_o *and* i_o are the output voltage and current of MMC, which are also the power supply of passive networks. U_{dc} is the dc-link voltage of MMC, maintained by HVDC system.

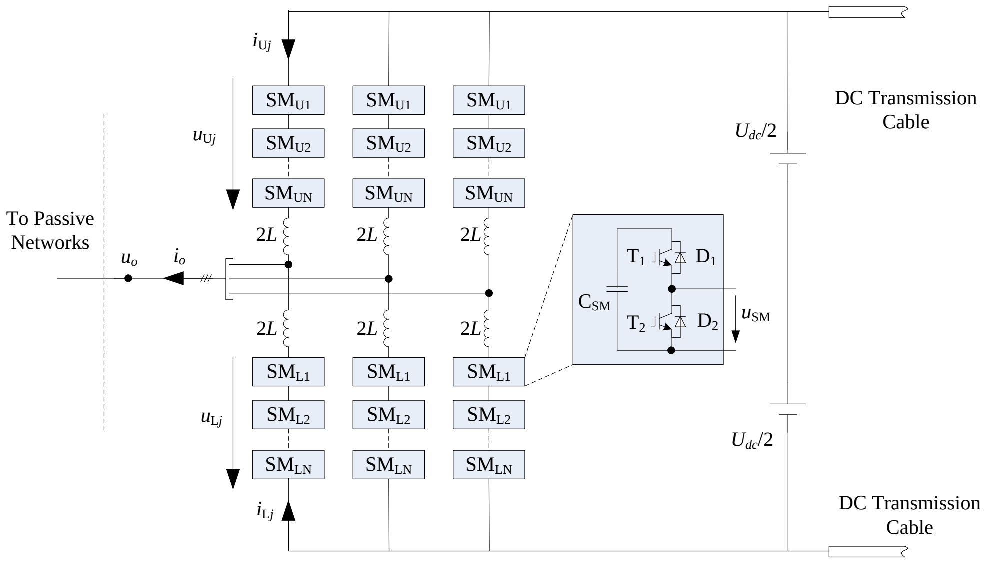


Figure 1 MMC-HVDC connecting passive networks

According to Kirchhoff's current law, the relation between output current and arm current can be obtained as

$$i_{oj} = i_{\mathrm{U}j} + i_{\mathrm{L}j} \tag{1}$$

Taking the neutral point *n* of the dc link as the reference point, the voltage equations can be written as

$$u_{oj} + 2L\frac{di_{\mathrm{L}j}}{dt} + 2Ri_{\mathrm{L}j} = u_{\mathrm{L}j} - \frac{U_{dc}}{2} \tag{2}$$

$$u_{oj} + 2L\frac{di_{\mathrm{U}j}}{dt} + 2Ri_{\mathrm{U}j} = -u_{\mathrm{U}j} + \frac{U_{dc}}{2} \tag{3}$$

where R is the equivalent series resistance of buffer inductors. Adding (2) and (3), one can obtain

$$u_{oj} + L\frac{di_{oj}}{dt} + Ri_{oj} = \frac{u_{\mathrm{L}j} - u_{\mathrm{U}j}}{2} = e_j \tag{4}$$

e_j is the imaginary inner alternating voltage generated in phase j [1]. According to (4),if the inner alternating voltage is regarded as the input variable, the converter output voltage and current can be directly controlled, then the widely used vector control based on synchronous coordinates in two-level VSC topology can be adopted to MMC[2]. However, when considering large amount of harmonics introduced by switching devices and non-linear loads in passive networks, the conventional vector control may not be satisfactory.

II Impact of Buffer Inductors on MMC Output Voltage Waveforms

Buffer inductors are indispensable parts for MMC, which have three important functions[3]:

a) Due to the discrepancy of three phase arm voltage, circulating current appears among the three- phase unit. Circulating current will do harm to the design and safe operation of the power devices and increase power losses. Buffer inductors can reliably minish circulating current.

b) Buffer inductors can restrain rate of current rise effectively under short circuit fault. Especially for the DC pole to pole fault, the peak surge current is mainly determined by the value of buffer inductors.

c) According to (4), the upper arm inductor and lower arm inductor are parallel at the output side, which can be regarded as output impedance of MMC, therefore affect the operation range of MMC.

For different functions, there are different design rules for buffer inductors. In the following analysis, the output voltage u_{oj} and output current i_{oj} are taken as the standand of per unit.

The desired inner alternating voltage e_j is assumed to be a sine wave

$$e_j = m\frac{U_{dc}}{2}\cos(\omega_0 t + \varphi_j) \tag{5}$$

where m is the modulation index. Thus (4) can be rewritten as

$$u_{oj} + L\frac{di_{oj}}{dt} + Ri_{oj} = m\frac{U_{dc}}{2}\cos(\omega_0 t + \varphi_j) \tag{6}$$

From (6) one can see that m is closely related to L. Assuming u_{oj}=1pu, i_{oj}=1pu, U_{dc}=2.8pu, to avoide overmodulation, L should not exceed 0.4pu.

From the viewpoint of suppressing circulating current, the relation between buffer inductors and circulating current is[4]

$$2L = \frac{1}{4\omega_0^2 C_{\mathrm{SM}} U_C}\left(\frac{S}{3I_{cirm}} + U_{dc}\right) \tag{7}$$

where S is apparent power of MMC, I_{cirm} is the peak circulating current, U_C is the submodule capacitor voltage. Submodule capacitor parameter C_{SM} can be calculated as[5]

$$C_{\mathrm{SM}}=\frac{S}{3mN\omega_o\varepsilon\left(U_C\right)^2}\left[1-\left(\frac{m\cos\varphi}{2}\right)^2\right]^{\frac{3}{2}} \tag{8}$$

where N is the number of submodule of each arm, ε is the fluctuation percentage of U_C, $\cos\varphi$ is the power factor. Assuming $N\times U_{\mathrm{C}}=U_{dc}$ under steady condition, substituting (8) into (7) , L can be expressed as

$$L=\frac{\frac{3m\varepsilon U_{dc}}{8\omega_o S}\left(\frac{S}{3I_{cirm}}+U_{dc}\right)}{\left[1-\left(\frac{m\cos\varphi}{2}\right)^2\right]^{\frac{3}{2}}} \tag{9}$$

From (9) one can see that the larger arm inductor is, the severer the fluctuation of capacitor voltage is, on the contrary, the smaller circulating current becomes. Assuming U_{dc}=2.8pu, m=0.9, $\cos\varphi$=0.9, ε=5%, S=3.33pu, to restrict I_{cirm} within 0.2pu, L need to be larger than 0.09pu.

From the viewpoint of restraining rate of current rise under DC pole to pole fault, L should satisfy[5]:

$$2L=\frac{U_{dc}}{2\alpha} \tag{10}$$

where α is the rate of surge current rise. To restrict α within 0.2pu per second, L need to be larger than 0.07pu.

In conclusion, the value rang of arm inductor is 0.09pu<L<0.4pu. Considering cost and volume, L is designed as 0.1pu in this paper. The designing process above is based on per-unit value, which has universal sense.

If passive networks connected to MMC-HVDC contain several switching devices and non-linear loads, large amount of harmonics will be introduced to MMC output current. Consequently, the various-order harmonic current flowing through arm inductors will severely distort the output voltage waveform. For example, assuming arm current contain 5% five-order harmonic, the voltage drop caused by harmonic is $5\omega_0 L\times 5\%$=0.025pu, which means THD of MMC output voltage will increase 2.5%. The power quality of passive networks is seriously deteriorated. Thus, it is necessary to take measures to supress the output voltage harmonic.

Ⅲ MMC Output Voltage Control Strategy Based on Parallel Resonant Controllers

The control object of MMC connecting to passive networks is to obtain stable and sinusoidal output voltage waveform. To achieve this, both PI controllers in synchronous frame [6] and Proportional+Resonant(PR) controllers in stationary frame [7] could be adopted. It has been proved that they are mathematically equivalent [8]. In this paper, PR controllers in stationary frame are choosen, as the coordinate transformation and the phase-locked loop (PLL) can be avoided. The transfer function of PR controllers can be written as

$$k_p + \frac{k_{ri} s}{s^2 + \omega_i^2} \tag{11}$$

where k_p *and* k_{ri} are proportional coefficient and resonant coefficient respectively. ω_i is the resonant frequency designed to coincide with the frequency of a sinusoidal reference input. Figure 2 gives the Bode diagram of PR controllers when k_p=1,k_{ri}=5, ω_i=100π. It can be seen that the gain of transfer function increases to infinity at the resonant frequency. This ensures zero-steady-state-error tracking of sinusoidal reference. Furthermore, one can observe that PR controllers have strong bandpass characteristics, which means several PR controllers can function simultaneously and independently.

Based analysis above, a novel control strategy with parallel resonant controllers is proposed in this paper, to suppress selected order harmonics. Since triple frequency current can't circuit in most passive networks, there is no need of triple frequency resonant controllers. Block diagram of proposed control strategy is shown as Figure 3, where

$$G_{PR} = k_p + \sum_{i=1,5,\ldots,n} \frac{k_{ri} s}{s^2 + \omega_i^2} \tag{12}$$

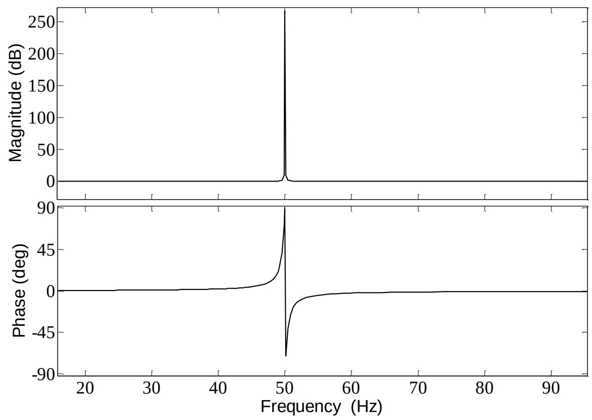


Figure 2 Bode diagram of PR controller when k_p=1,k_{ri}=5, ω_i=100π

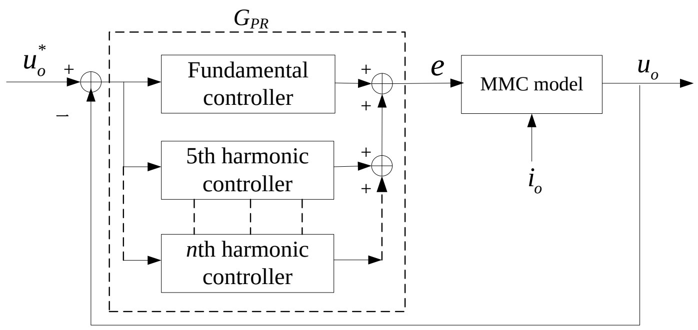


Figure 3 Block diagram of proposed control strategy

According Figure 3 and equation(4), MMC output voltage can be expressed as

$$u_0 = \frac{G_{PR}}{1+G_{PR}} u_o^* - \frac{Ls+R}{1+G_{PR}} i_o \tag{13}$$

One can see that the MMC output current i_o can be treated as disturbance for u_o, which is determined by passive networks. Since G_{PR} has infinity gain at the resonant frequency, one can obtain from (13)

$$u_0 = u_o^* \tag{14}$$

So the proposed control strategy can achieve zero steady error and totally eliminate the disturbance of low order output current. Substituting (12) into (13), u_o can be rewritten as

$$u_o = \frac{k_p + \sum\limits_{i=1,5,\ldots,n} \frac{k_{ri}s}{s^2+\omega_i^2}}{1+k_p + \sum\limits_{i=1,5,\ldots,n} \frac{k_{ri}s}{s^2+\omega_i^2}} u_o^* - \frac{Ls+R}{1+k_p + \sum\limits_{i=1,5,\ldots,n} \frac{k_{ri}s}{s^2+\omega_i^2}} i_o \tag{15}$$

It is obviously that the order of characteristic equation is very high, which means to design the controller parameters by the traditional poles assignment strategy is very difficult. As for two-level voltage source inverter(VSI), because of the phase lag introduced by LC filter, higher order harmonics will lag behind lower order harmonics. Thus resonant coefficients at different frequency should be different[9]. Reference [10] adopts a kind of resonant controllers with phase compensation function to solve this problem, but the phase compensation for each is also hard to design. Actually, since there is no LC filter on the output side of MMC, it is much easier to design controller parameters compared to two-level VSI. One can see from (13) that G_{PR} is the only element affecting system performance, while each resonant controller in G_{PR} functions independently as described above. Thus, with the same coefficients k_{ri}, identical dynamic performances and system stability can be achieved at all resonant frequencies. That means there is no need to design resonant coefficients separately. In other words, $k_{r1}=k_{r5}=\cdots\cdots=k_{rn}$ can be achieved. As a result, the control parameters designing process is significantly simplifed.

Further more, because of the strong bandpass characteristics of resonant controllers, the magnitude-phase characteristics of the systerm is exactly the same within controlable frequency. Therefore, it is possible to suppress all the integer-order harmonics content within the MMC control frequency.

IV Simulation Verification

A 49-level MMC-HVDC model is established in Matlab/Simulink. The passive network is fed by MMC-HVDC through a 31kV/10kV transformer, as shown in Figure 4. To validate harmonic suppressing performance of proposed control strategy, the passive network contains a rectifier load, which introduces large amount of harmonic to the network. The simulation parameters are shown in Table I. The simulation results of conventional feedback control in synchronous frame and proposed control are compared as follows.

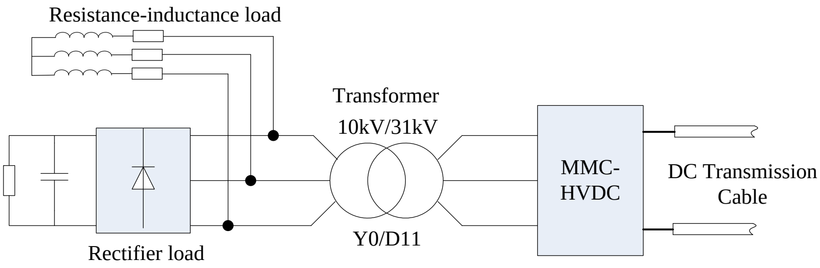
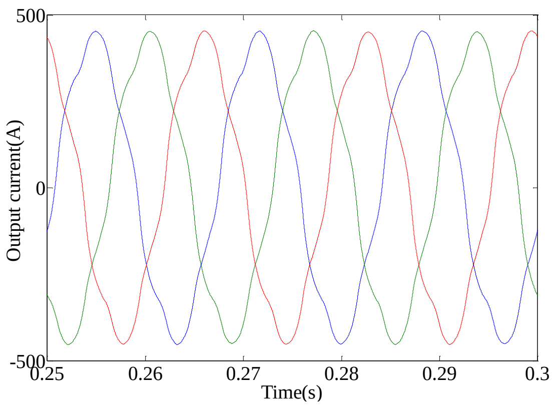


Figure 4 Setup of Simulation Model

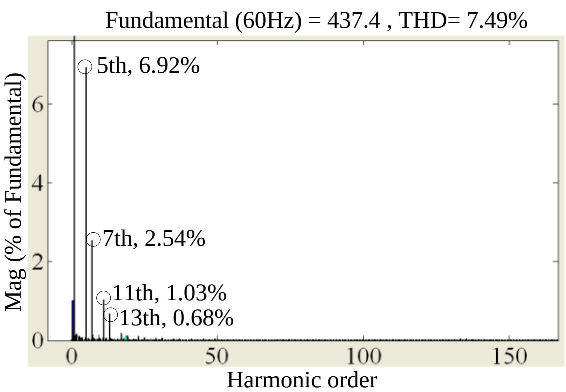
Table I SIMULATION PARAMETERS

parameters	values
Number of submodules of each arm N	48
DC transmission voltage U_{dc}	±30 kV
Submodule capacitor C_{SM}	3.7mF
Arm buffer inductor L	17.2mH
Arm Equivalent resistance R	0.1Ω
Control frequency f_s	8100Hz
Fundamental frequency f_o	60Hz
Rated apparent power of MMC S	20MVA
Rated output line voltage of MMC u_o	31kV

Figure 5 shows that the output line current of MMC-HVDC contains large amount of harmonics, where the 5^{th}, 7^{th}, 11^{th}, and 13^{th} harmonics are the dominant components. As a result, the output line voltage waveform with conventional control strategy is also seriously distorted, as shown in Figure 6, which might harm other equipments in the passive network. Besides the same order harmonics as output line current, the output line voltage also contains some 135^{th} sideband harmonics, which is caused by MMC control frequency(8100Hz/60Hz=135). Figure 7 shows the inductor voltage, arm voltage and SM capacitors voltage of phase A upper arm.It can be seen that the arm voltage is smooth sinusoidal. However, the inductor voltage contains large amount of harmonics, superimposing on the arm voltage to cause MMC output voltage distorted.

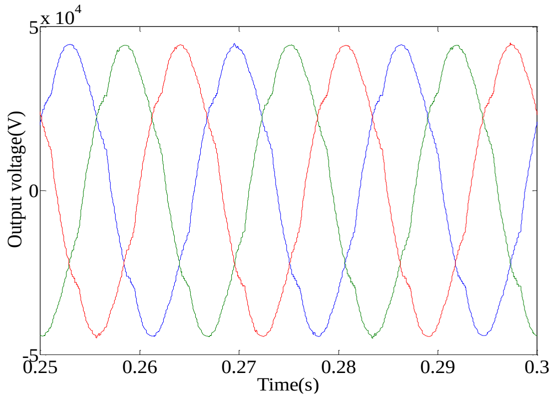


(a)

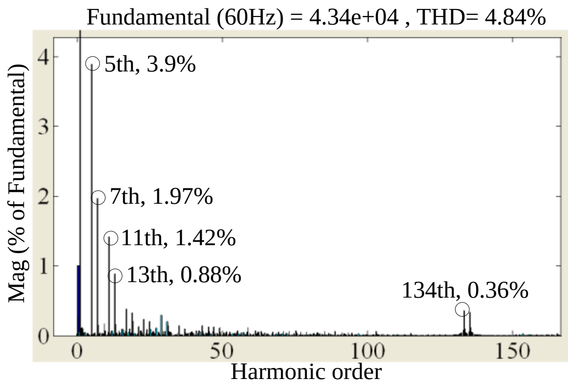


(b)

Figure 5 Output line current and its frequency spectrum of MMC-HVDC feeding rectifier load



(a)



(b)

Figure 6 Output line voltage and its frequency spectrum of MMC-HVDC with conventional control

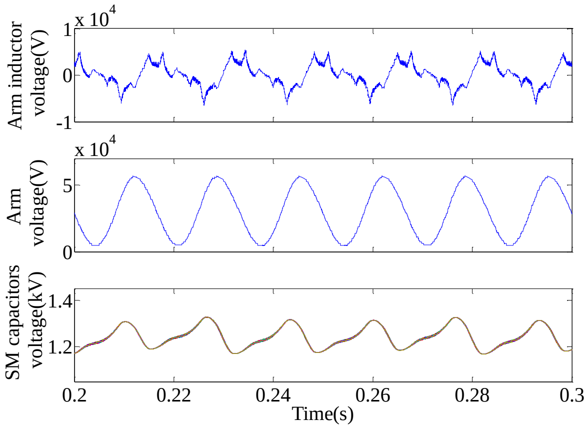
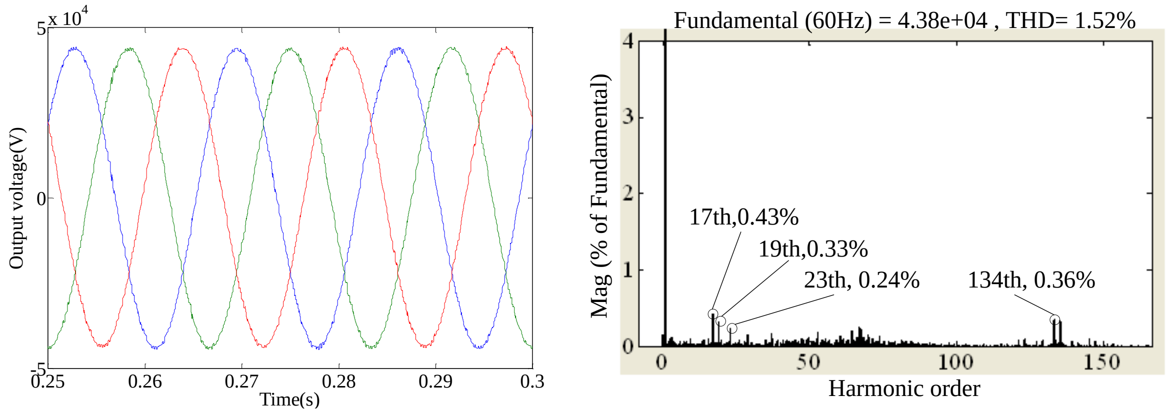


Figure 7 Arm inductor voltage, arm voltage and SM capacitors voltage of MMC-HVDC with conventional control

Figure 8 shows output line voltage and its frequency spectrum of MMC-HVDC with proposed control strategy. The 5^{th}, 7^{th}, 11^{th}, and 13^{th} harmonics are selected to be suppressed with parallel resonant controllers. The control coefficients are chosen as k_p=1, k_{r1}=k_{r5}=k_{r7}=k_{r11}=k_{r13}=500, which means the controllers are quite easy to tune. It can be seen from Figure 8 that smooth sinusoidal output voltage is obtained, and THD is lower than 2%. The uncontrolled 17^{th}, 19^{th}, 23^{th}, and higher order harmonics still exist, which can be easily eliminated by parallelling more resonant controllers. Figure 9 shows the inductor voltage, arm voltage and SM capacitors voltage of phase A upper arm with proposed control strategy. It can be seen that the arm voltage is no longer smooth sinusoidal, conversely contains large amount of harmonics.That is exactly what compensates the distortion of inductor voltage, and ensures the output voltage quality. In the meanwhile, compareing SM capacitors voltage in Figure 7 and Figure 9, one can see that the proposed control stratgy will not deteriorate voltage-balancing performance among SM capacitors.



(a) (b)

Figure 8 Output line voltage and its frequency spectrum of MMC-HVDC with proposed control strategy

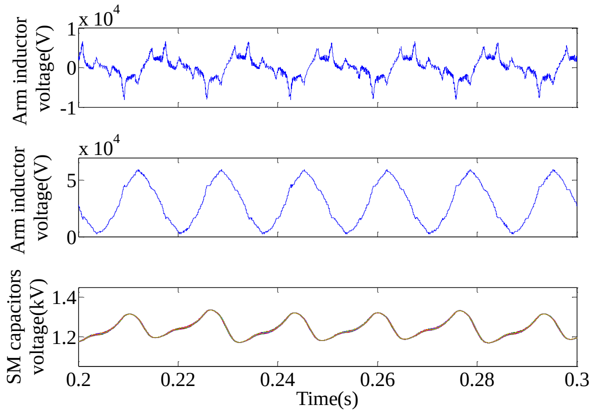


Figure 9 Arm inductor voltage, arm voltage and SM capacitors voltage of MMC-HVDC with proposed control strategy

V Conclusion

MMC-HVDC has great application prospects for power in-feed of passive networks, because of its control flexibility. However, when passive networks contain switching devices or non-linear loads, harmonic current flowing through arm buffer inductors will severely distort the output voltage waveform of MMC-HVDC. A novel output voltage control strategy based on parallel resonant controller in stationary frame is proposed. It can compensate the harmonics selectively and totally without coordinate transforming, to improve the quality of MMC-HVDC power supply. Moreover, due to the inherent characteristics of MMC-HVDC, parameter designing process for the proposed control is quite simple.

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Bipolar High Power Semiconductors for efficient HVDC Energy Transmission

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SUMMARY

The improvements in thyristor technology described in the paper will lead to more efficient thyristor valves for HVDC systems.
The 6-inch Light Triggered Thyristor (LTT, **Fig. 1**) is ready for application in all future HVDC transmission projects with ratings of up to 10..14 GW at DC currents of 5000 A to 6250 A and voltages of up to ±1100 kV. It will considerably reduce the complexity of the valves by eliminating electrical trigger and external protection functions.
The application oriented pulse peak method for routine tests of the voltage withstand capability will enable utilization of 9.5 kV reverse blocking capability. This results in a reduction of the number of series connected elements in a valve or at least a constant number of devices if voltage stresses on single elements increase due to higher stresses of the valves at increased currents up to 6250 A. The increased blocking capability in line with the high current and surge current capability (140 kA/70 kA) due to the Low Temperature Sintering Technology (LTS) makes it possible to cover the whole range of feasible applications of 6-inch-thyristors with one single device. Other manufacturers need to use different classes of blocking voltages to cover the individual current and voltage requirements.
The protection functions against overvoltage (BOD) and voltage rise (dv/dt) had already been integrated into the LTT thyristors. However, a new integrated Forward Recovery Protection (FRP) function has been recently successfully verified during routine testing of several hundred LTTs. As all other features of the thyristor remain unchanged the FRP function can now also be implemented in all other types of LTTs.

With completion of this step only three types of LTTs (4-, 5- and 6-inch with 9.5 kV reverse blocking voltage capability) will be available to cover the whole power and voltage range of HVDC transmission technology without the need for any electrical triggering or protection function leading to simple and reliable thyristor valve design.

KEYWORDS

Thyristor, Light Triggered, Integrated Protection, Forward Recovery Protection (FRP), Puls Peak

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1. Application driven demands for Bipolar Semiconductors

To enable economic transmission of large amounts of electrical energy from power generation centres to load centres High Voltage Direct Current (HVDC) transmission using Line Commutated Converters (LCC) has been established as the preferred technology. Although in recent years Voltage Sourced Converters (VSC) with IGBTs have gained increasing importance, thyristor devices are still favoured for applications in which ultra high voltages and high currents have to be controlled, because they have the best performance in terms of on-state losses and symmetric blocking capability. Thyristors are also used in Static Var Compensators (SVCs), like Thyristor Switched Capacitor (TSC) and Thyristor Controlled Reactor (TCR). In addition, bipolar semiconductor discs are applied as bypass thyristors (Crow Bar) or freewheeling diodes in HVDC VSC.

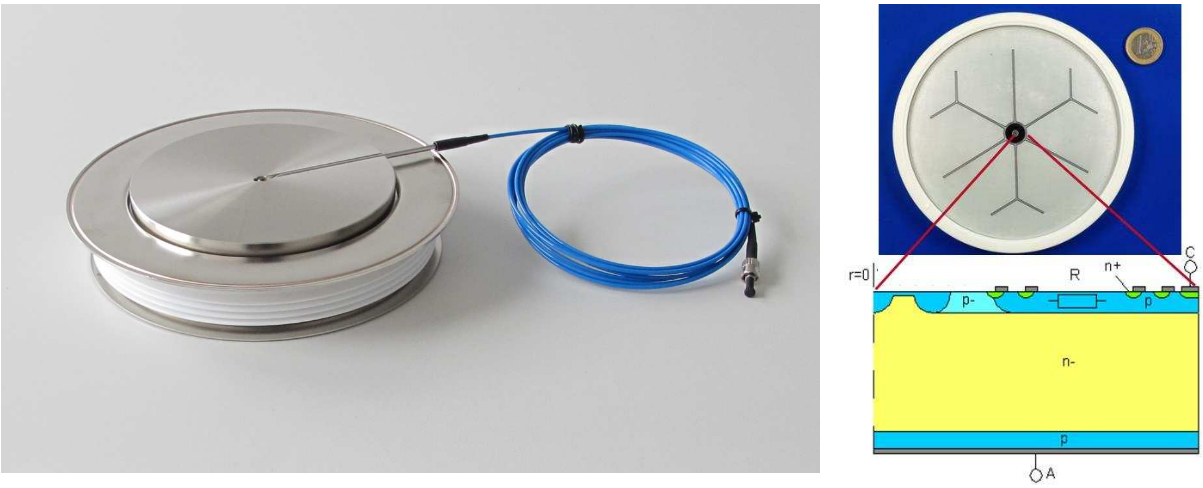

Fig. 1: 6-inch Light Triggered Thyristor LTT with integrated self-protection functions (a) V_{RRM}=9.5 kV; I_{DC}=6250 A; I_{TSM}>140 kA and corresponding Semiconductor Wafer (b)

While HVDC transmission is becoming more and more important and installed transmission capacities are growing on a rapid pace many customers are asking for lower costs along with increased reliability and availability, aiming also at extended maintenance periods. A feasible way to meet both goals is to reduce the complexity of the thyristor converters. This can on one hand be achieved by reducing the number of series connected elements which will also reduce the number of auxiliary components at the thyristor levels. The required higher blocking voltage capability of the thyristors can not only be implemented by increasing the thickness of the silicon wafers (which would also increase the losses) but also by more realistic definition and application of testing procedures. The real voltage wave shapes in an operating converter are non-sinusoidal containing steep voltage changes as well as repetitive transient voltage peaks caused by current extinction of thyristors. Testing is usually performed using pure sine wave voltages, which are easily available in test facilities, with amplitudes corresponding to the ones of the transient stresses. This procedure leads to higher stress of the tested elements than in the actual application. The use of more realistic wave shapes for thyristor testing helps to enable better utilization of thyristor voltage capabilities. Corresponding investigations have been performed leading to a test procedure using a sine wave blocking voltage with a superimposed short peak voltage **"Pulse Peak Measurement" (chapter 3)**.

Another possibility to reduce complexity of the valves is to integrate electronic functions into the thyristor which up to now are implemented in the valves as separate electronics boards. After eliminating the need for electric trigger circuits and external overvoltage protection as well as dv/dt protection now the last issue, namely the protection against forward transient voltages during the recovery period **(Forward Recovery Protection FRP)**, is solved.

A combination of thyristor modification together with application of an additional optical trigger pulse is used to replace the previously necessary electronics board (**chapter 4**). To omit this external electronic circuitry saves costs and improves the reliability ("Whatever is not present cannot fail").

For Ultra high power UHVDC links (e.g. 10 GW, 800 kV), DC-transmission currents of 6250A and very high surge currents are required. In case one thyristor valve loses its blocking capability the valve which fires next in the same half bridge will initiate a two phase transformer short circuit. Due to the low impedance of the high power transformers necessary for this kind of links short circuit currents will increase from 50kA in the “conventional” 800kV links to > 60kA in this future application. To meet this requirement and to simultaneously improve performance and reliability of the thyristor converters the 6-inch electrically triggered thyristor **[2]** used up to now was enhanced to a **6-inch Light Triggered Thyristor**. While meeting the nominal DC current requirements **(6250 A)** as well as the short circuit current requirements **(>70 kA) (Tab. 1, chapter 5.1)** the voltage withstand capability could be maintained (in fact, it could even be slightly increased to $\mathbf{V_{RRM}}$**=9.5 kV**). Typically, low loss design and technology (on-state and turn-off) by optimised charge carrier lifetime control are becoming more important for advanced HVDC transmission **(chapter 5.2)**.

2. Key Design and Technology of Bipolar Semiconductors for Ultra High Power Applications

2.1. Integrated Protection Functions for Overvoltage and dv/dt

Full advantage of the Light Triggered Thyristor is achieved, when safe fault triggering structures are introduced which protect the device in case the limits of the forward breakdown voltage or voltage rate of rise dv/dt are exceeded. The integrated overvoltage protection function realised by Break Over Diode (BOD) provides an efficient and reliable controlled turn on when the forward blocking voltage reaches values between 8 kV-9.5 kV **[3]**. Apart from the overvoltage protection function also a dv/dt protection function was integrated into the thyristor **[4]**.

2.2. Key Parameters for Silicon Wafers

State of the art silicon wafer technology enables the production of highly pure und defect free n-type float zone silicon wafers needed for high blocking voltages up to 9.5 kV. These wafers are doped via neutron transmutation to obtain a homogeneous resistivity distribution across the entire wafer in the n^--zone **(Fig 2a)**. The resistivity is in the range of 430 Ω·cm to 500 Ω·cm. The typical standard deviation for a pre- processed wafer is < 1%.

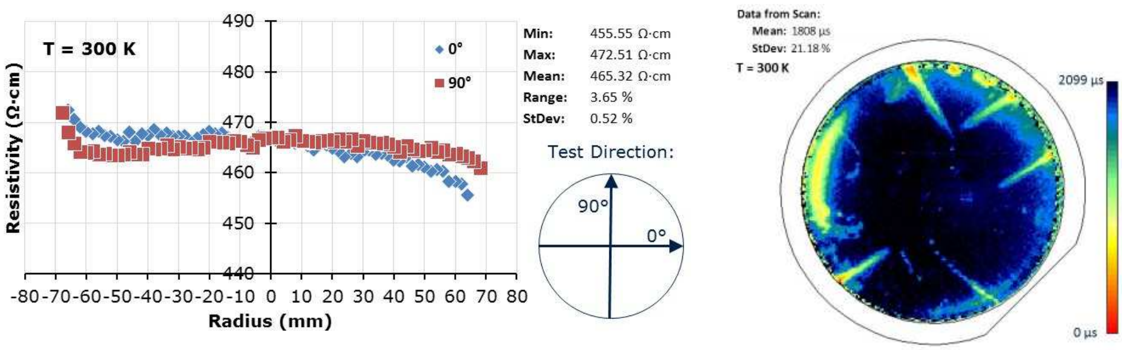

Fig. 2: Lateral distribution of resistivity (a) and distribution of carrier lifetime (ELYMAT) (b) of a pre-processed 6-inch wafer (thickness: ~1.5 mm)

An extremely low concentration of impurities in the base region of power devices is very important to obtain low leakage currents and on-state voltages and to enable well-defined control by means of lifetime controlling like electron irradiation. Therefore, high-purity processing in diffusion is absolutely necessary.

Vacancy agglomerates such as D-defects in the starting material and, consequently, their decoration by impurities have to be avoided by using a pre-processing step like oxidation or $POCl_3$ diffusion **[5]**. Wafers, which are pre-processed in this way show a very high carrier lifetime up to 2000 µs **(Fig. 2b)** and therefore a reproducible behaviour after lifetime controlling with respect to a defined relationship between reverse recovery charge and on-state voltage.

In order to achieve the highest possible active device area for the cathode and anode, resistivity and lifetime need to be very homogeneous up to the very edge of the wafers, even after the diffusion.

2.3. Low Temperature Sintering Technology (LTS)

The Low Temperature Sintering Technology (LTS), which is based on the principle of diffusion welding ensures, compared to a Free Floating (FF) interface, an excellent thermal contact between silicon and molybdenum carrier due to the metallurgical interface. Therefore the maximum operating temperature can be raised. Surge current capability (I_{TSM}), especially needed for HVDC applications, as well as blocking capability (V_{RRM}) and long term blocking stability increase significantly **[2]**. This can be proven as follows:

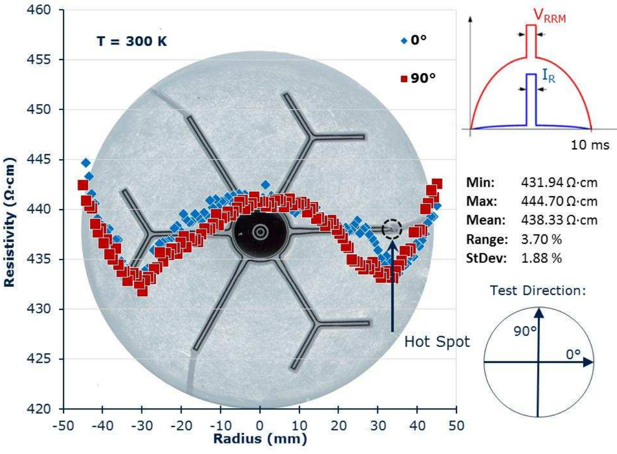

Fig. 3: Metallized surface of a 4-inch LTT and corresponding distribution of resistivity

4-inch 8 kV Light Triggered Thyristors have been purposely tested to destruction in order to evaluate the maximum blocking capability. The device **(Fig. 3)** had been exposed to a very high repetitive reverse voltage stress for several seconds at 50 Hz and a temperature of 373 K before it failed. The applied voltage waveform is composed of a base sine wave with chosen amplitude of 8 kV, super-imposed with a voltage peak of 2.2 kV and a pulse width of 300 µs. This represents a V_{RRM} of 10.2 kV. The blocking current at the voltage peak reached very high values between 2 A and 12 A.

The thyristors did not fail as one would expect in the junction termination region, which is outside of the metallized wafer and not shown in Fig. 3, but they failed in the p-base at the end of a gate finger. This hot spot is caused by a local thermal runaway which is accelerated by the lack of thermal coupling between gate finger area and the contact disc and by the reduced blocking capability in the wafer area around the minimum of resistivity.

To confirm this very high reverse blocking voltage capability, about 1800 devices of 4-inch 8 kV LTTs were stressed successfully with a repetitive peak reverse voltage V_{RRM} of 9.6 kV@RT and 10.0 kV@373 K, in both cases with a base sine wave of 8.0 kV. The test period was 6 s, which corresponds to a number of 300 surge voltage pulses.

This outstanding periodic blocking voltage capability can only be reached by means of LTS technology, where the whole wafer including the junction termination is bonded with the molybdenum carrier and therefore the power loss during high reverse current flow is sufficiently dissipated.

3. Pulse Peak Test

The voltage stresses for thyristor applications are determined by periodic and non-periodic voltage stresses defined in IEC 60747 **(Fig. 4a)**. The stress caused by the fundamental line voltage is superimposed by periodic voltage peaks, such as commutation peaks within the converter and other sporadic events, e.g. switching over-voltages.

In the application, the width of the peaks is only a few hundred microseconds. Nevertheless these peaks are the major design criteria for the blocking voltage design of the thyristors because the working voltages V_{DWM} and V_{RWM} are typically in the range of only 40 % to 60 % of that peak voltage stresses. Traditionally the established procedure is to test the maximum periodic blocking voltage of a thyristor at 50 Hz half sine wave (10 ms) routine production-test.

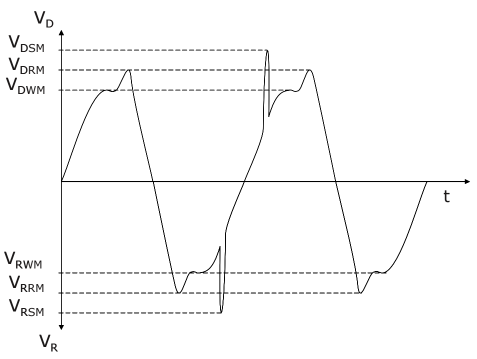

Fig. 4a: Typical blocking voltage wave forms in thyristor applications as defined according to standard IEC 60747

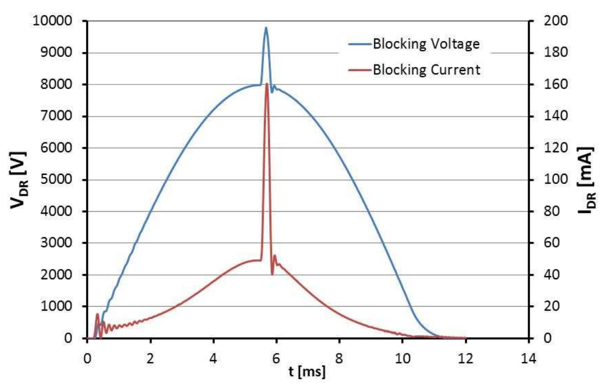

Fig. 4b: Measured blocking voltage and blocking current of a V_{RRM}=9.8kV thyristor according to new routine blocking test at T_{vj}=125°C

For this reason a new waveform for blocking voltage test is introduced in order to meet precisely the requirements of the application. **(Fig. 4b)**

Fig. 4b as an example shows the blocking current of about 50 mA at blocking voltage of 8.0 kV, which is the chosen amplitude of the base voltage sine wave. This base sine wave is now superimposed by a surge voltage with higher amplitude, but with a short pulse width. The blocking current is allowed to rise significantly which enables higher repetitive peak surge voltages V_{DRM} and V_{RRM}. A very high peak surge voltage of 9.8 kV with a pulse width of e.g. 300 µs is reached.

Some thyristor manufacturers use a 60% fundamental sine wave (10 ms) to test their devices. However, to ensure a high level of inherent voltage withstand capability, which is especially present when using press pack LTS devices, a higher level of e.g. 80 % of the new defined pulse peak V_{DRM} or V_{RRM} values is recommended. The proposed combination of the high level fundamental sine wave and the superimposed pulse peak stress applied during its routine test to each thyristor allows for a reliable operation of these devices in customers applications under all relevant voltage stress conditions with a sufficient safety margin.

Benefit for the applications: The number of series connected devices and corresponding components and thus the overall system cost can be significantly reduced, if the blocking voltage is increased from 8 kV to 9.5 kV. The on-state losses are not increased, since the pulse peak tested devices do not use a thicker silicon wafer.

4. Forward Recovery Protection (FRP)

A conventional thyristor is vulnerable during recovery time, because the middle p-n junction needs a certain period of time to reach its full blocking capability. If a forward voltage pulse occurs during this recovery time t_a, the response of the thyristor depends on the amplitude, the dv/dt, the duration, and the exact moment of the start of the voltage pulse. Most critical is the case, when large regions of the device have fully recovered and only a small part at the main cathode area is turned on by the voltage pulse. This may lead to current filamentation and may destroy the device. In order to avoid such a destructive failure, HVDC thyristors are protected by an external PC-board called a Recovery Protection Unit (RPU) that monitors the voltage across the device and generates a trigger pulse in case of any critical events.

4.1. Integrated Forward Recovery Protection

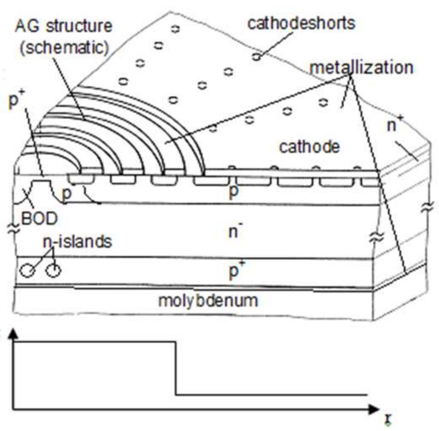

Fig. 5: Schematic sketch of the LTT and lifetime distribution $\tau(r)$ at a radial cross section **[4]**

The protection can also be realized by an integrated FRP. Two crucial measures have to be combined:

Firstly, the distribution of the charge carrier lifetime has to be modified such that it is reduced in the main cathode area of the device compared to the amplifying gate (AG) region **(Fig. 5)**. This measure protects the initial phase of the recovery period, up to about 300 µs to 400 µs after commutation.

Secondly, to cover the remaining time of the recovery period, up to about 1000 µs, more carriers must be generated or injected, e. g. by implemented phosphorus islands in the p- emitter of the inner AG structure **[4]**.

However, up to now it has not yet been possible to manufacture such devices with sufficient reproducibility. Therefore, another solution has to be found based on this principle **(chapter 4.3.)**

4.1. Technological Preconditions and Wafer Design for New FRP

The locally increased lifetime in the gate centre can be implemented by using a metal mask during electron irradiation. The 2D lifetime mappings of conventional 5-inch 8kV LTT with integrated BOD and dv/dt protection **(Fig. 6a)** and with the new FRP **(Fig. 6b)** based on a modified lifetime in the centre of the gate are compared.

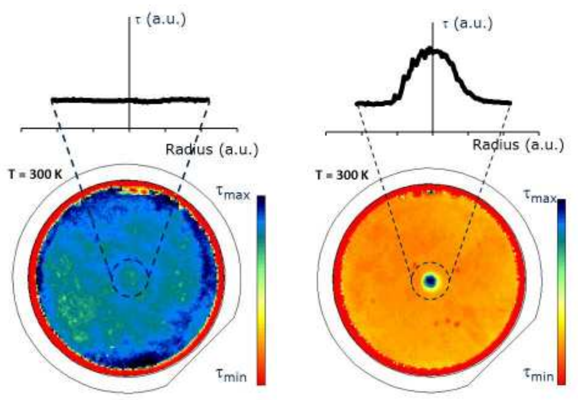

Fig. 6: Lifetime mapping (ELYMAT) of the cathode area of a 5- inch 8kV LTT without (a) and with FRP (b) after irradiation and appropriate preparation

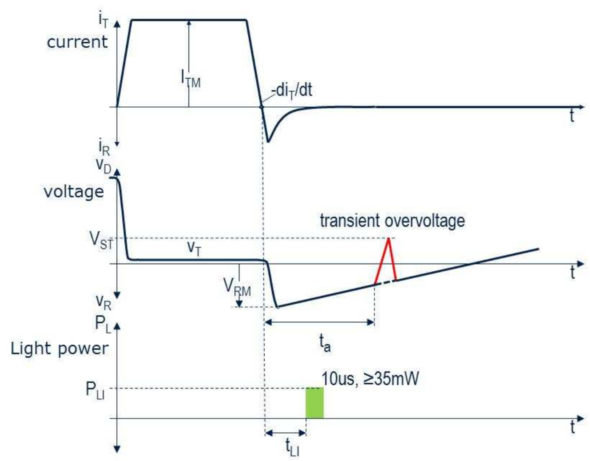

Fig 7: New FRP light pulse scheme

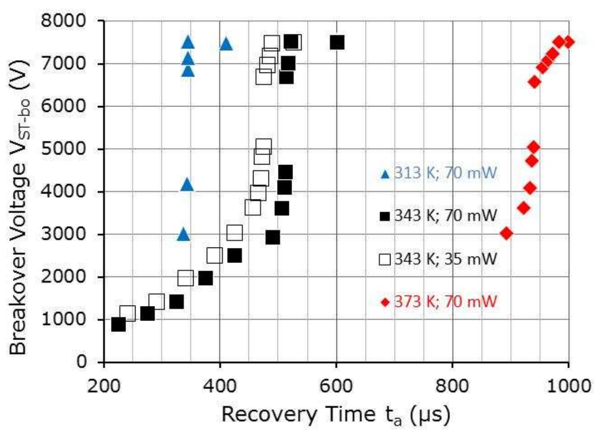

Fig. 8: FRP Robustness Test of one device at different test conditions

The lifetime had been adjusted properly by electron irradiation at 10 MeV to meet the HVDC requirements for the dynamic characteristics, in particular the reverse recovery charge and the circuit commutated turn-off time. In the centre within the region of the gate very high lifetimes were achieved, which is very close to the conditions prior to irradiation.

4.2. New Forward Recovery Protection by an Additional Light Pulse

The prevailing concept of FRP only triggers when a critical surge voltage occurs. In this case an additional light pulse is immediately generated by the Recovery Protection Unit (RPU). Due to the long transit time of the light pulse the RPU has to be placed near the thyristor.

In contrast, the idea behind the New FRP concept is the combination of a technological measure for realizing a higher lifetime in the amplifying gate (AG) of the thyristor **(chapter 4.1 and 4.2)** and a modification of the optical triggering on the user side.

The new FRP concept is based on an additional periodic light pulse which is applied to the LTT at a certain time t_{LI} after current extinction **(Fig. 7)**. The protection light pulse is not only generated on demand, but always during the whole operating time. It generates charge carriers in the optical gate with its higher lifetime which will safely turn on the thyristor only when a fault surge forward blocking voltage pulse occurs. Thus, the RPU and related auxiliary components are not needed for the new FRP concept.

During the verification of the new FRP with a large amount of 8 kV LTTs, all components were charged with a bias current (I_T=3kA). The time between current extinction and the application of the protection light pulse, t_{LI}, was adjusted to a value, that represents the most severe protection condition. The smallest time t_{LI}, taking the application jitter of the light pulse into account, was chosen.

Pre-examination on insufficiently protected components had been done which made sure that the tested devices are destroyed (surge voltage V_{ST}=7.5 kV, dV_{ST}/dt= 500 V/µs to 1000 V/µs). Most critical to a thyristor when it is turned on unexpectedly during its recovery time is the height of the current level at the first few microseconds. The current waveform corresponds to that of a di/dt event with a very high current rate of rise in the range of 3 kA/µs. If the thyristor is not turned on in the defined area within the inner AG region, the thyristor will surely be destroyed by such an inrush current.

While the amplitude of the surge voltage V_{ST} applied to the thyristor during its recovery period remained constant at about 7.5 kV, the amplitude of the voltage that the thyristor was able to block till breakover $V_{ST\text{-}bo}$ was influenced by different parameters **(Fig. 8)**. Those parameters are t_a, the time between the extinction of the bias current and the beginning of the surge voltage, the temperature and the light power P_{LI}.

At breakover voltages below 3 kV $V_{ST\text{-}bo}$ increases slowly with increasing t_a. There are still enough excess charge carriers in the whole thyristor area to turn on the thyristor at even smaller values of V_{ST}. Once the residual charge is almost emptied, at certain t_a above approximately 3 kV there is an abrupt steep increase in $V_{ST\text{-}bo}$ up to the maximum blocking voltage. In this time range, it is crucial whether there are enough charge carriers, which are increased by the additional light pulse within the optical gate for a safe turn on by FRP.

A study on several hundred 5-inch LTTs tested at a fixed temperature and light power resulted in a spread of the time for this abrupt increase of the breakover voltage of about 200 µs. Therefore it is assumed that in case of a fault event in a converter valve only single thyristors will be triggered by FRP, but never all at once.

For all tested parameters (t_a,T and P_{LI}) it could be demonstrated by this Robustness Test **(Fig. 7 and 8)**, that all devices were successfully protected by the new FRP method against surge voltages during the recovery time.

Even if P_{LI} is reduced to 35 mW, the FRP still worked sufficiently, stating, that there is a huge margin for tolerances of the light power due to the individually different power level of the laser diodes used as light sources and the other optical components. On the other side, the injected light power for the protection pulse must not take arbitrarily large values because it has a direct impact on the circuit commutated recovery time t_q of the thyristor. P_{LI} has to be chosen in a range, that t_q does not increase to undesired values e.g. above 400µs.

If not triggered by the additional protection pulse within the recovery period, LTTs with New FRP have the same behaviour as the previous ones. They are 100% backward compatible without restriction and can be used in existing applications where the new FRP-concept has not yet been applied. The increased carrier lifetime in the gate centre is only effective, if the LTT is illuminated with an additional protective light pulse during its recovery time.

5. 6-Inch Light triggered Thyristor

5.1. Surge Current Capability at Highest Blocking Voltages

Tab. 1: I_{TSM} of 3 different surge current wave forms; Clamping force and junction temperature before surge were 135 kN and $T_{vj,max}$ = 90°C

Pulses:	Single	Single	Triple
Waveform	sin	1-cos	3 x (1-cos)
V_{DM}:	0 V	> 5 kV	0 V
V_{RM}:	0 V	> 5 kV	> 2,0 kV
t_p:	10 ms	16,5 ms	16,5 ms
I_{TSM}	> 140 kA	> 74 kA	> 70 kA

The peak single pulse surge current with reapplied voltage for the 6-inch 9.5 kV Light Triggered Thyristors has been tested. It subjects to the temperature dependent forward voltage blocking capability and reaches more than 70 kA **(Tab. 1)**. No destruction or undesired forward voltage triggering occurred. The corresponding peak single pulse current (t_p = 10 ms) reaches very high values of more than 140 kA **[2]**.

5.2. Capabilities of Existing and Improved Technologies

The impact of technological measures on the performance of thyristors can be clearly represented by the technology curve of turn-on voltage V_T and the reverse recovery charge Q_r, which can be described by the following approach $Q_r = (V_T - V_{ref})^m \times 10^b$ **(Fig. 9)**.

This also applies to a comparison between different manufacturers. For example: A reduction in the silicon thickness is very beneficial to both parameters, so that the corresponding technology curve shifts towards smaller V_T and Q_r values. Of course, this makes sense only if the associated reduction of the blocking capability, which is determined by the silicon thickness, is acceptable.

More interesting, however, is an evaluation of measures which have, at a fixed silicon thickness, meaning without this significant negative compromise in the blocking capability, a favourable effect on V_T and Q_r. Controlling of carrier lifetime by means of high-energy electron irradiation (4 MeV and 10 MeV) is a usual procedure, whereby a higher energy shows a more advantageous effect on the technology curve **[6]**. **Curve B** of Fig. 9 shows the graph for a 6-inch 9.5 kV LTT when the components were treated only by electron irradiation at 10 MeV.

Further improvement **(Curve A)** can be achieved by a combined irradiation with electrons and light ions to locally reduce the carrier lifetime on the anode side. This improves the turn- off behaviour while still maintaining low on- state voltage (> 0.05 V is gained at fixed Q_r).

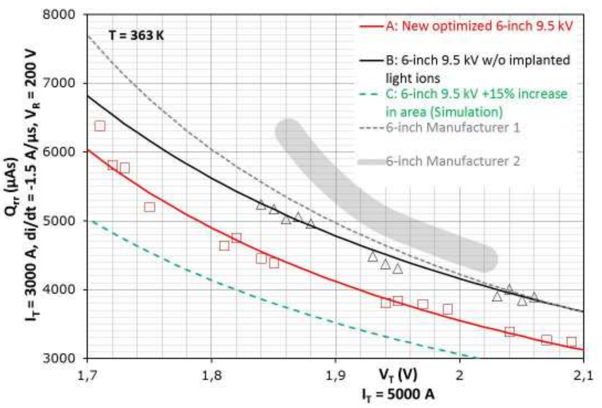

Fig 9: Trade- off curves between V_T and Q_r for different technologies and manufacturers

Finally, **Fig. 9** shows currently available curves of 6-inch devices of other manufacturers for UHVDC thyristors. The abscissa shows the on-state voltage tested at I_T=5kA due to availability of data of other manufacturers. Usually 6-inch devices are measured at a current of 6 kA or slightly above. The same does apply to those measurement conditions for Q_r given in Fig. 9.

6. Summary and Outlook

The improvements in thyristor technology described will contemporarily lead to more efficient HVDC thyristor valves. The 6-inch-LTT is ready for application in all future transmission projects with DC-currents of 5000 A to 6250 A considerably reducing the complexity of the valves by eliminating electrical trigger and protection functions. Using the pulse peak method for routine testing of the voltage withstand capability will enable utilization of 9.5 kV reverse blocking capability. This enables a reduction of the number of series connected elements in a valve or at least to keep the number of devices constant if voltage stresses on single elements increase due to higher stresses of the valves at increased currents up to 6250 A. The increased blocking capability in line with the high current and surge current capability (140 kA/70 kA) due to the Low Temperature Sintering Technology (LTS) makes it possible to cover the whole range of feasible applications of 6-inch-thyristors with one single device. Other manufacturers need to use different classes of blocking voltages to cover the individual current and voltage requirements.

The integrated forward recovery protection function (FRP) has been successfully verified during routine testing of several hundred LTTs. As all other features of the thyristor remain unchanged the FRP function can now also be implemented in all other types of LTTs.

With completion of this step only three types of LTTs (4-, 5- and 6-inch with 9.5 kV reverse blocking voltage capability) will be available to cover the whole power and voltage range of HVDC transmission technology without the need for any electrical triggering or protection function leading to simple and reliable thyristor valve design.

Further improvement of the new 6-inch 9.5 kV/6250 A device can be reached by increase of active cathode area by about 15 % using a improved junction termination **(Fig. 9, Curve C)**.

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Application of Concentric Rings of Ground Electrodes for HVDC Transmission

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SUMMARY

Circular ring shaped electrodes buried at a depth close to the surface of earth have been used quite widely as part of the return path of HVDC transmission system during mono-polar operation. Most of the earlier ring electrodes were built with a single ring, however, increased transmission ratings, higher top layer soil resistivity and availability of limited plot size are resulting in concentric two or three-ring electrode arrangements to meet the current density and step voltage criteria.

In this paper the effectiveness of, shallow buried horizontal rings in a coplanar, concentric, circular, multiple rings is quantified while meeting the set criteria. This analysis is based on analytical equations applicable to a two layer earth model, each layer with uniform resistivity with axis symmetric electrode.

This analysis for multiple rings is based on an extension of the single ring analysis in [1] and [2] by calculating the ground potential rise and gradient through an evaluation of self and mutual resistances of multiple rings. Also the contribution of each ring and each layer is presented that enables the optimal location and size of each ring.

This analysis establishes that the inner rings in a properly sized multiple rings could be effective in sharing substantial current and thus decrease the plot size, still meeting the current density and step voltage criteria, contrary to the statement in [1].

KEYWORDS

1. Ground electrode, HVDC, concentric electrodes, ring electrodes, multiple electrodes

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INTRODUCTION

Circular ring shaped electrodes buried at a depth close to the surface of earth have been used widely as part of the return path of HVDC transmission system during mono-polar operation. Most of the earlier ring electrodes were built with a single ring, however, increased transmission ratings, higher resistivity of top layer soil and availability of limited plot sizes are resulting in concentric two or three-ring electrode arrangements in meeting the current density and step voltage criteria.

The multiple ring electrodes have been in service for over at least 20 years with no reported cases of unsatisfactory operation [4]. However, with regard to inner rings reference [1] on page 265 states, that the "gain is very limited, not only because of the smaller surface of the inner ring, but also because of the insignificance of its relative participation in handling the current".

With this background, an analysis is undertaken, in this paper, to evaluate the effectiveness of additional rings on the step voltage and coke-soil boundary current density. These parameters are evaluated by calculating the self and mutual resistances between the rings and thus the current distribution between rings, by varying the separation distance between rings.

This analysis is undertaken for the case of axis symmetric concentric rings in a two layer earth model, each layer with uniform resistivity.

ELECTRODE DESIGN

a) Ground Model

In this analysis a top layer of uniform resistivity ρ_1 and thickness S_0 is assumed to layover a bottom layer of ρ_2 uniform resistivity bottom of infinite thickness. The ground model developed here closely follows that developed in [1] and [2] with finite resistivity bottom layer, instead of infinite resistivity in [1]. The electrode is assumed to be a horizontal ring (or concentric multiple rings) buried at a depth of g metres below the surface.

The influence of non-conducting layer of air above ground and ρ_2 resistivity bottom layer are taken care of by the application of method of images. The influence of air is implemented through an image of the electrode located above the ground with current equal to the actual electrode. While that of the bottom layer is taken care of by an infinite number of images upwards and downwards. Here the method of images proposed in [2] is adopted, where in for the image between the top layer and bottom layer the current of the image reduces by the ratio μ which is given by:

$$\mu = \frac{\rho_2 - \rho_1}{\rho_2 + \rho_1}$$

The location of images and current in each image, along with equations in calculating the self and mutual resistances between the rings, based on [2], is presented in the Appendix.
From these resistances the current distribution between rings is calculated as per equation (5) in the Appendix. The ground potential due to all rings is calculated by superimposing the contribution of each ring. The potential at a given location due to a single ring due current (I_0)

through it is calculated as per equation (3) in the Appendix. By superimposing the contribution from each ring the total potential in a multi-ring system is obtained.

b) Design Procedure

The size of a ground electrode is dictated by the allowable values of current density at the coke to soil boundary and step voltage on the ground, which depend on resistivity and depth of overburden soil.

In the case of a single ring electrode the diameter of the ring, cross sectional area of the ring and depth of burial are the variables over which the designer has any control. In the case of multiple rings the separation between the rings is an additional parameter that the designer can vary, besides the depth of burial and cross sectional of each ring.

The electrode design is an iterative process with depth burial, coke bed size and D as the variables that influence the design parameters J and E. The parameter E is influenced by burial depth and D, while J is influenced by coke bed size and D, thus the influence of h_1 and r_0 are independent of each other.

To quantify the effectiveness of additional rings a base case design with a single ring is considered first with assumed basic parameters; the basic parameters being: soil resistivity, thickness of each layer, depth of burial, coke cross section, and the criteria. By keeping the basic parameters constant the case of two and three ring configurations are evaluated by varying only the diameters of the rings. The design is based on the data given in Table 1.

Table 1
Basic Data for Electrode Design

Parameter	Symbol	Value
Continuous current, A	Id	5000
Thickness of top layer, m	S_0	100 to 400
Resistivity of top layer, Ohm-m	ρ_1	10 to 100
Resistivity of bottom layer, Ohm-m	ρ_2	1000
Number of rings		1, 2 or 3
Depth of electrode burial, m	h_1, h_2, h_3	2.5
Size of coke bed, m	r_1, r_2, r_3,	0.75
Radii of Rings, m	r_{01}, r_{02}, r_{03}	
Design value of coke-soil current density, A/sq m	J	0.5
Design value of maximum step voltage, V/m	E	(5.0 + 0.03*ρs)

c) Single Ring Electrode

The initial minimum required ring diameter complying with the current density and step voltage are calculated based on [3] and subsequently refined based on the actual calculations based on the equations given in the Appendix.

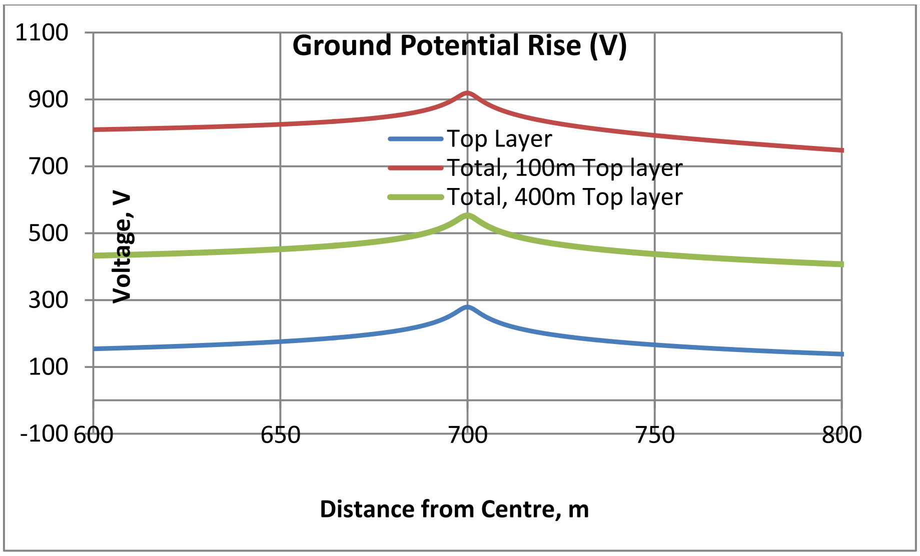
Additional step voltage and current density calculations are performed by varying the top layer thickness and resistivity while keeping rest of the variables in Table 1 constant. Calculations were done with top layer thickness varying from 100 m to 400 m in steps of 100 m. In Table 2 are shown the results for ρ_1 of 100 Ohm-m at 100 m and 400 m top layer thickness which indicate that the step voltages and current densities are almost independent of the top layer thickness, as expected due to the localized nature of these two parameters. At lower resistivity values (up to about 60 Ohm-m) the ring diameter is decided by the current density while at higher resistivity by the step voltage. It may be noted that even though the step voltage is almost independent of the top layer thickness, the surface potential rise is dependent on its thickness and the value of ρ_2 of the bottom layer as illustrated in Figure 1. Figure 1 shows the increase in ground potential rise as the thickness of the top layer is decreased from 400 m to 100 m top layer. Figure 2 shows the negligible influence of the bottom layer on the gradient for the case of 100 Ohm-m ρ_1 and 100 m top layer.

It is possible to reduce the ring diameter by increasing the depth of burial (if step voltage is the deciding parameter) or increasing the coke bed size (if current density is the deciding factor), however, the present design is based on the assumed data in Table 1.

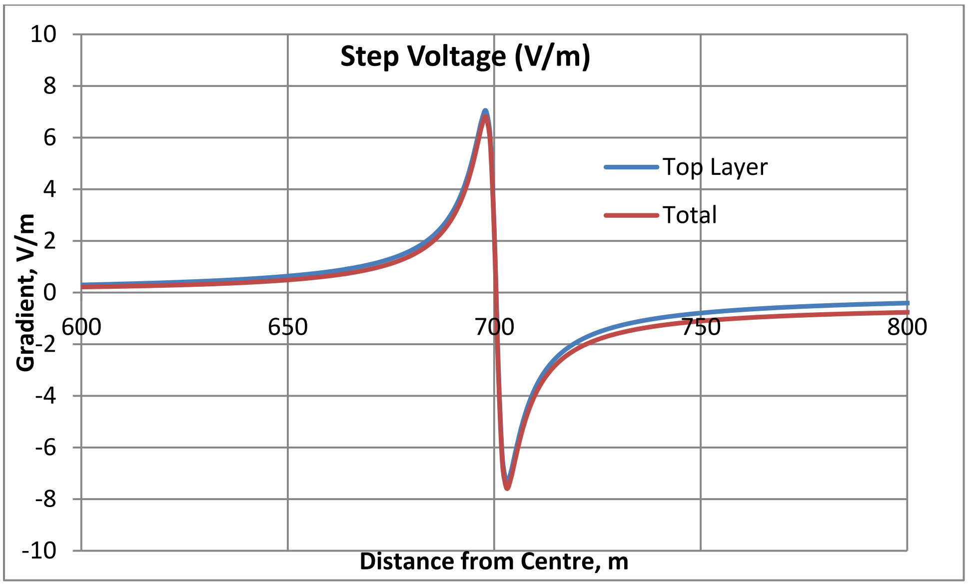
Table 2
Step Voltage and Current Density

S0	ρ_1	2*r01	J	E
100	10	1100	0.48	1
100	25	1100	0.48	2.5
100	50	1100	0.48	4.9
100	75	1100	0.48	7.3
100	100	1400	0.38	7.6
400	10	1100	0.48	1
400	25	1100	0.48	2.4
400	50	1100	0.48	4.7
400	75	1100	0.48	7.1
400	100	1400	0.38	7.4

The plots show the contribution of each layer on ground potential rise and gradient, which is very valuable in the design process and provides an insight into the influence of individual layers on the overall performance of the electrode.



Single Ring, 1400 m diameter, ρ0 =100Ohm-m, S0 = 100m
Figure 1



Single Ring, 1400 m, diameter, ρ_0 =100Ohm-m, S_0 = 100m
Figure 2

d) Two-Ring Electrode

If for a given electrode current the size of the available plot is found to be insufficient for a single ring electrode, use of a double ring electrode is to be explored. In this case we have the depth of burial and coke cross sectional size and the diameter of each ring as variables thus opening to a large number options, unless a systematic procedure is adopted.

With rings spaced reasonably apart, the step voltage is directly proportional to the current and inversely proportional to the diameter of the ring. If the rings are too close they could share the current close to each other but that could increase the step voltage of the outer ring due the influence of the inner ring. Similarly, if they are far apart, the inner ring may not carry sufficient current becoming almost ineffective. So efforts should be aimed at in increasing the inner ring current but not to the extent of overly influencing the gradient of the outer ring.

In achieving this design aim, the following procedure is adopted where we vary only the diameters of rings (indirectly separation between the rings) and keep the other variables constant, similar to the single ring case:

a) Estimate the initial diameters of the outer and inner rings at 60% and 40 % of the electrode current respectively, based on [3];
b) Increase the diameter of each ring by about 5 % to account for mutual effect of the other ring;
c) Calculate the self and mutual resistance between the rings; from this calculate the current division between rings;
d) Calculate the ground potential rise, potential gradient, and current densities with the above derived current division;
e) Vary the inner ring diameter until the gradient and current density criteria are met.

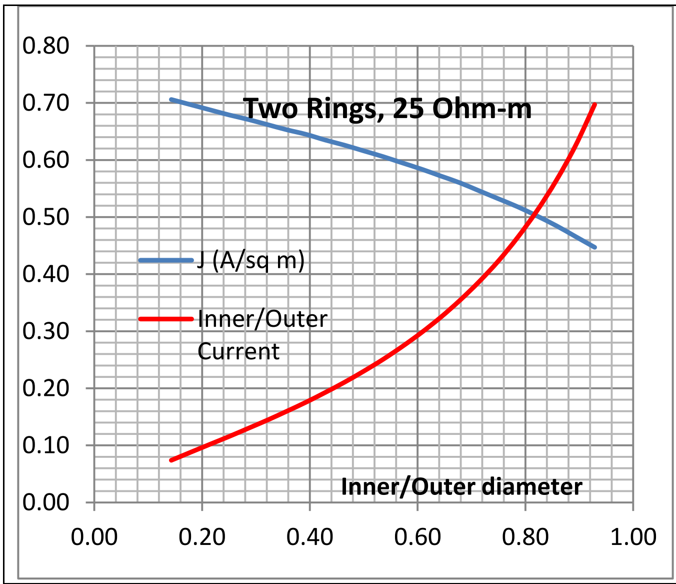
The initial estimates of outer and inner ring diameters are presented in Table 3, for the case of 25 to 100 Ω-m resistivity values. Keeping the outer ring diameter constant the inner ring diameter is varied from about 15 % to 90 % of the outer ring diameter.

Table 3
Initial Ring Diameter Estimates

ρ_1 (Ω-m)	Ring diameter (m)		Ruling Criteria
	Outer	Inner	
25	700	200 to 650	Current Density
50	700	500 to 650	Current Density
75	800	600 to 750	Current Density
100	900	700 to 850	Step voltage

The values of current density and current division between the rings are plotted as a function of diameter ratio in Figure 3, for the case of 25 Ω-m resistivity. As expected at lower values of inner ring diameter its share of current is fairly modest and for it to take any significant current its diameter has to increase to at least 60% of the outer ring. The current density decreases from about 0.7 A/sq m to 0.45 A/sq m, while the maximum step voltage (not shown here) decreases from 3.7 V/m to 2.7 V/m as the inner diameter is increased. The current density and current sharing curves intersect around 80 % diameter ratio, the optimal ratio for this case. This seems to hold true for the 50 Ω-m case as well.

At the optimal inner ring diameter it carries about 50 % of the outer ring current or 33 % of the total current thus reducing the maximum current density within the criteria while reducing the electrode plot size. It may be noted that the two ring design reduces the land area at the cost of increased coke volume, cable length and number of electrode elements.

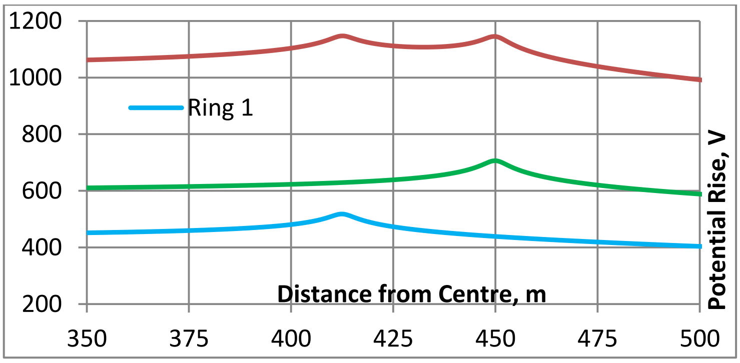


Current Division between two rings
Two rings, ρ_0 =25Ω-m & S_0 = 100m

Figure 3

Figure 4 shows the ground potential rise for 100 Ω-m resistivity top layer of 100 m, for the case of 825 m inner ring and 900 m outer ring diameters. The current distribution between the two rings is about 41 % in the inner ring and 59 % in the outer ring. The potential rise shows two peaks corresponding to the two rings.

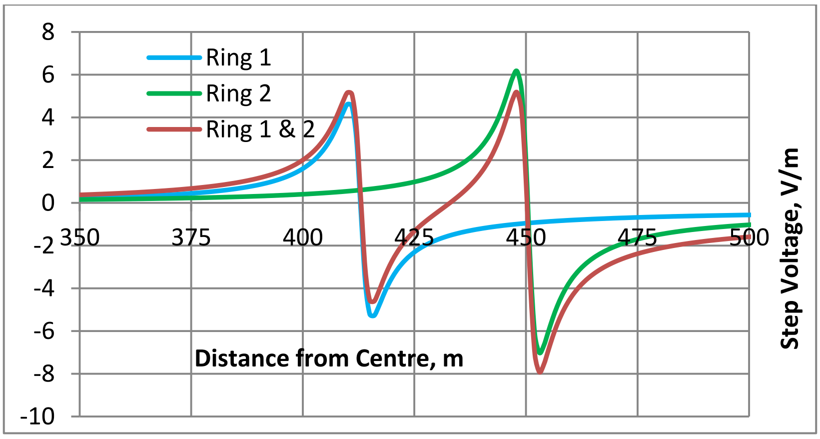
Figure 5 shows step voltages due to the individual rings and their combined effect. It may be observed that the peak values of the outer ring and two rings combined occurs at the same location, and the difference between these two peaks is the contribution due to the inner ring. The closer the inner ring to the outer ring the higher is its contribution to the overall step voltage, while if it is too high the outer ring will carry higher current resulting in higher step voltage. This emphasizes the fact that the placement of the two rings should be coordinated for an optimal design.



Potential Rise

Two rings, ρ_0 =100Ω-m & S_0 = 100m

Figure 4

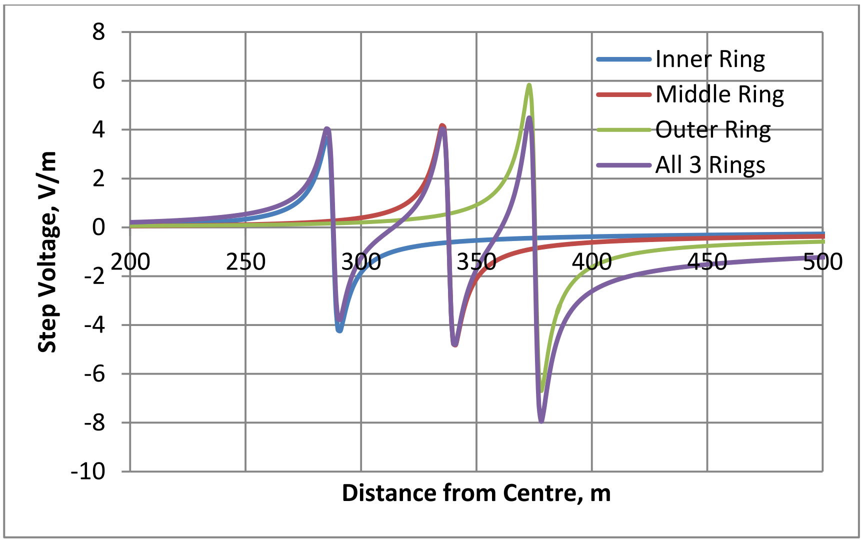


Step Voltage; Two rings, ρ_0 =100Ω-m & S_0 = 100m

Figure 5

e) Three-Ring Electrode

By following a procedure similar to the two-ring case with an initial estimate of outer, middle and inner ring diameters at 50%, 30% and 20% of the electrode current, the gradient and potential rises are calculated. The step voltage plots are shown in Figure 6 confirming that properly sized inner rings help in reducing the plot size while meeting the criteria.



Step Voltage; Three rings, ρ_0 =100Ω-m & S_0 = 100m

Figure 6

SUMMARY AND CONCLUSIONS

The required diameters of rings for 5000 A, 25 Ohm-m and 100 Ohm-m, 100 m thick top soil resistivity are presented in Table 4. These calculations were made with 2.5 m depth of burial and 0.75 m coke cross section.

It is demonstrated that with properly spaced rings, the inner rings do carry a significant amount of current contrary to the implication in page 265 [1], thus reducing the size of electrode plot size; the higher effect occurring at lower resistivity.

Table 4
Summary of Results

Number of rings	Top layer ρ Ohm-m	Diameter of ring (m)			Max J A/sq m	Max E V/m	Coke Volume (m^3)
		Inner	Middle	Outer			
1	25			1100	0.48	2.5	1944
2	25		575	650	0.50	2.9	2165
3	25	325	425	475	0.50	3.4	2165
1	100			1350	0.39	7.9	2386
2	100		825	900	0.35	7.9	3048
3	100	575	675	750	0.31	7.9	3534

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Appendix

The self-resistance $R(r_{01})$ of a ring electrode buried at a depth of h_1 in the top layer of ρ_1 resistivity overlaid on bottom layer of infinite thickness with ρ_2 resistivity is given by (1), while the mutual resistance (R_m) between two rings (radii r_{01} and r_{02}) is given by (2). The scalar potential V(*x*) at any point is given by (3) [2].

The terms c_{ns}, b_{ns} and d_{ns} defined in Figures 4, 5 and 6 are to be used, respectively, in calculating self-resistance, mutual resistance and surface potential by the equations given below:

$$R = \frac{\rho_1}{2\pi^2}\left\{\frac{K(kb_{01})}{b_{01}} + \frac{K(kb_{03})}{b_{03}} + \sum_{n=1}^{\infty}\sum_{s=1}^{4}\mu^n * \frac{K(kb_{ns})}{b_{ns}}\right\} \tag{1}$$

$$R_m = \frac{\rho_1}{2\pi^2}\left\{\frac{K(kc_{01})}{c_{01}} + \frac{K(kc_{03})}{c_{03}} + \sum_{n=1}^{\infty}\sum_{s=1}^{4}\mu^n * \frac{K(kc_{ns})}{c_{ns}}\right\} \tag{2}$$

$$V(r,0,h1) = \frac{I_0\rho_1}{2\pi^2}\left\{\frac{K(kd_{01})}{d_{01}} + \frac{K(kd_{03})}{d_{03}} + \sum_{n=1}^{\infty}\sum_{s=1}^{4}\mu^n * \frac{K(kd_{ns})}{d_{ns}}\right\} \tag{3}$$

Where:

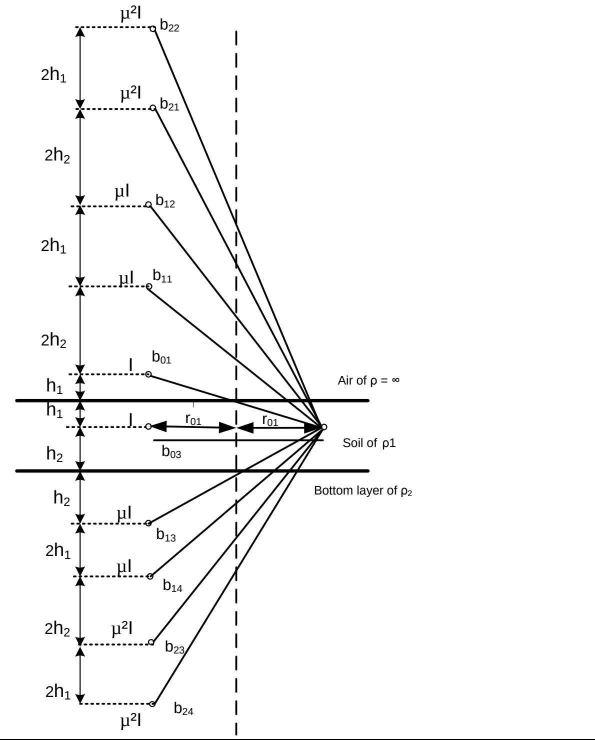
$$kb_{ns} = \frac{2*\sqrt{((r_{01}+r_1)*r_{01}}}{b_{ns}} \tag{4}$$

$$kc_{ns} = \frac{2*\sqrt{r_{01}r_{02}}}{c_{ns}} \tag{5}$$

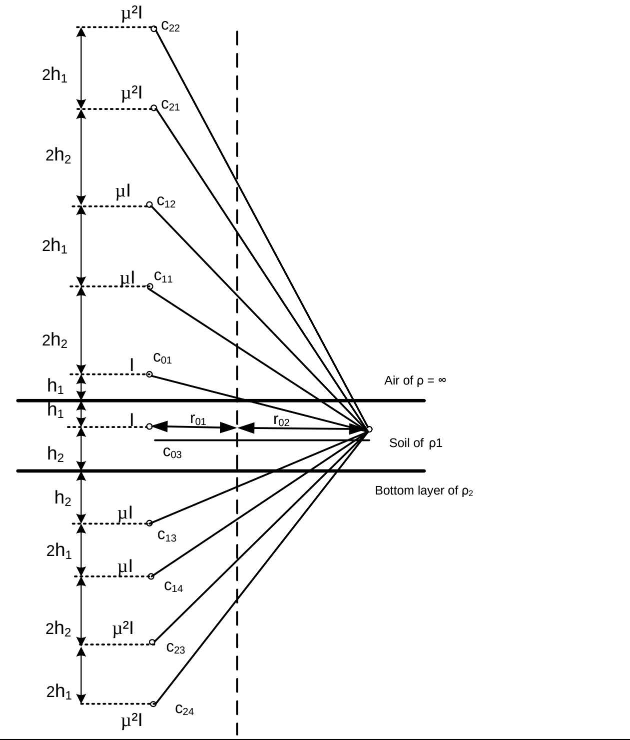
$$kd_{ns} = \frac{2*\sqrt{((r_{01}+r_1)*r_{01}}}{d_{ns}} \tag{6}$$

The current division among the rings is calculated by solving a set of simultaneous equations, which is shown in (7) for three ring case.

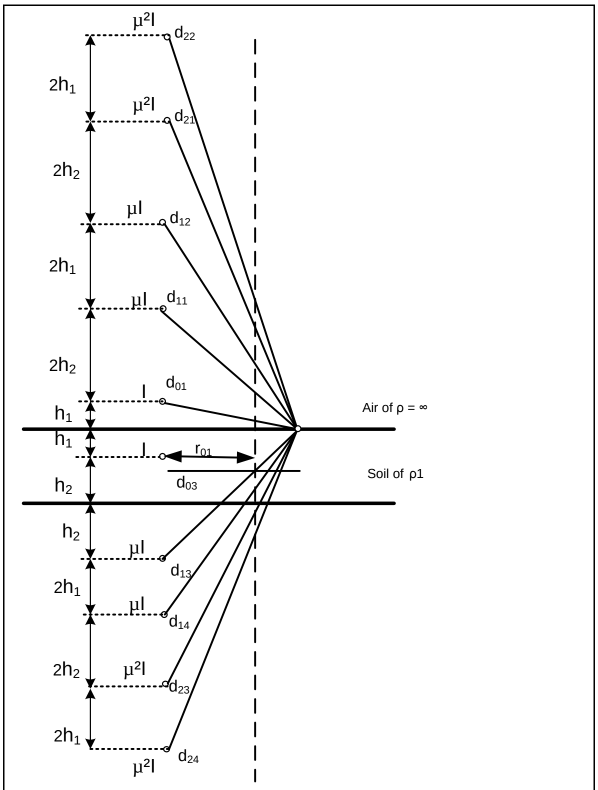
$$\begin{aligned} V &= I_1*R_{11} + I_2*R_{12} + I_3*R_{13} \\ V &= I_1*R_{21} + I_2*R_{22} + I_3*R_{23} \\ V &= I_1*R_{31} + I_2*R_{32} + I_3*R_{33} \end{aligned} \tag{7}$$



Electrode and images for Electrode Resistance
Figure 7



Electrode and images for Mutual Resistance
Figure 8



Electrode and images for Surface Potential
Figure 9

Development of VSC Technology based STATCOM by BHEL

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SUMMARY

STATCOM, Static Synchronous Compensator, is one of the Flexible AC Transmission System (FACTS) devices widely used in Transmission & Distribution (T&D) and industries for enhancing stability limits of power system network and improving power quality in distribution network. The STATCOM technology, which consists of IGBT based Voltage Source Converter (VSC) system, uses high speed DSP controllers for desired control strategy.

Bharat Heavy Electrical Limited (BHEL) has developed VSC based STATCOM technology for some of the important applications for distribution networks of industries. BHEL is currently developing VSC to address STATCOM requirements in transmission systems. A ±500 Kvar, 415 V, 3-ϕ, 2-level VSC based DSTATCOM was developed for power factor correction in industrial distribution application. This system was sponsored by CII – TIFAC and complete DSTATCOM was installed at Titanium shop of Mishra Dhatu Nigam (MIDHANI), Hyderabad. A 3-level VSC based ±2.5Mvar STATCOM was developed for arc furnace application to mitigate voltage flicker at Point of Common Coupling (PCC). This system is installed at foundry shop, Bhilai steel Plant (BSP).

Presently, BHEL is working on to further enhance STATCOM rating up 20 Mvar by developing water cooled IGBT power module. BHEL also initiated development of Cascaded Multilevel Converter (CMC) based STATCOM technology targeting rating of 300 – 400 Mvar to address the requirements of transmission utilities.

KEYWORDS

DSTATCOM, T&D, Power Quality, Voltage Sourced Converter, VSC, Arc furnace, Voltage Flicker mitigation, STATCOM, 2-level, 3-level, H-bridge, CMC, BHEL.

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1. INTRODUCTION

Indian power system network growing rapidly to match with the generations from conventional and green energy sources. Transmission voltages in the country stands at 765 kV from earlier 400 kV & 220kV. Recently, successful experiment at Bina (Madhya Pradesh) has given confidence to adopt 1200 kV as next voltage level in the transmission sector to achieve better efficiency. It has been continuous attempt of system planers to meet the challenges of system reliability, security and minimizing of technical losses.

Two severe power blackouts affected most of northern and eastern India on 30 and 31 July 2012. These blackouts have forced central utilities to review the measures taken for system security and reliability. To improve dynamic system stability during the disturbances in the network, the experts have recommended to install Static Synchronous compensator (STATCOM) at strategic locations in the network. Following this event, a large requirement of STATCOM equipment is envisaged by central and state utilities including the private players in T&D sector.

Technological developments over a period has made arc furnace based steel making more popular worldwide. In addition, use of variable / fluctuating loads such as welding equipment, rolling mills, wood chip mills, rock crushing equipment have become widespread. The increasing number and size of arc furnaces and fluctuating loads causing power quality problems such as flicker, harmonics and unbalance in the majority of cases. Deterioration in power quality is the main cause of concern to the utilities as well as to the customers, in addition to the reliability of power supply.

Flexible AC Transmission System (FACTS) devices have been used for power flow control, control of voltage levels, reactive power compensation, harmonic filtering and damping of oscillations to improve transient stability. STATCOM is a Voltage Source Converter (VSC) based FACTS device for instantaneous reactive power management. The STATCOM technology, which consists of IGBT based VSC system, uses high speed DSP controllers for fast response and controllability [1, 2]. STATCOM comprises of VSC(s) connected to the grid through coupling transformer and reactor for exchange of reactive power as per control objectives.

In this paper, technology demonstration for STATCOM by BHEL is presented with respect application area, VSC configuration and power rating over a period. In the first step, BHEL developed ±500 Kvar, 2-level Distribution STATCOM (DSTATCOM) for power factor improvement. In the next step, 2.5Mvar, 3-level STATCOM system was developed for arc furnace application. Presently, a water cooled H-bridge power module suitable for series connection to address high voltage & high power STATCOM (typical 50 Mvar rating) for transmission application is being developed,

2. STATCOM FOR POWER FACTOR CORRECTION

BHEL initiated development of Voltage Source Converter (VSC) based technology during nineties. Development of 1 MVAR STATCOM was taken up by BHEL in the year 1996-97 with the funding from CII – TIFAC (Confederation of Indian Industries - Technology Information Forecasting & Assessment Council) under vision 2020 program. Under this program, ± 500 Kvar, 415 V, 3-phase VSC using Insulated Gate Bipolar Junction Transistor (IGBT) devices was developed for industrial application. The ±500 Kvar VSC and 500Kvar fixed capacitor bank forming 1 Mvar STATCOM designed to provide fast acting reactive power control. Both, IGBT power converter and digital controller for STATCOM were manufactured at Electronics Division, BHEL Bangalore. After production testing, the equipment were installed at BHEL, Corporate R&D, Hyderabad at the incoming substation for complete functional testing of STATCOM. After successful functional testing, the STATCOM system was commissioned at Titanium shop of Mishra Dhatu Nigam (MIDHANI), Hyderabad.

A ±500Kvar 2-level VSC based DSTATCOM has been developed using the control strategy [3, 4] as shown in Figure-1. The control strategy for DSTATCOM involves the measurement of three-phase voltages and currents at the incoming sub-station and DC link voltage only. Pulse Width Modulation (PWM) technique has been used for switching of IGBTs. For full reactive power compensation of the load, the converter has to supply reactive power of the same magnitude, but of opposite sign. Thus, in such a case, the reactive power drawn from the source is zero. The reactive power supplied by the source is monitored and controlled in closed loop to maintain it at zero thereby achieving unity power factor.

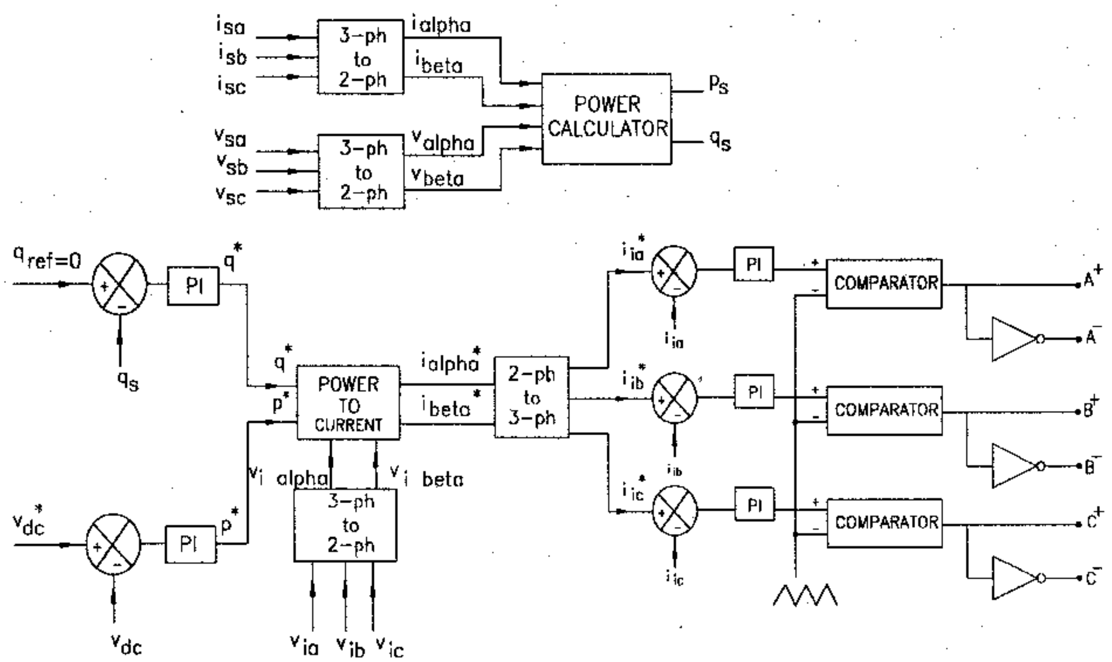

Figure-1: Control block diagram for D-STATCOM

Extensive experiments have been carried out on the DSTATCOM. The DSTATCOM has been tested both as variable VAR generator and with reference reactive power at zero. In variable VAR generator mode, the DSTATCOM has been tested for response of the DSTATCOM to step change in reactive power reference. Figure-2(a) shows the response of the DSTATCOM to step change in q_{ref} from lagging to leading reactive power. Figure-2(b) shows the source voltage and DSTATCOM current.

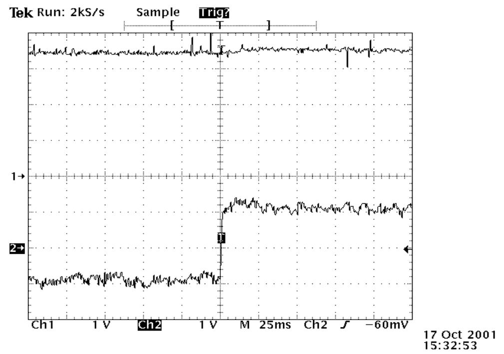

Figure-2(a) Response of DS'I'ATCOM for step change in q_{ref} from lagging to leading (Top trace: DC Link Voltage, Bottom trace: Reactive Power

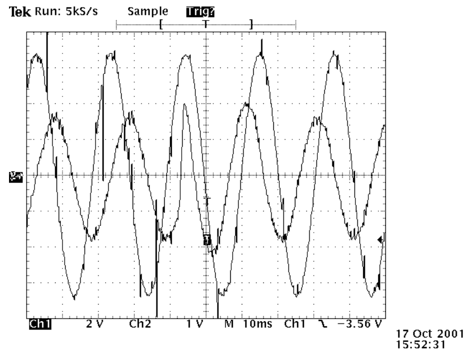

Figure-2(b) Transient response of Phase Voltage and Phase Current corresponding to Figure-2 (a)

Figure-3(a) shows the response of the DSTATCOM to step change in q_{ref} from leading to lagging reactive power. Figure-3(b) shows the source voltage and DSTATCOM current.

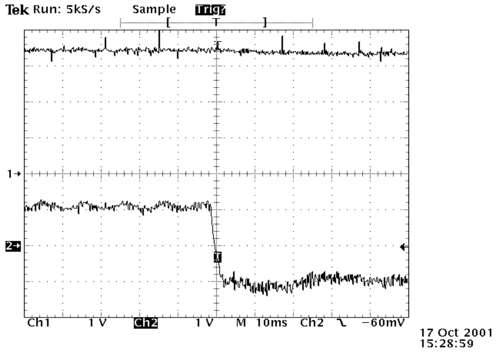

Figure-3(a) Response of DSTATCOM for step change in q_{ref} from leading to lagging (Top trace: DC Link Voltage, Bottom trace: Reactive power)

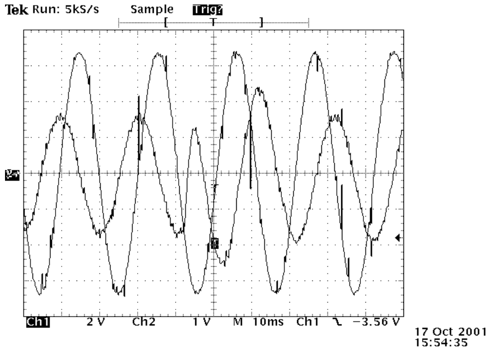

Figure-3(b) Transient response of Phase Voltage and Phase Current corresponding to Figure-3(a)

After extensive functional test in the laboratory, the DSTATCOM was installed at the premises of BHEL, Corporate R&D, Hyderabad. The substation receives power through 33 kV feeders. The incoming voltage is stepped down by a 33 kV / 6.6kV transformer. Various loads in the complex are fed through four numbers of 6.6 kV / 415 V transformers. The DSTATCOM was connected to the distribution network through a 415 V/ 6.6kV transformer. The DSTATCOM monitors the incoming voltages (33 kV, 3-phase) and currents and controls the DSTATCOM, such that the net reactive power drawn from source becomes almost zero. The schematic diagram of power circuit at BHEl, Corp. R&D is shown in Figure-4. After satisfactory operation at BHEL, Corporate R&D, the DSTATCOM has been shifted to M/s MIDHANI, Hyderabad for demonstration.

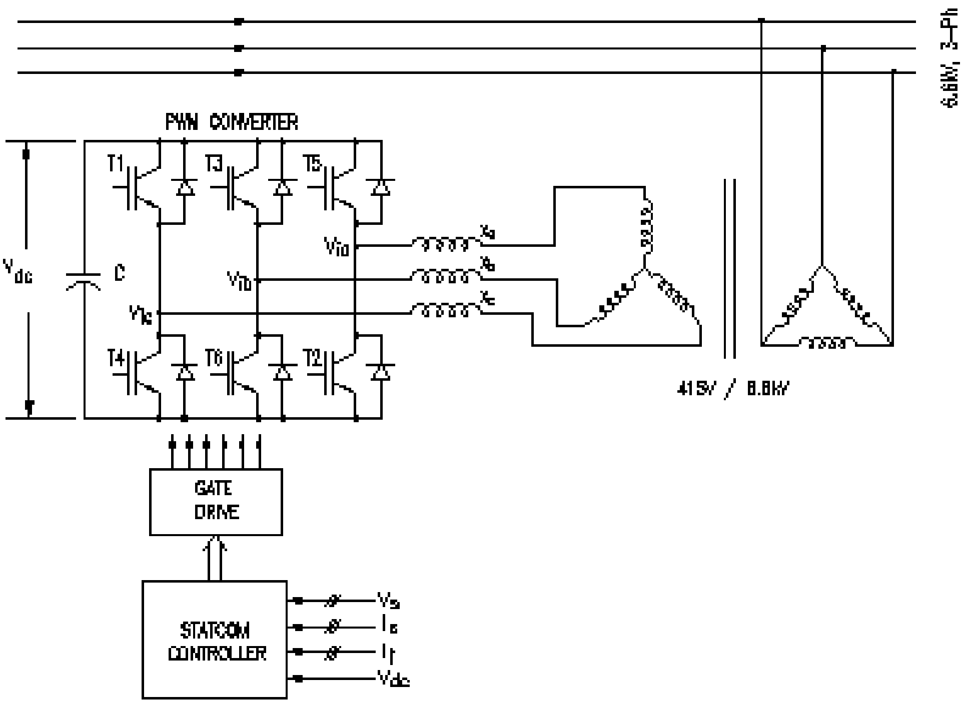

Figure-4: Schematic diagram of power circuit of DSTATCOM at Corp. R&D, BHEL, Hyderabad

The DSTATCOM has been erected and commissioned in Titanium Shop of MIDHANI, where there are several furnace auxiliaries and with heavily fluctuating loads. The DSTATCOM is operating in power factor control mode, such that the power factor remains near unity irrespective of fluctuating loads and the other line disturbances. The photographs of the DSTATCOM IGBT power and controller panels are shown in Figure-5. Extensive experiments have been carried out on the DSTATCOM for various other transient operating conditions and the performance has been found to be satisfactory. This DSTATCOM is capable of maintaining unity power factor at the receiving substation both during steady state and transient conditions.

Figure-5: Photograph of IGBT power and controller panels for ±500 Kvar D-STATCOM

3. STATCOM FOR ARC FURNACE APPLICATION

A step forward, BHEL took another development of 2.5 Mvar STATCOM for mitigation of voltage flicker at the Point of Common Coupling (PCC) of arc furnace [5]. This project was jointly funded by Ministry of Power (MoP), Govt. of India, through Central Power Research Institute (CPRI), Bangalore under National Perspective Plan (NPP) and BHEL. Indigenously designed and manufactured 2.5 MVAR STATCOM using higher rating IGBTs was installed & commissioned at foundry shop, Bhilai Steel Plant (BSP) of Steel Authority of India Limited (SAIL).

The single line diagram of the foundry power system along with STATCOM is as shown in Figure-6. The STATCOM consists of two inverters connected to 6.6 kV feeder of BSP through a three winding transformer. The transformer rating is 3 MVA, 6.6 kV /2.365 kV - 2.365 kV. There are two arc furnaces in foundry shop and they are connected to different 6.6kV feeders. The capacity of each furnace is 5T with peak reactive power demand of 2.5 Mvar. The operating voltage range of furnace is 142 V - 240 V and is connected to 6.6 kV feeder through 6.6 kV / 142 V-240 V transformer. Each inverter is designed to compensate the reactive power of ± 1.25 Mvar and thus the total reactive power compensation capacity of STATCOM is ± 2.5 Mvar.

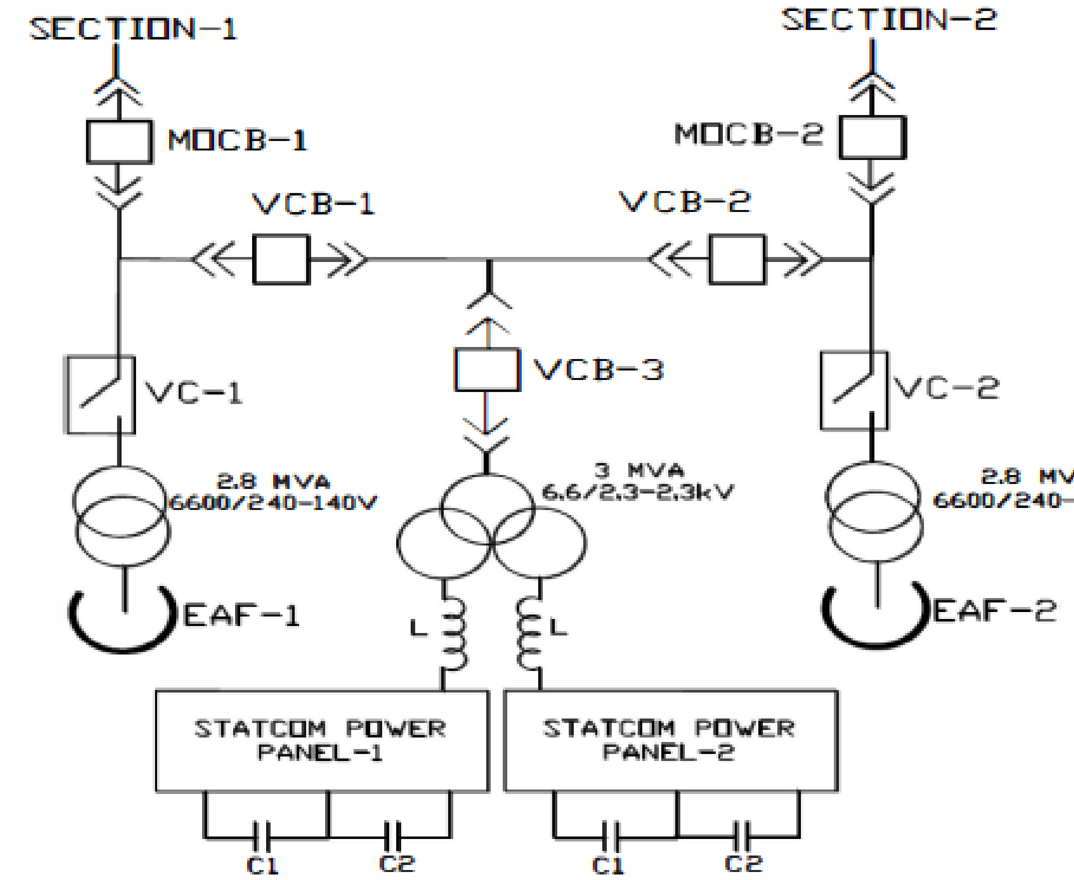

Figure-6: Single line diagram of power system at BSP

With suitable switchgear and signaling arrangement, the STATCOM can mitigate voltage flicker caused by any one of the Electric Arc Furnace (EAF) at a time. At any instant, total reactive and harmonic power to be compensated by STATCOM, is shared equally by each of the inverter. For this each inverter is controlled by an independent TMS320F2810 based DSP controller. The functions like Phase Locked Loop (PLL), calculation of load side reactive and harmonic currents, id current control, iq current control and dc link voltage control loops and SVPWM are implemented on DSP Controller. As STATCOM is designed to mitigate voltage flicker / fluctuations by injecting / absorbing reactive power as per arc furnace demand, implementation of PLL and neutral point voltage balancing of NPC inverter is a challenging task. Accordingly PLL has been designed and implemented based on positive sequence extraction method, to track the grid angle even under unbalanced distorted grid voltages [6]. When STATCOM compensates unbalanced reactive currents, neutral point voltage of dc link voltage deviates resulting in uneven voltage distribution between IGBTs, which may lead to premature failure of devices and also increase in THD of the inverter output voltage. The neutral point voltage deviation can be controlled by redistributing the timing of redundant P and N small vectors in SVPWM. In conventional SVPWM [7] [8], seven segment switching sequence is followed to generate inverter output voltage as per reference vector, in which dwell times for redundant small vectors (P-vector and N-vector), is distributed equally to minimize generation of harmonics and number of switching. In this development, a modified SVPWM [9] has been implemented to control neutral point voltage deviation by suitably re-arranging the dwell times of redundant small type P and N vectors. Besides voltage flicker mitigation, control scheme is also used for compensating the harmonic current components. The developed control block diagram of the STATCOM is shown in Figure-7.

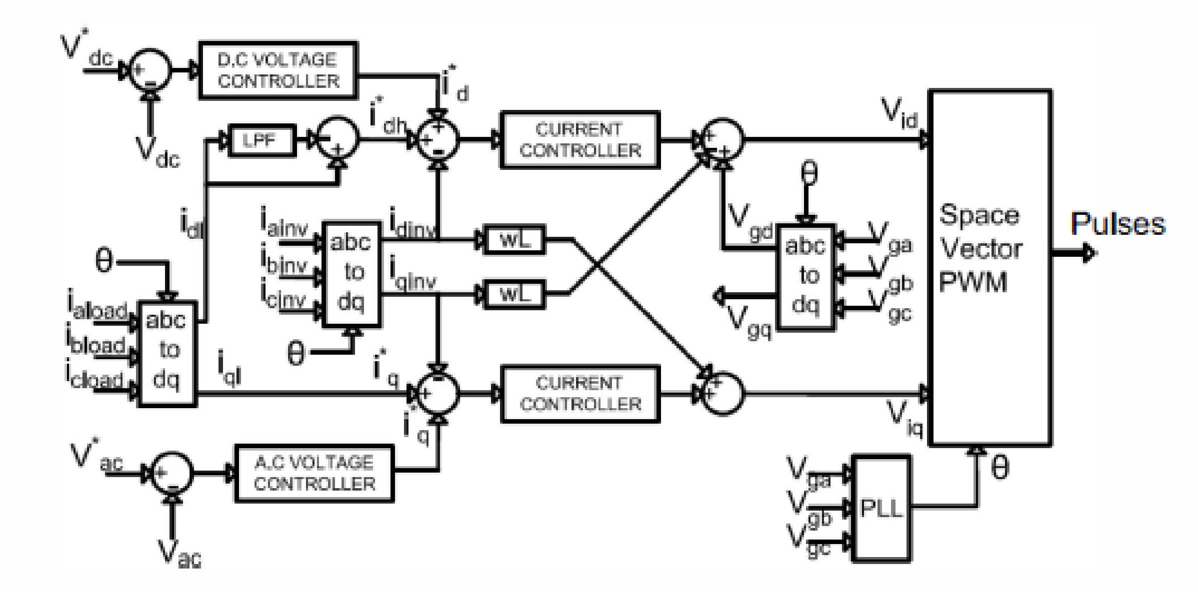

Figure-7: Control block diagram of the STATCOM

STATCOM is put into operation in arc furnace side reactive power compensation mode to control the voltage fluctuations. STATCOM reduces (a) the voltage fluctuations resulted from the rapidly varying reactive power drawn by the furnace (b) the total MVA demand from the source (c) MW demand from the source to the extent of losses and improvement of power factor near unity. Recordings were done at 6.6 kV voltage level of MOCB-l of incoming feeder of furnace. Figure-8 shows the effect of rms value of line voltage at 6.6 kV bus of foundry shop by the furnace operation, without and with STATCOM compensation. From the recorded data it is clear that without STATCOM, 6.6 kV bus of foundry shop sees large fluctuations in voltage with the average value is around 6.25 kV. But the operation of STATCOM has improved the voltage profile at 6.6 kV bus with less fluctuations and also the average value of the voltage also improved to 6.5 kV. Figure-9 shows the recorded data of total Kvar and power factor (PF) measured at MOCB-l of incoming feeder of furnace-l during the operation of furnace, without and with STATCOM operation. From the data it is clear that STATCOM improves the source side power factor to unity from 0.7 and reduces the Kvar demand from the source to zero. From the results it is very clear that STATCOM has improved the power quality of electric distribution system in steel plants due to arc furnace operation by reducing the voltage fluctuations, and improvement of power factor to unity.

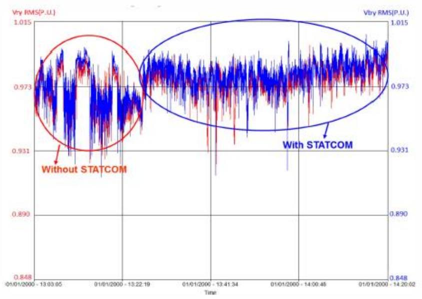

Figure-8: Voltage Profile of the foundry bus on 6.6kV side with and without STATCOM

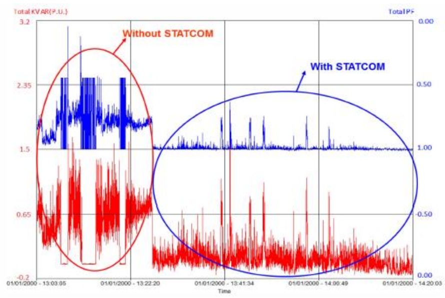

Figure-9: Recorded Kvar and total PF at foundry bus with and without STATCOM

The projected was handed over to BSP during May 2012 in a function attended by dignitaries from Central Electricity Authority (CEA) and senior officials from BHEL & Steel Authority of India Limited (SAIL). The photographs of the VSC & controller panels of STATCOM installed at Foundry Shop is shown in Figure-10.

Figure-10: A view of the installed STATCOM at Foundry shop of BSP

4. WATER COOLED POWER MODULE

The IGBT and clamping diodes in 3-level power module used in BSP STATCOM are mounted on surface of heat pipe heat sink. In the new power module these devices are mounted on the heat sink which is cooled by water to increase its power handling capability. Photographs of both these power modules are shown in Figure-11. With this development, BHEL can address STATCOM rating up to 20Mvar for industrial applications.

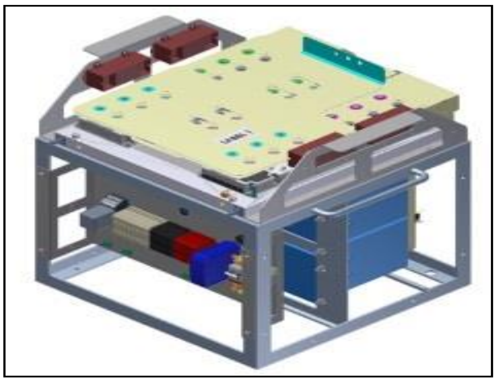

Figure-11(a) Water cooled power module

Figure-11(b) Air cooled power module

5. STATCOM FOR TRANSMISSION APPLICATION

It is proposed to develop 50 Mvar STATCOM for reactive power management in power transmission and distribution network for improving voltage profile and stability indices.

5.1 SCHEMATIC DIGRAM OF 50 MVAR STATCOM

Cascaded Multi-level Converter (CMC) based VSCs are proposed for development of 50 Mvar STATCOM. The H-bridge is modular in nature and a number of bridges can be cascaded to increase voltage and power rating. A single line diagram of 50 Mvar STATCOM is shown in Figure-12. There are four numbers of VSCs, each one of 12.5 Mvar capacity. The VSCs are connected in parallel through air core reactors. The converter sets shall be connected to transmission grid voltage (typically 220kV, 400 kV) bus through a two winding transformer.

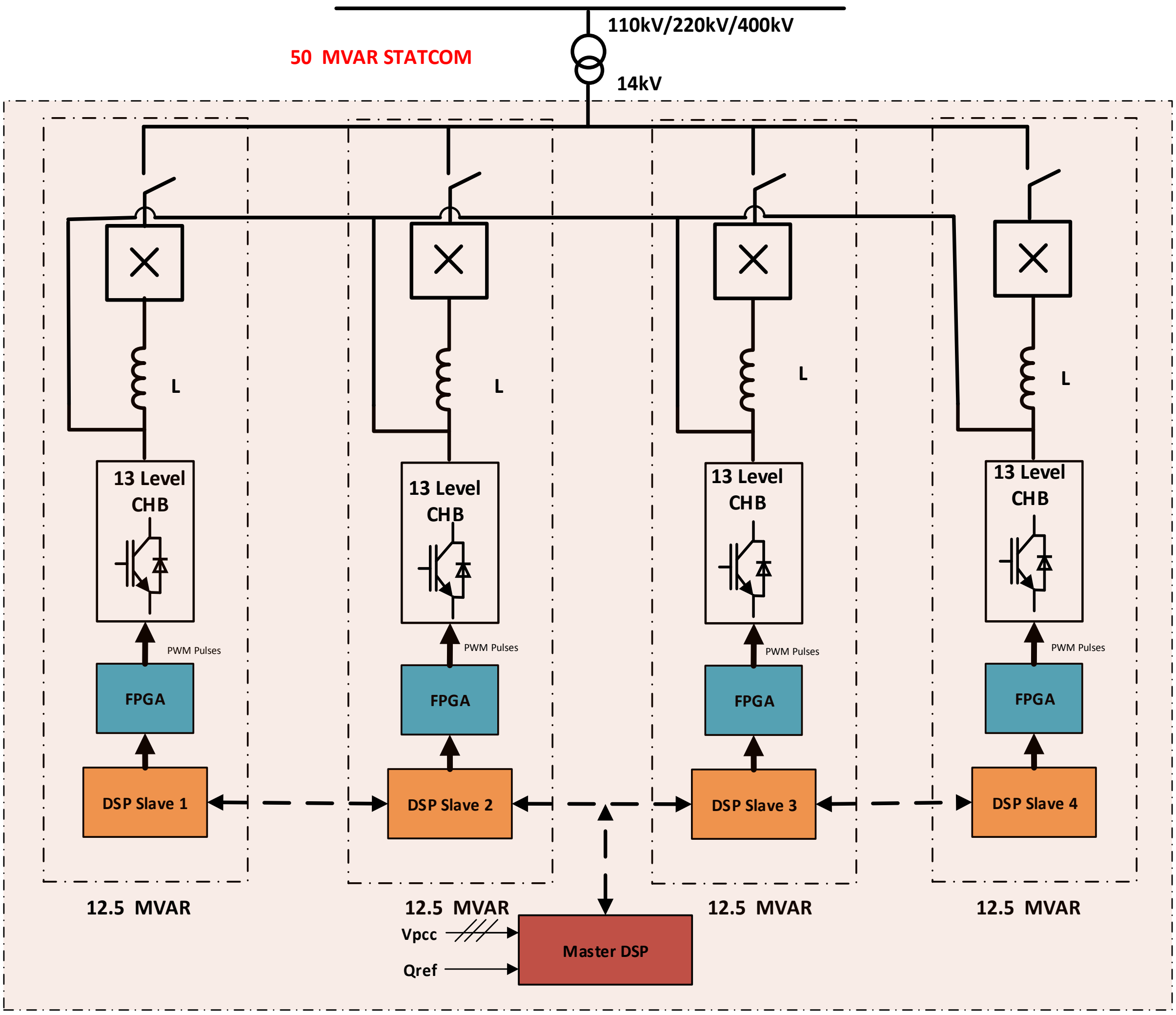

Figure-12: Schematic Diagram of 50 Mvar STATCOM

5.2 CONTROLLER IMPLEMENTATION

DSP and FPGA based control hardware shall be used for closed loop control of individual H-bridge DC link voltage, reactive power, voltage regulation etc. One additional DSP controller will be used as master controller. The output voltage waveform of voltage source converter will have multiple numbers of step to emulate sinusoidal voltage at supply frequency. The cascaded inverter will be switched with selective harmonic method to reduce harmonics. As shown in Figure-13, six H-bridges will be used per phase to obtain 13 voltage levels (Figure-14) in the phase voltage. The line-to-line voltage waveform will have 25 steps.

Protection logics will be implemented in DSP controller. Control, protection, diagnostics and HMI software will be developed and validated in Real Time Digital Simulator (RTDS) before incorporation in 50 Mvar STATCOM prototype.

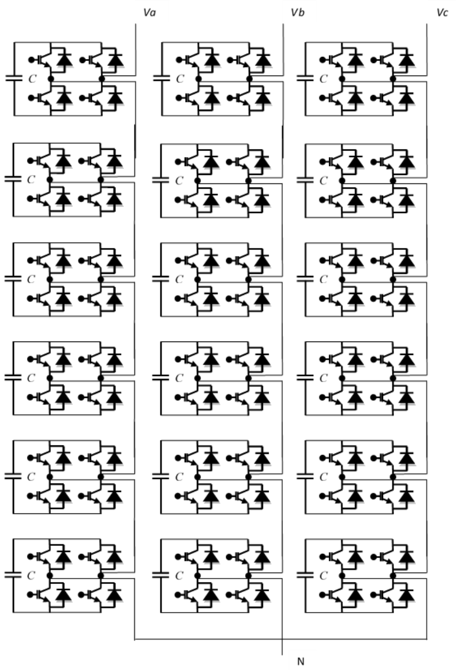

Figure-13: Power Circuit Diagram Cascaded Multilevel Converter

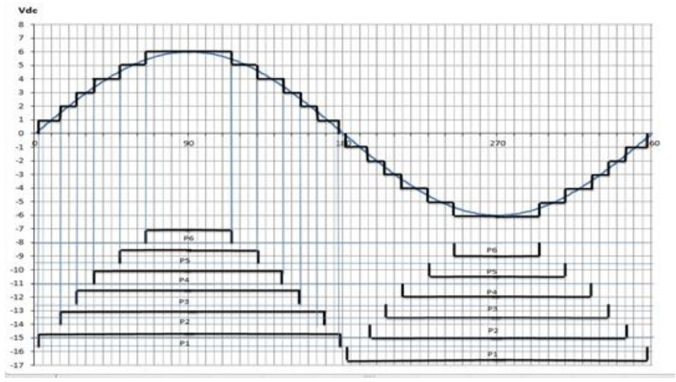

Figure-14: 13 voltage levels in the phase voltage

6. CONCLUSIONS

VSC based STATCOM systems of 0.5Mvar & 2.5Mvar ratings have been developed by BHEL for industrial distribution for power factor correction and mitigation for voltage flickers arising due to arc furnace respectively. The control strategy adopted for DSTATCOM enables it installation at any industrial premises without any modification. The STATCOM developed for arc furnace application has quarter cycle response time which makes it efficient for solving power quality problems. New developments initiated by BHEL shall enable it to address STATCOM requirements for T&D sector.

7. ACKNOWLEDGMENT

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Availability of Xiangjiaba-Shanghai ± 800kV HVDC Project for Last 5 Years

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SUMMARY

Xiangjiaba-Shanghai ± 800kV UHVDC project (XSH800 for short), the first ±800kV 6400MW HVDC project in the world, has successfully operated for 5 years. Its availability is analyzed in this paper, together with the equipment failures that affected the index.

It is shown by experience that the ±800kV UHVDC technique is safe and efficient. The problems that occurred in last 5 years and the measures taken both at XSH800 and other later UHVDC projects, are also introduced in this paper. The successful operation of XSH800 project has served as a model of UHVDC technique and promoted the rapid development of UHVDC projects.

KEYWORDS

UHVDC, Xjiaba-shanghai UHVDC project, Availability

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Overview

The Xiangjiaba-Shanghai project, XSH800 for short, the first ±800kV 6400MW HVDC project in the world, went into commercial operation on 2010.07.08, representing a landmark in the history of HVDC by improving both the DC voltage level and the transmission power to a new level. [1, 2] with the first 6 inch thyristor valve (800kV, 4000A), the biggest converter transformer (800kV, 322MW), the longest transmission line (1935km), and etc.

XSH800 project for the first time both raised the capacity of one 12 pulses converter to 1600MW and upgraded the DC voltage to ±800kV, and therefore improved the unit line corridor transmission capacity 1.5 times while reducing its unit line loss to 40%.[1]

Now XSH800 project has operated successfully for five years. It is time to evaluate its performance. The availability is analyzed in this paper, and the equipment failures that affected the index are introduced in detail, to provide reference for the coming new ±800kV projects over the world.

1. The performance of XSH800 project in last five years

2.1 Energy transmitted

Till 2015.07.08, XSH800 project has transmitted 93900 million kWh clean energy from Xiangjiaba hydro power station to Shanghai, saving 43 million tons of raw coal and reducing 83 million tons of carbon emission in total.

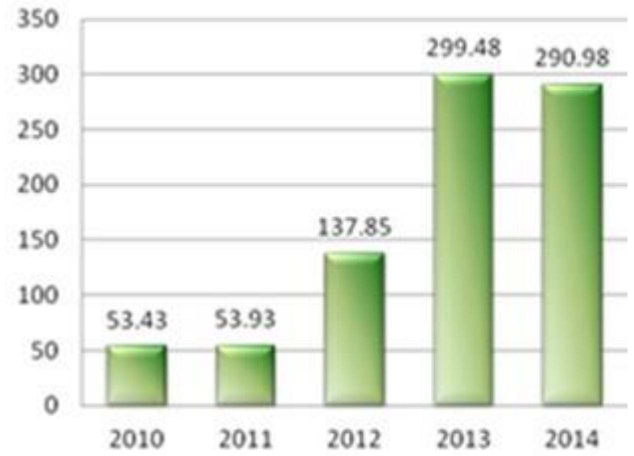

Fig. 1 The Energy transmitted by XSH800 project from 2010 to 2014

Figure 1 shows that limited by the relatively slow construction speed of the hydroelectric generators, the power transmission capacity was not fully utilized during first two and half years. After the generators were all put into operation at the end of 2012, running at full power from July to November, XSH800 transmitted 30000 million kWh every year, covering 1/3 of the electricity of Shanghai.

2.2 Availability

2.2.1 Forced energy unavailability

For XSH800 project, no bipolar or monopole forced outage occurred since its commercial operation. There were five converter forced outages in last five years at Fulong, the rectifier station. And there were no forced outage at Fengxian, the inverter station in last five years, which is another record for BDCC.

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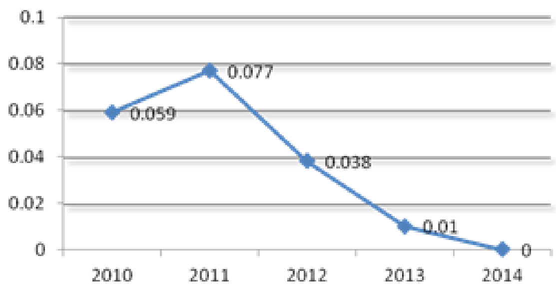
The forced energy unavailability of XSH800 is shown in Fig. 2. Its average is 0.0368%, much less than the designed index, which is 0.5%. With a continuous downward trend, it is promising that the forced energy unavailability can be limited to below 0.4% after 2012, as the stabilization of HVDC equipment and the growing of operation experience.



FEU	Forced energy unavailability		
	2010	2011	2012
average	0.744	0.421	0.605
min	0	0	0.038
XSH800	0.059	0.077	0.038

Fig. 2 Forced energy unavailability of XSH800 project **Table 1 FEU of HVDC projects all over the world**

According to the survey of the reliability of HVDC systems throughout the world during 2009 to 2012 by CIGRE AG B4-04 [3,4], the average forced energy unavailability of the HVDC projects, whose capacity are higher than 1000MW, was 0.59%, while that of XSH800 was 0.0368%, ten times lesser. And the forced unavailability of Itaipu reached 0.5% [5] at its second five years.

The excellent performance of XSH800 project, is a consequence of the fast development of HVDC technique in last 20 years, and also a further improvement of operating and maintenance standard in last 10 years. It has been proven that UHVDC technique is safe and efficient. The design stage statement that the reliability of UHVDC would be even better than that of lower voltage HVDC project [6, 7], is proven by practice also.

The five forced outages of XSH800 are shown in Table 2. The five outages are classified as following:

Control and Protection	2
Transformer	1
Thyrsitor valve	2,

All outages were related to design problems.

Table 2 The forced outage of XSH800 project

date	Reason of the forced outage	Solution to the forced outage
20100807	P2 LV converter was tripped due to maintenance of P2 HV converter OCT	Maintenance key is introduced which disable any protections of the outage converter
20100828	P1 HV converter was tripped due to Control LAN fault	The faulty LAN switch was replaced
20110502	P2 HV Y/Y-C transformer oil leakage due to broken rubber membrane	The broken rubber membrane replaced
20110830	P1 HV converter tripped by its cooling system low flow protection during pump switching	Optimal the settings of the protection, Optimal the power supply of the cooling control system
20130705	The over voltage protection of cooling pump frequency controller switched main pump after a commutation at inverter	Check the measurement accuracy of the frequency controller, Optimal the settings of the protections

2.2.2 Planned energy unavailability

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The planned energy unavailability of XSH800 is shown in Fig. 3, with an average of 7.1%. While according to the survey by CIGRE B4 [3, 4], the average planned energy unavailability of above 1000MW HVDC system is only 2.42%. The reason for the high planned energy unavailability lies on the fact that XSH800 operating under less pressure of power transmission in winter and hence getting a longer annual maintenance outage every year.

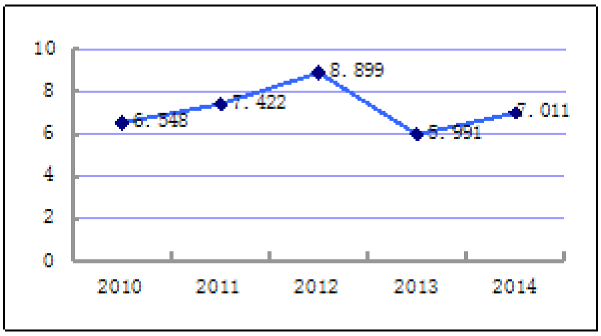

Fig. 3 Scheduled energy unavailability of XSH800 project

And there were 33 deferred outages in last five years, among which included 13 times for thyristor valves , nine times for converter transformers SF6 leakage or oil leakage, five times for DC yard (mainly for voltage dividers measurement fault and connection overheat), three times for GIS SF6 leakage, three times for C&P board failure.

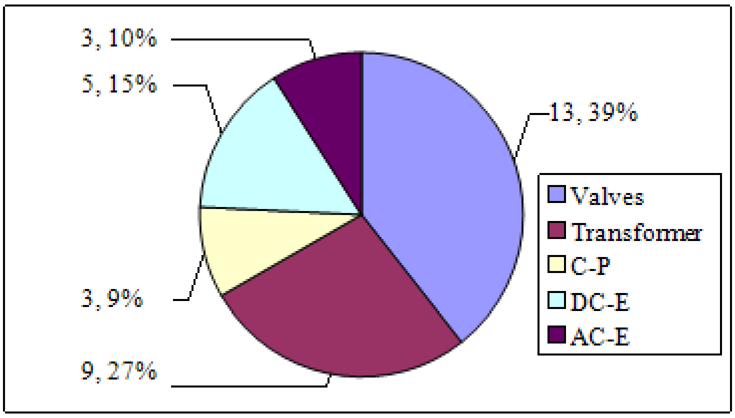

Fig. 4 The planned outages of XSH800 project

2.3 Issues that affected availability of XSH8000

During the five years operation of XSH800 project, some equipment problems have occurred. Proper solution to these problems are not only helpful for long time safe operation of XSH800 but also helpful for new UHVDC projects.

2.3.1 Temporarily lost of firing pulse at the rectifier station

Transient DC current drops were observed during system test of XSH800 project at the rectifier. 9 times of drop were captured in 2 hours on 20100228. Fig 5 shows such a drop.

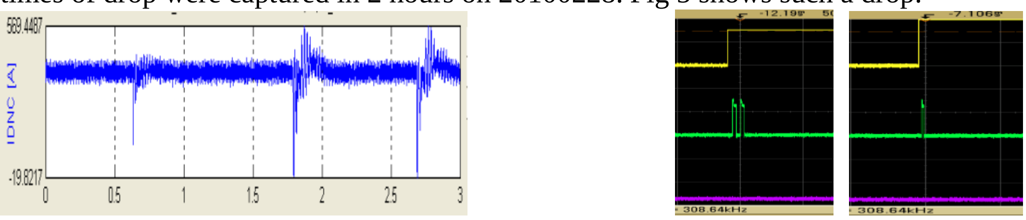

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Fig. 5 A typical current drop during normal operation   Fig. 6 The correct firing pulse (left) and the wrong one (right)

Based on the analysis of the TFR for two weeks, Control Pulse (CP), Firing Pulse(FP) and Check back Pulse of Y bridge valve 3 were monitored by a oscilloscope, which was trigged by the signal from converter control indicating a transient current drop. Fig. 6 shows the signals captured by the oscilloscope. Normally at the rising edge of the CP (yellow), two short pulses are sent to a thyristor as firing pulse, while in this case only one short pulse was generated by VBE. Corresponding thyristor electronics ignored the strange pulse because it was not a double pulses, therefore the thyristors were not fired and DC current dropped as the decreasing of the voltage across the valve.

Further investigation located the fault to a VBE software bug. One internal parameter was set to 8us, which is the time window for VBE to generate the double pulses. Due to the dispersion of the interface boards, sometimes the window was too small to generate two short pulses, so the parameter was changed to 10us. No similar fault occurred any more.

This event exposed the problem that VBE was not fully tested during factory test. So it is required in the later UHVDC projects that VBE should participate in the factory test.

2.3.2 The too sensitive flow protection at the rectifier station

Limited by the thermal property of the thyristor valve damping resistor, the low flow protection of the valve cooling system was set to trip converter as soon as its flow dropped to 50% of its nominal value. The settings was too sensitive to avoid the flow disturbance during cooling pump switching or auxiliary power switching and tripped converter respectively on 20110830 and 20130705, especially the later one.

On 20130705 a commutation failure at inverter station lead to an over voltage of 1.2p.u at the rectifier station AC bus. Hence the over voltage protection of the cooling pump frequency controller switched the pumps and caused a low flow for about 1.3 seconds, which is just met the condition of low flow fast trip.

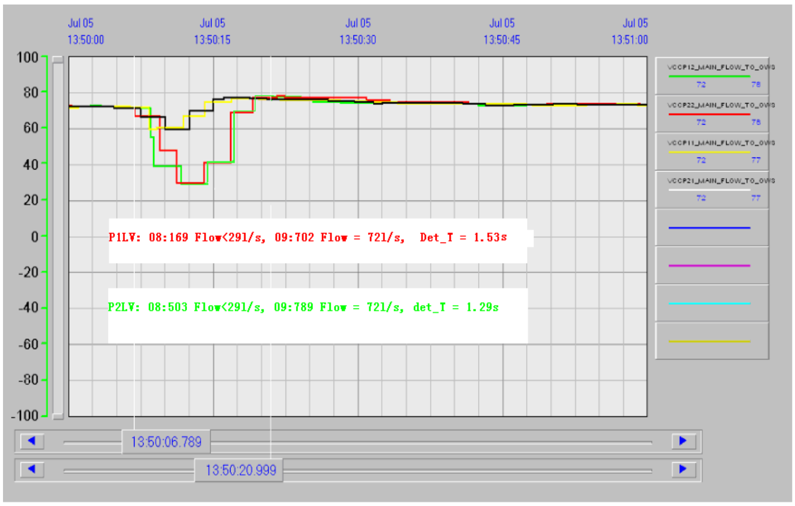

Fig. 7 The main flow of the 4 converters on 20130705

To solve the problem, the damping resistor was tested with the conditions of low flow at different firing angle. It was observed that it is ok for firing at 17 degree for 15s, at 40 degree for 7s, and at 90 degree for 1s. It was proven by the test that the damping resistor can work correctly for at least four seconds, without considering the cases running at 90 degree. This modification was introduced in other new UHVDC project, together with more attention to

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the protection settings of the Auxiliary power breakers, relays, and also valve cooling system frequency controller or soft starter.

2.3.3 Broken rubber membrane lead to a forced outage at the rectifier station

Continuous oil leakage was observed on 20110429 at the breather of transformer P2 HV Y/Y-C transformer, with a speed of 1.5 l/min. The transformer was tripped on 20150502 by its gas Relay. It was found by further checking that the rubber membrane was broken.

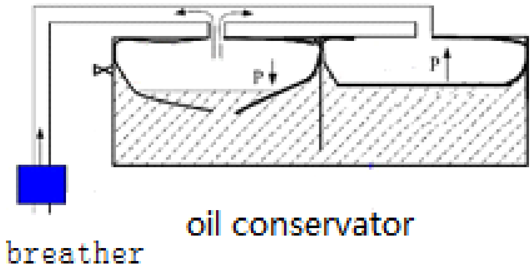

Fig. 8 The broken rubber membrane of the oil conservator tank Fig. 9 The structure of the oil conservator tank

The structure of the oil conservator is shown in Fig. 9. When the left membrane was broken, gas pressure of the right membrane increased and pushed the oil to rise quickly to the top of the conservator and flow down to the Silica-gel breather. Siphonage arose in this case. As more and more oil leaked from the breather, the oil level decreased until below the gas relay and the float dropped.

After this incident, it was decided that rubber membrane leakage detect device should be installed for the later projects, and operators should discover and handle low oil level fault timely.

2.3.4 Transformer coolers oil leakage at the inverter station

The transformers at the inverter station operated smoothly from 2009 to 2013. After flow power operation in the summer of 2013, it was found that H_2 in the transformer oil kept increasing due to leakage of 2nd cooler. At the beginning of 2014 similar leakage was found at several transformers.

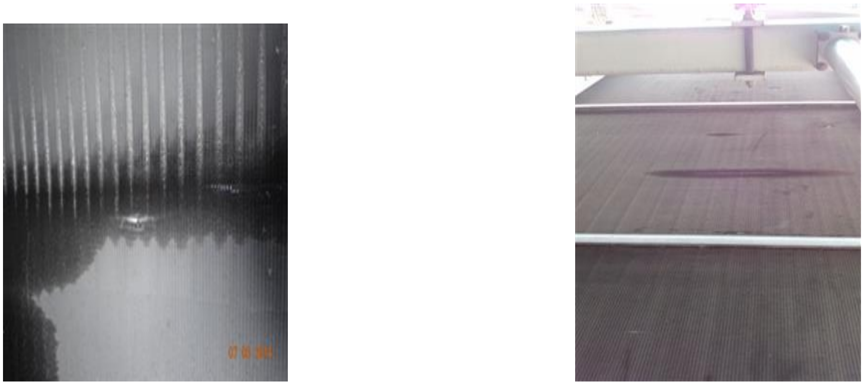

Fig. 10 Transformer cooler leakage at Fengxian station

It was noticed that all the leaking coolers were made by the same company. Related to the material and the processing techniques, small holes and damages appeared after long time of

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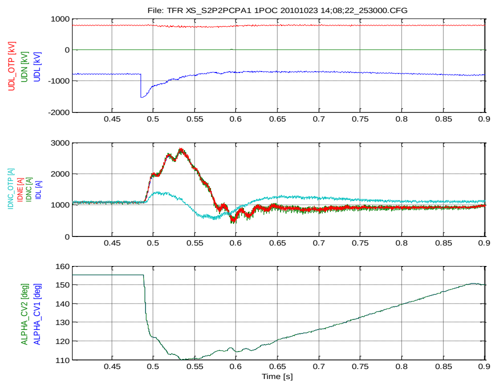
operation. The oil pipes for all the converter transformer coolers were replaced with stainless steel pipes in 2014.

2.3.5 DC voltage measurement fault at both stations

On 20101023 rectifier station noticed that Pole 2 DC voltage dropped from 800kV to 180kV for 400ms. By checking TFR of both station, we see the whole process. First the DC voltage of inverter jumped from -770kV to -1500kV. Then the voltage controller of inverter increased its extinction angle from 17 degree to 60 degree to limit the DC voltage. And thirdly the DC voltage at rectifier side dropped also till the voltage controller withdrew.



Date	Gas samples	H2O	C2H2	C2H4
0505	Taken from the divider	197	0.00	13.4
0507	New Gas	52	0.00	1.29
0710	Take from the divider after 3 measurement faults	300	0.10	1.89
0730	Take from the divider after the fault on July 21st	300	0.24	2.34

Fig. 11 DC voltage measurement fault at inverter side **Table 3 The gas analysis of rectifier pole 1 voltage divide**

This DC voltage measurement fault happened six times at rectifier station and five times at inverter station, and all in raining condition. Based on the statistics for the features of the fault and the conclusion of simulation, the fault was traced to voltage divider internal flashover. So the gas inside dividers was analyzed. Table 3 shows that C_2H_4 had reached 13.4ppm after all the previous faults. The dividers were refilled with new gas on 20110507, while C_2H_4 increased to 2.34 after four faults. This proved that partial discharge occurred inside the voltage divider and changed voltage divider ratio temporarily.

One of the divider was disassembled in the factory. Discharge marks were found on the resistor barrel. Further analysis deemed that it is better to fill the dividers with SF6 instead of N_2, for better insulation. After the dividers were refilled with SF6, no similar fault happened again till now. This measure was introduced to next three UHVDC projects too.

2.3.6 Transformer related issues

Generally speaking the transformers of XSH800 project operated smoothly in last five years, except following problems such as bushing leakage, oil leakage, and so on.

P1 HV Y/Y-B transformer bushing 2.1 was found leaking in August of 2011. The transformer was isolated and checked. Leakage spots were found on the bushing. So the transformer was replaced with a spare one and the bushing was disassembled for further check. A black pinhole was found on the insulator (Figure 12a), and burning marks was found on the conduct rod (Figure 12b).

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Fig. 12a the pinhole on the Insulator

Fig. 12b the marks on the conduct rod

On 20121128, the content of H_2 in the P2 LV Y/Y-C transformer jumped to 189ppm. After further checking it was found that the sensor of the online monitor device was broken. So the carrier gas, helium gas in this case, entered the transformer and was misjudged as H_2.

Several leakages were found at the end of 2013, at the position between the bushing ascending flange and the transformer body. Due to its higher potential, 800kV DC bushing is heavier. And the flange connected the DC bushing and the transformer body bearded not only the weight of bushing 2.2 but also part of the weight of bushing 2.1. So the upper part of flange got extra pulling force. That is why oil leakage were found at the same position on several transformers of this type.

To solve the problem a support frame was installed to reduce the stress of the flange. No more leakage occurred. This solution was also introduced to next three UHVDC projects too.

Fig. 14a 800kV converter transformer Oil leakage

Fig. 14b Bushing with the support frame

2.3.7 Main circuit equipment joint overheat

In last years, joint overheat has led to 1/3 of the whole deferred outages, especially when XSH800 was running in full power in every summer. The overheating mainly occurred at thyristor valve components and the connections of DC yard equipment.

On 20131018 the temperature of Fengxian pole 1 smoothing reactor DC side connection reached 186 ℃. On 20140606 the temperature of Fulong P2 HV Y/D-B valve reactor connector reached 110 ℃. On 20140907 Fulong P2 LV Y/Y-C valve reactor connector reached 138 ℃.

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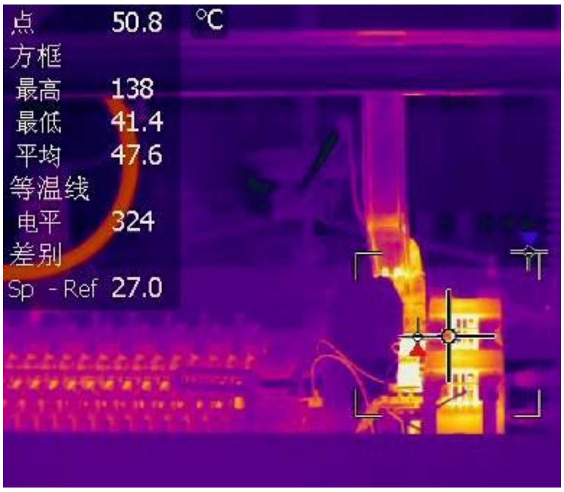

Fig. 15 The overheat of the valve reactor connectors

It was found that the valve reactor connector was made of aluminum and the other contact was made of copper, with a surface of 5874 square millimeter. So the current density at rated current would be 0.4 Amp per square millimeter, which is far below 0.0936, the value suggested by relative standard.

From July to September in 2014, about 4000 connectors or joins were checked. Some of them was found not to full fill the current density requirement. Those connectors were redesigned and rebuilt.

It is suggested that for new project, especially the project with higher transmission capacity, the material, current density, clamping force of all kinds of joint or contact between main circuit equipment should be verified at the design stage.

2.3.8 AC filter L2 overloaded at Fengxian

On 20110701 when XSH800 was running on 2700MW, the four AC filters switched in at Fengxian station tripped suddenly by L2 overload protection. In next 11 minutes, RPC was trying to switching in available filters, while every switched in filter was once again disconnected by its L2 overload protection. To avoid equipment failure, pole 1 was blocked while pole 2 remained running.

TFR showed that at the moment when four AC filters were tripped, the current through L2 was 427A, just meet the condition of fast trip. And RPC logic shows that at 2700MW three filters are needed for Absmin filter requirement. To investigate the reason of L2 overflow, the L2 current was monitored during adjust the transmission power. L2 current rose to 386A (91.5%) when ramping from 1000MW to 1700MW. And during the test, it was observed that L2 current increased 12A, reaching 94.3%, from 3 o'clock to 9 o'clock in the morning. And during the same time, the DEFF of the AC lines increased from 1.4% to 1.5%, mainly due to additional 5^{th} and 11^{th} harmonic. Since there was no change in the loading on XSH800, the harmonics produced by XSH800 should remained the same, so the increasing DEFF indicated that there were some other harmonic sources working during that time.

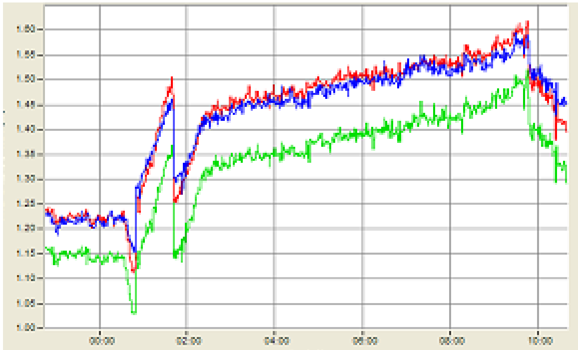

Fig. 16 DEFF during the test

The overload ability of L2 was reassessed and the settings of the overload protection was changed from 427A to 750A. And more detailed verification was carried out in the new UHVDC projects.

2.3.9 Transformer saturation protection at rectifier station

On 20150610, the saturation protection of P2 LV converter transformer activated and switched the control system of P2 LV. Since its saturation protection was not reset after the switching, P2 LV was blocked manually 30 minutes later, P2 HV converter transformer saturation protection also switched its control system. This time the saturation protection reset after the switching.

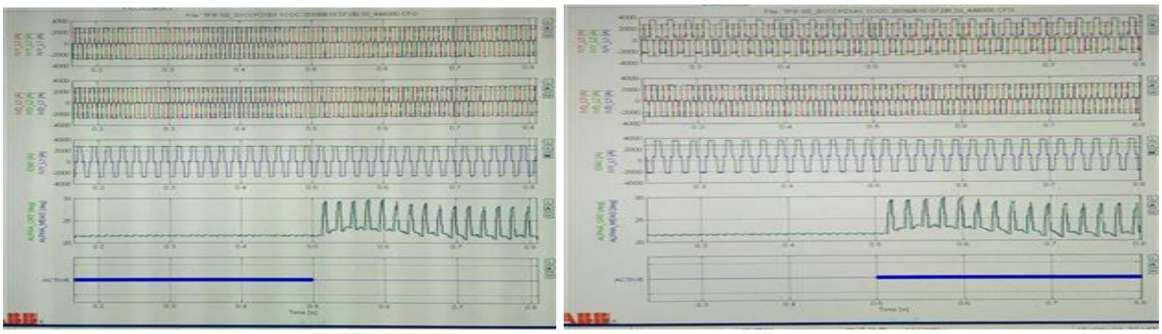

Fig. 17 TFR by P2HV control system B (left) & A (right)

TFR of HV shows that before 07:08:33 P2 HV was controlled by system B, with firing angle remaining 22 degree, while after 07:08:33, P2 HV was controlled by system A, with firing angle varying between 20 degree and 30 degree every 20ms. The abnormal firing angle of A system was a consequence of the big offset of IVY_L1 measurement of A system.

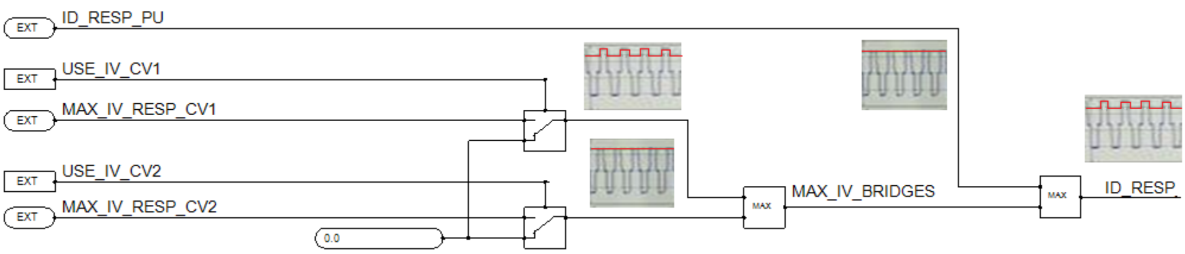

Fig. 18 The logic to calculate DC current response

The DC current control was located at pole level. The transformer valve side currents of high voltage converter and low voltage converter, together with the DC current are collected by pole control and and calculated according to the logic in Fig. 13. Since an offset of 600A was generated by IVY_L1 measurement board, the calculated ID_response turned out to be something like an offsetted square wave. This signal caused mis-operation of the current

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controller and generated a varying firing order. And the asymmetry of the firing pulses leaded to the saturation of both HV and LV converter transformer.

It is suggested that in the new UHVDC project, the transformer saturation protection switches pole control system instead of converter control system if current controller is located at pole level.

3 Conclusion

After analysis the reliability and related events of XSH800 project in last five years, the following conclusion can be drawn,
(1) XSH800 project has transmitted 93900 million kWh in last five years, with a forced energy unavailability as less as 0.0368%. It has been demonstrated that 800kV HVDC technology is safe and efficient.
(2) The issues that affected the reliability of XSH800 project in last five years have been properly solved, and the solutions have been introduced to the next three UHVDC projects of BDCC. XSH800 project served as a model of UHVDC technique and promote the rapid develop of UHVDC projects by its excellent performance.

(3) The scheduled unavailability is quite higher than the average parameter of the HVDC projects over the world. The primary reason is due to its long annual maintenance outage, and the secondary reason is too many deferred outages. It is promising to improve the availability of XSH800 by optimizing operation and maintenance policy and improving operation and maintenance standard.

End of text

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