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Planning the Next Nelson River HVDC Development Phase Considering LCC vs. VSC Technology

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SUMMARY

This paper will examine the technical feasibility of using voltage source converters (VSC) technology for Bipole III using a generic PSS/E transient stability model developed by ABB. The study has shown that VSC technology is feasible and can operate in a much weaker network compared to a traditional line commutated converter (LCC). The model indicated that it was feasible to operate the VSC in a weak network in the range of effective short circuit ratio (ESCR) between 1.2 and 1.3 with some minimal gain reduction to avoid control mode oscillations. For even weaker systems, additional frequency control would be required to make the VSC link look more like a synchronous machine with inertia. A single infeed VSC is limited to an ESCR of around 2.5 in order to prevent excessive underfrequency for 3-phase inverter faults, rectifier AC faults or a complete Bipole block.

Bipole III with VSC would not require 1000 MVAr of synchronous condensers (SCs) as a LCC would, which would save significant capital cost, operating and maintenance expense and losses.

DC fault recovery for a VSC is shown to be slower compared to LCC assuming fault clearing via ac breakers. However, this did not result in transient voltage or frequency criteria violations. The addition of DC breakers makes the performance of a VSC more similar to a LCC. Rectifier AC faults in the VSC resulted in reverse power flow in the inverter, which effectively made the power loss larger leading to larger frequency excursions at the inverter compared with LCC. Control modifications are recommended to minimize the impact on the frequency response at the inverter. There is voltage stability improvement if the VSC inverter quickly converts to a Statcom following DC line fault clearing.

KEYWORDS

HVDC; voltage source converter (VSC); line commutated converter (LCC); Nelson River; transient stability, frequency response, synchronous condenser (SC);

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1. INTRODUCTION

The Nelson River in northern Manitoba has a large hydro potential. To date, Kelsey (251 MW – 1960, Kettle (1224 MW – 1974), Longspruce (1027 MW – 1979) and Limestone (1343 MW – 1992) have been developed. Plans are underway to further develop Keeyask (630 MW – 2020) and Conawapa (1395 MW – 2025) in the next 10-15 years. The early transmission planning concepts in the late 1960's and early 1970's for delivering power from the lower Nelson involved the development of three HVDC links between common stations in both the north and south and on a common corridor. Detailed technical and reliability analyses were not performed for the ultimate development. Early studies only concentrated on the first two Bipoles [1].

Bipole I is rated at ±463.5 kV, 1854 MW and was put in service between 1972 and 1976 using mercury arc technology. The Nelson River mercury arc valves were the highest rated in the world at the time at 150 kV. These valves have since been retired and replaced with thyristor technology between 1992 and 2004. Between 1978 and 1985, Bipole II was constructed and commissioned. Bipole II is rated at ±500 kV and 2000 A.

Bipole I and II have been planned to maintain a minimum ESCR of 2.5, which has required the addition of 1860 MVAr of synchronous condensers (6-160 MVAr and 3-300 MVar units). The overall availability of the SCs is approximately 89%. Therefore, to be conservative, the ESCR is planned with 460 MVAr of SC out of service. Additional control features have been added to provide security against voltage collapse. The system undervoltage controller (SUVC) detects impending voltage collapse by monitoring the inverter voltage. If the voltage stays below 0.99 pu for more than 150 ms, a 345 MW DC reduction is initiated [2]. An U_d-hold control function freezes the dc voltage at a preset value, which creates a pseudo-constant current control mode. This control mode also helps to prevent voltage collapse.

The next Bipole in Manitoba is being planned to serve several purposes. The primary purpose is for reliability. Nearly 70% of the power in Manitoba is generated from three hydraulic stations on the Nelson River in northern Manitoba. This power is transmitted over a distance of 900 km via the Nelson River DC transmission to a major switching station (Dorsey) located near the major load centre of Winnipeg. Loss of the DC transmission corridor or loss of the Dorsey converter station puts the Manitoba load at risk of rotating black outs. While this is a low probability event, the risk is deemed too great and a high capacity DC line on a separate corridor terminated at a new substation called Riel is being planned to be in service in 2017. Riel is approximately 38 km east of Dorsey. In addition to reliability, the line will carry a large portion of the power from the next two proposed hydraulic plants, Keeyask and Conawapa, to supply both domestic load growth and future export sales.

Originally, the third Bipole was planned to use conventional thyristor technology as is used in Bipole II. Having three LCCs connected in close proximity raised multi-infeed concerns. In order to minimize interactions, Bipole III will be designed to maintain a minimum MIESCR [3] of 2.5. An MIESCR of 2.5 is maintained at both Dorsey and Riel with two SCs out of service at both Dorsey (460 MVAr) and Riel (500 Mvar). This requires a total of 1000 MVAr of synchronous condensers to be installed at Riel. The SCs are beneficial in providing inertia to support the southern frequency in case all of the inverters fail commutation or for rectifier faults that impact the power transfer capability of the bipoles. However, the added inertia also effectively increases the fault levels at several buses that may require significant equipment upgrades and replacements. Due to many technical concerns such as commutation failure and high fault levels, future hydro development is planned to use ac transmission following construction of Bipole III. As the AC system gets stronger, it is planned to retire synchronous condensers to manage the short circuit level.

Voltage source converter technology for dc transmission has evolved very rapidly since it was introduced in 1997 with the 3 MW, ±10 kV demonstrator project at Hellsjön, Sweden. In 2005, CIGRÉ Working Group B4-37 noted that LCC DC was still superior to VSC transmission in terms of capital cost and power losses for large-scale DC systems although there was no technical reason a 500-kV 3000-MW link could not be built [4]. This conclusion is out of date since the recent announcement that Skagerrak 4 between Norway and Denmark will be the first 500 kV VSC pole and is planned to be constructed by 2014 [5]. Skagerrak 4 is planned to be 700 MW, which is a feasible size for Bipole III assuming two parallel converters per pole (500-625 MW per converter). With the successful commissioning of the 950 km Caprivi Link Interconnector in Namibia in 2010, the application of VSC DC transmission to overhead lines has been shown to be feasible [18].

2. SHORT CIRCUIT IMPACTS

One of the main drivers for considering VSC technology for Bipole III is to mitigate the growing fault current in the Winnipeg area. Figure 1 indicates the growth in fault current at the Dorsey substation since the 1970s. The large jump in fault current around 1990 corresponds to the addition of 3x300 MVAr SCs at Dorsey [6]. The large jump around 2017-2020 corresponds to the addition of 1000 MVAr of SCs at Riel and a new 500 kV tie line to the United States. VSC technology avoids the need for synchronous condensers; hence the smaller jump in fault current.

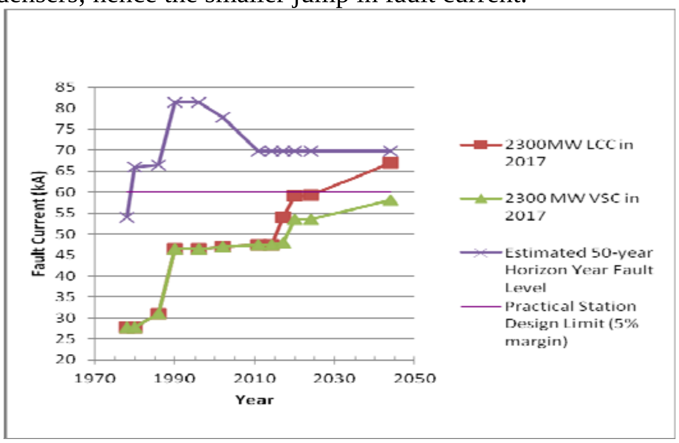


Figure 1: Fault current growth at Dorsey 230 kV substation, Winnipeg.

The Dorsey air-insulated substation has a practical design limit of 63 kA. Exceeding this value would require the complete rebuild of the station as an 80 kA gas-insulated substation. Air-insulated circuit breakers that are able to clear 80 kA at -50ºC do not currently exist. Alternative solutions to the fault current increase may develop over time, such as superconducting fault current limiters or a Statcom with high-speed energy delivery capability. A Statcom, by itself, would provide sufficient fast acting voltage support to prevent voltage instability but wouldn't be able to provide inertia to prevent excessive transient underfrequency. In addition, conventional Statcom controls have been shown not to work well in the presence of low order harmonic resonance as is the case with an LCC DC converter connected to a weak AC grid [16]. Modified controls have been proposed to make a Statcom perform closer to a synchronous condenser [16]. Considering the application of a Capacitor Commutated Converter (CCC) was deemed not feasible as such a scheme has never been used in an overhead line configuration before. In addition, performance of the CCC scheme during unbalanced faults, the need for continuously tunable or active filters and additional valve voltage stresses are a few disadvantages that outweigh the potential ability to operate in weaker AC networks [14]. Developing Bipole III as VSC would defer the need to investigate such new fault current limiting technology for at least an additional 20 years.

The VSC may contribute some short circuit current in contrast to conventional LCC [7] depending on the control mode and other factors. Assuming the converter operates in ac voltage control during the fault, the contribution to fault current is similar to a Statcom (i.e. capacitive current to support depressed voltage). It is possible to model the contribution using an impedance method, which limits the current to roughly 0.5 pu for close-in faults [8].

3. STUDY MODELS AND METHODOLOGY

A. AC System

The interconnected AC system models that were studied included future year winter peak and summer off-peak cases. Figure 2 provides a high level diagram of the DC inverters in the south of Manitoba at the Dorsey converter station and the future Riel converter station, as well as the province’s tie lines.

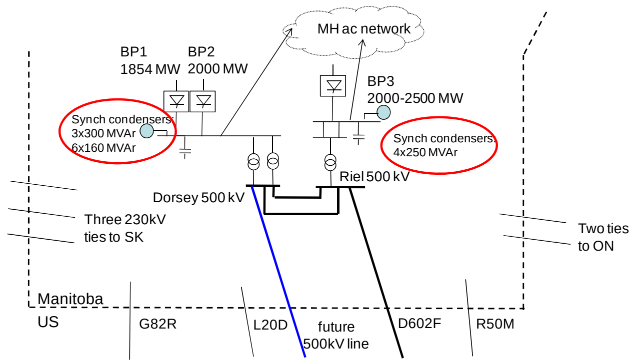


Figure 2: High level diagram of Manitoba Hydro’s southern system DC inverters and tie lines.

B. VSC DC Models

The VSC model used to represent the VSC DC bipole(s) was a generic PSS/E model developed by ABB [8]. This model was originally developed to represent typical ±80, ±160 or ±320 kV cable connections to offshore wind plants. Two of the ±320 kV models were connected in parallel to represent the bipolar overhead line for Bipole III. The same dc line parameters as in the LCC option (500 kV) were used and therefore the DC line losses are lower in the VSC option compared to the LCC option. This is a pessimistic assumption for inverter disturbances as less reactive power is available.

The Open VSC Model has been calibrated and checked against the response of a detailed converter model in PSCAD. The results in Figure 3 show that the PSS/E Open Model, in these cases, is virtually independent of time step in the range 1-10 ms. The blue curve from the PSCAD simulation shows a slightly faster reaction to the fault and a lower reduction of the direct voltage (UDC_A1).

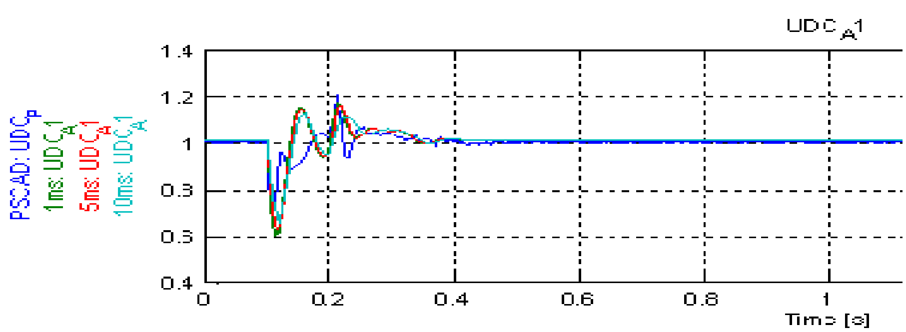


Figure 3: Sample graph from comparison between PSS/E model and full PSCAD model. 3-phase short circuit at rectifier with <10% remaining voltage.

Some of the reactive power responses at the point of common coupling (Qpcc) do not match in the transient time frame but settle to a good match. In fault cases with a dropping direct voltage (typically an ac fault in the converter that inject power in the dc system), the results in the PSCAD simulations shows a d-component of the phase current that drops faster than the current order, this makes for a faster decrease of the dc system discharge, and a smaller dip in dc voltage, which makes the system capable of fulfilling the reactive power order.

Currently the semi-conductor device of choice for VSC is the Insulated Gate Bipolar Transistor (IGBT). The IGBT ratings available today in a press-pack configuration depends on the number of sub-modules e.g. 2, 3, 4 or 6. Four submodules give the converter an ac rating of 1140 Amps and six submodules give 1740 Amps. The size of Bipole 3 is currently being optimized and is planned to be 2300±200 MW. Given the size of available IGBTs today, parallel converters will be required as shown in Figure 4. Parallel converters in a VSC Bipole would be consistent with Manitoba Hydro's reliability philosophy. Two series valve groups in each pole of a LCC would have similar reliability.

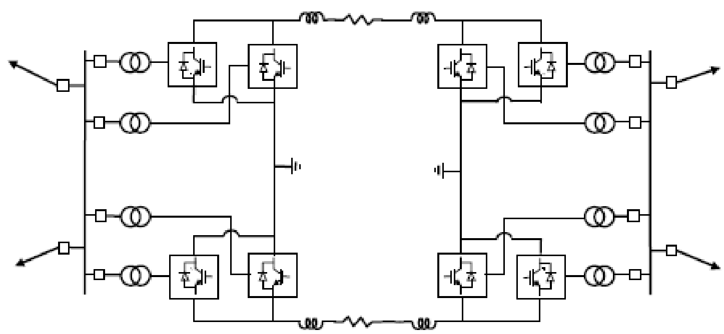


Figure 4: Bipole 3 conceptual single line diagram assuming voltage source converters.

C. Methodology

In order to make a comparison of the integrated AC system performance and the SC requirements for LCC technology versus VSC technology, transient stability simulations were performed for the following faults for each of the study scenarios:

- Solid three phase fault at the rectifier
- Solid three phase fault at the inverter
- Remote three phase fault at the inverter

The following study scenarios were evaluated and compared:

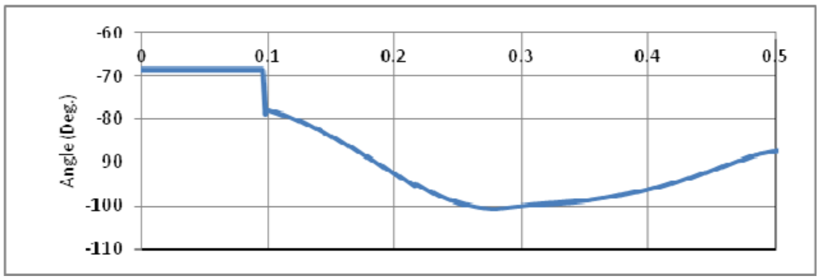
- Bipoles I, II and III as LCC
- Bipoles I, II as LCC, Bipole III as VSC
- Bipole I as LCC, Bipoles II and III as VSC
- Bipoles I, II and III as VSC
- Bipole I and II out of service, Bipole III as LCC and VSC

The key criteria for this study included:

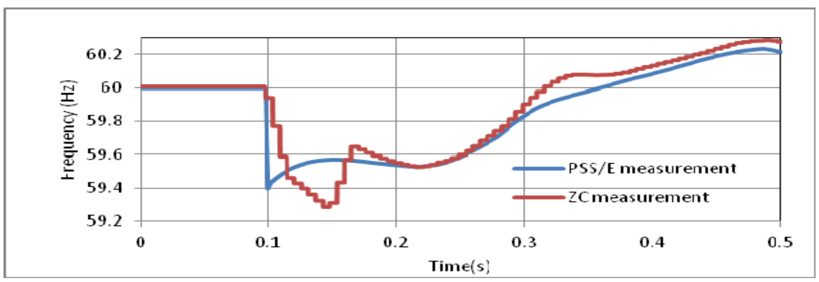
- Transient undervoltages should remain above 0.7 pu
- Transient overvoltages should remain below 1.3 pu for 200 ms.
- Transient underfrequency should not drop below 59.3 Hz for more than 100 ms. Minimum 2 cycle margin required. This prevents underfrequency load shedding.
- Min. frequency in Manitoba 58 Hz: prevent generator or Saskatchewan tie line tripping.

Accurate frequency measurement is a challenge with PSS/E. PSS/E measures the bus frequency by differentiating the bus angle and then passing through a low pass filter. For sharp changes in bus angle, the calculated frequency depends on the filter time constant. Usually in UFLS relays, the frequency is measured using zero crossings of the sine waves. A simple technique has been used to estimate the frequency based on zero crossings in this paper. The PSS/E bus voltage angle measurement is inserted into a sine function and the frequency is calculated from the output sine wave using measured zero crossings. The average over three cycles is taken to minimize the errors. Figure 5 (b) compares the frequency measurements for the bus angle change shown in Figure 5 (a). The bus angle suddenly dropped at 0.1s due to a fault and therefore the frequency of the system dropped. The PSS/E result shows the recovery of the frequency just after the initial drop. However, the rate of change in angle is still increasing (negatively) and therefore further drop in frequency is expected. The zero crossing measurement shows this change properly. These transient changes are important when determining frequency based load shedding criteria. Therefore, the zero crossings based frequency measurements were used in this paper.

The transient underfrequency criterion is quite severe compared to guidelines presented in [17]. The IEEE guide recommends a minimum effective inertia constant of 2 seconds in order to limit the frequency deviation to 5% (57 Hz). Such an inertia constant is needed in low inertia systems to prevent excessive frequency deviations for typical events such as commutation failure or dc line faults. Manitoba Hydro is connected to the North American power grid and must follow NERC standards. The NERC standards mandate that no load should be shed for a normal clearing fault. In addition, NERC standards require coordination of UFLS settings with neighbouring utilities. The first block of load shed is typically set at 59.3 Hz. High speed load shedding (6-7 cycles) is used to prevent out of step relays from operating on the 500 kV Manitoba to US interconnection, which will cause cascade tripping and separation of Manitoba from the main grid [19]. High inertia systems can utilize slower UFLS relays (eg. 5 to 30 seconds).



(a) Bus Angle Measurement



(b) Frequency Measurements (PSS/E uses 50 ms low pass filter)

Figure 5: Comparison of frequency measurement techniques.

4. TRANSIENT STABILITY SIMULATIONS

A. System Intact

For the system intact case, transient stability simulation results have been reported in [9]. To summarize, replacing one or more of the LCC links in Manitoba with VSC technology showed an improvement in the system performance for faults that are remote to the inverter buses at Dorsey and Riel. The major improvement was observed in the frequency dip that occurs during this type of fault as less power is lost temporarily during the fault because there are fewer (or no) LCC links that are failing commutation. The VSC links transmitted a significant amount of power during a remote ac fault. The VSC power transmitted during the fault depends on how low the terminal voltage is.

If Bipole III is built as a VSC without any new synchronous condensers at the Riel inverter station, the frequency dip in the southern system that occurs as a result of the VSC DC line fault worsens as shown in Figure 6 due to commutation failure occurring in Bipole I and II. However, the system response is still acceptable. The VSC DC line fault was found to be the defining faults of those studied when considering the feasibility to build or replace the bipole(s) with VSC technology. A rectifier AC fault also resulted in a significant frequency drop at the inverter and was independent of the technology. Once Conawapa is placed in service, the rectifier AC collector system will be split to prevent a single fault from impacting all Bipoles.

It should be noted that research in the area of solid state DC breakers is underway and faster and higher-rated breakers are expected to enter the market in the near future [10]. There are also new solutions proposed by some VSC manufacturers involving the use of a full H bridge in a multilevel configuration that do not require the use of a DC circuit breaker to mitigate the effects of DC line faults on the AC grid [11]. The impact of DC breakers will be further discussed in the next section.

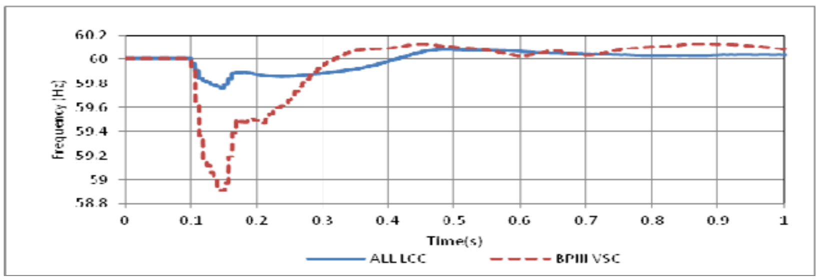


Figure 6: Manitoba southern system frequency response to a DC line fault.

B. Dorsey Station Outage

Bipole III is planned to be able to serve Manitoba load under the worst case condition of catastrophic failure of both Bipoles I and II considering outage of up to two syncs. This is the weakest AC network condition and defines the minimum ESCR of 2.37. The ESCR increases to 4.19 with all Riel SCs in service. For comparison, the VSC ESCR is 2.50 without using synchronous condensers. There are no filters assumed required with a multi-module VSC converter, which would degrade the ESCR and the VSC converters contribute 0.5 pu to the short circuit strength.

The VSC option, as studied, has more extreme deviations in underfrequency compared with the LCC option. However, in all cases, underfrequency load shed was not triggered for an N-1 disturbance (i.e. the frequency did not drop below 59.3 Hz for more than 100 ms) and the minimum frequency did not drop below 58 Hz. The conclusion could be that the ESCR limit for a single infeed VSC scheme is 2.5 to cover for loss of the VSC Bipole (Rectifier AC fault). Multi-infeed VSCs could potentially be designed to provide some inverter frequency control to improve the weak system response [15, 18].

Figure 7 shows one example of the frequency dip resulting from a three-phase normal-clearing rectifier AC fault. One would expect the frequency response to be the same as LCC because the DC links are the same size. However, in the case of the VSC, the inverter continues to try to extract rated power during the rectifier AC fault which helps drive the DC voltage down quickly. Once the DC voltage is lower than the AC voltage, the inverter diodes conduct to try to charge up the DC voltage, hence the power reversal. Potential solutions, that require further study, include considering a full bridge configuration rather than half bridge, modifying the control strategy to make both the rectifier and inverter responsible for DC voltage control [12] or blocking the inverter for a rectifier AC fault. The effect of converter blocking will be discussed in the next section.

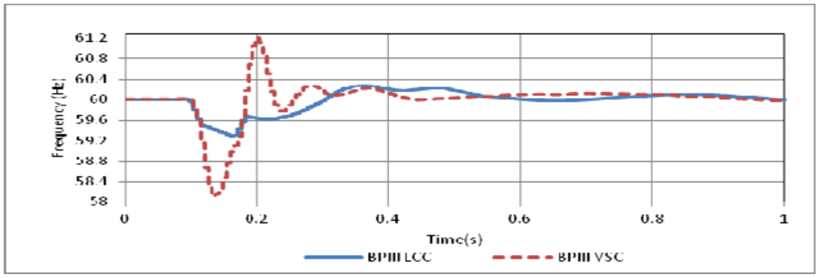


Figure 7: Frequency dip at Riel for a rectifier AC fault – 2000 MW Bipole III.

An inverter fault, also produces a severe underfrequency transient as shown in Figure 8. The VSC scheme has an improved response because the four 250 MVAr SCs are short circuited. However, UFLS relays are not expected to operate in either case.

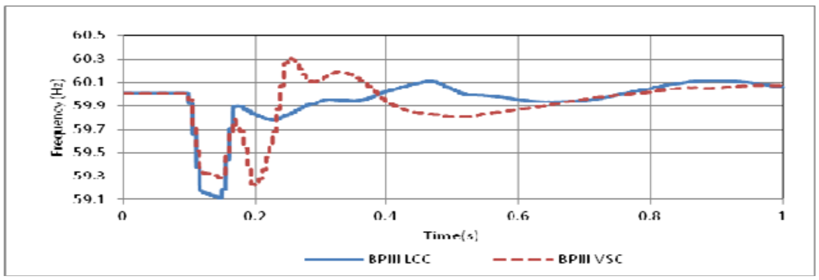


Figure 8: Frequency dip at Riel for an inverter AC fault – 2000 MW Bipole III.

A complete VSC pole block is more severe compared with an LCC pole block because the LCC scheme has much more voltage support connected to the 230 kV inverter bus. Tripping the LCC pole, frees up a lot of reactive power in the synchronous condensers as the LCC converters are no longer absorbing vars. However, if DC breakers are installed, a VSC scheme could be designed to immediately switch to Statcom mode once the DC breaker cleared the DC line fault and supply 0.5 pu of reactive power. In this case, the post disturbance transient voltage response would be comparable between the schemes. The next section will describe mitigation strategies in more detail.

5. TESTING MITIGATION STRATEGIES

A. DC Breaker Performance

A new ABB PSS/E Open VSC Model is available and is capable of modeling a DC breaker. Figure 9 compares the performance between using an AC and DC breaker assuming the following clearing times:

AC Breaker (time measured from the fault occurance):

After 100ms – trip ac breaker

After 500ms – Pole is back in operation

DC Breaker (time measured from the fault occurance):

After 20ms – trip dc breaker

After 120ms – Pole is back in operation

The PSS/E results still indicates com-fails for the Dorsey LCC Converters for the VSC option with DC breaker at Riel. However, the duration is much less. This may not be observed if detailed DC models are used. Typically, the AC voltage drop has to drop below 90% before a commutation failure is expected. There are on average 50 AC faults that cause commutation failure on Bipole I and II each year. The DC system recovered successfully from all events and only occasionally suffers from multiple commutation failures.

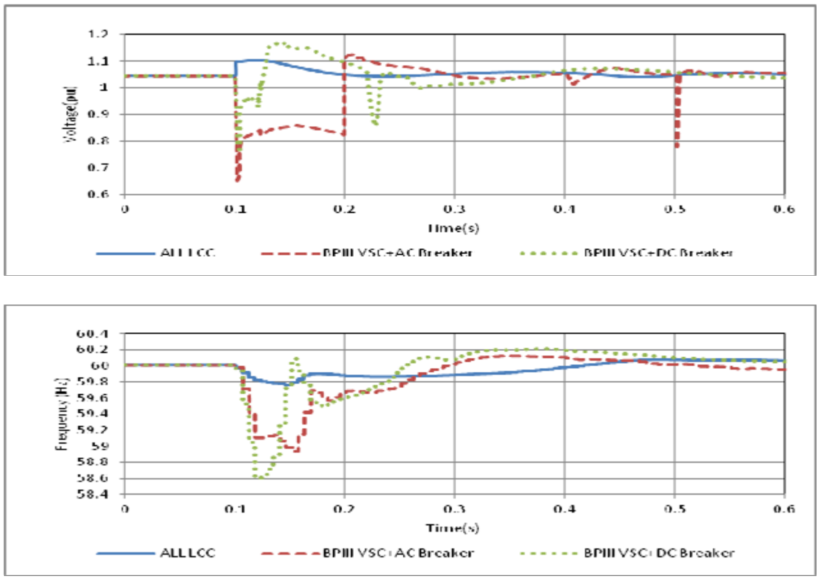
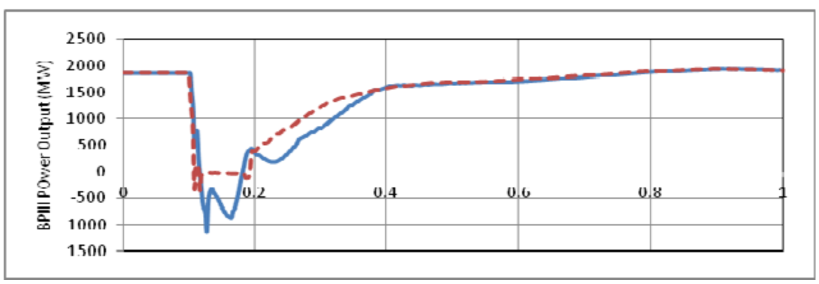


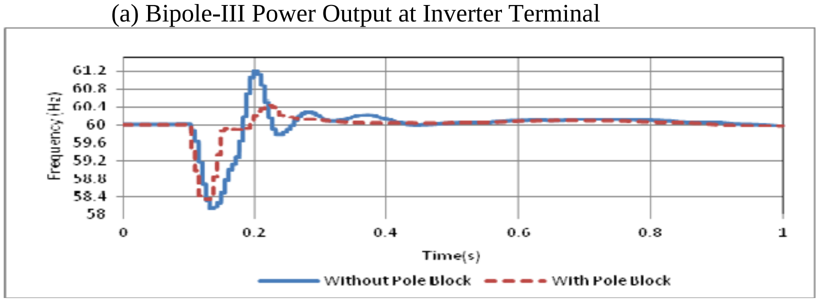
Figure 9: Temporary DC fault clearing. Top: Riel voltage, Bottom: Dorsey frequency.

B. Simulate pole blocking to eliminate reverse current at the inverter.

In order to try to improve the inverter frequency response for a rectifier AC fault, the inverter was blocked. The resulting bipole power order and frequency response are shown in Figure 10. The frequency response is improved and is acceptable. The LCC response with all SCs connected as shown in Figure 7 is superior as the SCs are providing a large inertial response. The VSC response could be further improved by only blocking reverse power while permitting reactive power control. This is the limiting case in terms of frequency performance.



(a) Bipole-III Power Output at Inverter Terminal



(b) Frequency Deviation at Inverter Terminal

Figure 10: Frequency changes at inverter terminal due to reverse power of 2000 MW VSC option for Dorsey-out powerflow scenario.

D. VSC with fast switch over to Statcom mode

For either a permanent pole block or Bipole block, a large power deficit results in the Winnipeg area. A significant portion of this lost power is supplied from the US. In the extreme situation following catastrophic failure of Dorsey, Manitoba will be importing heavily on the existing tie lines to supply peak load. Loss of all or part of Bipole III, will heavily stress this interface and could result in voltage collapse. The stress increases with the size of the Bipole. It is assumed that a bipole block will be due to a disturbance on the transmission line affecting both lines. Therefore, it is feasible that all inverter converters will remain healthy. Fast conversion of the VSC inverters to Statcom mode, prevents voltage collapse and makes the performance comparable to LCC. The frequency and voltage response for a 2500 MW Bipole block is given in Figure 11. A 2000 MW Bipole block was stable and the steady state post disturbance voltage at Glenboro (sending end of line G82R – Fig. 2) was 0.90 pu in both the LCC and VSC cases. For the 2500 MW Bipole block, the LCC case was actually unstable because the out-of-step relays on the 500 kV line activated. With the relay blocked, the lower plot in Figure 11 shows a minimum transient voltage less than 0.7 pu, which violates criteria. Both cases stabilize at 0.8 pu. After 2 seconds, the minimum acceptable voltage should be 0.9 pu or greater. Therefore, undervoltage load shedding is recommended.

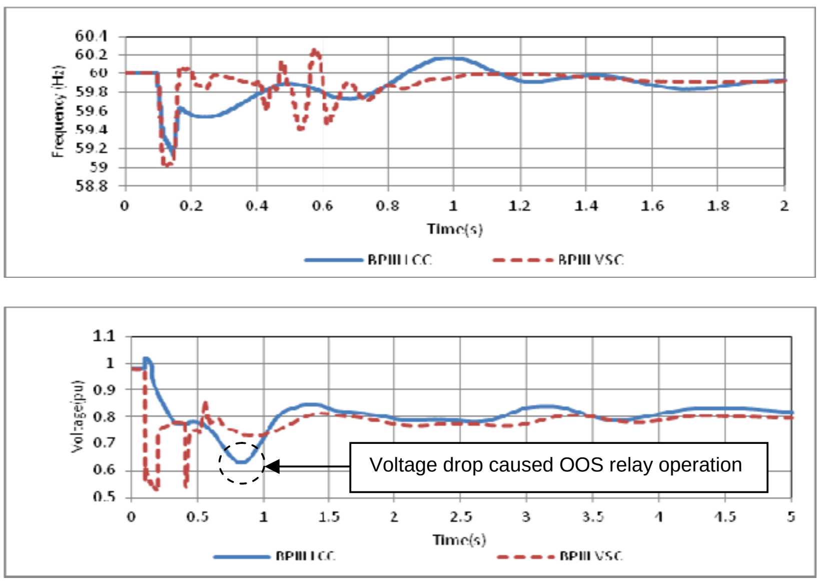


Figure 11. Bipole III block (2500 MW) with Dorsey out; Out-of-step relays blocked from line tripping. Top: Frequency response; Bottom: Glenboro 230 kV voltage.

7. CONCLUSIONS AND FUTURE WORK

Line commutated converter technology has over forty years of operational experience and would work for Bipole III in Manitoba with the application of synchronous condensers to strengthen the inverter bus and to provide voltage control. However, the large amount of synchronous condensers connected at the Dorsey substation and proposed to be connected at Riel will increase the short circuit level to the limit of commercially-available 230-kV equipment.

Voltage source converter technology, while relatively new, may be a feasible alternative. Studies have indicated that there are challenges, such as the need to quickly clear DC line faults and to prevent remote rectifier AC faults from impacting the inverter frequency response. Future work will investigate solutions, such as the application of DC breakers and VSC control modifications. In addition, fault current limiting and Statcom technology will be investigated to determine the feasibility of mitigating the impact of short circuit current from synchronous condensers on the Winnipeg area fault level.

For a single-infeed VSC scheme, it appears the ESCR limit is around 2.5, in order to prevent excessive transient underfrequency and avoid the need for SCs. For multi-infeed VSC, it may be possible to achieve a lower ESCR. For the Dorsey and Riel case study, it was possible to achieve a short circuit ratio of around 1.4 [8] with gain reduction in the VSC voltage regulator but the consequence was a slower voltage recovery. The Bipole controls would require significant modifications, such as participating in inverter frequency control, for weaker conditions [15, 18].

Line faults on VSC transmission with overhead transmission may result in larger transients, which may impact the design of transmission line tower structures [13]. The EPRI Reference Book assumed a symmetrical monopole configuration. It is expected that the transients with a bipole configuration will be lower. A PSCAD model for a VSC Bipole III converter will be developed in order to investigate the impact of the VSC on the insulation of the Bipole III transmission line.

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