# Mackinac VSC HVDC Flow Control Project Design

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***Abstract*—The need to control the power flow between the upper and lower peninsulas of Michigan initiated an investigation into available flow control technologies and their suitability for this project. After a thorough evaluation, it was determined that the Voltage Source Converter (VSC) HVDC technology best addressed system requirements. This paper describes how system characteristics and the capabilities of the available flow control technologies determined technology selection.**

***Index Terms*—Flow Control, HVDC, Voltage Source Converter (VSC)**

## I. The Need For Flow Control Between Michigan's Upper And Lower Peninsulas

The transmission systems in the eastern Upper Peninsula (UP) and northern Lower Peninsula (LP) of Michigan were designed to serve load, not transfer power. Historically, the eastern UP was connected to the LP before being connected to the rest of the UP. When the eastern UP was eventually connected to the rest of the UP, power transfers between the peninsulas became possible. For years high impedance across the UP and relatively low west to east energy flow bias meant these transfer flows were low and would rarely cause thermal or voltage issues. When issues did arise, they were usually resolved by splitting the system to separate the eastern UP from the rest of the UP (Fig. 1).

In recent years, the west to east flow bias has become stronger as the demand for low cost and/or environmentally friendly hydro, wind and coal generation has increased to the south and east of Lake Michigan (Fig. 2). Most of this power flow follows the low impedance path south of Lake Michigan; however, a small, but significant, portion of the flow flows through the higher impedance path north of the lake. Redispatching generation to avoid the thermal and voltage issues caused by this northern flow is difficult and expensive because there are few strong sources in the area. Building additional higher voltage lines to relieve the thermal and voltage issues created by this northern flow was investigated and found to be prohibitively expensive. The additional lines reduced the northern flow path impedance which lead to increased flows and more thermal and voltage issues, which required additional projects to resolve.

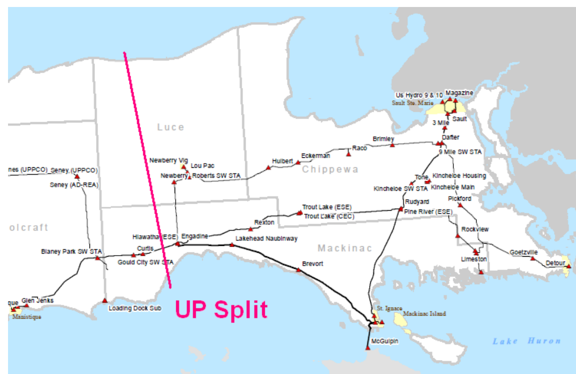



**Fig. 1.** Eastern UP Transmission System with Split


**Fig. 2.** Change in Flow Bias

One measure of the severity of the northern flow issue is the maximum angle across the open breakers used to split the UP. An angle of 44 degrees across these breakers indicates the potential for overloads under a certain outage condition. As shown in Tab. 1, the maximum angle across these open is increasing. In 2011 the voltage across the open breakers indicated that if the breakers had been closed, thermal issues would have existed on 95% of the days of the year. These increasing angles have caused the UP split to become, essentially, a permanent condition. Splitting the system is undesirable for a number of reasons, including (1) scheduling outages is difficult to impossible, (2) regulating voltages is more difficult, and (3) the process of splitting and reconfiguring the systems puts transients on the system, including the underwater cables across Mackinac Straits.

**Tab. 1.** Maximum UP Split Angle

| Year | Maximum Split Angle |
|---|---|
| 2007 | 72.8° |
| 2008 | 78.2° |
| 2009 | 80.1° |
| 2010 | 83.5° |
| 2011 | 87.6° |

Not only would building new projects to eliminate the need to split the UP system be expensive, because of outage restrictions when the system is split, it would be very difficult, if not impossible. These challenges to adding more transfer capability could possibly be overcome if the UP was being considered as an alternate path for significant energy transfers, but this is not being considered. Under present system conditions, with the UP split almost all of the time, some maintenance outages can’t be scheduled. Although maintenance can be delayed for a while, it eventually has to be done. With building our way out of this problem expensive and technically difficult, flow control became the preferred alternative. Because of its geographic location and electrical connections (two under water cables between the peninsulas) the Straits of Mackinac was selected as the location for the flow control device.

## II. FLOW CONTROL TECHNOLOGIES

Several flow control technologies were considered for the Mackinac Project. They included (1) series reactors, (2) phase shifting transformers (PST), (3) variable frequency transformers (VFT), (4) line Commutated Converter (LCC) HVDC (5) Capacitor-commutated converter (CCC) HVDC and (6) Voltage Source Converter (VSC) HVDC.

**Series Reactors** – Series reactors work on the very simple principle that when multiple paths are available, increasing the impedance of one path will decrease the flow on that path. ATC uses series reactors for flow control for a small number of lower voltages applications, usually where there are parallel lines with mismatched impedances. Adding a series reactor to the lower impedance line balances the flow on the two lines, maximizing the total flow on the two lines. The advantages of using a series reactor to control flow include its simplicity and cost. There are, however, several important disadvantages with using a series reactor for flow control. These include (1) the reactive losses created by the current flowing through the reactor, (2) the lack of adjustability, so that while a reactor reduces flow, it won’t really control it (adding adjustability would take away the advantage of simplicity), and (3) the potential for the reactor to become obsolete as system changes make it no longer be properly sized.

Even without considering control and obsolescence concerns, series reactors are not a viable option at Mackinac because the low short circuit capability in the area already makes voltage control challenging. Adding the reactive power losses of a series reactor large enough to adequately limit the flows between the peninsulas, would make system voltages unacceptable.

**Phase Shifting Transformer (PST)** – Although there are several different PST designs, their basic functions are the same, to change the phase angle difference across the transformer to controlling active power flow. Most PSTs are designed so the phase angle difference can be increased to increase flow or decreased to decrease flow. This is done by changing the tap on the PST regulating winding (Fig. 3).

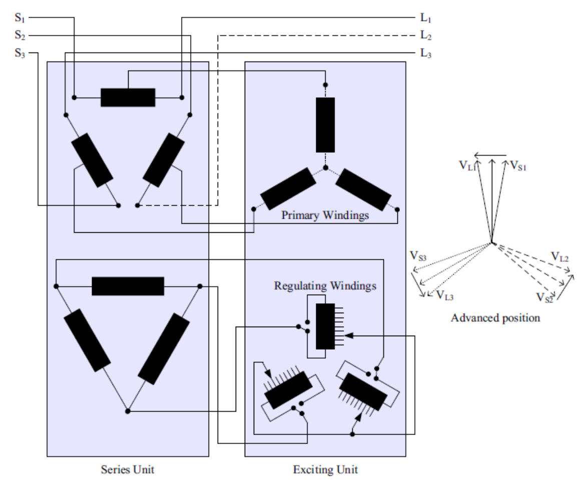



**Fig. 3.** Sample Phase Shifting Transformer Winding Configuration

Each PST tap usually changes the angle across the PST by a given amount, typically in the range of a single degree. Changing taps is done by mechanical switches that require inspection and maintenance after a given number of operations. Inspection will usually be required after about 80,000 operations and parts replacement after about 800,000 operations. Total replacement may be required after about 4,000,000 operations. The actual maintenance and replacement intervals will depend on the specific device design. Adjusting the PST by 9 taps every hour would make the 80,000 operation inspection interval approximately one year.

Phase shifters are designed for a specific maximum angle deviation, such as +/- 45°. To achieve a phase shift greater than about 75°, which might be necessary at Mackinac, would probably require multiple phase shifters in series. ATC owns a 230 kV, +/- 32° phase shifter at the Arrowhead end of the Arrowhead-Stone Lake-Gardner Park 345 kV line. That phase shifter is generally operated at a 0° phase shift. The phase shifter was designed to prevent voltage stability under outage conditions. The Mackinac phase shifter may be operated in response to market conditions, which could mean hourly adjustments as the west to east bias changes and the Ludington pumped storage facilities six 312 MW units cycles between pumping and generating.

Phase shifters are an established technology that ATC has experience operating. While a phase shifter installation can be designed to handle the angle requirements at Mackinac, there is the possibility that system changes could make the specified maximum PST angle unable to handle future system requirements. Although not desirable, a second PST could be implemented in series with the first to increase angle and flow control capability. Another concern with phase shifter technology is that if it is required to be adjusted frequently in response to market conditions, it could require frequent maintenance. Additionally, a PST will consume vars, but the var consumption will generally be comparable to or less than a similarly sized non-phase shifting transformer. A PST will not produce harmonic or non-harmonic distortion and will allow the flow necessary to feed load through it without requiring control adjustment.

**Variable Frequency Transformer (VFT) –** Within the past few years one manufacturer has created, patented and put into service at multiple locations a device they call a variable frequency transformer (VFT) that is used to control AC power flow between two systems. The device is essentially a continuously adjustable phase-shifting transformer with the added benefits that it can that smoothly ramp from one power level to another (no steps) and, like HVDC, be used to connect asynchronous systems (up to 3 Hz difference). It is fully adjustable from 0 to +/- its full MW rating. Although the standard sized unit can transfer 100 MW, higher flows and redundancy can be accommodated by putting multiple units in parallel.

The VFT is essentially a doubly fed electric machine with one connection to the stator and the other to the rotor. Changing the rotor position changes the phase angle and power flow across the device. Physically, the device resembles a vertical shaft hydroelectric generator with a three-phase wound rotor connected by slip rings to an external power circuit. A direct-current torque motor is connected to the shaft. Changing the torque applied to the shaft changes the power flow. If no torque is applied the shaft will rotate at a frequency equal to the frequency difference across the device.

While the VFT allows for reactive power flow between the grids it connects, it does not have the capability to use vars to regulate voltage. Its inertia enhances stability, providing a stabilizing influence on the system without requiring power injection. It does not create harmonic or non-harmonic distortion (making filters unnecessary). It is also has no sub-synchronous torsional or control interaction issues, making it compatible with nearby generation. It can supply real and reactive power in response to faults that can help stabilize a system and has some black start capabilities.

**Line Commutated Converter (LCC) HVDC –** Line Commutated Converters have been in commercial use since the 1950's. Although they can be used for flow control and to connect asynchronous systems, they have been primarily used to transfer large amounts of power long distances overhead economically or to transfer power via underground or underwater cables without the var and voltage control issues found with AC power transfer on cables.

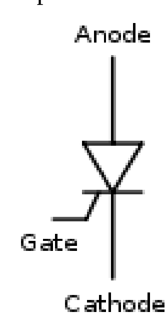



**Fig. 4** – Thyrister Schematic

Modern LCC HVDC installations use thyristers (Fig. 4) to convert AC to DC. Thyristers have two discrete states, current conducting (forward mode only) or current blocking (forward or reverse mode). A short-duration positive current pulse is applied to the gate to turn on the device, provided it is in forward-blocking state. Once turned on the thyrister conducts as a diode and the gate signal may be removed. A thyrister cannot be turned off by pulse application. To be turned off the current passing through the thyrister requires a “zero-crossing”. Thyristers are the device of choice for the highest power level DC lines because of their very low conduction and switching losses.

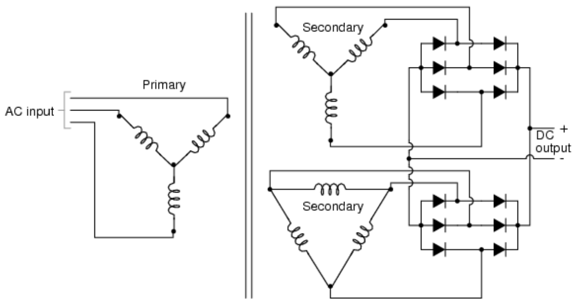
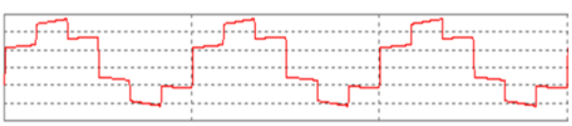



Fig. 5 – 12 Pulse LLC Inverter

Thyristers can be configured in a number of ways to for HVDC converters. The most popular are the 6- and 12-pulse rectifiers. The 12-pulse rectifier has the advantage of producing fewer harmonics than the 6-pulse rectifier. Regardless of whether 6- or 12-pulse rectifiers are used, LCC HVDC installations need to harmonic filters to prevent their characteristic harmonics from entering the system at excessive levels. Fig. 5 shows a 12-pulse LCC HVDC Inverter and Fig. 6 shows the current outputs from (a) a 6-pulse delta inverter, (b) 6-pulse wye converter, and (c) a 12-pulse converter.



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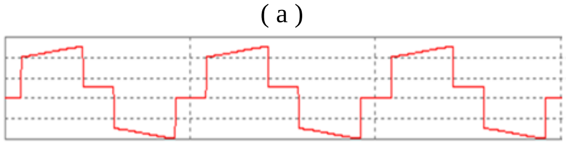

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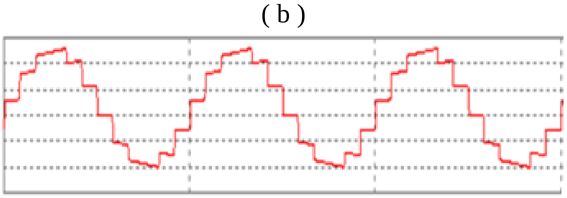

( c )

Fig. 6 – LCC Inverter Currents (a) 6-pulse Delta, (b) 6-pulse Wye, (c) 12-pulse

LCC HVDC has a number of advantages over AC transmission related to long distance transmission including lower line construction costs, smaller right-of-way requirements and lower losses, For flow control applications, LCC HVDC has the advantages of full controllability (system changes will not make the installation obsolete), increased stability with properly designed controls, and resistance to disturbances. The disadvantages of LCC HVDC include cost, part of which goes toward the special converter transformers required, significant var consumption (up to 50% of its rating), harmonic filtering requirements (which can be used to help meet var requirements), minimum short circuit current availability requirements (at least twice the device’s rating), possible control interaction with other nearby power electronic devices and possible sub-synchronous resonance issues with nearby generators. Control interaction and sub-synchronous resonance issues can be addressed by system studies and proper HVDC control design.

**Capacitor-commutated converters (CCC) HVDC** – If a LLC HVDC installation is located where the fault current is too low, its thyristers can fail to stop current because of its need for a period of reverse voltage after turn-off. The Capacitor-Commutated Converter (CCC) was developed to address this limitation and has been used in a small number of HVDC systems. The CCC differs from a conventional, line-commutated converter HVDC system in that it uses series capacitors inserted into the AC line connections, either on the primary or secondary side of the converter transformer. These series capacitors partially offset the commutating inductance of the converter and help reduce fault current requirements. This allows a smaller extinction angle to be used, reducing reactive power requirements. However, CCC has remained only a niche application because of the advent of voltage-source converter (VSC) which completely eliminates the need for an extinction time and allows fro HVDC operation at very low fault current levels.

**Voltage Sourced Converter (VSC) HVDC** – The development of higher rated self-commutating insulated gate bipolar transistors (IGBT), which are used in STATCOM devices, has allowed for the development of more flexible voltage sourced converter (VSC) HVDC control systems. One of the advantages of this technology includes controllable reactive power. VSC HVDC can independently control dynamic vars at each HVDC terminal. With the DC connection between the terminals out of service the VSC could be operated as two independent STATCOM devices. This dynamic var control capability allows for better system voltage and damping control. A second advantage of VSC HVDC is that it has no minimum short circuit capacity requirements and the device can be used to black start one side from the other. The IGBTs controllability makes it easier to create multi-terminal HVDC networks and are ideal for serving an "island" (a system whose only connection to the grid is through the HVDC). Another advantage is that standard transformers, rather than specially designed converter transformers, can be used.

The capabilities of the IGBT have allowed for different HVDC control methods to be developed. This allows for the advantage improved conversion techniques, but carries the disadvantages associated with developing technologies. The original VSC HVDC converters used series connected/pulse width modulation techniques (Fig. 6). This is a conceptually simple circuit, but the pulse width modulation creates distortion issues that include both harmonics and interharmonic frequencies, that must be addressed by filters. Series connected VSC converters also have higher switching losses. The most recent VSC installations use multilevel switching (Fig. 7), which builds a sinusoidal wave by "stacking" voltages of various time duration on top of each other. Multilevel switching has a number of advantages over series connected VSC HVDC. In exchange for more complex controls, multilevel switching allows for lower losses, minimal distortion, and an easily scalable design.

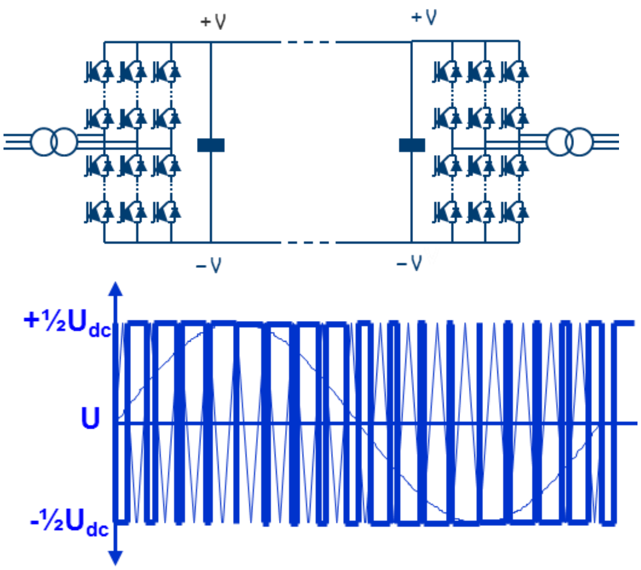


Fig. 6 – Series Connected Pulse Width Modulation VSC HVDC

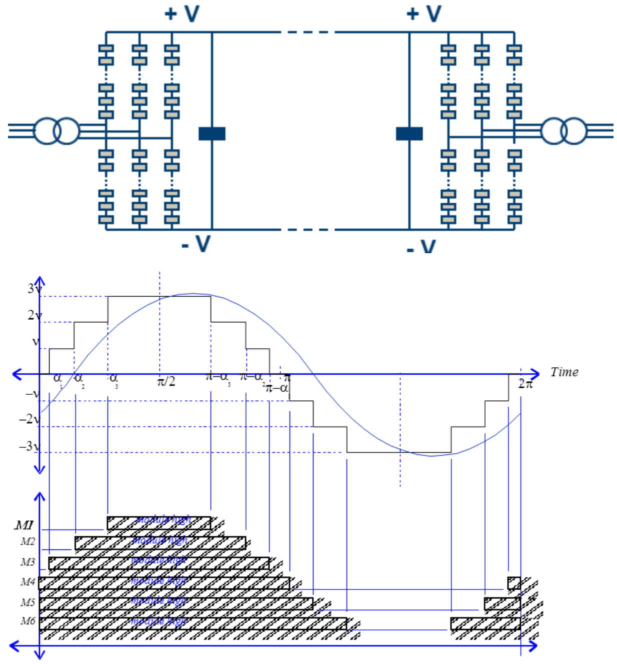


Fig. 7 – Multi-level VSC HVDC

By eliminating the need for most, if not all, harmonic filters, multilevel switching can significantly reduce HVDC station space requirements. In a typical LCC HVDC installation, AC harmonic filters cover nearly half of the area of the whole station.

In addition to cost (this is probably the most expensive solution), the concerns with the VSC are maintenance (3-7 days annually), control complexity and control performance under very weak system conditions. This is of particular concern under unplanned outage conditions where the only connection to the eastern UP, other than the HVDC, is a weak 69 kV line.

## III. MACKINAC SYSTEM AND REQUIREMENTS

The power system near Mackinac has a very low available short circuit current level even under intact system conditions. Outages further reduce the short circuit current. Because of the remoteness of any large generators, this is unlikely to change without major system changes that are not in the foreseeable future. In fact, the retirement of some smaller less efficient units that do not meet modern pollution standards may further reduce system strength. This system weakness not only means that the flow control technology chosen will have to be able to operate under low fault current conditions, but that it should not contribute to voltage control issues and create the need for a source of dynamic vars in the area.

Another issue of concern to ATC management was that whatever flow control technology was chosen, it should be a long term fix. System changes should not make the flow control obsolete. To evaluate the robustness of each flow control technology we not only looked at the possibility of additional lines or generators in the area, but also the possibility of connecting the UP to the Canadian grid at Sault Saint Marie.

Although current system conditions in the eastern UP and northern LP limit the flow between the two peninsulas to less than 100 MW in either direction, the decision was made to design the flow control for up to 200 MW in either direction to account for substantial future system growth and improvements.

## IV. Technology Decision

The Mackinac flow control technology decision was primarily driven by three conditions: (1) the low short circuit current available in the area, (2) the need to consider voltage regulation (i.e. flow control device var consumption), and (3) the robustness of the solution (i.e. would it maintain its functionality under a wide variety of future system conditions). Other concerns included cost, maintenance requirements, operation under fault and outage conditions, and losses. With this many requirements, no technology would be best at meeting all our concerns and compromises would be necessary.

While the cost and simplicity of Series Reactors were advantages, they were eliminated from consideration because of their var consumption. The system near Mackinac is too weak to add significant var consumption without adding additional, possibly dynamic, vars that would add expense and complexity and negate the advantages of the series reactors. The possibility of the series reactor becoming obsolete as the system changes was also a concern.

Phase Shifting transformers have a number of advantages that make them a strong contender for any flow control project. These include their ability under outage conditions to allow the flow necessary to keep system loads energized without needing complex controls. The primary disadvantages of the PST is the large angle across the systems at Mackinac that would probably require series phase shifters if not immediately, sometime in the future. Another concern with the PST was that if it was decided to change the PST tap hourly on response to market conditions, this could require frequent maintenance. The var consumption of the PST, which would not be a concern at a stronger location, was a concern at Mackinac.

The variable frequency transformer has some unique advantages, but like the series reactor, and probably the PST, at a weak part of the system, such as Mackinac, it would require dynamic vars to keep system voltage within a reasonable range. This is more of a concern under outage conditions, when dynamic vars, provided by power electronics, would probably be necessary. It was felt that if we were going to use power electronics for this project, it made more sense to use them to control MW flow as well as var generation, rather than just var generation for voltage control.

Also because the VFT is presently being produced as a 100 MW modular device, we would have to buy two devices to achieve our 200 MW transfer requirement. This has some advantages, i.e. redundancy and the ability to keep one unit in service while the other underwent maintenance, but also increased project costs.

The LCC HVDC option was taken off the table early because the system at Mackinac does not have sufficient short circuit capability for proper converter operation. This problem only becomes worse under outage conditions, when the ability to control flow may be even more important.

The CCC HVDC option was considered because of its ability to operate under low short circuit conditions, but even that capability is limited and pushing this technology to its limits created cost and reliability concerns. Again, the need for vars to stabilize system voltages would probably had required dynamic vars to maintain system voltage at an acceptable level.

Although one of the more costly solutions, VSC HVDC technology addresses all three major project concerns. Low available short circuit is not an issue with the VSC technology. Also, because the VSC technology can provide (or absorb) vars independently at each terminal of the device, voltage regulation issues are addressed. Finally, like the VFT and other HVDC options, its flow control capabilities would not be made obsolete by system changes.

Even with its advantages there are still concerns with the VSC technology. These concerns include maintenance requirements, control complexity, weak system operation, interaction with other power electronic controls on the system and potential sub-synchronous resonance interaction with system generators. Maintenance requirements are expected to be 3 to 7 days every year. There is the possibility of extending this schedule as we gain experience with the device. The Mackinac substation includes an HVDC bypass switch so that it may be possible, under the right system conditions, to close the bypass switch and operate the system closed (no split in the UP) without the HVDC in service. If this is not possible, it will be necessary to operate the system split as is done now. Control complexity is an issue, but we hope to take advantage of it by developing controls that will allow for fully automatic operation under the weakest unplanned system conditions with only local measurements. This is under development and future studies will determine if it is possible to do so. If it is not possible, remote measurements will be needed to ensure proper operation under unplanned island and "quasi-island" (very weak) conditions. Systems studies are also necessary to design HVDC controls that will not interact adversely with other electronic controls on the system or produce potentially sub-synchronous resonance issues.

## V. CONCLUSIONS

The decision to use VSC HVDC technology to control the flow between the Upper and Lower Peninsulas of Michigan was made after a thorough evaluation of available flow control technologies and their compatibility with the system at Mackinac. While all of the technologies have advantages and disadvantages and applications were they could each be the most appropriate choice, the unusual conditions at Mackinac make VSC technology the best choice for this application. The condition that drove the decision was primarily the weak system conditions at Mackinac, which precluded some of the flow control options and made the var generating/voltage regulating capabilities of the VSC particularly attractive.

Although the technology has been selected there is still work to be done before the flow control begins commercial operation in 2014. Control design studies have to be completed to make sure that control interaction with other nearby power electronics, especially wind farms, and the possibility of sub-synchronous tortional interaction with generating units are avoided. Finally, studies to determine the VSC response under unplanned "quasi-islanding" conditions will test the technology's capabilities.