Mackinac HVDC Construction and Testing

Michael B. Marz
American Transmission Company
W234 N2000 Ridgeview Parkway Court
Waukesha, WI 53188-1022
mmarz@atcllc.com

***Abstract*—The Mackinac back-to-back Voltage Source Converter (VSC) HVdc station began commercial operation in the summer of 2014. By controlling the power flow between the Upper and Lower Peninsulas of Michigan it is allowing system maintenance outages to be taken. Without flow control, maintenance had to be deferred, so putting the project in service quickly was a priority. Weak system conditions and the desire to limit control system inputs to locally measured quantities required the development of a unique control scheme. This paper discusses some of the design, construction, testing and operation issues faced by this project.**

***Index Terms*—Flexible AC Transmission Systems, Interharmonics, Power Quality, Voltage Source Converter (VSC) HVdc.**

I. Project Need, Requirements and Design

Michigan's Upper Peninsula (UP) and Lower Peninsula (LP) transmission systems were designed to serve load, not transfer power. When the eastern UP, which had been served radially from the LP via cables under the Straits of Mackinac, was connected to the rest of the UP, power transfers between the peninsulas and across the UP became possible, but system strength remained low. For years, high impedances and a minimal west to east power flow bias kept these transfers small and thermal or voltage issues associated with them were rare. When issues arose, they were usually resolved by splitting the system to separate the eastern UP from the rest of the UP (Fig. 1).

The west to east power flow bias is increasing as the demand for low cost and environmentally friendly generation from west of Lake Michigan increases south and east of the lake. Most of this power flows through low impedance paths west of the lake, but a small fraction flows through the higher impedance path north of the lake. The lack of strong sources in the UP make redispatching generation to avoid thermal and voltage issues caused by this northern flow difficult and expensive. Although undesirable because it makes taking maintenance outages almost impossible, splitting the UP system to control flow, once an occasional requirement, became an all but permanent condition. Upgrading existing or building new transmission lines to address the issues created by this northern flow was investigated and found to be too expensive and unachievable in the required timeframe. This made flow control the preferred method to address these thermal and voltage issues.

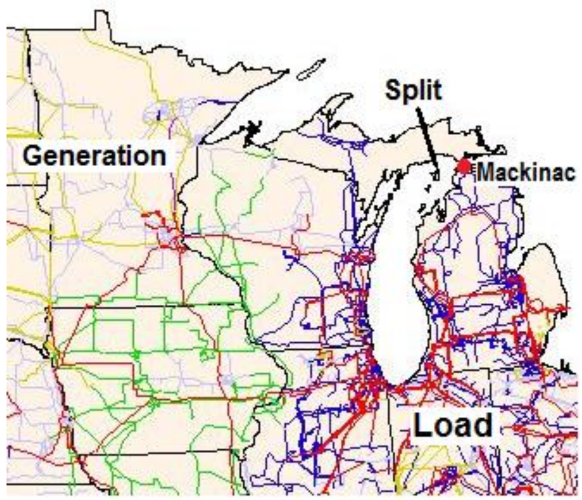

Fig. 1. Upper Midwest Flow Bias and Eastern UP Transmission System Split

Project Requirements

In addition to controlling power flow, the Mackinac project was required to (1) operate under weak (low fault current) system conditions and (2) not exacerbate, and possibly mitigate, voltage control issues in the area. The need for expensive dynamic reactive support in addition to flow control was to be avoided. Other concerns included (1) cost, (2) maintenance requirements, (3) operation under fault and outage conditions, (4) losses and (5) robustness to system conditions so that system changes would not make the project obsolete. There was also a strong preference for a control system that only used local system measurements, so that it would not be necessary to implement a special protection system (SPS) to protect equipment and maintain stability.

Project Design

Several flow control technologies were considered for the Mackinac Project including (1) series reactors, (2) phase shifting transformers, (3) variable frequency transformers, (4) line commutated converter (LCC) HVdc and (5) VSC HVdc. While all technologies evaluated had their advantages and disadvantages VSC HVdc was selected because its use of Insulated Gate Bipolar Transistors (IGBTs) allow it to (1) operate under lower system short circuit current conditions, (2) provide dynamic vars for voltage regulation independently at each dc terminal, (3) adjust real and reactive power flow quickly in response to system contingencies, and (4) control flows regardless of future system changes. Also, when the dc connection between the terminals is out of service and its flow control capabilities are unavailable, VSC HVdc can be operated as two independent STATCOM devices to provide voltage regulation. Additional benefits of VSC HVdc include its ability to help damp system oscillations, power an otherwise islanded system and black start a grid. [1]

The Mackinac HVdc was designed for 200 MW bi-directional real power transfer with +/-100 Mvar reactive power delivery at each terminal. A symmetrical monopole with a Cascaded Two Level (CTL) converter design (Fig. 2) was used to reduce losses and harmonic distortion when compared to earlier VSC designs.

The Mackinac HVdc's CTL design uses pulse width modulation (PWM) to produce a controllable power supply type voltage waveform (Fig. 3) similar to that of modular multilevel converters (MMC). [2] Although CTL VSC, unlike MMC VSC, generally requires filtering to keep distortion below established harmonic limits, the filtering requirements are significantly less than controllable switch type two level converter VSC. The high speed controls that change IGBT switching each cycle to give the HVdc many of its stability benefits also contributes to non-periodic (on a 60 Hz basis) voltages that are manifested as interharmonic distortion. The HVdc also produces interharmonic distortion because the IGBT cell switching frequency/pulse number is required to be non-periodic to prevent damaging converter capacitors.

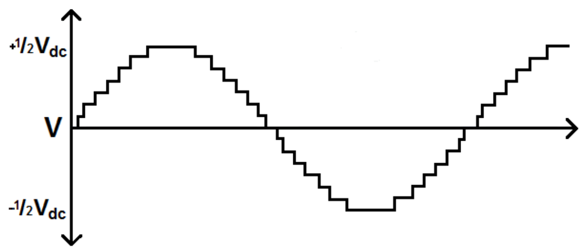

Fig. 3. Cascaded Two Level (CTL) Converter Voltage Waveform

The normal VSC HVdc control approach is vector current control, controlling the converter's instantaneous active power and reactive power independently through a fast inner current control loop that decouples the current into q and d components. Outer control loops can then use the d component to control active power or direct voltage and the q component to control reactive power or alternating voltage. This robust and reliable control method is used to control the relatively strong Mackinac South converter.

The Mackinac North bus can be extremely weak under certain contingencies, making vector current control unacceptable for the North converter. For the

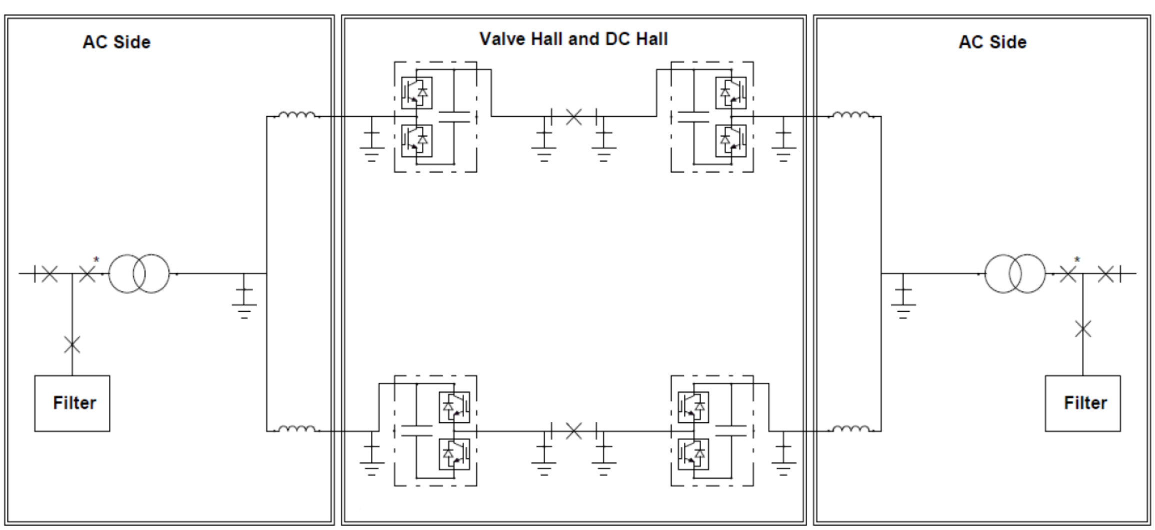

Fig. 2. Simplified One-Line Diagram of Mackinac HVDC Converter Station [3]

North converter a “phasor voltage control” was developed based on direct control of the converter’s internal ac voltage amplitude and phase. The basic principle is to keep the internal converter voltage a fixed phasor, constant amplitude and phase, in the steady-state. Amplitude control is extended to the Point of common coupling (PCC) by using impedance correction. Phase control is extended with a frequency droop and a phase angle offset to adjust the synchronizing power control. Synchronizing power is the power flow opposing increases in relative rotor angle between synchronous machines that keeps machines synchronized.

The North bus also has a damping controller tuned to approximately 1 Hz, to ensure positive damping at a natural mode related to the phasor voltage control strategy. This controller responds to North bus frequency deviations that while small, are continuous. [4] This means that unlike conventional LCC HVdc, Mackinac real power does not flow at a fixed set value. Mackinac real power flows, on average, at its set value, but continually varies by a few MW around its set value in response to system frequency deviations. This is necessary to receive the benefits of the HVdc damping controller and governor functions that give the Mackinac North bus converter dynamic characteristics similar to that of a large synchronous machine. These MW variations can be minimized by reducing the governor time constant, but too low of a time constant can also contribute to stability issues.

If intentionally or unintentionally connected to an islanded system, the North Bus converter will automatically determine that it is connected to an island, change to a fixed frequency and voltage mode with droop settings and continue to operate indefinitely.

A more difficult post contingent control system challenge than islanding is quasi-islanding, staying connected to the rest of the system through the Mackinac HVdc and a single 69 kV line following a contingency. A control system function that used only local measurements and would maintain system stability and prevent overloads under contingencies that resulted in quasi-islanded conditions had to be developed for the Mackinac HVdc.

A strategy of emulating the power-angle characteristics of an ac line during large disturbances to determine a new MW operating point for the HVdc, ac line emulation (ACLE), was implemented to maintain stability following disturbances that significantly change the ac network impedance. The Mackinac HVdc’s ACLE function monitors the voltage angle across the converter. After a disturbance characterized by a sudden large change in angle, the power order is recalculated and implemented according to the (simplified) equation:

$$P_{ref,ACLE} = \frac{V_1 \, V_2}{X} \sin(\delta_1 - \delta_2)$$

ACLE provides an automatic runback of the HVdc MW reference. This reduces the possibility of overloading transmission system components following the loss of key transmission facilities. The function also has the effect of synchronizing the North and South ac networks, which aids system recovery following a disturbance.

Extensive PSS/E and PSCAD studies were used to develop, demonstrate and test HVdc control performance. These studies used multiple system scenarios and contingency simulations to confirm power system and HVdc converter large disturbance stability. [4]

II. Project Components and Construction

The Mackinac Project had three major components: (1) relocating existing lines, (2) building an ac substation, and (3) building the HVdc substation. Minor components of the project included changes at substations adjacent to Mackinac, including protection upgrades.

Some of the land used for the new Mackinac substation was previously occupied by the three 138 kV lines now routed through the substation. These lines had to be moved to make room for the substation and allow for their connection into and out of the substation.

The new Mackinac ac breaker-and-a-half substation was built next to the existing Straits substation. The Mackinac substation has a North and a South bus that can be connected through the HVdc or by either (or both) of two bypass breakers. Previously, three 138 kV lines, one from the UP and two from the LP, were connected to Straits. Today, the three 138 kV line connected to Straits all connect to the North bus. The line previously connecting Straits to the UP is also connected to the North bus. The two lines previously connected Straits to the LP are connected to the South Bus, along with two new reactors used to compensate for the Mvars produced by the 138 kV cables under the Straits of Mackinac. The two shunt reactors previously used to compensate for the cable Mvars are still located at Straits, but with the addition of the HVdc, are electrically isolated from the cables.

The American Transmission Company (ATC) supplied a roughly graded site and a single large power equipment manufacturer was contracted to design, fabricate, furnish, deliver, construct, install, test and commission the HVdc on a turnkey basis (which necessitated a sales tax payment to the state of Michigan). The site provided is located in the UP, just north of the Straits of Mackinac, just outside St. Ignace, Michigan. The station was designed for temperature extremes ranging from 102˚ F to -50˚ F and a snowfall up to 200" annually. The station is controlled and monitored remotely from ATC operations facilities in Pewaukee and Madison, WI. Local, trained technicians provide first response troubleshooting and monthly inspection.

An aggressive project schedule was necessary because ATC needed the HVdc to be in service before maintenance outages could be taken in the eastern UP. Meeting any schedule would be challenging because Mackinac is a unique facility (the world's first large scale back-to-back HVdc system using VSC technology) using a new control methodology. A summary of the initial project schedule is shown in Table 1.

Table 1. Initial Project Schedule

February 2012	HVdc Contract Signed
Spring 2012	Start Line & AC Station Construction
August 2012	Start DC Underground Construction
April 2013	AC Substation & Lines Completed
June 2013	Start DC Overhead Construction
August 2013	Dynamic Studies & Factory Tests Complete
September 2013	Converter Building Completed
October 2013	Major Equipment Arrives
May 2014	Commissioning Completed
July 2014	Station Turnover to ATC

Although the project schedule (as is typical), started to become squeezed toward the end of the project, the project went into service as planned. The line relocations and ac switching station were not unusual and provided no unexpected challenges. The ac station had no transformers, so the longest lead time item was the reactors, which weren't needed until the HVdc went into service.

The HVdc building housing the valves, reactors, cooling and control equipment is approximately 300 feet long, 130 feet wide and 45 feet high (Fig. 4). The HVdc is a symmetrical monopole design. There are four valve halls, two on each floor of the two story building. The two HVdc reactor halls are two stories high and located on each end of the converter building. There is also a control building. Early concerns with locating a contractor to build such a specialized building in such a remote location were allayed when a company located in the UP was brought on the project.

The HVdc substation includes a variety of specialized equipment including transformers, reactors, capacitors, breakers, switches, etc. The project contractor's ability to manufacture much of this equipment helped them control project schedule.

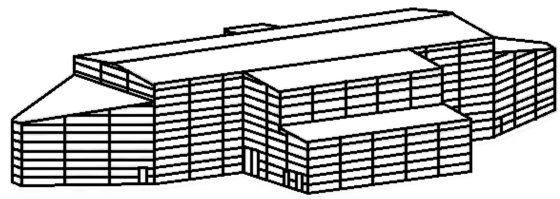

Fig. 4. Mackinac HVDC Building Design

The project schedule had the dynamic studies and factory tests being completed only one month before the converter building and two months before major equipment was to arrive. This points to the flexibility of the VSC controls. Major changes could be made to the controls using software without the need to change any hardware.

The project in service date was firm from the start, so working backwards from July 2014 gave a May 2014 date for completing commissioning (60 days were scheduled for a 30 day continuous operation test) and an October 2013 major equipment arrival date. This required construction during an unusually cold and snowy winter in the UP. While much of the work occurred inside the converter building, work still had to be completed outside, including digging trenches, connecting communications wires, etc.

III. Commissioning Tests and Operation Issues

Commissioning tests were designed to confirm that all HVdc station equipment met specifications and that the control system operated as designed and previously simulated during real time digital simulation (RTDS) tests. The commissioning tests were also designed to find and address "bugs" and unexpected operational issues. Project size, complexity and uniqueness, made it inevitable that Mackinac would have its share of issues.

The primary HVdc commissioning tests were designed to determine if the project met its MW and Mvar specifications (Fig. 5) without exceeding any equipment ratings. Since the existing transmission system can't handle the full 200 MW capability of the HVdc without voltage collapse, a test was devised where current was circulated through the HVdc bypass switch to allow 200 MW of flow through the HVDC converters. ATC System Operations was, rightfully, concerned about what would happen if something went wrong and the HVdc actually tried to push 200 MW through the system. The solution was to operate the HVdc radially so that any likely misoperation would disconnect the HVdc from the system.

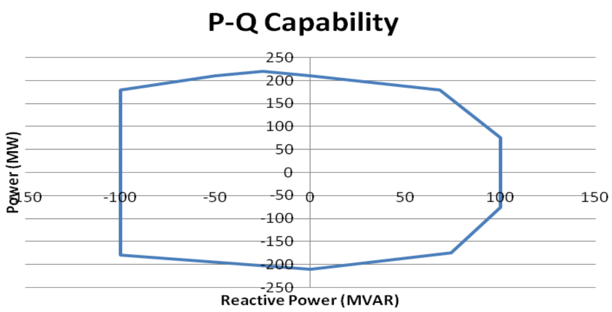

Fig. 5. VSC Converters' Capability Curve

Equally important were tests to confirm proper operation of the HVdc control system. These tests were designed to thoroughly test the controls while minimizing any risk to the system. Power order, active power control, reactive power control (both terminals independently and simultaneously), ac voltage control, high power transfer, black start, and by-pass, were among the many tests performed.

Although it was decided that creating a system event severe enough to trigger the HVdc's ACLE feature was not prudent, a scenario was developed where a very small section of the UP would be isolated to test the HVdc's automatic transition to and successful operation in islanding mode. For this test the HVdc power order was set to match the load in a small section of the UP. This section was then isolated from the rest of the UP to form an island connected to the HVdc. Since the island load initially matched the HVdc flow, the HVdc did not instantly detect that it was connected to an island. How fast the HVdc would detect the island and change its operating mode depended on how fast load changed in the island. In our test the HVdc made a successful transition to islanding mode, with no load loss or undesirable system voltages or oscillations, in approximately 45 seconds.

The ACLE function was tested by being manually triggering without a disturbance. This, as expected, did not significantly change power flow during the time ACLE was active. Automatic triggering of ACLE was not tested during commissioning. It was thoroughly tested in computer and RTDS simulations, but will have to wait for a real event on the system to be field tested.

Power Line Carrier

Soon after the Mackinac HVdc was first energized 138 kV power line carrier (PLC) terminal equipment at Mackinac failed. This failure was traced to high voltage in a high frequency resonant circuit in the PLC equipment. Although no failures occurred at other PLC locations, higher than acceptable voltages were found at remote PLC equipment. The HVdc was determined to be the source of a relatively wide band of high frequency signals that caused the local PLC failure and high voltages at remote PLCs.

The high frequency signals that caused the PLC failure had smaller magnitudes and higher frequencies (5 to 30 kHz) than would normally be a concern on the power system. High frequency signals of this magnitude are usually blocked or attenuated to an acceptable level by transformers or by traveling a significant distance down a transmission line. Other than a local resonance creating a damaging overvoltage in a PLC drain coil, there is little, if any, equipment located at transmission voltage levels that will resonate at these kHz frequencies.

The Mackinac HVdc was designed with a doubly tuned, 5^{th} and 30^{th} harmonic, filter. Although the filter was not sharply tuned, it did not sufficiently filter out the high frequency the PLC resonated at and plans were made to add a high pass filter at Mackinac. Although cost was an issue, the time to add the additional filter was a greater concern. The PLC was part of a redundant protection scheme, but its long term outage was still unacceptable. Replacement of the local PLC with a different communication method was considered, but filtering the high frequency signal was determined to be a better solution because it would eliminate the remote PLC overvoltages and allow other components with potential high frequency resonances to be connected to the system in the future.

After a thorough investigation the project contractor determined that the existing doubly tuned filter (Fig, 6a) could be modified to change the filter's 30^{th} harmonic component into a high pass filter (Fig. 6b). The modification included removing or bypassing one filter inductor. The modified filter still met project distortion limits and its components were not over stressed. Since this solution did not require significant additional equipment, it was able to be implemented quickly and at minimal cost.

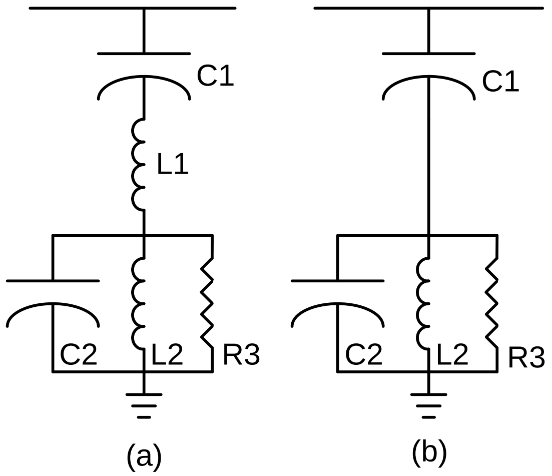

Fig. 6. Mackinac HVDC Filters (a) Original 5th and 30th Harmonic and (b) Modified 5th and High Pass

The modified filter has allowed the Mackinac PLC to be returned to service while the HVdc is in service. Voltages inside the local and remote PLCs are now acceptable.

May 28th Short Circuit

During testing on the afternoon of May 28th, Block 1 of the HVdc tripped when 7 IGBTs in one IGBT switch indicated that they were short circuited. No metering indicated any fault condition at the time and afterward all IGBTs passed inspection. After consulting with the project contractor's experts a potential cable from an electrode to the bottom corona shield was found to be installed incorrectly. The cable was touching the aluminum frame of an IGBT module at a different potential (Fig. 7), which caused its insulation to break down and create the short circuit that caused the trip. The damaged cable (Fig. 8) was replaced and all other valve cells in all four valve halls were inspected for similar problems. No additional problems were found. Post event analysis determined that the protection and control systems worked as designed.

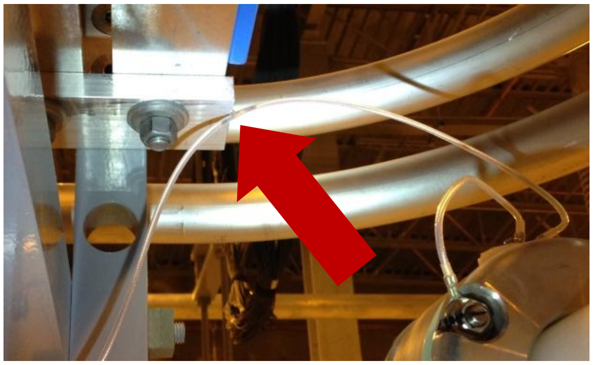

Fig. 7. Short Circuit Location

Fig. 8. Damaged Cable

July 16th Power Transfer Deviation

On the morning of July 16th HVdc power transfer made two unexpected deviations, from 40 MW to 130 MW and then 110 MW, which lasted approximately 2 seconds each (Fig. 9). HVdc reactive power, system voltage and system frequency also made equally severe deviations from their expected steady state values. No system events that would have triggered any HVdc control scheme to initiate these events occurred at the time.

The event was traced back to loose phase and neutral wire connections to a CCVT. At the time of the event a technician was working in a control panel looking for a location to connect measurement equipment. When he touched a loosely connected wire, the voltage measurement on one phase was lost. When the technician heard changes in the substation ambient noise he removed his hand from the control panel and the substation sounds returned to normal. The technician then touched the same wire in the control panel again and confirmed that it was the cause of the changes in substation ambient noise.

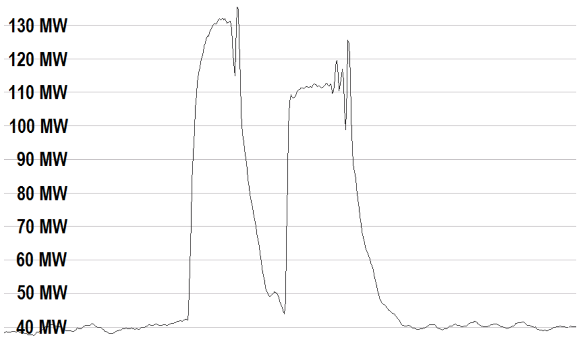

Fig. 9. July 16th HVDC Power Transfer with Two ~2 Second Deviations from 40 to 130 and 110 MW.

The loss of signal while touching the loose connections caused an incorrect "A system" control measurement to be recorded in transient fault recorder (TFR) logs. The parallel "B system" controls and TFR log measurements matched ATC system measurements that did not indicate any unusual system conditions. This confirmed that the HVdc control response that caused the increase in power was due to the loose connection and not an actual system event.

Event analysis determined that the HVdc control system reacted as it should have for a temporary loss of potential on a single phase: real and reactive power increased and then returned to its previous value once the potential measurement was restored. Other system parameters (frequency, voltage, etc.), reacted as expected to these power flow changes. If either voltage deviation had lasted a full 2 seconds, something that was within 200 milliseconds from occurring, the HVdc would have tripped as specified in its design. This event prompted a "do not touch" order, until all connections were reexamined for appropriate tightness.

August 27th HVDC Response to a Remote Fault

On August 27th a 345 kV line supplying power to the UP from Wisconsin tripped when a logging vehicle knocked down a tower on a clear day. The HVdc responded as designed, temporarily providing more power to the UP in response to a frequency deviation and permanently providing additional Mvars to support system voltage (Fig. 10). The MW support to the UP was only temporary because the ACLE feature of the HVdc was not in service when the fault occurred. If the ACLE had been in service and had triggered, the HVdc MW set point would have been increased and additional power would have continued to flow into the UP. With the ACLE not in service, it was left to the system operators to manually increase the HVdc flow to 65 MW from 40 MW to help support the UP system.

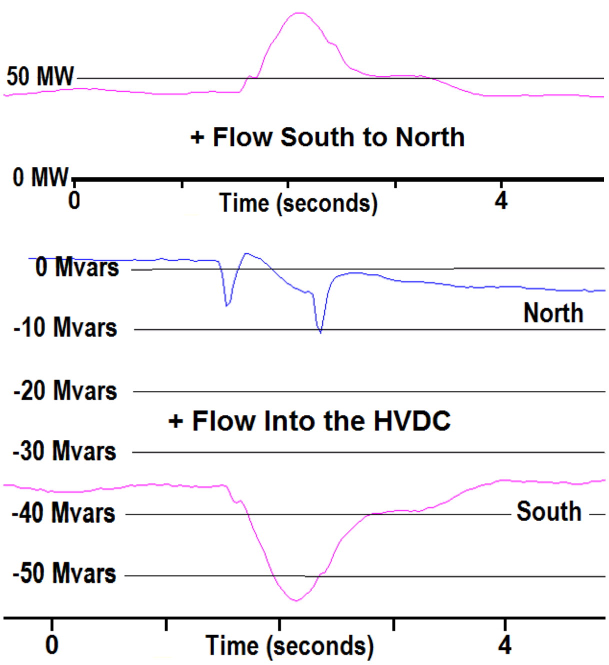

Fig. 10. August 27th HVDC MW and Mvar Flows Following Loss of a 345 kV Source to the UP.

The ACLE was not in service because all system operations studies had not been completed and approved at this time. Most system operations studies were performed using PSS/E dynamic simulations. These dynamic simulations used a somewhat simplified model when compared to the PSCAD transient design simulations, which used the actual HVdc control software.

To confirm the accuracy of the PSS/E dynamics model, simulations of identical events were run using the dynamic and transient models. Somewhat unexpectedly, the dynamics simulations showed a slightly better response than the transient results. The reason for this was traced to a delay in the transient model that was lost during the creation of the simpler dynamics model. To improve the response of the HVdc on the real system, the delay was taken out of the transient model and real system HVdc controls.

Power System Communication Issue

Unlike LCC HVdc which uses thyristers and produces integer harmonic distortion that is periodic on a 60 Hz basis, VSC HVdc uses IGBTs that allow switching and control schemes are not periodic on a 60 Hz basis and produce non-integer harmonics (interharmonics). Because of its periodic nature, LCC HVdc distortion (voltage and current) will be the same when comparing consecutive cycles, as long as the system is operating in the steady state. This is not true for the VSC HVdc, which uses a non-periodic cell switching frequency (pulse number) and takes advantage of IGBT switching capabilities to improve system stability by continuously making minor adjustments to its operating point.

To improve distribution system operations, many utilities have begun utilizing smart meters with communication functions to report energy usage and track outages. While several communication media can be used by these meters, one economical communication medium is the power system. By intentionally transiently distorting either the power system voltage or current (or both), communication signals can be sent to and from each meter over power lines. By subtracting consecutive 60 Hz waveforms the non-periodic communication signal can be extracted from the power system voltage or current with essentially any level of harmonic (60 Hz periodic) distortion on the system. The use of error checking and multiple communication attempts can make these systems very reliable.

Some distribution service providers near Mackinac have smart meter systems that use power lines as their communication medium. One distribution company experienced communication difficulties with a significant minority of their over 40,000 meters. The exact percentage of meters affected depends on how "affected" is defined. An unsuccessful attempt to communicate followed by a successful attempt isn't necessarily an issue or particularly unusual, even prior to HVdc operation. Preliminary analysis has shown the most severe communication issues occurring at meters connected to two substations. One of these two substations is located electrically near the HVdc, the other is further away from the HVdc than many stations not experiencing issues, but has some atypical design features.

Communication failures when using power lines as a carrier medium are not unique to VSC HVdc. Meters located near other large loads that produce non-harmonic distortion, such as arc furnaces, experience similar communication failures. In some cases these communication failures have required other communication methods to be employed.

Measurements at Mackinac have shown that interharmonic levels increase when the HVdc is in service (Fig. 11). Although individual interharmonic levels are reasonably consistent for a given system configuration and HVdc operating point, they can change significantly when either changes (Fig. 12).

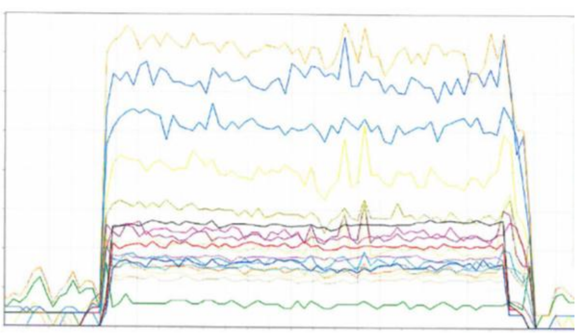

Fig. 11. Sample of Interharmonic Measurements with HVDC in Service for Approximately One Hour.

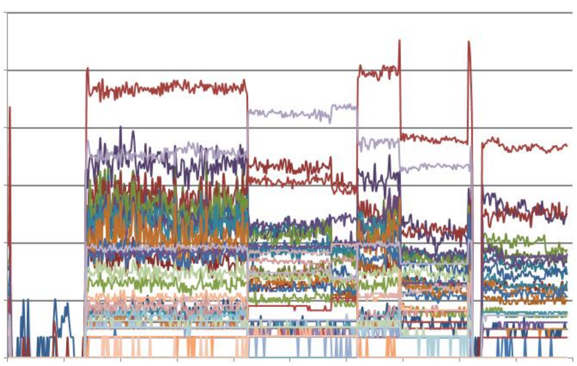

Fig. 12. Interharmonic Measurements during Changing System and HVDC conditions.

There are no IEC [5] or IEEE [6] interharmonic limits beyond those for frequencies below 120 Hz based on flicker effects. IEEE 519 recognizes that interharmonic can effect communications and "due consideration should be given" and "appropriate interharmonic limits should be developed on a case-by-case basis." The IEC has a suggested reference level of 0.2% for each interharmonic subgroup (a measure of the interharmonics between two consecutive harmonics) below the 50th harmonic, which appears to be designed to allow some communication over the power delivery network. About a decade ago when the IEEE had a task force looking into interharmonic limits, the criteria they were considering was not based on communications, but on the effects of interharmonics on power system equipment. Interharmonic limits based on power system equipment would be similar to existing harmonic voltage limits. At 69 kV IEEE recommended harmonic voltage distortion limits are 1.5% for each individual harmonic and 2.5% for total harmonic distortion, approximately an order of magnitude greater than the IEC reference levels based on power line communication interference.

Efforts are underway to determine how interharmonics are related to power line communication failures. This information will be used to diagnose problems with the non-communicative meters and determine a resolution to this issue. Whether or not modifying HVdc switching can significantly reduce interharmonics without limiting HVdc functionality is being investigated. If HVdc interharmonic output cannot be reduced, the ultimate solution to this problem will most likely be a combination of optimizing meter operation to reduce the number of meters that can't effectively use the power system as a communication path and providing an alternate communication path for any meters that can't effectively use the power system to communicate.

While this issue is being resolved the HVdc is fulfilling its purpose of controlling flows when needed to allow maintenance outages, but is being taken out of service periodically to facilitate communication over the power lines for meter reading and for outage monitoring purposes.

IV. Conclusion

The Mackinac VSC HVdc allows the upper and lower peninsulas of Michigan to be electrically connected, which is increasing transmission system reliability and flexibility and is permitting deferred maintenance to be completed. This solution to the problem of excessive flows across the UP was both more economic and timely than its alternatives.

Any project under a compressed time schedule, especially one utilizing a complex new technology in a relatively unique and isolated part of the system, will have issues in its implementation. While most of the issues encountered were routine for any project of this size, two issues were raised that should be addressed when considering installing VSC HVdc or any technology (such as Type 4 wind turbines) that uses IGBTs and produces interharmonic distortion.

The first issue is the importance of analyzing the effects of any high frequency signals on system equipment and, if necessary, designing appropriate mitigation strategies, such as a high pass filter. VSC HVdc IGBT switching produces high frequency (kHz) signals over a fairly large spectrum of frequencies. Since there usually isn't any equipment at transmission level voltages that will resonate at these kHz frequencies (other than PLC circuitry) and the signal level generally isn't high enough to cause any other problems, these signals are not usually an issue unless there is locally connected PLC equipment. The problem is usually only a local problem because these high frequency signals are generally attenuated to acceptable levels by passing through a transformer or traveling a long enough distance on a transmission line.

The second issue is the potential for VSC HVdc produced interharmonics to interfere with smart grid communication systems that use power lines as their communications medium. Any non-harmonic distortion on the system can interfere with communications over power lines, but a large interharmonic source such as a large wind farm using Type 4 turbines, a commercial level arc furnace or an HVdc installation is more likely to do so. As long as there are no industry standards on limiting power system distortion to allow for communications over power delivery circuits, this issue will need to be addressed on a case-by-case basis when installing any facility producing non-harmonic distortion, such as a VSC HVdc, near a system using power lines as a communications medium (or vice versa – installing a power line communication system near a VSC HVdc). This will require knowledge of the interharmonics produced by the VSC HVdc, the sensitivity of the communications system to interharmonics and how each interacts with each other and the system.

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