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System Impact Assessment of a Proposed Geomagnetically-induced Current Field Test at a Dominion Energy Virginia Substation

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SUMMARY

The negative effects of geomagnetic-induced current (GIC) flow in the power grid during geomagnetic disturbance events are well documented, and many simulation models have been developed to study these effects. However, validating these simulation models with physical data is difficult since these events are rare, and documented field tests are virtually non-existent. In response to this industry need, Dominion Energy, an electric utility in the U.S, plans to conduct a GIC field test at one of its substations. This paper provides a system impact assessment of the proposed test on the Dominion grid using electromagnetic transient simulations. The parameters evaluated against injected DC current magnitudes for different operating scenarios include peak current demand, reactive power consumption, voltage dip, as well as voltage and current harmonics, etc. It was found that scenarios where a nearby capacitor was operational resulted into noticeably higher voltage harmonics due to parallel resonance. Although the higher voltage harmonics did not violate the IEEE standard 519-2014 limits, it was conservatively recommended to put the capacitor out-of-service since the field test will occur during a shoulder month with moderate to low load. All things being equal, this study revealed that the system-level impact of the GIC field test would be minimal, and the proposed test should not affect the continuity and quality of power supply.

KEYWORDS

Geomagnetic Disturbance, Geomagnetically-induced current, GIC field test, Reactive power consumption, Harmonics, System impact assessment, Voltage unbalance

1 INTRODUCTION

Geomagnetic disturbances (GMD) have proven their ability to disrupt normal operation of the bulk electric system by causing blackouts in the Hydro-Quebec system in 1989 [1] and the southern Sweden power grid in 2003 [2]. In less extreme situations, GMDs have caused transformer damage, capacitor tripping, reactive power swings, and abnormal voltage levels in different parts of the world including the U.S., Canada, Finland, Sweden, South Africa, and New Zealand [3], [4], [5]. GMDs occur due to earth-directed corona mass ejections (CMEs) from the sun’s surface, typically a few days after solar flares or other solar eruptions. Compared to solar flares that travel at the speed of light, CMEs are “slow” moving expulsions of highly energetic plasma and magnetic fields that travel between 250 and 3,000 km/s [6]. CMEs interacting with the earth’s magnetic field create GMDs, which then cause geomagnetically induced currents (GICs) to flow in electric transmission lines on the earth’s surface. GICs have very low frequencies, typically less than 1 Hz, and thus are called quasi-DC; their flow in a predominantly 60 Hz AC power grid is an abnormality.

When these GICs flow into a high-voltage power transformer through its grounded-wye windings, they force the transformer into half-cycle saturation, which leads to undesirable electrical, mechanical, and thermal effects (see Table 1). Even though the primary effects of GIC flow occur at the transformers, many of the secondary effects have system-wide implications. An example of this is the 2003 blackout in Sweden, which began because a critical 130 kV line was tripped by a protection relay with high sensitivity to the third harmonic produced by a nearby transformer [6]. Factors that generally affect the severity of the GIC effects include transformer design (which determines the magnetic reluctance of the DC flux path), transformer age and loading history.

Table 1: Classes of effects for GIC flow in a transformer

Effect Class	Primary Effects	Secondary Effects
Electrical	• High reactive power consumption • Production of even and odd harmonics	• Abnormal voltage levels • Misoperation of protection devices • Abnormal heating of transmission lines and generator windings
Mechanical	• Transformer vibration and noise	• Mechanical stress on transformer fasteners • Noise pollution in the substation vicinity
Thermal	• Hotspot heating in transformer winding and structural parts	• Transformer protection trip • Permanent transformer damage

Considering that a GMD induced by space weather cannot be controlled, power systems engineers and researchers have great interest in investigating GMDs and mitigating the potential effects on the electric grid. On May 16, 2013, the U.S. Federal Energy Regulatory Commission directed the Northern America Electric Reliability Corporation (NERC) to develop standards to address the reliability risk of GMD on the U.S. power grid. The result was NERC’s TPL-007 reliability standard, which requires all transmission owners to identify potential impacts of specified GMD events on their systems and develop and implement a risk mitigation strategy [7]. This has led to numerous GMD/GIC related studies and simulation tools [8], [9], [10], [11], but to date no electric utility in the U.S. has performed a physical field test to validate the accuracy of these simulation models. The most recent documented field test in occurred in Finland about 20 years ago [12]. Since then, the internal design of transformers has developed considerably, and the results of that test may no longer be relevant today.

In response to this industry need, Dominion Energy, which has sponsored several GMD/GIC-related research projects [3], [13], [14], is planning a GIC field test in the fall of 2022 at one of its 500/230 kV substations. Before the GIC field test is conducted, its potential impact on Dominion’s grid needs to be evaluated and compensated for in order to ensure the continuity and quality of electricity supply to the company’s customers during the test. This paper investigates various potential system impacts of the proposed GIC field test, using real physical data collected from Dominion. The paper can serve as a guide to other transmission owners on the different system-level effects that must be evaluated during

the planning stages of a GIC field test. This study focuses on the electrical GIC effects such as reactive power consumption, voltage dips, and harmonics. Mechanical and thermal effects are outside the scope of our study.

The paper is organized as follows: Section 2 discusses the modelling of the Dominion Energy Virginia substation where the GIC field test will occur, followed by the validation of the model. Section 3 highlights the operating conditions and the simulation process employed in this investigation. Section 4 reports the simulation results, while remarks and conclusions are presented in Section 5.

2 MODELING THE DOMINION SUBSTATION AND SURROUNDING SYSTEM

The modelling process used three commercially available software packages: Aspen OneLiner, PSS/E and EMTDC/PSCAD. The bulk of the study was performed using PSCAD for electromagnetic transient (EMT) simulations. Despite the considerable modelling and computational effort required, an EMT model was chosen for this study because it allowed for detailed three-phase modelling, and it could accurately simulate the non-linear dynamic characteristics of a power system. Empirical studies have also shown that EMT tools are more accurate for GIC impact analysis than phasor-based simulation tools [15]. Aspen OneLiner was used to create a reduced network equivalent for a chosen area of interest including the substation where the GIC field test will be performed; this served as the basis for the EMT modelling in PSCAD. Then, PSS/E was used to provide bus voltage magnitudes and angles to replicate specific operational loading conditions in the EMT model. The EMT model also required some physical line parameters such as line conductor specifications and tower configurations, which were obtained from Dominion's equipment database. Initially, the EMT model was created to represent current system topology, then it was adjusted at a later stage to replicate the specific modifications that would occur for the GIC test. The following subsections provide more details about the modelling process.

2.1 Converting the Model from Aspen OneLiner to PSCAD

The substation where the GIC test will be performed is represented by Buses 1 and 2 at the terminals of transformers TX1 and TX2 in the network equivalent shown in Figure 1. TX1 and TX2 are three-phase grounded wye-connected autotransformers made up of banks of three single-phase transformers rated at 168 MVA ONAN¹ and 280 MVA ONAF². Thus, TX1 and TX2 have total maximum capacity of 840 MVA each. The transformer that will be subjected to the GIC field test is TX1. The study area included Buses 3 to 10, which are one bus-hop away from the two substation buses. This area was chosen to expose the system-level effects of the GIC test while making the EMT modelling task tractable. An extra Bus 11, which is two hops away from Bus 1, was added because it is connected to a static synchronous compensator that is the subject of other studies outside the scope of this paper.

Having defined the study area, Aspen OneLiner provided the boundary equivalents which include eight virtual generators and six virtual lines, which represent the system impedance at the boundary buses and the external transmission path between the boundary buses. The network equivalent also included four virtual transformers and 22 virtual phase shifters also representing external transmission paths; these are not included on Figure 1 to avoid overcrowding the figure. Only nine phase shifters that had positive sequence impedance below 5 p.u. were retained in the reduced model to reduce the modelling burden without considerably affecting accuracy.

¹ ONAN – Oil Natural Air Natural

² ONAF – Oil Natural Air Forced

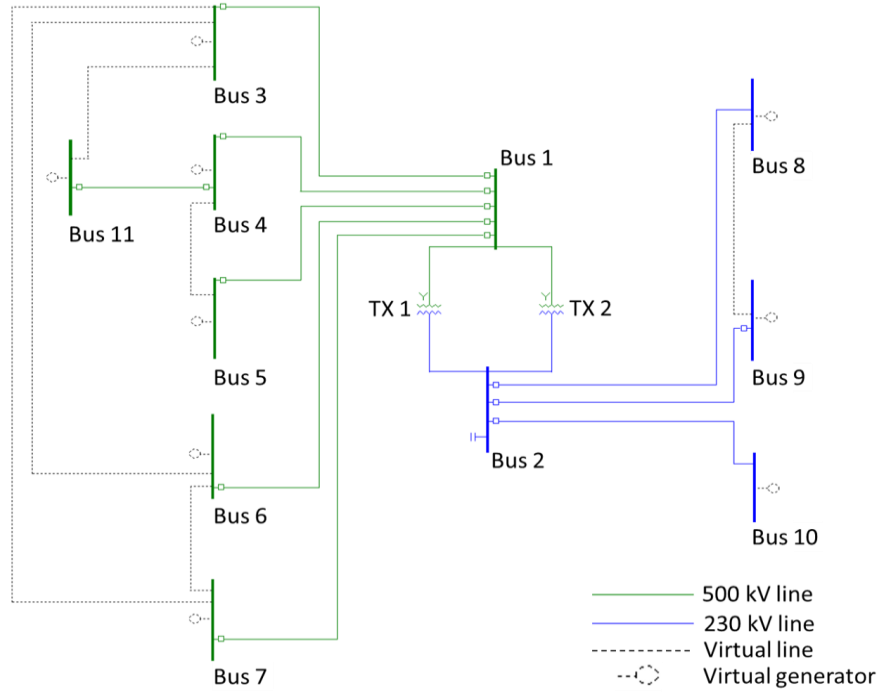


Figure 1: Reduced model of the study area of the Dominion grid

Noteworthy considerations in the replication of the reduced network in PSCAD are given below:

- i. **Substation Transformers:** TX1 and TX2 were modelled using PSCAD's generic three-phase autotransformer model at this stage. However, this model does not allow the direct input of the measured transformer I-V data points to represent the non-linear saturation characteristics of the transformers. The model does require parameters such as air core reactance, knee voltage and magnetizing current, which were not readily available. So a well-known rule-of-thumb was used: air-core reactance was estimated at twice the transformer leakage reactance [16]. The knee voltage, V_{knee} , and magnetizing current, I_m , were estimated by inputting the measured I-V data points into a curve-fitting optimization module designed for this purpose in PSCAD [17]. Figure 2 shows the transformers' saturation curve and the approximate curve corresponding to the derived V_{knee} and I_m ; the figure indicates that the derived parameters are accurate enough to model the saturation characteristics of the transformers.

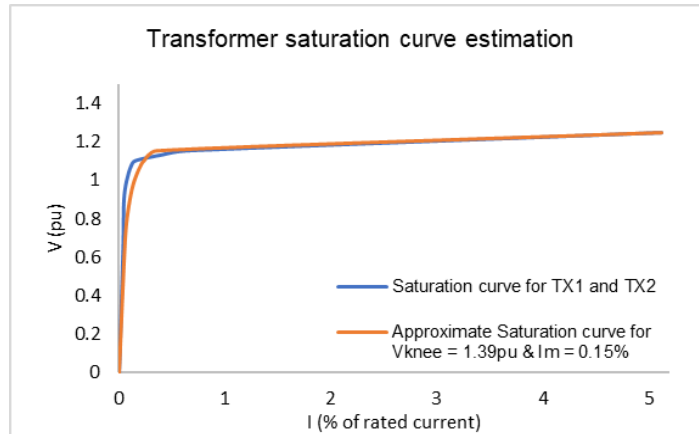


Figure 2: Comparison of measured saturation curve and approximate saturation curve corresponding to V_{knee} & I_m

- ii. **Transmission Lines:** The reduced model included nine real transmission lines which were modelled using the frequency-dependent-phase (FDP) models in PSCAD. These are PSCAD's most advanced but most complicated and computationally expensive line models that use

curve-fitting to duplicate the full frequency response of all line parameters. These models were used because harmonics propagation from the substation transformers to the rest of the system was of interest. For each line segment, the FDP transmission line models required the transmission tower configuration, conductor data, and ground wire data from the equipment database.

A single transmission line is often made up of several line segments, but the length of the shortest line segment modelled in PSCAD reduces the maximum simulation time step that can be used. Thus, line segments less than 10 km were lumped with adjacent line segments that had the same conductor type. The coordinates of the lumped line segments were calculated as the length-weighted average of the coordinates of all constituent line segments. This helped to reduce the modelling burden and increase simulation speed. Experience with FDP models have shown that the models often underestimate zero-sequence impedance of the lines; thus, additional 25 – 30 ohms zero-sequence impedances were added to some of the transmission lines by means of Pi-sections. The other six virtual transmission line were modelled as Pi-sections using the sequence impedances collected from the OneLiner model.

- iii. **Virtual generators:** The nine virtual generators were modelled in PSCAD as voltage sources behind series RL impedances. These voltage sources allowed the initial terminal conditions, including voltage magnitude and angle, as well as real and reactive power injection, to be user-defined while the program calculated the required voltage behind the impedances.
- iv. **Virtual transformers and phase shifters:** These were modelled as wye-wye connected transformers in PSCAD since the program does not include a specific phase-shifter model. In most cases, their zero-sequence impedance was larger than the positive-sequence impedance, so a compensating impedance was added to their neutrals to account for the difference.

After the creation of the EMT model in PSCAD, a fault study was undertaken to validate the model's accuracy by comparing fault currents at Buses 1 and 2 between the full OneLiner model before model reduction and the EMT model. Table 1 shows that the maximum absolute difference between the models in fault current magnitude and phase was less than 3%, proving that the EMT model is a reliable replica of the original OneLiner model.

Table 2: Validation of the EMT model using fault analysis

Fault Location	Fault Type	OneLiner fault Current (kA)	EMT model fault Current (kA)	% Absolute Error
Bus 1	3 phase-to-ground	31.40 $\angle$ -56.5	31.14 $\angle$ -57.0	0.8% $\angle$ 0.9%
	Line-to-Line	15.64 $\angle$ -55.9	15.57 $\angle$ -57.0	0.5% $\angle$ 1.9%
	1 phase-to-ground	7.87 $\angle$ -53.0	7.86 $\angle$ -52.2	0.1% $\angle$ 1.5%
Bus 2	3 phase-to-ground	34.67 $\angle$ -55.2	33.66 $\angle$ -55.9	2.9% $\angle$ 1.2%
	Line-to-Line	17.26 $\angle$ -55.0	16.83 $\angle$ -55.9	2.5% $\angle$ 1.6%
	1 phase-to-ground	9.76 $\angle$ -52.7	9.68 $\angle$ -53.2	0.7% $\angle$ 0.9%

2.2 Replicating Operational Loading Conditions in the EMT Model

Since system loading conditions are not included in OneLiner models, information about real operating conditions was obtained from steady-state energy management system (EMS) snapshots of the Dominion grid, available in PSS/E format. Because the actual operating conditions during the proposed GIC test cannot be known and would vary from time to time, two operating conditions were replicated in the EMT model. The operating conditions, drawn from historical data over the last three years, represented the highest and lowest transformer loading conditions that occurred within the same months that the test has been planned for. In the PSS/E snapshot cases, TX1 was disconnected, the power flow was solved, and the resulting voltage solutions were used as inputs in the EMT model to set the initial voltage magnitude and angle at the terminals of the voltage sources. Furthermore, the initial power flow injections at each bus were also set based on the power flow in PSS/E and the

estimated power flow in the virtual branches. Table 3 presents the static power flow solution in PSS/E and the power flow in the EMT model after reaching equilibrium for the high- and low-load cases.

Table 3: Comparison between static power flow in PSS/E and EMT power flow in PSCAD

Branch name	High Load power flow (MVA)		Low Load power flow (MVA)	
	Static	EMT	Static	EMT
TX1	0.0	0.0	0.0	0.0
TX2	579.9	536.6	142.2	130.9
Line 1-3	239.4	218.7	1015.4	1004.0
Line 1-4	1061.3	990.6	996.3	953.0
Line 1-5	1423.4	1407.0	1256.7	1249.1
Line 1-6	807.2	801.9	463.3	457.5
Line 1-7	847.5	834.9	624.0	610.3
Line 2-8	223.5	228.4	174.5	170.2
Line 2-9	213.3	142.3	156.9	147.9
Line 2-10	142.1	161.4	121.0	102.3
Line 4-11	183.3	160.2	7.7	106.2

The EMT model was not expected to precisely correspond to the static power flow since it models the changing dynamics in the power system. Moreover, the use of the FDP line models for which impedance values cannot be directly inputted, and the exclusion of equivalent branch paths with impedance values above 5 p.u. would have contributed to the differences in power flow solutions. Nevertheless, the power flow condition is not an intrinsic network characteristic and is highly probabilistic, hence, perfect conformity of the power flow in the EMT model to the static model was not required.

2.3 Adjusting the EMT Model According to the GIC Field Test Set-up

A back-to-back configuration for two out of the three of TX1's single-phase autotransformers was proposed for the GIC field test, as shown in Figure 3; this is a common configuration among transformer manufacturers to perform similar tests in the factory. This configuration allows the simultaneous testing of two transformers, and the joint inductance of the transformers serves to limit circulating current during the test. H_A , H_B , and H_C are the primary terminals and X_A , X_B and X_C are the secondary terminals of the three single-phase autotransformers (TX1A, TX1B and TX1C).

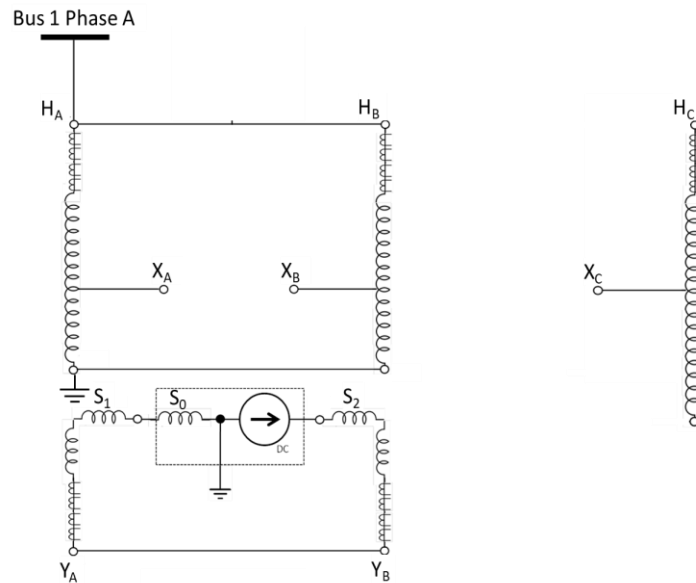


Figure 3: Modifications to TX1 for the GIC field test

On the primary side, H_B and H_C will be disconnected from Bus 1 but H_B will be looped to H_A , effectively connecting the primary sides of both transformers to Phase A. On the secondary side, X_C will be disconnected from Bus 2 to completely isolate TX1C, while 40 winding turns of TX1A and TX1B (out of a total of 1141 winding turns) will be separated to make tertiary windings Y_A and Y_B . The connection of the two tertiary windings will serve as the test circuit through which the DC current, which represents GIC, will flow. The galvanic isolation of the test circuit from the primary windings will prevent DC from flowing into the grid. S_0 is a reactor placed in the test circuit to limit potential circulating current that will flow if there is a voltage difference between TX1A and TX1B during saturation. S_1 and S_2 are auxiliary reactors inserted to limit fault current.

In the EMT model, TX1 was also replaced by a similar back-to-back configuration of two single-phase transformers with the same saturation characteristics as TX1. The single-phase transformers were modelled using the unified magnetic equivalent circuit (UMEC) transformer model in PSCAD, which models the core geometry and magnetic properties of the transformer core material [18]. This allows the program to consider the windings' self-inductances as well as the mutual inductances among all windings of the same phase and different phases. It was expected that the UMEC model would be more accurate than the classical transformer model for the purpose of this study, since the DC flux created by GIC injection depends not only on GIC magnitude but also on magnetic circuit reluctance, which is a function of core material and dimensions.

3 SIMULATING DC INJECTION

As previously mentioned, GIC, being quasi-DC, will be replicated by injecting DC current into the ad hoc transformer tertiary windings during the field test. This set up was achieved in the EMT model by placing a DC voltage source in the path of the tertiary windings (as in Figure 3). The DC voltage source was externally controlled by a voltage signal that ramped up at $2 \text{ kV}_{dc}/s$ until the DC current reaches a predefined target magnitude. Five DC current magnitudes from 310 to 1550 A (in steps of 310 A) were injected into the transformers' tertiary windings; these current magnitudes are equivalent to 10 to 50 A (in steps of 10 A) in the primary windings due to the transformers' winding ratio. These DC currents were injected into the transformers for the four operating scenarios presented in Table 4.

Table 4: Operating scenarios for DC injection tests

S/N	Scenario Name	Transformer Loading condition	Bus 2 capacitor operational status
1	High load/Cap out	High load	Out-of-service
2	High load/Cap in	High load	In-service
3	Low load/Cap out	Low load	Out-of-service
4	Low load/Cap in	Low load	In-service

Each DC injection was simulated for 120 seconds to allow the electrical effects of interest to reach equilibrium. This equilibrium was reached when the offset DC flux in the transformer core stopped increasing at the instant when the DC component of the magnetizing current became equal to the injected DC current [19]. Based on the size and calculation complexities of the EMT model in this study, each simulation second corresponded to about 20 seconds of clock time; thus, a 120-second simulation equals about 40 minutes in real time.

4 RESULTS AND DISCUSSION

4.1 Transformer Current Waveforms and Peak Current Demand

Due to the back-to-back configuration, DC current injected through the transformers' windings flows in opposite directions from each transformer's point of view, thus, their fluxes also experience a DC offset in opposite directions as shown in Figure 4. This phenomenon is peculiar to the deployed test configuration and is not generalizable to GIC flows in connected single-phase transformers which are typically connected in parallel during normal operation.

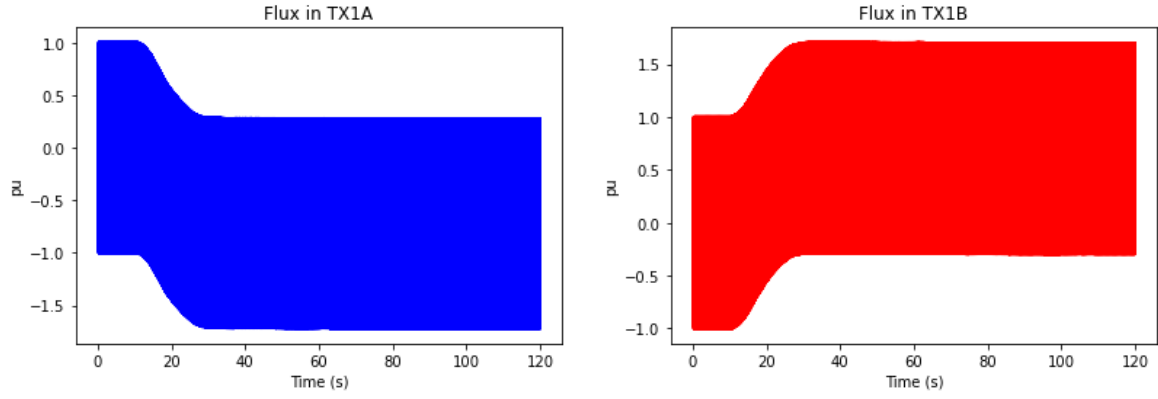


Figure 4: DC flux offset of transformers TX1A [left] and TX1B [right] after DC injection of 1550A commencing at 10 s

On the primary side, Figure 5 shows that the current waveforms of both transformers have characteristic shapes indicating that the transformers saturated in opposite direction and at different half-cycles. Since the transformers were not carrying load, their current waveforms were dominated by the shape of the magnetizing current when saturated and by the DC current when unsaturated. The DC currents at the primary side of the transformers were in the opposite direction of the flux creating them, according to Lenz's law. Thus, the super-position of the half-cycle magnetizing current, which peaked in the same direction as the flux, made the transformer current peak in the opposite direction of the DC current. The sum of both transformer currents resulted in the waveform seen on the right-hand plot of Figure 5, which is the total current drawn from the Phase A of Bus 1. As expected, the peak of the total current was less than the sum of the transformers' current peaks since they were a half-cycle out of phase.

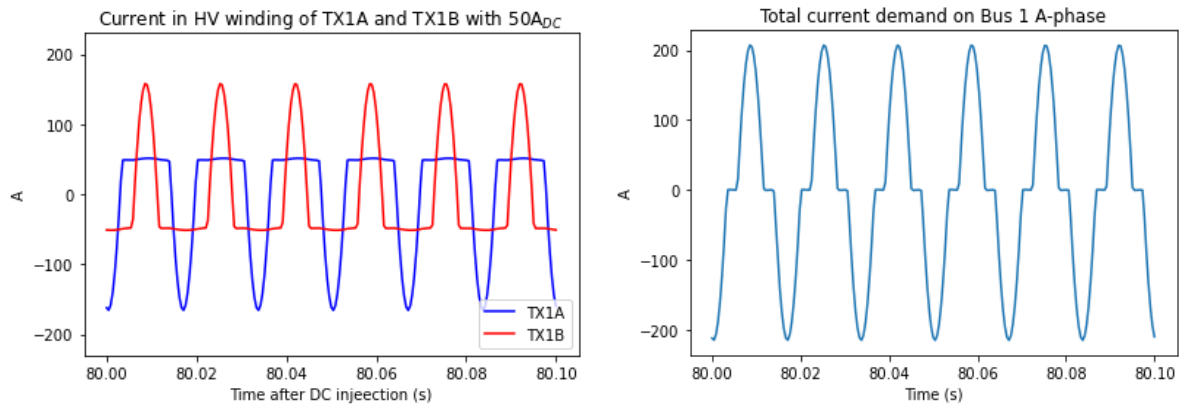


Figure 5: Primary-side currents of TX1A and TX1B [left] and total current demand on Bus 1 [right]

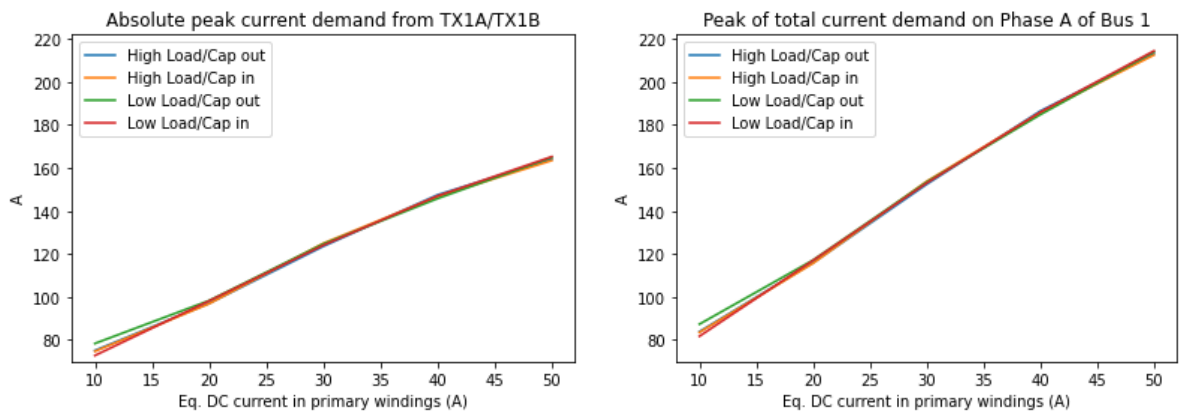


Figure 6: Peak current demand from TX1A & TX1B [left] and peak current drawn from Bus 1 Phase A [right]

Figure 6 above shows that the absolute peak current demand from the transformers and the total peak current drawn from the Phase A of Bus 1 increased linearly with DC current magnitude and both were largely independent of the operational scenarios. Note that the absolute peak current drawn by TX1A and TX1B were similar.

4.2 Reactive Power Consumption

Figure 7 presents the peak reactive power consumption (Q_{peak}) of the individual transformers and the total Q_{peak} on Phase A of Bus 1 across the operational scenarios. Similar to the current drawn by the transformers, the total $Q_{peak} @ Phase A < Q_{peak,TX1A} + Q_{peak,TX1B}$, thus it will be inaccurate to simply add the Q_{peak} of the individual transformers to calculate the total reactive power demand on the grid during the GIC test. Note that $Q_{peak,TX1A}$ is similar to $Q_{peak,TX1B}$, thus, the left-side plot of Figure 7 is applicable to both transformers.

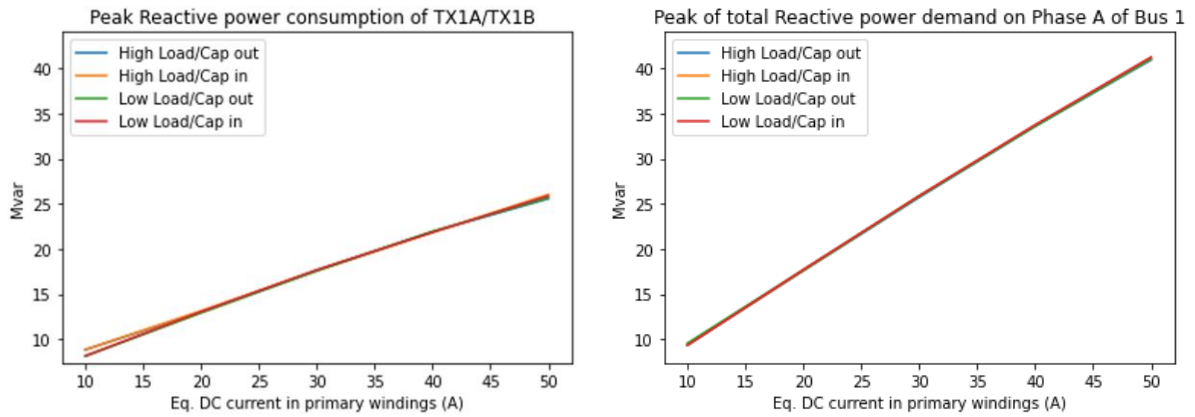


Figure 7: Q_{peak} of TX1A & TX1B [left] and Q_{peak} at Phase A of Bus 1 [right]

Furthermore, a linear relationship, independent of operating conditions, was also observed, hence, the general relationship between the Q_{peak} of the individual transformers and the DC current magnitude can be estimated as:

$$Q_{peak} = 1.05 \times I_{dc} \times V_{rms,ll}$$

Where I_{dc} is DC current in amperes and $V_{rms,ll}$ is the line-to-line RMS voltage at the transformer primary side in kilovolts.

To prevent a large voltage dip, it is vital that transmission operators ascertain that the reactive power reserve in their system is sufficient to supply the additional reactive power demand during a GIC test. The next subsection evaluates the voltage dip caused by the transformers' reactive power consumption.

4.3 Voltage Dip and Unbalance

This section evaluated the voltage dip due to the reactive power consumption of the transformers subjected to DC current. Since both transformers will only be directly connected to Bus 1 during the field test (recall Figure 3), the voltage dip on Bus 1 was first evaluated across all the considered scenarios as shown in the left side plot of Figure 8. The figure shows that voltage only dropped by less than 0.02 pu at the largest injected current of 50 A_{dc}; hence, voltage dip as a result of the GIC field test should not be significant. As expected, the scenario with the lowest voltage is the high load/cap out scenario, yet, the figure shows that the voltage magnitude of this scenario was still acceptable, given that the low voltage limit of 500 kV buses in the Dominion grid is 1.025 p.u during normal operating conditions.

To evaluate the voltage dip across the modelled system, the right-side plot of Figure 8 presents the percentage change in bus voltages for the high load/cap out scenario where Bus 1 had the lowest voltage. It can be seen that Bus 1 still has the largest voltage dip of 0.16%, thus, voltage dip in response to the increased reactive power demand during DC current injection is minimal. This proves

that the system reactive power reserve will be sufficient to supply the additional reactive power consumption of the transformers during the GIC field test.

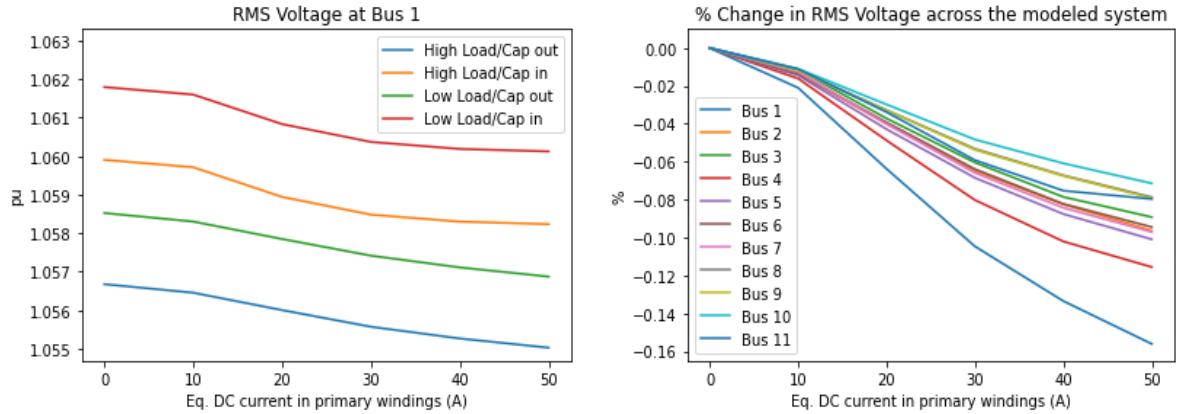


Figure 8: RMS voltage at Bus 1 against DC current magnitude for all scenarios [left] & percentage change in bus voltages across the system due to DC injection for the high load/cap out scenario [right]

A unique concern regarding the test set-up in this study was voltage unbalance due to reactive power demand on a single phase of Bus 1. Investigation into this revealed that the highest voltage unbalance of 0.4% occurred at Bus 1 for 50 A_{dc} injection in the low load/cap out scenario. This voltage unbalance value is acceptable, considering that the stringent voltage unbalance standards, e.g. NEMA MG1-1993, set the limit at 1% [20].

4.4 Voltage and Current Harmonics

The recommended harmonic limits in the IEEE standard 519-2014 [21] were used to evaluate the voltage and current harmonics in this study. Voltage and current harmonics at Phases B and C were evaluated and found to be negligible, which is reasonable since TX1A and TX1B were connected to Phase A (recall Figure 3). Hence, all the results presented in this section are only for the Phase A.

Figure 9 reveals that the total harmonic distortion (THD) at Buses 1 and 2 were less than the 1.5% recommended limit for buses with voltages above 161 kV and it was also verified that voltage THD at the other buses in the study area was less than 1%. Consistent with literature, the relationship between THD and DC current magnitude was found to be non-linear; exemplifying the difficulty in predicting harmonic distortion caused by GIC injection. Moreover, Figure 9 shows that scenarios with the capacitor in operation had considerably higher THD.

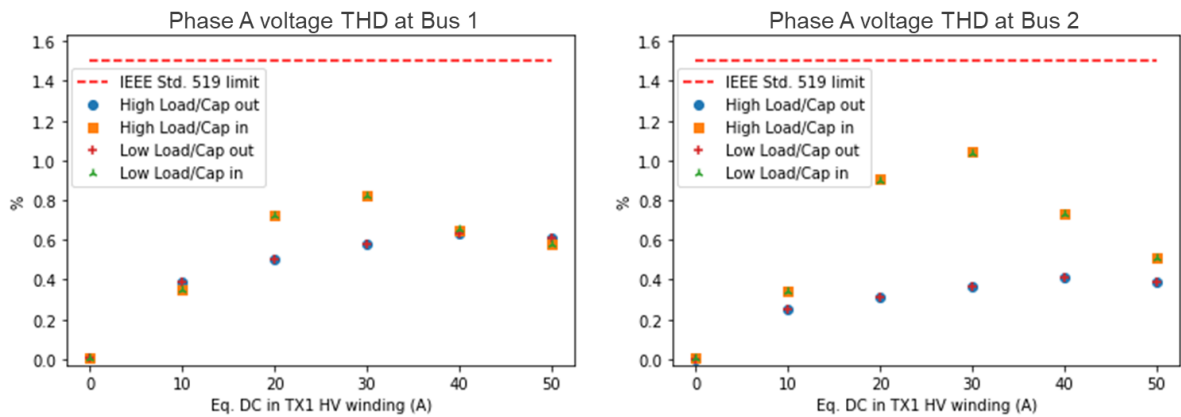


Figure 9: Voltage THD at Buses 1 and 2 for all tested scenarios

A closer look at the individual harmonic content for 30 A_{dc} at Bus 2 shows that the presence of the capacitor significantly increased the 7th harmonic in the voltage (see Figure 10). This observation led

us to perform a frequency scan at Bus 2. The impedance phase plot in Figure 11 shows that the presence of the capacitor significantly modified the system's frequency response, creating the potential for parallel resonance close to the 7th and 10th harmonics. The severity of this potential resonance can be seen by the much larger impedance values at these harmonic orders. The lack of significant 10th harmonic – and all even harmonics in general – is due to the back-to-back configuration of TX1A and TX1B, which produced identical, symmetrical current waveforms that shifted half-a-period; this severely limited the even harmonics from entering the grid. Out of an abundance of caution, it was recommended that the capacitor at Bus 2 be put out-of-service to limit voltage harmonics because the 7th harmonic content as seen in Figure 10 was close to the 1% limit for individual harmonic in voltage. Moreover, the GIC field test has been planned for a shoulder month with low to moderate system load, therefore, the voltage support function of the capacitor during the test period is inessential.

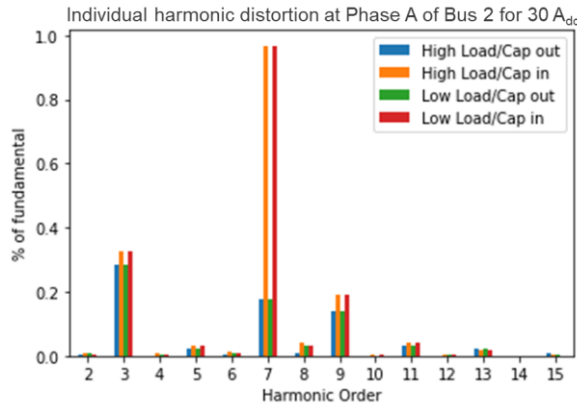


Figure 10: Individual harmonic distortion at Bus 2 for 30A_{dc} for all tested scenarios

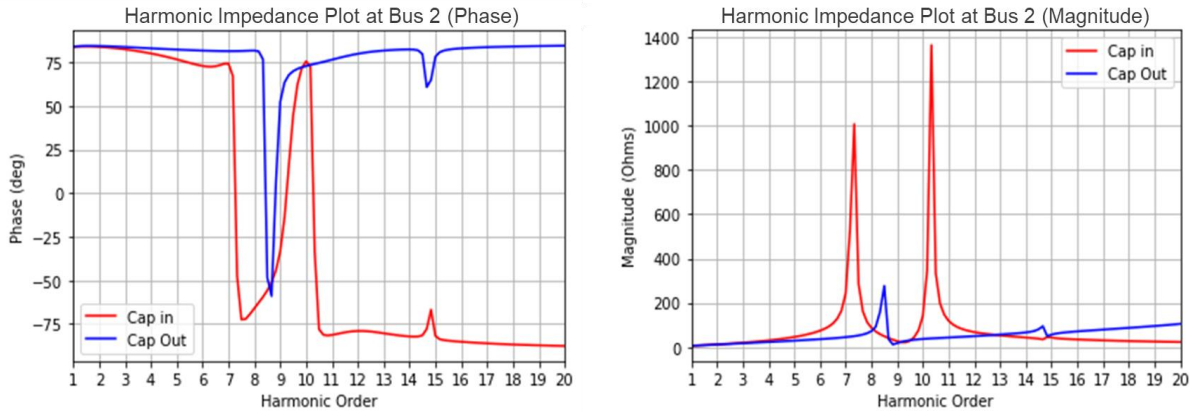


Figure 11: Plots of harmonic impedance phase [left] and magnitude [right] from frequency scanning at Bus 2

Total demand distortion (TDD) is the metric of evaluation for current harmonics, and the recommended TDD limit depends on the ratio of short-circuit current and maximum-demand current (I_{SC}/I_L) at a bus [21]. In our study, I_{SC}/I_L for all the buses studied (except Bus 1) was less than 25, thus their TDD limit is 1.5%. The I_{SC}/I_L for Bus 1 was above 25 but less than 50, for a TDD limit of 2.5%. Figure 12 shows that the TDD at Bus 1 exceeded the recommended limit in all scenarios when DC current injection was greater or equal to 20 A_{dc}, but TDD at Bus 2 never exceeded its prescribed limit. Fortunately, Bus 1 is not directly connected to Dominion's customers, and the TDD at the other modelled buses are less than their TDD limits as shown in Figure 13. Therefore, Dominion customers are not expected to experience any power quality issues during the GIC field test.

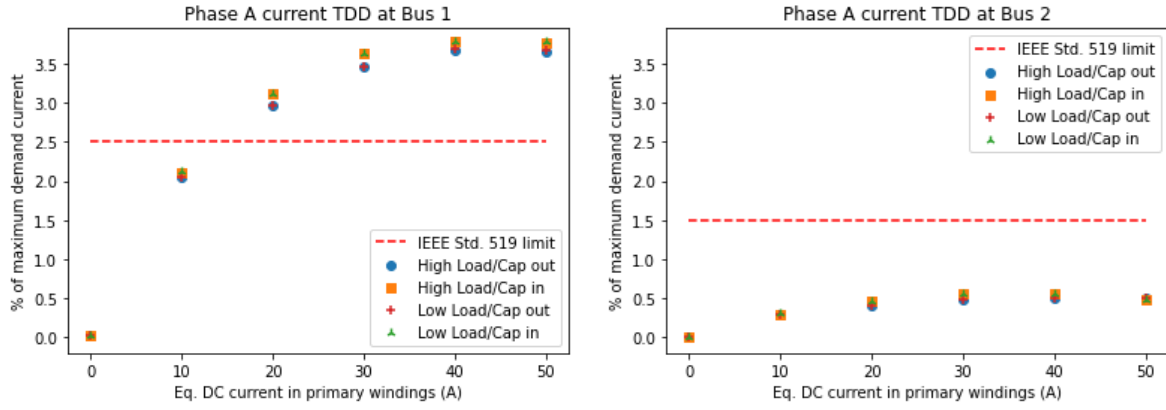


Figure 12: Current TDD at Buses 1 and 2 for all scenarios

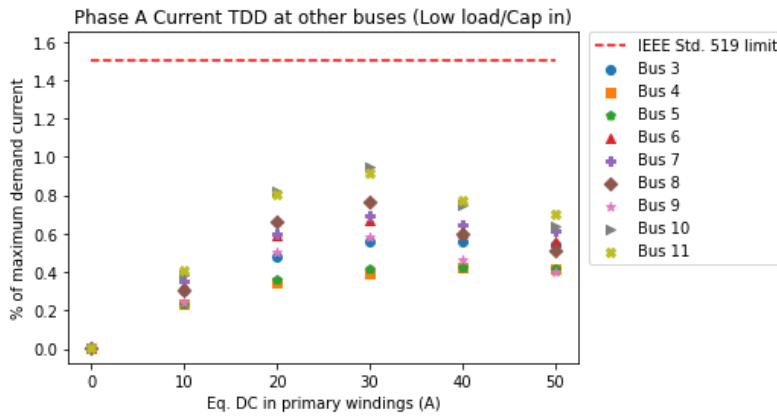


Figure 13: Current TDD at other modelled buses for the low load/cap in scenario (with highest current TDD)

4.5 Other Observed Electrical Interactions

While this paper outlines the study's most significant observations, space restrictions prevent us from detailing all the simulations performed in preparation for the GIC field test. However, listed below are other notable electrical interactions discovered during the EMT study:

- i. The sympathetic response of the parallel transformer TX2 to DC injection in the test transformer was low, only increasing RMS current drawn by TX2 by 0.6 A for a 50 A_{dc} injection.
- ii. Active and reactive power oscillations of 120 Hz with a peak-to-peak magnitude of 3 MW and 6 Mvar were observed at Bus 1 due to the connection of the test transformer to one phase. The oscillation magnitudes at other buses in the study area were significantly smaller.
- iii. The equilibrium values of the electrical effects of sequential injection of DC current into the transformers were the same when the DC current magnitude remained the same, as shown on the left-side plot of Figure 14. The right-side plot shows the 3rd harmonic current for the first and second DC injection periods. The only observable differences occurred during the transient period due to the residual magnetization of the transformer. This phenomenon was observed as well for the reactive power consumption, voltage harmonics and other current harmonic orders.

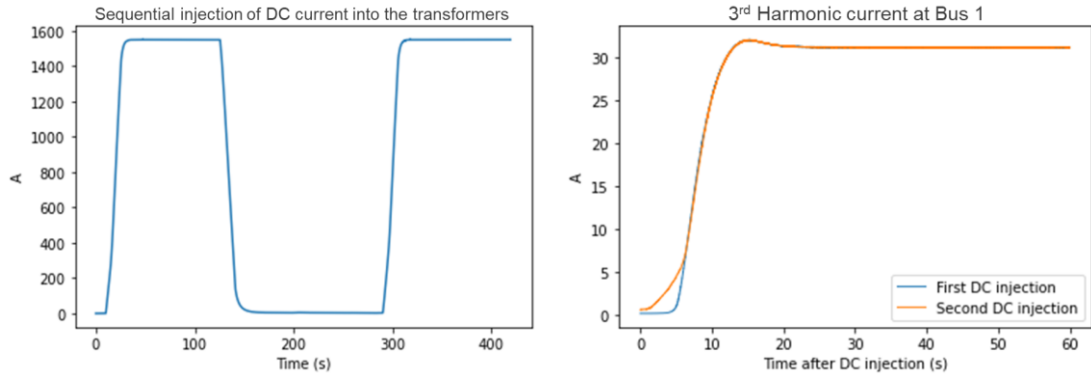


Figure 14: Effects of sequential injection of DC current in the transformers

5 CONCLUSION

This paper investigated the system-level impacts of a proposed GIC field test on the Dominion Energy power grid, using EMT modelling of the field test location and its surrounding system. The study was discussed in sufficient detail to provide guidelines for other providers wishing to conduct similar analyses when a GIC field test is being considered.

The study demonstrated that considerable current and reactive power will be drawn by the transformers subjected to DC current during the field test. Thus, it is important that transmission operators confirm that the reactive power reserve at the test location is sufficient before the test is performed. For the Dominion grid, study results indicated that the maximum voltage dip would be 0.16% for the highest DC magnitude that would be injected during the test, proving that the existing reactive power reserve is sufficient.

Voltage and current harmonics were also considered, and their magnitudes were evaluated against recommended limits in the IEEE Standard 519-2014. None of the buses in the study area violated their voltage THD limit across all scenarios, but the current TDD at one bus violated the limit for DC current magnitude $\geq 20 \text{ A}_{dc}$. However, this bus was not directly connected to any load, and current TDD at the buses downstream to it were shown to be below the recommended limits. A case of parallel resonance due to capacitor operation at one of the buses was also discovered, and it led to a conservative recommendation to put the capacitor out-of-service during the GIC field test.

Other investigations performed in preparation for the GIC field test include voltage unbalance, real and reactive power oscillations, sympathetic response of the parallel transformer, and effect of residual transformer magnetization on measured parameters. Overall, the study indicates that the impact of the proposed GIC field test on the Dominion grid will be minimal, and the continuity and quality of electricity supply should not be impacted. It is the authors' hope that this paper will provide the reader with a roadmap for developing a system-level impact assessment that should be performed in preparation for a GIC field test.

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