

Innovative Injection-based 100% Stator Earth-Fault Protection

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1 ABSTARCT

Injection-based 100% stator earth-fault protection has been used for many years. However traditionally signals with frequency between 10Hz and 25Hz have been injected into the stator winding. To inject such a signal, either a dedicated grounding transformer with secondary grounding resistor or injection on primary side of the grounding circuit, is normally used.

This paper will present a novel approach to such protection. Injection signal with frequency slightly higher than the power system rated frequency is used (e.g. 87Hz signal in a 50Hz power system). Such signal frequency enables the following advantages for new injection-based protection:

- 1) Injection is always performed on secondary side of a transformer. This transformer can be either a grounding transformer or a voltage transformer. Thus no change to the primary grounding circuit of the machine (e.g. splitting of the primary resistor in the star point) is required.
- 2) Injection via neutral point VT or even via open delta VT located at the generator terminals is possible. This ensures readily available injection point for almost any unit-connected generator.
- 3) Injection via a VT enables this protection to be applied to ungrounded or inductance/resonance grounded stator windings.
- 4) Because of the higher injection frequency the injection unit and the injection transformer are relatively small.

2 INTRODUCTION

Earth faults in the stator are the most common faults in a unit connected generators [1,2,3]. Such faults may cause severe damage and long outage time. Therefore measures are taken to detect such faults and to limit the consequences, should they appear. The stator winding grounding method is an important factor in the latter category. Appropriate impedance in the stator star point will limit fault current during a single phase to ground fault. However, if more than one ground fault appears at the same time, large current will circulate within the stator causing excessive iron damage. It is therefore important to detect even the first ground fault despite that its consequences may be very limited.

To detect stator ground faults, the basic method is to measure the voltage or current at the stator neutral point. If the ground fault occurs, an increased neutral point voltage and current will appear. However, these methods cannot detect fault close to the neutral point. They are thus referred to as “95 % stator ground fault protection” as they typically cover 95 % of the stator winding, dependent on the

settings [1,2,3]. Thus the last 5% of the stator winding close to the star point is not protected with such method. Further, such protection can only operate when the machine is energized (i.e. excited).

A ground fault close to the neutral point can not cause any direct harm to the machine due to quite limited voltage at the fault point. But it can become a serious threat if a second ground fault would appear. Thus, it is of outmost importance to detect such fault for large machines. A possibility to detect the fault close to the star point can be achieved by measuring the 3rd harmonic voltages generated by the machine [1,2,3]. As this method is dependent on the voltage generated by the machine itself, it can only be active when the machine is excited and if it produces sufficient amount of third harmonic.

It is often considered valuable to detect a ground fault even when the machine is at standstill. Therefore other methods are preferred. Obviously, such a method shall provide its own test signal and can therefore be active at all times, even at machine standstill. To inject a test signal into the machine, some provisions in the primary circuit and additional hardware are usually required. Therefore, these injection-based methods tend to be rather expensive and are usually considered for the large machines only. Some examples of such methods can be found in [1,2].

3 OPERATING PRINCIPLES OF EXISTING INJECTION SCHEMES

All previous injection schemes use a low frequency signal with fixed frequency (e.g. in range from 10Hz up to 25Hz) as an injection signal [4,5,6,7,8,9,10,11,12]. Such a frequency is used in order to easily suppress interfering signals with power system frequency and/or its harmonics (e.g. 3rd). Under healthy conditions, the amplitude of the voltage signal with the nominal frequency at the neutral point is very low. The neutral point voltage is mostly dominated by the third harmonic which can be up to several percent of the machine nominal voltage.

A standard digital filter will suppress exact harmonics of the extracted frequency, however all other frequencies will influence the measured signal. Thus by choosing an injection frequency as sub-harmonic to the power system rated frequency (e.g. 12,5Hz in 50Hz system), the signals having power system frequency and/or its harmonics (e.g. 3rd) will be completely suppressed by this filter. If the power frequency deviates from the nominal one, this suppression will however be less effective and there is a risk for unwanted operation. This probably may happen when the machine is not synchronized. Therefore, many present solutions incorporate an additional low-pass filter (hardware) to further suppress the power frequency and its harmonics [6,7,8,9,11,12].

A second motivation for a low injection frequency is to reduce the amount of capacitive current injected so that a resistive current caused by a ground fault is easier to detect. The capacitive current may limit the fault detection sensitivity for those systems that only measure the current magnitude and not the fault resistance. This is particularly important for large machine applications, typically a large hydro generator, which may have several μF as stator capacitance to ground. In such case, it may be difficult to detect high resistive ground faults in the stator winding by measuring only the injected current magnitude.

The primary quality factor of injection-based protection is the largest detectable ground fault resistance. From the preceding paragraph, it is clear that this value depends on the capacitive reactance of the stator and any other impedance to ground in the protected region. Additionally, the stator grounding impedance itself is also an important factor. In many designs, the grounding impedance is chosen as a resistor with roughly the same ohmic value as the stator capacitive reactance (at 50Hz). Such a grounding resistor has a typical value between 0,5k Ω to 2k Ω on the primary side. Note that the stator ground fault resistance will be effectively connected in parallel to this grounding resistor. Thus to detect a fault for example with 10k Ω the total measured resistance value will change for approximately 10% from the healthy condition. This in combination with the stator capacitance, which is also connected in parallel, will limit the overall sensitivity of the injection-based protection. Further, the stability of the grounding resistor (e.g. temperature variation, ageing etc.) will also influence the largest fault resistance that can be detected with confidence. It is common practice to recommend trip settings of this protection in the range 1k Ω to 5k Ω and alarm settings up to 10k Ω .

Most injection-based systems recommend injection through a dedicated grounding transformer or directly in the primary circuit. The main reason is that low frequency signal has a problem to propagate through a transformer due to its internal reactance. Most transformers used in the power

system are designed for 50Hz or 60Hz and perform poorly at lower frequencies. Note that for low frequencies, the transformer magnetising current is also increased comparing to 50Hz value. As this magnetizing current is also measured by the relay it will also influence the maximum relay sensitivity.

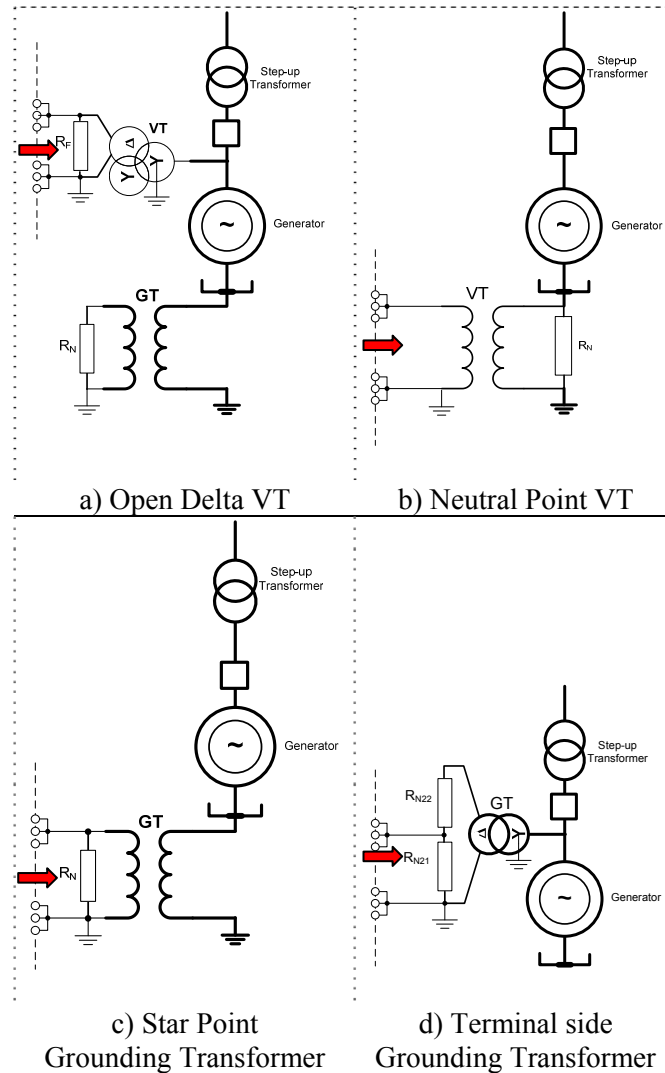


Figure 1: Injection point marked with red arrow

To enable the use of a voltage or a grounding transformer for injection, it is important to keep their internal reactance in mind. As already stated transformers used in the power system are designed for 50Hz or 60Hz signals and perform poorly at lower frequencies. Thus, it would be attractive to use an injection frequency close to, but slightly higher than the power system nominal frequency. Such a solution would have benefits hardware-wise, but it becomes much more difficult to use the digital filters (e.g. digital Fourier filter) typically used in numerical protection relays today as such a filter will have problems to reject the nominal power system frequency and its harmonics. Thus, another filtering method must be found. Using long filtering windows (e.g. 1s) and modern numerical filtering techniques such as interpolated FFT [13,14] it is possible to achieve suppression for all signals with frequency outside a $\pm 5\text{Hz}$ range around the injection frequency. In addition to the complex amplitude of the injected signal also an accurate estimate of the injected frequency is obtained in the filtering process. This additional information can be used to supervise the injection protection and prevent possible problems during machine start-up and shut-down. With such interpolated FFT methods, it is also possible to select any frequency to be extracted and therefore the injected frequency can be made

settable. There is a relatively large freedom to select the injection frequency but frequencies within range to known disturbances and their harmonics should be avoided (e.g. 16,67Hz used for railway supply in Sweden). Typically, an 87Hz injection signal is used in a 50Hz power system.

3.1 Injection system hardware

Central to the injection system is the oscillator which provides a square-wave signal of a selectable frequency with sufficient power. The oscillator is connected to the injection point as shown in Figure 1. The resultant voltage and current are fed to amplifiers that condition these two signals in order to use standard 110V voltage inputs into the protection relay. Thus, the injection signals must be amplified so it can be read with a sufficient signal-to-noise ratio by the relay. Figure 2 shows schematically the required connections. In the relay, the signals corresponding to voltage and current are digitized and analyzed to estimate the ground fault resistance, which is the basic input to the new stator injection-based protection function which is also performed by the same relay.

3.2 Impedance measurement

The principal design of the new injection method for the stator is illustrated in Figure 2.

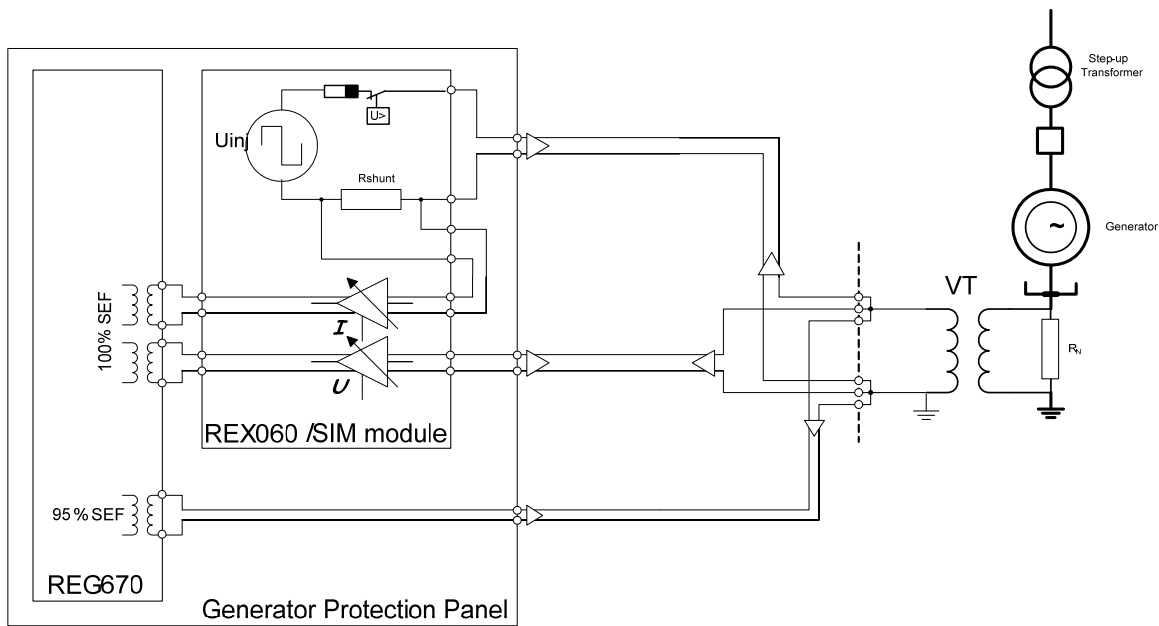


Figure 2: Principal design of the new injection method

An oscillator U_{inj} generates a square voltage signal which is fed via the connected transformer (e.g. VT as shown in Figure 2) to the stator winding and its associated circuit. The injected voltage and current signals (marked as U and I in Figure 2) are measured by the relay where their phasors at the injection frequency are filtered out [13,14]. The ratio of the voltage and current phasors gives complex impedance, which in the following text will be called the bare impedance (i.e. impedance seen at the relay input terminals). The equivalent impedance circuit seen from the relay input terminals is shown in Figure 3. Note that for simplicity it is assumed in this figure that the involved transformer (i.e. VT as shown in Figure 2) has ratio 1:1.

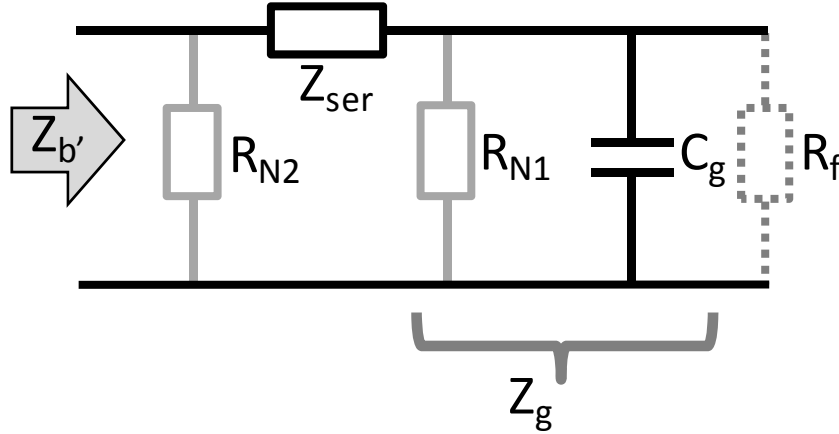


Figure 3: Equivalent impedance circuit seen by the relay

In Figure 3 $Z_{b'}$ is the bare impedance seen at the relay input terminals, Z_{ser} is transformer (i.e. VT) series impedance, R_{N1} is the primary grounding resistor, C_g is stator winding capacitance to ground and R_f is the fault resistance. Note that R_{N2} would be the grounding resistor in installations where it is physically located on the secondary side of the transformer (e.g. see Figure 1c). Note that R_{N1} and R_{N2} cannot coexist in one installation (i.e. only one of them can be present). Instead of measuring the bare impedance the relay should ideally measure the impedance from the stator neutral point to ground. This impedance is marked as Z_g on the equivalent impedance circuit shown in Figure 3. It can be shown that this impedance can be calculated from the bare impedance by using the following complex transformation:

$$Z_g = k1 \cdot Z_{b'} + k2 \quad (1)$$

Where $k1$ and $k2$ are two complex constants, which are installation dependent. These two constants are determined by the dedicated software tool during relay installation and commissioning procedure. In order to determine them, three measurements at commissioning need to be done:

- first measurement with healthy stator winding (e.g. normal condition $R_f = \infty$),
- second measurement with a known fault resistance (e.g. $R_f = 2k\Omega$)
- third measurement with a solid ground fault at the machine neutral point (e.g. $R_f = 0\Omega$).

From these three measurements the values for $k1$, $k2$ and a reference impedance Z_{ref} , (i.e. Z_g value for the healthy stator when $R_f = \infty$) are determined. Once these three complex values are stored in the relay, the actual fault resistance value R_f can be estimated by comparing the actual measured impedance with the stored value for the reference impedance. Once the fault resistance falls below the pre-set values alarm respectively trip signal is given by the relay with the appropriate time delay.

Note that the parameters $k1$ and $k2$ cannot be easily determined beforehand. Furthermore, for a sensitive detection of ground faults, a precise value of the reference impedance, Z_{ref} , is also needed. The determination of these parameters thus calls for measurements on site during commissioning and it is indeed most exact and practical to use the full injection system to perform these measurements. For these reasons, an Injection Commissioning Tool (ICT) was conceived, which is a PC tool that communicates with the relay, reading measurement values and setting parameters. The human interface guides the commissioning engineer through the required calibration measurements and calculates the resulting parameters which shall then be downloaded into the relay.

In addition to this important functionality, ICT performs a number of other useful tasks. There are a number of checks performed, in particular during the calibration process, that are intended to certify that the present installation will have a proper performance. Further, it can help to derive the

setting of additional reference impedances and monitor the measurement result. It also has a special feature that helps with selection of set alarm and trip values for R_f .

4 PERFORMANCE OF THE NEW INJECTION SCHEME

The system performance will be shown from recordings captured at a pilot installation. Several pilot installations have been utilized during the relay development, but only one will be presented here. This site has two identical 315MVA, 11kV, 500rpm hydro machines in a pump storage facility. The net water head is approximately 600m. The new injection scheme was installed on both machines. The total installation time in this facility is more than four equipment-years and we will here discuss some important observations of the equipment performance in this installation.

In pilot installations, it is important to obtain more information on the detailed performance of the equipment under test than in normal installations. Therefore, various results from the relay processing were logged to a PC continuously. Most important of these results is of course the measured impedance while other results, such as different voltages and delivered power may aid the understanding of the behaviour of the injection scheme. The logging equipment in the presented pilot installation had recorded all values several times every minute.

4.1 Pilot installation steady-state

The performance of the injection system is at its best during steady-state operation, either at machine standstill or in full machine operation. During starts and stops, a number of activities occur that poses additional challenges, such as varying rotational speed, closing of breakers, etc. Therefore the injection scheme performance, during machine start and stop procedures, is discussed latter in a separate section.

This pump storage facility experiences many starts and stops, usually acting as a generator during the day and as a pump during the night. Here the injection is done through a 32kVA, 11kV/240V one-phase, grounding transformer at 87Hz, as shown in Figure 1c. The secondary side grounding resistor has 0.385Ω , which is seen from the generator neutral point primary side as 884Ω . Two reference impedance values were used; one at standstill and the other one when machine is excited. Selection between these two reference impedance values is based on the RMS voltage magnitude at the stator neutral point. Namely, as soon as the machine is excited, sufficiently high third harmonic voltage will be present at the neutral point. Such behaviour is used to automatically switch between the two reference impedance values. Figure 4 illustrates the variation of the measured impedance to ground during a machine start and stop cycle. In Figure 4a variation of measured capacitance to ground (red line) is shown together with the corresponding capacitance value from the active reference impedance (thick gray line). In Figure 4b variation of measured resistance to ground (red line) is shown together with the corresponding resistance value of the active reference impedance (thick gray line).

From Figure 4, no resistance variations that are similar to the variation of the measured capacitance can be seen. The resistance do however show similar variations but to a much lesser extent. Most notable is the exponential decay after each stop which is probably caused by the neutral point resistor resistance change due to temperature variation (i.e. cooling down) with a time constant of some hours. Conversion of the measured impedance to an estimate of the ground fault resistance is made by comparing the actual measured impedance value and the reference impedance value. A plot of R_f will however be very difficult to read as R_f will be infinite when there is no fault. With noise added, the estimated R_f will jump between plus and minus infinity, making the scaling of the plot difficult indeed. Therefore it is better to plot the estimated fault conductance, $G_f = 1/R_f$, which is zero when R_f is infinite. A serious fault will give a large fault conductance which implies a small fault resistance. A plot of the fault conductance during the same time period as in Figure 4 is given in Figure 5.

The fault conductance variation during this period was about $0.02\text{k}\Omega^{-1}$; corresponding to a fault resistance of $50\text{k}\Omega$. Thus function would remain stable if the set value for alarm/trip level was below $50\text{k}\Omega$ which was the case in this pilot installation.

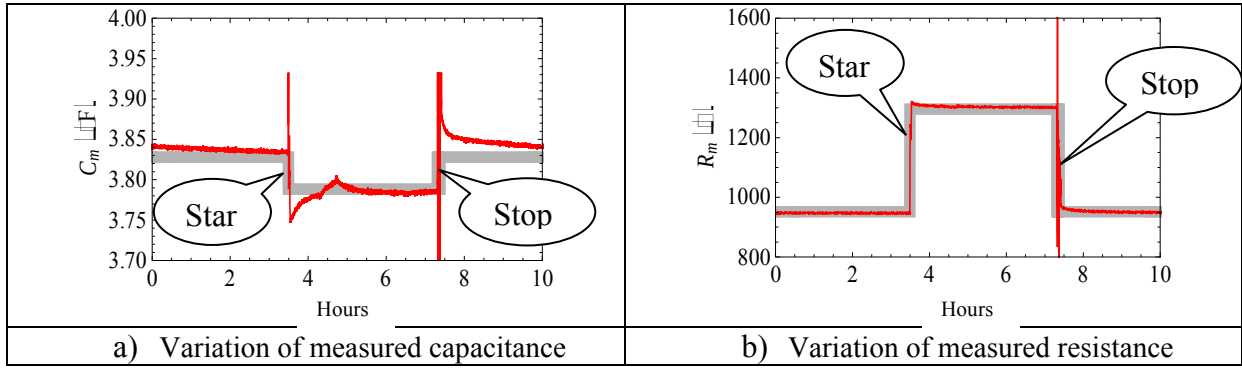


Figure 4: Variation of Z_g during normal operation

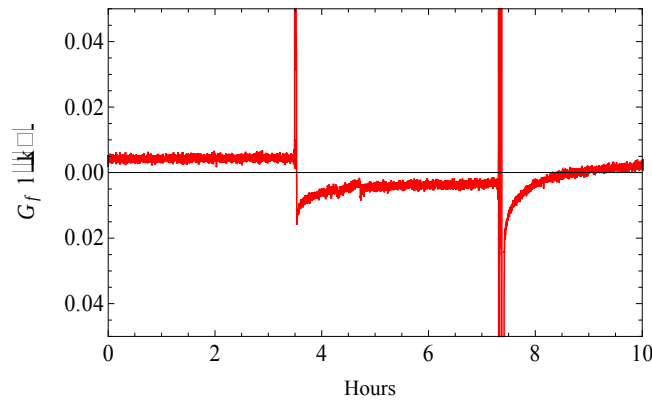


Figure 5: Variation of fault conductance

4.2 Pilot installation during start and stop sequence of the machine

A number of events occur when the machine is starting or stopping in a pump storage facility. For example during stop operation electrical braking is used. Note that, without any action, the rotor, which weighs approximately 500 tonnes, will take more than 30 minutes to stop. Electrical braking is initiated by making an intentional 3-ph short circuit at the machine terminals. Then, by controlling the excitation current a braking torque is produced which will bring the machine rotor to standstill within ten minutes. This operating procedure produces voltage with a variable frequency at the machine star point. Such a voltage can cause possible trouble for the injection scheme especially when its frequency (or any harmonic frequency) is equal to the injection frequency. Thus it was very important to check the behaviour of the injection equipment during such operations in this pilot installation.

The measured impedance by the injection protection during a typical stop sequence (i.e. electrical braking) in this pump storage facility is shown in Figure 6. A prominent feature in these plots is that temporarily impedance values occur that deviate strongly from the reference values. These are due to a variable frequency voltage signal (and its harmonics) that coincide and interfere with the injection frequency. As the machine rotor slows down, the harmonics passes through the injection frequency. Such interference can be detected by measuring the frequency of the resultant injection signal. Thus, such “operational problems” can be automatically detected by the new injection equipment, which then temporary blocks the relay trip logic in order to avoid any possibility for unwanted operation during braking.

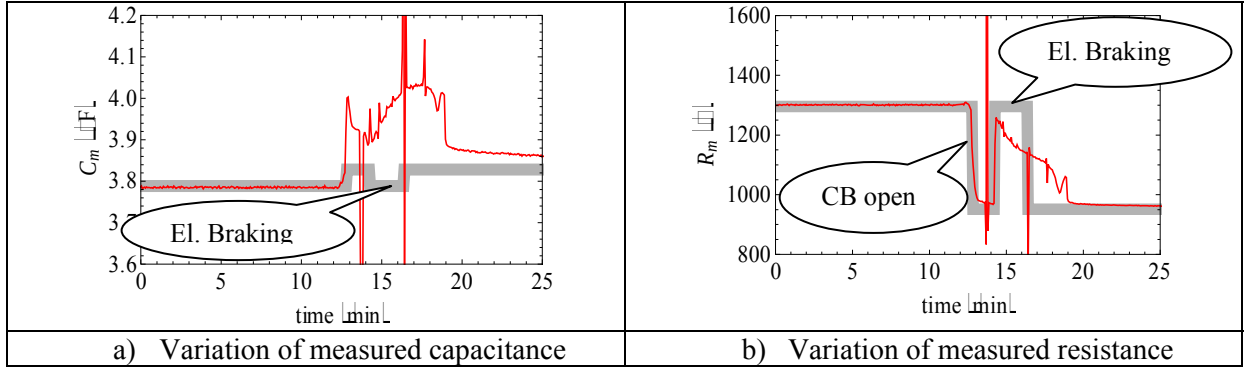


Figure 6: Variation of Z_g during electrical braking

In addition to the temporary erroneous values, there are other significant changes in the measured impedance during the braking operation, which lasts for roughly eight minutes. Most notable is perhaps the changes in measured resistance, which initially drops to the standstill value and then suddenly increases again to exhibit a gradual decrease toward the standstill reference. Obviously the braking process affects the neutral point voltage and thus the properties of the grounding transformer in the neutral point. Note that the reference impedance is changed accordingly and it appears from Figure 6 that the most appropriate reference is selected at all times.

During this braking operation, the maximal ground fault conductance was about $0.15 \text{ k}\Omega^{-1}$; corresponding to a fault resistance of about $7 \text{ k}\Omega$. This limits the maximal detectable ground fault resistance if no special attention in the function is made during electrical braking operation.

5 CONCLUSION

The main challenges of measuring the impedance to ground of a generator stator winding are presented. The presented method can be used to detect a stator ground fault by injection of a test signal with a specific frequency. To allow injection through typically available transformers that are connected either to the stator neutral point or to the generator high-voltage terminals, the injection frequency should be somewhat higher than the nominal power system frequency. This requires the use of another filtering algorithm than the ones customarily used today in the numerical relays. With this new filtering algorithm, several other important features are gained in addition to the desired suppression of the fundamental frequency and its harmonics, such as a high precision both for phasor and frequency estimates of the injected quantities. Additionally the injection frequency can be selected at site. Finally the main advantage of this technique is the possibility to perform injection via a voltage transformer which was not possible before. All these features are further described in [15].

Experience from the pilot installation indicates that the sensitivity of this method is not limited by the measurement accuracy. It is rather the variability of primary components at the specific site that imposes a limit on the largest ground fault resistance that can be detected with confidence. Under steady state conditions, i.e., at standstill or in operation, the pilot results indicate that about $30 \text{ k}\Omega$ is a reasonable upper limit for a detectable ground fault in the stator. During starts and stops, the site variability is larger, reducing the upper limit to around $10 \text{ k}\Omega$. It was also observed that the performance of this new protection scheme was not dependent on motor or generator operating mode of the machine.

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