PS Technologies Inc.

White Paper on DER Effective Grounding Screening and Study Methodology, TOV and TRV Study Methodology

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Executive Summary

The goals of this white paper are to inform the DER (distributed energy resource) project owners the importance of effective grounding and the associated TOV (temporary overvoltage) and TRV (transient recovery voltage) monitoring, and also to define a set of practical screening and study methodologies for the power industry in Alberta. The scope of work is stated in Section 1. PSTI has played a role in assisting AESO's investigation on three common issues in DER integration, namely, effective grounding, TOV and TRV.

Effective grounding is an important practice in power system operations. Both transmission and distribution systems make use of effective grounding scheme. In general, grounding affects the performance of protection schemes implemented in the power system. Insulation coordination, BIL (basic insulation level) and surge arresters are specified based on the required effective grounding. It is commonly expected, connecting a DER or an IPP (independent power producer) to the system shall not impact the effectiveness of the system grounding. TOV is heavily related to system grounding characteristics. Non-effective grounding can cause unacceptable level of TOV and uncontrolled TOV can result in equipment damage.

Many existing transformers with a Delta winding on the grid side were originally meant for supplying load and stepping-down voltage. However, as a unique practice in Alberta, numerous DER connections to the system are being proposed utilizing such transformers. Connecting generation to the system via a Delta winding can pose some technical challenges.

The aspect of effective grounding and TOV in several out-of-jurisdiction major utility companies' DER TIR (technical interconnection requirement) is provided in Section 1.

Besides other major utility companies' TIR, IEEE and CSA standards are extensively studied. Key findings and information are shared in this white paper. Study cases have been set up in both PSS®E and PSCAD. Three types of generators are modeled – synchronous machines, Type-3 WTG (wind turbine generator), and inverter-based (for PV and Type-4 WTG). In addition to being used in the proof of concept, these models can be used for further investigation and in real projects by study engineers.

The outcome of this investigation is a set of screening and study methodologies for both effective grounding and TOV. Possible mitigation methods are also suggested.

TRV issue associated with HV (high voltage) circuit breakers became paramount when a generator is interconnected to the system (or grid) via a non-effectively grounded transformer. Under the worst-case situation, TRV issue could disqualify a project being BTF (behind the fence). The introduction, background and study methodology of TRV are all presented in Section 7.

With the screening methodology and study methodology laid out in this white paper, and the subsequent and continuous collaboration amongst all market participants, including but not limited to, DER proponents, DER facility owners and operators, wire owners such as DFO (distribution facility owner)s and TFO (transmission facility owner)s, consultants, and AESO as the ISO (independent system operator), it is hoped that the technical assessments on effective grounding and related issues in DER connection projects are valuable, helpful and beneficial, and the operation of the power system will continue in a technically sound and prudent manner.

(Work for this White Paper was mainly done in 2020, with AESO and many Alberta wire owners' involvement. Despite of the final release and stamping is in March 2022, all real work was done and finalized by January 2021. In February 2021, EPRI had a publication, collected as reference [29] here, on a relevant topic. It is an important reference users of this White Paper may refer to. But this work did not directly get benefit from the EPRI report due to the paralleling of two investigations in 2020.)

1. Introduction

In preparation for a future state of higher DER penetration in Alberta, AESO has developed an AESO DER Roadmap. Activities within this DER Roadmap include evaluating the potential impacts of DER to the reliability of AIES (Alberta Interconnected Electric System) with inputs from DFOs (distribution facility owners) and TFOs (transmission facility owners).

One common issue AESO has observed is that DER developers sometimes utilize existing infrastructure designed for loads to connect the proposed DER. Adding a DER shall maintain the existing effective grounding scheme in AIES. Otherwise, during islanding (regardless of being intended or unintended, sustained or non-sustained) when one or more circuit breakers are opened up manually or as a result of a protective device operation, there are possible scenarios that a DER can energize part of the distribution and transmission system with non-effective ground or no ground. Ungrounded system with a new source may cause TOV which poses risks of damaging surge arresters and other apparatus specified based on the previous conditions of load supplying. Furthermore, TOV can contribute to TRV issues on switching device such that the switching device may fail to open.

There are at least two major differences between TOV and TRV. **One** is the effective duration. TOV ranges from a cycle to hours. TRV is in order of magnitude of tens of microseconds to a few milliseconds. **The other** is the equipment at risk. Uncontrolled TOV could damage surge arresters, insulators, cables etc. In the worst case, an iron core in a power transformer or a reactor, being saturated by TOV, could induce ferro-resonance and cause damage on many adjacent equipment in the power system. TRV is specifically related to circuit breakers only.

Recently, effective grounding issue, together with TOV and TRV, have become an escalating concern in many DER or generation projects.

1.1. System Grounding

System grounding directly affects TOV and TRV during certain system abnormal situation including short circuit faults. Among all possible types of faults, the most frequent type is the single-line-to-ground (SLG) fault. Upon the inception of a SLG fault, the transient over voltage appears on the un-faulted phases. The surge arresters are specified for the power system based on many parameters including the expected overvoltage in the system caused by switching and lightning transients as well as possible overvoltage caused by resonances, mutual coupling etc. Many of those are related to system grounding characteristics. System grounding affects the specification of surge arresters, and subsequently insulation coordination. Historically, for practicality, the T&D (transmission and distribution) system has been built and maintained to be effectively grounded. Technically, effective grounding strikes a balance between solidly grounded and ungrounded. Allowing a Dyn step-down load supply transformer with the Delta winding on the transmission side is a good example. Even though the Delta winding itself is ungrounded, the transmission line typically has a $X0/X1$ ratio of about 3.0, and the source at the system's far end of the line is effectively grounded. With those, the Delta winding on the transmission side is never an issue as the effective grounding requirement can be met anywhere on the system side as long as the transformer supplies load. Adding generation "behind" this Delta winding to export power through this Delta winding may disqualify the effective grounding characteristics on the system side.

The difference between solidly grounded system and effectively grounded system is that maintaining an effectively grounded system is more practical than designing a system that is solidly grounded everywhere. In a solidly grounded system, Delta transformer winding would always need to be accompanied with a grounding transformer. In an effectively grounded system, Delta windings may be allowed without a grounding transformer as long as there are other grounding sources in the adjacent area that can ground the system effectively. It is noteworthy that a solidly grounded Wye winding may not necessarily mean an effective grounded system. For example, if one generator, with its neutral being ungrounded or impedance grounded, is connected to the grid via a YGyg (grounded Wye: grounded Wye) transformer, the setup may not be automatically qualified for the effective grounding requirement. Despite of being a familiar term, effective grounding is probably one of myths to many technical people. It is the goal of this white paper to provide information and education. The particular issue related to placing generation behind a YGyg is explained in Section 4.1.3.

System grounding characteristics directly affect the overvoltage. Per IEEE Std C62.22, [4], overvoltage may be low-frequency, temporary and transient (surge). In the standard, "temporary overvoltage" (TOV) is defined as "an oscillatory overvoltage, associated with switching or faults (for example, load rejection, single-phase faults) and/or nonlinearities (ferro-resonance effects, harmonics), of relatively long duration, which is undamped or slightly damped".

For all types of generation -- machine based generation (gas turbine, Type 1/2/3 wind turbine) and inverter-based generation, (IBG, such as solar PV, Type 4 wind turbine, BESS - battery energy storage system), TOV could happen during switching or faults because of the interaction between generators (and controllers for inverter-based ones) and the power system characteristics.

The methodology of investigation on effective grounding and TOV is as follows:

a. Examine DER IT (interconnection transformer) winding configuration;
b. Use a sequence impedance based program (PSS®CAPE, ASPEN OneLiner and PSS®E) to conduct steady-state analysis on COG (coefficient of grounding) and EFF (earth fault factor);
c. Use a time domain program (PSCAD) to justify the above results of EFF for generators with clearly defined equivalent positive-, negative- and zero-sequence impedance.
d. Use a time domain program (PSCAD) to analyze COG and EFF for generators without clearly defined sequence impedance.

In Alberta, only those generation with more than one step-up voltage transformation to AIES are classified as DERs. A 13.8 kV to 13.8 kV transformer does not get counted as voltage transformation. A generator with one transformer stepping up machine terminal voltage (e.g., 13.8 kV) to AIES (e.g., 138 kV) is not deemed as a DER. Most DERs have an interconnection transformer to step up the voltage from 630 V to 25 kV which is the distribution system voltage, and then use a 25/138 kV transformer to connect to AIES. However, in this white paper, in order to help the readers to grasp the concepts of effective grounding, the interconnection transformer between a DER owner's facility and the incumbent wire owner's facility is assumed to be same as the GSU transformer (generator step-up transformer), and the term "interconnection transformer" (and some variants like IT, or DGIT, distributed generation interconnection transformer, or "connection transformer") may be used interchangeably with GSU transformer. For generators with 600 V terminal voltage, the interconnection transformer is assumed to step up the voltage to a medium voltage level such as 34.5 kV or 13.8 kV directly. For generators with 13.8 kV or 4.16 kV terminal voltage, the interconnection transformer is assumed to step up the voltage to a high voltage level such as 69 kV and above directly. There are situations where the generator voltage is stepped up from 600 V to 4.16 kV, and then from 4.16 kV to 34.5 kV or higher. For simplicity, only one tier of transformer is used in the discussion and modeling. When there are multiple layers of transformers, concepts in this white paper can also be applied to analyze the system grounding and the associated overvoltage issues.

Applying symmetrical components or sequence impedance theory and practice (applicable to rotating machines) to inverter-based generators actually has challenges. The manufacturer of a rotating machine can provide a set of sequence impedance that is quite easy for the modeling engineer to validate and to apply. Similarly, rotating machines made by different manufacturers may have small differences on equivalent sequence impedances. In other words, the behaviour or response of certain type of rotating machine has been well understood by power engineers. On the other hand, each inverter-based generator has its own proprietary control and control algorithms. Therefore, the response of an inverter-based generator during power system anomaly could be quite different depending on the particular manufacturer, and very different from that of a rotating machine.

Taking the negative impedance as an example, for rotating machines, due to the physics of tiny difference between two different rotating directions (clockwise and counter-clockwise), negative-sequence impedance is same or very close to the positive-sequence impedance. There is no such rationale for inverter controls. Furthermore, given the technology of power electronic converters and control algorithm, there is nonlinearity in which, voltage at a particular frequency might result in a series of currents at different frequencies. Therefore, the impedance measurement using classical approach might not be necessarily correct. For these reasons, the equivalent sequence impedance should be specified by the control's manufacturer.

Currently, one vendor may indicate negative-sequence impedance being equal to the positive-sequence, same as the rotating machines, while another vendor may indicate negative-sequence impedance being infinity or zero.

The deemed infinity negative or zero-sequence impedance becomes true if the inverter control is very sensitive to the abnormal negative or zero-sequence current (other than the controlled positive-sequence current) and thus does not allow any of them by shutting off at a low-level detection of negative-sequence current. In the general term of I = V / Z, if the current is allowed to be near zero, the correspondent impedance can be perceived as infinity.

The deemed zero negative or zero-sequence impedance becomes true if the inverter control is very insensitive to such abnormal current (other than the controlled positive-sequence current) and thus allows the negative or zero-sequence current to be very large (to the control's physical limit). In that sense, current could be very large and the correspondent impedance is very low and near zero.

For DER generators without a clearly defined sequence impedance, using phasor-based network analysis program such as PSS®CAPE, ASPEN OneLiner or PSS®E may be prone to modeling and simulation errors. In those cases, using time domain program like PSCAD would be beneficial as the manufacturer provided time domain model could be more intuitive and accurate. As a rule of thumb, the type of modeling software should be selected based on the type of study and expected outcomes from the study. Lack of data alone does not need the modeling engineer to switch from one simulation software like PSS®E to different one like PSCAD. If data are not available, based on the experience of the modeling engineer or at the advice of the manufacturer, typical data may be used if the study results are not affected from those typical data. The sequence impedance data only become important when an asymmetrical fault level is calculated. As later shown in the white paper, GFOV (ground fault overvoltage) study does require accurate model to simulate asymmetrical faults.

As this assignment includes TRV for IPPs (independent power producers) interconnected at the transmission level, the concept of TRV and the challenging examples are presented later in the white paper. For circuit breakers rated at 100 kV and above, the standard for type testing circuit breakers assumes the system is operated as effectively grounded.

Through the clarification on the subjects in this white paper, facility owners on the grid side (transmission and distribution) and developers on the generation side should have increased mutual understanding about the system grounding which is often more invisible or abstract than the physical connection via three-phase conductors. With system grounding properly designed and implemented, even with so many new generation facilities being added, the system shall be more likely to remain safe to operate.

1.2. Type of DERs

Generally, there are two types of DERs. Their characteristics related to grounding are briefly given here.

a) Rotating DER or Machine-Based DER

DER of this type includes backup generators, CHP (combined heat & power), landfill gas, small hydroelectric, and older WTG (wind turbine generator) of Types 1-3, simple cycle gas turbine or reciprocal engine. In power system modeling, a typical rotating machine (except for a Type 3 WTG with the complication of a crowbar) can be represented with a voltage source in series with a set of Thevenin impedance. The sub-transient impedance is about 0.15 to 0.2 pu. Therefore, applying a 3LG (three-phase-to-ground) fault on its terminal, the total positive-sequence fault current may be 5 to 6 pu of its rated nameplate current. The fault current contribution and calculation of overvoltage are well understood. Formula in Section 3.2 are derived decades ago for this type of DER.

b) Inverter-Based DER

Inverter-based DER includes solar PV (photovoltaic) power, BESS, Type-4 WTG, and fuel cells. In power system modeling, they can be represented by a voltage controlled current source with parallel impedance (a Norton impedance instead of Thevenin one). As mentioned in [19], inverter-based generators (IBGs) "generally behaved like constant AC current (or power) sources. This current source characteristic has profound impact on the overvoltage caused by ground faults, and therefore (on) grounding requirements." After injecting current onto a set of physical 3-phase inductors, the constant current (or power) inverters would be able to output a synthetic ac voltage.

Section 5.3.4 of [19] indicates "because of their current-regulated characteristics, inverter sources are only of material relevance to system grounding and ground-fault overvoltage considerations when the inverters are disconnected from the normal synchronous source which also provides grounding under normal conditions."

Negative and zero-sequence impedance need attention. Section 6.2 of [19] states "the inverter's response to negative-sequence imbalance, and the resulting effective negative-sequence impedance of the inverter, varies widely depending on the inverter's control algorithm.". And "the negative-sequence impedance is not a parameter typically provided by the inverter manufacturers. From the variation in control philosophy described above, it can be concluded that inverter negative-sequence impedance can range from the physical phase inductor impedance to infinity. The negative-sequence impedance can play a significant role in defining GFOV." The "behavior" of the negative sequence impedance clearly distinguishes IBGs from rotating machine based DERs.

Section 6.3 of [19] mentioned a three-wire inverter and a four-wire one. In either case, the equivalent zero-sequence impedance is between two extremes. One is near infinity, when the zero-sequence currents are actively canceled. The other extreme is, when "the controls are insensitive to zero-sequence current, the zero-sequence impedance would be as small as the output inductor impedance". The "behavior" of the zero-sequence impedance distinguishes IBGs from rotating machine based DERs. The connection transformer between the IBGs and the power grid could complicate the zero-sequence impedance network.

1.3. Independent Power Producer (IPP)

In this white paper, a power producer connected onto 69 kV and above, through voltage transformation only once, is referred to as an IPP. This is distinguished from a DER, which is connected onto medium voltage (MV) at the distribution level, most likely 35 kV or below.

Most technical points discussed in this white paper for DER are also applicable to transmission interconnected IPPs.

1.4. Technical Interconnection Requirement (TIR) from Other Jurisdictions

The following TIRs have been studied. A summary of effective grounding, TOV and TRV is shown below.

1.4.1. Hydro One, in [7]

For DG (distributed generation) connected to the 4-wire distribution system, it is required that TOV caused by the DG connection should not exceed 125% of nominal system voltage (line to neutral) anywhere on the distribution system and under no circumstance shall exceed 130%.

To meet the above requirement, some further specifications include:

- For conventional (rotating) generators:

  $1.5 <= X_{DG0}/X_{DG1} <= 2.5$

  where X_{DG0} and X_{DG1} are the zero-sequence and positive-sequence reactance of DG. They are calculated or simulated at the Point of Connection with the Point of Connection being open. They include both the generator's impedance and the GSU's, and are usually calculated on the system side of the GSU.

  With that, the control target of an overall Thevenin Equivalent positive and zero-sequence impedance on the grid with any or all DG sources and the existing grid sources in service should be in this range:

  $2 < X0/X1 < 3$, $R0/X1 < 0.4$

IEEE 142 (2007 Edition) indicates an effective grounded system will have a ground fault level that is at least 60% of the three-phase fault level. The three-phase fault level in pu is $1/X_1$. For rotating DERs, with $X_0/X_1 = 3$ (the upper boundary) and $X_1=X_2$, three-phase fault level, $I_1 = 1/X_1$, zero-sequence fault current for a ground fault is $3I_0 = 3/(X_1+X_2+X_0) = 0.6 * I_1$. The ratio of ground fault to three-phase fault, $3I_0/I_1 = 0.6$.

- For inverter-based DERs:

  $X_{DG0} = 0.6$p.u. +/-10%
  and
  $X_{DG0}/R_{DG0} >= 4$

For different purposes, the pu is based on different MVA as follows:

a. For sizing the grounding transformers, the total MVA rating of the sum of DGITs' MVA ratings, and high side (grid side) kV rating of the DGITs;
b. For sizing NGR (neutral grounding reactor), the MVA and high side kV rating of the DGIT for which the NGR is to be installed.

It was clearly shown in Hydro One TIR that a neutral reactor may be required to limit the ground short circuit current to solve the current desensitization problem with solidly grounded Wye windings, and a grounding transformer may be needed to keep TOV within limits with Delta windings on the system side.

There are seven (7) allowable DG interconnection transformer (DGIT) configurations for connecting to the 4-wire (effectively grounded) system. Many of those are incorporated into the latest CSA C22.3 No. 9-2020.

One noteworthy point in Hydro One's TIR is that the YGyg transformers were given some special attention. Three out of seven DGIT options for effective grounding system are for YGyg transformers.

- Option 3 shows that the DGIT needs a HVGT (high voltage grounding transformer) on the grid side, to be effective grounding. The DER generator's neutral may be impedance grounded. DGIT's Wye winding on the DER side may be ungrounded.
- Option 4 indicates the ground transformer in Option 3 can be waived if the generator neutral is solidly grounded. It also shows a NGR on the HV side winding's neutral may be needed to reduce the current desensitization to the station relays.
- Option 6 shows a DGIT is a variant to Option 3 but with HVGT waived. It is allowed only if DG size is < 1 MVA. Similar to Option 3, DG generator neutral is impedance grounded and a NGR may be required on the DGIT's grid side to avoid current desensitization. One difference with Option 3 is the DER side DGIT's Wye winding is solidly grounded.

To be concise, Options 2, 4, 6 and others are skipped. Those who are interested may refer to Hydro One TIR, listed as [7]. A PDF copy has been provided to AESO with many other references listed in Section 9.

1.4.2. Fortis Central Hudson, in [11]

It points out the benefit of choosing effective grounding is to avoid the potential overvoltage during phase to ground fault, which may damage the utility and the customer's equipment.

For that purpose, it is required that, while operating, DER system should be an effective ground source to the grid and shall not cause over-voltages greater than 135%. However, while the DER is not generating, the

DER system should not be a ground source to the grid in order to avoid the desensitization of the utility company's ground fault protection.

Following IEEE 142 (2007 Edition), the TIR requires the following specifications for rotating DERs:

$0 < X_0/X_1 < 3$, and $0 < R_0/X_1 < 1$

For inverted-based DERs, it recognizes the need to adjust the criteria. However, it only indicates the utility company will deal with the effective grounding on case-by-case basis. Fortis Central Hudson asks for the sequence impedance for the inverter-based DERs and reserves the right to specify a grounding transformer to reach the effective grounding status.

Most IBGs are ungrounded. Sequence impedance datasheets from manufacturers often show zero-sequence impedance being infinity or 9999 ohms. Most inverters have 3-wire only. Some with 4-wire but the fourth wire, despite appearing as a neutral, is only meant for sensing, but not rated for carrying fault current. For this ungrounded nature of IBGs, in order to meet the effective grounding requirement, it is usually required to choose an interconnection transformer that is a zero-sequence current source on the system side such as a Wye winding, or to install an additional grounding transformer (e.g., zig-zag, YGd with Delta floating) if DER exports power via a Delta winding on the system side.

To show how grounding transformers are used, four "examples of effective grounding configurations" from the TIR are shown here:

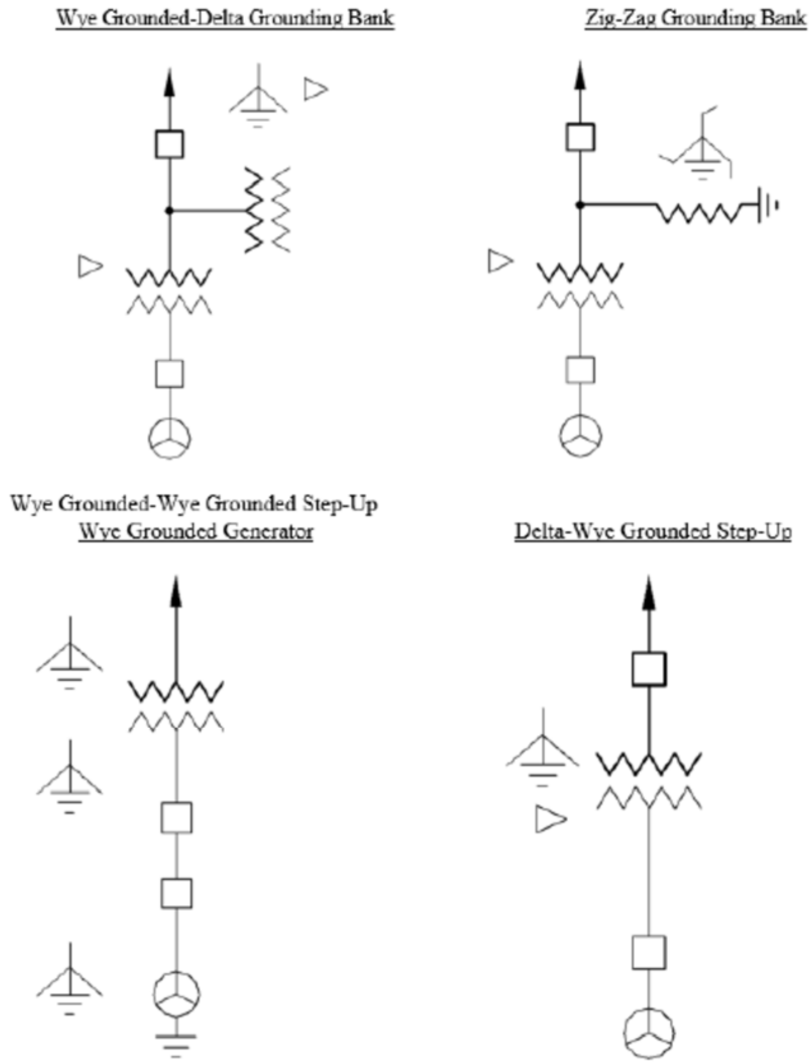

Figure 1: DGIT with Different Winding Configuration from Reference [11]

1.4.3. BC Hydro, in [5]

BC Hydro's primary distribution system is a three-phase four-wire multi-grounded common neutral system. BC Hydro specifies that DER transformer configuration in general is grounded Wye at high side (system side); Delta at low side (generator side)

In case that DER transformer configuration has a Delta winding at high side (system side) and ground Wye at low side (generator side), either a 3-phase grounding transformer with CTs (current transformers) will be installed on the high side to protect the equipment during line-to-ground fault, or a ground fault overvoltage relay to the high voltage side needs to be installed to trip the DER off.

In the case of a line-to-ground fault near the DER resulting in a reduction in ground current to the system ground over-current relay, BC Hydro requires the installation of a neutral reactor between the transformer primary neutral point and the ground on the DER site, in order to reduce the ground fault current contribution from DER.

In general, BC Hydro does not accept resistor grounding as it increases system losses, results in higher overvoltage on un-faulted phases and heat must be dissipated when ground current or unbalanced load current flows.

1.4.4. SaskPower, in [15]

SaskPower requires all DG facilities to utilize a step-up transformer configuration that provides a ground current source which qualifies as effectively grounded. Grounding transformers may be utilized to achieve an effectively grounded system.

To qualify as effectively grounded, the ratio of X0/X1 as seen by looking into the DG facilities at the Point of Delivery from SaskPower's Transmission System (with the generator operating) shall be

$0 < X0/X1 < 3$, and $0 < R0/X1 < 1$

Note that this is not calculated, simulated or "measured" on the generator terminal. It is perceived from the "Point of Delivery", usually at distribution voltage level, the higher voltage side of the DGIT.

1.4.5. PG & E, in [16]

For the 4-wire distribution system, it only lists two types of DGITs. One is Dy with a Delta winding on the grid side (21 kV), and an ungrounded Wye on the generator side. The other is YGd. In both cases, the generator is not grounded.

Note that AESO preferred term "YG" and all transformer vector group symbol is explained at the beginning of Section 4.

When having a Delta on the grid side, it recommends a YGd grounding bank, which is sized to limit the TOV to 1.15 of nominal.

1.4.6. Xcel Energy Colorado, in [17]

For directly connected rotating generators, Xcel Energy requires

$2.0 < X0/X1 < 2.5$ and $R0/X1 < 1$

to satisfy the effective grounding requirements and limit the impact to feeder ground fault relay coordination.

For rotating machine based DGs, Xcel Energy allows the following system configurations for DGITs that are deemed meeting the effective grounding requirements:

- Ground Wye : Ground Wye step up transformer. The generator must have a properly sized grounding bank, OR the generator neutral must be adequately grounded
- Delta (gen) : Ground Wye (system) step up transformer, with an NGR (reactor) on Wye side. It discourages an NGR (resistor) for high power loss concern.
- Delta : Delta with a properly sized grounding transformer on the system side.

For inverter-based DERs, it requires EFF to be <130%, and that such DERs must be effectively grounded on the secondary side. It has a set of criteria that are same as Hydro One's.

X_{DG0} = 0.6p.u. +/-10%
and
X_{DG0}/R_{DG0} >= 4

The pu is based on different MVA:

a. For sizing the grounding transformers, the total MVA rating of the sum of DGITs' MVA ratings, and high side (grid side) kV rating of the DGITs;
b. For sizing NGR, the MVA and high side kV rating of the DGIT for which the NGR is to be installed.

It points out that many three-phase inverters do not meet effective grounding requirements. Therefore, a grounding transformer is usually required.

1.4.7. Eversource Energy, in [18]

Eversource Energy is one of the largest energy delivery company in New England area.

Eversource Energy's requirement includes a criterion where effective grounding is required if any of the following is triggered:

- The fault current at the point of common coupling (PCC) is caused to increase at least 10 percent of the existing value
- In area where fault current is already deemed excessive
- DER capacity equals to or larger than 1 MW
- Anywhere there may exist a potential islanding concern regarding generation to load ratio

To achieve effective grounding, it requires 2 < $X0/X1$ < 3. Note that effective grounding check does not mean to lower grounding impedance. Adding NGR to reduce the ground fault current contribution but to stay within effective grounding requirement is also part of the effective grounding checking.

Eversource Energy also lists several transformer configurations for meeting the effective grounding requirements:

- A generator step-up transformer (GSU) with grounded Wye on high (system) side and Delta on low (gen) side.
- A GSU with grounded Wye : Grounded Wye and a grounding transformer on either side of the GSU, for DER that do not provide ground fault current.
- A GSU with Delta on high (system) side, a grounding transformer is needed on the high side.

2. Effective Grounding

To serve one of the many purposes of this white paper, which is to inform and educate, this section covers some aspects related to effective grounding, which may be unfamiliar to some technical people. In order to show what is exactly from the standards, a pair of double quotes ("") is used.

2.1. System Grounding

As indicated in IEEE Std C62.92.1-2016, [26], "the basic goals in selecting a grounding scheme for any given system are as follows:

a. Voltage ratings and degree of surge-voltage protection available from surge arresters
b. Limitations of transient line-to-ground overvoltage
c. Sensitivity and selectivity of the ground-fault relaying
d. Limitation of the magnitude of the ground-fault current
e. Safety"

There are different types of grounding scheme: ungrounded, solidly grounded, resistance grounded, inductance grounded, resonant grounded and capacitance grounded. The term "effectively grounded" is evolved from solidly grounded.

Per IEEE Std C62.22, [4], the Coefficient of Grounding, COG, is defined as the percentage ratio of E_{LG}/E_{LL} between the sound (un-faulted) phase voltage (E_{LG}) and system nominal line-to-line voltage (E_{LL}), for unbalanced faults (i.e. both single-line-to-ground, SLG, and phase-to-phase-to-ground, 2LG).

To quantify a grounding scheme being effective or not, IEEE Standard 141, [1] defines that if COG $\leqslant$ 80%, the grounding scheme is deemed as being effective. If a system's COG is higher than 80%, then it is non-effectively grounded. The definition of "effectively grounded" and "non-effectively grounded" are provided in Sections 7.1 and 7.2 in IEEE Std C62.92.1, [26].

The term COG has been somehow surpassed by EFF which is defined as COG multiplied by $\sqrt{3}$, in IEEE Std C62.92.1 [26]. Note that after $\sqrt{3} * 80\% = 1.38$ In IEEE 1547, Section 7.4.1.a, it mentioned 138% overvoltage is not allowed for longer than a power cycle (16.7 ms).

IEEE Standards C62.92.4 and C62.92.5 cover on the topics of grounding for distribution and transmission system respectively. IEEE C62.92.6 has a focus on inverter-based system.

2.2. Ground Fault Simulation

To determine whether system grounding is effective or not needs accurate model to simulate unbalanced faults. Many programs have better model accuracy on positive-sequence impedance network than zero-sequence impedance network.

2.3. The Modeling Issues

Effective grounding of a DER facility is perceived from the system side of a DGIT. So the DGIT's grounding scheme has more impact on grounding effectiveness than the generator. In discussing the modeling issues, the rest of section will focus on transformer modeling.

The discussion does not mean to provide complete modeling guide. It is meant to share some knowledge to modeling engineers, particularly the "tank effect" of the common distribution transformers in the format of 3-legged core, 2-winding YGyg.

There are at least two challenges in modeling transformers for ground fault study.

2.3.1. Software Tools

Software such as PSS®E usually creates some challenges on the detailed zero-sequence impedance modeling of an N-Circuit Transformer. One of the most confusing transformers to model is probably the 2-winding Wye-Wye one. Unless a zero-sequence impedance test report is available, modeling engineers may be forced to make assumptions on zero-sequence impedance modeling without knowing its core being 3-, 4- or 5-legged.

Without a stabilizing closed Delta which makes it a 3-winding transformer, a 3-legged core 2-winding transformer is lack of a zero-sequence current path. However, the transformer tank is forced to circulate some zero-sequence current and the third harmonics. The tank's capability in circulating zero-sequence current makes it possible to contribute zero-sequence fault current, and thus plays a role in protection and effective grounding. For this reason, it needs to be carefully treated in modeling.

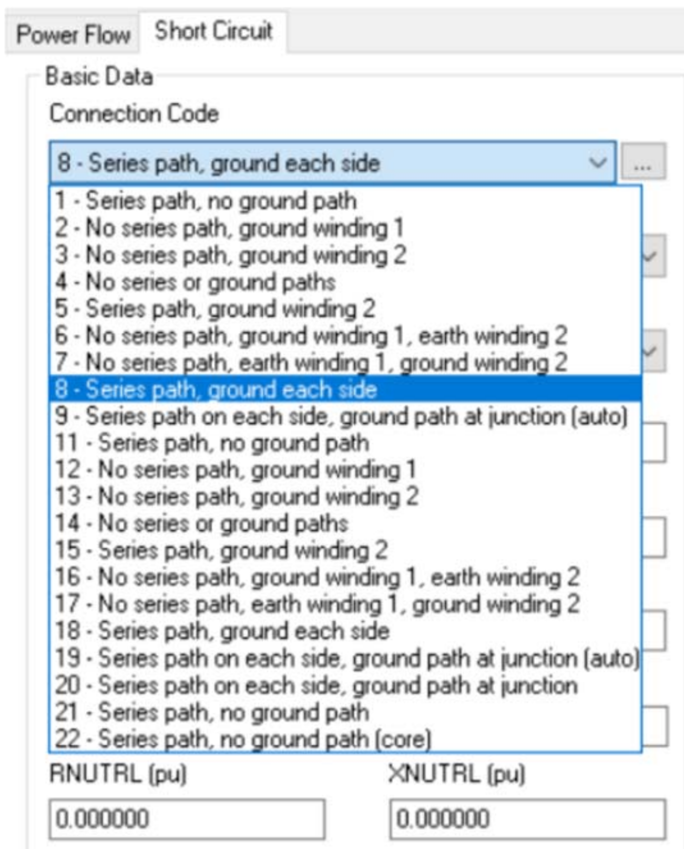

Figure 2: Zero-Sequence Impedance Modeling Page in PSS®E for 2-Winding Transformers

In PSS®E, Option 8 covers all 2-winding Grounded Wye / Grounded Wye transformers regardless of the core or shell types. Other options do not provide a chance for the user to model the tank effect. To minimize the confusion, when modeling a two-winding Grounded Wye / Grounded Wye transformer, it is recommended to always use Option 8 as indicated in the above screenshot. Other parameters after selecting Option 8 still need to be properly populated.

2.3.2. Zero-sequence Network Modeling

Transformers usually have very trustworthy positive-sequence impedance.

Different from positive-sequence network modeling, zero-sequence network modeling suffers the lack of zero-sequence impedance information. Zero-sequence impedance test report may not always be specified in the procurement process and thus some transformers in the past might have been shipped by the manufacturer without a zero-sequence impedance test report.

As in any modeling, justification on simulation results is indispensable. But different from 3-phase (3LG) fault results which can be quickly verified with a per unit calculation and then multiplying with the base current to figure out the primary current, the manual calculation on single-line-to-ground (1LG) short circuit current may not be that intuitive. Without a good justification, sometime ground fault simulation has more errors than three-phase fault simulation. This would become a challenge in analyzing effective grounding where ground fault simulation needs to be accurate.

2.3.3. Caution on Modeling Two-Winding Grounded Wye / Grounded Wye Transformers

As mentioned in Section 5.2.2, IEEE C62.92.4, [10], 2-winding YGyg transformers using five- or four-leg core design are susceptible to ferro-resonance. This is one of the reasons that 3-legged core 2-winding YGyg transformers are used widespread in the distribution to step down voltage and to supply load. It is well known that such transformers have a so-called "tank effect", described on page 138 of ABB T&D Book [9]. For instance, when a generator is being added to an existing Dyn step down transformer's Wye side, it is crucial to evaluate the tank effect through grounding effectiveness of the HV bus with the Delta winding. Often other YGyg load supplying transformers on the same HV bus can still hold the system neutral to be effectively grounded together with other HV transmission lines. In those cases, the accurate modeling of the 3-legged cored 2-widning YGyg transformers' tank effect could be important as it would require the generation developer to install a new grounding transformer at the HV side, in parallel with the HV Delta winding, or to install a new interconnection transformer for the generators.

Every type of transformer's zero-sequence impedance modeling should be watched in order to have a correct model for checking effective grounding. Modeling engineers should always request a zero-sequence impedance test report. In lack of a zero-sequence impedance test report, modeling engineers need to refer to AESO's Transformer Modeling Guide (2014). Regardless of having the zero-sequence impedance test report or not, at the end of the modeling, simulation results like 3I0, COG, EFF, should be justified with certain resources including but not limited to:

a. using the fault levels of 3LG and 1LG faults, and the ratio of both fault levels, from an older project with a similar transformer winding configuration.
b. using a different simulation software.

Due to being the most economical to build, and due to its lowest susceptibility to ferro-resonance (which is a common problem in distribution system, see Section 3.3), two-winding, 3-legged core type Grounded Wye / Grounded Wye (YGyg) transformers are commonly used in the distribution system to step down voltage for load supply. It is very likely that some DERs are to be proposed to connect to the system through these existing transformers. The iron core for such transformer could be in the format of shell type, 3-, 4- or 5-legged. 4-, 5-legged core type or shell type provides a zero-sequence flux path and its X0 is usually very close to X1. The tank of a 3-legged core YGyg transformer somehow functions as a virtual Delta winding in terms of stabilizing 3rd harmonics and circulating zero-sequence (load or fault) current. In a T-model, the vertical part representing magnetizing impedance, X0M, is 30-300% of the positive-sequence impedance. For example, when modeled on unit MVA basis (not system basis), a power transformer with X1=7.5%, would have a X0M in range of 2.25% to 22.5%. This is far less than the ideal transformer's X0M being "infinity". When the tank effect is correctly modeled, for such a transformer, regardless of the secondary side being connected to something or not, it will contribute zero-sequence fault current for an SLG fault on its HV side. For an SLG fault on its LV side, its zero-sequence current contribution is added on top of that from the HV system side.

The zero-sequence impedance test report for a 3-legged core YGyg transformer has the tank effect included already and shall not be replaced with an ideal YY transformer that does not circulate any zero-sequence current.

3. Temporary Overvoltage (TOV)

3.1. Definition of TOV

Per IEEE C62.22, [4], TOV is an oscillatory overvoltage associated with switching (for example, load rejection) or faults and/or nonlinearities (ferro-resonance effects, harmonics) of relatively long duration, which is undamped or slightly damped.

Duration for variety of temporary overvoltage is in range of tens of milliseconds or longer. The duration is understood as longer than a power cycle, from a few cycles to hours. The cause of TOV includes SLG faults, ferro-resonance, load rejection, loss of ground, long unloaded transmission line (due to Ferranti rise), and transformer-line inrush, back-to-back switching oscillations, or the combination of these.

For the most likely TOV, GFOV (ground fault overvoltage), unless the ground fault is cleared, overvoltage on healthy phases could continuously exist indefinitely. In the distribution system, ground fault clearing could normally be as long as a few to several seconds. Other TOV like ferro-resonance may last for hours. In [23], one example of a ferro-resonance lasted "for at least 30 minutes". The power transformer in the incident was not damaged, and was restored to service afterwards. For ferro-resonance in distribution systems, due to the low energy and low damage, the adjacent equipment may be able to withstand for hours.

3.2. Ground Fault Overvoltage (GFOV)

Ground fault overvoltage, GFOV, on the unfaulted phases lasts for the duration of the fault, till it is cleared. System grounding determines the magnitude of this type of overvoltage. GFOV establishes the minimum voltage ratings for surge arresters used on the system, per IEEE C62.92.4-2014, [10].

It should be noted that "arresters are applied to protect insulation from transient overvoltage and selected to ride-through TOVs. Arresters are not applied to distribution system to control TOVs due to faults, harmonics, and other sources.", [10]. The principle of applying arresters at the distribution level is to protect equipment from lightning damage. Arresters' MCOV (maximum continuous operating voltage rating) is specified to be above the anticipated TOV, whatever that value is, and above most ferro-resonances. In that sense, the surge arresters are not supposed to protect the T&D (transmission and distribution) system from TOV damage. And if the TOV is not mitigated within a level, it defeats the existing insulation coordination and needs adjustment on insulation coordination including boosting the arresters' MCOV and even the duty class (energy absorption rating). Those should be deemed as the last option as increase insulation coordination and BIL is far reaching and costly.

Since GFOV determines the minimum voltage rating of surge arresters, effective grounding has impact on BIL for both the system and the DER facilities.

Figure 6 in IEEE C62.22-2009, [4], provides some formula for manually calculating COG. They are useful for understanding Z0/Z1, X0/X1's impact on COG and EFF. A snapshot of those formula is shown below.

The following equations can be used to calculate the COG. The equations are applicable for $Z_1 = Z_2$, but do not include fault resistance.

Single line-to-ground (SLG) fault on phase a:

$$COG\,(phase\ b) = -\frac{1}{2}\left[\frac{\sqrt{3}k}{2+k} + j1\right]$$

$$COG\,(phase\ c) = -\frac{1}{2}\left[\frac{\sqrt{3}k}{2+k} - j1\right]$$

Double line-to-ground (DLG) fault on phases b and c:

$$COG\,(phase\ a) = \frac{\sqrt{3}k}{1+2k}$$

where:

$$k = \frac{Z_0}{Z_1} = \frac{R_0 + jX_0}{R_1 + jX_1}$$

In general, fault resistance tends to reduce COG, except in low-resistance systems. To include fault resistance (R_f), the definitions of k above would have to be modified as follows:

For SLG fault:

$$k = \frac{R_0 + R_f + jX_0}{R_1 + R_f + jX_1}$$

For DLG fault:

$$k = \frac{R_0 + 2R_f + jX_0}{R_1 + 2R_f + jX_1}$$

where:

R_f = Fault resistance

Figure 3: Formula to Calculate COG, from [4]

3.3. Other TOV

Compared with the transmission system, the distribution system is more prone to ferro-resonance. This is due to

a. many single phase or phase-to-phase connected loads,
b. opening phase (fuse blown, or internal single-pole-tripping-and-reclosing-and-lockout) for the 3-phase parts,
c. shunt capacitance along underground cables and switchable shunt capacitors.

Such resonance can be attributed to the matching of the following two:

a. the line-to-ground capacitance (stray along open air conductor or underground cable, or lump sum switchable capacitors for var support or power factor correction); and
b. the ungrounded transformer primary (Delta, Ungrounded Wye, phase-to-phase connected single phase, etc), or in case of grounded Wye 3-phase winding, one or two phase become open.

Note that except few air core ones, most inductive components, including the power transformers, usually has an iron core which is susceptible to saturation even if the applied voltage modestly exceeds its linear operational limit. The saturated inductance often resonates with the capacitance available in the system.

3.3.1. Open Phase and Shared Core in Transformers

Such resonance is very likely when one or two phases of a feeder become open, disconnected from the substation MV distribution bus. If the DER fails to detect the open phase situation, these open phases may be back-fed from the DER. When voltage elevates on these phases, the DER interconnection transformer could be saturated entering a resonance with the available capacitance. The interconnection transformer with a Delta winding on the system side is susceptible to the resonance related to open phase(s).

As mentioned in IEEE C62.92.4, [10], 4-legged, 5-legged core 2-winding YGyg transformers are susceptible to ferro-resonance. This is because when one or two phases are disconnected from the source, the phase-to-ground capacitance on either side of such transformers could enter into a resonance with the saturated transformer core. In contrast, the 3-legged core 2-winding YGyg transformers with little tank effect are less likely to resonate due to their better saturation behavior linked to the core limb structure, [27]. During an open phase period, with 3-legged core transformer's core loss higher than 4- or 5-legged ones, voltage induced by capacitance on the open phases is more likely to be drained and thus makes it less likely to build up overvoltage. Without voltage elevation, subsequently, the iron cores in the area are less likely to saturate.

It is well known that modern transformers with lower core loss than those manufactured in earlier than 1990's are more susceptible to ferro-resonance, [28]. IEEE C62.22, [4], and it even suggests a conservative approach to assume that a ferro-resonance is always possible for any open phase condition with the transformer and capacitance potentially matching.

3.3.2. Load Rejection Overvoltage (LROV)

For sub-system (e.g., after a portion being disconnected from the grid) at the transmission level, since there is no load to sink current, load rejection overvoltage (LROV) may occur and last till the inverters are shut down by protective devices. This is a common issue for transmission-connected large-scale renewable energy plants including solar PV and Type-4 wind generation facilities.

3.3.3. Utilizing a Step-Down Load Transformer as a Step-Up Transformer

As described in IEEE 1547.7-2013, Section 5.1.8, when the power flow direction reverts from MV to HV, it is likely to have higher operating temperature on those transformers because of voltage on the secondary (MV) winding being elevated. Such overvoltage has an effect on accelerating aging of the distribution transformers and loss of lifespan. Due to the fact that a core saturated transformer is subject to ferro-resonance, it is suggested that the ferro-resonance study include this scenario, if the DER exports through a transformer whose original function is to step down voltage from distribution for load supplying.

3.3.4. Transformer Inrush

Transformer inrush current could cause an overvoltage that saturates the power transformer's iron core and then resonates with the capacitance in the system, [6]. For DERs to be synchronized to the system from the LV side of the interconnection transformer, the unloaded interconnection transformer is always energized from the system side first. Energizing a transformer from a weak system with capacitance is prone to resonance. The interconnection study or the Overvoltage Study Report should cover this aspect.

3.3.5. Overvoltage caused by Line Drop Compensation

Typically, bus voltage of a power transformer (e.g., 138/25 kV) is regulated by a system comprising of two devices:

a. An LTC, onload tap changer, and
b. An LTC controller, a relay that issues commands to Raise or Lower the tap position of the LTC.

Section 7.1 in the IEEE PSRC Report, [2], indicated that the conventional Line Drop Compensation setting on LTC controllers can only work properly with radial load current, in direction from HV to MV. After the addition of a DER to the feeder, load current may decrease or revert the flow direction to become in the direction from MV to HV. If the LTC controller settings are left unattended, adding DER to a feeder with conventional Line Drop Compensation setting may cause overvoltage during the DER operation period. For the LTC controllers, when the DER is operating and then trips itself, voltage regulation could be impaired due to the time delays on the LTC controllers.

With DER being connected to a feeder, the LTC control should be adjusted. Some solutions are presented in [3] by Beckwith, one of the "tap changer control" major manufacturers.

Wire owners should pay attention to the voltage on transformers that were initially installed for purpose of stepping down voltage. Using them for stepping up voltage from DER may not only shorten the facility lifespan but also be subject to ferro-resonance due to core saturation related to elevated voltage on the secondary winding.

3.3.6. Self-excitation Overvoltage for Rotating DERs

When a generator is islanded and prior to anti-islanding to take down the island, self-excitation can occur if the load is capacitive and exceeds the amount the DERs can absorb, [5]. The excessive capacitance in the island can cause voltage swell. When the transformer cores are saturated, ferro-resonance overvoltage becomes likely. Voltage analysis needs to be done to avoid equipment damage to both system and DER.

If AVR (automatic voltage regulator) is not allowed, and if DERs are running in constant PF (power factor) control model, this may not be a concern.

3.4. Equipment Rating

Effective grounding affects insulation coordination and particularly the specification and installation of surge arresters. When the grounding is not effective, TOV occurs in the system and potential damage or failure to equipment may happen subsequently.

In selecting surge arresters, both MCOV and the energy capability must be appropriate for the operating system. In DER and IPP projects, it is then obvious that the insulation coordination study should show and prove that the existing surge arresters either remain capable or need an upgrade for the modified overvoltage profile in consideration of overvoltage protection coordination on power equipment such as transformer.

Since the MOA, metal-oxide arrester, has capability of operating for a limited period of time at voltage above its MCOV, each MOA has a V-T curve. An asserter meeting the IEC standards must withstand its rated voltage (Ur) for 10s, and Ur should equal at least the 10-second TOV capability. It could be common that a MOA can operate at 1.4 pu of MCOV for about 1 second, per Figure 4, for illustrating the concept, in [4].

Besides voltage withstanding capability, another important parameter with MOAs is its energy withstanding capability. In complex application when it becomes a question if existing MOAs' energy withstanding capability can withstand anticipated TOV, EMTP (or PSCAD) type of studies may be required to determine the arrester ratings. For simple applications, it is possible to do the manual calculation.

For power frequency TOV, evaluating surge arrester's duty can be done using the arrester manufacturer's published TOV withstand curves.

Evaluating arrester energy duty related to harmonic resonance like those during energizing a transformer in a weak power system might need modeling and simulation in time domain analysis (EMTP, PSCAD type).

Discharge current in surge arresters caused by ferro-resonance is of low magnitude, due to the power source's high impedance. As a result, surge arresters can be counted as a protection for such overvoltage. But they may fail due to protracted heating effect.

If surge arresters exist on a transmission line and a distribution feeder that is used to interconnect a DER or an IPP, they need to be evaluated with the modified grounding scheme. For example, if surge arresters were installed near a Delta winding on 138 kV side of a Dyn step-down load supply transformer. Once that transformer is repurposed to export power from its lower voltage side, surge arresters would be subject to TOV once the transformer is isolated from the rest of the system. Before the generation is taken down, surge arresters could be conducting due to the TOV caused by the generation on a Delta winding.

It is noteworthy that extra attention needs to be taken if surge arrester exposed to TOV risk is made in porcelain instead of polymer. The debris from possible explosion caused by TOV may catastrophically hurt field crew on site or damage nearby equipment.

Below discussion is on surge arresters that are inside a distribution facility or a transmission substation.

3.4.1. Distribution Equipment

On 4-wire multi-grounded distribution system (often grounded four times per mile, in an interval of 400 meters), surge arresters are connected phase to ground. Their grounding wire may be directly connected to the neutral (aka concentric neutral, the 4th wire) conductor or equipment tanks.

TOV magnitude and duration need to be figured out via studies so that the arresters' TOV withstand capability can be evaluated. Typically, at distribution level, GFOV is used as the TOV. It should be noted that the ground fault protection speed has an impact on surge arresters. Most distribution level MOA can withstand 1.38-1.45 pu overvoltage for about 1 s. IEEE 62.22-2009 indicates that GFOV may be assumed to be 1.25 pu in the 4-wire distribution system if the phase-to-ground resistance is < 25 ohms (related to how often the neutral is grounded), and the neutral conductor size is no smaller than 50% of the phase conductor size.

GFOV may be >1.25 pu if the neutral ground conductor size is smaller than 50% of the phase conductor size. As a result, many utilities use 1.35 GFOV in sizing arresters.

Arresters with higher duty-cycle, MCOV or more disc columns may be required if the TOV withstand capability is exceeded. Note that adopting arresters with higher duty-cycle and higher MCOV need to re-check the insulation coordination.

3.4.2. Transmission Equipment

At transmission level, surge arresters are applied to protect equipment such as transformers (for its external and internal insulation), capacitor banks and even circuit breakers inside a substation.

Both MCOV and TOV may be the decisive factor. Grounding effectiveness affects the TOV magnitude and duration and thus affects the existing surge arresters in substations adjacent to a DER or IPP being interconnected to the grid.

4. Effective Grounding Screening

The winding configuration of power transformers in this white paper follows IEC 60076-1, "Power Transformers – Part 1: General", 3rd Edition, 2011, for being concise. Two variations are created. One is the phasing between a Wye winding and a Delta winding is omitted as it is irrelevant here. So instead of showing Dyn1, only Dyn is shown. The other variation is based on AESO's preference to distinguish YG from YN. YG is meant to indicate a Wye winding's neutral is solidly grounded. YN or yn is covered in the IEC 60076-1. But YG or yg is not. YN or Yn simply means the Wye winding's neutral is brought out through a bushing and it is up to the user of the transformer to decide if to ground it, or how to ground.

4.1. Transformer Winding Configuration

Per CSA C22.3 No. 9 – 20, Clause 7.3.2, it is recommended to have the winding configuration of the customer-owned transformers reviewed and accepted by the wire owner. Further in the clause, it is pointed out that "the interconnection transformer is a critical component of the DER system and can affect other DER system elements. The power producer should contact the wires owner for the preferred winding configuration and transformer design."

For DERs connected at the distribution level, the ITs may be one of the three common formats: Yd, Yy, Dy. Note that the neutral on the Wye side could be either solidly grounded or impedance grounded. Ungrounded Wye shall not be allowed for the system side.

For generators connected at the transmission level, the most preferred winding configuration is Yd. Besides that, Yy, Yyd and Dy may also be possible.

Many inverter-based DERs have a neutral for sensing only, not for carry ground fault current. That kind of inverter-based DER itself cannot be an effective grounding source. In those cases, an interconnection transformer being the zero-sequence current source like YGd, YGygD, should be relied upon.

The impact of all four acceptable transformer winding configurations to the system is discussed below.

4.1.1. YGd (Type 1)

With a solidly grounded Wye on the system side and a Delta winding on the generator side, no overvoltage on the unfaulted phases would occur during a ground fault. For synchronous generators interconnected at transmission level, this is the most prevailing transformer winding configuration. In Alberta, generators with large MVA size (>200 MVA) at Sundance and Keephills power plants are connected to 240 kV system in this format. The ratio of ground fault current (3*I0) to the positive-sequence current during a 3LG fault is usually in the range of 2.5 to 3.0.

At the transmission level, with line relays installed at the power plant end, having a large ground fault contribution from this kind of transformers with the generator as the current source is not a big problem. But at the distribution level, feeder protection is ubiquitously of overcurrent type, and the relay is only installed at the substation end. Adding a solidly grounded Wye winding downstream to the feeder breaker could significantly desensitize the substation ground relay. In reality, when the issue of current desensitization is not resolved, ground faults could be yielded to the phase relays (responding to positive-sequence current) to operate, which is usually slower and less sensitive than the ground relay. In overcurrent feeder protection, phase element is set above the load. Since feeders usually have low load unbalance, ground relays can be set very sensitive. 80% of distribution faults are single-line-to-ground faults. Having ground protection being desensitized and letting phase relays operate for ground fault should be deemed dangerous to the utility company and to the public.

Causing current desensitization is a drawback of this winding configuration. The common mitigation is to add a NGR (reactor) to the Wye winding, to a degree that effective grounding is not compromised.

The symbol YGd can be used to represent the Wye winding being grounded through impedance.

4.1.2. YGygD (Type 2)

This is a 3-winding transformer with a closed Delta, often grounded on one corner. The Delta's MVA rating is usually one-third of the main winding's base MVA rating. The tertiary Delta winding could be buried or be accessible for connection via bushings.

With a solidly grounded Wye on the system side and a Wye winding on the generator side, and with a closed Delta winding circulating zero-sequence current, overvoltage on the unfaulted phases could be moderate. However, due to the MVA size of the Delta winding being smaller than the main Wye windings, a YGygD transformer may still have TOV that needs to be mitigated with a dedicated grounding transformer.

A NGR may be required for the Wye winding's neutral if the current desensitization mitigation is found necessary.

4.1.3. YGyg (Type 3)

YGyg interconnection transformers need careful modeling as its zero-sequence impedance could vary in a large range, depending on the iron core formats. If the YGyg transformer is of 3-legged core form, the tank effect should not be missed in the modeling.

When the LV side Wye is ungrounded, a grounding transformer on the system side is most likely required, even if the Wye on the system side is solidly grounded. Detailed study to prove the effective grounding needs to be done.

If the LV side Wye winding is grounded, and if the generator neutral is solidly grounded, a grounding transformer on the system side may not be required as long as the effective grounding requirement (EFF and GFOV) is met.

It is likely that a grounding transformer is required to be installed on the system side, depending on these factors, including but not limited to:

a. the size of the interconnection transformer,
b. if it has "enough" tank effect to circulate zero-sequence current to suit the need of effective grounding,
c. the grounding of the generator.

As mentioned in Annex C in [8], using this kind of transformer as an interconnection transformer has one drawback. GFOV in the distribution system can be passed onto the DER side. Some inverter-based DERs cannot handle such overvoltage and should then better adopt the YGd with a Delta winding on the DER side.

4.1.4. Dyg (Type 4)

With a Delta winding on the grid side, once the transformer with the connected generator is isolated from the grid, for a ground fault on the system side, the unfaulted phases would experience TOV as high as 1.732.

a. At Distribution Level

In 3-wire distribution system (rare or non-existent in Alberta where multi-grounded 4-wire distribution prevails), load transformers stepping-down voltage from MV usually have a Delta or an ungrounded Wye winding. At distribution system in Alberta, most step-down transformers are of YGyg format. Therefore, there shall not be too many Dyg transformers stepping down voltage from distribution voltage levels such as 34.5/35 kV, 27.6/25 kV, 15/13.8 kV, 5.0/4.16 kV.

For new DER facility, when connecting the DER behind these Delta windings on the system side, TOV is a concern. This kind of transformer does not cause the current desensitization on the substation overcurrent relay. But to meet the effective grounding requirement, grounding transformers are usually required to be connected on the system side.

b. At Transmission Level

At the transmission level, the number of stepping-down load transformers of Dyg (138 to 34.5 kV, 25 kV, 13.8 kV or 4.16 kV) is estimated to be over 400 in Alberta. Most of them serve either industrial loads or loads in cities.

Adding generation behind the Delta winding on 138 kV side may need to add a grounding transformer to effectively ground the Delta winding on the system side. But this may not be financially viable and requires additional regulatory approval.

With generation added onto the MV side of the transformer, the Delta winding on HV side cannot meet the effective grounding requirement. The following concerns on non-effective grounding for the period after the transformer is isolated from the system, and before the generator is shut down or cease to energize are as follows:

i. Protection of the transmission line as there is no current contribution from the generator for a ground fault on the line;
ii. TOV;
iii. TRV (transient recovery voltage) for breakers.

4.1.5. Three-Phase Transformer Consists of Three Single Phase Transformers

Although it might be rare to form a dedicated interconnection transformer using three single-phase units, the benefit of this kind of transformer bank is "it does not back feed an open phase as there is no shared magnetic core".

With Z0=Z1, the transformer bank formed by three single phase transformers can contribute zero-sequence current into a ground fault in the system. Its impact on the current desensitization needs to be studied.

4.2. Generator Grounding

In screening the effective grounding characteristics of DER and the system being modified by the DER interconnection, besides the DGIT's effect, it is necessary to check the generator grounding scheme as well. The effectiveness of the grounding scheme for a system or a subsystem cannot be solely dictated by the transformers only. The grounding scheme of the generators can affect the zero-sequence current contribution for faults on the system side of a DER unless there is a Delta winding that isolates the generator zero-sequence impedance from the system.

4.2.1. Rotating Machine Generators

Per IEEE C62.92.2-2017, [20], three main objectives of synchronous generator grounding are: to reduce damage for internal ground faults; to limit mechanical stress in the generator for external ground fault; and to limit temporary and transient overvoltage on the generator insulation. Regardless of which object dominates, the grounding scheme of the generator should always result in an effective, and often fast, ground protection on the unit. Six grounding schemes are listed in the standard in the order of increasing ground fault levels:

a. Resonant grounded;
b. Ungrounded;
c. High-resistance grounded;
d. Low-resistance grounded;
e. Low-inductance grounded;
f. Effectively grounded.

Some small units may use an automatic neutral breaker. Although it is an obvious way to prevent damage from the large ground fault, opening a neutral breaker makes the neutral ungrounded, which triggers both TOV and TRV issues. Generator grounding like this needs careful evaluation.

Low ground current is at the cost of higher temporary and transient overvoltage. Therefore, the DER or IPP developer has a lot to consider in the grounding of the generator itself. With clearly defined technical interconnection requirements from the grid, it should help the developer in making the right decision on generator grounding and interfacing with the grid.

High-resistance grounding on the generator with a Dyg (Delta on generator side) step-up transformer is common for unit-connected generation systems. Very often, it is a low ohmic resistor connected to the generator neutral via a distribution transformer.

For generators connected onto a bus with a feeder, the selection of the generator has to follow the feeder grounding requirement. If effective grounding is required for the feeder, then the generator has to be effectively grounded.

4.2.2. Inverter-Based Generators

More and more simulation software can model inverter-based generators as a voltage controlled current source (VCCS), [24], [25]. Most software now allows a data entry in tabular format with voltage varying in a range like 0.1 to 1.1 pu. From electrical circuit theory point of view, a current source has infinitely large internal impedance.

As explained in IEEE C62.92.6-2017, [19], the load impedance then dominates and determines the voltage on the healthy phase when there is a ground fault. If the majority of load is grounded, there is usually no GFOV. Otherwise, if the majority of load is ungrounded, there will be GFOV exceeding that is required for maintaining an effective grounding.

The "vast majority" of grid-tied inverters work as if they are 3-wire three-phase. The 4^{th} wire is for sensing but not for carrying neutral current. Such inverters' zero-sequence model is an open circuit. The inverters themselves are essentially ungrounded.

Even if the IBGs are equivalent to being ungrounded, through a properly selected winding configuration for the interconnection transformer, the DER may still meet the effective grounding requirement on the system side.

4.3. Sequence Component Diagram

Sequence component diagrams are great visualization in the screening of effective grounding. It is a great aid to software simulation. It is also of use to justify the modeling in software, and to justify the simulation results. Both references [2] and [14] are great source of information. The following two examples are shown.

For manual calculation, usually T-model is more useful and straightforward, while some simulation software uses π-model.

It should be noted that using sequence component analysis in inverter-based DERs is a big simplification. By assuming all such impedance being steady-state, the actual dynamic characteristics of the power electronic control are all lost. To certain degree, the sequence component analysis being conducted manually or via variety of steady-state simulation software may be effective for short circuit and fault level study, but could be insufficient or even incorrect for effective grounding and TOV studies.

Although this white paper deals with grounding and zero sequence impedance, it should be noted that, for inverter-based DERs, negative-sequence impedance may have significant impact on effective grounding and TOV. Different from rotating DERs whose negative sequence impedance being same or close to positive sequence impedance, inverter-based DERs' negative-sequence impedance could be shown by the manufacturers as much higher than positive-sequence impedance. When using a steady-state analysis software to analyze effective grounding and TOV and using the set of sequence impedance from the inverter manufacturer, the effect of negative-sequence and zero-sequence impedance could be significantly distorted or exaggerated. The modeling and study engineers should decide when to use time-domain data and time-domain program such as PSCAD.

4.3.1. YGd DGIT (Type 1)

The following are taken from the IEEE PSRC Report, [2].

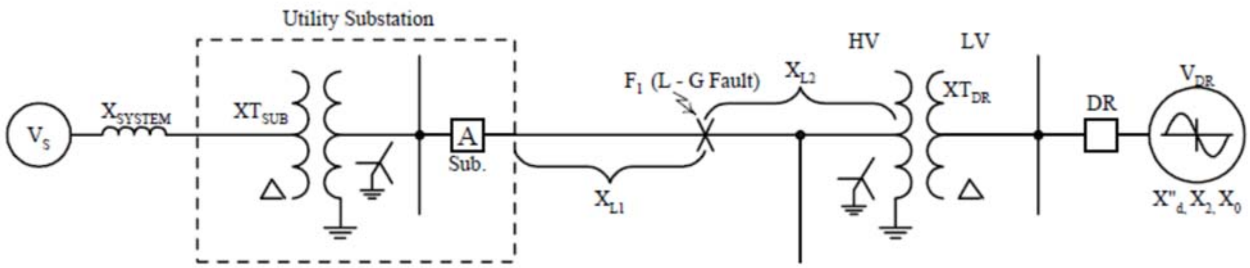

Figure 4: A DER with a YGd DGIT

In the above diagram, the DER's interconnection transformer is a YGd with the solidly grounded Wye winding on the feeder side, and a Delta on the generator side. The correspondent sequence component diagram or symmetrical component circuit is shown below.

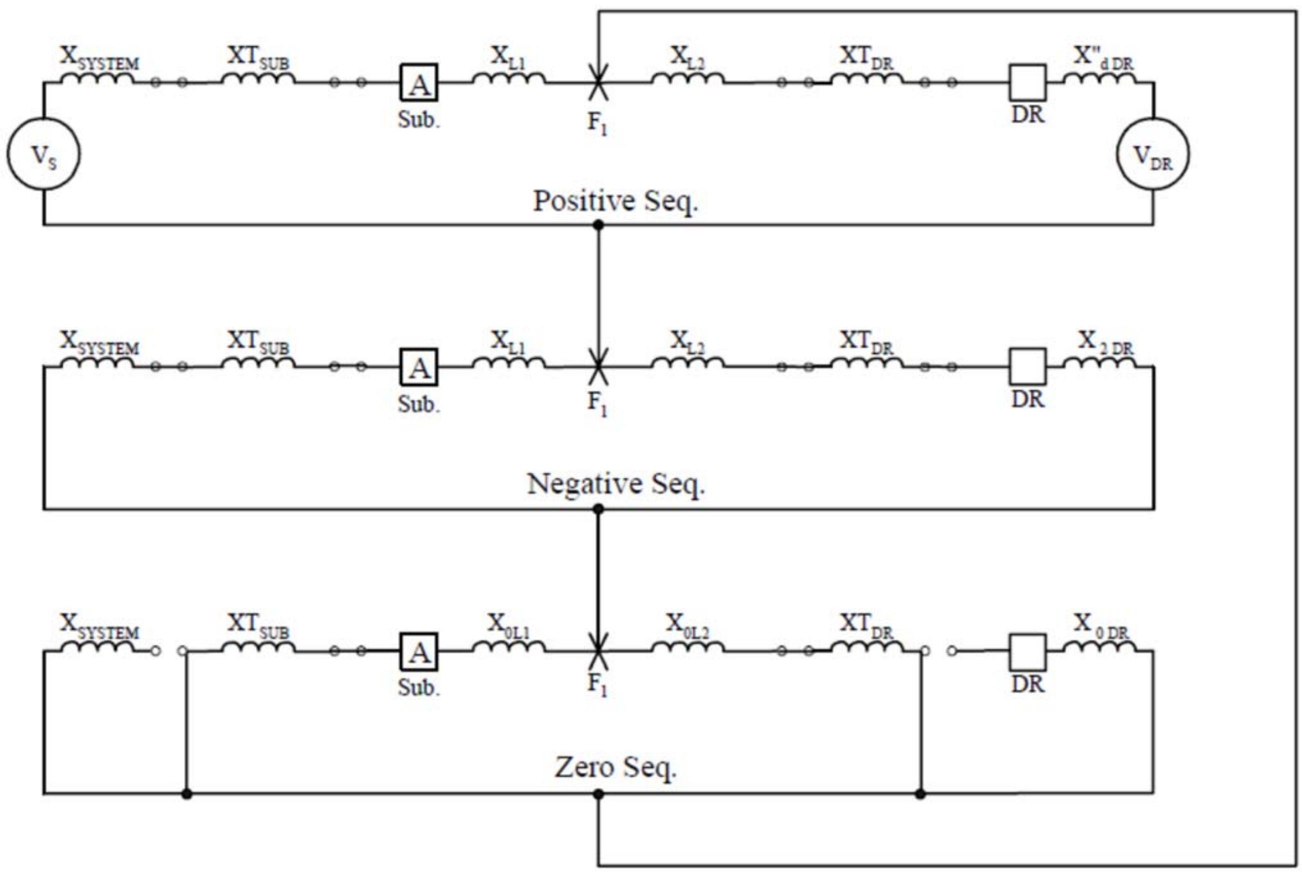

Figure 5: Sequence Impedance Network for a DER with a YGd DGIT

From Table 2-5 in AESO's Transformer Modeling Guide, [14], the zero-sequence impedance for the DER interconnection transformer (YGd) can be further detailed as:

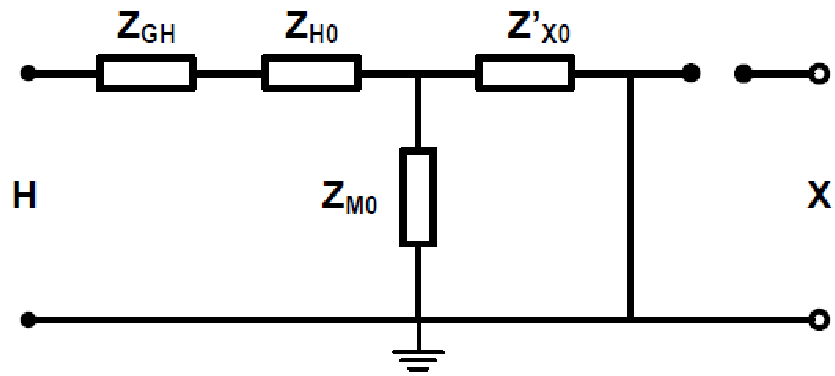

Figure 6: Sequence Impedance for a YGd Transformer, from [14]

(Note Z_{GH}=0 when HV Wye winding is solidly grounded.)

In the above Figure 5, the zero-sequence current will be splitting between the relay located at Substation A and the grounded neutral of the DGIT. Due to the presence of a Delta winding, the issue of current desensitization caused by the grounded Wye winding in the DGIT persists even if the DER is out of service. Both the ground fault current and the continuous load unbalance current suffer the desensitization from the standpoint of the substation relay. Under certain circumstances, since the DGIT's Wye winding circulates the unbalanced load current, during a sever load unbalance (e.g., due to a lateral fuse blown), the DGIT's load carrying capability may be reduced.

4.3.2. YGyg DGIT (Type 3)

With a YGyg interconnection transformer, one drawback is the substation relay may sense a ground fault inside the DER facility as shown on the below diagrams, from [2].

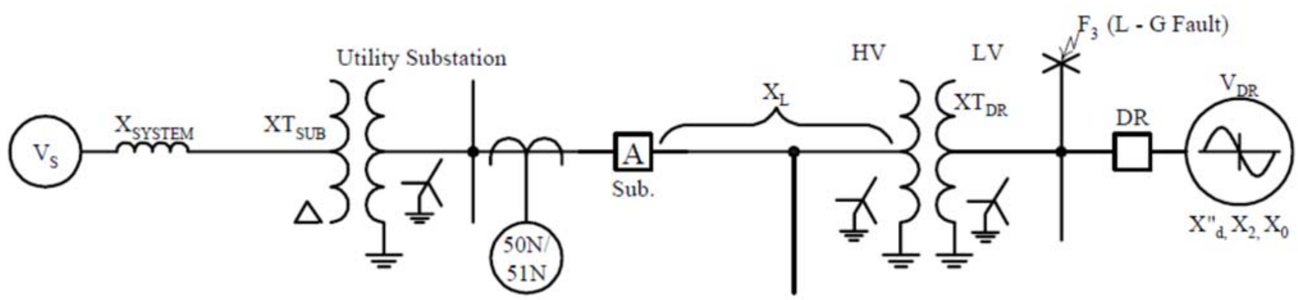

Figure 7: a DER with a YGyg DGIT, from Reference [2]

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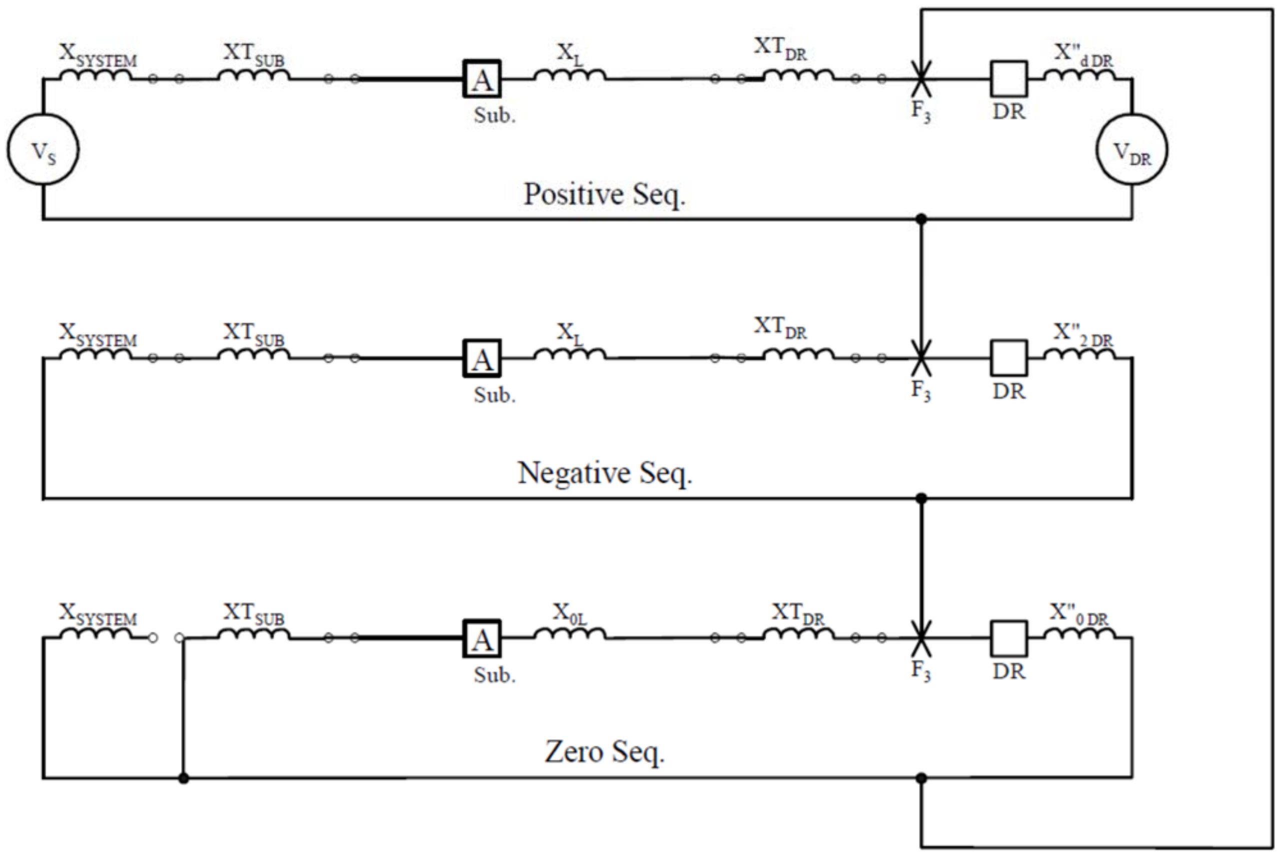


Figure 8: Sequence Impedance Network for a DER with a YGyg DGIT, [2]

From Table 2-2 in AESO's Transformer Modeling Guide, [14], the zero-sequence impedance for the DER interconnection transformer (YGyg) can be elaborated as:

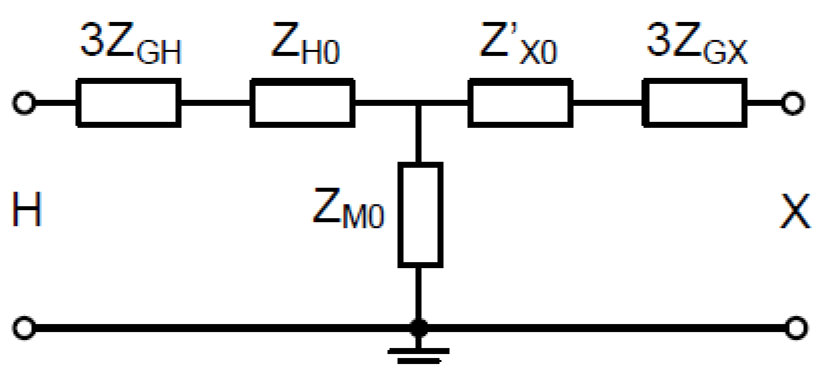


Figure 9: Sequence Impedance for a YGyg Transformer, from [14]
(Note Z_{GH}=0, Z_{GX}=0 when HV & LV Wye windings are solidly grounded.)

Note that, if this YGyg is of 3-legged iron core structure, then there is tank effect which could have a Z_{Mo} only 300-400% of the positive-sequence impedance of the transformer. For one transformer with Z1=7.5% or 0.075 pu of the self-impedance (based on nameplate MVA and kV), Z_{Mo} could be as small as 0.3 pu or 30%. All problems shown for the YGd transformer in the last section also present here. Since the YGyg transformer can pass on the zero-sequence current from the generator, when the generator is in service, the DER may cause significant current desensitization. When the generator is out of service, the DER can only contribute some zero-sequence current due to the tank effect. In [2], no tank effect is considered which is probably an oversight of the technical point.

In terms of the current desensitization, the smaller Z_{Mo}, the less current will be measurable to the substation relay, as more ground current is sourced from the DER path in the sequence component diagram on the last page. Therefore, in order to conduct a protection study to deal with the current desensitization, the tank effect on a 3-legged core 2-winding YGyg transformer cannot be simply ignored. Otherwise, the relay settings for the overcurrent relay inside the utility substation will be wrong.

4.3.3. Inverter-Based DER

Note that it is not easy to apply sequence component analysis onto inverted-based DER because non-rotating generators do not intuitively have a set of positive-, negative- and zero-sequence impedance. Thus time-domain simulation in EMTP, PSCAD type of software is more practical to analyze inverter-based DERs.

IEEE C62.92.6-2017, [19], suggests a zero-sequence network representation for an inverted-based DER as the below diagram, where a current source is shown, injecting onto a set of load impedance, after it is isolated from the grid. The feeder impedance is deemed to be much less than load impedance and is said in the standard that ignoring the feeder impedance does not change the result of the fault analysis.

The negative-sequence impedance ranges from tenths in pu (0.1 to 0.9) of inverter's base to infinity.

Similarly, zero-sequence impedance is usually an open circuit, as mentioned in the above Section 4.2.2.

The positive and negative-sequence load impedance may be assumed to be the same, approximately equal to V^2/S_{Load}. The zero-sequence load impedance "is of critical importance as it provides zero-sequence continuity." It is defined by only the phase-to-ground connected load, [19].

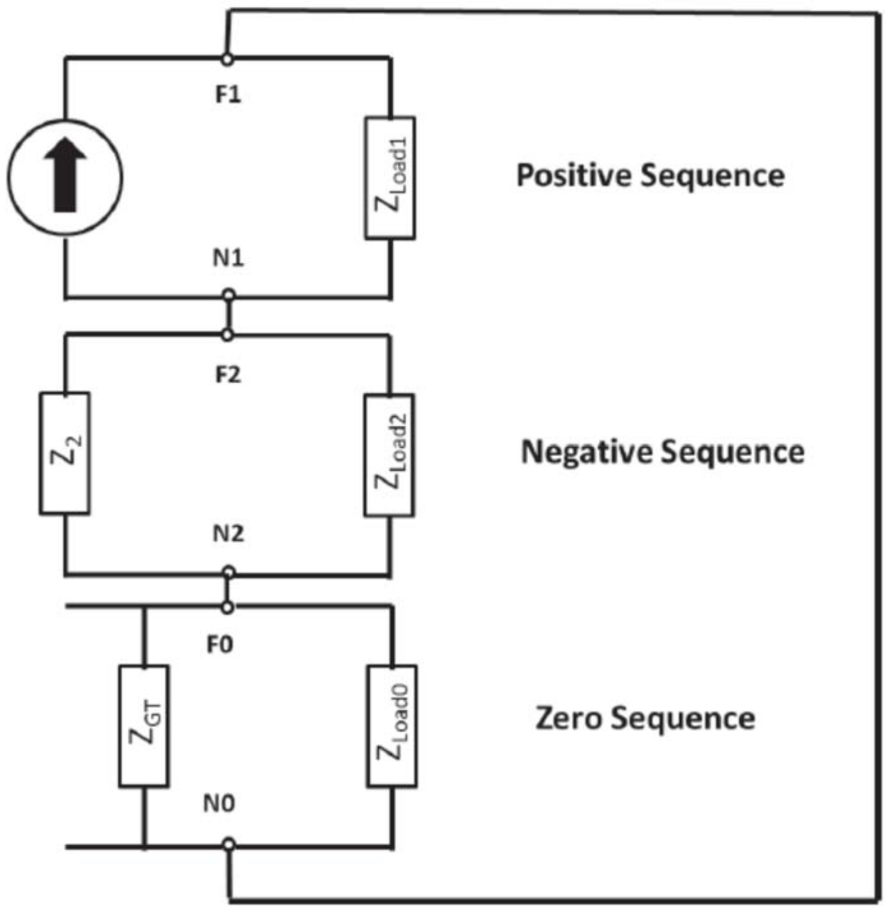
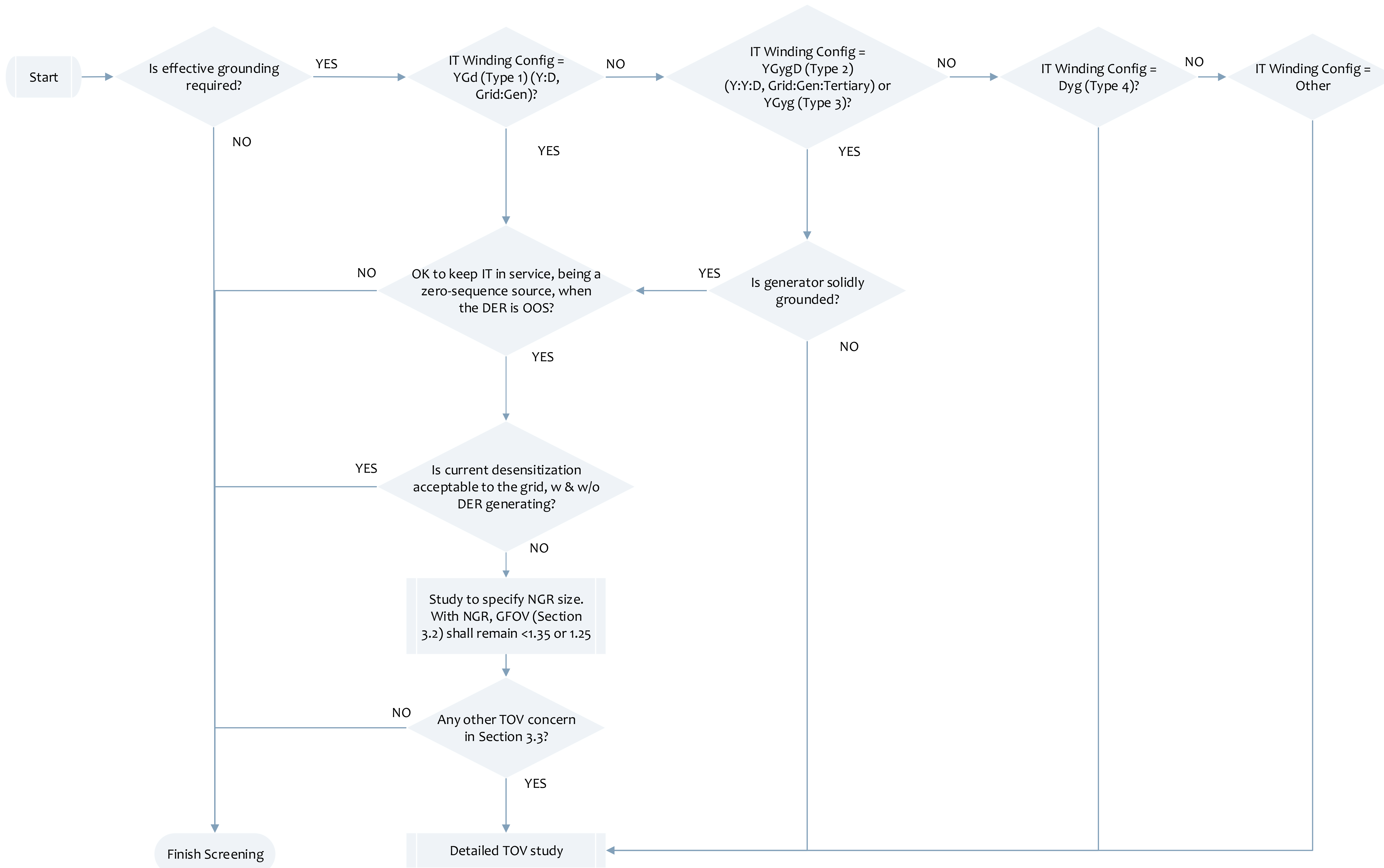


Figure 10: Sequence Impedance Network for a Current Source IBG

4.4. Effective Grounding Screening Flowchart



5. Effective Grounding Study Methodology

5.1. Data Inputs

5.1.1. Inputs to be Provided by Wire Owner

a. System grounding characteristics
   - 3-wire or 4-wire
   - single- or multi-grounding
   - If multi-grounded, how many grounding points within a mile or one km
   - neutral return resistance ohm/m and if it is subject to seasonal changes
   - concentric neutral or grounding conductor details (absolute size like 4/0, or relative size like 100%, 50%, 33% of phase conductors)

b. Short circuit model of the system in format of sequence impedance, including but not limited to,
   i. Thevenin Impedance for the MV bus;
      Note that it is usually redundant to provide both Thevenin Impedance and short-circuit fault levels. When both are provided, the sender should ensure they are correctly correlated, not conflicting. The transmission network's impedance is included and has less effect as the HV/MV transformers' impedance dominates the MV bus Thevenin Impedance.
   ii. Feeder impedance between the substation feeder breaker and the DER location;
      It is usually not practical to simulate a distribution system with all connected load and generation. However, those of importance should be included in the model.
   iii. Existing ground fault current contribution source on the feeder.

c. Maximum allowance of current desensitization, usually 10% of ground fault level measurable to the substation feeder relay, at post-project stage;

d. Acceptable GFOV magnitude on the healthy phases for ground faults (usually in range of 1.25 to 1.38 depending on each wire owner's practice and insulation coordination);

e. Existing DER on the feeder, and in adjacent area, if deemed relevant.

5.1.2. Inputs to be Provided by DER Through Wire Owner

a. SLD (single line diagram);

b. Short circuit model of the DER interconnection transformer
   Nameplate
   Test report

c. Generator short circuit model
   For rotating DERs, in format of sequence impedance for steady-state (60 Hz) analysis;
   For inverter-based DERs, in format of PSCAD type for time-domain analysis, PLUS a set of equivalent sequence impedance data.

d. Grounding details for the interconnection transformer

e. Grounding details for the generators or the inverters

5.2. What to check

a. Over-voltage on healthy phases for ground faults;

The method of X0/X1 ratio is of value in specifying equipment. The X0/X1 ratio check is from the standpoint of POI (point of interconnection). But from the point of view of ensuring effectiveness of grounding, checking GFOV is more straightforward.

b. Total fault current within equipment rating capacity;
   On distribution level, equipment with ground fault current rating limit usually includes circuit breakers, reclosers, MVIs (medium voltage interrupters) and fuses.
c. For DERs, desensitization to the substation relays does not cause the ground relay/element to have a fault current reduction more than 10% of that before the project.

As mentioned in IEEE C62.22, [4], soil resistivity could be a factor and cause a system grounding being effective in one season and non-effective in another season. Historical experience should have justified using a constant soil resistivity like 100 ohm-meters in calculating zero-sequence impedance for lines and feeders. But the concentric neutral size affects the split of return ground fault current between the neutral conductor and the earth. When the neutral conductor size is below standard, detailed models should include neutral conductors on the feeder.

5.3. Acceptance Threshold

Although standards and some other utilities use parameters like X0/X1, and R0/R1, in defining effective grounding, it is deemed more practical to focus on GFOV on the healthy phases. This shall help deal with situations like inverter's sequence impedance is less intuitive than rotating machines, and is often hard to interpret, especially for negative- and zero-sequence impedance of inverters. From the system point of view, monitoring EFF and GFOV to be 1.38 pu or less is more direct and effective in enforcing the important system grounding scheme.

Each wire owner can specify its own acceptance GFOV in the TIR. It is usually between 1.25 and 1.38. The lower, the less stress on the existing insulation in the system. This acceptance level on GFOV should be based on each company's insulation coordination including surge arrester specification.

Each wire owner company should include the allowable maximum ground fault current in the TIR, such as 5 kA, besides the limit for three-phase fault current.

Ground fault current desensitization may be allowed to be a percentage of the post-project total fault current measurable to the feeder ground relays in the utility company's substation. One major utility, Fortis Central Hudson, in [11], limits the ground fault current contribution to 10% of the pre-project level, at PCC. Control via NGR to let substation relay only lose 5-10% measurable current could be a practical approach.

5.4. Mitigation Measures

5.4.1. TOV

At the distribution level, if a DER is added through an interconnection transformer with a Delta on the system side, or if the TOV is higher than the wire owner's acceptable maximum value, review and adjust the region's surge arrester MCOV and insulation level may be opted as an alternative to adding a grounding transformer.

When adding grounding transformers such as a zig-zag or a YGd with Delta side floating (the so-called "naked Delta"), current desensitization issue to the substation feeder relay needs to be watched and resolved.

When it is not feasible in a project to add the grounding transformer, other alternatives should be resorted to including changing the interconnection transformer's winding configuration, the generator's grounding scheme, or accept the non-effective grounding as a fact and evaluate and upgrade the grid accordingly.

5.4.2. Current Desensitization

In Section 6.2.1. of IEEE 1547-2018, it is suggested to adjust the existing overcurrent protection to compensate for the fault current change after interconnecting a DER. However, there could be a limit that how much current desensitization and how much fault current change the existing protection system can accommodate. This needs a detailed protection coordination study.

For feeder protection being de-sensitized by a DER IT's solidly grounded winding at the system side, adding NGR (reactor) to the DER IT may be the most effective way. Doing so, the solidly grounded Wye becomes impedance grounded.

The "room" for the newer DER on a particular feeder may diminish depending on relative location among the substation and different DERs on the same feeder. A detailed modeling in the distribution feeder, and further study is required as part of the protection study which is beyond the scope of this white paper.

Note, as pointed out in Annex C of CSA C22.3 No.9-20, ground protection at the substation end can still be desensitized if there are multiple low-impedance grounding sources on the feeder. Existing load supply transformers' solidly grounded Wye winding, if having zero-sequence path like a Delta winding on the LV side, or tank-effect on a 3-legged core YGyg transformer, need to be considered.

It is likely that the NGR mitigation is not effective if there are many low-impedance grounding sources. When that becomes the case, two other mitigation measures would be:

a. Upgrade the protection on the feeder, and
b. Change the Wye winding on the system side to a Delta

The protection upgrade should be part of the protection study, which is out of the scope of this white paper.

5.4.3. Total Ground Fault Level Exceeds the Existing Facility's Rating

It is necessary to do a detailed study where the equipment rating may be exceeded.

Adding a single DER with a short tap onto a feeder, the worst location having the highest fault level is near the tap on the downstream side of the DER, not between the substation and the DER location. Downstream to the DER, it is likely to have the fault current contributed from both the substation and the DER. Considering current desensitization, assuming substation transformer source contributes 3 kA zero-sequence current, and the DER can source 1.8 kA, the total ground fault current can be 4.8 kA. Therefore, it is usually preferred to add NGR to the DER interconnection transformer to solve the ground fault current problem. However, adding an NGR to the substation's (e.g., 138/25 kV) transformer should be avoided as it worsens the current desensitization issue on the substation ground relays.

As mentioned in 5.3, one major utility, Fortis Central Hudson, in [11], limits the ground fault current contribution from DER to 10% of the pre-project level, at PCC.

6. TOV Study Methodology

This section is meant to provide an instruction for a DER connection TOV study.

Temporary overvoltage affects the equipment specification, withstanding capability and safety. It is advised for each DER interconnection project to have a study report evaluating the overvoltage performance on the DER facility and on the adjacent power system for all credible operational mode. The grounding method of the interconnection transformer and the generator or the inverter is the key factor in adding a DER facility to the existing effectively grounded power system.

Note that, as mentioned in Section 1.1, in this white paper, it is assumed the interconnection transformer is the only transformer between a generator and the interconnection system.

As discussed in Section 3, TOV in DER or IPP projects can be induced or caused by these factors:

a. Presence of a Delta winding without a grounding path;
b. Ground faults;
c. Load rejection;
d. Over-excitation of rotating generators;
e. Switching;
f. Ferro-resonance.

6.1. Study and Modeling Assumptions

6.1.1. Inputs to be Provided by Wire Owner

a. Short circuit model of the system in the format of sequence impedance, including but not limited to:
    i. Thevenin Impedance for the distribution substation bus;
    ii. Feeder impedance between the substation feeder breaker and the DER location;
    iii. Existing ground fault current contribution source on the feeder.
b. Shunt capacitor switching strategy (auto or manual; frequency; criteria etc.);
c. Saturation curve of power transformer in the distribution substation;
d. Existing DER and major load on the feeder, and in the adjacent area, if deemed relevant;
e. Special operational modes, including in-line reclosers;
f. Voltage regulating equipment, e.g., DVAR, DSTATCOM, etc.

6.1.2. Inputs to be Provided by DER Owner Through Wire Owner

a. SLD;
b. Short circuit model data of the DER interconnection transformer
    Nameplate
    Test report
c. Generator short circuit model
    For machine-based DERs, in format of sequence impedance for steady-state (60 Hz) analysis; For inverter-based DERs, in format of PSCAD type for time-domain analysis, PLUS a set of equivalent sequence impedance data. Refer to AESO's PSCAD guide (to be published on the website soon) for consistent and quality data sharing.
d. Grounding details for the interconnection transformer

e. Grounding details for the generators or the inverters

6.2. Study Scenarios

a. Faults (SLG and LLG) on feeders or lines, including fault clearing and restoration (reclosing)
b. Energization of transformers
c. Energization of feeders or lines (only if DER or IPP is relevant)
   If a line or feeder is energized without the DER or IPP, then this scenario is not applicable.
d. Switching
   i. Load rejection
   ii. Generator tripping
   iii. Reactive power devices (shunt capacitors) switched-in and switched-out
   iv. Single phase switching
e. Open phase
   Even if single-phase-tripping-and-reclosing (with or without single-phase-lockout) is not enabled, open phase scenario needs investigation. One common cause of open phase is a blown fuse on one or two phases.
f. Unbalanced Load
   Distribution has intentionally connected single phase loads and loads connected phase-to-phase.
g. For a Delta winding on the system side, a three-phase fault
   A three-phase fault, not a three-phase-to-ground fault could be a floating situation. If it is not deemed incredible, it needs to be included in the study.

6.3. Study and Modeling Requirements

Data provided should be detailed enough for time-domain (PSCAD) type of modeling and simulation.

a. Ground fault resistance
b. Concentric neutral size relative to phase conductors (33%, 50%, 100% etc.)
c. Existing surge arrester rating MCOV, type (gapped or gapless)
d. If single phase tripping-and-reclosing (with single or three-phase lockout) is enabled
e. Distribution feeder electrical characteristics, open air or underground, including shunt capacitance

For a sub-system ungrounded by a Delta winding, a ground reference is normally required in PSCAD in order to execute the simulation. In this case, the stray capacitance (in the range of several nF, nano Farad) of the transformer or substation buswork should be modeled. It creates a ground reference and the phase-to-ground voltage can then be easily measured.

6.4. Study Methodology

Build and justify a set of accurate short circuit models. Pay extra attention to zero-sequence impedance model.

Check the adjacent area in distribution system for its configuration, if it is multi-grounded 4-wire system or not.

As mentioned in Section 3.3, ferro-resonance study should always be required for DER projects and can be kept together with the effective grounding study.

6.5. Study Tools

PSCAD or similar software is the best choice for analyzing TOV, TRV, insulation coordination, ferro-resonance and power electronics.

6.6. Study Outputs

Temporary overvoltage. Power quality issues like harmonics can also be monitored during the study.

6.7. Acceptance Criteria and Mitigation Measures

DFO or TFO may have different risk tolerance. For example, 3-phase unground fault may drive the TOV to be >1.38 pu prior to the DER being tripped. But wire owners may perceive the likelihood is non-credibly low so the risk is deemed acceptable. For such cases, wire owners should share the study report and conclusion with AESO for common understanding. After all, AESO and the TFOs have shared responsibility on reliability.

6.7.1. Acceptance Criteria

TOV study results should be compared with wire owners' surge arrester ratings.

Similar to those in Section 5.3, GFOV and ferro-resonance overvoltage should be less than the required value by each wire owner. The definition is for EFF to be no greater than 1.38 pu. But according to each company's practice and especially their insulation coordination including the surge arrester rating. Below 1.38 pu, 1.25 – 1.30 pu are common.

6.7.2. Mitigation

This white paper focuses on providing understanding about unique overvoltage associated with non-effective grounding system, or with DER. The mitigation being discussed here is different from protection of power system from being damaged by overvoltage. When things, including applying these mitigations, are done right, the likelihood to have overvoltage is avoided or limited. Overvoltage protection as the last line of defense is a separate issue.

Optimization of interconnection transformer's winding configuration is one effective mitigation method as most TOV is related to system grounding. Factors in the optimization may include engineering, economics and practicality. Connecting a DER behind an existing transformer does not have much choice on the winding configuration and may need the installation of NGR or grounding transformer on the system side. For a DER project with a new, dedicated transformer, there will be multiple choices of winding configuration like those listed as Type 1 – 4 in Section 4.1. Each's suitability should be compared in order to choose the best one for the project. The grounding of the generator or IBG is another factor. Some ungrounded generators including most IBGs may prefer a Delta winding on the LV side of the transformer as the generator neutral is ungrounded.

To mitigate ferro-resonance, de-tuning is often necessary. Further, as recommended in IEEE C62.92.4-2014, [10], these practices should be followed:

a) Place the fuses and single-phase switches close to the transformers;
b) Use YGyg transformers as much as possible for load supply;

c) Connect single-phase transformers from phase-to-neutral rather than from phase-to-phase.

In [7], as part of the interconnection protection at the DER side, Hydro One specifically stipulates to implement a ferro-resonance protection element with ANSI Device Number 59I, which is an overvoltage protection responding to the peak-value of voltage, and faster than RMS-value-based overvoltage measurement.

For TOV related to islanding, or separating from the grid, if the magnitude cannot be mitigated to an acceptable level, a reliable transfer trip (TT) based anti-islanding scheme may be imposed on the project. Having the TT based anti-islanding minimizes the potential risk on the transmission protection created by the DER. The TT based anti-islanding scheme operates much faster than the DER's built-in AID (anti-islanding detection) which has a requirement to "cease to energize" within 2 seconds, per IEEE 1547. The input of a TT scheme may include the TRIP signal from fault detection relays at the remote buses. The output of the TT may be sent via redundant TPR (tele-protection) channels, or via a single channel with fail-safe feature, to trip the DER off directly. Implementing such an extensive TT is costly. Therefore, it is better to design a DER that can meet the effective grounding, and does not have TOV/TRV issues, at the first place.

Even with active detections, the DER side's AID depends on many factors to be effective. It is practical to use the Sandia screening method (originated in publications of Sandia National Laboratories, USA) to qualify some DER integrations with TT being waived. But the TOV study should examine the robustness of the whole system. For example, the system integrity should not be compromised if a single contingency, N-1, happens. Such an N-1 may include the DER's built-in AID failure, a CT (current transformer) secondary winding failure, a VT (voltage transformer) failure or the VT fuse failure, or a breaker failure. The power system's integrity is heavily relying on protection redundancy. Important protection like those on the transmission lines has not only fully redundant dual primary protection, but also local and/or remote backup protection.

Despite being different from protection, redundancy and robustness for system or mechanism maintaining effective grounding and conducting anti-islanding may be evaluated with an informed decision made on case-by-case basis.

7. TRV and Study Methodology

Per classification in Alberta, DERs refer to those power sources being connected to the transmission system at > 100 kV via more than one stage of voltage transformation. Obviously all DERs are eventually connected to the transmission system. Due to many substations having only two transmission lines, when one line is scheduled to be out of service (OOS), a DER would be connected to the transmission system radially. For a fault on the transmission line, when the first circuit breaker on either end of the line (usually the stronger end) is tripped by the protective relays, the circuit breaker's TRV capability could be challenged. On the non-system side of the circuit breaker, if the grounding is not effective, there will be TOV issue which can increase the likelihood of the breaker's TRV (transient recovery voltage) rating being exceeded.

Besides the DER, for generators being directly connected to the transmission grid via a Dyn transformer with the Delta winding on the system side, effective grounding, TOV and TRV issues could occur.

TRV, by definition, see [13], is the voltage that appears across the terminals or a pole of a circuit breaker after interruption. There are two successive time intervals for voltage to establish upon interruption. The first time-interval is a transient one, and voltage during that period is called TRV. During the second time-interval, the steady state or power frequency voltage is established across the open pole. In physics, the transient response is the consequence of the sudden stop of current shortly after the arc being extinguished upon current wave's zero crossing.

The TRV issue can be attributed to high voltage circuit breakers being designed and type-tested to interrupt current in an effectively grounded power system. When interrupting currents in a non-effectively grounded system, either the rate of TRV or the magnitude of TRV, or both, could cause an unsuccessful interruption, loss of thermal stability and breaker failure. If the rate of rise of recovery voltage (RRRV) is too steep, failure to interrupt may occur even if the magnitude of TRV does not exceed the breaker's TRV amplitude capability. TRV has very high frequency components and needs to be studied in a time-domain analysis program such as PSCAD, or similar, not in a phasor or steady-state program like PSS®E, PSS®CAPE or ASPEN OneLiner.

Per IEEE C37.04, [12], circuit breakers rated below 100 kV has Kf (aka Kpp), first-pole-to-clear factor, of 1.5, for system operated at the voltage range being ungrounded. The definition of Kf is the ratio of the recovery voltage after the first pole extinguishes the current to the normal voltage when all three poles clear the current. Breakers rated 100 kV and above, the first-pole-to-clear factor of 1.3 is required with assumption on most, if not all, systems operating at this voltage range being effectively grounded. There are breakers at 100 kV and above that are rated with Kf = 1.5, intended to be applied in ungrounded faults in effectively grounded systems [22].

TRV is the voltage difference between an open pole. One side of an open pole is the system side. The other side is usually the load side. Factors affecting TRVs include the current being resistive, capacitive or inductive, system and load characteristics, the particular breaker's arcing characteristics (different breakers for the identical installation may have different TRV). Grounding scheme could have impact on both system and load characteristics. Arc extinguishing always happens when current is crossing zero. When capacity or inductive current crosses zero, voltage is at the maximum and would have the maximum transient response.

Note that TRV rating of a circuit breaker is based on interrupting three-phase-to-ground faults at the rated symmetrical fault current and at the maximum rated voltage, [13]. Further, three-phase ungrounded fault is not considered due to extremely rare likelihood. Breakers rated below 100 kV have TRV ratings based on ungrounded system. For systems 100 kV to 170 kV, the system can be operated either ungrounded or effectively grounded. Only for circuit breakers applied on system above 170 kV, the TRV ratings assume an effectively grounded system.

In general, TRV is not a concern for breakers at the distribution level but could be a real concern for breakers at the transmission level. It is suggested to always require TRV and TOV to be included as part of the effective grounding study. Regardless of an effective grounding study being done or not, wire owners are ultimately responsible for ensuring the suitability of their equipment to withstand the altered system characteristics after a new generation (being DER or not) is interconnected.

7.1. Study and Modeling Assumptions

Models for TRV studies could be developed using the PSS®E study cases provided by AESO as the basis for the TRV study. As there are usually multiple study cases associated with a given project, the model with the highest short circuit levels should be used in order to produce the most conservative results (usually the Winter Peak case).

The PSCAD model may be developed manually or converted from PSS®E using the conversion tools (such as E-Tran application from Electranix). In either case, the study engineer must refer to the appropriate PSS®E case for correct short circuit levels in order to properly set equivalent sources at the model boundaries.

Since TRV is a high frequency phenomenon, it is primarily impacted by equipment in close proximity to the breaker being studied. Therefore in most situations it is sufficient to limit the detailed model to include the substation under consideration, and the neighboring substations up to one bus away. The size of the model should not be expanded beyond what is necessary to maintain accuracy in order to reduce modeling effort and improve simulation run-time speeds.

7.2. Study Scenarios

The study scenarios should include one or more of the following scenarios:

- Terminal Fault
- Short-Line-Fault,
- Transformer Limited Fault, and
- Out-of-Phase Switching.

When performing fault simulations, the breakers at the substation should be pre-configured as either open or closed such that fault current through the breaker under study is maximized in order to produce the worst-case scenario.

7.3. Study and Modeling Requirements

This section presents guidelines and requirements for modeling various equipment for TRV studies.

a. The generator

Since TRV is a high frequency phenomenon, it is generally acceptable to use a voltage source with proper impedance to model the generators. This impedance is normally the sub-transient impedance of a synchronous generator or the equivalent sub-transient impedance of an inverter-type generator. If available, the model provided by the manufacturer can be used. However, it must be sure that the model was developed for TRV study purpose.

b. Transmission Lines

The PSCAD Frequency Dependent Model or equivalent model shall be used. The complete geometry for the predominant structure type (i.e., conductor size, bundling, phase spacing, height above ground, etc.) can be used. The transpositions and mutual coupling between transmission lines should be modeled correctly.

c. Transformers

The standard transformer model available in the selected study tool may be used. The transformer saturation has limited impact on the TRV study and can be neglected. However, transformer capacitance constitutes a significant portion of the overall stray capacitance at a substation and may have a significant impact on results. Thus, it is critical to model the transformer capacitance.

d. Bus Work

Bus work connected to the breaker under study shall be modeled as an inductance based on the physical geometry of the substation.

e. Switched Shunt Capacitors

The most significant impact of switched shunt capacitors is to have a large mitigating effect on RRRV, however they may also cause a corresponding rise in peak TRV. Therefore, if shunt capacitors are present at the substation under study, then they should be switched off for the initial simulations in order to assess a worst case for RRRV. Sensitivity scenarios should then be run with the capacitors in service in order to observe their impact on peak TRV.

f. Switched Shunt Reactors

The presence of switched shunt reactors will tend to offset the benefits of the inherent capacitances at a substation, and therefore they should be included in the model to provide a worst case. It is generally not necessary to run sensitivity scenarios for switched shunt reactors.

g. Static Var Compensator (SVC)

SVCs are designed to compensate for voltage excursions from nominal values and may intend to mitigate TRV. Therefore, SVCs should be excluded from the model or switched off in order to provide the worst-case scenario.

h. Series Capacitors and Reactors

Series capacitors and reactors have a significant impact on TRV, and thus must be included in the model if they are installed within one bus of the substation under study. Modeling parameters should be based on the manufacturer's specifications or derived from a design document if the equipment has not yet been procured.

i. Bushings, Instrument Transformers, Circuit Breakers, Arresters and other Miscellaneous Devices

The stray capacitance for these miscellaneous devices shall be included.

Once the simulation model has been fully developed, it must be verified to ensure the expected short-circuit levels, power flow solution and the desired voltage levels at the studied breakers.

7.4. Study Methodology

The study is generally carried out in the following steps:

a. Define the study scenarios;
b. Create the study model and run the simulations;
c. Compare the recorded TRV and RRRV to the applicable standard test-duty TRV/RRRV capability;
d. Determine mitigation measures or recommendations.

7.5. Study Tools

It is unlikely to analyze TRV by formula manually. Time-domain computer simulation program, such as PSCAD or similar software (e.g., EMTP-ATP, EMTP-RV, or MATLAB), is the best choice for analyzing TRV.

7.6. Study Outputs

The voltage across the breaker terminals shall be recorded. The TRV peak and RRRV can be calculated from this voltage record. In addition, the fundamental frequency RMS current at the moment of interruption should be also recorded and used as the basis for the selection of applicable standard test-duty envelope.

7.7. Acceptance Criteria and Mitigation Measures

7.7.1. Acceptance Criteria

To ensure a successful breaking operation, the circuit breaker must be capable of withstanding the voltage imposed across the interrupter such that arc is extinguished successfully and prevented from re-igniting (re-strike). The ability of a breaker to achieve this is characterized by the TRV capability envelopes defined in the IEC 62271-100 [21] and IEEE C37.06 [22] standards, along with the following two parameters:

- The peak value of the TRV;
- The RRRV which is defined as the rate at which the voltage rises across the open contacts of the breaker just after the contacts separate.

The requirement of the successful operation of any breaker is as below:

- Voltage across the breaker must not cross the boundary of the applicable TRV capability envelope;
- The peak TRV and RRRV values must not exceed the applicable limit;
- Envelopes in between the standard envelopes may be interpolated depending on the breaking current observed. The interpolation is performed according to IEEE C37.011 [13].

7.7.2. Mitigation

TRV mitigation includes at least the following:

a. Use a circuit breaker with higher TRV capability (i.e., higher voltage and/or short circuit current rating);

b. Modify the circuit breaker's TRV performance.

Some SF_6 circuit breakers can be refined with different gas mixture and pressure to get a different TRV performance. But it may reduce the maximum current interrupting capability. It has also been used by manufactures to add grading capacitors across the circuit breaker to improve the TRV capability.

c. Modify the system to change its TRV characteristics.

One of the most practical method to change the system's TRV characteristics is to place shunt capacitors to the bus, or the line, or on one/both terminals of the circuit breaker, [13]. Often, this can bring the system TRV below the TRV rating of the circuit breaker.

As mentioned in Section 5.17, IEEE C62.22-2009, [4], surge arresters may be connected across the circuit breaker to provide an economical solution as a very direct means of controlling TRV amplitude so as to ensure the circuit breaker can withstand the TRV. Placing surge arresters as shunts onto both sides of the breaker can achieve same function of protection as well, but it requires more detailed studies to confirm.

If the issue emerged as a result of connecting a generator behind a Dyn load transformer with the Delta winding on the system side, the effectiveness of grounding can be improved by adding grounding sources to the system side, using zig-zag transformers, YGd transformers with Delta side floating. Assuming the generator needs to connect onto the Wye side, the Dyn transformer can be replaced with a 3-winding transformer in the format of YNynD. One of the reasons for such load sites to adopt a Delta winding on the system side is to block the harmonics. Therefore the study should show that changing to a 3-winding YNynD transformer does not lose that function. Leaving the old Dyn as-is and adding a new zig-zag or YGd transformer does not affect the harmonic blocking function on the Delta winding.

8. Study Example Cases for Effective Grounding, TOV and TRV

A series of cases were studied in this section to illustrate the impact of different grounding on TOV and TRV. All cases were studied using time-domain simulation software PSCAD/EMTDC. Considering the TOV studied here is temporary overvoltage in power frequency (i.e., 60 Hz), it is also possible to use phasor-domain simulation tools, such as PSS®E, given accurate sequence impedance being available for the well-established synchronous machine model. Therefore, the TOV associated with the synchronous generator was studied in both PSCAD and PSS®E in Section 8.1. For IBGs, the sequence impedance may not be always available or as meaningful as synchronous generators. Thus it is recommended to perform the study in time-domain simulation tools (such as PSCAD) using the time-domain model provided by the vendor.

The type of interconnection transformers is from those being discussed in Section 4.1.1 to 4.1.4. The simulation models of the example cases are included in Appendices 10.1 to 10.3.

Type of Interconnection Transformer	Symbol	Winding Configuration
Type 1	YGd	WYE-Grounded : DELTA
Type 2	YGygD	WYE-Grounded : WYE-Grounded : DELTA
Type 3	YGyg	WYE-Grounded : WYE-Grounded
Type 4	Dyg	DELTA : WYE-Grounded

During the GFOV study, an SLG fault is applied on the system side. Voltage is measured on the system side too, i.e. the HV side of the GSU. Measurement of line-to-ground voltage on a Delta winding follows the solution described in Section 6.3. Transformers are modeled with the cores unsaturated.

To illustrate the concept of TOV, the power system is not modeled, which means the DER is being disconnected from the substation. The TOV being revealed reflects the steady state in an islanding formed with the DER. This is close to the real situation when a feeder fault is cleared off by the breaker in the substation. If the DER is connected to the system, a ground fault usually does not produce so phenomenal overvoltage.

8.1. Synchronous Machines Modeled in both PSCAD and PSS®E

In this section, the TOV associated with synchronous machine under different grounding configuration were studied. The results (power frequency RMS value) from both PSCAD and PSS®E are shown in the Table below. The cases with schematics shown in Appendices 10.1 and 10.2 can facilitate some further investigation with real cases in the ongoing projects.

Type	System	Voltage, kV (Grid / Gen)	TOV (pu) - Single-Phase-to-Ground			TOV (pu) - Two-Phase-to-Ground		
			PSCAD	PSSE	Error (%) *	PSCAD	PSSE	Error (%) *
1	YGd	25 / 0.48	1.131	1.142	0.94	1.195	1.175	-1.64
2	YGygD	25 / 0.48	1.077	1.062	-1.40	1.097	1.094	-0.24
3.a	YGyg - with generator solidly grounded	25 / 0.48	1.131	1.145	1.22	1.200	1.178	-1.81
3.b	YGyg - with generator impedance grounded	25 / 0.48	1.658	1.717	3.54	1.459	1.479	1.36
4.a	Dyn 20 ohm	138 / 13.8	1.684	1.688	0.24	1.473	1.444	-1.99
4.b	Dyn 192 ohm	138 / 4.16	1.693	1.714	1.22	1.465	1.468	0.18
4.c	Dyg	25 / 0.48	1.701	1.722	1.23	1.468	1.482	0.97
4.d	Dyn 20-ohm w/ Gen on y side // YGyg - w/ tank effect	138 / 13.8 138 / 25	1.248	1.254	0.44	1.283	1.331	3.77
4.e	Dyn 20-ohm w/ Gen on y side // YGyg - w/o tank effect	138 / 13.8 138 / 25	1.654	1.728	4.45	1.466	1.575	7.45

*   Error (%) = (PSSE-PSCAD)/PSCAD*100

The comparison between Cases 4.a and 4.b can reveal the difference of NGR being j20 ohm or j192 ohm. Cases 4.d and 4.e are meant to demonstrate the effect of tank effect of a YGyg transformer. The symbol // means “in parallel with”. Case 4.d has a synchronous generator connected on the Wye side of a Dyn GSU. The GSU is connected in parallel with a YGyg transformer with the tank effect modeled. Case 4.e differs from 4.d only with the tank effect removed.

As shown in the above table, the results from PS®E matches reasonably well with the results from PSCAD simulation and it is acceptable to use PSS®E model to study the temporary overvoltage caused by different transformer connection types for synchronous generators (either DER or IPP). As shown in the above table, for most cases, results from PSS®E are slightly higher. From system integrity point of view, having a higher TOV may be better.

The results from PSCAD simulation are relatively smaller than PSS®E results because of the magnetizing branch of the transformers. The magnetizing branch of the transformer provides an additional grounding path, which impacts more with the increase of terminal voltage.

A comparison between Cases 3.a and 3.b shows that for Wye-Grounded : Wye-Grounded transformers, whether it can form an effective grounding system depends on whether the generator is solidly grounded or not. Even if the generator is solidly grounded, a YGyg transformer may be accepted as an effective grounding method, actual study and detailed modeling would still be required. In Hydro One’s TIR, [7], a pure topology screen and acceptance can be granted for such a configuration only if the DER is less than 1 MVA.

The previously discussed tank effect on the 2-winding 3-legged transformers is manifested in the comparison between Cases 4.d and 4.e where the DER is connected at the 13.8 kV side and then connected to 138 kV grid via a Dyn 20-ohm transformer’s Delta winding. The Wye side has a 20-ohm NGR. Having a load transformer YGyg, 138/25 kV, with tank effect, in parallel with the Dyn GSU, the Delta winding’s ungrounded behaviour had been mitigated via the zero-sequence current circulating capability of the paralleling YGyg load transformer. EFF is reduced to 1.331 and lower. Without modeling the YGyg transformer’s tank effect, in Case 4.e, EFF goes up to 1.728.

8.2. PV inverters Modeled in PSCAD

Summary of the simulation results is shown in the below table.

Cells highlighted in yellow color are failed ones, due to the <1.35 pu TOV check. Between the two tables (the below one and the Table in Section 8.1), since the only difference is on generators being synchronous machines or PV inverters, based on these PSCAD studies, a preliminary conclusion can be drawn up as PV inverters are more likely to fail to meet the effective grounding requirements. This can be attributed to the large negative-sequence and zero-sequence impedance of IBGs. The following can be observed from the comparison between the two tables:

a. Most highlighted values in the below table are higher than those in the table for synchronous machines;
b. The specific YGygD case (Case 2) does not meet effective grounding requirement in the below table, while Case 2 in the table for synchronous machines meets the requirement;
c. The specific YGyg case (Case 3.a) does not meet effective grounding requirement in the below table, while Case 3.a in the table for synchronous machines meets the requirement.

Type	System	Voltage, kV (Grid / Gen)	TOV (pu) Single-Phase-to-Ground	TOV (pu) Two-Phase-to-Ground
			PSCAD	PSCAD
1	YGd	25 / 0.48	1.183	1.284
2	YGygD	25 / 0.48	1.353	1.362
3.a	YGyg - with generator solidly grounded	25 / 0.48	1.774	1.710
3.b	YGyg - with generator impedance grounded	25 / 0.48	1.774	1.710
4.a	Dyn 20 ohm	138 / 13.8	2.117	1.773
4.b	Dyn 192 ohm	138 / 4.16	2.143	1.846
4.c	Dyg	25 / 0.48	2.295	1.815
4.d	Dyn 20-ohm w/ Gen on y side // YGyg - w/ tank effect	138 / 13.8 138 / 25	1.065	1.017
4.e	Dyn 20-ohm w/ Gen on y side // YGyg - w/o tank effect	138 / 13.8 138 / 25	1.963	1.680

8.3. Type-3 WTG Modeled in PSCAD

Summary of the simulation results is shown in the below table.

The Type-3 WTG model is one of the generics provided by PSCAD. There are some obvious discrepancies between SLG and 2LG (two-line-to-ground) faults. For example, in Case 4.c, TOV for a SLG fault is 3.907 pu, while for a 2LG fault, it is only 1.280 pu. This could be due to the issues in the generic model.

For both PV inverters and WTGs, the studies should use the manufacturer provided product specific, proprietary time-domain model.

After all, the modeling and the study engineers should always try to justify the model and the simulation results prior to taking action based on the study results.

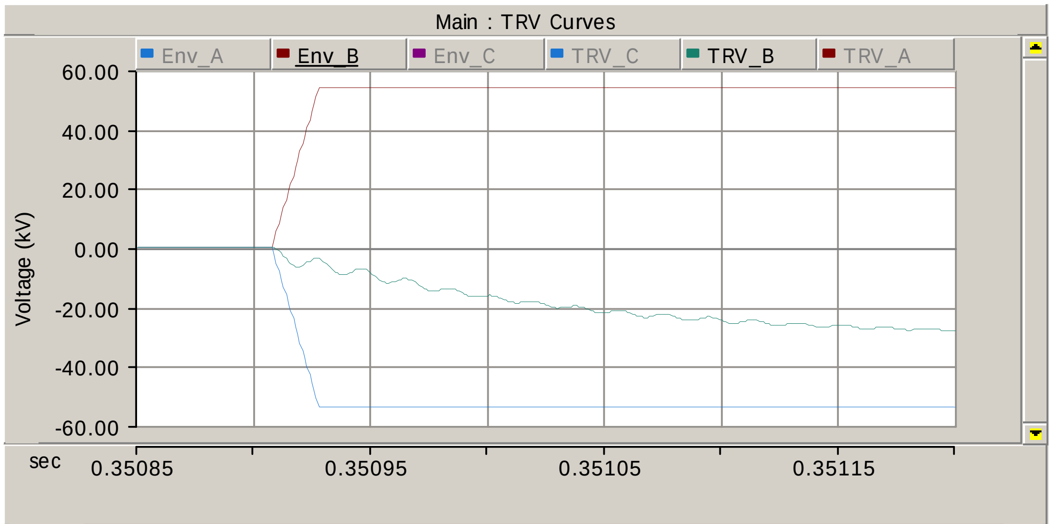
Type	System	Voltage, kV (Grid / Gen)	TOV (pu) Single-Phase-to-Ground	TOV (pu) Two-Phase-to-Ground
			PSCAD	PSCAD
1	YGd	25 / 0.48	1.211	0.888
2	YGygD	25 / 0.48	1.620	0.809
3.a	YGyg - with generator solidly grounded	25 / 0.48	1.550	0.808
3.b	YGyg - with generator impedance grounded	25 / 0.48	N/A	N/A
4.a	Dyn 20 ohm	138 / 13.8	2.765	1.171
4.b	Dyn 192 ohm	138 / 4.16	3.528	1.135
4.c	Dyg	25 / 0.48	3.907	1.280
4.d	Dyn 20-ohm w/ Gen on y side // YGyg - w/ tank effect	138 / 13.8 138 / 25	0.540	0.323
4.e	Dyn 20-ohm w/ Gen on y side // YGyg - w/o tank effect	138 / 13.8 138 / 25	1.626	0.505

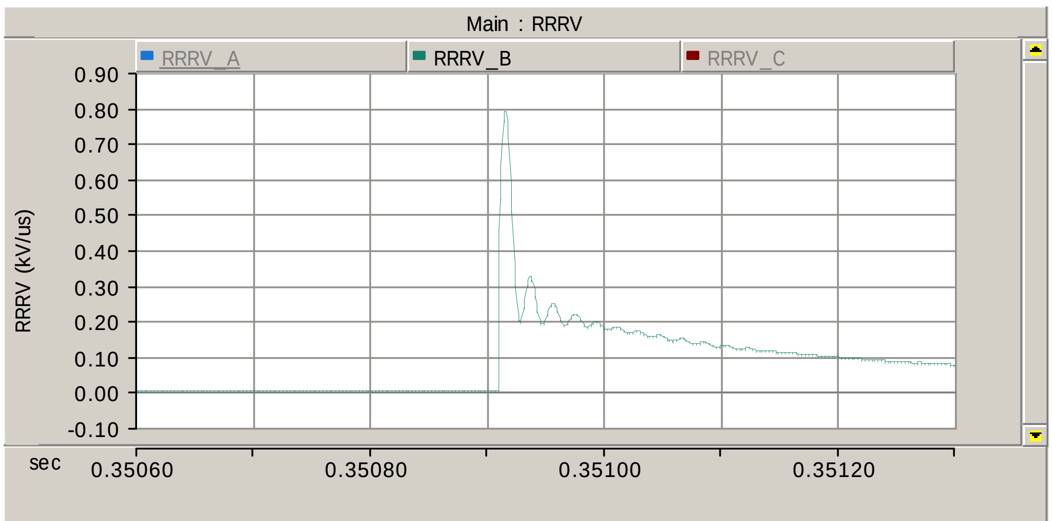
8.4. TRV Study in PSCAD

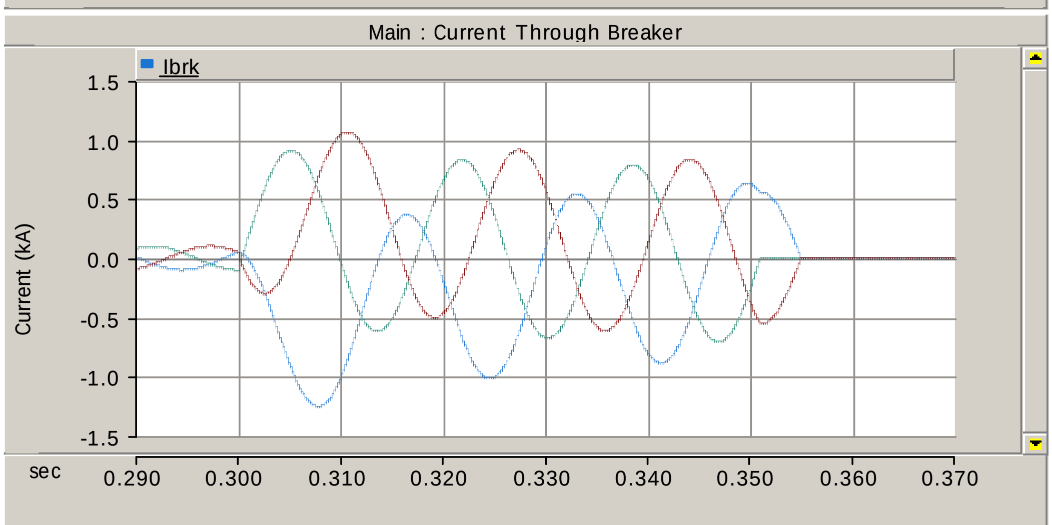
This subsection presents one TRV study example performed in PSCAD. Summary of the simulation results is shown in the below table.

Scenario	Interrupting current (rms, kA)	Interrupting current (%)	Applicable TRV envelope	TRV max (kV)	RRRV max (kV/us)	TRV limit (kV)	RRRV limit (kV/us)	Violations of TRV envelope
1	0.67	2.7	T10	30.4	0.79	56.9	3.16	No

A set of sample waveforms is plotted on the next page.







The PSCAD example case is shown in Appendix 10.3.

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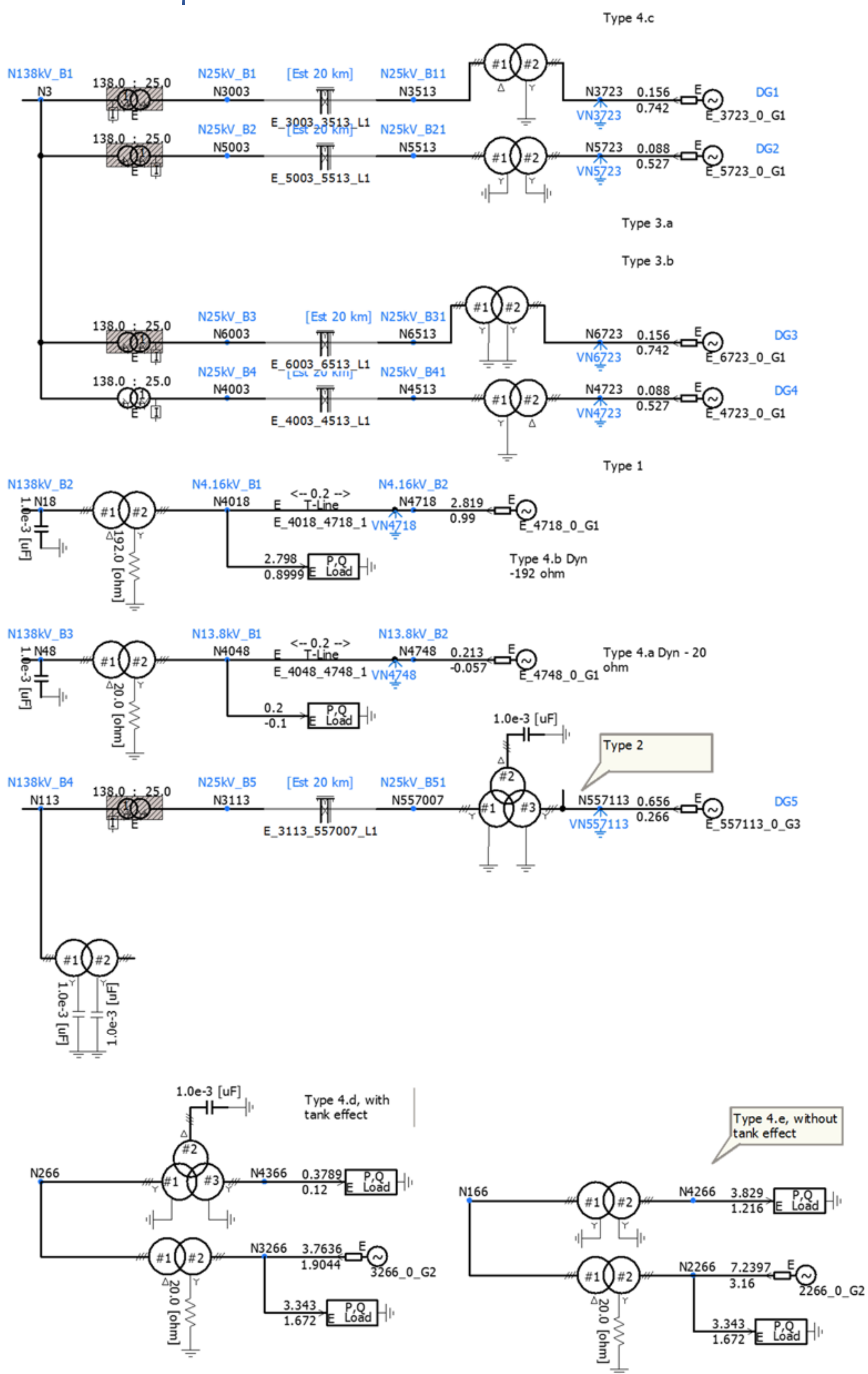
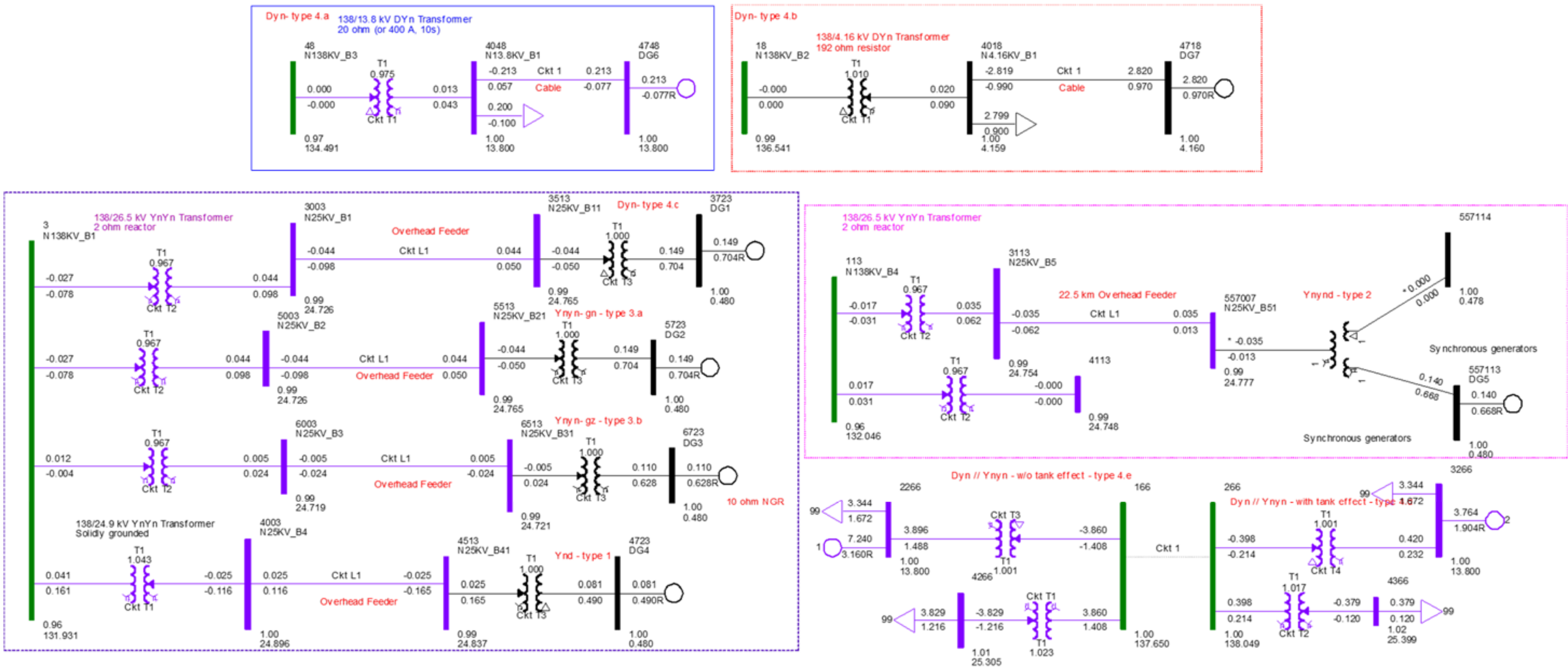
10. Appendices

10.1. PSCAD Example Cases for TOV



10.2. PSS®E Example Cases for TOV



10.3. PSCAD Example Case for TRV