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National Grid's Technical Review of Pterra Consulting's Report R149-16 "Assessment of Inverter-based Distributed Generation Induced Ground Fault Overvoltage on Delta-Wye Substation Transformers"

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I. Introduction

The addition of generation sources, such as distributed generators[1] ("DG"), to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, the substation transformer, effectively turning a station designed for load into a generation step-up transformer and as a source terminal to its transmission line supply. Good utility protection practice is to disconnect all source terminals of the line for any fault on the line for the safety and reliability of the electric power system ("EPS"). Protection of a transmission side ground fault overvoltage on power transformer equipment from any source on the secondary side will, depending on the protection schemes in place at any substation, require ground fault (or zero sequence) overvoltage ("$3V_0$") protection equipment.

Lightning (or surge) arresters are applied for short duration surges such as lightning and switching transients designed to protect equipment based on its value, impulse insulation level, and expected discharge currents the arrester must withstand. A ground fault overvoltage can remain longer than the conditions intended for surge arrester design and application, which places equipment, line workers, and the general public at risk.

Resulting from an action item in National Grid's second NY DG Optimization Workshops on November 18, 2016 at its Albany, NY offices, NYS Department of Public Service ("DPS") provided Pterra Consulting's Report R149-16 "Assessment of Inverter-based Distributed Generation Induced Ground Fault Overvoltage on Delta-Wye Substation Transformers" on Jan. 4th, 2017 to National Grid for review. This document submits National Grid's technical response to Pterra's methodology, assumptions, and conclusions.

II. Where there is agreement

National Grid finds some areas of agreement with Pterra's report.

A delta connection on the transmission side and wye-grounded connection on the distribution side cannot contribute zero sequence ground fault current during single line to ground faults on a transmission line, resulting in the voltage on the unfaulted phases to rise significantly and rapidly. These overvoltages have the potential to exceed insulation levels of the substation and transmission line equipment, and maximum continuous operating voltage of surge arresters. It is agreed that ground fault overvoltage ("GFOV") and unseen ground faults on transmission systems are of concern and require mitigation.

It is agreed that ANSI C62.92 defines effective grounding at approximately 138% overvoltage maximum. National Grid's protection practice designs for 125% maximum overvoltage and is recognized good engineering practice by the electrical power industry. The margin of protection is based on the

[1] *DG (distributed generation) and DER (distributed energy resource) are used in synonymous meaning in this report.*

protection practices used by National Grid for the X_0/X_1 and R_0/R_1 calculations that provide 125% for effective grounding cases. Pterra's result for a generation:load ratio of 1:1 producing an approximate full 173% overvoltage, as reported in Table 3-1 on page 10 of their report, is consistent with National Grid's expectations of the large zero sequence voltage.

In Pterra's second bulleted item on page 19 of their report, they describe the GFOV is partially mitigated if the generation:load ratio is lower than 1:1, i.e. if the island formed by the source breaker that opens to clear the single-line to ground fault has less inverter-based generation than load. It is agreed that this is consistent with expectations because GFOV and load-rejection overvoltage ("LROV") occur simultaneously, and LROV can actually lead to an undervoltage in islands that have less generation sources. Where there is a sufficiently low generation:load ratio, the reduction in positive sequence voltage caused by the LROV will offset the increase in zero sequence voltage caused by the GFOV. The result is that GFOV mitigation is arguably not needed in situations where the generation:load ratio will always be below some threshold value.

Where there is a sufficient reduction in the positive sequence voltage magnitude, the LROV and GFOV will cancel out in the sense that the unfaulted phase voltage magnitudes will not rise. LROV is not truly linear with generation:load ratio. However, if a "small signal" linear approximation is used as a reasonable first-order starting point, a generation:load ratio of 58%, should lead to complete GFOV cancellation such that the voltage rise on the unfaulted phases is zero. This is with expectation that National Grid's present 67% planning criteria threshold would allow an overvoltage of just under 120%, which is below the value of 138% given in IEEE C62.92 and within National Grid's 125% maximum overvoltage protection margin for 15kV class effectively grounded distribution systems. Also, the 138% maximum overvoltage criteria is applied by National Grid for transmission and subtransmission systems since typically there is no grounded conductor (i.e. neutral) and connections are made delta ungrounded to serve loads, making the EPS 'uni-grounded' rather than 'effectively grounded'.[2] Pterra's simulation results suggest near-perfect cancellation of GFOV at a generation:load ratio of 65% that actually supports the 67% National Grid planning criteria threshold value where GFOV mitigation is not required.

Although Pterra's report presented in the middle of page 13 does not provide the specific formula for quality factor, it was derived and found to be correct.

III. Where there are concerns

National Grid notes some areas of concern with Pterra's methodology, assumptions, and conclusions in their report.

A. On the methodology:

1. Pterra's report is lacking in procedural details. Although National Grid acknowledges that in some cases the authors are constrained by nondisclosure obligations, the following items should be addressed in more detail.
    a. The absolute power levels tested are not given. Generation:load ratios are provided, but not the PV plant AC output ratings.
    b. The inverter models, the PV plant model, and the arrester models are not described. Whether a switching or averaged inverter model is used, whether the inverter AC filters are explicitly represented according to the manufacturers' schematics, whether large PV plants were represented by scaling or by individual inverter models, the impedances of the PV plant transformer, whether transformer R-L loading was included in the generation:load ratio, and the curve representations for the arresters are all important for results interpretation. It would also be best to clarify the number of sets of arresters simulated (we assume there is only one).

[2] *http://www.arresterworks.com/arresterfacts/pdf_files/selecting_arrester.pdf*

2. The report does not include any discussion of the results. This is especially important in the interpretation of the first bullet in section 4.1, "Conclusions", on page 19 of the report, where it is stated that some inverters are capable of detecting a single line to ground fault condition and trip almost instantaneously. The fastest-tripping inverter trips reliably within eight cycles of fault initiation and within three cycles of island formation, and if the anti-islanding is turned off, it is not clear what inverter trip mechanism might be at work here. Without any discussion, it is not possible to base any broader conclusions or policy decisions on the notion that some inverters trip quickly upon fault or island formation.
    a. It is also important to bear in mind that when low-voltage ride-through ("LVRT") and low frequency ride-through ("LFRT") requirements are imposed, they are likely to force a modification of the behavior of the very fast-tripping inverters.
    b. An inverter that trips immediately upon formation of a single-phase fault is probably in violation of most LVRT requirements, and manufacturers will be adjusting their controls and relaying in the future to ensure LVRT compliance. This means that those inverters that did trip instantaneously on single line to ground fault formation in the testing reported here will likely not do so in the future.
3. It would be valuable to include a set of simulations in which the DER is a synchronous generator instead of an inverter. It is not completely clear how much difference this change would make, but it is suspected that the conclusion that no GFOV mitigation is required if the generation:load ratio is below 67% may be impacted by this change because the LROV mechanism is very different for synchronous generators than for inverters, and thus the magnitude of the partial cancellation effect may be different.
4. National Grid has some comments on Pterra's decision to turn off the anti-islanding in the inverters in their study.
    a. It is understood that the exclusion of anti-islanding is intended to be a conservative approach to analyze the DG facility's protection coordinating with the EPS, but given the fact that anti-islanding will alter inverter current phase shifts, the assumption that neglecting anti-islanding should be demonstrated.
    b. There is likely value in seeing the results both with and without the inverter islanding detection enabled for worst case protection coordination with the EPS; however, note that in IEEE 1547 revision working group meetings, it is cautioned against using islanding functions for detecting faults causing the DG to be unable to see faults on the EPS.
5. It is evident that in effect there was no multiple-inverter test in this report, because in the only multi-inverter tests run one of the two inverter types tripped immediately after fault formation.
6. In question is the use of a wye-grounded:wye-grounded transformer at the PV plant in the report.
    a. For this particular study the impact may be negligible, but there is an impact of the transformer configuration on both the steady state and transient magnitudes of the inverter terminal voltages, and many commonly-available commercial PV inverters require an ungrounded winding on the side facing the PV inverters.
    b. If this effect is neglected, it is suggested Pterra's report should include at least an example case demonstrating that the effect is suitably small.
7. It is important to report the surge arrester energy dissipation vs. time in those simulations where the arresters are included.
    a. When dealing with inverter-based sources, the use of time-voltage capability curves does not always accurately predict whether a surge arrester will "blow".
    b. During an overvoltage event, as the peak of a current cycle is approached and the voltage approaches the knee point on the arrester I-V curve, the arrester will begin presenting a nonlinear load to the system that will start shunting off the current.
    c. The surge arresters thus cause the generation:load ratio to vary nonlinearly over the course of a line cycle. The arresters do limit the voltage, but they never reach a fully-on, low-impedance condition.

   d. It is important to see the energy dissipation in this case.

8. Pterra's report needs to consider a generator plant, delta connected with a $3V_0$ scheme, on the same transmission line as the subject load substation. This would need to be included as many lines have other generators connected to them. To this end, National Grid frequently allows DG to connect to the transmission system directly and in those cases, they are required to have their own $3V_0$ (device function 59N) scheme. These are expected to trip off for ground faults on the supply side and National Grid evaluates the DG facility and its load accordingly in the transmission or subtransmission analysis since it becomes disconnected.

B. On the assumptions:

1. The report should identify what functions in the inverter can detect single line to ground faults on the delta side of a transformer.
2. The report needs to consider:
   a. Other untested inverters and rotating machine generators as if they would produce the same overvoltage as the studied scenarios in the report. "In the absence of rotating generators" is not a likely scenario on many National Grid distribution substations.
   b. Close-in faults as well as faults further down the transmission line.
   c. Load further away from the substation and not just at the substation high side.
3. Adequate engineering margin is necessary for good utility practice such as the 67% planning criteria established by National Grid as corroborated by Pterra's findings.
4. The voltages in per unit of the MCOV need explanation in the report. Equations for obtaining these per unit voltages should be included or referenced.
   a. 1.73pu on a $34.5kV_{LL}$ circuit is 34.5kV seen on the L-N connected arresters. A 22kV arrester is subject to 34.5kV, which is 1.57pu on the arrester base (1.57pu of 22kV MCOV).
   b. A 22kV arrester cannot withstand 1.57pu voltage (on its MCOV base) for seconds.
   c. Line arresters, according to National Grid's distribution standard, for 34.5kV would be 22kV MCOV.
   d. National Grid generally considers a system to be effectively grounded with $X_0/X_1<3$ and $R_0/R_1<1$ for 125% maximum GFOV.
   e. Note: Given that the DG is generally located on the Y side of National Grid's substation delta-grounded wye power transformer, the DG provides positive sequence current only to transmission side single line to ground faults (prior to the transmission source terminals tripping) and so tend to "push" the transmission system away from being effectively grounded under normal conditions.
5. The sources for surge arrester damage curves need to be stated.
6. Regarding Figure 3-1 on page 13, the definitions of EVP, MH4, PH4, Ur, Uc, and all acronyms are needed. Also, the stated source for the plot is needed.
7. In Table 3-3, the scenarios 24 through 28 are intended to study the impact of multiple inverter-types connected to the same feeder and modeling of high quality load factors. This is the right approach, although the multiple inverter types have to include different manufacturers to eliminate the concern of unusual interaction between algorithms. Any analysis will require obtaining each of the manufacturer's algorithms.
8. Pterra's report should consider that with the IEEE1547 revision coming soon that inverters will need to comply with voltage regulation and voltage/frequency ride through requirements. Then evaluate what would change if it did.

C. On the conclusions:

1. Regarding Pterra's recommendation to consider all connected loads to the transmission or sub-transmission supply side of substation power transformers into the planning criteria threshold for inclusion in calculations:

   a. Including DG adds another source terminal to the transmission line. Relying on the load (which may or may not be present) on the transmission side of a close in ground fault to the substation to force the DG offline on undervoltage would not be good utility practice to disconnect all terminals of the line for a fault on the line.
   b. Transmission loads may be switched into different configurations, and relying on transmission load will limit National Grid's switching capability.
   c. The level of risk at the transmission level is higher than on distribution systems where the most likely worst case contingency is having the heaviest loaded feeder disconnected from the power transformer.
   d. The transmission system is considered when a substation experiences reverse power flow, because the backfeed amongst the transformers on the line can potentially backfeed further up into the system (i.e. having multiple 'load' substations moving up the hierarchy in the system).
2. Findings in Pterra's report may need to be edited, as they appear to rely on data in section 3.2 related to surge arresters and the voltages they are subject to during ground faults based on National Grid's surge protection criteria discussed above.
   a. Pterra's conclusion should account for when the EPS is operating at 95% or 105% nominal voltage as permitted by ANSI C84.1 in the analysis of temporary overvoltages (TOV).
   b. The 15-second maximum run time for the fault when the smaller arresters are used is a very long run on time for a fault. Placing utility equipment, arresters, and the general public at risk for this period of time is unacceptable.
3. On page 2 in the second bullet under Findings, it should read 'no overvoltage >138% is observed' rather than 'no overvoltage is observed'.
4. The complexity and expense of adding grounding transformers would be higher than $3V_0$ protection in transmission substations.

IV. Where there is disagreement

National Grid respectfully disagrees with Pterra's report in the following areas.

National Grid must use the 'worst case' scenario on Page 14 due to the lack of information provided by the inverter industry for fault response and means of fault detection. The utility must understand what the functions in the inverter are that can detect single line to ground faults on the delta side of a transformer and without the inverter characteristic model, the utility is without confidence in the inverter's proper protection of the EPS. If the device is physically capable of producing the overvoltage, it must be planned and have the ability to trip. The control systems in the device may fail. Overall, the full understanding is needed of an inverter's limitations of a proposed protection method due to contingencies, changes in equipment, etc. Good utility practice is to assume as close to worst case as reasonable for fault protection. Note that the worst case is expected when none of the inverters can detect the fault and subsequent islanding condition. Such a case is essentially similar to have an island composed of a single type of inverter with ineffective protection scheme.

Transmission loads are unnecessary to include in the utility planning criteria threshold. This is due to the fact that adding DG adds another source terminal to the transmission line. Good utility protection practice is to disconnect all terminals of the line for a fault on the line. Relying on the load (which may or may not be present) on transmission system to force the DG offline on undervoltage is not good utility protection practice. Also, transmission loads may be switched into different configurations at any time and relying on the transmission loads will limit the utility's switching capability. On transmission circuits the risk level is greater than on distribution feeders (where the most likely worst case contingency is having the heaviest loaded feeder disconnected from the transformer). Only the transformers sourcing (whether backfeeding by generation or by paralleled circuits) will need $3V_0$ protection because once they are tripped off the condition is mitigated. National Grid does consider the transmission system when a substation could backfeed by evaluating other source terminal conditions and protection control schemes in place before determining the final need for $3V_0$ protection for safety and reliability of the EPS and to the public.

The report states that up to 100% generation:load ratio can be tolerated if the action of surge arresters is accounted in the analysis. This conclusion appears to be based on Scenarios 18 and 22 in Table 2 on page 12 of the report. However, the 1.38 pu limit applies to the "PU" column and not the "PU of MCOV" column in Table 2, and thus both Scenarios 18 and 22 actually violate the 1.38 pu limit. In fact, the only scenarios that do not violate the limit are the 65% generation:load cases. Therefore, National Grid respectfully disagrees that the results indicate generation:load ratios of 100% are permissible where lightning (surge) arresters are installed that in fact surge arresters are necessary to protect the equipment for lightning and switching surges being very short in duration regardless of $3V_0$ protection installed or not.

National Grid reviewed the negative sequence voltage protection concept on the distribution side (voltage or current) as a proposed alternative to ground fault overvoltage (GFOV or $3V_0$) protection. The complexities with this alternative results in potential nuisance tripping and the inability to see and trip for ground faults on the transmission EPS and renders it unacceptable. Consider that National Grid transmission systems are designed to:

- Have a single point ground at generation source substations,
- Distribution substations typically have a delta high-side transformer connection,
- Have Line-to-Line or delta connected loads,
- Have surge arresters to protect utility equipment from damaging overvoltage conditions such as lightning and switching surges, and
- Be effectively grounded, where overvoltages would be $\leq$138%, and more typically $\leq$125% overvoltage, during ground faults.

Based on these considerations above, the only ground connection that can be relied on by the utility is the ground source at the remote station owned by National Grid. However, this ground connection is disconnected when the remote end trips for the ground fault. This leaves the remaining system ungrounded when DG is energizing the delta high-side transformer in the distribution station. Due to the system being designed for effective grounding, it is important to use relaying protection to avoid submitting the transmission surge arresters to overvoltages higher than they were installed to protect for in a steady state voltage condition during ground faults. The arresters can fail catastrophically in this condition, and therefore this operation needs to be avoided for the safety of personnel and equipment in the substation. Negative sequence relaying would rely on the surge arresters conducting, which would not be acceptable due to the coordination time constraints involved in avoiding surge arrester damage. See Appendix A for an illustration of the sequence diagrams in this case.

National Grid recognizes adding a grounding transformer on the transmission side may be a possible option; however, it would result in the need to re-design the protection system of the entire line and possibly many substations in the vicinity due to the effect on ground relaying. This raises complexities to operating systems with nonstandard designs and at higher expense. National Grid offers the $3V_0$ protection as a best practice solution.

Pterra's report makes a statement on page 3 that the use of a ground switch on a distribution feeder is a possible countermeasure to $3V_0$. As stated in the Nov. 18th, 2016 workshop, National Grid prohibits ground switches due to reliability and safety of the EPS and utility workers and general public. Where National Grid has had ground switches in the system from legacy installations, they have since been removed.

V. Conclusions and Recommendations

It is National Grid's technical opinion that the present planning criteria is supported by Pterra's findings. At this time for determining the need for $3V_0$, National Grid will continue with its 67% ratio of *maximum* generation of a distribution feeder to the *minimum* load assuming an N-1 contingency (one feeder with largest net load[3] being open on the same bus) at the substation. Minimum load calculations that consider solar PV DG systems not occurring in the same period as minimum EPS daytime load[4] is under further review for daytime loading period in the Northeastern US and if existing inverter-based DER can be removed from the calculations.

In order to detect ground fault overvoltage conditions, $3V_0$ protection on the primary side of the transformer is required and becomes part of system modifications attributed to the impact of a generator connection on the distribution system. This $3V_0$ protection will disconnect the generation from the substation transformer and stop the generation and the transformer from contributing to the transmission-side overvoltage condition. Since typical distribution systems will have multiple inverters with different manufacturers and various protective device algorithms resulting in conflicting protective coordination and operation between them, inverter manufacturers must provide accepted short circuit models or one that is universally accepted by the inverter industry that can be applied using commercially available short circuit software programs (*e.g.*, ASPEN, CAPE, and CYME). Without this critical information for utility analyses, utilities need to make assumptions and the $3V_0$ scheme along with the current review process is the best utility practice for detecting ground faults on an ungrounded system. Inverter manufacturers need to work with utilities to demonstrate their protection mechanisms in a transparent manner and influence the IEEE1547 standard and UL1741 testing standard to include tests that will fulfill the needs of utilities for information to rely on for protection of utility equipment and the EPS.

National Grid implements standard equipment and installation methods in its substations for $3V_0$ protection equipment as good utility practice. Substations evaluated for this equipment as impacted by DG are based on the standard and if site specific restrictions are encountered to install 115kV capacitive coupling voltage transformer ("CCVT") for example, other alternative means as available are considered. Ability to construct considering space, outage management, mobile transformer scheduling, etc. is assessed in the decision-making process included in National Grid's DG impact study results.

National Grid will continue collaboration with Pterra and others proposing alternatives to GFOV requirements working within the system protection operating criteria of all of National Grid's systems. Developing standard models by the inverter manufacturer industry for use on various standard short circuit analytic software, e.g., ASPEN, CAPE, and CYME, would likely reduce the number of assumptions that are presently needed to analyze inverter GFOV impacts.

[3] *Net Load = Feeder Min Load – Feeder DG*.

[4] *Daytime light load and the absolute light load are determined by National Grid, which daytime is presently defined between 8AM and 8PM*.

Appendix 1: National Grid Illustration of Negative Sequence Voltage Review for GFOV

The sequence diagrams for a transmission ground fault are shown as follows.