Generation Line-Tap Connection Impact on Transmission Ground Fault Protection

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***Abstract*—Transmission interconnection requests for solar-based electricity generation systems in the US have been steadily rising. Among these requests, for small, solar generation systems that are near existing transmission lines, but are far away from existing distribution network infrastructure, interconnecting to these lines via a line-tap is a normal practice. Furthermore, in the US, there are several challenges associated with connecting generation systems via a line-tap that impact their existing interconnecting transmission system's protection system. This paper presents an example, practical case study based on a US solar generation system that interconnects to an existing transmission line via a line-tap. Challenges associated with such a connection, affecting the interconnecting transmission system's protection system, lessons learned, and potential solutions to address those challenges are discussed in detail.**

***Index Terms*--Power system planning, power system protection, power transmission, renewable energy sources.**

I. INTRODUCTION

Transmission interconnection requests for solar-based electricity generation systems in the US have been steadily rising [1]. Among these requests, for small, solar generation systems that are near existing transmission lines, but are far away from existing distribution network infrastructure, interconnecting to these lines via a line-tap is a normal practice.

In the US, as discussed below, there are several challenges associated with connecting generation systems via a line-tap that can impact the protection system of an existing interconnecting transmission system.

For safety, generation systems, which are a source of short-circuit currents, when operated in parallel with their respective interconnecting host utility's transmission electricity systems, are expected to trip under sustained fault conditions [2].

In the US, for unbalanced faults involving ground in the interconnecting transmission system, protection requirements for these generation sites, including for full-converter (Type-4) based Inverter-based-Resources (IBRs), to trip are generally based on detecting site's zero-sequence currents [3]. These site zero-sequence currents are sourced from the site's Main Power step-up Transformer (MPT), which has its transmission-voltage, Y-side solidly grounded.

Unlike Type-3 IBRs, such as doubly-fed induction generators, which produce sufficient negative-sequence currents during faults, the requirements for negative-sequence short-circuit currents from Type-4 IBRs in the US are not consistent [3]. Furthermore, unlike in Germany [4], the requirement for negative-sequence currents from IBRs is also not standardized in the US and such requirement is also not mandated or applied across all US Independent System Operators (ISOs) [3]. To address these aspects, the recent IEEE Std. 2800-2022 [5] established a set of uniform technical minimum requirements (including the requirement of IBRs' negative-sequence short-circuit current contributions) for the interconnection, capability, and lifetime performance of IBRs interconnecting with transmission and sub-transmission systems. However, this IEEE standard is yet to be widely adopted and applied by the US ISOs.

In weak transmission grids, interconnection of generation systems (with their MPTs' transmission voltage, Y-sides solidly grounded) onto existing transmission lines via line-taps lead to several protection challenges: for example, they may reduce line-end zero-sequence current contribution, leading to reduced ground overcurrent relays' sensitivity to detect unbalance faults on those lines; change transmission line apparent impedances that ground distance relays, located at either end of that line, would see, leading to relay zone overreach issues; etc. Under these circumstances, the US transmission system owners may stipulate a switching station with a three-breaker ring interconnection (instead of a line-tap) and pass related costs to the generation developer. For most small generation systems that require interconnecting to nearby transmission lines, three-breaker ring connections are generally cost prohibitive, making such generation systems, therefore, infeasible.

Sections below present as follows: a) an example, practical case study based on a US solar generation system that interconnects to an existing transmission line via a line-tap; b) challenges associated with such a connection, affecting the interconnecting transmission system's protection system; c) lessons learned; and d) potential solutions to address those challenges.

II. TRANSMISSION-CONNECTED SOLAR FARM

A simplified Single-Line Diagram (SLD) of the solar Photovoltaic (PV) generation system and its interconnecting transmission system is shown in Figure 1. The 115 kV overhead circuit between stations A and B, Line-AB, is expected to be tapped at point LT-2 for connection to the proposed solar PV generation site (the project). Line-AB is 82.7 km long; LT-2 will be situated approximately 16 km from Station-A.

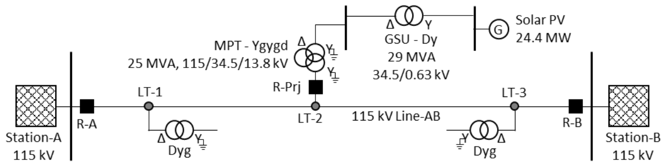


Figure 1. Simplified study transmission and solar PV system SLD

Along Line-AB, two other line taps, LT-1 and LT-3, are present. These connect to 115/34.5 kV Dyn1 transformers, supplying downstream distribution systems. By virtue of its location in the surrounding transmission system, Station-A is a weak source of zero-sequence fault current, while Station-B is a strong source.

Two relays (R-A and R-B) at the ends of the Line-AB protect the circuit and other tapped interconnections on the same line. Upon activation of a trip in these relays, a Direct Transfer Trip (DTT) signal from these relays is expected to be sent to the solar PV site and trip the site (note that the DTT scheme is the site's primary protection). Line-AB shares its right-of-way with other circuits. Thus, zero-sequence mutual coupling can impact the operation of ground fault protection.

The project is approximately 24 MW solar PV farm, comprising 116 210 kVA, 630 V solar PV inverters: 100 inverters, stepped-up via their 5 Dy5 transformers, rated 5 MVA, 34.5/0.63 kV; and 16 inverters, stepped-up via their single Dy5 transformer, rated 4 MVA, 34.5/0.63 kV. The 34.5 kV side of these transformers is connected to the solar farm's 34.5 kV collector busbar via a 34.5 kV cable network. The 34.5 kV collector is stepped-up to 115 kV via a three-winding YNynd MPT, rated 25 MVA, 115/34.5/13.8 kV. The 115 kV side of the MPT, via the project's 115-kV circuit breaker (controlled by its relay, R-prj), is connected to the Line-AB, via LT-2, via a short (approximately 200 ft) overhead line. The project MPT's 115 kV side Voltage Transformer (VT) and Current Transformer (CT) ratios are 1000:1 and 100:5, respectively. The solar inverters, including during fault conditions, are not a continuous source of significant negative-sequence currents.

For studies presented here, the ISO's ASPEN short-circuit models, referred to here as Base Case (BC) models, for the transmission system, to which the project is expected to interconnect, were used. These base case models, which were for the years 2019, 2022, and 2027, account for planned changes in the ISO's network for system operation and planning purposes.

The solar generation at the project's collector busbar was modeled using an aggregate representation, comprising of a single generator (with a maximum short-circuit current contribution of approximately 110% of the nominal current value), a single 34.5/0.63 kV step-up transformer, and a single 34.5 kV collector cable, as shown in Figure 1. The remainder of the project's equipment (i.e., the MPT and the interconnecting 115 kV overhead line connecting the MPT to the Line-AB at LT-2) were modeled in detail.

A. Solar Farm Interconnection Challenges

During the project's System Impact Study (SIS), which utilized the ISO's 2019 base case model, it was observed that, for Single Line to Ground (SLG) faults at Station-B, a connection of the project at LT-2 on the Line-AB leads to a significant reduction in the available zero-sequence short-circuit current contribution from the Station-A, diminishing the ability of the Station-A's protection relays to reliably detect ground faults. It was understood, from a conversation with the utility, that for the ground overcurrent function in the Station-A's relay to operate properly, for a SLG fault at Station-B, a minimum zero-sequence short-circuit current of 160 A, which is twice the pickup value of 80 A setting in that relay, from Station-A, was required.

Furthermore, interconnection of the project to the ISO's system, particularly, with the MPT's 115 kV Y-side solidly grounded, is also expected to provide current infeed to the interconnected transmission line, affecting the apparent impedance of the ground distance protection relays, located at the Station-A and Station-B, respectively, would see.

III. Study Methodology

For the studies detailed here, only classical, bolted faults, with zero or negligible short-circuit impedance between the short-circuit point and the ground, were considered. Unless otherwise mentioned in the paper, these faults were all with the network pre-fault voltages assumed flat at 1 p.u.

Initially, a review of the ISO's 2019, 2022, and 2027 base cases, comparing the short-circuit levels near the project areas, was conducted. Following this, for the ISO's 2019, 2022, and 2027 base cases, potential Station-A short-circuits contributions, for an SLG fault (Phase-A to ground) at Station-B for pre-project and post-project connected cases were simulated. Among these, for the post-project connected cases, the impact of impedance grounding on the MPT 115 kV Y-side for various Neutral Ground Reactor (NGR) sizes (in p.u., on the MPT's MVA-base, 15 MVA) was evaluated.

Furthermore, to assess the impact on the Line-AB apparent impedances that a ground distance relay, located at Station-A, would see, for a SLG fault at Station-B, the Station-A's apparent impedances, based on the Station-A voltage and Line-AB current measurements at the Station-A, were calculated:

- $Z_A = V_A / [I_A + 3 \cdot k_0 \cdot I_0]$, where Z_A is the Phase-A impedance in Ω, VA is the Station-A's Phase-A line-to-ground voltage in kV, k_0 is the zero-sequence current compensation factor, and I_A and I_0 are the Phase-A and zero-sequence current contributions, in kA, through the Line-AB measured at the Station-A. Impedances, Z_B and Z_C, for the same SLG fault on Phase-A at Station-B were calculated as follows: $Z_B = V_B / [I_B + 3 \cdot k_0 \cdot I_0]$ and $Z_C = V_C / [I_C + 3 \cdot k_0 \cdot I_0]$.
- $k_0 = [Z_0 - Z_1] / [3 \cdot Z_1]$, where Z_0 and Z_1 are the zero-sequence and positive-sequence impedances of the 115 kV path between Station-A and Station-B.
- Impedances, Z_A, Z_B, and Z_C, that the R-A ground distance relay, at Station-A, would see for a SLG fault at

Station-B was calculated for various project connection and MPT 115 kV Y-side grounding scenarios and were then compared and analyzed in detail.

Similar apparent impedance calculations were made for the ground distance relay at Station-B (with SLG faults applied at Station-A).

The project's solar inverters, during fault conditions, are not a continuous source of significant negative-sequence currents. However, if they were a continuous source of significant negative-sequence short-circuit currents, with the setup as follows, the impact of such short-circuit current contributions was studied for all ISO base cases for various but equal slopes (k) of positive- and negative-sequence dynamic reactive currents, ranging k={2,6}: a) the inverter contributes a maximum short-circuit current of 1.1 p.u. of the inverter's nominal current value for inverter terminal voltages, ranging 0-1 p.u.; b) the inverter shuts down when the inverter's terminal phase-voltage exceeds 0.0-1.1 p.u. range; and c) MPT's 115 kV Y-side is solidly grounded. For these studies, for each k value (which is the slope of the solar inverters' both positive- and negative-sequence dynamic reactive currents), the site MPT's 115 kV positive- and negative-sequence short-circuit currents, for Phase-A SLG faults at Station-B, were simulated, using the pre-fault network voltages calculated from a linear solution. Obtained results were then analyzed.

IV. Results and Discussion

Principal results from the performed studies, per the methodology detailed in the previous section, are discussed below.

A. *Review of ISO Base Cases' Short-Circuit Levels*

A short-circuit analysis of the ISO's 2019, 2022 and 2027 bases cases was performed. Two scenarios, pre-project (before project connection) and post-project (with the project connected to the model), were considered. Bolted three-phase-to-ground (3LG), two-phase-to-ground (2LG) and SLG faults were applied at nine principal nodes in the vicinity of the project location. Results from these studies are summarized in Table I.

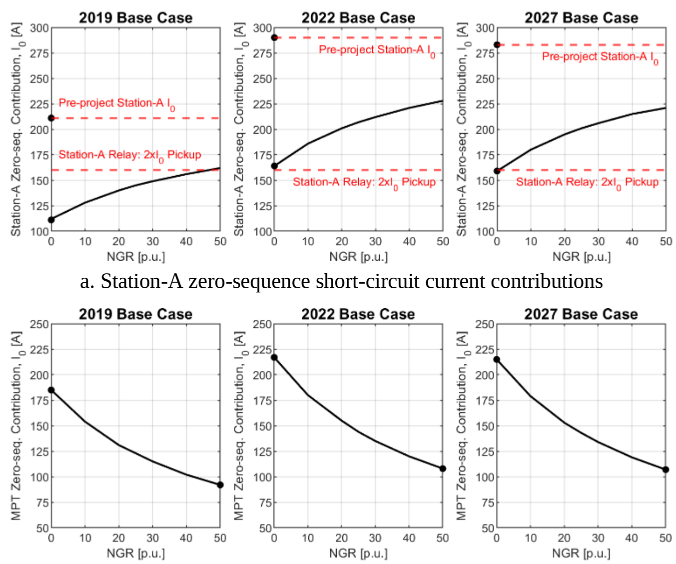
TABLE I. Short-Circuit Levels (SCLs) Between ISO Base Cases

ISO Base Case	ISO's Nodes	Pre-project SC Levels			Post-project SC Levels		
		3LG	2LG	1LG	3LG	2LG	1LG
2022 BC SCL increase against the 2019 BC	Node 1	18%	18%	6%	18%	16%	8%
	Node 2	6%	9%	21%	6%	9%	20%
	Node 3	5%	8%	21%	5%	8%	20%
	Node 4	5%	8%	21%	5%	8%	20%
	Node 5	6%	9%	21%	6%	9%	20%
	Node 6	6%	9%	21%	6%	8%	20%
	Node 7	-5%	-4%	-4%	-5%	-4%	-4%
	Node 8	8%	6%	6%	7%	6%	6%
	Node 9	7%	6%	6%	7%	6%	6%
2027 BC SCL increase against the 2019 BC	Node 1	9%	9%	3%	9%	8%	4%
	Node 2	8%	11%	24%	8%	11%	24%
	Node 3	8%	11%	24%	8%	11%	24%
	Node 4	8%	11%	24%	8%	11%	24%
	Node 5	8%	11%	24%	8%	11%	24%
	Node 6	8%	11%	24%	8%	11%	24%
	Node 7	-5%	-4%	-4%	-5%	-4%	-4%
	Node 8	27%	23%	22%	27%	22%	22%
	Node 9	25%	21%	21%	25%	21%	21%

Table I shows that in ISO 2022 and 2027 base cases, the short-circuit contributions at the selected principal nodes, for the considered fault types, were generally higher than those short-circuit contributions in the ISO 2019 base case.

B. *Zero-Sequence Short-Circuit Current Contributions*

For a SLG fault on Phase-A at Station-B, the zero-sequence current contributions from Station-A and the MPT's 115 kV terminal were measured for varying sizes of NGR (connected to the neutral of the MPT's 115 kV wye winding). Results from these studies are summarized in Figure 2 (note that all currents and thresholds shown in the figure are primary currents). Figure 2a shows the I_0 contribution from Station-A (black trace), while Figure 2b shows the I_0 contribution from the MPT terminal (black trace). Additionally, for reference, in Figure 2a, Station-A's zero-sequence current contributions without the project connection, marked as *Pre-project Station-A I_0*, are also shown.



a. Station-A zero-sequence short-circuit current contributions

b. MPT's 115-kV side zero-sequence short-circuit current contributions

Figure 2. Short-circuit contributions for various MPT NGR sizes

In the ISO 2019 base case, without and with the project connected, with MPT's 115 kV side considered solidly grounded (i.e., NGR = 0 p.u.), the Station-A's zero-sequence short-circuit current contributions, for a SLG short-circuit at the Station-B, were 210 A and 111 A, respectively. These values (210 A and 111 A) are marked in Figure 2a's top-left plot using black dots.

Additional studies found that, using the same ISO 2019 base case, with the project connected to the ISO's system and the project MPT's 115 kV Y-side NGR=50 p.u., the Station-A's zero-sequence short-circuit current contribution, for a SLG short-circuit at the Station-B, would reach 162 A—a value that exceeds the threshold (of 160 A, marked in Figure 2a as *Station-A Relay: $2xI_0$ Pickup*) for proper ground overcurrent current function operation in relay R-A. This can also be seen on the right side in the top plots in Figure 2a.

In the ISO 2022 and 2027 base cases, however, with the project connected to the ISO's system and with the project MPT's 115 kV Y-side maintained solidly grounded (i.e., NGR = 0 p.u.), the Station-A's zero-sequence short-circuit current contributions, for a SLG short-circuit at Station-B, were 164 A and 157 A, respectively. These values (164 A and 157 A) were close to or above the 160 A threshold—refer to the bottom black dots in the top-middle and top-right plots in Figure 2a. For the ISO 2027 base case, a minimum MPT's NGR value of 1 p.u. is needed for the 157 A value to exceed the *Station-A Relay: 2xI$_0$ Pickup* threshold of 160 A.

In the same ISO 2019, 2022, and 2027 base case studies, with the project connected and the MPT's 115 kV Y-side solidly grounded, the MPT's zero-sequence short-circuit contributions are 185 A, 217 A, and 215 A, respectively—refer to the top black dots in Figure 2b. For the considered NGR sizes, including the largest size (50 p.u.), the MPT's zero-sequence short-circuit contributions were within the project's 115 kV relay's (R-Prj) minimum ground overcurrent pickup values. Furthermore, the MPT's minimum zero-sequence short-circuit contributions, shown in Figure 2b (using the bottom black dots), for the considered NGR sizes for the site's 115 kV CT ratio (100:5), were within typical ground overcurrent (50N) pickup setting ranges of most modern relays.

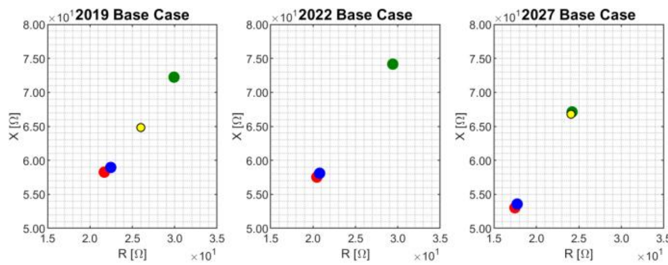
For the ISO 2019, 2022, and 2027 base cases, with the project connected to the ISO's system and with the project MPT's 115 kV Y-side ungrounded, the Station-A's zero-sequence short-circuit contributions, for a SLG short-circuit at the Station-B, were 211 A, 290 A, and 283 A, respectively, and are above the 160 A threshold value. These values (211 A, 290 A, and 283 A) were the same or very close to the values when the project was not connect-ed to the ISO's system.

C. *Ground Distance Relay-Related Impedances*

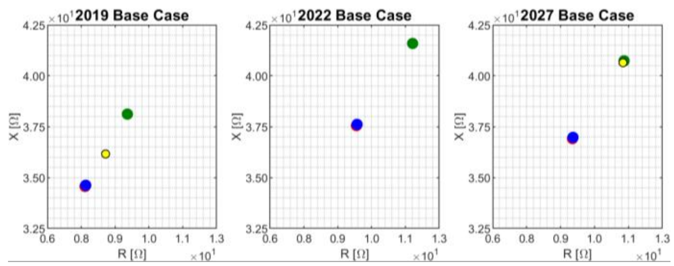
For the ISO 2019, 2022, and 2027 base cases, impedances that the ground distance relays (R-A and R-B) at Station-A and Station-B, respectively, would see, for a SLG fault at Station-B and Station-A, respectively, were calculated for various project connection and MPT grounding scenarios. Results from these studies are summarized in Figure 3.

In Figure 3, the plots in the three (left, middle, and right) columns are results for the ISO's 2019, 2022, and 2027 base cases, showing Phase-A impedances the R-A and R-B ground distance relays would see for a SLG fault (applied on Phase-A) at Station-B and Station-A, respectively. In Figure 3, the impedances (represented using dots) in red, green, blue, and yellow pertain to the project connection scenarios as follows: pre-project (project is not connected to the ISO's system); post-project (project is connected to the ISO's system), with the MPT's 115 kV Y-side operated solidly-grounded; post-project, with the MPT's 115 kV Y-side operated un-grounded; and post-project, with the MPT's 115 kV Y-side operated with an NGR. With the post-project with the MPT's 115 kV Y-side operated with NGR cases, as an NGR was only needed for the ISO 2019 and 2027 base cases, the impact of identified NGRs (50 p.u. and 1 p.u. for the ISO 2019 and 2027 base cases, respectively) are shown in Figure 3. For the post-project case, during-fault MPT's 115 kV Y-side simulated voltages for SLG faults (applied on Phase-A) at Station-A and Station-B, applied separately, and for selected MPT's 115 kV Y-side grounding setups, are summarized in Table II.

As shown in Figure 3, the connection of the project to the ISO's system, irrespective of the ISO base case used, would lead to a change in the apparent impedances the R-A or R-B ground distance relays would see (refer to the red and green dots in Figure 3). However, the impact of these changes in the system's apparent impedances, related to the current infeed, could be addressed by reviewing the ground distance relay settings, including redefining the protection zones accounting for those impedance changes.



a. Line-AB apparent impedances, as seen by R-A relay, for a SLG fault at Station-B



b. Line-AB apparent impedances, as seen by R-B relay, for a SLG fault at Station-A

Figure 3. Apparent impedances measured by the line-end ground distance relays for the considered SLG faults

TABLE II. POST-PROJECT: MPT'S 115 KV Y-SIDE DURING-FAULT VOLTAGES

ISO Base Case	SLG Fault Location	MPT Grounding	Sequence Voltages			Line-to-Gnd. Voltages		
			Pos. Seq. (kV)	Neg. Seq. (kV)	Zero Seq. (kV)	Phase-A (%)	Phase-B (%)	Phase-C (%)
2019	Stn.-A	Ungrounded	54.3	10.9	30.6	19%	117%	115%
		NGR=50 p.u.	53.8	11.4	27.6	22%	114%	111%
	Stn.-B	Ungrounded	56.9	8.3	9.0	60%	100%	98%
		NGR=50 p.u.	56.9	8.3	7.8	62%	99%	97%
2022	Stn.-A	Ungrounded	56.5	10.1	33.8	19%	121%	123%
	Stn.-B	Ungrounded	59.0	7.5	10.7	62%	103%	102%
2027	Stn.-A	Ungrounded	56.0	10.7	33.7	18%	121%	122%
		NGR=1 p.u.	54.9	11.8	26.7	25%	114%	112%
	Stn.-B	Ungrounded	58.9	7.7	10.6	61%	103%	102%
		NGR=1 p.u.	58.9	7.7	7.6	66%	101%	99%

Alternatively, if the project is operated with the MPT's 115 kV Y-side ungrounded, no significant apparent impedance changes to the system that either the R-A or R-B ground distance relay would see are expected (refer to the red and blue dots in Figure 3). Furthermore, if the project is operated with the MPT's 115 kV Y-side ungrounded or with selected NGRs, for SLG faults at Station-A or Station-B, the simulated negative-sequence and zero-sequence voltages at the 115 kV side of the MPT, with the 115 kV VT ratio (1000:1), are within typical negative-sequence overvoltage (59Q) and neutral overvoltage (59N) pickup setting ranges of most modern relays. Additionally, if the project is operated with the MPT's 115 kV Y-side ungrounded or with selected NGRs, for SLG faults at Station-A, the 115 kV side's line-to-ground voltages of the MPT, particularly the un-faulted phases, could exceed above equipment's voltage design tolerances (typical 110% of the nominal voltage value): Cases with MPT's line-to-ground voltages exceeding 110% of the nominal voltage value are highlighted in red in Table II. To protect the MPT and the project against these during-fault overvoltages, the project 115 kV side relay's (R-Prj) phase overvoltage element (59) could be used.

D. *Negative-Sequence Short-Circuit Current Contributions*

The project's inverters, during external fault conditions, are not known to contribute negative-sequence currents. However, if they are assumed to contribute negative-sequence short-circuit currents, the impact of such short-circuit current contributions was evaluated for all ISO base cases for various slopes of the negative-sequence dynamic reactive current, ranging 2-6. The site MPT's 115 kV positive- and negative-sequence short-circuit currents, for various solar inverter's *k* values and SLG faults at Station-B, were simulated. Results from these studies are summarized in Table II.

TABLE III. MPT'S 115 KV SHORT-CIRCUIT CONTRIBUTIONS

ISO Base Cases	Pos. Seq. Currents (A)					Neg. Seq. Currents (A)				
	k = 2	*k* = 3	*k* = 4	*k* = 5	*k* = 6	*k* = 2	*k* = 3	*k* = 4	*k* = 5	*k* = 6
2019	37.3	49.9	53.6	-	-	20.7	27.3	25.5	-	-
2022	38.5	52.2	63.3	65.0	75.3	20.2	26.7	32.7	27.4	67.1
2027	37.2	50.5	71.0	-	-	18.1	25.6	37.8	-	-

Table II results show that the 115 kV negative sequence current contribution from the project are a function of the solar inverters' negative-sequence dynamic reactive current slopes—with high *k* values generally leading to higher solar inverters' negative-sequence short-circuit current contributions and higher inverter terminal voltages. For *k* values 5 and 6, for ISO base cases 2019 and 2027, the inverter terminal voltages exceeded the selected inverter design voltage tolerance threshold of 1.1 p.u. (on the inverter's nominal voltage rating), leading to the solar inverter shutdown and, therefore, no inverter short-circuit contributions (these cases are marked using "-" symbol in Table II). This suggests that a *k* value to be used for an IBR-project should be determined at the project design stage and or as part of the ISO's SIS.

Furthermore, for the selected solar inverters' negative-sequence current contribution, simulation setup (pre-fault network voltages calculated from a linear solution), and 115 kV CT ratio (100:5) setup, the simulated MPT'S 115 kV negative-sequence short-circuit current contributions in Table II were within typical negative-sequence overcurrent (50Q) pickup setting ranges of most modern relays.

V. CONCLUSIONS

The paper presented an example, practical case study based on a US solar generation system that interconnects to an existing transmission line via a line-tap, challenges associated with such connection, affecting the interconnecting transmission system's protection system, lessons learned, and potential solutions to address those challenges. Based on the discussed challenges and presented studies, there are several potential mitigation options for the IBR generation developers, transmission utilities, and ISO to consider; a few options are listed below:

- Consideration of the site's MPT's 115 kV Y-side operated as ungrounded, coupled with 115 kV ground fault detection using the site relay's voltage elements as the site's secondary protection, along with the utility's signal-based DTT primary protection. As the site's MPT's 115 kV Y-side operated as ungrounded, the apparent impedance seen by the ground distance relay at Station-A will not change significantly; therefore, Station-A's existing ground distance relay settings may work.
- Consideration of the site MPT's 115 kV Y-side solidly or impedance grounding, coupled with 115 kV ground fault detection using the site relay's current elements as the site's secondary protection, along with the utility's signal-based DTT primary protection. This option may require a review of the Station-A ground distance relay settings, including a redefinition of the relay's protection zones, accounting for the apparent impedance changes due to the site connection to the ISO's system.
- For generation projects with IBRs with significant negative-sequence current injection capability, the site MPT's 115 kV Y-side negative-sequence protection elements could be used, given a suitable *k* value to be used for the project is prior determined.

It should be noted that consideration of these options is subject to the outcomes of a project's equipment (including, IBRs' capabilities, such as negative-sequence short-circuit current contributions) and setup, the project's SISs, the host utility's protection philosophy, and the ISO's system operational criteria and constraints.

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