Utilities Perspective on Protection Challenges with High IBR Penetration

ABSTRACT

Utilities have seen rapid increase in Solar, Wind, and Battery Energy Storage Resources that interconnect to their electric system through Inverters. Inverter-Based Resources (IBRs) have fault current characteristics that are unlike the fault current response of traditional rotating-machine-based generators, which is well known and repeatable. IBR's non-traditional fault current behavior is due to the IBR control scheme, which is configured to provide a clean AC output but also protect the inverter's sensitive power electronics devices from damage, one source of which is overcurrent. This results in low fault current magnitude, low or no negative sequence current injection, the variability of sequence component currents, the variability of voltage with respect to current angles, and the lack of inertia. The control scheme also results in a fault current response that can vary between manufactures and between models of the same manufacturer.

High penetration of IBRs can adversely affect the protection schemes applied in areas with high penetration of IBRs. With the proliferation of IBRs, utilities are finding out that conventional protection schemes are not adequately equipped to protect the electric systems. This is mainly because the existing protection elements and practices have been designed based on the fault current response of conventional rotating machines. In several cases, the available literature does not provide any clear solution for the issues when the protection scheme does not operate properly near IBRs.

This report identifies various protection challenges due to IBRs that industry is facing, from the utility perspective. Instead of facing on one issue, this report looks broadly on all the challenges that system protection has experienced with high penetration of IBRs. Based on the IBR response from various utilities during real fault events and gathering perspective from different utility SMEs via questionnaire, the report summarizes on gathered data and internal experiences.

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ACRONYMS AND TERMS

Acronym/Term	Definition
AEP	America Electric Power
BESS	Battery Energy Storage System
CAISO	California Independent System Operator
CT	Current Transformer
DER	Distributed Energy Resources
DFR	Digital Fault Recorder
DFT	Discrete Fourier Transform
EMT	Electro Magnetic Transient
EPIC	Electric Program Investment Charge
ERCOT	Electric Reliability Council of Texas
FIDS	Fault Identification Selection
HIL	Hardware-In-the-Loop
IBR	Inverter Based Resource
IEEE	Institute of Electrical Engineers, Inc.
NATF	North American Transmission Forum
NERC	North American Electric Reliability Corporation
OOS	Out-of-step
OST	Out-of-Step Tripping
PG&E	Pacific Gas and Electric
PMU	Phasor Measurement Unit
POTT	Permissive Overreach Transfer Trip
PRC	Public Resources Code
PSB	Power Swing Blocking
PSRC	Power System Relaying and Control Committee
PTP	Precision Time Protocol
PV	Photovoltaic
RTDS	Real-Time Digital Simulator
SAR	Standards Action Request
SCADA	Supervisory Control and Data Acquisition
SME	Subject Matter Expert
SSCI	Sub Synchronous Control Interaction
SSO	Sub Synchronous Oscillation

Acronym/Term	Definition
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
ZPM	Zero Power Mode

Introduction

US Department of Energy (DOE) issued funding opportunity announcement in September 2022 through its subsidiary Energy Efficiency and Renewable Energy (EERE) and sought proposals to demonstrate wind and solar plants to provide grid services and improve grid reliability. PG&E in partnership with other organizations submitted the proposal to EERE on the topic of Protection of Bulk Power Systems with High Contribution from Inverter-Based Resources and won the award in September 2023. PG&E partners include ETAP (Software vendor), Quanta Technology (Engineering Consultancy organizations), Sandia National Lab (Research laboratory), University of New Mexico (University), and Duke Energy (Utility).

The main goals of this project are to identify protection issues associated with high IBR penetration and propose potential solutions, improve short circuit models for IBRs that can be used for wide-area coordination, and create a Sensitivity-Driven Wide-Area Protection (SWAP) coordination analysis tool for systems with high penetration of Inverter Based Resources (IBRs).

This report focuses on reviewing the protection challenges that utilities face due to high IBR penetration levels. Instead of focusing on one or two aspects, the report relies on information from various papers, working groups, vendors and protection engineers and presents wide range of protection challenges with high IBR contribution. As part of data gathering, we collected real fault data for events associated with IBRs and summarized some of the interesting events. We also sent questionnaire to SME's of various utilities and response to the questionnaire is summarized in the report.

In the next phase of the project, we would focus on improving IBR models, developing protection schemes that mitigate the protection challenges and develop a software tool to study wide area protection issues.

Overview on IBR Protection Challenges and impacts

IBR's have a fault current response that is unlike the traditional machine fault current response, which is well-known and repeatable, in which current protection elements and practices have been designed around. IBR's non-traditional fault current behavior is due to the IBR control scheme. The control scheme is configured to provide a clean AC output, but also protect the inverter's sensitive power electronics devices from damage, one source of which is overcurrent. This results in low fault current magnitude, low or no negative sequence current injection, the variability of sequence component currents, the variability of voltage with respect to current angles, and the lack of inertia. The control scheme also results in a fault current response that can vary between manufacturers and between models of the same manufacturer.

High penetration of IBRs can adversely affect the protection schemes applied in areas with high penetration of IBRs. If conventional protection schemes fail to operate during fault simulations, then unconventional protection schemes need to be considered. In several cases, the available literature does not provide any clear solution for the issues when the protection scheme does not operate properly near IBRs.

These result in protection challenges described below.

Modeling Challenges

All protection system studies begin with a thorough fault study, this analysis is required in specifying the type of protection that should be used for a given system configuration and in the development of the protective relay settings. Further, fault studies are critical to determine what protection equipment and changes are required and if coordination is maintained after the introduction of new IBR generation.

As noted above IBR fault current response to system disturbances does not have the same characteristic as machine-based generation and is determined for the most part by the IBR inverter control algorithm. This can vary between manufacturers and between models of the same manufacturer. The most accurate method of modeling IBRs is the time domain modeling in EMTP and PSCAD software, but this is not practical for large power systems. Various commercial software and technical groups have suggested modeling approaches in the phase domain; however, these models are based on the control schemes of IBR for which the data is not readily available from manufacturers. Due to the evolving nature of control schemes and fault current characteristics, there is a need to investigate other methodologies and alternatives for modeling.

During unbalanced faults, it appears that loading will affect the IBR short circuit characteristic which could influence how the protective elements operate (reference IEEE PSRC C32 WG report "Protection Challenges and Practices for Interconnecting Inverter Based Resources to Utility Transmission Systems"). Presently loading is not modeled as part of a fault study and will not accurately simulate fault response during full load conditions. Research needs to be done to see the effect of loading and high penetration of IBRs on this modeling approach.

Despite some improvements, there are discrepancies regarding IBR modeling utilizing voltage control current source techniques and the accuracy is dependent on the IBR manufacturers following the generic IBR fault models. Industry studies indicate that models can have inaccuracies up to 40% (reference CAISO IBR Modeling Working Group 2021)

There is ongoing industry effort by IEEE PSRC C45 working group (protection and short circuit modeling of systems with high penetration of IBRs) to improve the modeling of IBRs and protection schemes with high penetration of IBRs. This project will share IBR model improvement results with C45 WG.

Some of the utilities in Europe are using EMTP models to run hardware in the loop (HIL) testing for relay testing and exporting the data into protection programs that are phase domain programs for regular protection engineer work (reference CAISO IBR Modeling Working Group 2021). The interface between time domain models and commercially available phase domain model software will be useful for the industry.

PG&E has previously utilized its RTDS facilities to test the protection functions in microgrids and to study the ability of IBRs to sense and respond to changes in system frequency.

PG&E and California IOUs have noticed convergence issues when modeling a large number of IBRs and running fault studies in common commercially available fault simulation programs (reference CAISO IBR Modeling Working Group 2021). This issue will become critical with the high penetration of IBRs.

Another issue of IBR modeling relevant to breaker rating evaluation is how to model IBR's during the uncontrolled fault current phase that can take 1-2 cycles. The uncontrolled fault currents can cause erratic magnitude calculations for protective relays until the inverter controls achieve steady state (reference NATF report Version 1.0, Document ID: 1639). This could result in either replacing equipment that is not overstressed, or not replacing overstressed equipment.

Due to the above modeling issues, the NATF forum report on Inverter-Based Resource Interface states "Conventional short circuit modeling techniques and software available for protection design are of little use in simulating the fault response of IBRs " (reference NATF report Version 1.0, Document ID: 1639).

Utilities have noticed that model verification (whether it is Aspen/Cape or an EMT model) needs to be performed with methods such as hardware-in-the-loop (HIL) testing or using system fault data. More detail about HIL testing is described later in the proposal.

Shown below are several of the challenges that IBRs introduce for the protection of the electric power grid.

Low fault current contribution

Fault Current is a function of proprietary IBR control schemes and IBRs limit fault current to protect the inverter hardware. Low IBR fault current presents challenges to phase overcurrent protection due to the ineligibly to set the element low enough for fault detection while not limiting the full output rating of the IBR. Low fault contribution from IBRs can also result in slow fault clearing or, in the worst case, prevent protection from detecting fault and isolating faults. Relays at the IBR terminals can have distance element fault detectors not picking up or overcurrent elements not operating correctly.

For overcurrent relays, assume the phase element's pickup is set to a value that is above the full load condition. Yet, in an IBR-dominated system with lower fault current levels, the calculated pickup current might fall below the load currents. This complicates the relay's ability to differentiate between normal load and fault conditions, especially when the fault current contribution from the IBR is relatively small. This issue highlights that the traditional phase overcurrent scheme may not be reliable in systems with a high IBR penetration.

Additionally, phase overcurrent settings are difficult to determine using steady state short circuit analysis because of unknown contributions from the IBRs (C32 report)

Negative sequence quantities not available or not reliable for IBRs

Most of the existing IBR installations inject only positive sequence currents in response to unbalanced faults. Protective relays widely use negative sequence quantities for directional control and for some distance applications. The lack of negative sequence current injection could also result in mis-operation of the direction elements and unbalanced (i.e. phase to phase) faults not being detected or the protection capability for unbalanced faults being significantly degraded. This will become a more significant issue for protection systems with higher penetration of IBRs (reference NATF report Version 1.0, Document ID: 1639). Distance protection, negative sequence directional elements, and polarization may be a challenge.

For IBR's that inject negative sequence current, the current and voltage phase angle must be stable and of the correct value (reference IEEE 2800-2022). With the dynamic nature of IBR control and lack of standardization, the response from inverters is not repeatable, and generic models do not represent the actual controls of inverters. Inconsistency in phase relationships between I2 and V2 poses challenges to protection applications.

German VDE grid code has standardized the negative sequence current injection from inverter-based resources. German grid code in their specification also fixes the angles of the positive and negative-sequence current phasors with respect to the positive and negative sequence terminal voltages, addressing the issue of unexpected angular differences between the phasors.

Organizations that manage transmission grids in US (like CAISO) have not incorporated IEEE 2800 requirements around negative sequence current during faults but may address in future.

The magnitude of negative-sequence current provided by IBR varies from manufacturer to manufacturer but is always significantly lower than in magnitude produced by conventional sources. To detect such low magnitudes of negative-sequence current, the relays must be set very sensitively, which jeopardizes the security of the protection scheme.

Challenges with rapid frequency change

For a conventional system, inertia keeps the system stable for 3 seconds or longer, which is sufficient for the relays to operate. This is not the case for IBR dominated systems.

Frequency can change suddenly due to low or no inertia of IBRs. This can result in several issues like high rate of change of frequency, low memory polarization, and accuracy of frequency tracking by numerical relays.

Frequency response of IBR may cause issues with frequency tracking and with high penetrations of IBRs, protective relays may not track frequency accurately and result in protection system errors.

PG&E has observed frequency tracking issues by microprocessor relays when the transmission system separates, leaving only IBRs on the distribution system connected to the isolated electric system. For one incident on 70 kV, a sudden frequency shift exceeded the relay's frequency tracking limit and the voltage signal reported by the relay was oscillating which prevented the overvoltage element from operating. When the frequency was calculated by Discrete Fourier Transform (DFT), the frequency was found to be much lower (54.8 Hz) than the frequency reported (60 Hz) by the relay, and voltage magnitude was stable for 54.8 Hz signal.

The figure 1 below shows the actual phase voltage and frequency response calculated by DFT performed in Excel.

Event at 70kV PG&E substation, where microprocessor relay failed to trip, because of the inverter sudden frequency shift (from 60Hz to 55Hz in very short time). This sudden frequency shift exceeded relay's frequency tracking limit. The voltage magnitude oscillated, which led to the relay failure to operate.

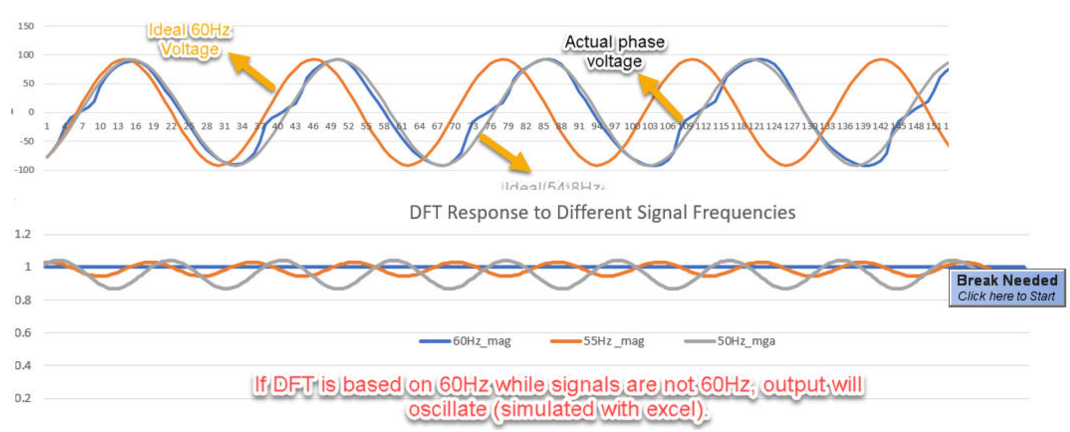

Figure 1. DFT Analysis of phase voltage event recorded by relay

Figure below shows the voltage signal oscillations that prevent the overvoltage element to trip.

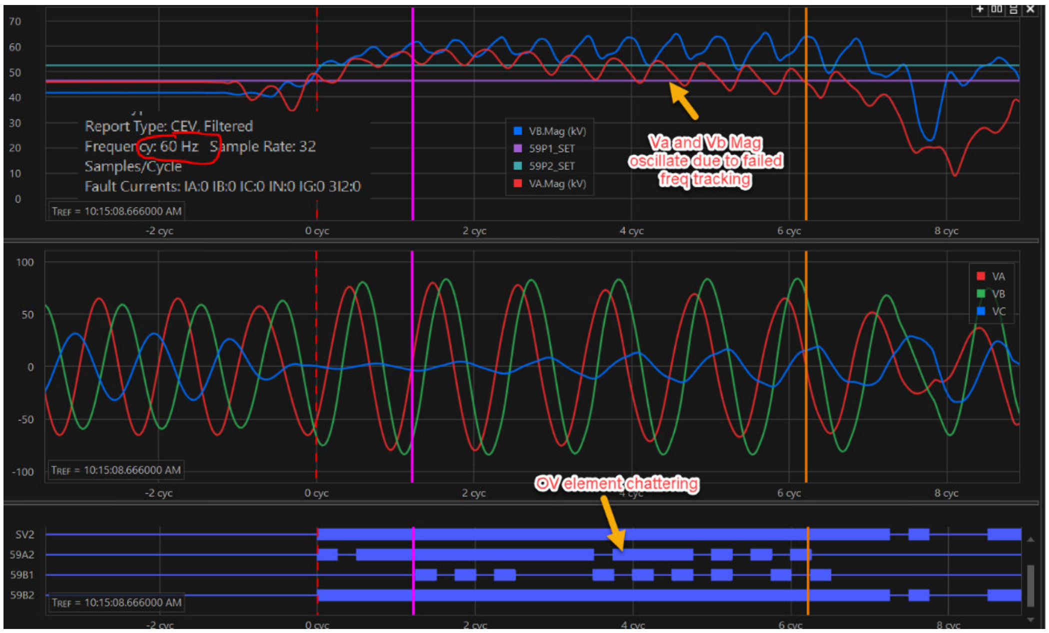

Figure 2. Oscillography from relay showing overvoltage on distribution transformer when transmission system separates.

The inverter frequency measurements have also been found incorrect as they may not represent the true system frequency. Inverters can measure near instantaneous frequency changes of fault voltage waveforms that do not represent the true system frequency. NERC report on Southern California 2016 event suggests implementing a minimum time delay for frequency detection and / or filtering.

Memory Polarization Issue

With conventional sources, memory polarization will expand the mho circle for forward faults and shrink the mho circle for reverse faults. This helps the dependability of protection schemes for close-in faults.

The shift of generation mix to IBR dominated generation decreases the total inertia of spinning mass connected to the Electric Grid. Memory polarization may not work with IBR sources that have low inertia, and the mho circle will shrink for forward faults and not able to detect faults. The loss of inertia could result in a mis-operation of the distance elements that use "memory" or "Cross-Phase" polarization. The relatively high source impedance of IBR's and the possibility that the IBR may produce off-nominal current and voltage frequencies may result in an incorrect operation of the memory or cross phase polarization of the distance element and inadvertent operation of the distance element (reference NATF report Version 1.0, Document ID: 1639)

Source impedance depends on the IBR control system, the mho expansion can be anywhere on the R-X plane – not necessarily behind the relay. It makes memory polarization unreliable.

Reference: SEL Presentation, Protection in an IBR World

Reference: Working Group C32, Protection Challenges and Practices for Interconnecting Inverter Based Resources to Utility Transmission Systems

Distance Protection Performance

In systems with a high penetration of IBRs, the angle between memory voltage and the measured fault voltage will be variable, since the phase angle relation will depend on the controls of the IBR instead of the synchronous generators. Also, due to the low system inertia associated with IBR, the frequency slip between the pre-fault system and faulted system may render the use of memory voltage vector invalid. Self-polarized distance relays, on the other hand, will determine the direction of the fault correctly in systems with IBRs, if fault voltage and current are of sufficient magnitude to make phase comparisons. However, these relays most probably will find the polarizing voltage magnitude to be too small to reliably process for comparison in the relay. This is because IBR dominated systems are weak and have high source impedance behind the relay compared to the impedance of the protected zone.

Most of the phase and ground distance relays are supervised by phase and ground fault detectors, respectively, which are set to pick up under fault currents. The fault detectors will face the same issues as overcurrent elements. For ground distance elements, the unbalanced current magnitude may be close to the minimum current that the ground fault detectors can detect due to low negative sequence currents from IBRs.

In summary, for the distance elements, (i) the Low amount of fault current may prevent supervising fault current detectors from operating resulting in distance element security issues. , (ii) Lack of I2negative sequence current injection by IBRs, may prevent the directional element from operating correctly during unbalanced faults which in turn can prevent proper operation of the distance element ., (iii) Dynamically changing IBR source impedance may result in further misoperations due to memory polarization issues, (iv) Inconsistence expansion of the mho circle resulting in reduced reach accuracy and risk of overreach or underreach tripping., and (v) There could be problems identifying the faulted phase for unbalanced faults.

The non-homogeneous phase angle relationship between IBR and remote source impedances negatively impacts reliability of distance relay as well.

Reference: IEEE Transaction on Power Delivery, Transmission Line Protection for Systems with Inverter Based Resources – Part 1: Problems, Published in August 2021

Faulted Phase Identification Logic

Fault type identification may misbehave due to currents injected by IBRs. Positive and Negative sequence currents by IBRs during faulted conditions can vary in frequency from the frequency of their respective terminal voltages. The frequency of voltage is determined by the Thevenin equivalent of sources which have infinite inertia and keep the frequency constant. The frequency of current from IBRs is determined by IBRs which have low inertia and may not increase the power to counteract the disturbance and support the grid frequency. This results in unstable frequency for currents from IBRs and unpredictable relationships between I0 and I2. Fault Identification Selection (FIDS) logic in microprocessor relays identifies the faulted phase for all faults involving ground by comparing the angle between I0 and I2. In these cases, the FIDS logic utilizing I2 and I0 for directional reference determination will not operate properly. This was shown by the study led by Sandia Laboratories by conducting electromagnetic transient simulations (EMT) for an unbalanced faulted system with IBRs and then playing back the output of simulations on two relay manufacturer relays. Sandia's study results showed inconsistent fault identification for ABG faults.

The phase distance element (ZP) for a LL element can operate and overreach for a resistive LG fault. Similarly, ground distance element (ZG) can operate and overreach for LLG fault. To prevent overreach, the relay utilizes faulted phase identification logic to determine if it is AG fault or BC fault, if it is AG fault or BCG fault. If the faulted phase identification logic is not working properly, there is a possibility that 21 elements may overreach.

Faulted phase identification logic is also useful for single pole tripping and targeting.

Reference: Sandia Report (SAND2020-0265) Impact of Inverter-Based Resource Negative-Sequence Current Injection on Transmission System Protection

Reference: Challenges and Solutions in the Protection of Transmission Lines Connecting Nonconventional Sources – (Authors: SEL, EDF Renewables – Published in August 2023)

Reference: Inertia Response and Short Circuit Contribution for Distributed Generation Impact Improvement (PG&E EPIC Report – Published in 2019)

Directional Element Performance

Directional relays operate by comparing the phase shift between an operating quantity and a polarizing quantity. This is usually done by comparing the phase angles of the operating current and polarizing voltage against the maximum torque line in a plane that has polarizing voltage on the horizontal axis and operating current on the vertical axis. Conventionally, the fault voltage serves as the polarizing quantity, while the fault current acts as the operating quantity. Directional elements can utilize positive, negative, or zero sequence quantities to ascertain the fault's direction. In networks predominantly comprised of IBRs, negative sequence fault response from IBRs varies from one manufacturer to another and some IBRs may generate none or very low negative sequence current in response to unbalanced fault. The phase angle of the negative-sequence current with respect to the negative-sequence terminal voltage is uncontrolled. This can result in not sensing the directionality of the fault correctly and has caused relay mis-operations in the past where the relays were polarized by negative sequence quantities.

For microprocessor relays, it is common practice to use the negative sequence voltage polarized elements for determining the direction of fault. For a forward fault, the negative sequence current would lead the negative sequence voltage, whereas for a reverse fault, the negative sequence current would lag the negative sequence voltage. Negative sequence directional elements are enabled only when the respective sequence current is above a minimum threshold value.

The inverter control system of solar generation and BESS facilities will likely restrict the magnitude of negative sequence current during unbalanced faults. Type III wind turbines generate negative sequence current, but the negative sequence current response is unlike that of conventional synchronous sources and is not readily known.

With the uncertainty of negative sequence response from IBRs, a negative sequence current based scheme cannot be relied upon to provide reliable directional protection. Various analyses of IBR responses for line-to-ground faults have also confirmed that negative sequence directional elements or current elements cannot be applied on a line connecting IBR facility.

Zero sequence polarization can be an option for directional elements when negative sequence voltage or current polarization cannot be applied. Depending on the transformer configuration, zero sequence currents and voltage can be low for the directional elements and careful study is required to make sure that directional elements operate correctly.

Reference: Energies Journal Publication "Impact of Inverter Based Resources on System Protection" February 17, 2021.

Reference: Sandia Report (SAND2020-0265) Impact of Inverter-Based Resource Negative-Sequence Current Injection on Transmission System Protection. Published in 2020

Reference: IEEE PSRC Report of Working Group C32 of the System Protection Subcommittee, Protection Challenges and Practices for Interconnecting Inverter Based Resources to Utility Transmission Systems.

Apparent Impedance Oscillations

Negative sequence current (I2) injected by an IBR may have a different frequency than negative sequence voltage (V2) and this can result in oscillatory behavior of distance elements for LG and LL faults. Frequency of the Negative sequence voltage (V2) is held stable by the Power System that has strong inertia, where I2 from the IBR is supplied by a source that has low inertia and does not maintain stable frequency.

Apparent impedance oscillates significantly due to the currents injected by the IBR. In the time domain fault simulations with IBR models, I2 appears to have a higher frequency than V2. This makes the I2 phasor rotate with respect to V2, resulting in a loss of security and dependability for protection elements that use I2. The same behavior has been observed from the relay events that are close to IBR terminals.

Inconsistent I2 frequency causes the following issues for distance elements:

- Potential overreach for Zone 1
- Potential underreach for Zone 2

Oscillating impedance can result in potential overreach for Zone 1 and the Zone 1 element may pick up for fault outside of Zone 1.

Phase distance element Zone 2 may drop out because of an oscillating apparent impedance due to the currents injected by the IBR resulting in an underreach condition.

Phase distance Zone 1 may also overreach due to CVT transients. This is common for all weak sources and IBRs.

Reference:

- Reference: Sandia Report (SAND2020-0265) Impact of Inverter-Based Resource Negative-Sequence Current Injection on Transmission System Protection
- IEEE Transaction on Power Delivery, Transmission Line Protection for Systems with Inverter Based Resources – Part 1: Problems, Published in August 2021

Type 3 WTG Challenge

Type 3 wind turbines have trouble with 3P faults since this type of fault decreases the flux in the generator more rapidly over time, and loss of voltage at the generator terminals may adversely impact the frequency of currents injected into the rotor.

Study led by Sandia and NERC in collaboration with Inverter manufacturers and Relay manufacturers showed that Type 3 wind turbines behaved well for LG faults and all relay elements operated reliably. I2 and V2 are stable. I2 had a coherent frequency with other signals, such as V2 and I0, allowing protection to behave reliably. The well-behaved response is due to Type 3 wind units effectively behaving as an induction generator, depending on the operating point, and the flux in the generator being maintained during the fault.

Reference: Transmission Line Protection for Systems with Inverter-Based Resources – Part 1: Problems (IEEE Transactions on Power Delivery, Vol. 36, No. 4, August 2021

Uncontrolled Response Challenge

IBRs cannot respond instantly, resulting in a timeframe greater than one power cycle where the response is not standardized. Relays can respond in this one cycle time frame.

For many IBRs, it takes two or more cycles for the IBR control system to respond to the fault conditions and adjust the output currents in response to a fault. This is the typical time interval during a fault when protection elements are expected to operate. In many cases, this can result in delayed protection operation or a relay misoperation.

Momentary Cessation or Zero Power Mode (ZPM)

IBRs may exhibit momentary cessation when no current is injected into the electric grid by the IBRs during low or high voltage conditions outside the continuous operating range. Momentary cessation can affect the fault current and reliable operation of protection devices. Design parameters for transmission connected IBRs need to be established so that they do not exhibit momentary cessation.

In addition to loss of generation on transmission, frequency drop, stability issues for operations, momentary cessation also inhibits the distance (or overcurrent) protection for internal line faults.

For the Blue Cut Fire in California (Southern California 8/16/2016 event) caused by a 500 kV fault, approximately 1200 MW of solar generation was lost, the majority of which was caused by momentary cessation for voltages outside the continuous operating range of IBRs.

After the Blue Cut Fire event, inverter manufacturers recommended changes to the inverter settings to add a time delay to inverter frequency tripping that will allow the inverters to ride through the transient period without tripping or momentary cessation. NERC issued several additional recommendations to alert the industry of the risk of momentary cessation. NERC Standard PRC-029 for frequency and voltage ride-through requirements for IBRs is being prepared to add clarity to the frequency and voltage tripping areas for IBRs.

During routine fault event investigations, PG&E has seen a few momentary cessation phenomena from IBRs connected to PG&E Electric Transmission System. IBRs from different manufacturers connected to the same transmission bus behave differently in that one manufacturer IBR will exhibit momentary cessation while other IBR manufacturers do not. The figure below shows the oscillography for manufacturer 1 showing momentary cessation while the oscillography for manufacturer 2 for the same event shows the inverter ride through the disturbance. It should be noted, the inverter started injecting current soon after voltage returned to normal.

California ISO does not allow momentary cessation on transmission connected IBR.

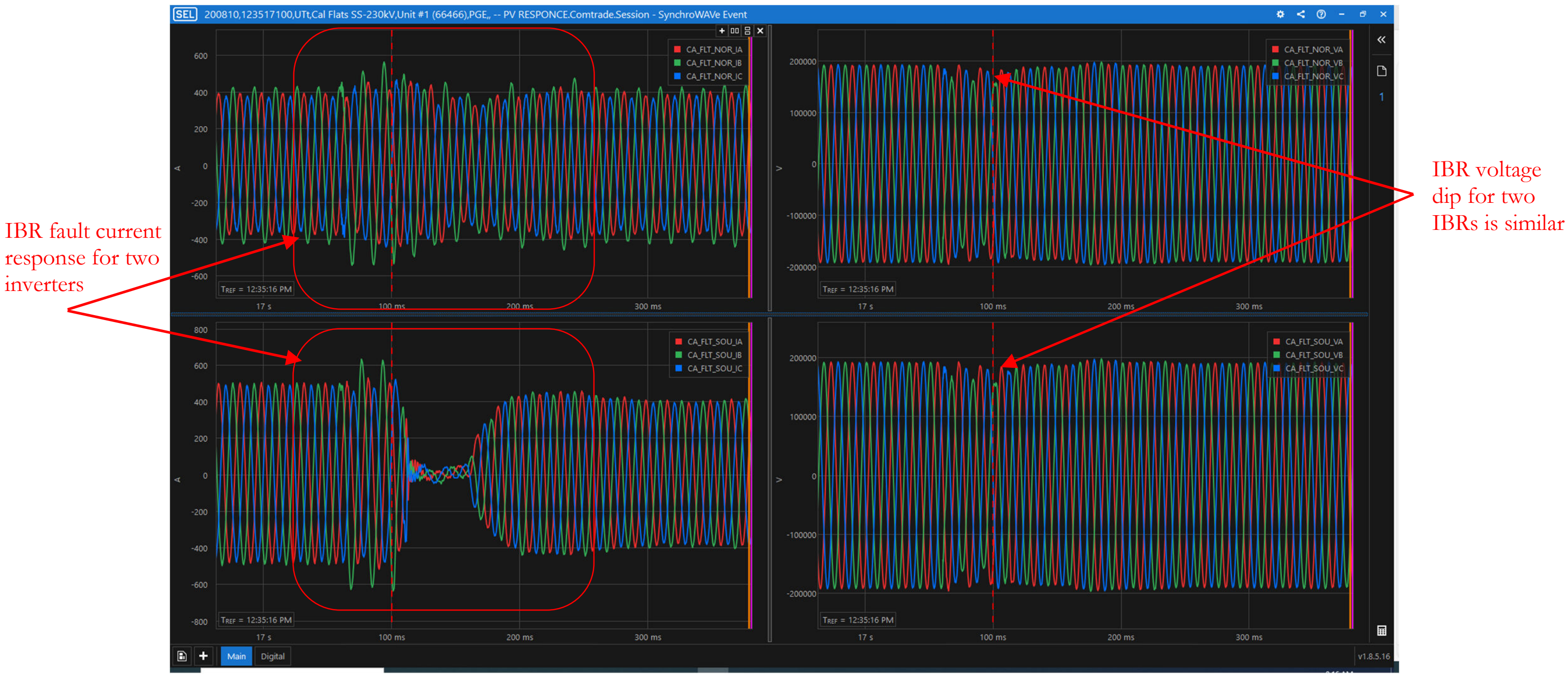

Figure 3. Relay oscillography for two IBRs connected to the same transmission bus and experiencing voltage dip from an external fault.

Inadvertent Tripping of Inverters

NERC Report on 2022 Odessa Disturbance studied the widespread loss of solar PV and synchronous generation caused by a normally cleared fault in Texas on June 4, 2022. The report on 2022 Odessa disturbance identified several cases of inadvertent tripping of solar PV resources.

Inverters may have internal instantaneous overcurrent tripping that is not settable. The inverter may trip before the AC overcurrent protection of the plant.

Inverters tripped due to PLL loss of synchronism. NERC guidance is that PLL can resynchronize to the grid within a couple of electrical cycles and should not result in tripping.

There can be multiple layers of protection functions within the inverter that can result in inadvertent tripping. NERC report on detailed findings about Odessa events list several causes of abnormal solar PV performance that includes inverter AC overvoltage, inverter DC bus voltage unbalance, incorrect ride-through configuration, PLL loss of synchronism etc. The report's list of causes includes several cases where cause was unknown or not analyzed. NERC report recommends these be comprehensively studied with EMT models.

According to the NERC report, inverter instantaneous AC overvoltage tripping is a recurring cause of IBRs connected to bulk electric system. Current standards of PRC-024-3 (NERC Standard for Frequency and Voltage Protection Settings for Generating Resources) do not solve the problem of instantaneous overvoltage tripping and there is a need for a new compliance standard for voltage ride through for IBRs.

Multiple solar facilities tripped for unknown reasons that were attributable to firmware issues. Internal logs were overwritten and there was no data to determine the cause of trip.

The challenges posed by inadvertent tripping cannot be resolved by protection settings. Inverter controls are complex and have their own settings that conflict with the ride-through standards. NERC reports on major events (like Odessa events in 2021 and 2022) involving IBRs show that protection relay settings have been unable to stop these events. Standards and Testing procedures need to ensure that IBRs do not trip inadvertently. Protection settings would then be coordinated with the updated standards.

Reference: NERC report on 2022 Odessa Disturbance published in December 2022

Fault ride-through issues:

There have been several cases where IBRs tripped for out-of-section faults. This has resulted in unnecessary loss of generation, making the electric grid vulnerable to cascaded outages. Protection scheme security is required to ensure that IBRs stay online for external disturbances.

Existing NERC voltage and frequency ride-through standards (PRC-024-3) are not adequate for ensuring IBRs remain connected and support the electric grid during disturbances. NERC accepted the Standards Action Request (SAR) in 2023 to modify PRC-024-3 or replace the standard with a performance-based frequency and voltage ride-through standard (PRC-029) that ensures that the generator remains connected to Bulk Power System during system disturbances. NERC is also developing standard for Disturbance Monitoring and Reporting Requirements for IBRs (PRC-028) and a standard for Unexpected IBR Event Mitigation (PRC-030). These three standards would support IBR ride through and help reduce inadvertent trips that are affecting the reliability of the Electrical System.

Issues with POTT schemes

POTT scheme often uses either directional ground distance or directional zero sequence overcurrent or directional negative sequence overcurrent relays for ground fault detection. Misoperation of the directional elements (67N, 67Q) and or phase distance elements can result in a misoperation or non-operation of the pilot scheme. 67Q element may malfunction due to either too low negative sequence current or changed angular relation of negative sequence voltage and current phasors.

Due to unreliable negative sequence current from the IBR, the relay located near the IBR may not detect the directionality of fault correctly and could result in a mis-operation. For example the impacted relay can see the fault in front of the relay as a reverse fault and fail to send the permissive trip signal, resulting in the remote relay not tripping for in-section fault. another example could be, the relay near the IBR facility incorrectly sends an echoed back permissive signal because it had failed to detect the reverse fault. (C32 report)

Issues with Blocking Schemes

Line relays near the IBR facility may have difficulty in sensing faults on its line due to low levels of fault currents produced by the wind and solar farms.

DCB scheme may have difficulty in detecting line faults due to the low IBR current value. This could result in a blocking signal is not sent to the remote end resulting in a subsequent trip of the remote end and loss of the line.

Challenges with Power Swing Protection Schemes

An increased footprint of IBR within a region significantly reduces the regional inertia that challenges the reliability of the existing power swing blocking or out-of-step protection systems.

Simulations of the test system show that the power swing relay successfully detected stable / unstable power swings under synchronous generation scenario. However, when synchronous generation was replaced with wind generation, the power swing protection failed to detect the power swing and did not issue a power swing blocking (PSB) signal. (IEEE C32 working group report)

In another test case, the impedance trajectory reversed direction and the relay mistakenly declared an OOS condition and issued an OST signal.

Conducted simulations show that IBR's affect both the rate of change of the swing impedance and the swing trajectory and can impact the operation of both PSB and OST. (IEEE C32 working group report) resulting in misoperations of these elements.

Interactions of IBR with Series Compensated Transmission Line

The control system of an IBR, particularly Type III wind generation, can interact with a series compensated transmission line to create a sub synchronous oscillation (SSO) phenomenon, which is often categorized as sub synchronous control interaction (SSCI).

There were three reported SSCI events in 2017 on the AEP transmission system within ERCOT. All three events started after wind farms were radially connected to series compensated transmission lines after adjacent transmission lines outages. (C32 working group report). The sub synchronous oscillations were around 22 to 26 Hz.

The quickly rising voltage and current magnitude from the oscillation can damage primary equipment including series capacitor banks, synchronous generators turbine shafts, power transformers etc. Most relays operate on the fundamental frequency and are slow to act for current and voltages with a sub synchronous component. (IEEE C32 working report)

Unintentional Islanding

Unintentional islands can cause safety hazards and cause power quality issues that are detrimental to the customers served by transmission owners and operators. Special protection schemes (automatic anti-islanding schemes) and operating procedures are required to separate the generation sources forming the island. These anti-islanding schemes are expensive to install and maintain.

Inverter Based Distribution Energy Resources (IB-DERs) have anti-islanding detection mechanisms and separate in 2 seconds after the grid separates. These methods work to actively perturb frequency or voltage of the IBR, which is stable when connected to the system. When the IBR is disconnected from the system the perturbation results in a frequency or voltage trip. Due to this instability characteristic most of the IBRs on transmission do not have active anti-islanding detection and there is a concern that active anti-islanding on transmission may impede LVRT capabilities and produce power quality issues.

Large amount of IBRs on Distribution affecting the Transmission

High penetration of IBRs on the distribution system can also introduce some unique challenges to the transmission system, for example, high voltages for unbalanced faults, high phase voltages during single line to ground faults due to neutral shift, ferro-resonance, transformer overloading and unintentional islanding. The aggregate total amount of Distribution Energy Resources (DERs) may become significant enough to affect the transmission system protection, and DERs may contribute fault current to transmission line faults. During the design of Protection schemes, the impact of distribution connected DER on the transmission needs to be evaluated.

Distribution level generation has historically not been modeled in the transmission for fault studies. With the shift in generation to distribution, utilities must figure out how to model distribution generation for fault studies on transmission.

DERs connected to ungrounded transformers can result in overvoltage of the transmission system and interconnected equipment during Single line to ground faults after the remote transmission breakers have opened to clear the fault. The interconnected transmission equipment that is normally subjected to phase to ground voltage will be subjected to phase-phase values on the unfaulted phases. Transformer bushings, lightning arrestors, and insulators must be checked to verify that they can sustain phase-phase voltages. If required, ground fault overvoltage scheme could be installed on the transformer high side tripping the station feeder breakers to separate the transmission equipment from the DERs.

Large amounts of DERs can result in power flow from distribution to transmission and in some cases overload the distribution transformers. If required, reverse power relays can be installed to protect the transformers from damage or measures are applied to limit the generation from DERs.

Perspective from Utilities on Issues Today

A questionnaire was developed to gather information from subject matter experts (SMEs) of different utilities about protection challenges, modeling approaches, and fault responses and to discuss ideas on how they foresee solving the problem that higher penetrations of IBRs will pose in the future.

Questions and their responses are compiled here to see the current practices and how utilities foresee in future.

Participating utilities: AEP, TEPCO, SDGE, SMUD, Duke Energy, Southern Company

How are you modeling IBRs for Fault duty and Protection studies?

Utilities are modeling the IBRs as synchronous machines and adjusting the R, X and/or current limits of the synchronous machine models. Utilities have tried newer modeling methods introduced by fault simulation software vendors (like Aspen and CAPE) but have moved away from using the new methods because these models are still evolving. One of the issues with newer model types like voltage controlled current source is that newer model types are removed when reducing the network or providing a Thevenin equivalent. For the neighboring utilities, it is common to exchange the Thevenin equivalent with each other and utility companies need the ability to reduce the network. One utility complained that Type 4 shuts down in software (due to convergence issues).

Some utilities are adding tags to generators and distributed sources to identify what type of generation is being modeled. This allows the generator of a particular type to be toggled off/on in the future.

One international utility is using EMT analysis tools for modeling IBRs and doing plant level studies.

Have you established guidelines for modeling Type 3, Type 4 wind turbines, PV plants, and Battery Energy Resources for the above studies?

Some Utilities have not established any guidelines for modeling IBRs, some rely on the software vendor (like CAPE or Aspen) to establish guidelines, and some have established guidelines and are adopting to the evolving models.

One utility is not modeling wind turbines as sources. There are also questions about modeling the generation source as both PV and BESS.

What are the Protection Challenges that your utility is currently facing with IBRs interconnecting your Transmission system?

Absence of fault current when the IBR is on a radial feed is a big challenge. Utilities are applying current differential or direct transfer trip.

Utilities with compact systems (ie short lines) that presently require line current differential protection are not facing issues.

Based on one response, when anti-islanding detection is enabled for IBRs, voltage flicker has resulted. There is also a concern that in case of fault on a transmission with multiple IBRs, once the transmission circuit breakers will open, the multiple IBR anti-islanding detection relays/elements may interfere with each other.

IBRs can continue to generate power during grid outages. This poses an anti-islanding risk, where the IBR unintentionally operates as an unintended islanded.

During disturbances, IBRs may experience momentary cessation or trip offline if voltage or frequency deviates significantly (IBRs are sensitive to grid voltage and frequency variations).

IBR Controls often suppress injection of unbalanced currents during faults, which renders negative sequence components used for fault detection undependable.

With IBRs interconnecting to Transmission system, the utility is relying on transfer trip based anti-islanding protection which has been challenging to implement, especially when there is series of ring buses between two network sources.

Some utilities are running protection studies based on peak case, i.e., all generation online. With higher penetration of IBRs, utilities may want to analyze protection performance for off-peak cases.

What are the protection challenges that you foresee in future with high penetration of IBRs?

There is concern with high penetration, that system fault current will decrease, and conventional protection schemes may be degraded or in the worst case do not operate. SMEs think that synchronous generation will still be required for existing protection philosophy that relies on impedance-based protection or overcurrent protection.

Utilities will have to employ current differential across the system on all lines. However, this is not being investigated and we don't know what kind of redundancy in communication would be required to make that work reliably.

Utilities with large hydroelectric facilities may have less adverse impact from high penetration IBR. Hydroelectric facilities provide inertia and fault current and reducing the impact of IBRs.

IBRs may not be capable of generating sufficient negative sequence fault current with guaranteed angles. Consequently, this desensitizes protection functions reliant on negative-sequence components, such as polarization units in distance relays, which carries over to communication-aided protection schemes, such POTT and DCB schemes.

High penetration of IBRs in power systems create weak systems prone to fast power swings. Conventional distance relays may be susceptible to these fast power swings, potentially causing overtrips. They can generate off-nominal fault currents which are filtered out in the relays. These off nominal currents or voltages can be dangerous to the system but will not be detected by relays due to filtering.

Commercialized short circuit software such as CAPE and ASPEN, commonly used in utilities for protection coordination and breaker rating studies, lack a comprehensive IBR model. This deficiency introduces several uncertainties in grid operation and planning.

Utilities see protection challenges with higher IBR penetration, but they cannot quantify them due to modeling challenges.

Do you receive the events from IBRs facilities, and do you analyze them?

Utilities are not analyzing IBR responses for all the events. It has to do with timeliness of the event retrieval process, effort and coordination required to get the event from the IBR generation owner. There is also lack of industry standard for fault event data retrieval for IBRs.

One utility observed that upon request, IBR generation owners will provide records. However, record retrieval may take a long time. PRC-030 should address the fault record issues with the timeliness of records.

Utilities are not receiving events from the IBR facilities and have hard time capturing anything of significance with their DFR and PMU infrastructure.

Do you analyze IBR events? Any interesting events to share?

Utilities have seen some sub-synchronous oscillation issues, one utility observed interesting oscillations soon after commissioning of IBR plant that needed mitigation along with interactions with an adjacent combined cycle gas-powered large generation facility.

There have been cases of IBRs going offline for system disturbances many buses away. Utilities have also observed that at night solar plants are not contributing any fault current (it could be a setting in the inverters).

Utilities have observed some cases where momentary cessation was observed.

What are the things that you would like the industry to focus on with higher IBR penetration?

Timely retrieval of fault records

Lack of SCADA data form IPPs

Synthetic inertia capability from BESS

Negative sequence current injection during fault conditions.

Developing accurate and efficient short circuit models for IBRs, considering their fast dynamics and interactions with the grid. Modeling in traditional short circuit programs is the highest priority for another utility.

Understanding performance of traditional protection schemes in high penetration IBR systems is next in line (after modeling).

With higher penetration of IBRs, the overall strength of the Bulk Power System decreases. More research and development is needed around advanced protection schemes tailored to IBRs to ensure grid stability and reliability.

Researching backup protection measures like undervoltage safeguards and zero sequence overcurrent elements to mitigate risks associated with IBRs, especially during communication failures or fault conditions.

What items would you want Inverter Manufacturers to support or provide for higher IBR penetration?

Model information comes very late from the manufacturers. This causes delays with the Short Circuit studies and relay settings.

Inverter manufacturers are reluctant to share the model with utilities. It is difficult to obtain time domain models (PSCAD models) or phasor domain models unless non-disclosure agreement is signed. This can take a long time. Time domain models are needed to validate phase domain model data.

Inverter Manufacturers provide accurate EMT models.

Inverter manufacturers should collaborate with ASPEN and CAPE to develop a comprehensive and reliable Inverter-Based Resource (IBR) model for short-circuit and protection coordination studies. Additionally, they should provide the necessary data required to accurately model IBRs in these software platforms.

Have you observed any differences in the fault response for BESS during charging and discharging modes?

Normally, the failure response in charging mode is thought to be delayed. However, we have also confirmed cases where there is no difference in failure response between charging and discharging modes.

In your short circuit model, do you currently model load? Do you model cap banks, shunt reactors, or other forms of reactive support (e.g. SVC, STATCOM)?

Utilities are not modeling load in the fault simulation software. One utility is modeling cap banks and shunt reactors. One utility has started looking into modeling loads and shunt reactive devices with mixed results.

Analysis of Fault Event Data from IBR

PG&E collected events from the relays on the transmission lines connected to IBRs and reached out to other utilities for sharing relay events for studying IBR response to faults.

PG&E applied sensitive undervoltage trigger to relays on transmission lines connected to IBRs. Sensitive triggers allowed capturing the relay events for external faults even when the relay did not call for trip. We found some interesting events when the IBR response varied from one manufacturer to another and provided some insights into the IBR behavior with the voltage fluctuations.

Other utilities shared the mis operation events and other interesting events. Analyzing the events proved that protection challenges are real, and utilities are experiencing protection issues on lines that connect to IBRs.

Event 1: Solar Facility (160 MW solar facility)

Relay Location: Relay is located at remote end of Solar facility tie line. Fault is between Station A and Station B (reverse fault for relay at terminal looking towards the Solar facility (Single line diagram with the fault location is shown below).

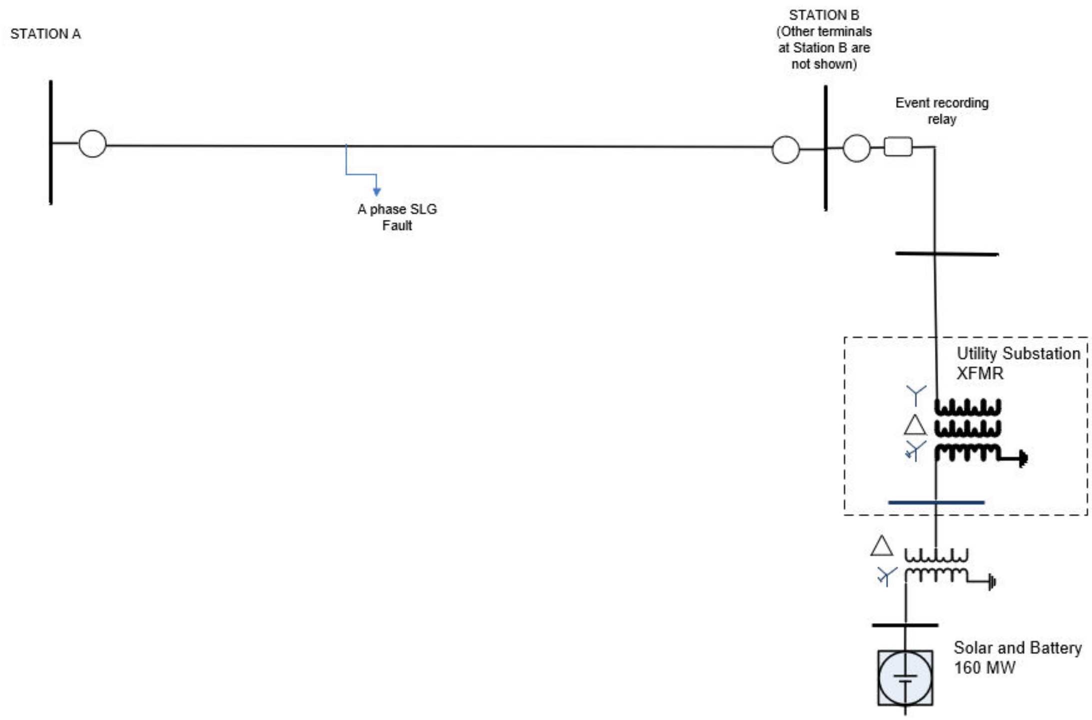

Figure 4. Single line diagram showing 160 MW IBR, location of event recording relay and the actual fault

Issues Observed:

- Relay momentarily showed forward fault for a reverse fault based on the negative sequence directional elements.
- Relay not able to identify faulted phases.

The above two issues can also be attributed to unpredictable negative sequence current. We looked at the relay settings and directional priority was set to prefer negative sequence voltage. Relay initially declared the forward fault for a fault occurring in reverse direction. Zero sequence directional element did not declare the forward fault.

Unstable relationship between I0 and I2 was shown in this case as well and relay was unable to determine the faulted phase.

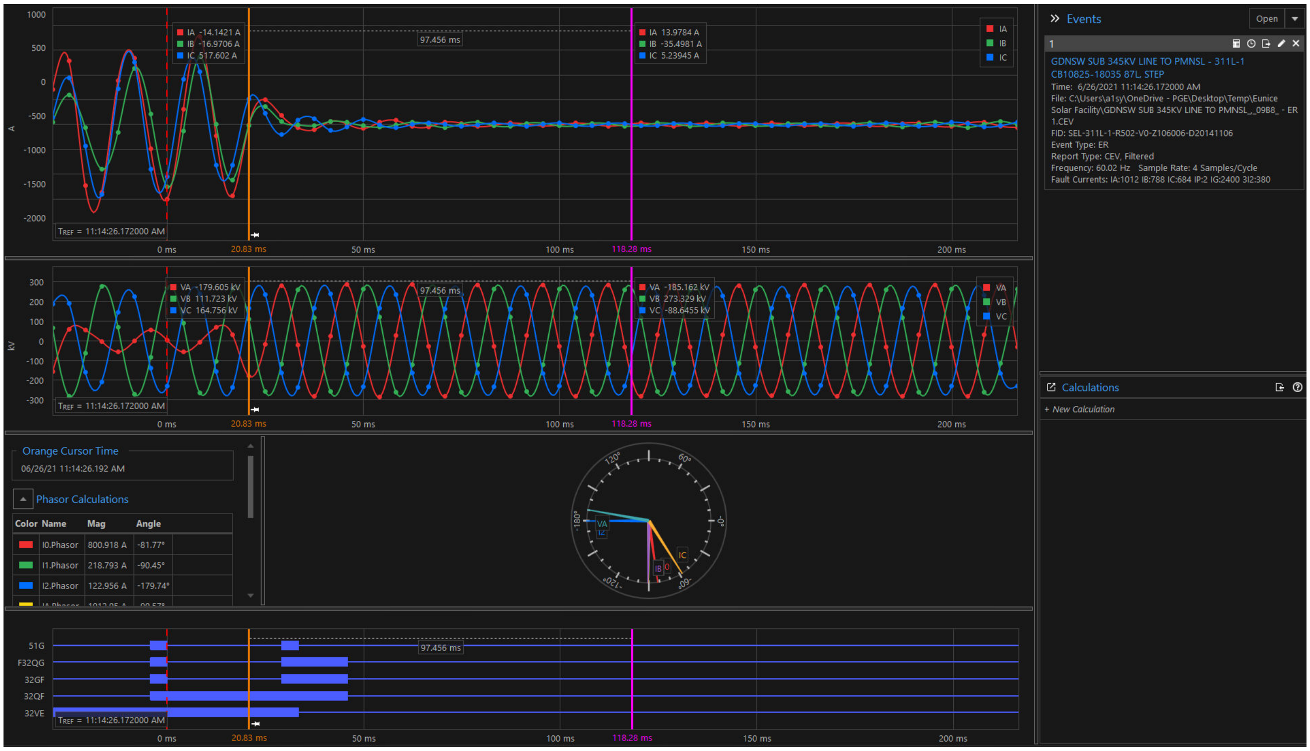

Figure 5. Oscillography from the event recording relay

32QF = Asserted

32QR = Asserted

Figure 6. Phasor diagrams (V2 and I2) plotted from the oscillography of event recording relay

Event 2: Wind IPP end relay (Type IV wind turbines, 145 MW)

Relay Location: Relay is located on high voltage side. In addition to the contribution from wind turbines, relay is seeing the zero-sequence contribution from the system through YDY transformer.

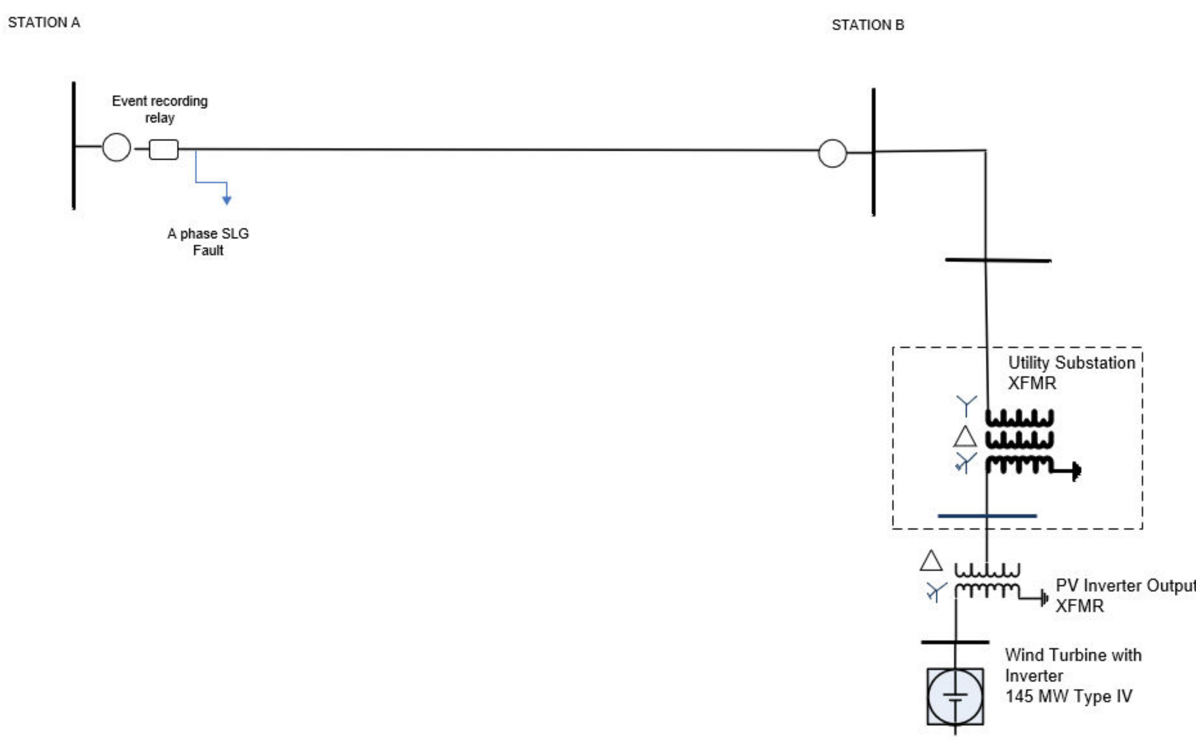

Figure 7. Single line diagram showing 145 MW Type IV wind turbine, location of event recording relay and the actual fault

Issues observed:

- Relay incorrectly reported CG fault for AG fault.

Angle between I0 and I2 is seen rotating during the event. I0 is contributed from the system (through delta winding of the transformer) and is stable whereas I2 is being contributed from IBR and has unstable frequency. This results in unpredictable and changing angular relationship between I0 and I2. Fault identification selection (FIDS) logic utilizes I2 and I0 for directional reference and does not operate properly as shown by the event below.

Figure 8. Oscillography from event recording relay near IBR

I0 and I2 phasor at fault inception

I0 and I2 phasor at later stage of fault

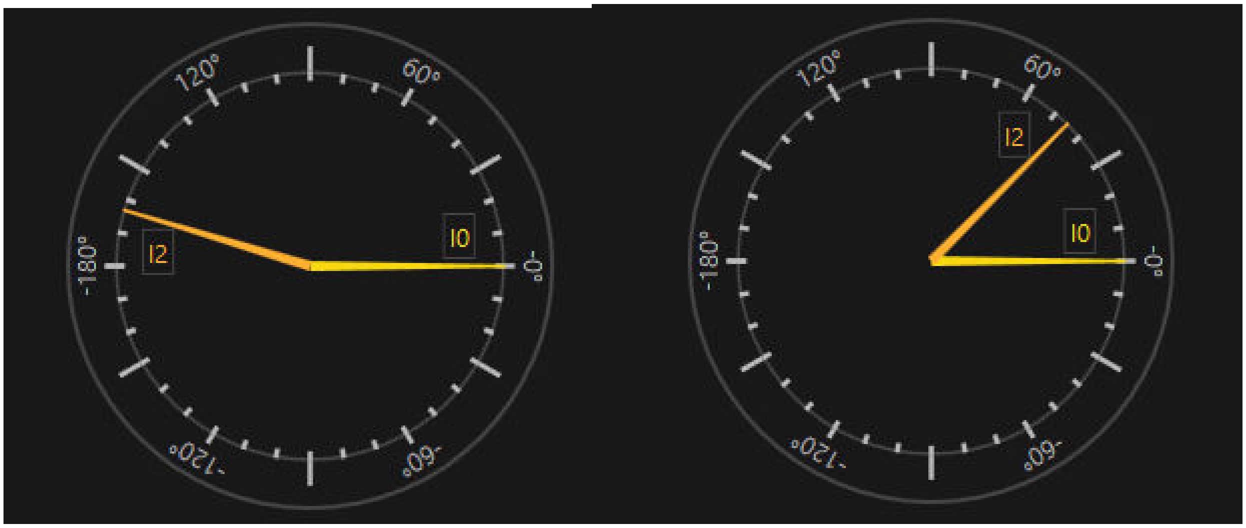

Figure 9. I0 and I2 phasors plotted from Oscillography from event recording relay

Event 3: Solar Facility (Type IV Solar Facility, 1.96 MW)

There is no positive sequence or negative sequence contribution from IBR as seen from the event. Only contribution is zero sequence, and it is from the tertiary winding of the step-up transformer. Most likely, the event happened when there was no sun (relay recorded 4:56 AM on 1/2/2022.

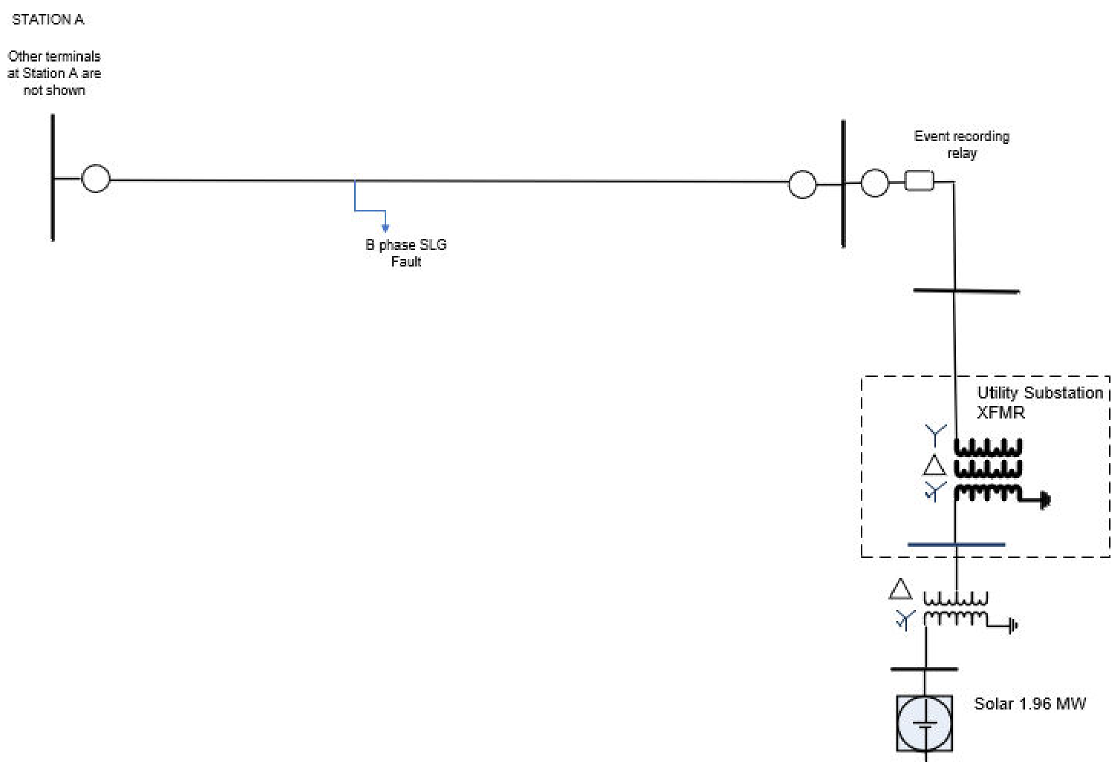

Figure 10. Single line diagram showing 1.96 MW solar facility, event recording relay and location of fault.

Issue observed:

- Relay was not able to determine the faulted phase.

In this case, relay is not able to determine the faulted phase because of the absence of negative sequence current.

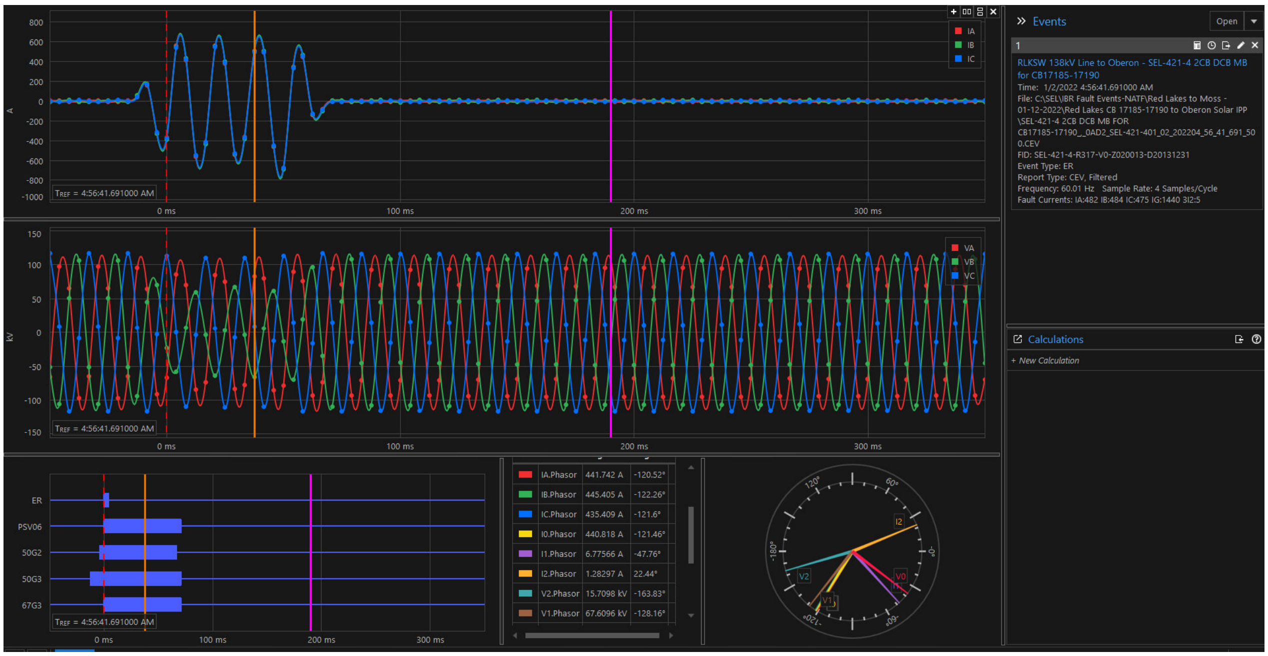

Figure 11. Oscillography of the event from relay located closed to IBR

Event 4: Misoperation of protection scheme for Interconnection lines connecting Solar IBRs to 230 kV transmission

In another event shared by a utility, misoperation of the interconnection line protection resulted in separation of IBRs and activation of anti-island trip scheme. Shown below is a single line diagram with IBRs connecting to the transmission line through Switching Station C.

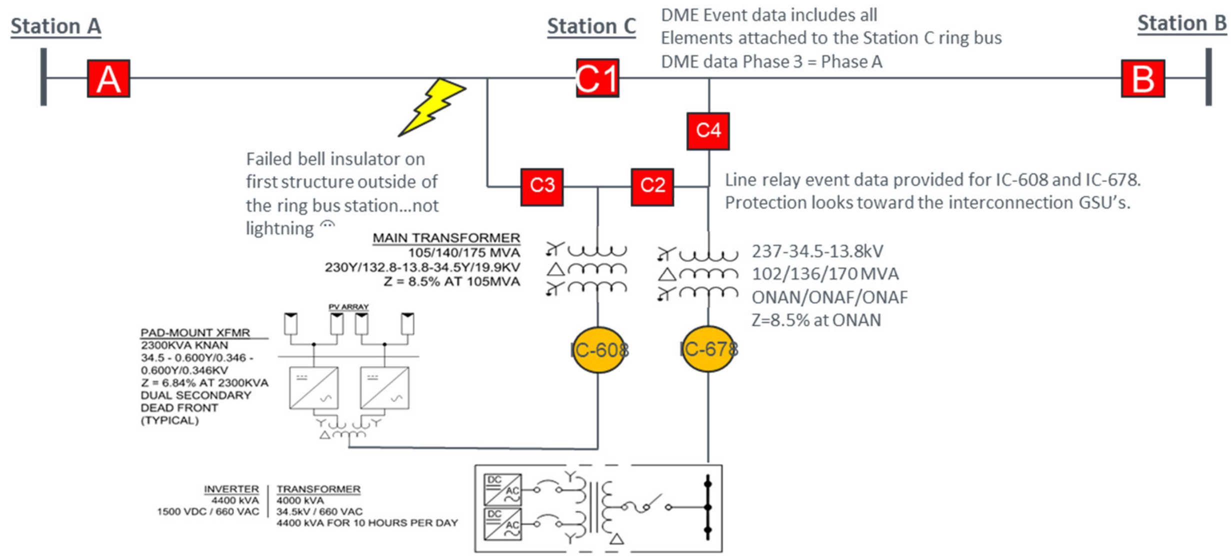

Figure 12. Oscillography of the event from relay located closed to IBR

Figure 13. Oscillography of the event from relay located closed to IBR

At the time of fault, around 35MW of generation was coming into transmission from each solar interconnection. Close in A-G fault happened on station C to station A 230 kV line. Protection on the 2 interconnection lines to the Solar IBRs misinterpreted fault as forward direction and tripped breakers C2, C3 and C4 for an out of section fault (in reverse direction). IBR contribution to the AG fault lasted 3 cycles. Protection on Station C – Station A operated correctly.

The misoperation of the interconnection line protection resulted in all four breakers at Sation C to open, which activated the anti-island trip scheme.

Analysis of the oscillography showed that negative sequence current from IBR was inconsistent and contributed to the relay wrongly determining the fault as forward direction, whereas the fault was in reverse direction. Another interesting observation from this event was that relay did not pickup the overcurrent and directional elements for the first two cycles of the fault when the fault current was not stable.

PG&E IBR Events

There were some interesting oscillography that was captured in the process. Some of the interesting events are presented below:

Event 5: BESS Event showing fault response during charge mode

BESS was in charge mode initially. During the fault event, the system configuration changes and the behavior of controller changes with the system configuration changes (remote end opens). It is necessary to perform longer simulations with system configuration changes to study the inverter response.

Interested behavior observed during the fault event was that fault phase BESS current contribution dipped and fault current magnitudes changed multiple times.

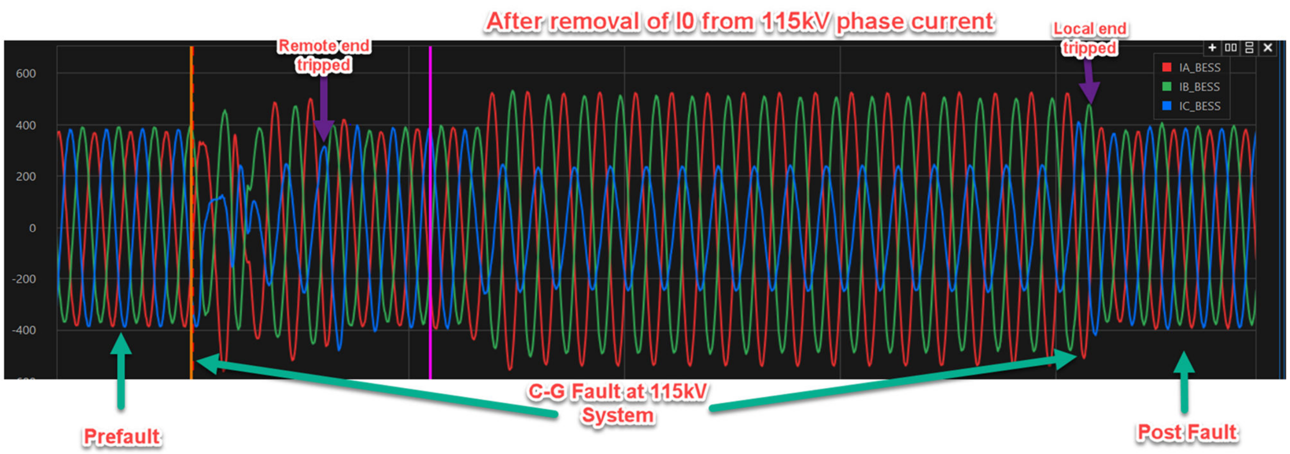

Figure 14. Oscillography from the relay event showing the changes in the response with the fault and remote breaker opening

Event 6: PG&E PV Event

Relay is located on distribution 12kV feeder looking into the PV (12MW) plant. Fault was out of section A-C phase fault.

- IBR provided ample negative-sequence current.

This feeder relay did not have directional elements, but the significant negative-sequence current produced during this short fault period resulted in a consistent reverse fault impedance characteristic as calculated from the phasors shown below (calculated _ZAC value).

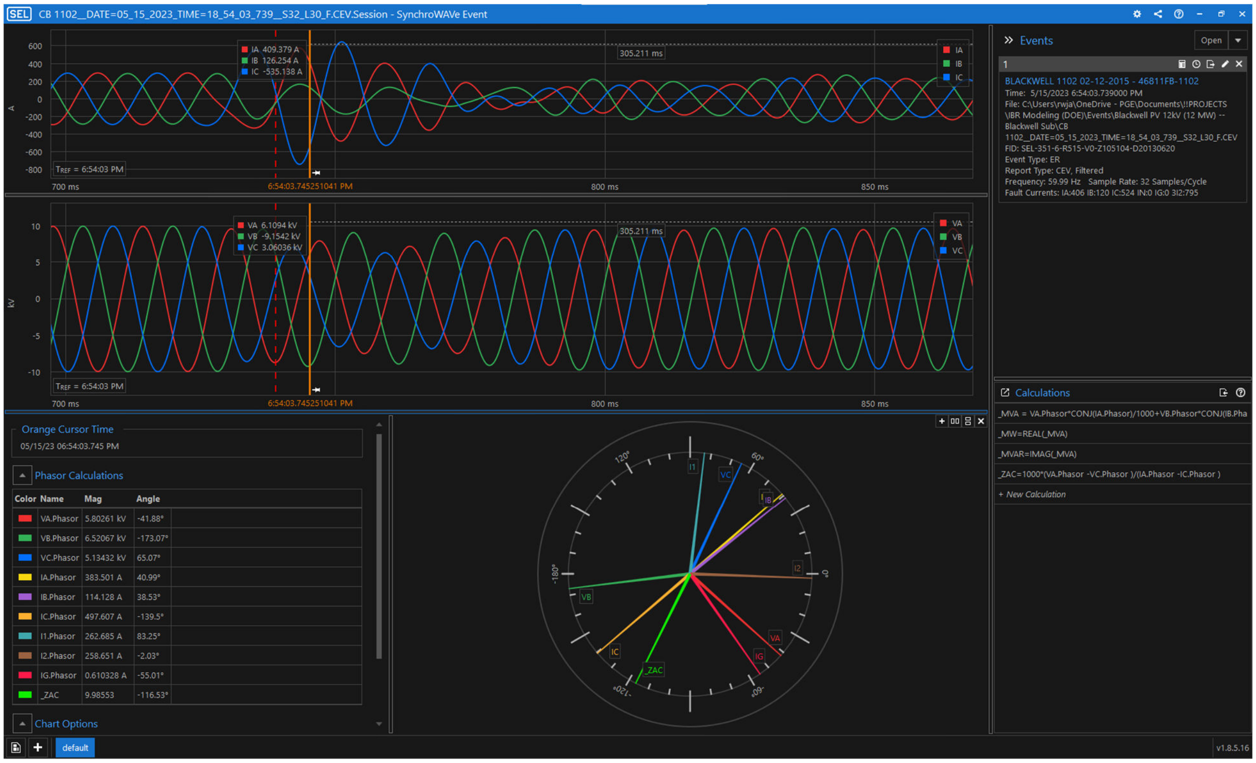

Figure 15. Oscillography from 12 kV feeder relay looking into the PV during out of section fault

Event 7: PV Event showing current oscillations

Oscillography below shows fault response of 225 MW Solar facility connected to 230 kV. Fault was an out of section LL fault on 115 kV line.

There is a large DC offset and second harmonic. Oscillography shows current oscillations with each oscillation lasting 100 milli seconds.

During the event, 230 kV voltage dropped to approximately 0.9 pu due to external fault on 115 kV line.

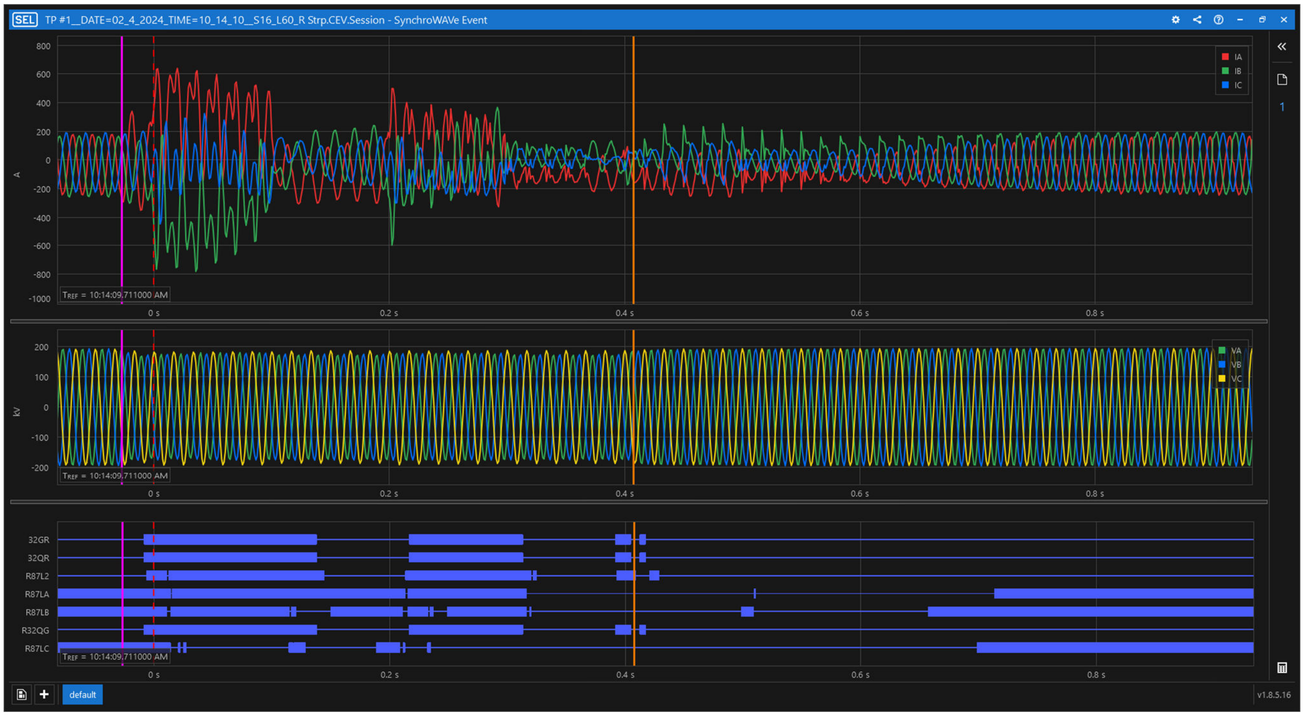

Figure 16. Oscillography showing fault response of 225 MW solar facility connected to 230 kV for out of section fault

Fault response can be explained by modeling the reactive power support during the fault as per WECC model. According to WECC model for reactive power support, the curve is not continuous by nature as shown in the figure below.

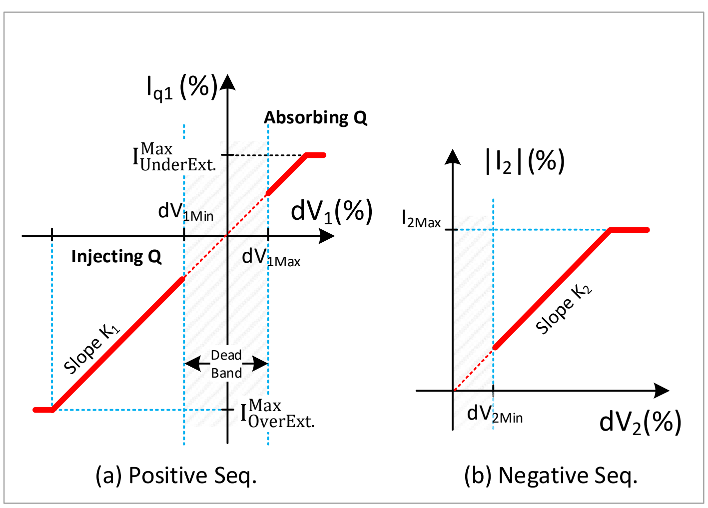

Figure 17. Reactive power support as per WECC model

Reactive current vs voltage difference curve is forced to be continuous within a 100 milli seconds time frame. For K = 2 (whereas K = dI / dV) and dV1max = (0.1 + e) pu, there will be a sudden 0.2 pu current injection. This causes a non-uniform response. Such behavior can be modeled in dynamic response simulations with oscillations showing dc offset and second harmonics.

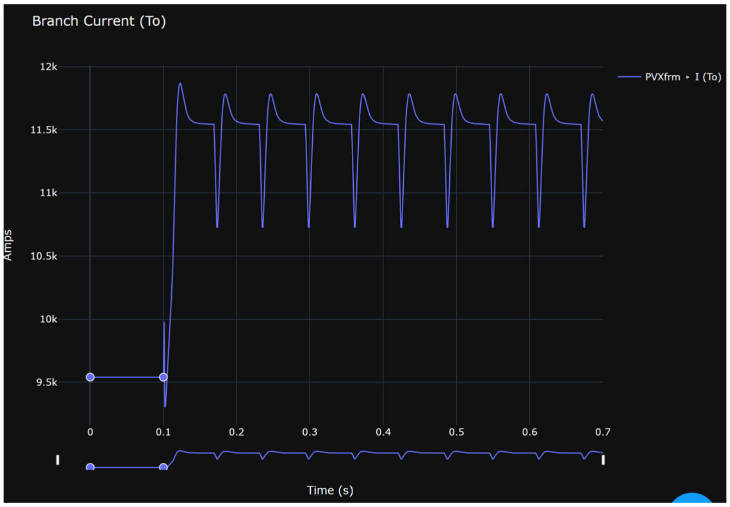

Figure 18. Dynamic response simulations

Some manufacturers have implemented dead band in the reactive power support during fault as shown below:

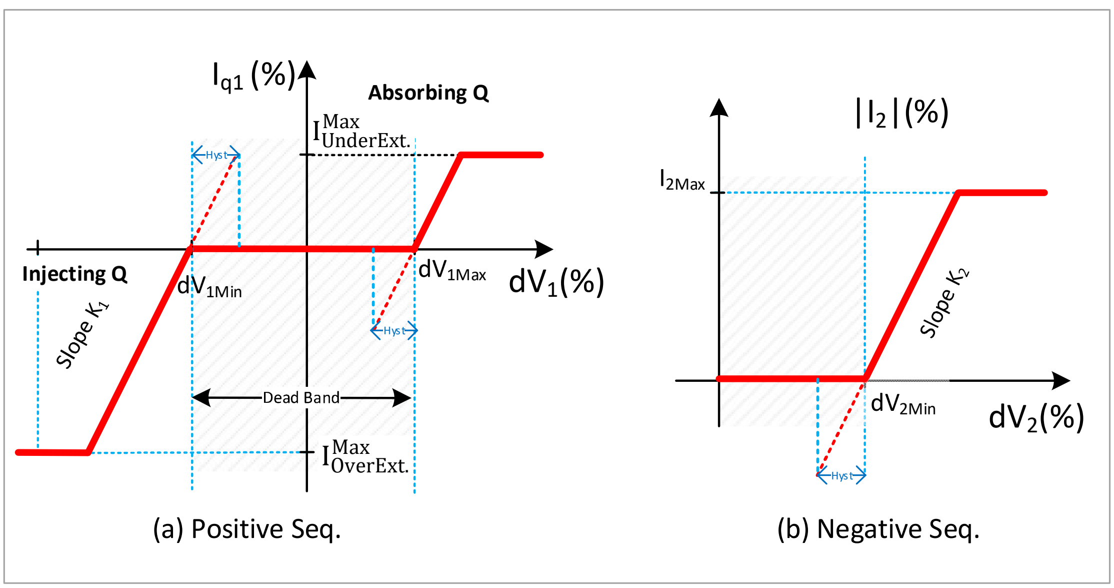

Figure 19. Reactive power support with dead band implementation

This dead band prevents sudden current injection of 0.2 pu and will prevent oscillatory response of IBRs. Simulated fault response after implementing a dead band results in non-oscillatory behavior as shown below.

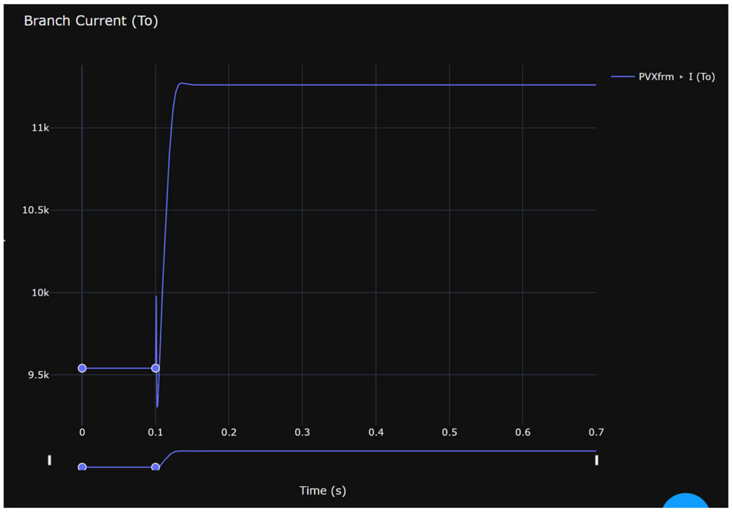

Figure 20. Simulated fault response with a dead band

Event 8: Solar plants with inverters from two manufacturers (showing momentary cessation from the IBRs of one manufacturer.

IBRs from different manufacturers connected to the same transmission bus behave differently in that one manufacturer IBR will exhibit momentary cessation while other the manufacturer IBR did not. Figure below shows the oscillography for manufacturer 1 showing momentary cessation while the oscillography for manufacturer 2 for the same event shows the inverter ride through the disturbance. However, the inverter came back from momentary cessation quickly.

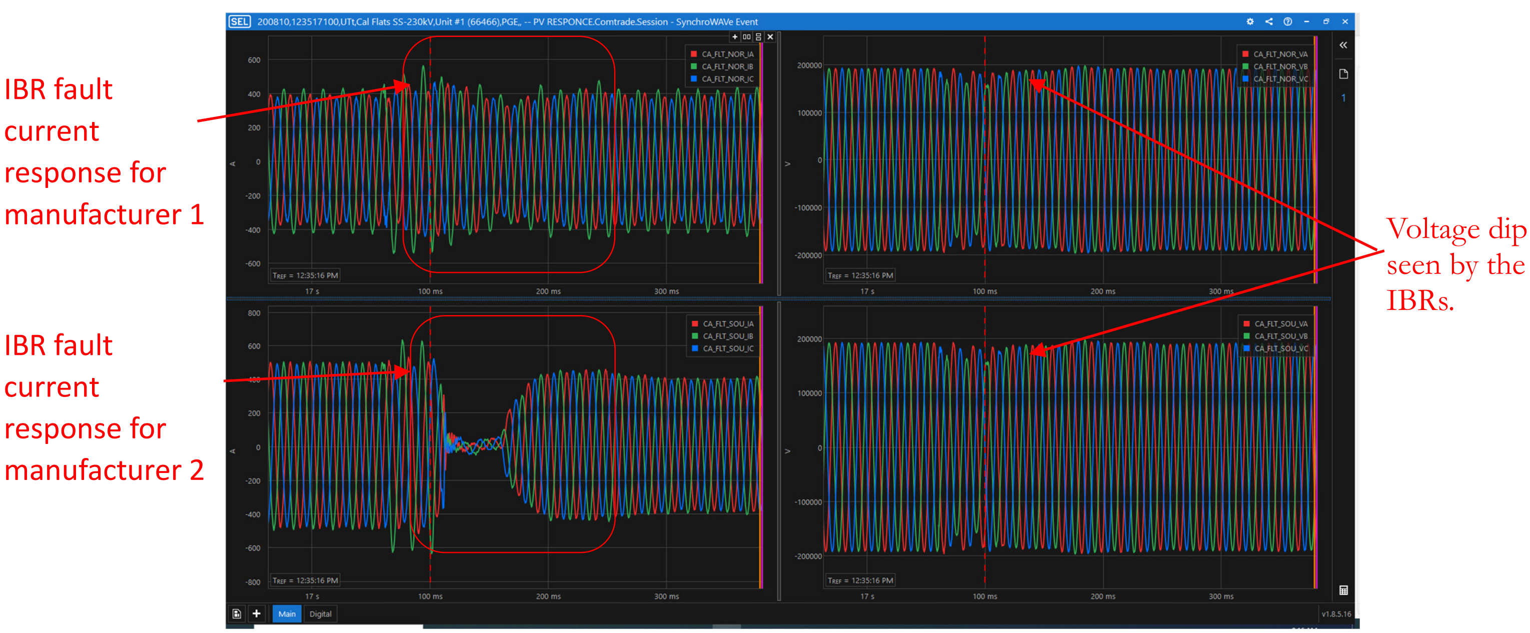

Figure 21. Relay oscillography for two IBRs connected to the same transmission bus and experiencing voltage dip from an external fault.

Event 9: PG&E event, DERs back feeding into Transmission

Event at 70 kV PG&E substation, where microprocessor relay programmed to detect ground fault overvoltages failed to trip because of the sudden frequency shift (from 60 Hz to 55 Hz in a very short time).

For a fault on 70 kV, the transmission relays operated to clear the line to ground fault on transmission. DERs from distribution were still generating which caused overvoltage on ungrounded 70 kV transmission. PG&E has microprocessor relays on high side of distribution bank to detect the overvoltage and trip the feeder breaker. With the loss of transmission, DERs could not keep the frequency stable, and frequency dropped from 60 Hz to 55 Hz very quickly. This sudden frequency shift exceeded relay's frequency tracking limit. Relay showed oscillating voltage magnitude caused by inability of the relays to track frequency which led to the relay failure to operate.

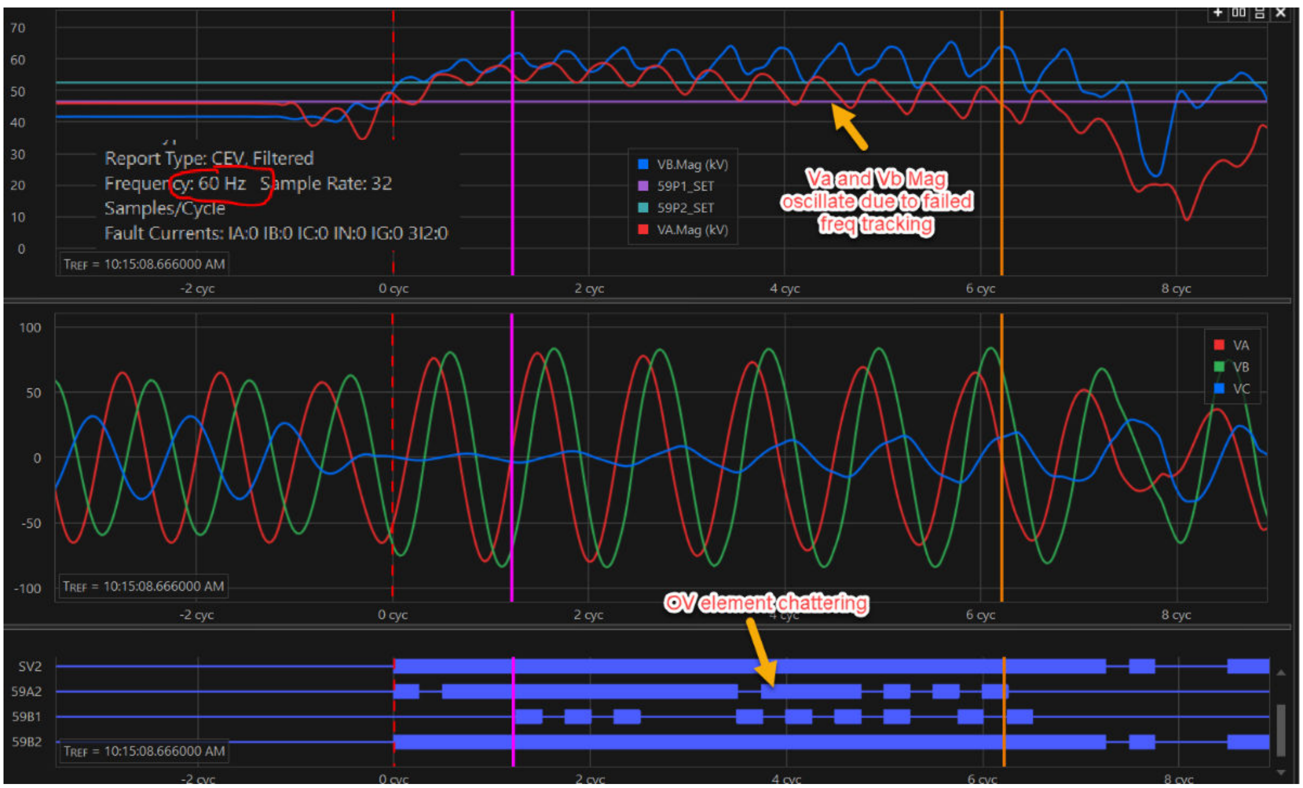

Figure 22. Oscillography from relay showing overvoltage on distribution transformer when transmission system separates.

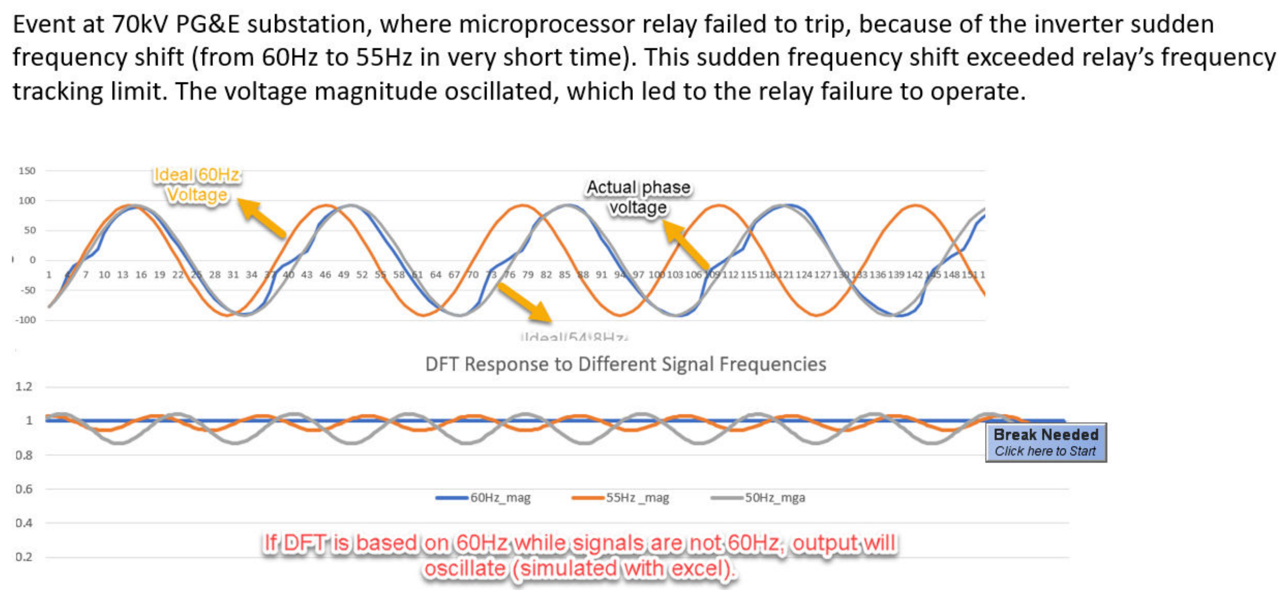

Figure 23. DFT Analysis of phase voltage event recorded by relay

Conclusions

PG&E and other utilities are seeing a rapid increase in renewable resources being added to the generation mix. Most of the renewable resources use inverters to connect to the electric grid. IBRs present unique challenges to conventional protection schemes, and higher contribution of IBRs can result in degradation of reliability if these challenges are not addressed.

This report identifies the protection challenges due to IBRs, gathers data from field protection events, and summarizes questionnaire responses from industry experts.

Commercialized short circuit software such as CAPE and ASPEN, commonly used in utilities for protection coordination and breaker rating studies, lack a comprehensive IBR model. This deficiency introduces several uncertainties in grid operation and planning. Fault currents produced by IBRs exhibit significant differences compared to fault currents by synchronous machines. Low fault current, lack of negative sequence currents, and fast-changing frequency contribute to various protection issues. Industry is already experiencing these protection issues, and this report highlights the protection issues and presents some field events highlighting some of the issues. The report references various reports, industry working groups, and NERC reports for high-profile IBR events. Based on the questionnaire responses, SMEs of various utilities are concerned about protection challenges due to high penetration of IBRs and want to develop solutions that ensure grid stability and reliability. These solutions should include developing accurate and efficient short circuit models, improving protection schemes, researching grid-forming inverters, and developing tools to automate protection analysis in an IBR-dominated generation mix.

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