Quispe and Orduña
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Protection and Control of Modern Power Systems

REVIEW

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Transmission line protection challenges influenced by inverter-based resources: a review

Juan Carlos Quispe[1,2*] and Eduardo Orduña[1]

Abstract

High penetration of renewable energy sources (RES) leads to new challenges for protection devices. Protection schemes are typically designed according to the dynamic behavior of rotating machines as generation sources, while the RES dynamic response, mainly governed by inverters, is not considered. Consequently, some relevant algorithms of transmission line protection are experiencing challenges because of the fact that magnitude and phase angle comparison, amount of negative-sequence, and short-circuit current level are affected by the RES. Therefore, an in-depth study of this issue is necessary, one which considers the main causes and new methodological criteria solutions. This work presents an extensive literature review of the evaluation of electrical protection performance and the effects of RES connected to a power grid through inverters. Bibliographic data on many representative publications related to this topic are obtained to show the current research lines and their proposed solutions. In addition, this work identifies the main protection functions affected and describes the new protection schemes that consider RES. Finally, an analysis and discussion of the selected bibliography are presented.

Keywords: Inverter-based resources, Inverter control system, Photovoltaic plant, Transmission line protection, Wind farm

1 Introduction

In recent years, electrical power systems (EPSs) have experienced continuous evolution, much of which relates to RES. This is largely driven by international commitments to reducing CO_2 emissions, social demands to tackle climate change, government incentives for clean energy, and fast cost reduction of new technologies. Wind farms (WFs) and photovoltaic plants (PVPs) are the main RES. These can significantly influence EPS. A previous report [1] indicates that their presence in EPS will continue to increase.

RESs can be classified into two groups from a dynamic point of view. The first group includes generation sources based on rotary machines connected directly to a grid, whereas the second group includes generation sources connected to a grid through power electronics (PE) equipment operating under the principles of fast converter switching and associated control systems. Many authors refer to the second group as an RES connected to the grid through an inverter as an interface, or simply inverter-based resources (IBRs) as shown in Fig. 1. This configuration is designed to take advantage of efficient use of energy [2], and new ways of energy generation have been developed and implemented on a large scale, such as the renewable power plants presented in [3].

An important aspect of IBRs is the ability to control the current rising rate and limit the short-circuit (SC) current without intervention from external circuits. For the WFs, each type of technology has a different SC-current behavior [4]. Therefore, the SC-current feature is an important issue, as the use of inverter-based generation continues to expand in EPS [5]. Consequently, traditional schemes in transmission line protection (distance, differential and directional overcurrent) which are composed of protection elements as the logic inputs of the

*Correspondence: juancarlosqh@ieee.org

[1] Institute of Electrical and Energy – CONICET, Universidad Nacional de San Juan, San Juan, Argentina
Full list of author information is available at the end of the article

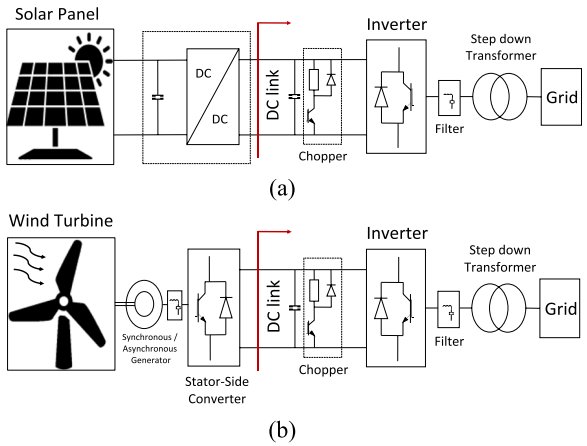


Fig. 1 Structure of IBRs: **a** photovoltaic plant, **b** wind farm type IV

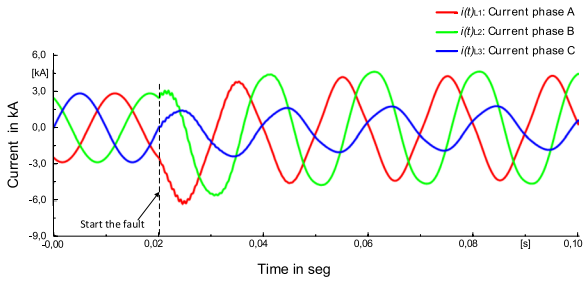


Fig. 2 SC-current behavior during a two-phase fault

main scheme, may experience challenges. Each element is based on algorithms, whose inputs are phasor signals of voltage and current in all sequences. Moreover, RESs may significantly affect some input quantities of protection algorithms and thus affect certain schemes such as negative-sequence directional, fault-type identification and phase directional elements, or impedance measurement. Therefore, traditional relays may be inadequate, since protection schemes and logics consider a system composed of synchronous generators.

Voltage and current signals present limited transient magnitudes accompanied by high harmonic distortion, as studied in [6, 7]. Low-inertia systems, complex IBR models, interactions between synchronous machine controllers and inverter controllers are studied in [8]. High penetration of IBRs entails changes in the paradigms for coordination of control and protection systems, as indicated in [9].

Therefore, this new generation source affects scheme protection. This has made it an interesting research topic. Accordingly, this paper analyzes the most representative of transmission line (TL) protection schemes in systems influenced by IBRs through an exhaustive bibliographic review. Finally, a summary of the main proposed solution methods to reduce or mitigate effects is provided.

2 Characteristics of IBR operation and fault response

The capacitor in a DC link (Fig. 1) decouples fault dynamics in an EPS with events associated with wind speed and solar intensity variation. While the fault response time is very fast, the intermittent response is slow. Therefore, an inverter is the main device which influences the dynamic behavior of IBRs during an electrical fault because their actuation time is mainly focused on the response time of the power system control [10]. The main fault control system uses voltage and current signals measured at the point of common coupling (PCC), and then their control process uses phasor signals obtained by Fourier transform (FFT) of measured signals, and it typically requires a 1 cycle time window [11]. However, a mutual agreement on the response time requirements between IBR owners and operator entity must have a clear technical base [12].

In the presence of electrical faults, energy conversion by traditional generation sources or synchronous generators is based on electromagnetic procedures and energy storage involves magnetic fields. Therefore, during a fault or transient, variations in the stored magnetic energy cannot occur instantaneously because a certain transitory period must elapse until stabilization under new conditions, as represented by (1). On the other hand, signals directly affected by IBRs are divided into three periods. In the first period there is an SC-current peak which depends on the values of the *LCL* filter and capacitor in the DC link, and it may reach magnitudes higher than 2 per unit (p.u.) on the inverter's base rating. The second period involves regulation, during which the inverter control system operates to regulate the DC link voltage in order to supply current governed by grid codes (GC) according to fault ride-through (FRT) characteristics and limit the SC-current peak. Finally, during the third period, the inverter output current reaches and maintains an approximately constant value (Fig. 2). Consequently, the IBR's behavior is not typical and may be represented as a function of fault conditions, their structures, and their control system setting parameters, as shown in (2).

$$\begin{aligned} i_{GS} =& \sqrt{2}E_q\left[\left(\frac{1}{x_{d}''}-\frac{1}{x_{d}'}\right)e^{-\frac{t}{T_{d}''}}\right. \\ &+\left.\left(\frac{1}{x_{d}'}-\frac{1}{x_{d}}\right)e^{-\frac{t}{T_{d}'}}\right)+\frac{1}{x_{d}}\Bigg]\cos\left(\omega t+\varphi_{\phi}\right) \\ &-\sqrt{2}\frac{E_q}{x_{d}''}\cos\left(\varphi_{\phi}\right)e^{-\frac{t}{T_a}},\quad t\geq t_0 \end{aligned} \tag{1}$$

$$i_{IBR} = Function(FC, ST, CSS), \quad t \geq t_0 \tag{2}$$

where *FC* means fault conditions (fault resistance, angle of insertion, fault location), *ST* refers to structure and *CSS* to control system setting.

x_d'': Subtransient reactance
x_d': Transient reactance
T_d'': Subtransient time constant
T_d': transient time constant
E_q: Quadrature axis voltage
x_d: Synchronous reactance
T_a: Armature time constants

Inverters usually have a saturation block that limits the fault currents to protect PE devices. This block is generally set to values between 1.1–1.3 p.u. [13] but can be up to 1.5 p.u. in special cases. Differences in the SC-current magnitude for each type of generation source is evident in Fig. 3. A static generator / IBR shows a different current magnitude feature after faults from other sources. Another clear example of the SC-current behavior is presented by different types of WFs and is described in [14, 15]. In addition, the characteristics of WF-IV generator (Full-scale converter generator, FSC) are different from those of a WF-III generator (Doubly fed induction generator, DFIG), while features of these generators are also different from WF-I and II generators.

On the other hand, it is known that the impedance angles of synchronous generators are stable and approximately close to 90°, while the internal impedance angles of IBRs may oscillate, and can even be capacitive, resistive, or inductive depending on the operation mode. The inverter control system causes these characteristics as it tries to keep the phase shift balanced even in the presence of faults. In addition, IBR behavior heavily relies on control system strategies during FRT. These are defined by modern GCs [16]. FRT requires the inverters to stay connected and provide reactive power support to grid during a fault without tripping. Furthermore, utilities set the FRT requirements of each interconnection, and IBRs are expected to behave in a certain way during disturbances, as specified by Standard IEEE-1547 [17]. Therefore, characteristics of FRT are highly dependent on electrical system behavior [18–21] summarize the requirements and GC configurations adopted in many countries from Europe, Asia, and America.

RESs should be designed with capabilities to operate in three possible modes, namely voltage, power factor and reactive power control. These are related to the following characteristics:

- Low voltage ride through profiles (Voltage–time profile).
- Reactive power requirement as a function of active power at nominal voltage (PQ profiles).
- Reactive power requirement as a function of voltage (UQ profiles).

The required reactive current (Iq) behavior may change according to system needs. For example, in Fig. 4, the slope "k" may vary over the range of $2 \leq k \leq 6$. The current limits (ΔIq_{max}, ΔIq_{min}) may be ± 1.0 or ± 1.1 p.u. and the voltage dead-band ($U_{dead\ band}$) can be in the range of 2.5–10% [22]. These FRT characteristics cause different behavior in the reactive fault current.

From the structure of IBRs, the inverters do not supply zero-sequence current (I_0) because of no ground return connection. Additionally, the negative-sequence current (I_2) is controlled and usually has a minimum magnitude [5]. The operating features and fault response of IBRs are summarized in Table 1.

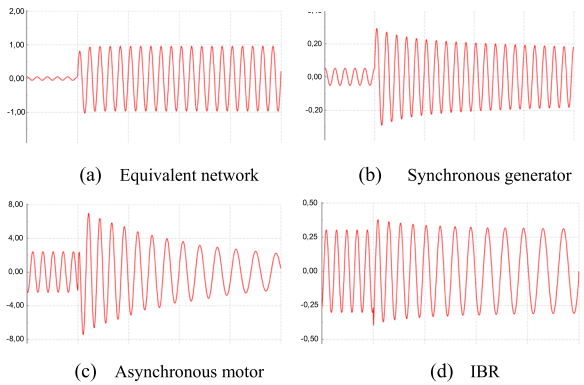


Fig. 3 SC-current features for different sources

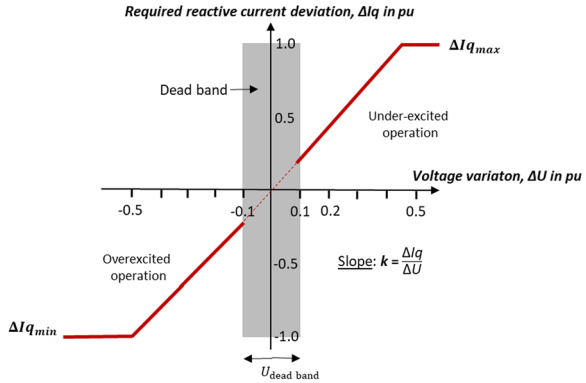


Fig. 4 Reactive power vs voltage support characteristic

Table 1 Operating characteristics of IBRs

IBR components	Operation steady-state	Fault response
Control system	Limited current amplitude Controlled phase-angle current	Controlled fault current duration (response time) Limited fault current amplitude Affected by FRT configuration type (GC) Controlled phase-angle current
Structure	A small amount of negative-sequence No presence of zero-sequence quantities	Fast transient depends on the capacitive filter (*LCL*) and Cd Unstable internal impedance A small amount of negative-sequence No presence of zero-sequence quantities

3 Main protection schemes in transmission lines (TLs)

This work focuses on the main protection schemes in TLs:

- Distance protection.
- Differential protection.
- Directional overcurrent protection.

In addition, protection elements and logics that can be used as inputs to the above-mentioned schemes include:

- Directional element protection.
- Negative-sequence protection.
- Fault-phase identification logic, fault identification selection (FIDS).

3.1 Distance protection (function 21)

Function 21 is a reliable and selective protection for TLs where their terminals are relatively far apart, i.e., for long lines [23]. It is a protective relay with responses to input quantities based mainly on a function of the electrical circuit distance between a relay location and the point of the fault [24]. This protection scheme determines the fault impedance by relating the phasor values of measured voltage and current. The calculated impedance is then compared with zone settings by the TL's impedance in order to verify a condition where this impedance is within the protection zone, and under that condition sends a trip action to the breaker [25]. Equation (3) shows the fault impedance calculation for a TL, where m is the percentage of fault location measured from bus R, Z_{TL} is the TL phasor impedance, $M-1$ and $M-1$ are the phasor fault current contributions of the TL terminals, and $\lambda \in \mathbb{R}_+$ is the phasor fault impedance. This fault is protected from both TL ends as shown in Fig. 5. In general Z_K can be represented as a resistance (*Rf*).

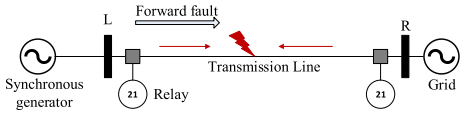


Fig. 5 Fault in TL with two power supplies

$$\overline{Z}_R = \left(m \cdot \overline{Z}_{TL} + \overline{Z}_K\right) + \frac{\overline{I}_L}{\overline{I}_R}\overline{Z}_K \tag{3}$$

$$\Delta X = \frac{\left|\overline{I}_L\right|}{\left|\overline{I}_R\right|}\overline{Z}_K \cdot \sin\left(\angle\left(\overline{I}_L, \overline{I}_R\right)\right) \tag{4}$$

$$\Delta R = \frac{\left|\overline{I}_L\right|}{\left|\overline{I}_R\right|}\overline{Z}_K \cdot \cos\left(\angle\left(\overline{I}_L, \overline{I}_R\right)\right) \tag{5}$$

Equations (4) and (5) represent reactance and resistance impedance variations (ΔX and ΔR) obtained from Eq. (3), respectively. Therefore, the fault impedance calculated by relays depends on magnitude and phase angle relationships of the current signals from both ends and the fault impedance. In a three-phase system (ABC), distance relay algorithms determine three phase–phase loops (21AB, 21BC, and 21AC) and three phase–ground loops (21AG, 21BG, and 21CG). The operation logic consists of activating the following conditions using AND logic:

- *Impedance calculation* zone 1 setting is 80% of the TL impedance, zone 2 setting is 120% of the TL impedance with a time delay, and zone 3 covers almost all the TL adjacent with high time delay. When a fault impedance is inside the zone, this logic is activated.
- *Fault detector threshold (starting)* The overcurrent applied setting should be approximately 1.2–1.3 of the maximum load current for phases (I_n) and 0.3–0.5 of the current transformer rating for ground fault currents. For under-impedance, the voltage threshold is controlled by current, so that the pick-up sensitivity of voltage is increased as the current increases. Typical settings are: $I>0.25I_n$, $I>>2.5I_n$, as well as $V(I>)=70\%V_n$ and $V(I>>)=90\%V_n$. Other methods are angle-dependent under-impedance starting (VI/ϕ) and impedance starting [26].
- Directional elements.
- Fault-phase identification logic.

The above two conditions will be discussed in detail below. It should be highlighted that directional elements and fault-phase identification logic use polarization of voltages. These include phases not involved in the fault. Table 2 shows a summary of all operating and polarizing variables.

It is important to mention that some relay manufacturers use zero- and negative-sequences for polarization, as detailed further below.

3.2 Differential protection (function 81)

The operating principle of differential protection is represented as:

$$I_{op} \geq I_{op0}, I_{op} = \left|\bar{I}_L + \bar{I}_R\right| \tag{6}$$

$$I_{op} \geq k \cdot I_{res}, I_{res} = \left|\bar{I}_L - \bar{I}_R\right| \tag{7}$$

where $\boldsymbol{b} \in \mathbb{C}^M$ and $\lambda \boldsymbol{b}\boldsymbol{b}^{\mathsf{H}}$ are the differential current and restriction current, respectively. An element generates a tripping signal when λ is greater than a percentage of $\boldsymbol{b}$ and a minimum pickup current is exceeded. $\boldsymbol{b}$ is the threshold value that prevents relay malfunction when the restriction current is close to zero with "*k*" as the restriction coefficient.

The differential operation of the currents is conducted using phasor measurements for each phase. The operation logic of this protection function consists of the activation of the following conditions using an AND logic:

- Threshold current for start.
- Fault-phase selection logic.
- Angular difference of currents.

For internal faults (Fig. 6), the current angles for both sides of a TL are in phase under ideal conditions. In general, the angle difference depends on the source voltage angles (pre-fault power flow condition) and the angles of the system impedances at both sides of the fault point [25].

Many manufacturers also choose to use zero- and negative-sequence elements to provide sensitive protection in the presence of unbalanced faults.

Table 2 Polarization configuration

Polarization	Operating	Polarizing	Details
Self-polarization	$Z_R I_{XY} - V_{XY}$	V_{XY}	$XY = AB, BC, CA$ Z_R: impedance setting
Cross-polarization without memory	$Z_R I_{XY} - V_{XY}$	$-jV_Z$	$XY = AB, BC, CA$ $Z = C, A, B$ Z_R: impedance setting
Cross-polarization with memory	$Z_R I_{XY} - V_{XY}$	$-jV_{Z\_MEM}$	$XY = AB, BC, CA$ $Z = C, A, B$ Z_R: impedance setting
Positive-sequence memory polarized	$Z_R I_{XY} - V_{XY}$	$-jV_{Z1\_MEM}$	$XY = AB, BC, CA$ $Z = C, A, B$ Z_R: impedance setting
Self-polarization	$Z_R(I_X + kI_R) - V_{XG}$	V_{XG}	$Z = A, B, C$ $I_R = I_A + I_B + I_C$ $k = (Z_0 - Z_1)/3Z_1$
Cross-polarization without memory	$Z_R(I_X + kI_R) - V_{XG}$	jV_{YZ}	$X = A, B, C$ $YZ = BC, CA, AB$ $I_R = I_A + I_B + I_C$ $k = (Z_0 - Z_1)/3Z_1$
Positive-sequence memory polarized	$Z_R(I_X + kI_R)$-V_{XG}	V_{X1_MEM}	$X = A, B, C$ $I_R = I_A + I_B + I_C$ Z_R: impedance setting

3.3 Directional element protection (function 32)

(a) Directional elements for phase fault protection (32P)

Directional elements mainly determine the direction of faults (forward or backward). Therefore they are part of the principal protection schemes and these elements respond to a phase change between a polarized quantity and an operational quantity (Table 2). In the example in Fig.7the voltage (*V*) represents the polarized quantity and current (*I*) the operational quantity. The operating condition is given as:

$$\varphi_{sen} + 90^\circ > Arg\left(\frac{\overline{V}_{an}}{\bar{I}_a}\right) > \varphi_{sen} - 90^\circ \tag{8}$$

where λ represents the maximum sensitivity angle, which can be equal to the TL impedance angle from bus to fault point. This expression can be represented in an impedance plane (*R-X*) as shown in Fig. 8.

TL impedance features are predominantly inductive. Thus, when the current lags with respect to the voltage, a forward fault occurs. In contrast, when the current signal changes its sign, it is considered a backward fault.

(b) Directional elements for ground fault protection

During a ground fault, the negative- and zero-sequence, voltage-polarized directional elements respond to impedance. Therefore, voltage-polarized directional elements are complemented by 32Q or 32G. The most common schemes that can be used to detect fault direction are shown in Table 3.

The 32I element can determine the direction when the fault-type identification (FID) logic trips and indicates a

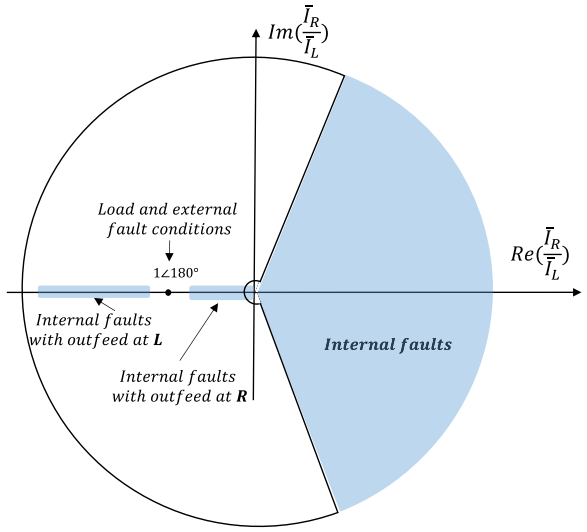


Fig. 6 Alpha plane characteristic

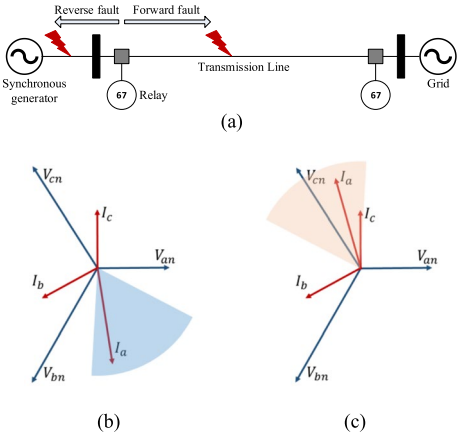


Fig. 7 Directional element operation. **a** General electrical system, **b** Blue zone means forward condition, and **c** Orange zone means reverse condition

balanced fault. In comparison, the 32Q or 32G elements are used when the FID logic asserts an unbalanced fault. In addition, some manufacturers also use combinations of these elements.

3.4 Negative-sequence protection

This protection depends on negative-sequence current which has advantages over zero-sequence current. For instance, it is insensitive to zero-sequence mutual coupling and is not vulnerable to excessive tripping on external ground faults on TLs that share right of way. Moreover, it requires only a simple calculation. Its functions are as follows.

(a) Negative-sequence overcurrent element (50Q/51Q)

This function operates from a starting threshold value known as a pickup setting and a time dial. With synchronous generators, it does not present any issue in starting because of high negative-sequence current. In practical application, the thresholds are set at least higher than 1.5 times the nominal rated current.

(b) Directional negative-sequence overcurrent element (67Q)

Unlike the previous function, this is characterized by determining the directionality of a fault based on the negative-sequence voltage (V_2) and current values, as shown in Fig. 9.

The criterion is based on the fact that a forward/reverse fault causes a phase angle of approximately − 90°/90° for the voltage phasor with respect to the current phasor [27–29]. This assumption stems from the highly inductive nature of the negative-sequence network in a network dominated by synchronous generators.

3.5 Faulted-phase identification

Phase selection is important in preventing incorrect operation as it allows the identification of faulty phases and is part of protection schemes. There are schemes that have changed and are applied to phase fault selection loops, such as:

- A computationally efficient numerical method of characterizing distance elements onto a single point on a number line.
- Positive-sequence memory polarization for low- (or zero-) voltage faults for over 1 s.
- FIDS logic that uses measured negative- and zero-sequence currents.
- Decision trees (DTs) algorithm, including magnitude of currents, delta currents, magnitude of voltages, delta voltages, and impedances. Because of the structure of the DT, not all criteria are evaluated to obtain a result.

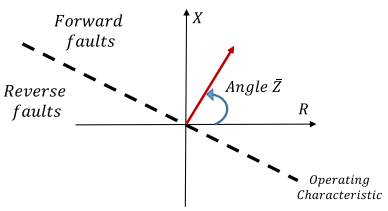


Fig. 8 *X-R* plane of forward and reverse fault characterization

Table 3 Polarization for zero- and negative-sequence

Polarization	Operating	Variables	Comments
Zero-sequence current polarization (32I)	$T = Re[3I_0 . I_{POL}^*]$	I_0, I_{POL}	I_{POL}: Current polarization
Negative-sequence voltage polarization (32Q)	$z_2 = Re[V_2 (I_2 .1\angle Z1_{ANG})^*]/I_2^2$	I_2, V_2, $Z1_{ANG}$	$Z1_{ANG}$: impedance setting
Zero-sequence voltage polarization (32 V)	$z_0 = Re[3V_0 (3I_0 .1\angle Z0_{MTA})]/(3I_0)^2$	$3I_0$, $3V_0$, $Z0_{MTA}$	Z_{0MTA}: maximum torque angle, setting

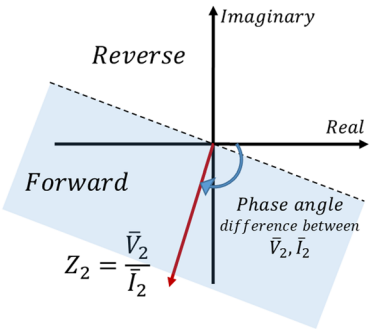


Fig. 9 Apparent negative-sequence fault impedance seen by 67Q

Therefore, fault identification logic can also be used to differentiate balanced and unbalanced faults. This function serves as an input element for main functions.

(a) FIDS Logic

This scheme involves the identification of a fault type based on a phase angle relationship between negative- and zero-sequence currents. The fault loop classification method was shown in Fig. 7. A successful FIDS operation is based on the validity of the assumed mathematical relationships between the phase angles of zero- (I_{a0}) and negative-sequence (I_{a2}) quantities of phase A (Fig. 10, Table 4). In a network dominated by synchronous generators, this relationship is valid because of the inductive nature of the negative-sequence network and the impedance of the machines [30].

3.6 Directional overcurrent protection (function 67)

Directional overcurrent protection uses directional elements to supervise the operation of overcurrent elements [25]. This element has been described in the previous section. On the other hand, when three-phase and phase-to-phase SC faults occur at any point in a power system,

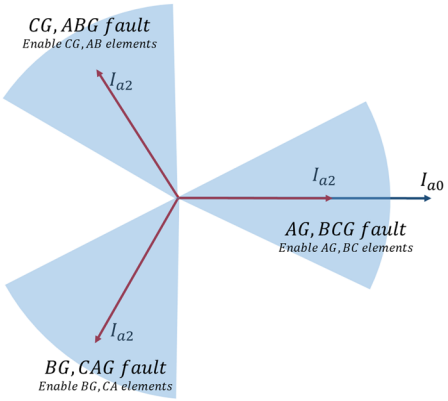


Fig. 10 Fault identification criteria

the amplitude of the SC-current is usually larger than the load current, and thus the overcurrent protection is distinguished from a normal operating state by the amplitude of currents [31]. This criterion is simple and reliable, and easy to implement. The operating logic is based on (9), where I_{set} is the starting threshold current:

$$I > I_{set} \tag{9}$$

It has been shown that all functions and protection elements are based on different schemes, while some of them present certain variations because of the operating logics of different manufacturers. In general, phasors and polarization are two important and useful tools in traditional power system protection, and these concepts are essential in understanding power system performance during both normal and abnormal operation. Phasors are composed of magnitude and angle, while polarization is a comparison between two phasor quantities. The phasors are derived from transforming sinusoidal signals by FFT.

In addition, a referential percentage of influence of the phasor quantities and comparisons among them for each protection function are shown in Table 5. It can be seen that distance protection and directional element require the most signals for their protection scheme. This indicates that distance protection will be greatly affected by the influence of IBRs while differential protection will be largely unaffected.

4 Review of the state of the art

This review is focused on challenges of TL protection studies considering the influence of IBRs. The cited works are based on experience and theory. M, while many new protection methods have been developed to suppress or minimize the effect of IBRs.

Table 4 FIDS logic

Angle between I_{a2} and I_{a0}	Fault type permission
I_{a2} is ± 30° of I_{a0}	Permit AG or BC
I_{a2} lags I_{a0} by 90° – 150°	Permit BG or CA
I_{a2} leads I_{a0} by 90° – 150°	Permit CG or AB
I_{a2} leads *or* lags I_{a0} by 30° – 60°	Select the ptp mho element with the lowest calculated reach. Compare |*Rag*| with the |*Rf*| of that element
I_{a2} lags I_{a0} by 60° – 90° or 150° – 180°	Select the ptp mho element with the lowest calculated reach. Compare |*Rbg*| with the |*Rf*| of that element
I_{a2} leads I_{a0} by 60° – 90° or 150° – 180°	Select the ptp mho element with the lowest calculated reach. Compare |*Rcg*| with the |*Rf*| of that element

ptp is phase-to-phase, *Rag*, *Rbg*, *Rcg* are A, B, C phase-to-ground fault resistances respectively, and *Rf* is the fault resistance

4.1 Protection scheme challenges with IBR integration

(a) Challenges in distance protection

The main problems of TLs emanating from IBRs in distance relays are described in this section. A previous study in [32] describes the impedance behavior of IBRs with FRT under two different GCs: the European (EU) and the North American (NA). It is shown that reactive current required by the EU-GC translates into impedances seen near the reactive axis. In contrast, the power factor requirement of the NA-GC translates into impedances along the resistive axis. As a result, in both cases, the impedances seen from faults are far from the actual fault impedances. Therefore, it concludes that the variations of the impedances seen depend on the control strategies implemented in the IBRs. This is further stated in [33], where it is reported that the impedance measured on the IBR side has a different characteristic, causing conventional distance protection to malfunction, as the inverter control system limits the SC-current and controls the angle shift. However, in [34], it emphasizes problems in the response time of the control system (rise time) when the IBRs supply reactive power. It shows that a slow response time causes a malfunction in the distance relay, since zone 2 might be mistaken for zone 1 during a fault. In [35], distance protection behavior is detailed in a distribution system with high penetration of IBRs, and a dynamic analysis is conducted in a three-dimensional system (*R, X, t*). Different behavior from synchronous generators is observed because of the fault current limit. In [36], it shows that the phase distance element of zones 1 and 2 may overreach and drop out, respectively, because of an oscillating apparent impedance caused by currents injected by the IBRs. This is reinforced in [37], in that the impedances seen by distance relays outside an IBR present a problem of overreaching zones, caused by the inverter control system.

Reference [38] presents a polarization problem in an impedance relay type mho affected by the variable impedance of a WF-III or DFIG. This is caused by transient and steady-state components in the SC-current injection before reaching a stable value. Reference [39] describes some effects of WF-III on distance protection. As protection relays are not acquainted with the behavior of the generator, this leads to large variations between the phases of the fault current and voltage. Consequently, this causes a chaotic trajectory for the impedance values.

In the same line of research, reference [40] describes the presence of back-to-back converters as a predominant problem source and their effects on distance protection. It indicates that PE converters not contributing to fault current are the main problem. Meanwhile, in [41], the impact of converter in voltage source converters of high-voltage direct current (VSC-HVDC) of the distance relay coordination is described. This presents an overestimation effect on impedance measurements because of the control system, and is similar to the behavior of IBRs. In [42], it shows that effects on distance protection due to the control scheme of the VSC-HVDC connected offshore WF during an AC fault are caused by the amplitude and phase of currents controlled by the WF. In [43], the impact of a modular multi-level converter (MMC-HVDC) on distance protection is described. This is due to changes in the operation mode of the converter control reducing the range of zone 2 of the distance relay, resulting in malfunction. Finally, reference [44] shows the effects of a VSC on distance protection due to the control strategies of the converter. Thus a synchronous compensator is considered in the installation. A summary is shown in Table 6.

(b) Challenges in differential protection

In [53], problems in the differential protection of TLs are described, and it indicates that the differential relay on the side of IBRs presents some challenges in line protection sensitivity, such as a starting logic and phase detection. This is due to a low influence of current penetration and the inverter control strategy, which presents different behavior in each phase of the three-phase current system as it depends on the voltage drop level of each phase. Reference [54] shows an important factor that affects differential protection, where the angular difference of the fault phasor current at the line terminals may be greater than 90° under a phase-to-phase fault but not sufficient. It concludes that the problem lies in

Table 5 Influence of variables on principal functions and element protection

Protection function	Magnitude							Angular offset between				Shift angle of each phase	Magnitude and angle	Percentage of usage
	I1	V1	Z1	I2	V2	I0	V0	(I1,V1)	(I2,V2)	(I0,V0)	(I2,V0)	(IABC,VABC)	(IL,VR)	%
(a)	✓	✓	✓			✓	✓	✓		✓		✓	✓	69.2
(b)	✓												✓	15.3
(c)	✓	✓		✓	✓	✓	✓		✓	✓		✓		69.2
(d)	✓			✓		✓					✓	✓		38.4
(e)				✓	✓				✓		✓			30.7
(f)	✓			✓		✓								23.0

(a) Distance protection (21)—impedance calculation and fault detector threshold

(b) Differential protection (87)

(c) Directional element protection (32)

(d) Fault-type identification logic, phase selection logic (FIDS)

(e) Negative-sequence protection

(f) Overcurrent protection

the angular difference between the currents, as a phase–phase fault generates an angular difference of almost 180° on the network side, while remaining at almost 120° on the IBR side. This is due to control strategies during the FRT period, as seen in Table 7.

(iii) Challenges in directional element protection

In [55], a real event is analyzed and problems in the directionality of an overcurrent relay are observed. In this case, a distortion in the fault signals and the change in angular differences between voltages and currents affected the ability of existing protection relays to identify the correct direction of the fault. Manufacturers use negative-sequence quantities for this method.

(iv) Challenges in negative-sequence overcurrent protection

Other studies [50, 56] describe the main factors of IBRs in negative-sequence protection. Concerning the 50Q/51Q elements, the main problem affects the pickup as the negative-sequence current may be smaller than the activation threshold. Concerning the 67Q element, as in the previous case, it presents starting problems. It also shows directionality problems as the angular relationship of the negative-sequence voltage and current phasors under IBRs is modified.

In [51], problems in TL protection are described and, in particular, the use of negative-sequence quantities for detecting unbalanced faults is covered. GC considers the behavior of negative-sequence quantities in unbalanced faults [57]. The negative-sequence control capability of the DFIG is limited, whereas the fully rated converter WT is able to suppress the negative-sequence current completely. Finally, effects of IBRs on their own protection are considered, though it further involves systemic protections. Experiences in Germany are discussed [58] (Table 8).

4.2 Protection schemes with IBR integration

(a) Adaptive protection schemes and modification of traditional protection

Addressing the distance protection algorithms influenced by IBRs, the most commonly used schemes are adaptive methods. In [62], a combination of conventional distance protection, voltage drop, a new directional element, and a communication-assisted method is used. In [39], a modification of a permissive overreaching transfer trip (POTT) of a tele-protection scheme is proposed, where the remote relay (grid side) uses an overreach zone based on impedance, while the WF-side relay detects the fault direction according to the properties of the current waveform. However, in [33], an improved scheme based on time delay and the zero-sequence of impedance and overcurrent signal for starting is proposed, whereas [40] proposes the mandatory use of differential protection on TL in the presence of IBRs. In [41], a new method is proposed to reset the distance protection parameters that present overreach or underreach by calculating an apparent impedance based on Z_{bus}. An adaptive coefficient of variation is proposed in [63] to calculate the zone 2 configuration according to the fault type and the equivalent sequence impedances of WFs. Because of the large fluctuations of the FWs connected to the grid, reference [64] proposes an adaptive method for distance protection using information on the bus voltage, current, and the number of generating units connected at that time. In

Table 6 Causes and effects on distance protection due to IBRs

Distance protection (21)					
Function		**References**	**Technology**	**Cause**	**Effect**
Zone impedance (zone 1, zone 2)	21	[32]	IBR	Control system parameters, current limit setting	The relay impedance can be far away from the actual fault impedance
		[34]	IBR	Low SC current, reactive current rise time	The initial fault impedance by distance relay moves closer to zone 1 setting even for zone 2 faults
		[39]	WF-III	The frequencies of the fault current and voltage can be well apart	Oscillating impedance
		[33]	IBR	Phase angles are controlled by inverter control system	The impedance has a great amplitude and phase offset
		[40]	Back-to-back Converter	Power electronic converters do not tend to contribute to the fault current	The impedance by relay is very high and it can see outside of the protection zones
		[44]	VSC	Design of control system, lower SC-current level	The measured impedance locus has transients. The impedance moves in and out from the effective zone during the fault
		[36]	IBR	Low-magnitude currents that may behave incoherently with the voltages	Phase distance element zone 1 may overreach; zone 2 may drop out; oscillating apparent impedance
		[37]	IBR	Inverter control system	Effect on impedance, zone 1 overreach
		[41]	VSC-HVDC	Reactive power control of VSC-HVDC	Relay tends to overestimate the fault distance
		[42, 43]	WF/VSC-HVDC	Different FRT controls, control of current amplitude and phase	Malfunction of the distance relay; the higher line distance relay zone 2 is narrowed
		[45]	IBR	Inverter reactive power current	Over reach or under reach of impedance measurement
		[46–48]	WF-III	Depends on the operating mode	Affects the trip boundaries of the distance relay
Overcurrent starting	50	[35]	IBR	Inverters are nonlinear electronic devices	Insufficient SC-current, delay in operation
Directional element	32P	[38]	WF-III	The short-circuit current mainly consists of a transient component and a steady-state component	Effect on positive-sequence voltage polarized impedance relay
		[36]	IBR	Current limited by the inverter	The phase directional element may misbehave when a three-phase fault disconnects the IBR
	32Q	[36]	IBR	Negative-sequence current limited	The negative-sequence directional element may misbehave
		[49]	WF-III	Low voltage ride requirements	The relationship between the current and voltage phase angle in negative-sequence is not readily known
		[50]	IBR, WF-III	Improper magnitude and phase angle of negative-sequence current	The negative-sequence current is not the leading voltage as in a conventional source
		[51]	WF-III	Low-voltage ride through requirements	Improper magnitude and phase angle of the negative-sequence current
Fault-type identification and selection	FID	[52]	WF-III	Slip and crowbar resistance	The approximately unequal positive and negative currents will critically affect the phase selectors according to their variation components

Table 7 Causes and effects on differential protection due to IBRs

Differential protection (87L)				
Function	**Refences***	**Tech****	**Cause**	**Effect**
Threshold current start	[53]	WF	Current limit protection by inverter control	Starting current does not operate
Phase selection logic	[53]	WF	Inverter control strategy, low-voltage ride-through	The inverter acts to increase the phase current phase
	[54]	IBR	Control strategies during FRT	The angular difference of the faulted phase is not enough

*Reference, **Generator technology

[51], the use of zero-sequence current generated by the power transformer that connects the IBR to the grid is proposed. In this case, it is necessary to have a grounded star connection on the grid side. Additionally, in [43], an adaptive distance relay based on the measurement information on HVDC-side common connection points is developed.

For differential protection, reference [53] develops new adaptive protection schemes taking signals from auxiliary undervoltage components for starting the differential protection logic and components with zero-sequence for phase selection. An aspect to consider in this criterion is the verification of faults in remote lines as they also produce undervoltage. Another study in [55] proposes an adaptation of a directional detection algorithm through line angle modification and positive-sequence modification in order to increase the magnitude of negative-sequence quantities, whereas [65] presents a voltage-based phase selector scheme as the adjustment using current-based phase selectors present problems under the influence of IBRs. In [66], a scheme based on reactive power flow is developed, while [67] proposes an adaptive scheme for phase selection. This method is based on the weighting of different parameters, such as current magnitude, delta current, voltage magnitude and delta voltage, impedances, and symmetric components. The above described methods are summarized in Table 9.

(b) Protection schemes based on transient signals and/or artificial intelligence

In [69], a differential protection method is developed using transient current signals, which uses the Pearson correlation method of transient signals from line ends. Therefore, this correlation focuses on the similarity of the waveforms and the polarity, and is not influenced by amplitude. The method found weaknesses for long lines (>200 km) due to the capacitive effect. Reference [70] develops a protection scheme using frequency components. A frequency spectrum of internal and external fault currents is extracted, and the calculation of an attenuation factor distinguishes the protection zones, thereby determining a threshold for those zones. This study concludes that signals generated by converters present higher noise. However, the proposed work requires many spectral analyses with very high-frequency signals so high-speed signal processing is needed.

In [71], the importance of signal processing methods for information extraction is highlighted. Many methods are presented considering use of transitory signals, based on wavelet transform (WT) of traveling waves, principal component analyses (PCAs), park transform of traveling waves, Teager energy operator (TEO), empirical decomposition in the joint mode (JM) of the traveling wave, and a mathematical morphology (MM) function. All these methods are used for transient signal extraction and require short time windows. Therefore they are less affected by the inverter control system, as these methods require the acquisition of signals at high-frequencies.

Table 8 Causes and effects on directional and negative-sequence overcurrent protection due to IBR

Directional (32) and negative-sequence overcurrent protection				
	References	**Technology**	**Cause**	**Effect**
Directional element protection	[55]	IBR	Strategies inverter control	Distortion signals, abnormal angle between V and I
	[59]	WF-IV	Control the phase angle	Malfunction of phase comparison
Negative-sequence overcurrent protection	[50, 60]	IBR	Limited current, inverter control	Activation threshold. Different angles between V2 and I2
	[51]	IBR	Insufficient amount of negative-sequence	The overcurrent function will not be activated
	[57]	WF	Specification of the amount of negative-sequence in the GCs	The increased amount of the negative-sequence influences the amount of the positive-sequence
	[61]	WFs	Insufficient amount of negative-sequence	Fault response interferes with directionality

Table 9 Adaptive protection schemes and modification of traditional protection

References	Protection function to be improve	Proposed protection scheme	Advantages	Disadvantages
[62]	Distance	Combination of voltage drop and a new directional element and is communication assisted	Fast operation and reliable	Communication wire is required, more costly
[39]	Distance	Modification in the POTT teleprotection scheme	Easy implementation, fast operation and reliable	Requires a channel of communication, more costly
[33]	Distance	Use time delay and zero-sequence	Avoid using negative-sequence	Drag zero-sequence problems
[40]	Distance	Use differential protection	Fast operation	More costly, no back-up protection
[41]	Distance	Resets distance parameters based on Z_{bus}	This method may be safe	No adaptive in nature
[63]	Distance	Adaptive coefficient and equivalent sequence impedance	Adaptive in nature	Logic circuit is more complicated due to complex calculation
[64]	Distance	Adaptive scheme using voltage and current information	Adaptive in nature	Complex calculation
[51]	Distance	Use zero-sequence from transformer	Avoid using negative-sequence	Drag zero-sequence problems
[43]	Distance	Adaptive scheme based on the measurement information on common connection points	Adaptive in nature	Implementation of logic circuit is more complicated
[45]	Distance	A new transmission line pilot protection scheme based on the accurate distributed line model	Easy implementation and fast operation	Communication wire is required, more costly
[68]	Distance, differential	Use of a modified differential protection scheme	Fast operation	More costly, no back-up protection
[53]	Differential, phase selection	Use auxiliary undervoltage components. Use zero-sequence	Avoid using negative-sequence	Drag zero-sequence problems
[55]	Directional element	Line angle modification in positive-sequence	Adaptive in nature and it may be safe	Complex calculation
[67]	Phase selection	Use the weighting of different parameters (V, I, ΔV, ΔI, Z, etc.)	Easy implementation and adaptive in nature	Complete study is required
[65]	Directional element, phase selector	Based on voltage (Undervoltage)	Easy implementation	It is not entirely safe because it only relies on tension
[66]	Directional element	Based on reactive power flow	Easy implementation	It is not entirely safe because it only relies on reactive power, no adaptive in nature

A method using artificial neural networks (ANN) is proposed in [48], where an adaptive unit, based on weight calculation for online seen impedance, for adjusting the trip characteristic of the distance relay using local information is designed. This is to avoid incorrect operation due to intermittent operation of WFs. Therefore, the set points of different zones of a distance relay must be changed simultaneously.

In [72], a scheme to detect and classify faults within a WF-III using an adaptive neuro-fuzzy inference system method is developed, while methods using machine learning for systems with high penetration of distributed generation governed by investors have also been developed. Reference [73] proposes a method of distance protection with support vector machines (SVMs). Reference [74] proposes a methodology to determine the directionality of currents in distribution feeders caused by distributed generation, based on decision trees (DTs) and SVM. The above described methods are summarized in Table 10.

5 Analysis of the literature review

Most works consider that the principal challenges emerge when the main variables used by protection relays are controlled by IBRs.

A low SC-current magnitude causes overcurrent-dependent algorithms not to be activated, e.g., overcurrent starting. In addition, the limited current may affect the measurement of fault impedance, so can influence the impedance calculation.

Table 10 Protection schemes based on transient signals and/or artificial intelligence

References	Protection function to be replaced	Protection scheme	Advantages	Disadvantages
[69]	Differential protection	Uses the Pearson correlation method	This method is dependable	Complex calculation
[70]	Distance protection	Uses signals in different frequency spectral	This method is dependable and secure. Avoids phasor signals	Complex calculation and requires a good method to filter the signal
[71]	All function	Uses signal processing (WT, PCA, TEO, JM, MM, etc.)	This method is dependable and secure	Often present complex calculation and requires finding the appropriate mother function
[48]	Distance protection	ANN	This method is dependable and secure. Fast and adaptive in nature	Require a lot of information for training
[72]	Detect and classify faults	Neuro-fuzzy	This method is dependable and secure. Good performance to identify faults	Complex calculation and require a lot of information for training
[73]	Distance protection	SVM	This method is dependable and secure	Only applies under certain conditions
[74]	Directional element	DT-SVM	This method is dependable and secure. Good performance to identify directionality	Complex calculation

Inverters may force the fault current contribution to be fully balanced regardless of the type of fault. When the angle of phasor signals is controlled by IBRs, the shift angle of voltage and current in all sequence quantities for each phase (ABC) may exhibit non-traditional behavior. In addition, the electrical system behaves inductively, while the inverter control may behave as inductive, capacitive or resistive. Therefore, this may lead to errors in impedance measurements, comparison of positive- and negative-sequence shift angles, comparison of shift angles for each phase, comparison of the phasor current signals of the TL ends, and in the relationship between polarized and operational quantities.

Traditionally, negative-sequence quantities can be used as the main protection in order not to rely on zero-sequence quantities. This is a case where directional supervision for distance elements can be used to increase security. Thus, the lack of negative-sequence current by IBRs may cause the directional supervision to fail to trip and, in turn, disable the distance elements.

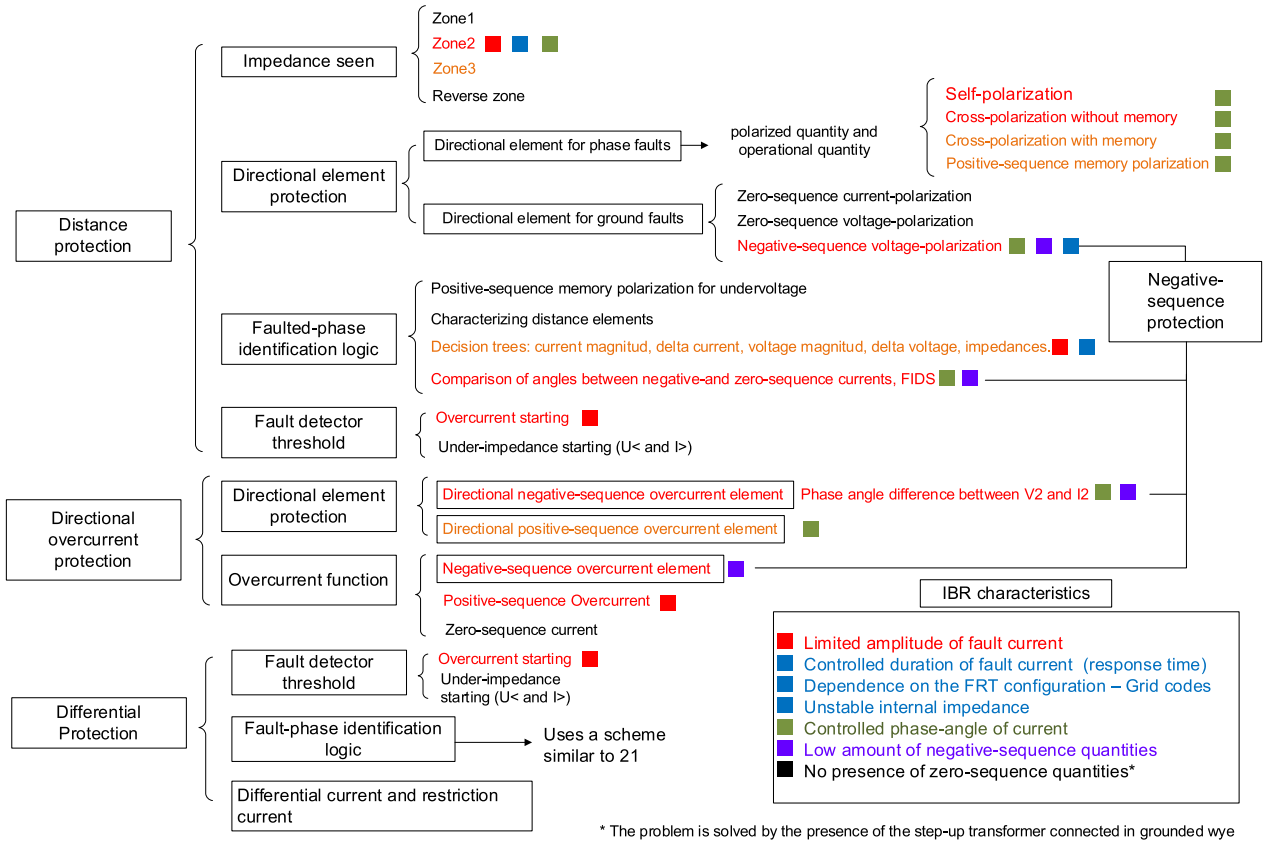
Figure 11a shows a summary of all the main protection functions of TLs. Each IBR characteristic affects a different algorithm, so a colored square is included to reference the correlation.

Most of the cited cases present a greater emphasis and analysis on distance protection because this function and its elements are most affected by the inclusion of IBRs. The strategies most widely implemented in traditional protection schemes emphasize adaptive algorithms and the modification of traditional protection. These schemes perform impedance calculations considering the variable impedance of the IBRs and are also supported by the use of other quantities or other schemes that are not affected by IBRs, e.g.:

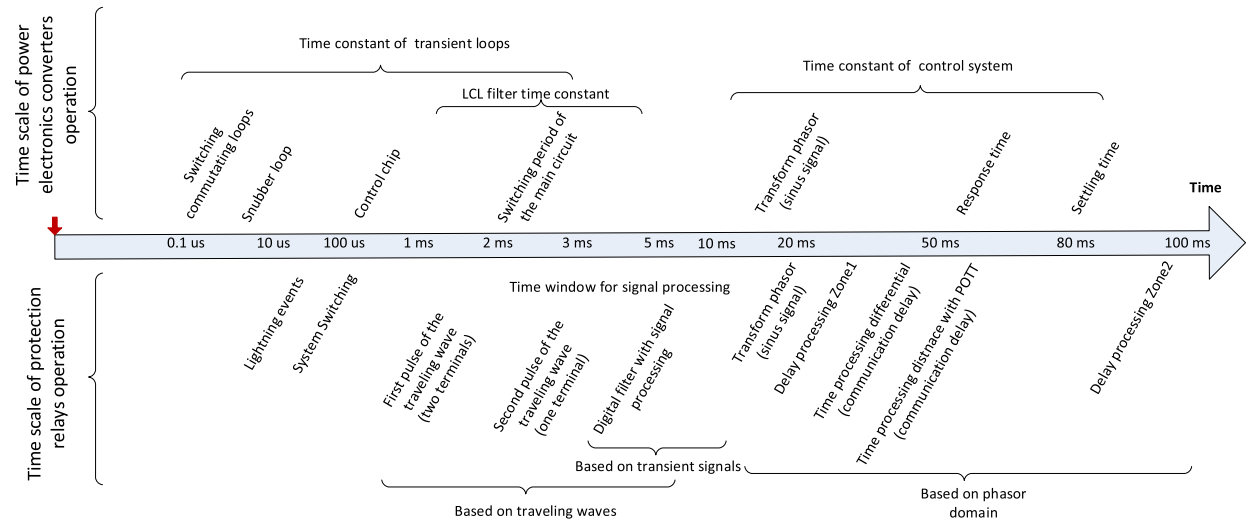
- Voltage drop/undervoltage
- Zero-sequence quantities
- New communication assisted
- Modification tele-protection
- Differential protection
- Adaptation impedance
- Reactive power flow
- Fast voltage and current drop

However, many require communication systems or back-up elements, resulting in high investment costs. Consequently, it may be considered that the protection functions based on phasor domain may present more and more challenges and the solution in modifying the traditional schemes could reach a point where the schemes become very complex to implement, expensive to acquire or even reduce the sensitivity of equipment. Figure 11b shows the operating time scale of the relays compared with fault response time scale of IBRs. The overlap between the two behaviors can be observed, so any change in IBRs may cause new challenges in the relays.

On the other hand, transient signal protection schemes are based on time domain and use electromagnetic transient signals. In this case, the new methods use signals at high-frequency with short time windows (ultra-fast protection) and suitable models of IBRs. The signal processing for the digital filter can be developed using the different methods described above. These emphasize immunity to the effect of IBR control. However, this



(a)



(b)

Fig. 11 **a** Effects of IBR characteristics on the main protection functions. **b** Response time scale for the IBR operation and relays operation

method presents weaknesses such as high sensitivity to harmonics and noise, high computational requirement, hard to select the mother function, and depends on periodic signals. Moreover, artificial intelligence algorithms can use time domain and phasor domain information. These algorithms focus on the training of these

parameters or machine learning, which means that they require high levels of information processing.

Consequently, the analysis of the impact of IBRs on EPS is considered a great challenge that requires research into the criteria of their operation for a systematic transformation of the current electrical network to allow high penetration of sustainable energy.

6 Conclusions

This paper described the operating characteristics of the main transmission lines protection, the challenges introduced by IBRs in these protection schemes and some possible solutions proposed by several authors. It was observed that the operational behavior, governed by the settings of its inverter power control system, and the structure of these IBRs cause such challenges affecting mainly the functions used by a distance and directional relay. In addition, the influencing factors are related to the same operating time scale, since the response times of inverter power control system coincide with the actuation times of relays. Therefore, high penetration of IBRs into transmission systems requires in-depth study of the development of new and existing protection schemes, as modification or adaptation is inevitable in the future.

On the other hand, ultra-fast protection schemes whose time scales are less than the response time of the power control system are theoretically unaffected or affected to a lesser extent. Such is the case of protection based on traveling waves. However, these methods need complementary functions which in many cases may depend on the behavior of the generation source. Therefore, for systems with high penetration of IBRs, pertinent studies are required to confirm the reliability of these schemes.

Abbreviations

RES: Renewable energy sources; EPS: Electrical power systems; WF: Wind farm; PVP: Photovoltaic plant; PE: Power electronics; IBR: Inverter-based resources; SC: Short-circuit; TL: Transmission line; DC: Direct current; PCC: Point of common coupling; FFT: Fast Fourier transform; LCL: Inverter filter *LCL*; GC: Grid codes; FRT: Fault ride-through; FC: Fault conditions; ST: Structure of IBRs; CSS: Control system setting of IBRs; FSC: Full-scale converter generator; DFIG: Doubly fed induction generator; PQ: Active and reactive power; UQ: Voltage and reactive power; FIDS: Fault identification selection; FID: Fault-type identification; DT: Decision trees; EU: Europe; NA: North America; VSC: Voltage source converters; HVDC: High-voltage direct current; MMC: Multi-level converter; POTT: Permissive overreaching transfer trip; WT: Wavelet transform; PCA: Principal components analyses; TEO: Teager energy operator; JM: Joint mode; MM: Mathematical morphology; ANN: Artificial neural networks; SVM: Support vector machines.

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Author contributions

IBR analysis, literature survey, analysis of traditional protections, challenges of IBRs to traditional protections, discussion of solutions presented by the references. All authors read and approved the final manuscript.

Authors' information

Juan Carlos Quispe (1990-), male, Ph.D. candidate at National University of San Juan, Argentina and researcher at Universidad Tecnológica del Perú, Major in power system control and protection, and electromagnetic transients.
Eduardo Orduña (1958-), male, Ph.D. and Professor at National University of San Juan, Argentina, Major in power system control and protection.

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Declarations

Competing interests

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Author details

[1]Institute of Electrical and Energy – CONICET, Universidad Nacional de San Juan, San Juan, Argentina. [2]Universidad Tecnológica del Perú, Lima, Peru.

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