A Review of Distance and Overcurrent Protection Considering Increased Inverter-Based Resources

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***Abstract*—As the bulk electric system is increasingly pushed to higher penetration levels of renewable energy, the overall fault characteristics of the system are significantly impacted. Protective relays are designed to detect faults and control breakers so that the system is more resilient. Two of the most commons protection schemes are directional comparison blocking and ground overcurrent. To prepare for the future, protective relaying methodology needs to be continually re-evaluated as new technologies are developed. This paper presents a review of past research and protection methodology for distance and ground overcurrent schemes, and the changes necessitated by inverter-based resources.**

***Index Terms*—Overcurrent, distance, protection, inverters**

I. Introduction

The power system is the largest and most complicated machine that has been created. Even more so, it is constantly being changed and upgraded with expanded infrastructure and new technologies. In recent years, inverter-based resources (IBRs) have been increasingly added to the power system to offset conventional power generation [1]–[4]. Power electronics-based devices are increasingly leveraged to diversify generation and improve control of the grid. Unlike traditional generation, inverter-based resources are commonly distributed across the grid. With the intermittent nature of IBRs, power flow can drastically change throughout the day. These changes also affect power system protection. Grid modernization has resulted in non-standard characteristics in relay operation [5], [6].

Relay mis-operations occur when the relay either fails to detect a fault, or incorrectly triggers a fault response under non-fault conditions. In both cases, the results can be catastrophic. If a fault is present and not isolated, equipment has a high probability of being damaged as the fault persists. In the case of a non-fault condition where the relay operates, unnecessary de-energization can result in high costs.

In [7], several mis-operations are examined due to relay defects. More adequate testing is described, including very accurate hardware-in-loop (HIL) simulations with very accurate system models.

[8] provides a few examples of catastrophic mis-operations. These mis-operations included errors that occurred due to previously correct assumptions on the power system. Previously, transformers would consistently produce a 2nd harmonic level of 20% in this case. Improvements in transformer design lowered the harmonic, causing the relay to fail to operate on a fault.

[9] discusses some detailed statistics on U.S. mis-operations during the January 1, 2011 through March 31, 2012 period. Mis-operations were overwhelmingly categorized as unnecessary trips with very few failures to trip. The majority of mis-operations occurred due to incorrect settings, logic, or design errors. This emphasizes the need for precise understanding of fault conditions in the protected region, to properly set relays.

[10] explores the zone 3 mis-operation that caused multiple system wide cascading event blackouts. These blackouts include the 2003 Northeastern US-Canada blackout and the 2015 Turkish blackout. The 2003 Northeaster US-Canada blackout resulted in a loss of 62 GW and left more than 51 million people without power. In emergency conditions caused by an initial fault, the relays were unable to distinguish between heavy load and fault conditions. As each relay mis-operated, load was continually re-distributed to surrounding lines which created the cascade.

From these examples, the cost of improper protection is clear. It is necessary to develop improvements to protection alongside any changes from other power system advancements.

Section II discusses distance and overcurrent protection schemes. Section III analyzes studies on the impact of new technology on protection. Section IV analyzes potential solutions to problems discovered in section III. Section V theorizes future work that could be performed on the topic. Section VI concludes the review.

II. Protection Schemes

The protection schemes considered in this review include distance and overcurrent protection. These are the most common schemes and are widely used at all levels. Differential protection is increasingly common but is still often avoided due communication requirements leading to high cost. For this reason, differential protection will not be considering in this study.

A. Distance

Distance protection is one of the most common protection schemes. In this method, relays measure current and use the voltage level of the system to calculate an effective source impedance.

Distance schemes determine how far away faults are located, and if they are within a set zone, the relay will trip. The distance of the fault is calculated in impedance. The impedances of the surrounding lines are used to calculate the relay settings and then the relay is set based on a desired percentage of the impedance in the protected line [11].

The basis for any distance scheme is the reach setting. The protected region is the line between the relay and the set reach. Reach is set as a percentage of the line length, where the line length is considered in impedance units rather than distance. Impedance can be used due to the uniformly distributed impedance along the length of the line. The impedance, which can be thought of as electrical distance, is thus directly correlated with physical distance when considering the line.

The apparent impedance is calculated to determine if it falls within the protected region. Apparent impedance is calculated as show in (1):

$$Z_{apparent} = V/I_{relay} \tag{1}$$

V refers to the voltage level of the line, which is usually built into the scheme design as a constant. I_{relay} is the current through the relay. The resulting value of $Z_{apparent}$ is the electrical distance between the relay and ground. When the apparent impedance is less than the line impedance, this indicates a fault to ground is occurring somewhere on the line.

Originally, electromechanical relays were used for distance protection schemes. In electromechanical relays, distance protection was set using a balance beam circuit as shown in Fig. 1. The turns ratio determines the restrain current. At the restrain current, electromagnetic forces will tip the balance beam and connect the trip contact as operating ampere-turns surpasses the set restraining ampere-turns, as seen from [11]:

$$N_1 \cdot |I| > \frac{|V|}{R} \cdot N_2 \tag{2}$$

The shape of the protected region was controlled using multiple electromechanical elements in combination. Cylindrical relays were used to add elements with set ranges based on impedance angle [11]. An example of a complex distance characteristic is shown in Fig. 2, where two distance relays and a cylindrical relay are combined using comparators. Characteristics beyond the basic mho (circular) scheme were complicated and expensive, so the mho scheme was the most widely implemented [11].

In the 1970s, static relays were created. Static relays utilized solid-state components like logic gates, rectifiers, and timers to recreate the operation of electromechanical relays. However, static relays were not commonly implemented, and were quickly replaced by microprocessor relays [11].

From the 1980s to present time, microprocessor relays have become the most common implementation for power system protection.

Originally, distance protection only considered the positive-sequence representation of the line. Per phase protection is

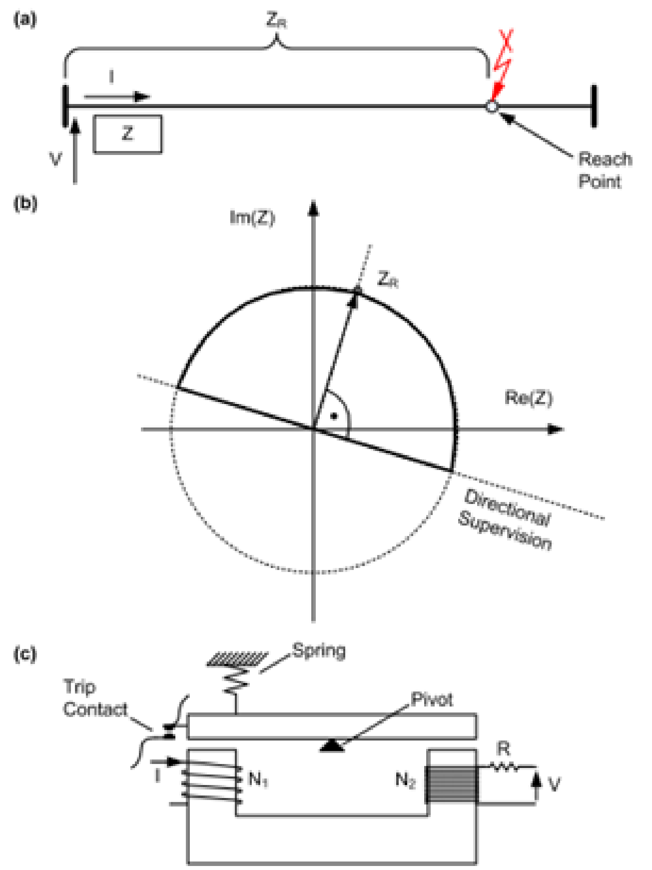

Fig. 1. Distance element reach (a), mho characteristic (b), and implementation with a balane beam relay (c) [11]

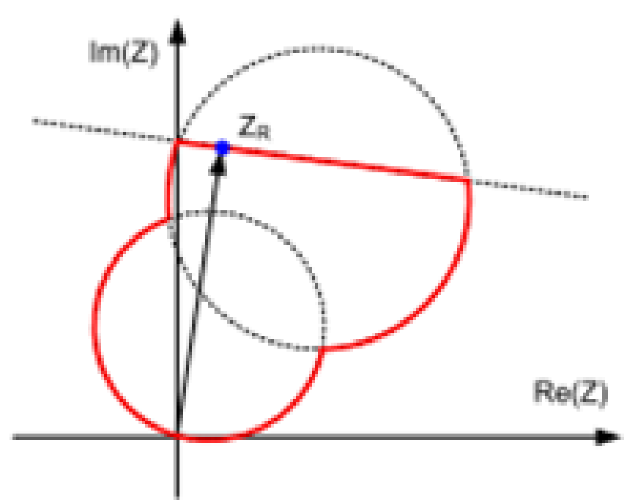

Fig. 2. Example of Distance Characteristic Using Combination of Elements [11]

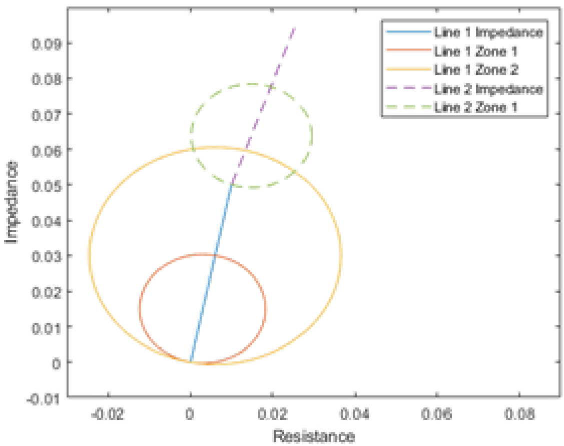

Fig. 3. Example of Distance Protection Zones

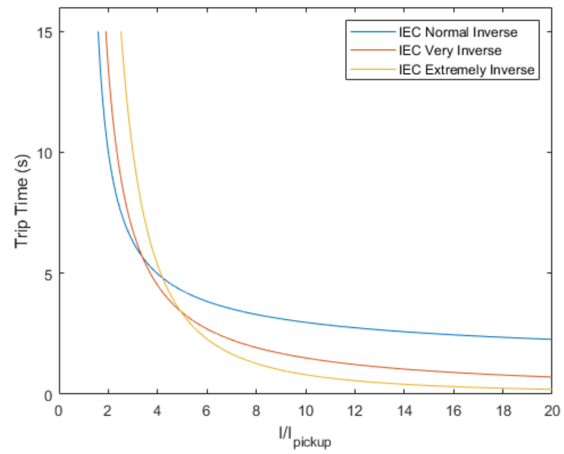

Fig. 4. Example Time-Overcurrent Curves [12]

more common now, where the relay considers each phase-to-ground loop and each phase-to-phase loop [11]. These loops are usually written as AG, BG, CG, AB, BC, CA, where A, B, and C are phases and G is ground. The equations for the AG loop are shown in (3).

$$V_{Loop} = V_A \text{ and } I_{Loop} = I_A + \frac{Z_0 - Z_1}{3Z_1} I_G \tag{3}$$

Where V_{Loop} is the set voltage magnitude used to calculate the impedance of the loop, and I_{Loop} is the measured current that will be used to calculate the impedance of the loop.

Distance protection is often set using multiple zones to coordinate between relays. Commonly, zone 1 covers only a portion of the protected line, while zone 2 overreaches the protected line into the next line. If the calculated impedance from the relay falls in zone 1, the relay will trip. However, if the calculated impedance falls in zone 2, the relay will be delayed so that if the fault is in the next line, time is allowed for a closer relay to trip first. This coordination results in reduced outage area in response to faults.

Distance protection zones can be plotted based on resistance and impedance of the protected line. An example of this with positive sequence zones is shown in Fig. 3.

B. Overcurrent

Overcurrent schemes are the most basic protection schemes. Overcurrent schemes operate based on a time-overcurrent characteristic. At a measured current, the relay will trip after the corresponding time for a chosen characteristic. If the overcurrent reduces before the trip time elapses, then the relay will not trip. Commonly, overcurrent schemes only consider ground current measured at the relay. Examples of time-overcurrent curves are shown in Fig. 4.

The equation for setting an overcurrent relay is shown in (4). TDS refers to the time dial setting. In electromechanical relays, the TDS was set using a physical dial. Although the dial does not exist in microprocessor relays, the name persists. A and B are constants selected based on standardized inverse curves. I is the measured current at the relay, and I_p is the set pickup current. The resulting t in the equation is the time that will elapse before the relay trips [5].

$$t = \frac{A}{(I/I_P)^B - 1} \cdot \text{TDS} \tag{4}$$

Often, lines are protected by multiple relays. The primary relay is set, and then the backup relay time dial setting is selected so that the backup will always trip after the primary. If set correctly, the failure of the primary relay will still be protected by the backup relay.

III. Impacts of Emerging Technology

A. FACTS

Flexible AC Transmission System (FACTS) refers to power electronic devices used to add additional control to the power system. FACTS devices are utilized to improve efficiency and control in existing infrastructure. [13] simulates the impact of a thyristor-controlled series capacitor (TCSC) FACTS device on a distance relay. In a simple system, a TCSC is added to control a transmission line. Faults are tested with and without compensation from the TCSC, and impedance is measured from one end of the line. The measured impedance significantly increased, causing the relay to under-reach the fault and mis-operate in both line to ground (L-G) and line to line (L-L) fault scenarios. Table I lists two significant cases of this under-reach.

TABLE I
Impedance for Various Faults [13]

Fault	Fault Location (km)	Impedance of uncompensated line (ohm)	Impedance of compensated line (ohm)
L-G	150	60	124
L-L	150	40	90

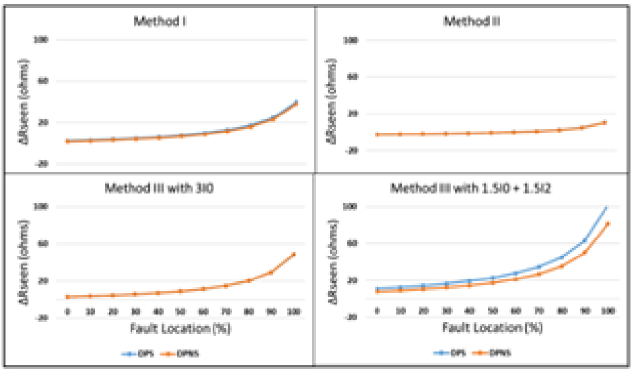

Fig. 5. R error for LG fault in strong system at $R_f = 5$ ohms [14]

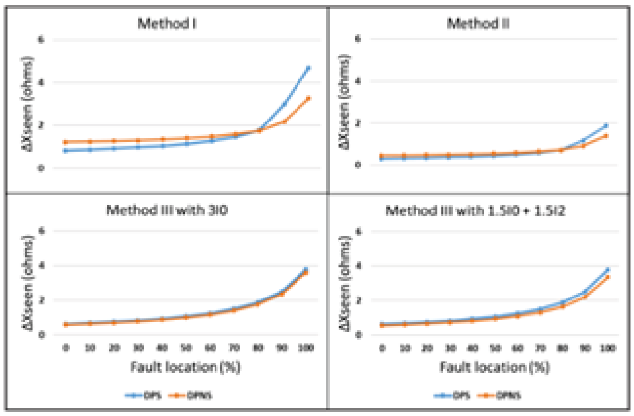

Fig. 6. X error for LG fault in strong system at $R_f = 5$ ohms [14]

B. IBRs

While the impact of specific renewable energy sources should be considered, characteristics of IBRs regardless of energy source is important to consider.

In [14], the impact of IBRs on impedance-based protection is studied. Several fault impedance calculations are compared for L-G and L-L faults. IBRs with positive sequence injection or positive and negative sequence injection are both considered. Fig. 5 and Fig. 6 show the resulting impedance calculation error for the L-G fault. No method was completely accurate across all situations, and the error increased with fault distance. The resistance error was much greater than reactance error.

[15] shows the effect of IBRs on negative-sequence directional relays. Lines that only connect to IBRs are identified and compared with lines connected to traditional generation. When faults are simulated on the lines only connecting to IBRs, much less negative-sequence current is injected than lines with traditional generation. This results in distance relays on lines connected to IBRs under-reaching faults in the direction of the traditional generation. This study has also been performed utilizing HIL testing [16], with the same result.

Short circuit current behavior of IBRs and the impact on distance protection has also been studied [17], [18]. Specifically,

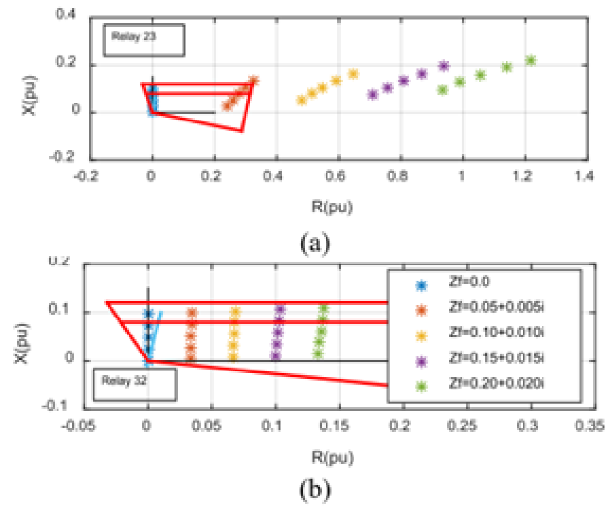

Fig. 7. impedances seen for single phase ground faults (a) IBR-side (b) grid-side [17]

relays on the IBR side and grid side of a fault are compared at several fault locations and fault impedances. The results, as seen in Fig. 7, show that during asymmetrical faults, the IBR side relay often under-reaches and fails to operate on a fault. The asterisks represent faults while the area outlined in red is the trip region.

In [19], protection challenges with bulk penetration of renewable energy resources are demonstrated. Specifically, the low fault current provided by IBRs results in under-reach in distance relays and too little fault current to trip overcurrent relays. Additionally, the operation of the renewable energy sources can change the fault characteristics of the IBRs. In islanded operation, all issues are amplified. It is proposed that a new protection scheme, likely adaptive, is needed.

C. Wind

Wind generation also has varied short circuit current characteristics. One important factor for wind generation during faults is referred to as crowbar protection. Double-fed induction generators (DFIGs) are used to connect wind generation to the grid. The stator of a DFIG directly connects to the grid, and the rotor connects to a back-to-back converter. Due to the direct connection of the stator, crowbar protection is implemented to protect the power electronics during a fault. The short circuit current characteristics vary when crowbar protection is activated, so the impact must be considered. When crowbar protection activates, the power electronics are disconnected from the rotor and replaced with a series resistance. In such cases the DFIG will no longer be a source of short-circuit current.

The short circuit current characteristics of wind generators varies with and without crowbar protection [20]. Without crowbar protection, wind generation has much lower short circuit current than traditional generation during faults, as shown in Fig. 8. However, some short circuit current is

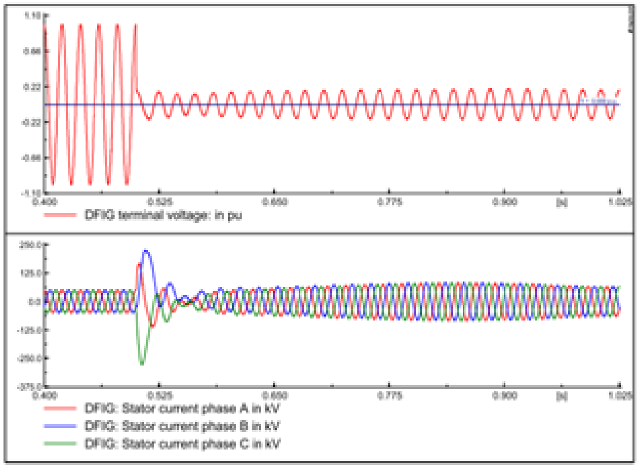

Fig. 8. Short Circuit Characteristic of DFIG without crowbar [20]

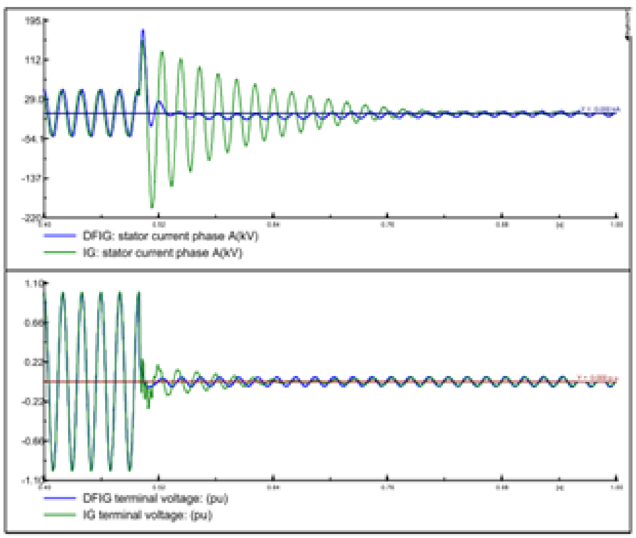

Fig. 9. Short Circuit Characteristic of DFIG with crowbar [20]

still injected and is controllable by the power electronics. When crowbar protection is triggered, all control from power electronics is lost, as the DFIG is bypassed. In this case, fault current is reduced additionally, as shown in Fig. 9.

[21] looks at symmetrical fault characteristics at different wind speeds. The results show that wind speed does have an impact on fault current. In the worst case, short circuit current dropped by 46% when the wind speed was reduced from 15.5 m/s to 10.5 m/s.

[22] looks at unsymmetrical fault characteristics. A method to predict DFIG short circuit current is formulated and proven. Based on this formula, a change in protective relaying is recommended due to limited short circuit current.

[23] looks at wind turbine negative sequence current control and the impact on protection. The negative sequence control in DFIG is deemed limited, such that line-to-line short circuit current may fall within the limits of load current. Distance relays would be unable to detect a line-to-line fault and would mis-operate.

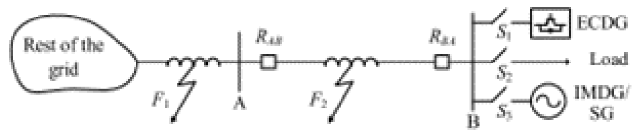

Fig. 10. Study microgrid system [28]

D. Photovoltaic

The distributed nature of photovoltaic energy poses additional challenges related to power flow. [24] tests the impact on increased PV penetration in the IEEE 33-bus test case. At low percentage, the impact on fault current is negligible. As the penetration increases, the power flow direction is gradually changed and the short circuit current varies up to 7 times the expected value.

[25] considers fault characteristics of large-scale PV plants. It is again found that fault current is reduced so that overcurrent relays fail to operate, and the fault persists.

[26] looks at PV characteristics and impact on power quality and protection. Reverse power flow from PV plants is found to cause mis-operations by protective relays upstream. The recommended solution is to disconnect PV plants during faults. However, this is contradictory to recent ride-through requirements of renewable generation, which intend for PV plants to assist in withstanding faults.

[27] studies phase-to-phase fault distance relay mis-operation due to PV integration. In the study, reverse power flow results in distance relays mis-operating. The relays fail to calculate the correct fault impedance. [27] deems that in systems where PV increases penetration enough to reverse power flow, traditional distance protection should be discouraged.

IV. Proposed Solutions

As evidence shows, current protection schemes will be insufficient as grid technology continues to advance. New protection schemes must be considered. Proposed solutions widely vary. Some studies propose new or updated versions of existing protection schemes. An increasing number of studies suggest that protection must be adaptive to the operation of the grid.

A. Updates to Existing Schemes

[28] introduces a new directional element for microgrids. The element is created by superimposing the potential fault impedances in the system over each possible breaker configuration. The topology considered is shown in Fig. 10, with possible fault regions shown in Fig. 11. The new element in Fig. 12 enables protection regardless of power flow direction. The study considers IBR operating normally or emulating conventional generation and finds that the new element is sufficient to detect faults in both cases.

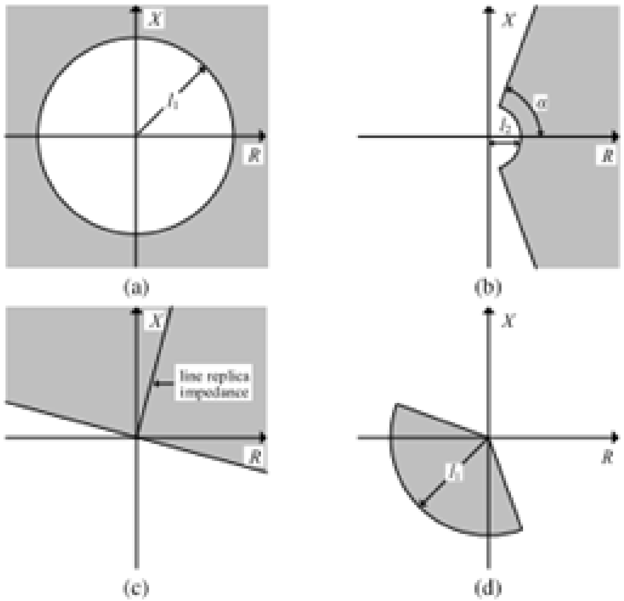

Fig. 11. Negative sequence impedance zones for R_{AB} (a) fault at F_1 and S_1 closed, (b) fault at F_1 and S_1, S_2 closed, (c) Fault at F_1 and all switches closed, (d) Fault at F_2 [28]

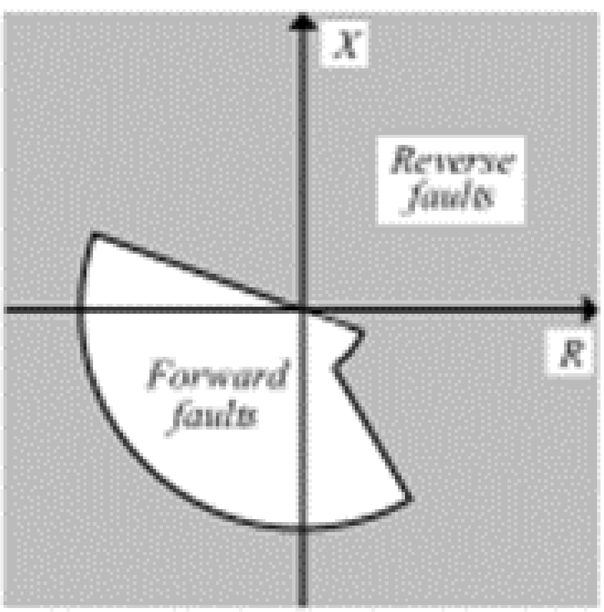

Fig. 12. Proposed negative sequence directional element [28]

B. Adaptive Schemes

Rather than patch existing schemes, many studies have suggested adaptive protection schemes should replace existing protection. These schemes have some mechanism of adaptability, changing depending on the condition of the power system [29].

[30] introduces a voltage factor due to limited short circuit current during faults from IBRs. The faulted phase voltage at a relay is calculated by (5) for 3 phase or (6) for 2 phase faults. When a fault occurs closer to the relay, the voltage is significantly lower. The voltage factor is multiplied by the time delay (7), resulting in relays close to the fault triggering much faster, even if the fault current is not high on the time delay curve. This method is self-coordinating, ensuring that the closest relay to the fault will be the first to trip. As voltage increases further from the fault, so does the time delay.

$$u^{(3)} = \frac{I_F^{(3)} Z_{F_{equal}}}{U_F} \tag{5}$$

$$u^{(2)} = \frac{2I_F^{(2)} Z_{F_{equal}}}{\sqrt{3}U_F} \tag{6}$$

$$t = K_u T_{set} u \tag{7}$$

Where I_F is the measured current, $Z_{F_{equal}}$ is the fault impedance seen by the relay, U_F is the rated voltage level, K_u is a constant used for coordination, and T_{set} is the time dial setting [30]. u then becomes a ratio of measured to rated voltage at the relay. The effect of specific IBR operation is not discussed in this study. It would be interesting to consider if reactive power capabilities of DG would impact this new element in any way.

Several algorithms adapt protection based on infeed from DG. [12] covers multiple settings groups that are swapped offline based on DG mode estimation. Periodically, the relay uses the measured current as an input to a genetic algorithm designed to estimate what combination of DG is active. Based on that estimation, an appropriate settings group is selected.

[31]–[36] removes the need for estimation by utilizing additional communication. The relays change distance zones based on infeed current measurements from DG. The infeed is communicated to the relay from the DG so that expected impedance can be adjusted.

Building on this, [33], [34] discuss protection utilizing centralized computing with full observability. Rather than protection engineers setting the time-overcurrent curve in overcurrent relays, the relays would automatically be provided a curve based on the proposed algorithm running on the central computer. The status of all breakers in the system would be used on a central computer. The computer would run a power flow analysis on the system with the current breaker statuses. Based on the analysis results, and 3-phase fault simulations at each node, the computer would cycle through relay settings until all faults would be detected. This process is shown in Fig. 13.

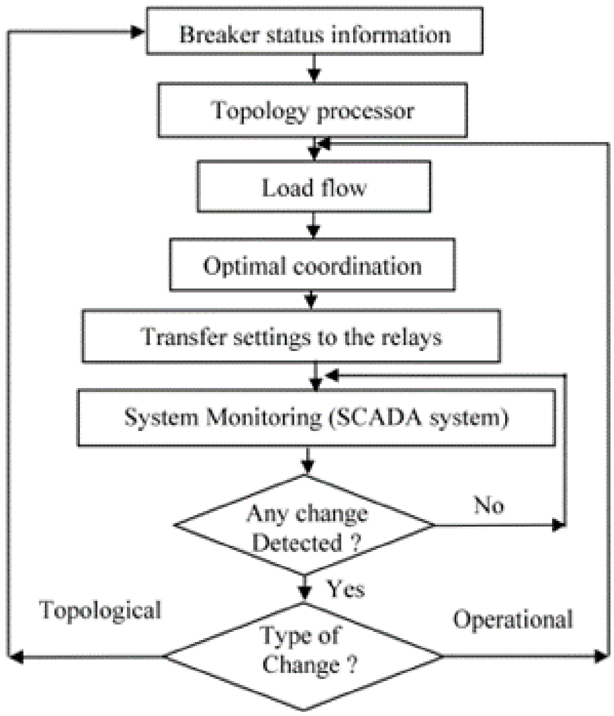

Fig. 13. Flowchart of proposed centralized adaptive optimal coordination algorithm [35]

In [34], the algorithm for centralized protection is referred to as Differential Evolution Multi-Object algorithm (DEMO). DEMO monitors network operation, breaker statuses, and DG states. Once the data is gathered, load flow and contingency simulations are automatically executed as protection settings are iterated, until all required contingencies are protected. This process repeats when changes occur to operating conditions or new DG forecasts are provided.

The objective function has 3 independent objectives in [34]. As shown in (8), the first objective is the primary relay operation, the second objective is the backup relay operation, and the third objective is the coordination variable [34].

$$\text{Multi-objective functions} \begin{cases} OF_1 = (\sum_{i=1}^{NCP} t_{p,i}) \\ OF_2 = (\sum_{i=1}^{NCP} t_{b,i}) \\ OF_3 = (\sum_{L=1}^{NCP} E_{CTL_L}) \end{cases} \quad (8)$$

Here, $t_{p,i}$ and $t_{b,i}$ are the operation times of the ith primary and backup, respectively. NCP is the number of coordination pairs and E_{CTL_L} is the coordination time interval error. The error is calculated based on (9), where CTI is the minimum delay between primary and backup timers. In [34], CTI is set at 0.3 seconds.

$$CTI \leq t_b - t_p \quad (9)$$

Additional constraints are added based on overcurrent protection settings. (10,11) are constraints based on the time dial and pickup setting limits. In [34], the dial range is between 0.5

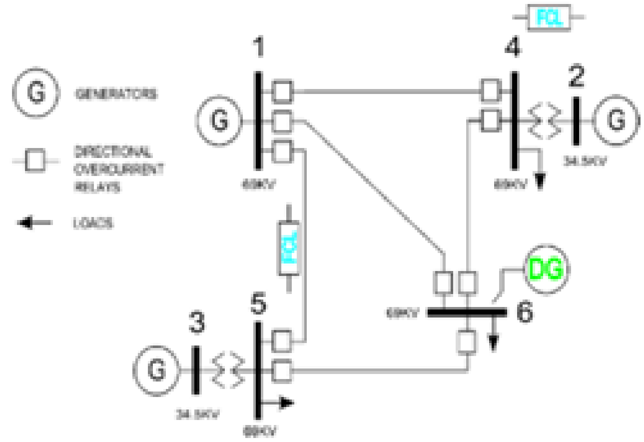

Fig. 14. 6 bus interconnected system in [34]

and 10, while the pickup range is between 140% and 160% of max current in no-fault conditions.

$$dial_{min} \leq dial \leq dial_{max} \quad (10)$$

$$I_{pickup,min} \leq I_{pickup} \leq I_{pickup,max} \quad (11)$$

The system tested in [34] is somewhat small. It consists of 6 buses interconnected in a base case, expanded case, DG case, and DG plus added fault current limiter case. The single-line diagram of the base case is included in Fig. 14.

While the methodology of [34] is promising, the demonstration of results from the study is extremely lacking. The results of the study are provided in table II. It is demonstrated that the addition of the adaptive protection scheme reduces the number of violations (NV), as well as the relay operation times. However, this demonstration fails to show the online performance of the adaptive scheme. Dynamic simulations in the final case with varying system elements must be performed to demonstrate the real-time optimization and adaption of protection.

TABLE II
DEMO CASE COMPARISON [34]

Cases	tp	tb	CTI	NV
Base	0.90	1.32	0.42	0
Expansion	0.89	1.31	0.41	6
DG	0.94	1.38	0.45	5
DG+FCL	0.90	1.69	0.79	2
APS+DG+FCL	0.31	0.62	0.32	0

The computational requirements for centralized protection are neglected in all studies. There are many factors for this aspect, including processing, communication, and even cooling costs. Presumably, the settings would need to be updated close to real-time, which would require a very powerful simulator.

[37], [38] utilize similar centralized computing approaches but rely on PMU observation as well. The topology of the system as well as voltage and current measurements from the

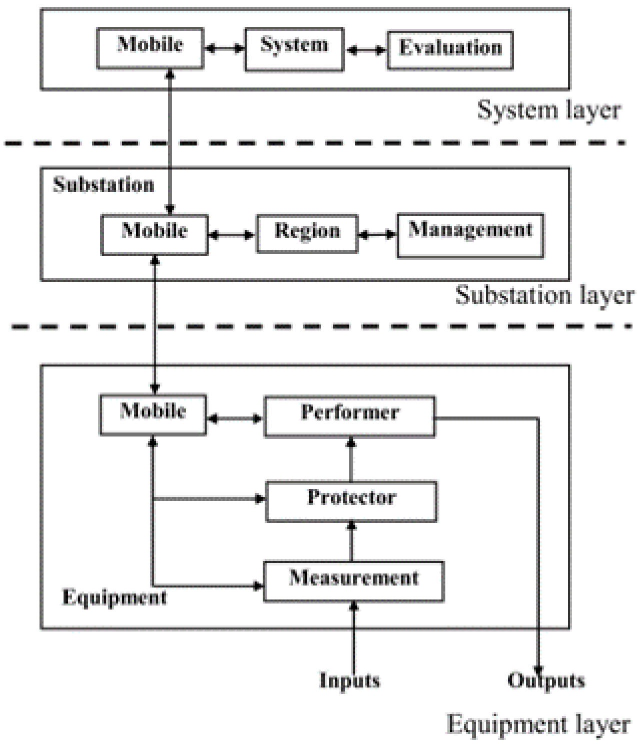

Fig. 15. Multi-Agent Protection Structure [39]

PMU form an even greater knowledge of the system to update protection in real-time.

As devices and data streams are added, the requirements increase further. Again, these studies do not address practical feasibility, only theoretical potential.

[39]–[41] propose multi-agent approaches to protection. Since relays are traditionally deployed on every line, employing artificial intelligence to allow agents at every location to communicate and interact is theorized. The agents are broken down into layers as shown in Fig. 15. Each agent is given a singular task. With the measurements from each of the agents, a precise distance protection trip region is also proposed, as shown in Fig. 16.

As with the centralized computing studies, practical requirement considerations are omitted. However, the multi-agent approach has additional communication requirements as many data streams are occurring simultaneously between each agent. The potential mis-operation due to communication failure increases exponentially as agents are added.

These adaptive methods have been theorized but testing so far has only been performed utilizing software simulations. None of the schemes have been implemented on physical relays. The simulation models have also been on relatively small systems, where the computational load is easily managed, and the communicated data requires relatively low bandwidth. Additionally, no mention of communication modeling is found. Issues like latency or packet loss are not considered in the performance of these methods.

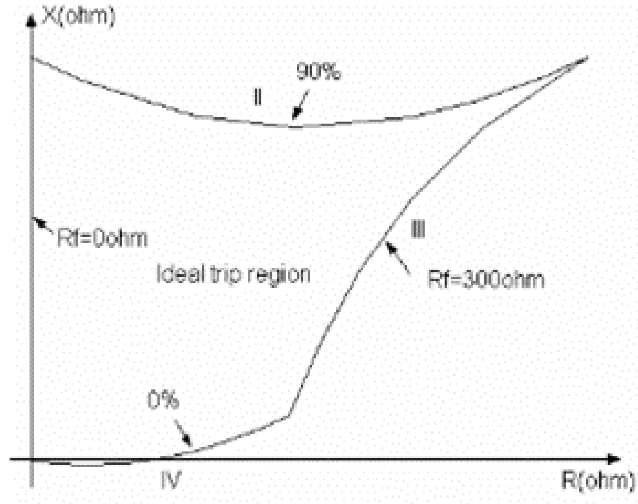

Fig. 16. Ideal Trip Region [39]

V. Future Work

The negative impact of IBRs on protection is clear. While many new protection schemes are proposed, these schemes have only been tested on simulations.

A. General Adaptive Schemes

For the more developed schemes, implementation in real-world models to prove their effectiveness would be a good next step, testing with contrived fault conditions. Additionally, recorded fault data could be utilized to test each of these schemes and compare performance with historical performance of existing protection. With the computational capabilities of microprocessor relays, schemes can even run alongside existing protection in the BES. However, the new schemes would merely record if a fault occurred, and not result in any physical impact until the scheme is deemed successful.

B. Centralized Computing

Considering centralized computing, further research would need to be performed before implementation. In this case, there is much more to the scheme than an electrical engineering solution. New software needs to be developed and tested to act as each layer. Additionally, communication requirements must not be taken for granted. The creation of a realistic communication model with latency and packet loss considerations should be completed before these schemes are deemed viable. Even once each of these steps is complete, the hardware of the BES may need to be upgraded to enable the required communication at appropriate speeds.

C. Multi-Agent Schemes

For multi-agent approaches, a similar lack of knowledge exists. Communication and coordination requirements would need to be determined for each component (i.e., mobile, evaluation, management, performer, protector, measurement, etc.). The communication requirements of a multi-agent scheme

TABLE III
SUMMARY OF PROTECTION SCHEMES

Scheme	Underreach	Overreach	Mis-coordination	Reverse Power Flow	Existing Hardware
Traditional	At Risk	At Risk	At Risk	At Risk	Yes
New Distance Element	At Risk	At Risk	At Risk	Protected	Yes
Mode Estimation	Improved	Improved	Improved	At Risk	Yes
Infeed Adaptive	Improved	Improved	Improved	Improved	No
Centralized	Protected	Protected	Protected	Protected	No
Multi-Agent	Protected	Protected	Protected	Protected	No

would only increase upon those of a centralized scheme. Backup protection in case of agent failure would also need to be outlined.

D. Study on Power System Protection

With regards to this paper, an additional review on differential protection would also be a beneficial next step. Currently, differential protection is not used as widely as distance or overcurrent protection, especially at the distribution level. However, the cost of implementing a centralized computing or multi-agent approach raises the concern that widespread use of differential relays may be comparatively inexpensive and just as effective.

VI. CONCLUSION

In this review, studies on the impact of IBRs to overcurrent and distance protection were reviewed and summarized. The most significant issues were discovered to be limited fault current and lack of negative sequence current component. In many cases, protection failed to operate. In other cases, protection was unable to distinguish between large loading levels and fault conditions, losing selectivity and requiring either relay operation in non-fault conditions or dangerous loss of sensitivity. Due to the distributed nature generation utilizing IBRs, the concern is compounded. Not only will the fault characteristics be significantly different, the change in power flow will also create additional protection complications.

Proposed advancements to protection were also reviewed. Many potential protection solutions were identified. Additional elements to existing protection schemes were proposed. Entirely new schemes based on emerging technologies were also reviewed. However, these solutions must still be tested to determine their merit. Several potential paths forward for these schemes were discussed in the future work section. Table III summarizes the discussed schemes.

Until a new protection scheme is implemented, the sensitivity of protective relays will only decrease as IBRs are added to the grid. However, the implementation of a new protection method will likely resolve the issues created by IBRs. Additionally, a centralized computing or adaptive approach would allow a straightforward path to continually update protection as new technology demands. Universal observability seems to be a logical conclusion for power system management, including protection. However, the studies reviewed in this paper which proposed such methods did little to contribute to the technology required to move in that direction.

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