Adaptive Protection – What Does It Mean And What Can It Do?

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Abstract— **As soon as protection uses an outside variable to change an operating characteristic it becomes adaptive, but levels of adaptability and the need for it are changing. As renewable generation resources, such as wind and solar, replace large synchronous machines, protection needs change. This paper focuses on how changes in the bulk power system impact protection settings and how those settings can be optimized to reflect changing system conditions. Techniques for initiating and communicating the change commands are discussed. The interconnection of protection, wide area control, and automation are evaluated to present not only what is and can be done today but what will need to be and could be done tomorrow.**

Communications between these systems is a limiting factor, and an enabling factor, for adaptive protection to make it possible to maintain system stability during the rapid changes we are seeing. The speed of the message from an Energy Management System (EMS) to the relays impacts the protection characteristics that can be changed. The protocol used to send a message impacts both the speed and the devices that can be made adaptive. The information available to be transmitted by the protocol defines how adaptations can be made.

True adaptive protection is a combination of advanced algorithms, communications, and shared information. Forces outside the control of the electric power industry have determined that changes are coming to force new requirements on protection and control. This paper presents how adaptive solutions will meet those new requirements.

***Index Terms*—Adaptive Protection, Distributed Generation, Infeed**

I. Adaptive Protection

From an adaptive protection standpoint, the first matter is what would need to be changed depending on system conditions beyond what can be measured at the relay. While it is possible to use measurements at the relay to adapt to varying conditions [1] this paper will only discuss remote measurements to be used to change relay characteristics.

II. Relay Considerations

There are operating characteristics in the protective relay itself that are critical to adaptive protection that need to be considered. For example in the case of figures 1 or 2 the communication indicating a change of breaker state could trigger a change in the setting group of the relay. Changes in breaker state (or disconnect) are a common time for faults to occur so it would be best if the relay does not have a protection gap during a change in setting or setting group. This is the case in some relay types and not in others. The delay in some relays when changing setting groups can range from a few milliseconds to a few cycles or seconds. This may not be a significant time delay in a distribution system but could be unacceptable in a transmission system with significant fault duty or short critical clearing times.

Another consideration is communications to the relay and protocols available. While almost any digital or contact input can be used to change a setting group, changing an individual setting or multiple settings requires an automated messaging system with this capability. The IEC61850 protocol has messaging and file transfer functions that are ideal for this approach. Of course the signal must also be received at the relay. A dual path, such as PRP or HSR could be considered for a critical communication of information necessary to coordinate protection. If the setting change is not time sensitive then a high speed fail-over of the communication channel might not be important.

The read / write capability of the flash memory used in the relay must also be considered. According to Wikipedia the range of read/writes in flash can vary from 1000 to 1,000,000. If a setting is changed only every hour (if based on changes in wind or sun this is not unreasonable) then there will be about 10,000 changes in settings per year. This means that flash memory capabilities alone would limit the life of the relay to as low as one month. Even if flash was 100,000 cycles the relay would be limited to a ten year life. Considering the 30 year life expected by many utilities this could be an unacceptable limitation.

III. Protection Elements

The evolution of protection has been to make it more adaptive to changing system conditions. The move from overcurrent elements to distance elements for transmission line protection was in response to the need to accommodate changing generation connections, which would increase fault current for faults beyond the desired operating point, possibly causing incorrect trips. When the need for non-local information impacts relay performance we see the need for adaptability.

A. OVERCURRENT PROTECTION

Perhaps the most common protection on the system today is overcurrent based protection. It is also impacted more than any other by connection of Distributed Energy Resources (DER) and Distribution Feeder Automation (DFA) changes. Consider the system of figure 1.

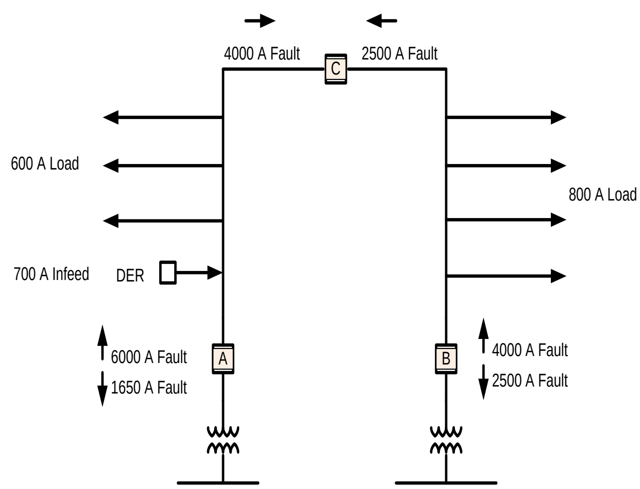

Fig. 1. Distribution system with fault and load currents

Let us consider how the overcurrent elements located at circuit breakers A and B are impacted by the infeed of the DER and the position of circuit breaker C. With breaker C open and no infeed from the DER we can apply the rule of thumb that the overcurrent setting should be half the minimum fault current and twice the maximum load current at breaker A. In this case that puts the setting at A anywhere between 1200 and 2000 Amps. At B we have a non-optimal setting below 2500 Amp fault current and above 800 Amp load. Splitting the difference gives us an overcurrent setting of 1650 for the relay at location B.

With the breaker C closed the settings get more complicated. Assuming one source is also open when C is closed we now have a maximum load current of 1400A at B (with A open) and a minimum fault current of 1650 Amps. With very minimal margin we must lower the overcurrent setting to a middle point of 1525 Amps.

Of course we need to know that C was closed to do anything to the setting at B. The setting situation would be greatly improved if B "knew" that the DER was feeding 700 Amps into the system. That being the case the load is reduced to 700 Amps and the overcurrent setting can be greatly reduced.

B. RECLOSING

Faster reclosing will aid in stability and continuity of service but unsuccessful reclosing will harm stability and cause equipment stress or damage. The risk of an unsuccessful reclose attempt can be mitigated if the current is as low as possible. Under many conditions it is possible to determine in advance which end of a line will have less fault current available. However if conditions change dynamically then a dynamic solution is necessary to determine which end of a line has a lower fault current contribution. Since relays on each end are measuring the current, it is straight forward to share magnitude via a 61850 message and a local compare determines which end recloses after a fault.

C. Distance Protection

Consider the problem a distance relay faces in the system shown in figure 2.

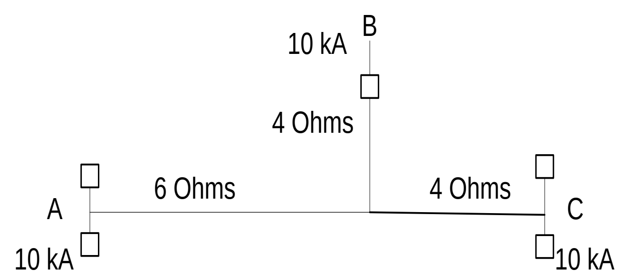

Fig. 2. Three terminal line

With the circuit B out of service the relay at A would be set to 9 ohms to see 90% of the line. With circuit B in service the relay at A the infeed from B would make the apparent impedance to C look like 14 ohms, so to see 90% of the line would require a reach setting of 12.6 ohms, a 40% increase from the no infeed condition. Because of channel delays faults cleared by zone 1 tripping will always be a half cycle or more, faster than communication assisted tripping. If the multi-terminal configuration coincided with a shorter critical clearing time then it would be advantageous to use a signal from the breaker at B indicating it was closed to change the reach of the relays at C and A. This would provide faster clearing of many faults. Expanding adaptive protection, if the fault current available from terminal B was transmitted to the relays at terminals A and C, the reach setting at those locations could be made much more precise for ideal protection.

Distance relays have the advantage of not being impacted by source magnitude, but they are limited by the load impedance. NERC rules [2] require that relay settings not limit line loading. Settings impacted by this rule include relay reach and load encroachment. The rule refers to maximum transfer capability and maximum seasonal rating of the circuit.

Consider the impedance characteristic of figure 3 showing both the mho zones and the load cutout region.

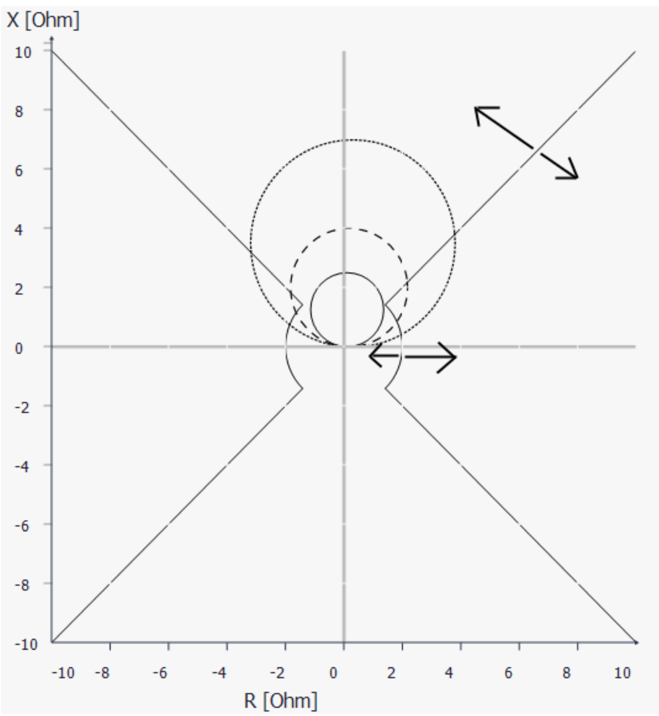

Fig. 3 mho characteristic with load encroachment

In the case of one regional electric operator it was recognized that by changing the relay characteristics on a dynamic basis they could take advantage of the full capacity of the line at any given time, without compromising protection. In this case though, it is more than a simple pickup setting or reclose initiate. To change the load cutout region there is the angle of the positive, negative, upper and lower region as well as the inner radius of the characteristic. In addition, there is not a single change to any of these settings that would accommodate the change in system conditions. The values could be any quantity within a range, depending on loading and line capability, usually a function of ambient temperature, wind, and time of day. In this case a complete setting file is transmitted to the substations in a wide area from a central location. Using 61850 file transfer protocol the settings are distributed to individual relays.

D. Breaker Failure

Breaker failure protection timing is typically determined by system critical clearing time. As the breaker failure time gets shorter, security of the scheme is reduced. It is not unknown for circuit breakers to operate slightly slower than rated if it has been an extended time since the prior operation. Security could be improved if breaker failure time could be increased during times where conditions increase critical clearing time. The signal to trigger this change would probably have to come from a central location that performs the calculation.

E. Under / over frequency

Considering the system in figure one, look at the underfrequency load shedding that might be applied to the relay at location A. With the breaker at C open, it is quite possible that there will be outfeed from the distribution circuit if the DER is in service. In this case it would be counterproductive to trip the feeder in an underfrequency condition. This protection (or control) adaptation can be accomplished with simple logic within the relay at A. If power direction is available in the relay (i.e. potentials are connected) it is simple to override underfrequency load shedding if there is reverse power flow.

IV. DATA SOURCES

The network itself can provide information to the local relay, such as in the frequency control above. In other cases system voltage or rate of change of a measured quantity can be used. Rate of change elements can be used to change characteristics. It is a common practice in some areas to use a rate of change of frequency (ROCOF) element to accelerate underfrequency load shedding. In other systems a sudden change in current or voltage can be used to supplement other protection elements.

A. Breaker auxiliary switches

Where an adaptive decision is made locally, auxiliary switches may be the best source of information to be used. Auxiliary switches are not perfect however. Mechanical or contamination (wasp nests) can cause a switch to not give a proper output. For critical operations it would be best to have an additional or supervisory input to validate the switch. An open switch can be confirmed by a current measurement of a relay connected to the element showing zero current for example. Likewise a low set current element pickup can confirm a closed switch. These elements may already be available at the location of the auxiliary switch. In the example of figure 1, it would be normal for the control of the circuit breaker at each location to have an overcurrent element that could be used for supervision in addition to its normal protection functions.

B. Distributed Energy Resource (DER) contribution

Knowing the fault and load contribution from a DER could certainly be used to improve relay settings (see fig. 1). The problem is that direct inputs from DER systems may be difficult to get. If there is a single connection point it is possible to use a measurement or auxiliary contact from that point. If the DER is distributed, such as distribution rooftop solar or scattered windmills with individual transformer connection points it is more of a problem. The larger the DER the more likely it is to have information available, although even rooftop solar installations provide on-line access to energy output. There are concerns about connecting any utility system to an outside influence. Cyber attacks in the Ukraine [3] in both 2015 and 2016 appeared to be malicious and originating with communications from outside the utility impacted.

C. EMS / DMS Control and Supervision

For some adaptable protection schemes, central measurement and computation systems are the only way to calculate the necessary changes. Changes to load cutout elements, breaker failure times, power swings, and similar elements cannot be made using local measurements. Central management systems can send digital or file messages to change either setting groups of whole setting files. It is by using all the data available from the system EMS that the in service scheme shown in figure 3 is being done in an in-service installation.

V. Communications

Information transmitted determines the communication needs. If a complete file is to be transmitted then a simple serial channel is out of the question due to latency needs. The setting file of a modern relay may be well into the Mb size and a serial data rate could make the information obsolete by the time the file could be sent. Likewise, a single data point can be sent easily by serial, unless path redundancy is required. The required level of redundancy may depend on how critical the protection at a specific location is. Bulk transmission applications may justify dual path (such as PRP or HSR) while the distribution system of figure 1 may not justify the cost of a dual path.

VI. SUMMARY

As the power system changes the opportunity to use adaptive protection to get the most out of the existing infrastructure is too great to ignore. Modern microprocessor relays have significant adaptive capability but to use it requires understanding the limitations of the entire system; power network, data collection, communications, and the relay itself. Even if adaptive protection is not required for an application today, there is always the possibility of a need tomorrow. If the adaptive protection can delay or eliminate the need for an additional power line then almost any cost would be justified.

References

[1] Adaptive Autoreclosure to Increase System Stability and Reduce Stress to Circuit Breakers,

Jörg Blumschein, Yelmaz Yelgin – Siemens, Andrea Ludwig – 50 Hertz Transmission GmbH

[2] NERC Standard PRC-023-1 – Transmission Relay Loadability

[3] BBC, Technology – Jan 11, 2017