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Enhancement of Distribution System Protection Through Automatic Network Reconfiguration

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***Abstract*— The distribution system is a key component of the power system since it delivers electricity to clients and is where revenue is collected. The distribution system is exposed to fault conditions. When these fault conditions strike, the distribution system's power lines are disturbed, and customers lose power. Power utilities lose revenue and battle to sustain power reliability standards. When the supply of power is not provided in agreement with the contract, power companies suffer penalties from their customers. In the past, electric companies used a "trouble call system" to detect outages, whereby consumers experiencing power outages would phone in and report them. The power utility would dispatch the field crew to restore power. Due to this method, customers will be out of supply for a long period of time. As a result, using the IEC 61850 GOOSE message application, this study developed a relay control technique to emulate the automatic reconfiguration of the distribution system under fault conditions. The designed technique is simulated and tested in a lab-scale environment.**

Keywords*— *Network reconfiguration, IEC 61850 GOOSE message, overcurrent protection.

I. INTRODUCTION

Overcurrent protection relays are essential in the distribution network. They are placed in strategic positions in a distribution system feeder. When a fault condition occurs, the relay detects, interrupts, and isolates the faulty section of the line. Relays are normally coordinated with other field devices such as reclosers, sectionalisers, and fuses to decrease the number of power outages [1]. The overcurrent protection function is investigated in the first part of the literature study as follows. In a power system, distribution system faults occur more frequently than in other sectors, resulting in service interruptions to customers [2].

Different researchers have been discussing the development of smart grids and how they can enhance reliability, and quality of power. One subdivision of the smart grid is the initiative of feeder automation (FA). FA is used to reduce outage time, reduce restoration time, improve power quality, and reduce maintenance costs [3]. In [4], a shift from a manual-operated distribution system feeder to an intelligent system with intelligence embedded in the remote terminal unit (RMU) and compact secondary substation is presented. [5] proposed a self-healing protection scheme for the distribution system. The proposed method is simulated in software using a 9-bus distribution system, and the results are analyzed before and after implementing the self-healing technique. The paper concluded that the self-healing method improves the security and reliability of the distribution system. Authors [6] reviewed theoretical aspects of fault detection, isolation, and restoration (FDIR) at the distribution level. The study discusses the technological, environmental, and economic challenges of distribution system self-healing. In [7], authors suggested an FDIR method based on IEC 61850 GOOSE messages. The algorithm considers the capacity constraints of the feeder, switches, and transformers to shorten the service restoration time. [8] presented a technique for reconfiguring a 22kV distribution system using DIgSILENT software. The paper demonstrated discrimination between upstream and downstream protection devices and back-feeding of the downstream segment of the network which gets isolated due to an upstream fault.

A lab-scale test bench is implemented to emulate the automatic network reconfiguration of the distribution system under fault conditions. The first section of this paper underlines the placement of protection devices and various methods of feeder automation. Modelling and simulation of the distribution network are described in section 2. Short circuit studies are presented in section 3. Implementation of the lab-scale test bench and emulation of the network reconfiguration are covered in section IV. Simulation results are discussed in section V. Sections VI and VII provide the conclusion and future work.

II. DISTRIBUTION NETWORK MODELLING AND SIMULATION

In this section, a 22kV distribution network with two radial feeder lines protected by four overcurrent relays, and simulation findings are analyzed. The simulation examines the performance and coordination of overcurrent protective relays. As illustrated in Fig.2, each feeder in the considered distribution network includes two relays, one SEL-351 relay at the feeder's outgoing and a second SEL-351 relay downstream of the distribution line. The performance of the overcurrent relaying system is studied by simulating faults in different parts of the distribution network.

A. Load flow study for the considered distribution network

Analysis of the load flow simulation is performed in this section. To be considered successful under three-phase steady-state conditions, a power system network's generation must supply load and losses; the voltage on busbars must remain close to the actual rated values, generator operation must remain within stipulated real and reactive power limits; and overhead transmission lines, distribution lines, and transformers must not be overloaded [9].

It should be noted that the load flows are carried out with both transformers operational and the tap changer set to position two. The reason for setting the tap changer position to tap two is that it can provide the entire load from both feeders A and B with the normal open point (NOP) open, and either feeder A or B when the NOP is closed, without

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affecting the voltage profile. The load flows are run for the three configurations listed below, with reference to the network diagram with load flow shown in Fig.2.

1. When the NOP is open and both feeder circuit breakers (A and B) are closed, Feeder A is supplying its own load, and feeder B is supplying its own load.
2. When the NOP is closed, the circuit breaker at feeder B is open, and feeder A supplied the whole distribution system network.
3. When the NOP is closed, the circuit breaker at feeder A opens, and feeder B supplies the full distribution system network.

Under normal conditions, the studied distribution system operates with the two parallel transformers in service and NOP open as shown in Fig.1. Two transformers are present to prevent outages if one fails or needs to be serviced. When the NOP is closed due to maintenance or fault conditions in one feeder, the feeder that is not under maintenance or fault condition will back-feed the network via the NOP. With the NOP open, the load flow for the first configuration is done to make sure that each feeder can supply its load. The load flow for the second configuration is done to guarantee that feeder A can supply the whole distribution system via NOP. The load flow for the third configuration is done to verify that feeder B can supply the whole distribution system via NOP. The load flows of the three configurations are run in common to validate that the voltage profiles of each configuration are within the [10] limitations established in IEEE standard 141-1993 criteria. To ensure that none of these arrangements overload transformers and overhead lines, and that power system standards and regulations are not breached. The load flow analysis calculates the rate of flow of current, real, and reactive power in the distribution system under consideration.

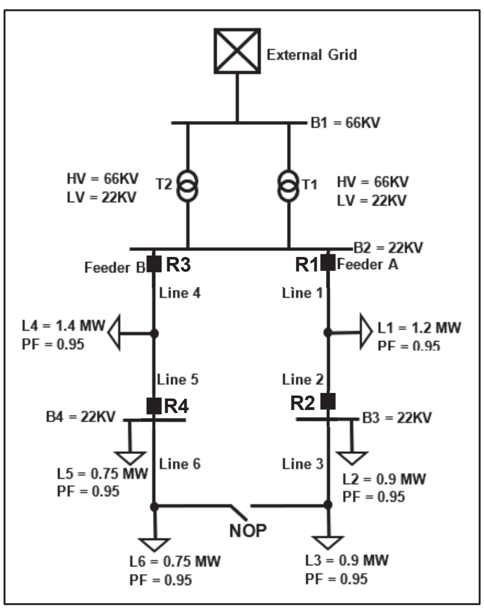

Fig.1: Single line diagram of the modeled distribution network

The load flow investigations in Table 1 are based on three scenarios: 1) NOP open with circuit breakers (CBs) at the outgoing of feeders A and B closed, 2) Feeder A feeds the network with NOP closed, and 3) Feeder B feeds the network with NOP closed.

TABLE 1. SUMMARY OF THE SIMULATION RESULTS WITH CONISDRED THREE SCNERAIOS

Power System components	Scenario 1	Scenario 2	Scenario 3
	Voltage in p.u		
Bus 1 (Slack	1	1	1
Bus 2 (PV)	1.03	1.028	1.029
Bus 3 (PQ)	1.009	0.978	0.965
Bus 4 (PQ)	1.013	0.954	0.987
	Transformer simulation results		
Transformer 1 Transformer 2	2.98MW 1.08Mvar 0.94 PF 0.03kA 31.75% loading	3.08MW 1.26Mvar 0.92 PF 0.03kA 33.26% loading	3.05MW 1.22Mvar 0.93 PF 0.03kA 32.87% loading
	Load simulation results		
Load 1	1.2MW 0.394Mvar 0.95 PF 0.033kA	1.2MW 0.394Mvar 0.95 PF 0.033kA	1.2MW 0.394Mvar 0.95 PF 0.035kA
Load 2 Load 3	0.9MW 0.3Mvar 0.95 PF 0.025kA	0.9MW 0.3Mvar 0.95 PF 0.03kA	0.9MW 0.3Mvar 0.95 PF 0.03kA
Load 4	1.4MW 0.46Mvar 0.95 PF 0.038kA	1.4MW 0.46Mvar 0.95 PF 0.041kA	1.4MW 0.46Mvar 0.95PF 0.038kA
Load 5 Load 6	0.75MW 0.25Mvar 0.95 PF 0.02kA	0.75MW 0.25Mvar 0.95 PF 0.02kA	0.75MW 0.25Mvar 0.95 PF 0.02kA

III. SHORT CIRCUIT STUDIES

A. Short circuit simulation study

A summary of the short circuit simulation findings is provided in this section. Short circuits are applied in both feeders A and B of the modeled distribution network. The location of the faults are as follows: fault F1is simulated on lines 1 and 2 of feeder A, fault F2 is simulated on line 3 of feeder A, fault F3 is simulated on lines 4 and 5, and fault F4 is simulated on line 6 of feeder B as shown in Fig.1. The summary of the short circuit simulations is presented in table 2. The table provides the type of fault simulated, fault location, and short circuit current generated. From the simulation results, it is observed that the fault current is high upstream as you get closer to the source (transformer) and lesser as you move downstream away from the source.

TABLE 2. SHORT CIRCUIT STUDY SIMULATION RESULTS

Fault type	Fault location	S (MVA)	I (kA)
Single-phase to ground fault	F1 at Feeder A (Line 1 at 1%)	73.8	5.81
Three-phase fault	F1 at Feeder A (Line 1 at 1%)	186.21	4.89
Single-phase to ground fault	F3 at Feeder B (Line 4 at 1%)	74.05	5.83
Three-phase fault	F3 at Feeder B (Line 4 at 1%)	186.45	4.89

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B. Current transformer (CT) selection

As described in [11], the maximum design load current of a power system network should not exceed the rated CT primary current when using current transformers for protection relaying reasons. To reduce wiring weight and provide the best capability and performance, the highest CT ratio permissible should typically be chosen. Under maximum symmetrical primary fault current, the CT ratio should be large enough that the CT secondary current does not exceed 20 times the rated current [11].
The CT ratio chosen is 300:1. When Feeder A supplies the whole distribution system, as shown in Fig.2 with 168A, the highest feasible load current of the investigated distribution system network is reached. Because it is less than CT primary current, this current conforms to the IEEE C37.230-2007 guidelines. As shown in Table 2, When a single-phase to ground fault is simulated, the maximum fault current is the highest. This value is 5.83kA, as given in Table 2. When the maximum fault current is divided by the CT ratio (5.83kA/300 = 19.43A), the result is less than 20 times the rated CT secondary current. All four reclosing relays utilized in this paper have a CT ratio of 300:1.

C. Overcurrent protection configuration settings

The phase time overcurrent pick-up (51P) currents were determined by multiplying the normal load current by 1.5, the residual time overcurrent pick-up (51G) was determined by multiplying the phase pick up current by 25%, and the phase instantaneous (67P1) was determined using the conductor damage curve. The settings for relay R1 and R2 are presented in Table 3.

TABLE 3. OVERCURRENT PROTECTION SETTINGS FOR RELAYS R1 AND R2

Protection device name	Branch	Overcurrent ANSI codes	Type of overcurrent Characteristic curve	I Pick up in primary	I Pick up in Secondary With a CT ratio of 300:1	Time dial	Direction
Relay 1 (R1)	Line 1	51P	IEC Normal inverse	(168×1.5) =252A	0.84A	0.13	Non-Directional
		67P1	IEC Definite time	3900A	13A	0	
		51G	IEC Normal inverse	(252×0.25) =63A	0.21A	0.17	
Relay 2 (R2)	Line 2	51P	IEC Normal inverse	(135×1.5) =202.5A	0.68A	0.05	
		51G		(202.5×0.25) 50.63A	0.17A		

I.V. LAB-SCALE IMPLEMENTATION OF THE NETWORK RECONFIGURATION SCHEME

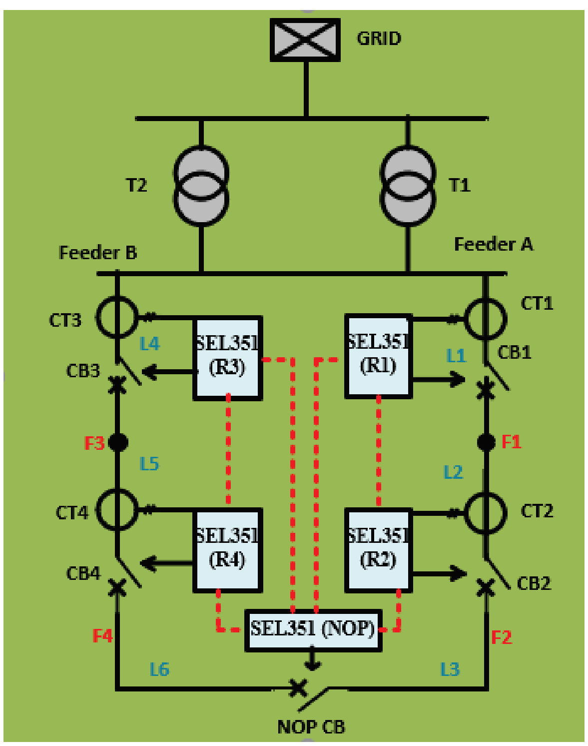

Fig.2: Network reconfiguration control scheme

This section intends to replace the traditional hardwire that was used to transfer signals between protection monitoring devices by introducing the IEC 61850 standard lab-scale implementation which uses GOOSE communication between relays R1, R2, NOP, and Omicron CMC 356 test injection device. The data that is sent between these relays is event-based. The mechanism of the publisher/subscriber system is used for data exchange. Fig. 2 shows the modelled distribution network's IEC 61850 GOOSE message-based network reconfiguration control scheme.

A. Developed logic for a network reconfiguration scheme

Figures 4, 5, and 6 show the developed logic for relays R1, R2, and NOP, respectively. Fig.3 is developed for fault conditions occurring between relays R1 and R2 in Fig.3. At this fault, R1 will trip and multicast GOOSE messages are delivered to trip the binary input on the Omicron 356 to open the virtual circuit breaker mapped to the binary output.

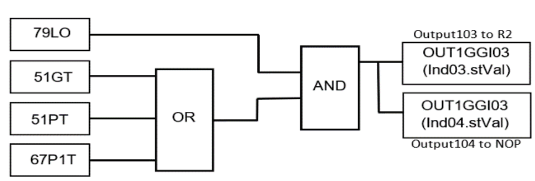

Fig.3: Logic for relay R1

The high status (logical 1) from any of the overrent elements (51GT, 51PT, or 67P1T) and 79LO input signals to

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the AND gate, as well as the AND gate's high output, are directed to the NOP through outputs 103 and 104 via the GOOSE signal as shown in Fig.4. The trip and lockout state GOOSE messages for R1 serve as the input to R2. In receipt of R1 trip and lockout, R2 trip and lockout, and send a close GOOSE message to the NOP through output 103. The logic for R2 is depicted in Fig.4.

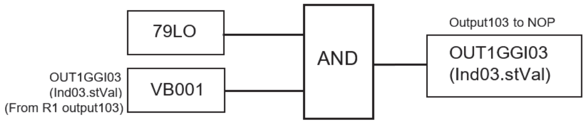

Fig.4: Logic for relay R2

When the NOP relay receives both close GOOSE signals from R1 and R2, it closes the NOP circuit breaker mapped to the binary output of the Omicron 356 device. This logic is depicted in Fig.5.

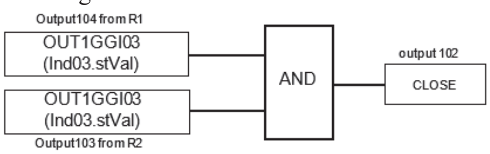

Fig.5: Logic for NOP relay

V. SIMULATION RESULTS

A study case was performed using the IEC 61850 standard -based GOOSE network reconfiguration control scheme to assess the performance of the overcurrent relays for the distribution system. The fault currents in table 3 are used to conduct the study. For this study, a single-phase to ground fault is simulated at Relay R1. A single-phase to ground fault is the most common fault in overhead lines [12], hence it is simulated.

Table 3. Primary and secondary fault currents

Relays	Single-phase to ground fault currents	
	Primary current	Secondary current
R1	1727.1A	5.757A
R2	843.12A	2.81A

A. Single-phase to ground fault on R1

A single-phase to ground fault current of 5.757A secondary is simulated to R1. This means the maximum current is 2442.49A (1727.1A $\times$ $\sqrt{2}$ = 2442.49A). As depicted by the fault current waveform in Fig. 6, the fault is simulated between the red phase and ground. Due to this fault, R1 operated at 345ms. Fig.6 also presents the items triggered when the fault was simulated.

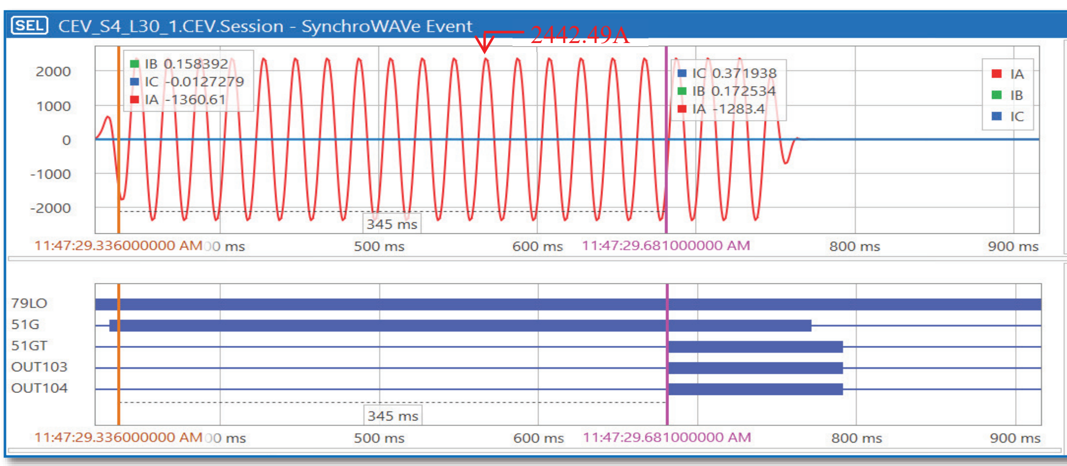

Fig.6: Relay R1 operation to a single-phase to ground

Since there was current injected to R1, the 79LO element was already asserted, 51G asserted to pick up the 5.757A simulated fault currents, 51GT asserted to clear the fault, and both OUT103 and OUT104 were asserted to send the trip to open through the GOOSE message signal to the relays R2 and NOP. The conduct of relay R2 to send a close GOOSE message signal to the NOP relay due to the trip signal sent by relay R1 is shown in Fig.7

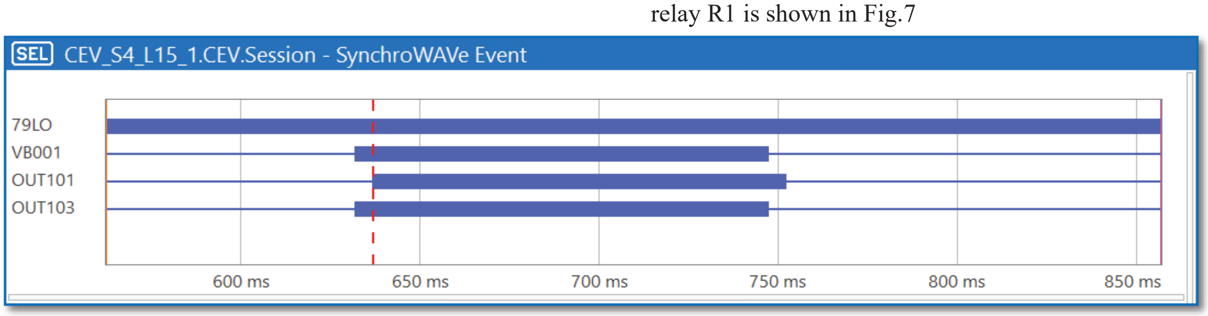

Fig.7: R2 operation due to R1 trip signal

79LO was already asserted because the R2 device was switched on, VB001 was asserted to subscribe to the trip GOOSE message published by R1, OUT101 was asserted because the trip is mapped to OUT101, and OUT103 was asserted to send a close GOOSE signal to the NOP relay. Fig.8 depicts the NOP relay response to sending the close signal due to the GOOSE message broadcast by R1 and R2.

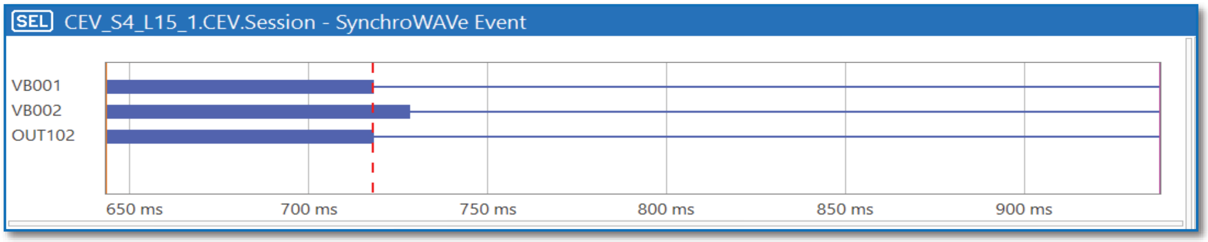

Fig.8: NOP relay operation

VB001 and VB002 of the NOP relay asserted (Fig 8) their subscribe to the GOOSE message broadcast by R1 and R2. Because the close signal is mapped to output 102, OUT102 is asserted. When both VB001 and VB002 of NOP are asserted, it signifies that both R1 and R2 are tripped to open and NOP can securely close NOP to the back-feed line section between the NOP and R2 illustrated in Fig.2.

VI. CONCLUSION

The IEC 61850 GOOSE-based network reconfiguration scheme simulation test was carried out at DEECE CPUT's CSAEMS lab. Using the omicron test injection device CMC 356, and relay operating parameters are monitored. The simulation results are analyzed using the considered study case. The practical implementation of the IEC 61850 GOOSE-based simulations on the case study demonstrated that the designed IEC 61850 network reconfiguration scheme may reconfigure the distribution system in the event of a fault. This technique enhances the distribution system's reliability. The practical information gained in this paper will instruct protection engineers on how to configure and deploy the network reconfiguration scheme using IEC 61850 standard-based GOOSE message application for any industrial distribution network to increase network protection performance through automatic reconfiguration under fault conditions.

VII. FUTURE WORK

For future research, it will be interesting to see network reconfiguration tested in a real-time system. Customers on the interrupted feeder would be reconnected by the alternative healthy feeder.

VIII. ACKNOWLEDGEMENTS

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