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Protective Relay Coordination in an Injection Substation Using Short Circuit Analysis.

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ABSTRACT: This research aims to improve relay coordination in the Port Harcourt Distribution Network using Marine Base 2 X 15MVA, 33/11kV Injection substation as a case study. The method employed is short circuit analysis of the network to determining the sequence of relay coordination to faulton both the existing and enhanced cases, and then applyingElectrical Transient Analyzer Program (ETAP 19.0.1) to model and simulate the network using data gotten from the Port-Harcourt Electricity Distribution Company and the Transmission Company of Nigeria.The result reveals that for the existing case, tripping sequence violation occurred on the 4 (four) primary feeder relays with their respective backup. Churchill feeder fault analysis reveals a total time of operation between the primary relay and its backup for a 3-phase fault as 83.3ms, 213ms, 137ms and 110ms while the order of tripping operation is from feeder breaker, 33kV line breaker, 33kV control panel breaker and 11kV incomer control breaker for the existing case while the improved case, the time of operation is 226ms, 343ms, 411ms and 420ms. This shows the right order of coordination from feeder breaker to 11kV incomer control breaker, 33kV control panel breaker and 33kV line breaker. 3-phase fault on NPA feeder for the existing case, shows the order of time of operation in response to fault as82.9ms, 137ms, 213ms and 110ms. Thus, the sequence is from feeder breaker, 33kV line breaker, 33kV control panel breaker and 11kV incomer control breaker, and improved case is226ms, 343ms, 411ms and 420ms. Fault on Station Road feeder for the existing caseshowsa total time of operation as 84.9ms, 137ms, 213ms and 110ms, whilethe improved case is 240ms, 373ms, 416ms and 420. The total time of operation for a fault on Amadi North feeder for the existing case is 83.6ms, 244ms, 165ms and 110ms while the improved case sequential time of operation is 239ms, 373ms, 416ms and 420ms. The implication of the existing case is that during fault, the sequence of operation is in the order of 1 4 3 2. This counters the right sequence which is 1 2 3 4. In conclusion, because of the improper coordination level of the existing case, a fault will cause serious damage to lives and properties as well as hamper the revenue of the distribution company due to the outage area affected**.**

KEYWORDS: Relay, Injection, Substation, Protection, Coordination, Marine Base.

I. INTRODUCTION

An electric power system is a network of electrical components utilized to generate, transfer, and consume electricity [1]. Primary distribution network received bulk power from transmission system at 33kV by means of stepped-down transformer while secondary distribution network received power at 11kV from a primary distribution network by means of stepped-down transformer [2].Finally, the electricity is carried by a distribution power line until it reaches the final customer. According to [3], electric power distribution system is the final stage of power supply system as well as the part of the electrical power system that is most visible to the end users. The study also show the distribution system as the most viable to the end users.

For a stable power supply, the power system network should be protected. Power system protection is a part of electrical engineering that takes care of constant monitoring of the system to ensure maximum electrical supply continuity while avoiding equipment damage. According to [4], electrical power when compared with the various types of power, plays great role on how a society operates, and as a result, it is important for a government to provide a stable power supply among other things to meet the growing demand of its citizens. The system's designer or engineer tries to come up with a system configuration, he or she will never be able to build a system that will never fail for any reason. The relevance of the protection system and protective

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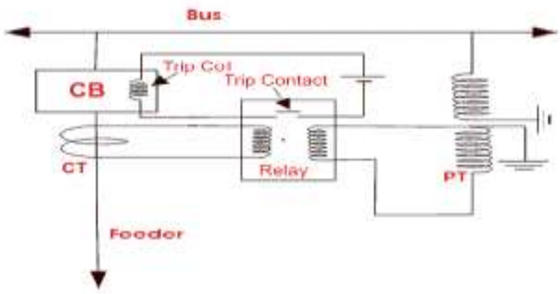
relays becomes clear at this point. When a fault in an electrical circuit is detected, a protective relay analyzes operating conditions on the circuit and trips circuit breakers.

Relays must be designed to detect abnormal or undesirable situations and deliver a tripping signal to the circuit breaker, isolating the affected area without affecting adjacent areas. Statistics show that many relay trips are caused by wrong or poor settings rather than real failure[5]. A protective relay instructs a circuit breaker to disengage a system component that has failed. One of the key responsibilities of the protection system is to detect and isolate the faulty part as quickly as possible.

As previously indicated, a shunt fault generates a quick build-up of current. Thus, it is only reasonable to use current magnitude as a positive indicator of the presence of a fault. As a result, the most often used technique of distribution system protection is overcurrent protection. In power systems, the overcurrent relay is one of the most utilized protection relays[6].



Source : [7]

Figure 1.1: Basic Circuit Diagram of Protective Relay Scheme

Fig 1.1 illustrate the fundamental circuit breaker control connections for the opening action. The relay attached to current transformer and the potential transformer actuates and closes its contacts when a fault occurs within the protected circuit.

When the breaker trip coil is energized, the breaker working mechanism is activated. This allows the flow of current from the battery to the trip circuit and opening action is established. The relay is responsible for the activation of the trip circuit and the faulty section is isolated by the circuit breaker.

There are different types of relays depending on its mode of operation and application. For this study, I shall focus on over current relay and its coordination. [8] say that coordination of relays is an instrument in which any relay nearest to the defect location works, but the backup relay works sequentially to secure the backup in cases of failure. A comparison of the operating time of the relays in response to a variety of overcurrent is conducted while selecting or establishing these protective relays. According to [9], a new or revised coordination is required, when the available fault current from the power supply is increased, heavy loads are introduced or old equipment is replaced with new equipment, a fault shuts down a substantial section of the system, or when protective devices are modified. According to [10], protection should be designed in any power system network so that protective relays send a signal to the circuit breaker to isolate the faulted portion of the network as quickly as possible, preventing equipment damage, operator injuries, and ensuring minimal system disruption while maintaining service to the healthy portion of the network.[10] also say that in the event of failure of primary relays, backup relays take charge when the pre-set time has elapsed. In line with this journal, the relay should also be able to distinguish between normal and abnormal condition. Because coordination method must ensure quick, selective, and reliable operation, it is a key aspect of the protection system. The impact of this assures the safety of human lives and property to a significant extent.

1.1 Statement of Problem

Most times, a substation feeder relay, and a supply-side (incomer) relay trip on the same fault. This is known as an over trip, and it is not good. As a result, not only are the customers served by the defective feeder inconvenienced, but all customers supplied by the other feeders from the same supply-side relay and breaker are also inconvenienced. Also, there have been several cases of electrocution due to line cut.Calabar electrocution resulted to the death of 7 persons and various degrees of injuries on 11 others in February 2017. However, the report further revealed that a cut conductor of a certain 11kV feeder fell on a building where people were watching football and the feeder failed to trip [11]. According to Vanguard February 13, 2010, there was an electrocution in the city of Port Harcourt, River State. A high-tension line belonging to Power Holding

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Company of Nigeria, disengaged and landed on two commercial buses, electrocuting the passengers on the spot, according to report, the tragic incident occurred in the Obio/Akpor local government region, in Oginigba, close to Slaugher, Trans-Amadi. These incidents are unwelcomed and are typically attributed to a lack of relay coordination.

1.2 Aim of Study

This research work is aimed to study Protective Relay Coordination in an Injection Substation with Over Current Relays using Marine Base 2×15MVA, 33/11kV Injection substation as case study.

1.3 Significance of Study

This study would be to provide correct relay coordination that will guarantee improved operation by making sure that a faulty part of the power system is detected and isolated automatically without causing an over-trip or causing damage to live and property.

II. LITERATURE REVIEW

For a stable power supply, the power system network should be protected. Relays and circuit breakers are used to protect the system. There are numerous types of current protective devices, according to [12], each of which is sensitive to the fault current. The location and type of devices to be safeguarded are the most important selectivity criteria. Distance relays are typically used for long-distance transmission lines, differential relays for transformer protection, directional overcurrent relays for meshed networks, overcurrent relays for generators, motors, and feeders, and pilot relays for long-distance, switching in hazardous areas, cable, and power equipment protection. Overcurrent relay (OCR) is one of the most used protective devices used in power system. According to [13], in power system, overcurrent and earth fault relay coordination are very important to correctly identify fault and provide proper sequence of fault clearing. During system design, the fault current calculation is used to determine the coordination of this protective relay. In the event of fault, protective relays should be able to communicate with relays on adjacent buses within a set time frame. The choice of discrimination and selectivity depends on the time curve characteristics used for relay coordination for power system network to execute appropriate commands to isolate only faulty component from the healthy system [14]. To have a working time difference between the primary relay and back up relays, there is a strong need for calculation, to determine the Time setting multiplier (TSM) and Plug setting multiplier (PSM) of the relays. A protection system must have a coordination time interval (CTI). This is a time frame between a primary relay and a backup relay operation.For traditional relays, this interval is between 0.3 and 0.5 seconds, but for numerical relays, it is set at 0.2 seconds, implying that they work faster than conventional relays or traditional relays, [12]. As a result, the primary relay operation time and CTI must be considered when coordinating relays. The voltage, current, and power flow of line, bus, transformers are determined by the load flow analysis. Plug settings of the relay can also be ascertain using load flow studies. To determine the PSM of a relay, a short circuit analysis is required. The TMS of the backup relay can then be obtained using this PSM. As a result, in relay coordination, load flow and short circuit analysis are necessary.Many protective relays on radial feeders are coordinated by Standard time current (STI) curves, pickup values, and time dial. Overcurrent protection is mostly utilized for distribution feeders. The goal is to respond as quickly as possible to faults in the primary zone, while deferring actions for faults outside of its protection zone. The magnitude of fault current is inversely proportional to the operating time of overcurrent relay. The parameters associated with operating characteristics are the relay pick-up (Ip) and time delay setting (TDS) [14]. For appropriate coordination system, use relays with identical operating characteristics in series with each other wherever possible, and make sure the relay furthest from the source has current settings equal to or lower than the relays behind it. That is, the primary current needed to operate the relay in front is always the same as or less than the primary current needed to operate the relay behind it. The Plug Setting Multiplier (PSM) controls the relay current, whereas the Time Dial Settings control the time. Unless monitored by an under-voltage relay, the plug-setting must not be less than the maximum load including allowable continuous overload. The load will not be delivered if the relay does not allow it. When evaluating the plug-setting, keep in mind that the relay pick-up varies from 1.05 to 1.3 times the plug-setting, according to industry norms.On the time – current characteristics graph, the over current relay coordination curve for the feeder must be below the feeder overload and feeder short circuit damage curves, according to [15]. In addition, the feeder's overcurrent relay coordination curve must be higher than the capacity curve. An overcurrent relay is a type of protective relay that activates when the load current exceeds its set pickup value. Current setting multipliers on overcurrent relays typically range from 50 to 200 percent in 25 percent increments, referred to as plug setting (PS).

[6] made a review of Optimal Overcurrent Relay Coordination. In this work, a proposed method for overcurrent (OC) relay coordination is introduced based on numerical relay qualities of several settinggroups. Attempts have been made to include all overcurrent relay coordination methods. Its techniques, such as Artificial Intelligence and the Nature Inspire Algorithm, as well as other traditional

methods for over current protection. The traditional method is divided into three categories: trial and error, topological analysis, and optimization method. The artificial intelligence (AI) and nature inspired algorithms (NIA) based optimization methods were applied to solve both overcurrent relays and directional overcurrent relays coordination problem.

[16] wrote on Directional Overcurrent Relay Coordination using Artificial Immune Algorithm. In his paper, an optimization methodology is proposed based on AIS (Artificial Immune System) to solve the problem of coordinating the overcurrent relay in distributed system. AIS algorithm utilizes the adaptive clone selection. In this method, both the Pickup current and the TMS are considered as optimization parameters.It is used to obtain the optimal setting of overcurrent relays in 5 buses distribution system. By comparing the results with the other methods, a reduction in operation time of the relays is achieved by AIS algorithm. The results show that AIS can be faster and more reliable than other optimization methods for solving the coordination problem. The proposed algorithm is general and can be applied for any distribution system.

III. MATERIALS AND METHOD

3.1 Research Materials

Materials required for this research analysis and investigation are obtained from the Port Harcourt Electricity Distribution Company (PHEDC) and the Transmission Company of Nigeria (TCN).

Table 3.1: Available Data required for Calculations and Simulation from PHEDC and TCN

S/N	Parameter	Assumptions
1	Route length of 33kv line	4.5km
2	Maximum load on 33kv line	15.3MW
3	T1B 30MVA Impedance at Transmission station	12.5%
4	T1 15MVA Impedance at Marine Base Injection Substation	10.52%
5	T2 15MVA Impedance at Marine Base Injection Substation	10.6%
6	Peak load on Churchill 11kv Feeder	2.8Mw (168Amps)
7	Peak load on NPA 11kv Feeder	2.7Mw (162Amps)
8	Peak load on Station Road 11kv Feeder	3.5Mw (210Amps)
9	Peak load on Amadi North 11kv Feeder	3.3 Mw (198Amps)
10	Conductor Size	150mmsq
11	Conductor type	AAC
12	Cable size	240mmsq
13	CTRs Incomer	1250-800/1
	CTRs Outgoing	600-300/1
14	Base MVA	100
15	Relay Type	Schneider O/C and E/F Relay
16	Conductor Resistivity at 32 °	$2.83X10^{-8}$
17	33kv line spacing	3ft= 914.4mm

3.2. Method of Analysis

The methods employed here are load flow studies, short circuit current calculation and relay coordination with standard inverse and definite time.

3.3. Network Model and Simulation of Existing Case using Short Circuit Analysis

From equation 3.1, the Resistance of a conductor is given as:

$R = \frac{\rho L}{A} (\Omega)$

From Table 3.1,

Conductor Resistivity at 32 ° (R) = $2.83X10^{-8}$

Route length of conductor = 4500meters

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Conductor size =150mmsq
Therefore,
R= $2.83X10^{-8} \times \frac{4500}{1.5\times10-4} = 0.849\ \Omega$
Also, from equation 3.2,
A $= \frac{\Pi d^2}{4}$, where d $= 2\times\sqrt{\frac{A}{\pi}} = 2r$
$d = 2\times\sqrt{\frac{150}{\pi}} = 13.82$mm
$r = \frac{d}{2} = \frac{13.82}{2} = 6.91$mm
Using equation 3.4 and 3.5, we have:
$Xo = 0.1445\log_{10}\left(\frac{DGMD}{r}\right) + 0.0157$
$Xo = 0.1445\log_{10}\left(\frac{914.4mm}{6.91}\right) + 0.0157 = 0.3223\Omega/km$
From equation 3.5, line reactance is:
$X = x_o\ l_o$
$X = 4.5 \times 0.3223 = 1.4503\Omega$
From equation 3.6, the distributed series impedance becomes:
$Z_1 = R + jX$
$Z_1 = 0.849 + j1.4503$
$Z_1 = \sqrt{((0.849)^2 + (j1.4503)^2)} = 1.6805\Omega$
For the Admittance,
$Z_o = Y = \frac{1}{Z} = G + jB$
$\frac{1}{Z} = \frac{1}{0.849 + j1.4503}$
$\frac{1}{Z} = \frac{1}{0.849 + j1.4503} \times \frac{0.859 - j1.4503}{0.859 - j1.4503}$
$\frac{1}{Z} = (0.3006 - j0.5135)$ siemens
Therefore,
$Z_o = \frac{1}{Z} = \frac{1}{0.3006 - j0.5135}$
$Z_o = 3.3267 - j1.9474$
$Z_o = \sqrt{(3.3267)^2 - (j\ 1.9474)^2}$
$Z_o = 2.6971\ \Omega$
For Source Impedance,
From table 3.1,
Base MVA = 100 and Source % Impedance = 12.5%
Source Impedance $= \frac{\%Z\times BaseMVA}{TransformerMVA}$
Source Impedance $= \frac{12.5}{100} \times \frac{100}{30}$
$Z_{SP.U} = 0.417$p.u
$Z_{1P.U} = \frac{Z1\times BaseMVA}{(Kv)2}$
$Z_{1P.U} = \frac{1.6805\times100}{(33)2} = 0.1543$p.u
If Transformer Base impedance for T1 and T2 is 100MVA,
For Transformer 1 at Marine Base Injection Substation,
$Z_{T1P.U} = \frac{10.52}{100} \times \frac{100}{15} = 0.70$p.u
For Transformer 2 at Marine Base Injection Substation,
$Z_{T2.PU} = \frac{10.6}{100} \times \frac{100}{15} = 0.71$p.u

The total fault impedance on T1 at Marine Base Injection Substation.
$Z_F = Z_S + Z_1 + Z_{T1}$
$Z_F = 0.417 + 0.1543 + 0.70 = 1.2713$ p.u
Total fault impedance on T2 at Marine Base Injection Substation,
$Z_F = Z_S + Z_1 + Z_{T2}$
$Z_F = 0.417 + 0.1523 + 0.71 = 1.2793$ p.u
Fault MVA $= \frac{BaseMVA}{TotalfaultImpedanceatMarineBaseInjectionsubstation}$
For T1, Fault MVA $= \frac{100}{1.2713} = 78.66$MVA
For T2, Fault MVA $= \frac{100}{1.2793} = 78.17$ MVA
Full load current for 15MVA Transformer
Primary full load current $I_p = \frac{P}{\sqrt{3}.V_l} = \frac{15\times10^6}{\sqrt{3}\times33\times10^3} =$ 262.43Amps.
Secondary full load current $I_s = \frac{P}{\sqrt{3}.V_l} = \frac{15\times10^6}{\sqrt{3}\times11\times10^3} =$ 787.30Amps
Therefore,
Fault current= $\frac{Fault\ MVA}{\sqrt{3}\times VLL}$
For $T_1 = \frac{78.66\times1000}{\sqrt{3}\times11} = 4.129$KA
For $T_2 = \frac{78.17\times1000}{\sqrt{3}\times11} = 4.103$KA

3.4. Theoretical Relay Settings Calculations
3.4.1. Churchill Feeder
Churchill Feeder has the following reays :
Relay 6 : Protective Relay
Maximum load of Churchill 11kV feeder = 168Amps
TMS = 0.08 (Simulated Set Value)
Taking time difference between two Relays as 100ms (Primary and Back up)
CT Ratio = 600/1A
$PS = \frac{168}{300} = 40\%$
Curve Type: Standard Inverse
Fault current (ETAP) on Churchill Feeder = 4.458kA
$PSM = \frac{I_f}{PS\times CTRatio} = \frac{4.458\times1000}{0.4\times600} = 18.575$
$T = \frac{0.14}{PSM^{0.02}-1} \times TMS$
$T = \frac{0.14}{18.575^{0.02}-1} \times 0.08 = 186$ms

RELAY 4: T_2 11kV Incomer
Time of operation of Relay 2 = 100 + 186 = 286ms
$I_f = 3.505$KA
$PSM = \frac{I_f}{PS\times CTRatio} = \frac{3.505\times1000}{0.6\times800} = 7.3$
$0.286 = \frac{0.14}{7.3^{0.02}-1} \times$MS
TMS = 0.083

RELAY 2: T_2 33kV Control Panel
Time of Operation of Relay 3 = 100 + 286 = 386ms
$I_f = 1.168$KA
$PSM = \frac{I_f}{PS\times CTRatio} = \frac{1.168\times1000}{0.6\times300} = 6.49$

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$0.386 = \frac{0.14}{6.49^{0.02}-1} \times TMS$

TMS = 0.1

3.4.2. NPA FEEDER

NPA feeder is made up of the following relays :

Relay 7 : Protective Relay

Maximum load of NPA 11kV feeder = 162Amps

TMS = 0.081 (Simulated Set Value)

Taking time difference between two Relays as 100ms

CT Ratio = 600/1A

PS = 40%

Curve Type: Standard Inverse

Fault current (ETAP) on NPA Feeder = 4.494kA

$PSM = \frac{I_f}{PS \times CTRatio} = \frac{4.494 \times 1000}{0.4 \times 600} = 18.725$

$T = \frac{0.14}{PSM^{0.02}-1} \times TMS$

$T = \frac{0.14}{18.725^{0.02}-1} \times 0.081 = 188ms$

RELAY 4: T_2 11kV Incomer Relay

Time of operation of Relay 2 = 100 + 188 = 288ms

I_f = 3.505KA

$PSM = \frac{I_f}{PS \times CTRatio} = \frac{3.505 \times 1000}{0.6 \times 800} = 7.3$

$0.288 = \frac{0.14}{7.3^{0.02}-1} \times TMS$

TMS = 0.083

RELAY 2: T_2 33kV Control Panel Relay

Time of Operation of Relay 3 = 100 + 288 = 388ms

I_f = 1.168KA

$PSM = \frac{I_f}{PS \times CTRatio} = \frac{1.168 \times 1000}{0.6 \times 300} = 6.49$

$0.388 = \frac{0.14}{6.49^{0.02}-1} \times TMS$

TMS = 0.1

3.4.3 STATION ROAD FEEDER

Station road feeder is made up of the following :

Relay 8 :Protective Relay

Maximum load of Station Road 11kV feeder = 210Amps

TMS = 0.08 (Simulated Set Value)

Taking time difference between two Relays as 100ms

CT Ratio = 600/1A

PS = 50%

Curve Type: Standard Inverse

Fault current (ETAP) on Station Road Feeder = 4.561kA

$PSM = \frac{I_f}{PS \times CTRatio} = \frac{4.561 \times 1000}{0.5 \times 600} = 15.2$

$T = \frac{0.14}{PSM^{0.02}-1} \times TMS$

$T = \frac{0.14}{15.2^{0.02}-1} \times 0.08 = 200ms$

RELAY 5: T_2 11kV Incomer Relay

Time of operation of Relay 5= 100 + 200 = 300ms

I_f = 3.397KA

$PSM = \frac{I_f}{PS \times CTRatio} = \frac{3.397 \times 1000}{0.7 \times 800} = 6.07$

$0.300 = \frac{0.14}{6.07^{0.02}-1} \times TMS$

TMS = 0.08

RELAY 3: T_2 33kV Control Panel Relay

Time of Operation of Relay 3 = 100 + 300= 400ms

I_f = 1.168KA

$PSM = \frac{I_f}{PS \times CTRatio} = \frac{1.132 \times 1000}{0.6 \times 300} = 6.29$

$0.400 = \frac{0.14}{6.29^{0.02}-1} \times TMS$

TMS = 0.1

3.4.4 AMADI NORTH ROAD FEEDER

Amadi north road feeder is made up of the following :

Relay 9 : Protective Relay

Maximum load for Amadi North Road 11kV feeder = 198Amps

TMS = 0.08 (Simulated Set Value)

Taking time difference between two Relays as 100ms

CT Ratio = 600/1A

PS = 50%

Curve Type: Standard Inverse

Fault current (ETAP) on Amadi North Road Feeder = 4.632kA

$PSM = \frac{I_f}{PS \times CTRatio} = \frac{4.632 \times 1000}{0.5 \times 600} = 15.44$

$T = \frac{0.14}{PSM^{0.02}-1} \times TMS$

$T = \frac{0.14}{15.44^{0.02}-1} \times 0.08 = 199ms$

RELAY 5: T_2 11kV Incomer Relay

Time of operation of Relay 5= 100 + 199 = 299ms

I_f = 3.397KA

$PSM = \frac{I_f}{PS \times CTRatio} = \frac{3.397 \times 1000}{0.7 \times 800} = 6.07$

$0.299 = \frac{0.14}{6.07^{0.02}-1} \times TMS$

TMS = 0.08

RELAY 3: T_2 33kV Control Panel Relay

Time of Operation of Relay 3 = 100 + 299= 399ms

I_f = 1.132KA

$PSM = \frac{I_f}{PS \times CTRatio} = \frac{1.132 \times 1000}{0.6 \times 300} = 6.29$

$0.399 = \frac{0.14}{6.29^{0.02}-1} \times MS$

TMS = 0.1

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IV. RESULTS AND DISCUSSION

4.1 Existing Relay coordination on Marine 2×15MVA, 33/11kv Injection Substation

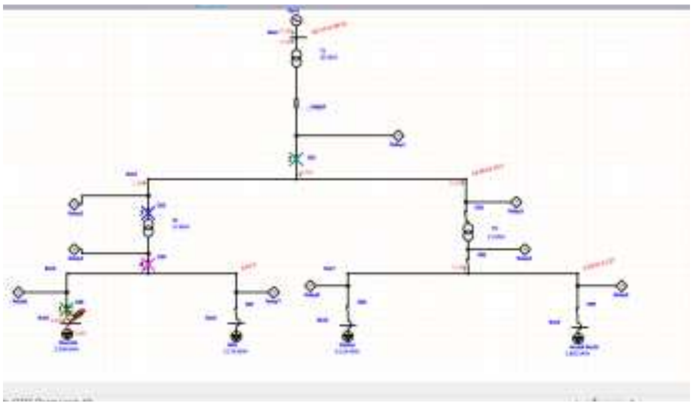

Figure 4.1: Existing Circuit Breaker Tripping Sequence for Fault on Churchill Feeder

Figure 4.1 clearly shows the order of tripping sequence for a 3-phase simulated fault of the existing case, injected on Churchill feeder. The tripping sequence is in the order of: Feeder circuit breaker → 33kV line Breaker→ 33kV Control Panel Breaker → 11kV Incomer Breaker. This response to fault violates the right order of operation.

CB6 – CHURCHILL
CB4 – T2A 11KV INCOMER
CB3 - 33KV CONTROL PANEL
CB1 - 33KV LINE BREAKER

Table 4.1: Relay response sequence with time of operation for Existing Case

Sequence-of-Operation Events - Output Report: Untitled

3-Phase (Symmetrical) fault on connector between CB6 & Churchil. Adjacent bus: Bus4

Data Rev.: Base Config.: Normal Date: 08-01-2022

Time (ms)	ID	If (kA)	T1 (ms)	T2 (ms)	Condition
23.3	Relay6	4.458	23.3		Phase - OC1 - 51
30.0	Relay1	0.791	30.0		Phase - OC1 - 51
83.3	CB6		60.0		Tripped by Relay6 Phase - OC1 - 51
110	CB1		80.0		Tripped by Relay1 Phase - OC1 - 51
117	Relay2	1.168	117		Phase - OC1 - 51
137	CB2		20.0		Tripped by Relay2 Phase - OC1 - 51
153	Relay4	3.505	153		Phase - OC1 - 51
213	CB4		60.0		Tripped by Relay4 Phase - OC1 - 51

Table 4.1 represents the operation of relays with its associated circuit breakers and the corresponding tripping time (ms) for 3-phase fault on Churchill feeder of the existing case. There is a clear violation of relay response to fault when compared with the proper sequence

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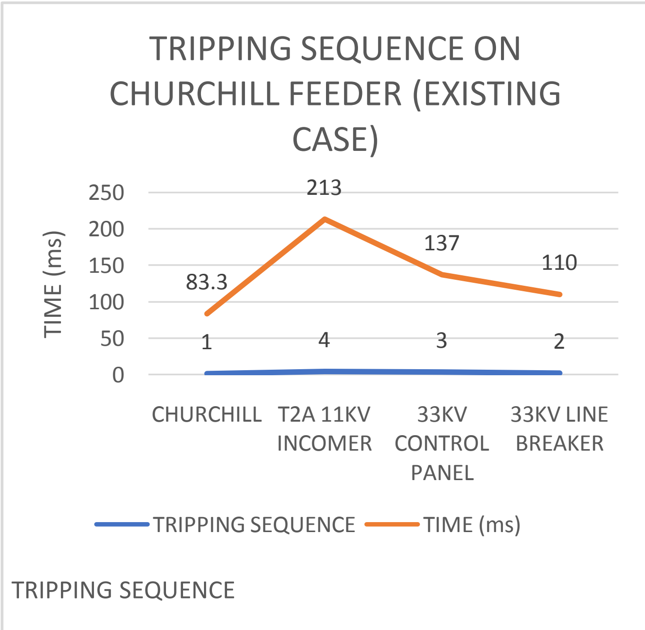

Figure 4.2: Graph showing Sequence of Circuit Breaker Operation for Fault on Churchill Feeder (Existing Case)

Fig 4.2 shows a graph representation of the various circuit breaker tripping sequence with its associated time of operation in response to a 3-phase fault on Churchill feeder of the existing case.

4.2. Improved Relay coordination on Marine Base 2×15MVA, 33/11kv Injection Substation

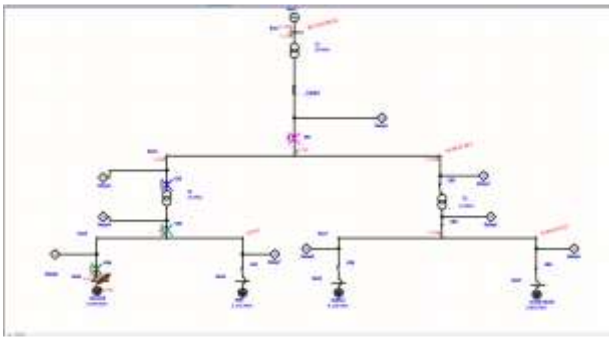

Fig 4.3 : Improved Circuit Breaker Tripping Sequence for Fault on Churchill Feeder

Fig 4.3 explains the simulated sequence of tripping for a 3-phase fault on Churchill 11kV outgoing feeder for the improved case. This mode of operation shows the right order, which is: Feeder Circuit Breaker → 11kV Incomer Breaker → 33kV Control Panel Breaker → 33kV line Breaker.

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Table 4.2: Improved Relay response sequence with time of operation

Sequence-of-Operation Events - Output Report: Untitled

3-Phase (Symmetrical) fault on connector between CB6 & Churchil. Adjacent bus: Bus4

Data Rev.: Base Config: Normal Date: 15-01-2022

Time (ms)	ID	If (kA)	T1 (ms)	T2 (ms)	Condition
186	Relay6	4.458	186		Phase - OC1 - 51
226	CB6		40.0		Tripped by Relay6 Phase - OC1 - 51
283	Relay4	3.505	283		Phase - OC1 - 51
331	Relay2	1.168	331		Phase - OC1 - 51
340	Relay1	0.791	340		Phase - OC1 - 51
343	CB4		60.0		Tripped by Relay4 Phase - OC1 - 51
400	Relay7	0.954	400		Phase - OC1 - 51
411	CB2		80.0		Tripped by Relay2 Phase - OC1 - 51
420	CB1		80.0		Tripped by Relay1 Phase - OC1 - 51

Table 4.2 represents the operation of relays with its associated circuit breakers and the corresponding tripping time (ms) for the improved case for a 3-phase fault on Churchill feeder.

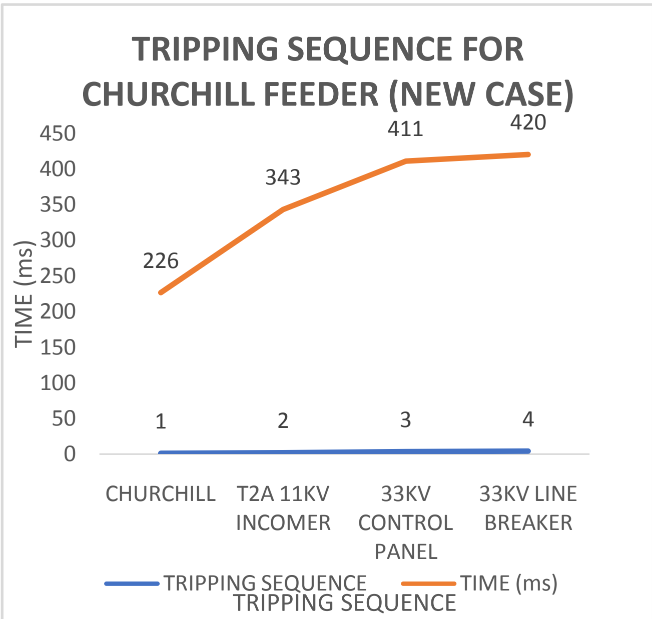

Fig 4.4: Graph showing Sequence of Circuit Breaker Operation for Fault on Churchill Feeder (Improved Case)

Fig 4.4 shows a graphical representation of the various circuit breaker tripping sequence with their associated time of operation in response to a 3-phase fault on Churchill feeder for an improved case.

Table 4.3 : Comparison of Existing Case with New Case onChurchillFeeder

FEEDER	TRIPPING SEQUENCE	TIME (ms)	
		EXISTING	New
CHURCHILL	1	83.3	226

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T2A 11KV INCOMER	2	213	343
33KV CONTROL PANEL	3	137	411
33KV LINE BREAKER	4	110	420

Table 4.3: Comparing Sequence of Operation for Circuit Breakers

Table 4.3 clearly shows the distinctive difference between the existing and improved case regarding sequence of operation of various circuit breakers to fault on Churchill 11kV outgoing feeder.

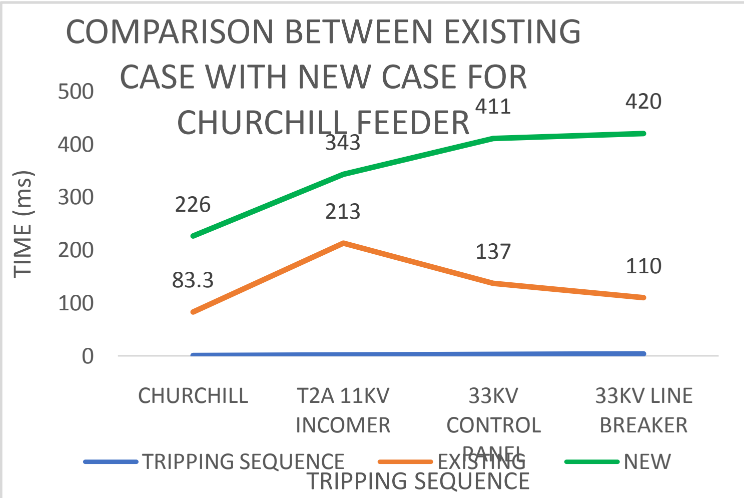

Fig 4.5 Graph comparing sequence of Circuit Breaker Operation for Fault on Churchill Feeder (Existing Case vs New Case)

V. CONCLUSION AND RECOMMENDATIONS

5.1 CONCLUSION

In Power systems and other arears, protective device coordination is a priority for reliability of supply. To ensure appropriate coordination, the parameters of the relay should be correctly examined. Power systems relays should be adequately coordinated to provide primary as well as back up protection, and at the same time prevent erroneous operation and hence avoid unnecessary outage of healthy parts of the system. In this work, a short circuit analysis was carried out to determine the system fault current. After modelling of the existing network by injecting a 3phase fault on ETAP 19.0, it is observed that thereis a mal operation of the protective devices in response to the fault. This necessitated an adjustment on time current curve (TCC) to tackle the inappropriate operation leading to an improved case. Furthermore, manual computation and comparison of relay settings with simulated figures for both existing and improved cases revealed a gap between the existing case and improved case coordination. The result obtained by both methods i.e., manual calculation and simulation are almost the same on improved case. Lastly, a thorough comparison is carried out to justify result based on sensitivity, security and selectivity. The result shows that the improved case validates the attributes of a sound protective relay in response to fault.

5.2 RECOMMENDATIONS

After carrying out proper analysis in Port Harcourt Electricity Distribution network, the following points are recommended

i. Electromechanical Relays should be phased out and replaced by numerical or digital relays.

ii. Routine test should always be carried out on our various protective devices to ascertain their functionality.

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