FINDINGS OF THE COMMITTEE APPOINTED TO INVESTIGATE POWER SYSTEM FAILURES ON NOVEMBER 29, 2021 AND DECEMBER 03, 2021

ANNEXES OF THE FINAL REPORT

MINISTRY OF POWER

SRI LANKA

21.02.2022

Annex A1

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මගේ අංකය எமது இல My Ref. No.	PE/TECH/D/03/06	ඔබේ අංකය உமது இல Your Ref. No.	-	දිනය திகதி Date	04/12/2021

Prof. Lilantha Samaranayake (Chair)

Department of Electrical and Electronic Engineering, University of Peradeniya

Dr. Tilak Siyambalapitiya, Managing Director, Resource Management Associates Pvt Ltd

Mr. E.A. Rathnaseela, Additional Director General, Department of Public Finance

Mr. Nalinda Illangakoon, Vice Chairman, Ceylon Electricity Board

Dr M.N.S. Perera, Additional Secretary (Policy, Technical and Research), Ministry of Power

Mr Sugath Dharmakeerthi, Additional Secretary, Ministry of Power

Mr Andrew Navamuni, AGM/ Generation, Ceylon Electricity Board

Total Power Failure in the Country on 03rd December 2021

I am pleased to invite you to serve as Chair/ Member in the Committee to investigate the incident of island-wide power failure occurred on 03rd December 2021. The Committee is expected to provide the best independent judgment of the incident, based on your expertise.

The committee is expected to:

a. Identify the reasons for the power failure

b. Review the study reports of similar incidents occurred in the past and progress of the implementation of recommendations made by such committees.

c. Make recommendations for remedial measures that need to be taken by the CEB to prevent such incidents in future.

d. Investigate whether this is an incident which could have pre-planned / which could have been avoided

Ms. Indika Ranathunga, Senior Assistant Secretary of this Ministry will be the Convener of the Committee and she can be contacted through 0716843454 or indikaranatunge@yahoo.com

I shall be thankful if this invitation is accepted by you.

Sincerely

Wasantha Perera
Secretary
Ministry of Power

Copies

1. Secretary to HE the President
2. Secretary to Hon. Prime Minister
3. Secretary to the Treasury
4. Chairman, Ceylon Electricity Board
5. General Manager, Ceylon Electricity Board

Annex A2

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මගේ අංකය / எனது இல. / My No. PE/TECH/D/03/06 | ඔබේ අංකය / உமது இல. / Your Ref. No. | දිනය / திகதி / Date 22.12.2C

Prof. Lilantha Samaranayake, (Chairman)
Department of Electrical and Electronic Engineering, University of Peradeniya

Dr. Tilak Siyambalapitiya, Managing Director, Resource Management Associates Pvt ltd

Mr. E.A. Rathnaseela, Additional Director General, Department of Public Finance

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Mr. Sugath Dharmakeerthi, Additional Secretary, Ministry of Power

Mr. Andrew Navamuni, AGM/ Generation, Ceylon Electricity Board

Power Failures in the Country on 29th November 2021 and 03rd December 2021

Further to my letter of even number dated 04.12.2021 on the above subject.

In addition to the information sought by the said letter, you are kindly requested to study the incident of power failure occurred on November 29, 2021 and report considering your independent judgement of both incidents.

Wasantha Perera
Secretary

Annex B

Summary of the committee meetings.

No.	Date	Time	Venue	Participants	Remarks
1	6th Dec. '21	10 – 16:30	CEB / System Control Centre	Committee members and 26 Engineers from CEB, covering Generation, Transmission, Protection and System Control of CEB	Meeting minutes attached in Appendix 3
2	7th Dec. '21	20:00 – 22:00	Online	Committee members	Analyzed the data & reports received and decided the way forward
3	8th Dec. '21	12:00 – 13:00	Online	Committee members with Protection System expert.	Analyzed the operation of the Protection Relays
4	8th Dec. '21	13:30 – 16:00	Online	Committee members and 13 Engineers from CEB, covering Generation, Transmission, Protection and System Control of CEB	Q & A session to clear some of the unclear observations, with the intention of establishing the real cause of the fault.
5	11th Dec. '21	8:30 – 14:30	Kotmale Power Station	Committee members with DGM Transmission Protection & Control, Chief Engineer (Protection Development) & Chief Engineer (Protection Maintenance)	Checked the relevant relays in the Kotmale-Biyagama Line 01 and Line 02. Downloaded the relay logs and relay settings of the same.
6	12th Dec. '21	20:00 – 22:00	Online	Committee members with Protection System expert	Further analyzed the tripping of Kotmale-Biyagama Line 01 and Line 02.
7	13th Dec. '21	8:00 – 9:00	Faculty of Engineering	Committee members with Electrical Engineer – Protection	Obtained data on Kotmale New Anuradhapura Lines

8	13th Dec. '21	12:00 - 13:00	Online	Committee members with Chief Engineer/System Control Centre	Obtained generation and load data for the bus bars under pre-fault conditions to study the load flow
9	14th Dec. '21	16:15 – 18 - 45	Online	Committee members	To review the progress and decide the way forward
9	14th Dec. '21	20:00 – 22:00	Online	Committee members with Eng. Jayasiri Karunanayake (Protection System expert)	Discussed the fault propagation via the New Anuradhapura line 02.
10	16th Dec. '21	14:00 – 16:00	Online	Committee members with Mechanical Engineering expert on Coal Power plants.	Discussed the role of Lak Vijaya Power Station in the system failure, measures to prevent it from unwanted shutdown in a system failure.
11	17th Dec. '21	16:00 – 18:00	Online	Committee members	Discussed the findings of records from the delays and digital fault recorders.
12	20th Dec. '21	15:00 – 17:00	Online	Committee members	Discussed the draft Interim Report circulated.
13	23rd Dec. '21	9:00 – 10:30	Online	Committee members	Discussed revisions to the draft Interim Report circulated.
14	27th Dec. '21	10:00-12:00	Online	Secretary to the Ministry of Power & Committee members	Submission of the Interim Report Followed by a presentation
15	6th Jan. '22	Received the CEB response to the Interim Recommendations			
16	11th Jan. '22	15:10 - 16:30	Online	Committee members	Preparation for the physical meeting with

					the CEB staff on the following day
17	12th Jan. '22	10:00 – 16:30	NSCC	Committee members & all relevant CEB staff	Met AGM/Transmission, DGM/Transmission O&M, DGM/Transmission Protection & Control with their teams and discussed their responses to Interim Recommendations Met OEM staff of BEN6000 DFR and got the calibration report
18	14th Jan. '22	17:15-18:30	Online	Committee members	Discussed the progress of the Final Report
19	21st Jan. '22	Received CEB responses to the concerns raised at the physical meeting with them on the 12th January 2022 at NSCC			
20	22nd Jan. '22	15:00 – 16:30	Online	Committee members	Online load flow simulation using PSSE software on the most updated national grid model with CEB appointed Engineer from the Generation and Transmission planning division
21	26th Jan. '22	21:00-23:00	Online	Committee members	Discussed the responses from CEB on the cross questions by the committee to its previous responses to the Interim Recommendations
22	31st Jan. '22	10:00-12:00	Online	Committee members	Meet the LVPS Engineering staff online to discuss the Auxiliary Power,

					House Load and Safe Shutdown issues
23	3rd Feb. '22	Received responses to the queries made to OEM of SIEMENS 7SL87 and 7SS52 relays			
24	3rd Feb. '22	15:15-16:30	Online	Committee members	Discussed the progress of the Final Report

Annex C

Meeting held on 06th December 2021 at 10.00am at the Auditorium of the National System Control Center

to investigate the total power failure in the country on 03rd December 2021

Participants- List is attached

Matters discussed and decision taken

No.	Matter discussed	Division responsible	Decision taken
01	DGM (Tr. C&P) and his staff explained the sequence of events pertaining to the tripping of Biyagama - Kotmale 220 kV Line 01 and 02 using a Power Point Presentation. **The Key points of Presentation are appended below.** Biyagama - Kotmale Line 02 had tripped at 11.27.14 hrs. Siemens 7SL87 Line Differential Relay had operated and tripped the line. As per records obtained from BEN Digital Disturbance Recorder, the B phase current had reduced and Neutral Current had increased at Biyagama end. Then the B phase had tripped from both ends and subsequently all three phases have tripped from Kotmale end. Around 11.27.36 hrs Biyagama - Kotmale Line 01 had been tripped by Non-directional Earth Fault function of Siemens 7SL87 Main Protection Relay of Kotmale end. i.e. Line 01 had tripped after about 22 seconds from Line 02 tripping After tripping of Biyagama – Kotmale Line 01 and 02, the power system had undergone a severe power swing condition for about 6 seconds. Subsequently, at around 11.27.44 hrs. Kotmale – Anuradhapura Line 01 had tripped from New Anuradhapura end.	Control and Protection Branch of Transmission Division.	Following documents information to be submitted by Control and Protection Brancl on or before 2021-12-09. 1. Failure report for incident happened on 2021-12-03. 2. Relay Events and Settings for Biyagama – Kotmale Line 01 an 02 3.BEN Records
02	It was informed that the Partial Power failure that had happened on 29th December 2021 had occurred due to	Transmission Protection	Report on 29th event to be submitted on 09th December 2021

	raining and lightning, causing an indirect strike from tower to line.	and Control branch	
03	Grid connection of Mahaweli Complex. DGM (MC) explained 1) At 11.27.13.2785 Biyagama line 2 tripped by line differential protection. 2) At 11.27.35.6510 Biyagama line 1 tripped by line E/F, (earth fault) protection. 3) With the above incident the rest of power system had been isolated from the Mahaweli complex 220kV system causing its frequency to increase (by 654MW with 146 MVAR) only loading to Mahiyangana and Badulla area 4) Therefore, U03, U02 and U01 machines at Kotmale power station rejected the loads by over frequency protection at 11.27.40.0998, 11.27.40.1028 and 11.27.40.1184 respectively 5) Thereafter U01 and U02 machines at Victoria, both machines at Randenigala and both machines at Rantambe power stations had tripped by over frequency protection at about 11.27.41 6) Subsequently U03 at Victoria and U01 at Upper Kotmale tripped by unit transformer over fluxing and U02 at Upper Kotmale tripped by Excitation heavy fault. 7) After occurrence of above event 2, 132kV system of Mahaweli Complex experienced an under-frequency condition that tripped machines at Ukuwela and Bowathenna by under frequency protection. Thereafter DGM(MC) explained restoration process 1) Usually, Engineers at power stations had been instructed to follow set of standing orders in case of a total failure by NSCC (National System Control Center) which include opening of unopened line breakers, resetting of flags latches and to ensure that machines are in ready for start condition.	Mahaweli Complex	Report to be submitted on 10th December 2021

	2) Accordingly, at about 12.15 hrs. NSCC instructed to charge Biyagama line 1 from Kotmale power station. The OE informed that Breaker 530 on Biyagama line 1 need to check before closing as PRV (pressure release valve in the arcing chamber) had operated. 3) Therefore, NSCC instructed to charge Biyagama line 2 in which breaker 630 had failed to close when attempting to charge the line. 4) When this incident had been informed to DGM (MC) who was also present at Kotmale power station at that moment suggested to close it manually without delaying restoration process as the annunciation panel hasn't indicated any alarm. 5) However, when attempting to close CB 630 manually, it was noticed that breaker closed event immediately followed by a breaker tripping command coming from the distance protection relay 6) This was communicated to the ES from Transmission Division came to Kotmale switch yard for some other work at that moment from transmission protection branch who reset it thereafter. 7) After that Biyagama line2 was charged by Kotmale U01 machine at 13.05hrs after delaying the restoration process to Biyagama by nearly 40.0 minutes due to inability to close CB 630. 8) Thereafter as per the instructions of NSCC U02 and U03 at Kotmale power station had also been connected to the power system at 13.58 and 14.33 respectively. 9) While restoring Biyagama lines toward Colombo side, Bus Bar 2 at Kotmale was separated to restore the power system toward Anuradhapura side by the machines at Upper Kotmale and machines at Victoria power station had also been used to restore the power system toward Mahiyangana and Baddulla side. **10)** Victoria system had been synchronized to Kotmale system by 14.59hrs and in similar manner Upper Kotmale system had also been synchronized to Kotmale system by 16.07hrs and thereafter entire 220kV system of Mahaweli complex had operated as		

	a single system by controlling the frequency from a Kotmale machine		
04	**<u>Communication mechanism</u>** The committee chairman inquired about the method of remote accessing of engineering workstations and other equipment related to system operations installed at GSs. Then, EE(Communication) explained that there are two separate /parallel optical fibre based networks (SDH & GbE) and the connectivity is provided through these two networks. The committee chairman asked to forward a report on communication system.	Communication Branch	Report on communication and access process to be submitted on 10th December 2021
05	**<u>Lakvijaya protection</u>** DGM (Protection –Generation) explained response of all protection systems due to failure ; With trip of Biyagama line 2 and 1, frequency of generators of Mahaweli complex in 220kV networks has started to increase, while frequency of rest of generators in power system has started to decrease. Most of generators in Mahaweli complex has tripped on over frequency, while three generators, which do not have over frequency protection had tripped on over flux protection (81O). There was a severe power swing condition, in both Mahaweli complex 220kV networks, as well as in rest of the power system, including Lakvijaya units (LVPP). Unit #03 and unit #01 of LVPP had tripped on composite low voltage over current (50C) due to this power swing condition. Standard practice of plant contractor (CMEC) is to trip whole unit at operation 50C, and not tripping generator circuit	Generation Protection branch	Report to be submitted on 10th December 2021

	breaker only. This philosophy of contractor is acceptable as unit will not be successful, in attaining house load mode, for a fault of this nature, involving reduction in system voltage. 50C is also intended as a backup protection for differential protection function of Generator and main transformer.		
06	**Restoration** DGM (Protection –Generation) said there had been three tripping of Samanalawewa units, during restoration process, due to a certain malfunction in new protection system and this will be corrected as soon as possible. At 1st, CE (SO) elaborated the cascade sequence of the total system failure which had occurred on 03.12.2121 at 11:27hrs. Rejection of 670 MW of Mahaweli generation which had led to a significant frequency decay and caused the cascade tripping of other generators in the system. Further he explained broadly, the events that had occurred and how it led to a total system failure by drawing diagrams on a white board. After that he explained how the system restoration had been initiated and continued until the entire power system was completely restored. System had been restored in parallel from 7 different sub systems from New Laxapana machines, Kelanithissa small GTs, Kotmale machines, Victoria machines, Upper Kotmale machines, Kelanithissa GT7 and Kukule generators. Mahaweli system restoration had been delayed due to delay in energizing the Kotmale-Biyagama both ccts from Kotmale end. Kotmale OE stated that they had pressed the reset button on the lock out relay and but it had still been unable to switched ON CB 630. However, it was told that ES from transmission protection branch who were there at that time reset the same lockout and it had succeeded. Then after	System control	Reports to be submitted on 10th December 2021

	energizing the Kotmale Biyagama cct 02 at 13.01 hrs System restoration had continued from Kotmale machines. Then it was explained that restoration of supply to Lakvijaya PS from Upper Kotmale via New Anuradhapura. Laxapana system restored without any significant issues and restoration from Samanalawewa machines got delayed due to tripping of Samanalawewa machines during the line charging. Generation protection engineer explained that it is due to malfunctioning of line charging mode enabling logic.		

Indika Ranatunga
Senior Assistant Secretary
Ministry of Power
The Convener to the Committee

Meeting held on 12th January 2022 at 10.00am at the Auditorium of the National System Control Center to investigate the total power failure in the country on 03rd December 2021

Participants - List is attached

Matters discussed and decision taken

No.	Matter discussed	Decision taken
01	**Interim Recommendations** **1. Establish the actual cause of tripping of Kotmale-Biyagama Line 02 on 03rd December 2021, with proper technical basis and physical evidence.** **Response of CEB** Kotmale-Biyagama Line 02has tripped due to occurrence of C phase to earth fault (magnitude 520A) in transmission line and/or connected ie-CT, VT lighting Arrester etc. This fault current has been recorded in main 1, main 2 relays and the BEN 6000 digital disturbance recorder. The CEB explained that they suspected the reason for failure could be attributed to a fire made by an old lady in the vicinity of the tower under the transmission line. However, after a lengthy discussion, it was noted that no tangible evidence could be found by CEB to include that the reasons for the tripping was the fire under the Transmission line. The CEB informed that, the system is there to keep line wise record and if it is permanent fault, they do rechecking and maintain a separate event file for the same.	Failure Analysis Report for 13 Trippings occurred in Biyagama – Kothmale Line 01 and 02 from 2015 up to now, to be submitted. Committee requested CEB to share the event file to check the records for persisting faults & faults that had cleared immediately.
02	**2. Establish the reason for operation of end fault protection while the line has undergone what is believed to be a single line to earth fault and the faulty line was already isolated from the network.** The committee inquired about how and why the field wiring had been changed without a proper reason or prior intimation. It was informed that the Transmission, Operation and Maintenance Branch had replaced the breaker after the original commissioning of new 220kV	

	Protection System upgrade in 2014. The Transmission Control & Projection Branch also accepted that a wiring mistake had occurred in Centre Breaker of the Biyagama/ Kothmale Line during installation & subsequently corrected by the staff of the Transmission Control & Protection Branch in December 26th 2021 & January 03rd 2021. This was discussed at length and members of the committee informed CEB to clearly demonstrate & differentiate the facts between sabotage and mistake (wiring error) and informed that the responsibility of establishing the facts lies with CEB. It was also noted that similar incident had been occurred on 29th November 2021 and same lines tripped, however, damage was considerably less as incident had occurred during the night time. Committee further highlighted that if a wiring mistake was noted/seen, the relevant CEB officers should have informed the mistake at the very first date of the investigation, but had failed to do so. Therefore, the committee informed that they have reasonable doubt regarding the explanations given by CEB.	
03	**3. Establish/explain the reason for tripping of Kotmale-Biyagama 220kV line 01 on December 03, 2021, after line 02 had been isolated from both ends, with credible supporting data, and scientific justifications.** **Committee investigated about the basis of setting of earth fault current setting of 220 kV transmission lines at 80A and revision of same setting to 160A after total system failure.** DGM(C&P) informed to the committee, the setting of 80A extracted from the Protection Settings Standard which was developed under the leadership of Dr A.P. Thennekoon DGM(C&P) during the period July 2017 to Aug 2019. Further, DGM(C&P) informed that large zero sequence current is flowing in the Biyagama – Kothmale Line 1 and 2 and E/F current setting of 80A in main 1 relay could result a mal-operation of the relay without an actual fault in the line. Thus, to avoid unnecessary tripping of the circuit, it has been decided to increase of E/F current setting to 160A. Committee was of the view that haphazard changing of Protection relay settings is not a professional approach to resolve any problem and required C & P branch to justify the setting change from 80A – 160A with proper calculations based on concepts.	Report on mal operation of End Fault Protection Scheme/incorrect circuit breaker open status information to Bus Bar Protection Scheme in Kothmale Line 01 and 02 at Biyagama GSS to be submitted.

04	**4. Explain why the end fault protection scheme was implemented without necessary safeguards, knowing that a single-line-to-earth fault may trip the entire line with lockout, even if the fault is cleared. Explain also whether this situation had prevailed since the initial installation of 220kV Protection System in 2014, and if that was the case. The reason for not having experienced similar tripping in the past, given that single-line-to-earth faults are among the most common line faults.** **Committee investigated about the applying of two E/F setting in Kotmale Biyagama circuit 02 at Kothmale and Biyagama ends. Biyagama end applied setting was 150 A while Kotmale end it was 80 A.** Control and Protection branch responded that due to the limited interruption period C&P staff have not been able to carry out this setting revision in Line 2 at Biyagama end.	Testing of Siemens 7SL87 Relay and check the performance of E/F protection function for relays installed in Transmission Network
05	**5. Establish the reason for the operation of the backup Earth Fault relay after a substantially long duration of 22.33 seconds, despite the neutral current having become zero after 288ms from the pickup. Explain why primary protection such as differential protection implemented on the Kotmale-Biyagama 220kV line 01 was not activated but earth fault protection, which is a backup protection scheme, forced the shutdown of the line.** **Committee questioned about the continuous neutral current flow in Kotmale Biyagama circuit during system steady state and regarding other 220kV circuits which are installed same relay.** Control and Protection branch agreed to test protection relay of other 220kV circuits and submit a report by Friday. (21.01.2022)	Writing to OEM a. To clarify the drop off characteristics of E/F protection function of 7SL87 - Main 1 Protection Relay from Siemens. b. To clarify User Login and Logout events that have occurred in P545 - Main 2 Protection Relay from Schneider.
06	**6. Provide the records on access to relays and explain why such information is missing or incomplete.** CEB submitted e-mail correspondence with the relay manufacturer. The committee noted that all the queries raised in the e-mail had not been answered & requested CEB to follow up & obtain responses for same.	

Indika Ranatunga
Senior Assistant Secretary
Ministry of Power
Convener to the Committee

Protection Relay Settings of Kotmale-Biyagama 220 kV Transmission Line

Annex D

February 2022

This document provides the protection settings of Main 1 relays of circuit 2 and circuit 1 of Kotmale-Biyagama 220 kV transmission line at Kotmale power station and Biyagama grid substation ends. The list of contents is given in Table 1.

Table 1 – List of Contents

Appendix Number	Content
Appendix 1	Main 1 Relay Settings – Kotmale – Biyagama Line 2 – Kotmale Substation
Appendix 2	Main 1 Relay Settings – Kotmale – Biyagama Line 2 – Biayagama Substation
Appendix 3	Main 1 Relay Settings – Kotmale – Biyagama Line 1 – Kotmale Substation
Appendix 4	Main 1 Relay Settings – Kotmale – Biyagama Line 1 – Biyagama Substation

Appendix 1 - Main 1 Relay Settings – Kotmale – Biyagama Line 2 – Kotmale Substation

General \Rated values

Number	Settings	Value
21.9001.101	Rated current	All: 2000 A
21.9001.102	Rated voltage	All: 220 kV
21.9001.103	Rated apparent power	All: 762.1 MVA

General \Line data

Number	Settings	Value
21.9001.149	Neutral point	Settings group 1: grounded
21.9001.112	C1 per length unit	Settings group 1: 0.003 µF/km
21.9001.148	C0 per length unit	Settings group 1: 0.003 µF/km
21.9001.113	X per length unit	Settings group 1: 0.306 Ω/km
21.9001.114	Line length	Settings group 1: 70.5 km
21.9001.108	Line angle	Settings group 1: 82.96 °
21.9001.104	Kr	Settings group 1: 2.32
21.9001.105	Kx	Settings group 1: 0.84
21.9001.106	KmR	Settings group 1: 2.33
21.9001.107	KmX	Settings group 1: 0.72
21.9001.109	Gnd.curr.ratio(MutComp)	Settings group 1: 85 %
21.9001.119	CT saturation detection	All: yes
21.9001.120	CT saturation threshold	Settings group 1: 5.00 A
21.9001.111	Series compensation	Settings group 1: no
21.9001.110	Series capacit. reactance	Settings group 1: 40 Ω

General \Measurements

Number	Settings	Value
21.9001.158	P, Q sign	Settings group 1: not reversed

Process monitor

Closure detec.

Number	Settings	Value
21.1131.4681.101	Operating mode	Settings group 1: Iopen,Vopen,ManCl
21.1131.4681.102	Action time after closure	Settings group 1: 0.05 s
21.1131.4681.103	Min. time feeder open	Settings group 1: 0.25 s

1pol.open det.

Number	Settings	Value
21.1131.4711.101	Operating mode	Settings group 1: with measurement

Volt.criterion

Number	Settings	Value
21.1131.4801.101	Threshold U open	Settings group 1: 60.000 V

68 P.swing blk		
Number	**Settings**	**Value**
21.5311.1	Mode	Settings group 1: on
21.5311.103	Max. blocking time	Settings group 1: ∞ s

68 P.swing blk \Zones to be blocked		
Number	**Settings**	**Value**
21.5311.102	21 Distance prot. 1.Z 1	true
21.5311.102	21 Distance prot. 1.Z 1B	true
21.5311.102	21 Distance prot. 1.Z 3	true
21.5311.102	21 Distance prot. 1.Z 4	true
21.5311.102	21 Distance prot. 1.Z 5	true

Fault locator		
Number	**Settings**	**Value**
21.8671.1	Mode	Settings group 1: on
21.8671.101	Start	Settings group 1: with operate
21.8671.102	Parallel-line compensat.	Settings group 1: yes
21.8671.103	Load compensation	Settings group 1: yes

Mes.v.fail.det		
Number	**Settings**	**Value**
21.2671.1	Mode	Settings group 1: on
21.2671.115	Asym.fail.-DO on netw.flt.	Settings group 1: no
21.2671.113	Asym.fail. - time delay	Settings group 1: 10 s
21.2671.102	3ph.fail. - phs.curr.release	Settings group 1: 0.10 A
21.2671.103	3ph.fail. - phs.curr. jump	Settings group 1: 0.10 A
21.2671.101	3ph.fail. - VA,VB,VC <	Settings group 1: 5 V
21.2671.107	Switch-on 3ph. failure	All: on
21.2671.106	SO 3ph.fail. - time delay	Settings group 1: 3 s

21 Distance prot. 1

General		
Number	**Settings**	**Value**
21.901.2311.110	Zone timer start	Settings group 1: on dist. pickup
21.901.2311.107	Dist. characteristic angle	Settings group 1: 82.9 °
21.901.2311.105	Ground-fault detection	Settings group 1: 3I0 or V0
21.901.2311.103	3I0> threshold value	Settings group 1: 0.10 A
21.901.2311.102	V0> threshold value	Settings group 1: 1.66 V
21.901.2311.104	3I0 pickup stabilization	Settings group 1: 0.1
21.901.2311.108	Loop select. with ph-ph-g	Settings group 1: block leading phase
21.901.2311.106	Parallel-line compensat.	Settings group 1: yes

Pickup Z<		
Number	**Settings**	**Value**
21.901.3661.101	Min. phase-current thresh	Settings group 1: 0.10 A
21.901.3661.102	Use ph-g load cutout	All: yes
21.901.3661.103	R load cutout (ph-g)	Settings group 1: 42.45 Ω
21.901.3661.104	Angle load cutout (ph-g)	Settings group 1: 41.9 °
21.901.3661.105	Use ph-ph load cutout	All: yes

Number	Settings	Value
21.901.3661.106	R load cutout (ph-ph)	Settings group 1: 42.45 Ω
21.901.3661.107	Angle load cutout (ph-ph)	Settings group 1: 41.9 °

Z 1

Number	Settings	Value
21.901.3571.1	Mode	Settings group 1: on
21.901.3571.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3571.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3571.11	1-pole operate allowed	Settings group 1: yes
21.901.3571.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3571.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3571.109	Directional mode	Settings group 1: forward
21.901.3571.102	X reach	Settings group 1: 18.34 Ω
21.901.3571.103	R (ph-g)	Settings group 1: 25.45 Ω
21.901.3571.104	R (ph-ph)	Settings group 1: 14.67 Ω
21.901.3571.113	Zone-inclination angle	Settings group 1: 3 °
21.901.3571.110	Operate delay (1-phase)	Settings group 1: 0 s
21.901.3571.112	Operate delay (multi-ph.)	Settings group 1: 0 s

Z 1B

Number	Settings	Value
21.901.3572.1	Mode	Settings group 1: on
21.901.3572.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3572.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3572.11	1-pole operate allowed	Settings group 1: yes
21.901.3572.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3572.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3572.109	Directional mode	Settings group 1: forward
21.901.3572.102	X reach	Settings group 1: 25.89 Ω
21.901.3572.103	R (ph-g)	Settings group 1: 37.47 Ω
21.901.3572.104	R (ph-ph)	Settings group 1: 25.89 Ω
21.901.3572.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3572.110	Operate delay (1-phase)	Settings group 1: 0.25 s
21.901.3572.112	Operate delay (multi-ph.)	Settings group 1: 0.25 s

Z 3

Number	Settings	Value
21.901.3573.1	Mode	Settings group 1: on
21.901.3573.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3573.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3573.11	1-pole operate allowed	Settings group 1: no
21.901.3573.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3573.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3573.109	Directional mode	Settings group 1: forward
21.901.3573.102	X reach	Settings group 1: 30.68 Ω
21.901.3573.103	R (ph-g)	Settings group 1: 43.42 Ω
21.901.3573.104	R (ph-ph)	Settings group 1: 29.2 Ω
21.901.3573.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3573.110	Operate delay (1-phase)	Settings group 1: 0.5 s
21.901.3573.112	Operate delay (multi-ph.)	Settings group 1: 0.5 s

Z 4		
Number	**Settings**	**Value**
21.901.3574.1	Mode	Settings group 1: on
21.901.3574.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3574.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3574.11	1-pole operate allowed	Settings group 1: no
21.901.3574.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3574.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3574.109	Directional mode	Settings group 1: reverse
21.901.3574.102	X reach	Settings group 1: 2.16 Ω
21.901.3574.103	R (ph-g)	Settings group 1: 10.98 Ω
21.901.3574.104	R (ph-ph)	Settings group 1: 5.28 Ω
21.901.3574.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3574.110	Operate delay (1-phase)	Settings group 1: 1 s
21.901.3574.112	Operate delay (multi-ph.)	Settings group 1: 1 s

Z 5		
Number	**Settings**	**Value**
21.901.3575.1	Mode	Settings group 1: off
21.901.3575.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3575.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3575.11	1-pole operate allowed	Settings group 1: no
21.901.3575.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3575.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3575.109	Directional mode	Settings group 1: forward
21.901.3575.102	X reach	Settings group 1: 36.169 Ω
21.901.3575.103	R (ph-g)	Settings group 1: 22.109 Ω
21.901.3575.104	R (ph-ph)	Settings group 1: 7.109 Ω
21.901.3575.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3575.110	Operate delay (1-phase)	Settings group 1: 1 s
21.901.3575.112	Operate delay (multi-ph.)	Settings group 1: 1 s

85-67N Dir. comp.

85-67N Dir.com		
Number	**Settings**	**Value**
21.1301.5761.1	Mode	Settings group 1: on
21.1301.5761.101	Send prolongation	Settings group 1: 0.1 s
21.1301.5761.102	Send delay	Settings group 1: 0 s
21.1301.5761.105	Trans. blk. pickup delay	Settings group 1: 0.04 s
21.1301.5761.106	Trans. blk. dropout delay	Settings group 1: 0.05 s
21.1301.5761.104	3I0 threshold rev./forw.	Settings group 1: 75 %
21.1301.5761.11	1-pole operate allowed	Settings group 1: no
21.1301.5761.103	Operate delay (1-phase)	Settings group 1: 0 s

85-67N Dir.com \Send with		
Number	**Settings**	**Value**
21.1301.5761.140	67N GFP gnd.sys.1.Definite-T 1	true

85-67N Dir.com \Operate with		
Number	**Settings**	**Value**
21.1301.5761.141	67N GFP gnd.sys.1.Definite-T 1	true

Switch onto fault 1

Stage 1		
Number	**Settings**	**Value**
21.1341.5941.1	Mode	Settings group 1: on
21.1341.5941.2	Operate & flt.rec. blocked	Settings group 1: no
21.1341.5941.6	Operate delay	Settings group 1: 0 s

Stage 1 \Configuration		
Number	**Settings**	**Value**
21.1341.5941.102	50/51 OC-3ph 1p 1.Inverse-T 1	false
21.1341.5941.102	50N/51N OC-gnd-A1.Definite-T 1	false
21.1341.5941.102	50N/51N OC-gnd-A1.Inverse-T 1	false
21.1341.5941.102	50 high-speed 1pol 1.Standard 1	true
21.1341.5941.102	67N GFP gnd.sys.1.Definite-T 1	false
21.1341.5941.102	21 Distance prot. 1.Z 1	true
21.1341.5941.102	21 Distance prot. 1.Z 1B	true
21.1341.5941.102	21 Distance prot. 1.Z 3	false
21.1341.5941.102	21 Distance prot. 1.Z 4	true
21.1341.5941.102	21 Distance prot. 1.Z 5	false

External trip 1pole 1

Stage 1		
Number	**Settings**	**Value**
21.291.931.1	Mode	Settings group 1: off
21.291.931.2	Operate & flt.rec. blocked	Settings group 1: no
21.291.931.11	1-pole operate allowed	Settings group 1: no
21.291.931.6	Operate delay	Settings group 1: 0.05 s

50/51 OC-3ph 1p 1

General		
Number	**Settings**	**Value**
21.221.2311.101	Emergency mode	Settings group 1: no

Inverse-T 1 \General		
Number	**Settings**	**Value**
21.221.871.1	Mode	Settings group 1: on
21.221.871.2	Operate & flt.rec. blocked	Settings group 1: no
21.221.871.11	1-pole operate allowed	Settings group 1: yes
21.221.871.26	Dynamic settings	All: no
21.221.871.8	Method of measurement	Settings group 1: fundamental comp.
21.221.871.3	Threshold	Settings group 1: 0.75 A
21.221.871.110	Pickup delay	Settings group 1: 0 s
21.221.871.108	Type of character. curve	Settings group 1: IEC normal inverse
21.221.871.113	Min. time of the curve	Settings group 1: 0 s
21.221.871.109	Reset	Settings group 1: disk emulation
21.221.871.101	Time dial	Settings group 1: 0.34
21.221.871.115	Additional time delay	Settings group 1: 0 s

50N/51N OC-gnd-A1

General		
Number	**Settings**	**Value**
21.211.2311.101	Emergency mode	Settings group 1: no
21.211.2311.9	Measured value	Settings group 1: 3I0 calculated

Definite-T 1 \General		
Number	**Settings**	**Value**
21.211.751.1	Mode	Settings group 1: on
21.211.751.2	Operate & flt.rec. blocked	Settings group 1: no
21.211.751.26	Dynamic settings	All: no
21.211.751.8	Method of measurement	Settings group 1: fundamental comp.
21.211.751.3	Threshold	Settings group 1: 0.825 A
21.211.751.4	Dropout ratio	Settings group 1: 0.95
21.211.751.101	Dropout delay	Settings group 1: 0 s
21.211.751.6	Operate delay	Settings group 1: 1.1 s

Inverse-T 1 \General		
Number	**Settings**	**Value**
21.211.781.1	Mode	Settings group 1: on
21.211.781.2	Operate & flt.rec. blocked	Settings group 1: no
21.211.781.26	Dynamic settings	All: no
21.211.781.8	Method of measurement	Settings group 1: fundamental comp.
21.211.781.3	Threshold	Settings group 1: 0.04 A
21.211.781.108	Type of character. curve	Settings group 1: IEC normal inverse
21.211.781.113	Min. time of the curve	Settings group 1: 0 s
21.211.781.109	Reset	Settings group 1: disk emulation
21.211.781.101	Time dial	Settings group 1: 0.38
21.211.781.115	Additional time delay	Settings group 1: 0 s

50 high-speed 1pol 1

Standard 1		
Number	**Settings**	**Value**
21.981.3961.1	Mode	Settings group 1: on
21.981.3961.102	1-pole operate allowed	Settings group 1: no
21.981.3961.101	Activation	Settings group 1: on CB closure
21.981.3961.3	Threshold	Settings group 1: 2.00 A
21.981.3961.4	Dropout ratio	Settings group 1: 0.9

67N GFP gnd.sys.1

General		
Number	**Settings**	**Value**
21.1111.2311.114	Polarization with	All: V0 + IY or V2 + I2
21.1111.2311.101	Angle forward α	Settings group 1: 338 °
21.1111.2311.102	Angle forward β	Settings group 1: 122 °
21.1111.2311.103	Min. zero-seq. voltage V0	Settings group 1: 3.3 V
21.1111.2311.115	Dir.reslt=forw.at V0<min	Settings group 1: no
21.1111.2311.104	Min.3I0 f.increas.dir.sens.	Settings group 1: 0.03 A

Totally Integrated Automation Portal		

Number	Settings	Value
21.1111.2311.107	Min. neg.-seq. voltage V2	Settings group 1: 1.400 V
21.1111.2311.106	Min. neg.-seq. current I2	Settings group 1: 0.03 A
21.1111.2311.116	Dir.corr.at ser.comp.lines	Settings group 1: no

Definite-T 1 \General

Number	Settings	Value
21.1111.4861.1	Mode	Settings group 1: on
21.1111.4861.2	Operate & flt.rec. blocked	Settings group 1: no
21.1111.4861.114	Directional mode	Settings group 1: forward
21.1111.4861.11	1-pole operate allowed	Settings group 1: no
21.1111.4861.8	Method of measurement	Settings group 1: 1-cycle filter
21.1111.4861.130	Blocking by prot. pickup	Settings group 1: every pickup
21.1111.4861.129	Op.mode at 1p dead time	Settings group 1: blocked
21.1111.4861.112	Hold mode 1p dead time	Settings group 1: 0.04 s
21.1111.4861.115	Dynamic settings	All: no
21.1111.4861.111	Stabiliz. w. phase current	Settings group 1: 10 %
21.1111.4861.3	Threshold	Settings group 1: 0.08 A
21.1111.4861.6	Operate delay	Settings group 1: 60 s

Definite-T 1 \Blocking by

Number	Settings	Value
21.1111.4861.140	87 Line diff. prot..Group indicat.	true
21.1111.4861.140	87 Stub diff. prot. 1.Group indicat.	true
21.1111.4861.140	21 Distance prot. 1.Z 1	true
21.1111.4861.140	21 Distance prot. 1.Z 1B	true
21.1111.4861.140	21 Distance prot. 1.Z 3	false
21.1111.4861.140	21 Distance prot. 1.Z 4	false
21.1111.4861.140	21 Distance prot. 1.Z 5	false

85-21Perm.underr.

85-21Perm.unde

Number	Settings	Value
21.1281.5671.1	Mode	Settings group 1: on
21.1281.5671.101	Send prolongation	Settings group 1: 0.1 s
21.1281.5671.11	1-pole operate allowed	Settings group 1: yes
21.1281.5671.102	Operate delay (1-phase)	Settings group 1: 0 s
21.1281.5671.103	Operate delay (multi-ph.)	Settings group 1: 0 s

85-21Perm.unde \Send with

Number	Settings	Value
21.1281.5671.140	21 Distance prot. 1.Z 1	true
21.1281.5671.140	21 Distance prot. 1.Z 1B	false
21.1281.5671.140	21 Distance prot. 1.Z 3	false
21.1281.5671.140	21 Distance prot. 1.Z 4	false
21.1281.5671.140	21 Distance prot. 1.Z 5	false

85-21Perm.unde \Operate with

Number	Settings	Value
21.1281.5671.141	21 Distance prot. 1.pickup general	false

Number	Settings	Value
21.1281.5671.141	21 Distance prot. 1.Z 1	false
21.1281.5671.141	21 Distance prot. 1.Z 1B	true
21.1281.5671.141	21 Distance prot. 1.Z 3	false
21.1281.5671.141	21 Distance prot. 1.Z 4	false
21.1281.5671.141	21 Distance prot. 1.Z 5	false
21.1281.5671.141	85-21Perm.underr..receive (direct trip)	false

27 Undervolt.-V1 1

General		
Number	**Settings**	**Value**
21.151.2311.104	Current-flow criterion	Settings group 1: on
21.151.2311.101	Threshold I>	Settings group 1: 0.05 A

Stage 1		
Number	**Settings**	**Value**
21.151.481.1	Mode	Settings group 1: off
21.151.481.2	Operate & flt.rec. blocked	Settings group 1: no
21.151.481.10	Blk. by meas.-volt. failure	Settings group 1: yes
21.151.481.101	Pickup delay	Settings group 1: no
21.151.481.3	Threshold	Settings group 1: 50.600 V
21.151.481.4	Dropout ratio	Settings group 1: 1.05
21.151.481.6	Operate delay	Settings group 1: 3 s

Stage 2		
Number	**Settings**	**Value**
21.151.482.1	Mode	Settings group 1: off
21.151.482.2	Operate & flt.rec. blocked	Settings group 1: no
21.151.482.10	Blk. by meas.-volt. failure	Settings group 1: yes
21.151.482.101	Pickup delay	Settings group 1: no
21.151.482.3	Threshold	Settings group 1: 44 V
21.151.482.4	Dropout ratio	Settings group 1: 1.05
21.151.482.6	Operate delay	Settings group 1: 0.5 s

Weak infeed

Weak infeed		
Number	**Settings**	**Value**
21.1331.5821.101	Echo block time after Tx	Settings group 1: 0.05 s
21.1331.5821.102	Echo and operate delay	Settings group 1: 0.04 s
21.1331.5821.103	Echo pulse	Settings group 1: 0.05 s
21.1331.5821.104	Weak infeed action	Settings group 1: echo and WI operate
21.1331.5821.105	85-21/67N common chan.	Settings group 1: yes
21.1331.5821.106	Undervoltage threshold	Settings group 1: 50 V

87 Line diff. prot.

General		
Number	**Settings**	**Value**
21.831.2311.1	Mode	Settings group 1: on

Number	Settings	Value
21.831.2311.11	1-pole operate allowed	Settings group 1: yes
21.831.2311.102	Min. current for release	Settings group 1: 0.00 A
21.831.2311.104	Supervision Idiff	All: no

I-DIFF		
Number	**Settings**	**Value**
21.831.3451.1	Mode	Settings group 1: on
21.831.3451.2	Operate & flt.rec. blocked	Settings group 1: no
21.831.3451.3	Threshold	Settings group 1: 0.20 A
21.831.3451.101	Thresh. switch onto fault	Settings group 1: 0.20 A
21.831.3451.6	Operate delay	Settings group 1: 0 s

I-DIFF fast		
Number	**Settings**	**Value**
21.831.3481.1	Mode	Settings group 1: on
21.831.3481.2	Operate & flt.rec. blocked	Settings group 1: no
21.831.3481.3	Threshold	Settings group 1: 3.00 A
21.831.3481.101	Thresh. switch onto fault	Settings group 1: 3.00 A

87 Stub diff. prot. 1

General		
Number	**Settings**	**Value**
21.1431.2311.1	Mode	Settings group 1: on

S-DIFF		
Number	**Settings**	**Value**
21.1431.8401.1	Mode	Settings group 1: on
21.1431.8401.2	Operate & flt.rec. blocked	Settings group 1: no
21.1431.8401.3	Threshold	Settings group 1: 0.300 A
21.1431.8401.6	Operate delay	Settings group 1: 0.3 s

S-DIFF fast		
Number	**Settings**	**Value**
21.1431.8431.1	Mode	Settings group 1: off
21.1431.8431.2	Operate & flt.rec. blocked	Settings group 1: no
21.1431.8431.3	Threshold	Settings group 1: 2.00 A

Line 1\Ciruit-breaker interaction

Protection group	Circuit-breaker group(s)
Line 1\ 85-67N Dir. comp.\ 85-67N Dir.com	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ Switch onto fault 1\ Stage 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ External trip 1pole 1\ Stage 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 50/51 OC-3ph 1p 1\ Inverse-T 1	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ 50N/51N OC-gnd-A1\ Definite-T 1	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ 50N/51N OC-gnd-A1\ Inverse-T 1	Circuit breaker 1:Trip, Circuit breaker 2:Trip

Protection group	Circuit-breaker group(s)
Line 1\ 50 high-speed 1pol 1\ Standard 1	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ 67N GFP gnd.sys.1\ Definite-T 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 87 Line diff. prot.\ General	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Start auto.recl., Circuit breaker 2:Trip
Line 1\ 87 Stub diff. prot. 1\ General	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 21 Distance prot. 1\ Z 1	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Start auto.recl., Circuit breaker 2:Trip
Line 1\ 21 Distance prot. 1\ Z 1B	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 21 Distance prot. 1\ Z 3	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 21 Distance prot. 1\ Z 4	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 21 Distance prot. 1\ Z 5	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ 85-21Perm.underr.\ 85-21Perm.unde	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Start auto.recl., Circuit breaker 2:Trip
Line 1\ 27 Undervolt.-V1 1\ Stage 1	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ 27 Undervolt.-V1 1\ Stage 2	Circuit breaker 1:Trip, Circuit breaker 2:Trip

Appendix 2 - Main 1 Relay Settings – Kotmale – Biyagama Line 2 – Biayagama Substation

General \Rated values		
Number	**Settings**	**Value**
21.9001.101	Rated current	All: 2000 A
21.9001.102	Rated voltage	All: 220 kV
21.9001.103	Rated apparent power	All: 762.1 MVA

General \Line data		
Number	**Settings**	**Value**
21.9001.149	Neutral point	Settings group 1: grounded
21.9001.112	C1 per length unit	Settings group 1: 0.003 µF/km
21.9001.148	C0 per length unit	Settings group 1: 0.003 µF/km
21.9001.113	X per length unit	Settings group 1: 0.306 Ω/km
21.9001.114	Line length	Settings group 1: 70.5 km
21.9001.108	Line angle	Settings group 1: 82.92 °
21.9001.104	Kr	Settings group 1: 2.32
21.9001.105	Kx	Settings group 1: 0.84
21.9001.106	KmR	Settings group 1: 4.98
21.9001.107	KmX	Settings group 1: 1.03
21.9001.109	Gnd.curr.ratio(MutComp)	Settings group 1: 85 %
21.9001.119	CT saturation detection	Settings group 1: yes
21.9001.120	CT saturation threshold	Settings group 1: 5.00 A
21.9001.111	Series compensation	Settings group 1: no

General \Measurements		
Number	**Settings**	**Value**
21.9001.158	P, Q sign	Settings group 1: not reversed

Process monitor

Closure detec.		
Number	**Settings**	**Value**
21.1131.4681.101	Operating mode	Settings group 1: Manual close only
21.1131.4681.102	Action time after closure	Settings group 1: 0.05 s
21.1131.4681.103	Min. time feeder open	Settings group 1: 0.25 s

1pol.open det.		
Number	**Settings**	**Value**
21.1131.4711.101	Operating mode	Settings group 1: with measurement

Volt.criterion		
Number	**Settings**	**Value**
21.1131.4801.101	Threshold U open	Settings group 1: 30 V

Fault locator

Number	Settings	Value
21.8671.1	Mode	Settings group 1: on
21.8671.101	Start	Settings group 1: with operate
21.8671.102	Parallel-line compensat.	Settings group 1: yes
21.8671.103	Load compensation	Settings group 1: no

Mes.v.fail.det

Number	Settings	Value
21.2671.1	Mode	Settings group 1: on
21.2671.115	Asym.fail.-DO on netw.flt.	Settings group 1: no
21.2671.113	Asym.fail. - time delay	Settings group 1: 10 s
21.2671.102	3ph.fail. - phs.curr.release	Settings group 1: 0.03 A
21.2671.103	3ph.fail. - phs.curr. jump	Settings group 1: 0.05 A
21.2671.101	3ph.fail. - VA,VB,VC <	Settings group 1: 10 V
21.2671.107	Switch-on 3ph. failure	Settings group 1: on
21.2671.106	SO 3ph.fail. - time delay	Settings group 1: 3 s

68 P.swing blk

Number	Settings	Value
21.5311.1	Mode	Settings group 1: on
21.5311.103	Max. blocking time	Settings group 1: oo s

68 P.swing blk \Zones to be blocked

Number	Settings	Value
21.5311.102	21 Distance prot. 1.Z 1	true
21.5311.102	21 Distance prot. 1.Z 1B	true
21.5311.102	21 Distance prot. 1.Z 3	true
21.5311.102	21 Distance prot. 1.Z 4	true
21.5311.102	21 Distance prot. 1.Z 5	true

21 Distance prot. 1

General

Number	Settings	Value
21.901.2311.110	Zone timer start	Settings group 1: on dist. pickup
21.901.2311.107	Dist. characteristic angle	Settings group 1: 82.9 °
21.901.2311.105	Ground-fault detection	Settings group 1: 3I0 or V0
21.901.2311.103	3I0> threshold value	Settings group 1: 0.05 A
21.901.2311.102	V0> threshold value	Settings group 1: 3.333 V
21.901.2311.104	3I0 pickup stabilization	Settings group 1: 0.1
21.901.2311.108	Loop select. with ph-ph-g	Settings group 1: block leading phase
21.901.2311.106	Parallel-line compensat.	Settings group 1: yes

Pickup Z<

Number	Settings	Value
21.901.3661.101	Min. phase-current thresh	Settings group 1: 0.10 A
21.901.3661.102	Use ph-g load cutout	Settings group 1: yes
21.901.3661.103	R load cutout (ph-g)	Settings group 1: 68.589 Ω
21.901.3661.104	Angle load cutout (ph-g)	Settings group 1: 42 °
21.901.3661.105	Use ph-ph load cutout	Settings group 1: yes

Number	Settings	Value
21.901.3661.106	R load cutout (ph-ph)	Settings group 1: 68.589 Ω
21.901.3661.107	Angle load cutout (ph-ph)	Settings group 1: 42 °

Z 1

Number	Settings	Value
21.901.3571.1	Mode	Settings group 1: on
21.901.3571.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3571.121	Blocked if diff.prot.active	Settings group 1: yes
21.901.3571.11	1-pole operate allowed	Settings group 1: yes
21.901.3571.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3571.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3571.109	Directional mode	Settings group 1: forward
21.901.3571.102	X reach	Settings group 1: 17.258 Ω
21.901.3571.103	R (ph-g)	Settings group 1: 34.453 Ω
21.901.3571.104	R (ph-ph)	Settings group 1: 15.368 Ω
21.901.3571.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3571.110	Operate delay (1-phase)	Settings group 1: 0 s
21.901.3571.112	Operate delay (multi-ph.)	Settings group 1: 0 s

Z 1B

Number	Settings	Value
21.901.3572.1	Mode	Settings group 1: on
21.901.3572.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3572.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3572.11	1-pole operate allowed	Settings group 1: no
21.901.3572.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3572.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3572.109	Directional mode	Settings group 1: forward
21.901.3572.102	X reach	Settings group 1: 25.888 Ω
21.901.3572.103	R (ph-g)	Settings group 1: 40.507 Ω
21.901.3572.104	R (ph-ph)	Settings group 1: 21.422 Ω
21.901.3572.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3572.110	Operate delay (1-phase)	Settings group 1: 0.25 s
21.901.3572.112	Operate delay (multi-ph.)	Settings group 1: 0.25 s

Z 3

Number	Settings	Value
21.901.3573.1	Mode	Settings group 1: on
21.901.3573.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3573.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3573.11	1-pole operate allowed	Settings group 1: no
21.901.3573.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3573.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3573.109	Directional mode	Settings group 1: forward
21.901.3573.102	X reach	Settings group 1: 35.389 Ω
21.901.3573.103	R (ph-g)	Settings group 1: 47.172 Ω
21.901.3573.104	R (ph-ph)	Settings group 1: 28.087 Ω
21.901.3573.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3573.110	Operate delay (1-phase)	Settings group 1: 0.5 s
21.901.3573.112	Operate delay (multi-ph.)	Settings group 1: 0.5 s

Z 4		
Number	**Settings**	**Value**
21.901.3574.1	Mode	Settings group 1: on
21.901.3574.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3574.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3574.11	1-pole operate allowed	Settings group 1: no
21.901.3574.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3574.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3574.109	Directional mode	Settings group 1: reverse
21.901.3574.102	X reach	Settings group 1: 2.157 Ω
21.901.3574.103	R (ph-g)	Settings group 1: 23.859 Ω
21.901.3574.104	R (ph-ph)	Settings group 1: 4.774 Ω
21.901.3574.110	Operate delay (1-phase)	Settings group 1: 0.5 s
21.901.3574.112	Operate delay (multi-ph.)	Settings group 1: 0.5 s

Z 5		
Number	**Settings**	**Value**
21.901.3575.1	Mode	Settings group 1: on
21.901.3575.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3575.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3575.11	1-pole operate allowed	Settings group 1: no
21.901.3575.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3575.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3575.109	Directional mode	Settings group 1: forward
21.901.3575.102	X reach	Settings group 1: 97.27 Ω
21.901.3575.103	R (ph-g)	Settings group 1: 96.049 Ω
21.901.3575.104	R (ph-ph)	Settings group 1: 76.964 Ω
21.901.3575.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3575.110	Operate delay (1-phase)	Settings group 1: 1 s
21.901.3575.112	Operate delay (multi-ph.)	Settings group 1: 1 s

Switch onto fault 1

Stage 1		
Number	**Settings**	**Value**
21.1341.5941.1	Mode	Settings group 1: on
21.1341.5941.2	Operate & flt.rec. blocked	Settings group 1: no
21.1341.5941.6	Operate delay	Settings group 1: 0 s

Stage 1 \Configuration		
Number	**Settings**	**Value**
21.1341.5941.102	21 Distance prot. 1.Z 1	false
21.1341.5941.102	21 Distance prot. 1.Z 1B	false
21.1341.5941.102	21 Distance prot. 1.Z 3	false
21.1341.5941.102	21 Distance prot. 1.Z 4	false
21.1341.5941.102	21 Distance prot. 1.Z 5	false
21.1341.5941.102	50/51 OC-3ph 1p 1.Inverse-T 1	false
21.1341.5941.102	50N/51N OC-gnd-A1.Inverse-T 1	false
21.1341.5941.102	50N/51N OC-gnd-A1.Definite-T 1	false
21.1341.5941.102	50 high-speed 1pol 1.Standard 1	true
21.1341.5941.102	67N GFP gnd.sys.1.Definite-T 1	false
21.1341.5941.102	67N GFP gnd.sys.1.Definite-T 2	false

External trip 1pole 1

Stage 1		
Number	**Settings**	**Value**
21.291.931.1	Mode	Settings group 1: on
21.291.931.2	Operate & flt.rec. blocked	Settings group 1: no
21.291.931.11	1-pole operate allowed	Settings group 1: no
21.291.931.6	Operate delay	Settings group 1: 0.05 s

50/51 OC-3ph 1p 1

General		
Number	**Settings**	**Value**
21.221.2311.101	Emergency mode	Settings group 1: no

Inverse-T 1 \General		
Number	**Settings**	**Value**
21.221.871.1	Mode	Settings group 1: on
21.221.871.2	Operate & flt.rec. blocked	Settings group 1: no
21.221.871.11	1-pole operate allowed	Settings group 1: yes
21.221.871.26	Dynamic settings	All: no
21.221.871.8	Method of measurement	Settings group 1: fundamental comp.
21.221.871.3	Threshold	Settings group 1: 0.75 A
21.221.871.108	Type of character. curve	Settings group 1: IEC normal inverse
21.221.871.109	Reset	Settings group 1: disk emulation
21.221.871.101	Time dial	Settings group 1: 0.22

50N/51N OC-gnd-A1

General		
Number	**Settings**	**Value**
21.211.2311.101	Emergency mode	Settings group 1: no

Inverse-T 1 \General		
Number	**Settings**	**Value**
21.211.781.1	Mode	Settings group 1: on
21.211.781.2	Operate & flt.rec. blocked	Settings group 1: no
21.211.781.26	Dynamic settings	All: no
21.211.781.8	Method of measurement	Settings group 1: fundamental comp.
21.211.781.3	Threshold	Settings group 1: 0.075 A
21.211.781.108	Type of character. curve	Settings group 1: IEC normal inverse
21.211.781.109	Reset	Settings group 1: disk emulation
21.211.781.101	Time dial	Settings group 1: 0.38

Definite-T 1 \General		
Number	**Settings**	**Value**
21.211.751.1	Mode	Settings group 1: on
21.211.751.2	Operate & flt.rec. blocked	Settings group 1: no
21.211.751.26	Dynamic settings	All: no
21.211.751.8	Method of measurement	Settings group 1: fundamental comp.
21.211.751.3	Threshold	Settings group 1: 0.825 A

Number	Settings	Value
21.211.751.4	Dropout ratio	Settings group 1: 0.95
21.211.751.101	Dropout delay	Settings group 1: 0 s
21.211.751.6	Operate delay	Settings group 1: 1.1 s

50 high-speed 1pol 1

Standard 1		
Number	**Settings**	**Value**
21.981.3961.1	Mode	Settings group 1: on
21.981.3961.102	1-pole operate allowed	Settings group 1: no
21.981.3961.101	Activation	Settings group 1: on CB closure
21.981.3961.3	Threshold	Settings group 1: 1.50 A
21.981.3961.4	Dropout ratio	Settings group 1: 0.9

85-21Perm.underr.

85-21Perm.unde		
Number	**Settings**	**Value**
21.1281.5671.1	Mode	Settings group 1: on
21.1281.5671.101	Send prolongation	Settings group 1: 0.05 s
21.1281.5671.11	1-pole operate allowed	Settings group 1: yes
21.1281.5671.102	Operate delay (1-phase)	Settings group 1: 0 s
21.1281.5671.103	Operate delay (multi-ph.)	Settings group 1: 0 s

85-21Perm.unde \Send with		
Number	**Settings**	**Value**
21.1281.5671.140	21 Distance prot. 1.Z 1	true
21.1281.5671.140	21 Distance prot. 1.Z 1B	false
21.1281.5671.140	21 Distance prot. 1.Z 3	false
21.1281.5671.140	21 Distance prot. 1.Z 4	false
21.1281.5671.140	21 Distance prot. 1.Z 5	false

85-21Perm.unde \Operate with		
Number	**Settings**	**Value**
21.1281.5671.141	21 Distance prot. 1.pickup general	false
21.1281.5671.141	21 Distance prot. 1.Z 1	false
21.1281.5671.141	21 Distance prot. 1.Z 1B	true
21.1281.5671.141	21 Distance prot. 1.Z 3	false
21.1281.5671.141	21 Distance prot. 1.Z 4	false
21.1281.5671.141	21 Distance prot. 1.Z 5	false
21.1281.5671.141	85-21Perm.underr..receive (direct trip.)	false

85-67N Dir. comp.

85-67N Dir.com		
Number	**Settings**	**Value**
21.1301.5761.1	Mode	Settings group 1: on
21.1301.5761.101	Send prolongation	Settings group 1: 0.05 s
21.1301.5761.102	Send delay	Settings group 1: 0 s
21.1301.5761.105	Trans. blk. pickup delay	Settings group 1: 0.02 s

Number	Settings	Value
21.1301.5761.106	Trans. blk. dropout delay	Settings group 1: 0.05 s
21.1301.5761.104	3I0 threshold rev./forw.	Settings group 1: 75 %
21.1301.5761.11	1-pole operate allowed	Settings group 1: no
21.1301.5761.103	Operate delay (1-phase)	Settings group 1: 0 s

85-67N Dir.com \Send with		
Number	**Settings**	**Value**
21.1301.5761.140	67N GFP gnd.sys.1.Definite-T 1	true
21.1301.5761.140	67N GFP gnd.sys.1.Definite-T 2	false

85-67N Dir.com \Operate with		
Number	**Settings**	**Value**
21.1301.5761.141	67N GFP gnd.sys.1.Definite-T 1	true
21.1301.5761.141	67N GFP gnd.sys.1.Definite-T 2	false

67N GFP gnd.sys.1

General		
Number	**Settings**	**Value**
21.1111.2311.114	Polarization with	Settings group 1: V0 + IY or V2 + I2
21.1111.2311.101	Angle forward α	Settings group 1: 338 °
21.1111.2311.102	Angle forward β	Settings group 1: 122 °
21.1111.2311.103	Min. zero-seq. voltage V0	Settings group 1: 0.770 V
21.1111.2311.115	Dir.reslt=forw.at V0<min	Settings group 1: no
21.1111.2311.104	Min.3I0 f.increas.dir.sens.	Settings group 1: 0.03 A
21.1111.2311.107	Min. neg.-seq. voltage V2	Settings group 1: 0.770 V
21.1111.2311.106	Min. neg.-seq. current I2	Settings group 1: 0.03 A
21.1111.2311.116	Dir.corr.at ser.comp.lines	Settings group 1: no

Definite-T 1 \General		
Number	**Settings**	**Value**
21.1111.4861.1	Mode	Settings group 1: on
21.1111.4861.2	Operate & flt.rec. blocked	Settings group 1: no
21.1111.4861.114	Directional mode	Settings group 1: forward
21.1111.4861.11	1-pole operate allowed	Settings group 1: no
21.1111.4861.8	Method of measurement	Settings group 1: 1-cycle filter
21.1111.4861.130	Blocking by prot. pickup	Settings group 1: every pickup
21.1111.4861.129	Op.mode at 1p dead time	Settings group 1: blocked
21.1111.4861.112	Hold mode 1p dead time	Settings group 1: 0.04 s
21.1111.4861.115	Dynamic settings	All: no
21.1111.4861.111	Stabiliz. w. phase current	Settings group 1: 10 %
21.1111.4861.3	Threshold	Settings group 1: 0.125 A
21.1111.4861.6	Operate delay	Settings group 1: 60 s

Definite-T 1 \Blocking by		
Number	**Settings**	**Value**
21.1111.4861.140	21 Distance prot. 1.Z 1	true
21.1111.4861.140	21 Distance prot. 1.Z 1B	true
21.1111.4861.140	21 Distance prot. 1.Z 3	true
21.1111.4861.140	21 Distance prot. 1.Z 4	true

Number	Settings	Value
21.1111.4861.140	21 Distance prot. 1.Z 5	true
21.1111.4861.140	87 Line diff. prot..Group indicat.	true

Definite-T 2 \General		
Number	Settings	Value
21.1111.4862.1	Mode	Settings group 1: off
21.1111.4862.2	Operate & flt.rec. blocked	Settings group 1: no
21.1111.4862.114	Directional mode	Settings group 1: non-directional
21.1111.4862.11	1-pole operate allowed	Settings group 1: no
21.1111.4862.8	Method of measurement	Settings group 1: 1-cycle filter
21.1111.4862.129	Op.mode at 1p dead time	Settings group 1: blocked
21.1111.4862.112	Hold mode 1p dead time	Settings group 1: 0.04 s
21.1111.4862.115	Dynamic settings	All: no
21.1111.4862.111	Stabiliz. w. phase current	Settings group 1: 10 %
21.1111.4862.3	Threshold	Settings group 1: 0.165 A
21.1111.4862.6	Operate delay	Settings group 1: 0.3 s

Definite-T 2 \Blocking by		
Number	Settings	Value
21.1111.4862.140	21 Distance prot. 1.Z 1	false
21.1111.4862.140	21 Distance prot. 1.Z 1B	false
21.1111.4862.140	21 Distance prot. 1.Z 3	false
21.1111.4862.140	21 Distance prot. 1.Z 4	false
21.1111.4862.140	21 Distance prot. 1.Z 5	false
21.1111.4862.140	87 Line diff. prot..Group indicat.	false

Weak infeed

Weak infeed		
Number	Settings	Value
21.1331.5821.101	Echo block time after Tx	Settings group 1: 0.05 s
21.1331.5821.102	Echo and operate delay	Settings group 1: 0.04 s
21.1331.5821.103	Echo pulse	Settings group 1: 0.05 s
21.1331.5821.104	Weak infeed action	Settings group 1: off
21.1331.5821.105	85-21/67N common chan.	Settings group 1: no
21.1331.5821.106	Undervoltage threshold	Settings group 1: 50 V

87 Line diff. prot.

General		
Number	Settings	Value
21.831.2311.1	Mode	Settings group 1: on
21.831.2311.11	1-pole operate allowed	Settings group 1: yes
21.831.2311.102	Min. current for release	Settings group 1: 0.00 A
21.831.2311.104	Supervision Idiff	Settings group 1: no

I-DIFF		
Number	Settings	Value
21.831.3451.1	Mode	Settings group 1: on
21.831.3451.2	Operate & flt.rec. blocked	Settings group 1: no

Number	Settings	Value
21.831.3451.3	Threshold	Settings group 1: 0.20 A
21.831.3451.101	Thresh. switch onto fault	Settings group 1: 0.20 A
21.831.3451.6	Operate delay	Settings group 1: 0 s

I-DIFF fast		
Number	**Settings**	**Value**
21.831.3481.1	Mode	Settings group 1: on
21.831.3481.2	Operate & flt.rec. blocked	Settings group 1: no
21.831.3481.3	Threshold	Settings group 1: 1.20 A
21.831.3481.101	Thresh. switch onto fault	Settings group 1: 1.20 A

Line 1\Ciruit-breaker interaction

Protection group	Circuit-breaker group(s)
Line 1\ 21 Distance prot. 1\ Z 1	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip
Line 1\ 21 Distance prot. 1\ Z 1B	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 21 Distance prot. 1\ Z 3	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 21 Distance prot. 1\ Z 4	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 21 Distance prot. 1\ Z 5	Circuit breaker 1:Trip
Line 1\ Switch onto fault 1\ Stage 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ External trip 1pole 1\ Stage 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 50/51 OC-3ph 1p 1\ Inverse-T 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 50N/51N OC-gnd-A1\ Inverse-T 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 50N/51N OC-gnd-A1\ Definite-T 1	Circuit breaker 1:Trip
Line 1\ 50 high-speed 1pol 1\ Standard 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 87 Line diff. prot.\ General	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip
Line 1\ 85-21Perm.underr.\ 85-21Perm.unde	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip
Line 1\ 85-67N Dir. comp.\ 85-67N Dir.com	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 67N GFP gnd.sys.1\ Definite-T 1	Circuit breaker 1:Trip
Line 1\ 67N GFP gnd.sys.1\ Definite-T 2	Circuit breaker 1:Trip

Appendix 3 – Main 1 Relay Settings – Kotmale – Biyagama Line 1 – Kotmale Substation

General \Rated values		
Number	**Settings**	**Value**
21.9001.101	Rated current	All: 2000 A
21.9001.102	Rated voltage	All: 220 kV
21.9001.103	Rated apparent power	All: 762.1 MVA

General \Line data		
Number	**Settings**	**Value**
21.9001.149	Neutral point	Settings group 1: grounded
21.9001.112	C1 per length unit	Settings group 1: 0.003 μF/km
21.9001.148	C0 per length unit	Settings group 1: 0.003 μF/km
21.9001.113	X per length unit	Settings group 1: 0.306 Ω/km
21.9001.114	Line length	Settings group 1: 70.5 km
21.9001.108	Line angle	Settings group 1: 82.96 °
21.9001.104	Kr	Settings group 1: 2.32
21.9001.105	Kx	Settings group 1: 0.84
21.9001.106	KmR	Settings group 1: 2.33
21.9001.107	KmX	Settings group 1: 0.72
21.9001.109	Gnd.curr.ratio(MutComp)	Settings group 1: 85 %
21.9001.119	CT saturation detection	Settings group 1: yes
21.9001.120	CT saturation threshold	Settings group 1: 5.00 A
21.9001.111	Series compensation	Settings group 1: no

General \Measurements		
Number	**Settings**	**Value**
21.9001.158	P, Q sign	Settings group 1: not reversed

Process monitor

Closure detec.		
Number	**Settings**	**Value**
21.1131.4681.101	Operating mode	Settings group 1: I open and V open
21.1131.4681.102	Action time after closure	Settings group 1: 0.05 s
21.1131.4681.103	Min. time feeder open	Settings group 1: 0.25 s

1pol.open det.		
Number	**Settings**	**Value**
21.1131.4711.101	Operating mode	Settings group 1: with measurement

Volt.criterion		
Number	**Settings**	**Value**
21.1131.4801.101	Threshold U open	Settings group 1: 60.000 V

68 P.swing blk

Number	Settings	Value
21.5311.1	Mode	Settings group 1: on
21.5311.103	Max. blocking time	Settings group 1: oo s

68 P.swing blk \Zones to be blocked

Number	Settings	Value
21.5311.102	21 Distance prot. 1.Z 1	true
21.5311.102	21 Distance prot. 1.Z 1B	true
21.5311.102	21 Distance prot. 1.Z 3	true
21.5311.102	21 Distance prot. 1.Z 4	true
21.5311.102	21 Distance prot. 1.Z 5	true

Fault locator

Number	Settings	Value
21.8671.1	Mode	Settings group 1: on
21.8671.101	Start	Settings group 1: with operate
21.8671.102	Parallel-line compensat.	Settings group 1: yes
21.8671.103	Load compensation	Settings group 1: yes

Mes.v.fail.det

Number	Settings	Value
21.2671.1	Mode	Settings group 1: on
21.2671.115	Asym.fail.-DO on netw.flt.	Settings group 1: no
21.2671.113	Asym.fail. - time delay	Settings group 1: 10 s
21.2671.102	3ph.fail. - phs.curr.release	Settings group 1: 0.10 A
21.2671.103	3ph.fail. - phs.curr. jump	Settings group 1: 0.10 A
21.2671.101	3ph.fail. - VA,VB,VC <	Settings group 1: 5 V
21.2671.107	Switch-on 3ph. failure	Settings group 1: on
21.2671.106	SO 3ph.fail. - time delay	Settings group 1: 3 s

21 Distance prot. 1

General

Number	Settings	Value
21.901.2311.110	Zone timer start	Settings group 1: on dist. pickup
21.901.2311.107	Dist. characteristic angle	Settings group 1: 82.9 °
21.901.2311.105	Ground-fault detection	Settings group 1: 3I0 or V0
21.901.2311.103	3I0> threshold value	Settings group 1: 0.10 A
21.901.2311.102	V0> threshold value	Settings group 1: 1.66 V
21.901.2311.104	3I0 pickup stabilization	Settings group 1: 0.1
21.901.2311.108	Loop select. with ph-ph-g	Settings group 1: block leading phase
21.901.2311.106	Parallel-line compensat.	Settings group 1: yes

Pickup Z<

Number	Settings	Value
21.901.3661.101	Min. phase-current thresh	Settings group 1: 0.10 A
21.901.3661.102	Use ph-g load cutout	Settings group 1: yes
21.901.3661.103	R load cutout (ph-g)	Settings group 1: 18.25 Ω
21.901.3661.104	Angle load cutout (ph-g)	Settings group 1: 41.9 °
21.901.3661.105	Use ph-ph load cutout	Settings group 1: yes

Number	Settings	Value
21.901.3661.106	R load cutout (ph-ph)	Settings group 1: 42.45 Ω
21.901.3661.107	Angle load cutout (ph-ph)	Settings group 1: 41.9 °

Z 1

Number	Settings	Value
21.901.3571.1	Mode	Settings group 1: on
21.901.3571.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3571.121	Blocked if diff.prot.active	Settings group 1: yes
21.901.3571.11	1-pole operate allowed	Settings group 1: yes
21.901.3571.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3571.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3571.109	Directional mode	Settings group 1: forward
21.901.3571.102	X reach	Settings group 1: 18.34 Ω
21.901.3571.103	R (ph-g)	Settings group 1: 25.45 Ω
21.901.3571.104	R (ph-ph)	Settings group 1: 14.67 Ω
21.901.3571.113	Zone-inclination angle	Settings group 1: 3 °
21.901.3571.110	Operate delay (1-phase)	Settings group 1: 0 s
21.901.3571.112	Operate delay (multi-ph.)	Settings group 1: 0 s

Z 1B

Number	Settings	Value
21.901.3572.1	Mode	Settings group 1: on
21.901.3572.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3572.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3572.11	1-pole operate allowed	Settings group 1: yes
21.901.3572.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3572.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3572.109	Directional mode	Settings group 1: forward
21.901.3572.102	X reach	Settings group 1: 25.89 Ω
21.901.3572.103	R (ph-g)	Settings group 1: 37.47 Ω
21.901.3572.104	R (ph-ph)	Settings group 1: 25.89 Ω
21.901.3572.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3572.110	Operate delay (1-phase)	Settings group 1: 0.25 s
21.901.3572.112	Operate delay (multi-ph.)	Settings group 1: 0.25 s

Z 3

Number	Settings	Value
21.901.3573.1	Mode	Settings group 1: on
21.901.3573.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3573.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3573.11	1-pole operate allowed	Settings group 1: no
21.901.3573.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3573.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3573.109	Directional mode	Settings group 1: forward
21.901.3573.102	X reach	Settings group 1: 30.68 Ω
21.901.3573.103	R (ph-g)	Settings group 1: 43.42 Ω
21.901.3573.104	R (ph-ph)	Settings group 1: 29.2 Ω
21.901.3573.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3573.110	Operate delay (1-phase)	Settings group 1: 0.5 s
21.901.3573.112	Operate delay (multi-ph.)	Settings group 1: 0.5 s

Z 4		
Number	**Settings**	**Value**
21.901.3574.1	Mode	Settings group 1: on
21.901.3574.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3574.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3574.11	1-pole operate allowed	Settings group 1: no
21.901.3574.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3574.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3574.109	Directional mode	Settings group 1: reverse
21.901.3574.102	X reach	Settings group 1: 2.16 Ω
21.901.3574.103	R (ph-g)	Settings group 1: 10.98 Ω
21.901.3574.104	R (ph-ph)	Settings group 1: 5.28 Ω
21.901.3574.110	Operate delay (1-phase)	Settings group 1: 1 s
21.901.3574.112	Operate delay (multi-ph.)	Settings group 1: 1 s

Z 5		
Number	**Settings**	**Value**
21.901.3575.1	Mode	Settings group 1: off
21.901.3575.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3575.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3575.11	1-pole operate allowed	Settings group 1: no
21.901.3575.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3575.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3575.109	Directional mode	Settings group 1: forward
21.901.3575.102	X reach	Settings group 1: 36.169 Ω
21.901.3575.103	R (ph-g)	Settings group 1: 22.109 Ω
21.901.3575.104	R (ph-ph)	Settings group 1: 7.109 Ω
21.901.3575.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3575.110	Operate delay (1-phase)	Settings group 1: 1 s
21.901.3575.112	Operate delay (multi-ph.)	Settings group 1: 1 s

85-67N Dir. comp.

85-67N Dir.com		
Number	**Settings**	**Value**
21.1301.5761.1	Mode	Settings group 1: on
21.1301.5761.101	Send prolongation	Settings group 1: 0.1 s
21.1301.5761.102	Send delay	Settings group 1: 0 s
21.1301.5761.105	Trans. blk. pickup delay	Settings group 1: 0.04 s
21.1301.5761.106	Trans. blk. dropout delay	Settings group 1: 0.05 s
21.1301.5761.104	3I0 threshold rev./forw.	Settings group 1: 75 %
21.1301.5761.11	1-pole operate allowed	Settings group 1: no
21.1301.5761.103	Operate delay (1-phase)	Settings group 1: 0 s

85-67N Dir.com \Send with		
Number	**Settings**	**Value**
21.1301.5761.140	67N GFP gnd.sys.1.Definite-T 1	true

85-67N Dir.com \Operate with		
Number	**Settings**	**Value**
21.1301.5761.141	67N GFP gnd.sys.1.Definite-T 1	true

Switch onto fault 1

Stage 1		
Number	**Settings**	**Value**
21.1341.5941.1	Mode	Settings group 1: on
21.1341.5941.2	Operate & flt.rec. blocked	Settings group 1: no
21.1341.5941.6	Operate delay	Settings group 1: 0 s

Stage 1 \Configuration		
Number	**Settings**	**Value**
21.1341.5941.102	21 Distance prot. 1.Z 1	true
21.1341.5941.102	21 Distance prot. 1.Z 1B	true
21.1341.5941.102	21 Distance prot. 1.Z 3	false
21.1341.5941.102	21 Distance prot. 1.Z 4	true
21.1341.5941.102	21 Distance prot. 1.Z 5	false
21.1341.5941.102	50/51 OC-3ph 1p 1.Inverse-T 1	false
21.1341.5941.102	50N/51N OC-gnd-A1.Inverse-T 1	false
21.1341.5941.102	50N/51N OC-gnd-A1.Definite-T 1	false
21.1341.5941.102	50 high-speed 1pol 1.Standard 1	true
21.1341.5941.102	67N GFP gnd.sys.1.Definite-T 1	false

External trip 1pole 1

Stage 1		
Number	**Settings**	**Value**
21.291.931.1	Mode	Settings group 1: on
21.291.931.2	Operate & flt.rec. blocked	Settings group 1: no
21.291.931.11	1-pole operate allowed	Settings group 1: no
21.291.931.6	Operate delay	Settings group 1: 0.05 s

50/51 OC-3ph 1p 1

General		
Number	**Settings**	**Value**
21.221.2311.101	Emergency mode	Settings group 1: no

Inverse-T 1 \General		
Number	**Settings**	**Value**
21.221.871.1	Mode	Settings group 1: on
21.221.871.2	Operate & flt.rec. blocked	Settings group 1: no
21.221.871.11	1-pole operate allowed	Settings group 1: yes
21.221.871.26	Dynamic settings	All: no
21.221.871.8	Method of measurement	Settings group 1: fundamental comp.
21.221.871.3	Threshold	Settings group 1: 0.75 A
21.221.871.108	Type of character. curve	Settings group 1: IEC normal inverse
21.221.871.109	Reset	Settings group 1: disk emulation
21.221.871.101	Time dial	Settings group 1: 0.34

50N/51N OC-gnd-A1

General		
Number	**Settings**	**Value**
21.211.2311.101	Emergency mode	Settings group 1: no

Inverse-T 1 \General		
Number	**Settings**	**Value**
21.211.781.1	Mode	Settings group 1: on
21.211.781.2	Operate & flt.rec. blocked	Settings group 1: no
21.211.781.26	Dynamic settings	All: no
21.211.781.8	Method of measurement	Settings group 1: fundamental comp.
21.211.781.3	Threshold	Settings group 1: 0.04 A
21.211.781.108	Type of character. curve	Settings group 1: IEC normal inverse
21.211.781.109	Reset	Settings group 1: disk emulation
21.211.781.101	Time dial	Settings group 1: 0.38

Definite-T 1 \General		
Number	**Settings**	**Value**
21.211.751.1	Mode	Settings group 1: on
21.211.751.2	Operate & flt.rec. blocked	Settings group 1: no
21.211.751.26	Dynamic settings	All: no
21.211.751.8	Method of measurement	Settings group 1: fundamental comp.
21.211.751.3	Threshold	Settings group 1: 0.825 A
21.211.751.4	Dropout ratio	Settings group 1: 0.95
21.211.751.101	Dropout delay	Settings group 1: 0 s
21.211.751.6	Operate delay	Settings group 1: 1.1 s

50 high-speed 1pol 1

Standard 1		
Number	**Settings**	**Value**
21.981.3961.1	Mode	Settings group 1: on
21.981.3961.102	1-pole operate allowed	Settings group 1: no
21.981.3961.101	Activation	Settings group 1: on CB closure
21.981.3961.3	Threshold	Settings group 1: 2.00 A
21.981.3961.4	Dropout ratio	Settings group 1: 0.9

67N GFP gnd.sys.1

General		
Number	**Settings**	**Value**
21.1111.2311.114	Polarization with	Settings group 1: V0 + IY or V2 + I2
21.1111.2311.101	Angle forward α	Settings group 1: 338 °
21.1111.2311.102	Angle forward β	Settings group 1: 122 °
21.1111.2311.103	Min. zero-seq. voltage V0	Settings group 1: 3.3 V
21.1111.2311.115	Dir.reslt=forw.at V0<min	Settings group 1: no
21.1111.2311.104	Min.3I0 f.increas.dir.sens.	Settings group 1: 0.03 A
21.1111.2311.107	Min. neg.-seq. voltage V2	Settings group 1: 1.400 V
21.1111.2311.106	Min. neg.-seq. current I2	Settings group 1: 0.03 A
21.1111.2311.116	Dir.corr.at ser.comp.lines	Settings group 1: no

Definite-T 1 \General		
Number	**Settings**	**Value**
21.1111.4861.1	Mode	Settings group 1: on
21.1111.4861.2	Operate & flt.rec. blocked	Settings group 1: no
21.1111.4861.114	Directional mode	Settings group 1: forward
21.1111.4861.11	1-pole operate allowed	Settings group 1: no
21.1111.4861.8	Method of measurement	Settings group 1: 1-cycle filter
21.1111.4861.130	Blocking by prot. pickup	Settings group 1: every pickup
21.1111.4861.129	Op.mode at 1p dead time	Settings group 1: blocked
21.1111.4861.112	Hold mode 1p dead time	Settings group 1: 0.04 s
21.1111.4861.115	Dynamic settings	All: no
21.1111.4861.111	Stabiliz. w. phase current	Settings group 1: 10 %
21.1111.4861.3	Threshold	Settings group 1: 0.08 A
21.1111.4861.6	Operate delay	Settings group 1: 60 s

Definite-T 1 \Blocking by		
Number	**Settings**	**Value**
21.1111.4861.140	21 Distance prot. 1.Z 1	true
21.1111.4861.140	21 Distance prot. 1.Z 1B	true
21.1111.4861.140	21 Distance prot. 1.Z 3	false
21.1111.4861.140	21 Distance prot. 1.Z 4	false
21.1111.4861.140	21 Distance prot. 1.Z 5	false
21.1111.4861.140	87 Line diff. prot..Group indicat.	true
21.1111.4861.140	87 Stub diff. prot. 1.Group indicat.	true

85-21Perm.underr.

85-21Perm.unde		
Number	**Settings**	**Value**
21.1281.5671.1	Mode	Settings group 1: on
21.1281.5671.101	Send prolongation	Settings group 1: 0.1 s
21.1281.5671.11	1-pole operate allowed	Settings group 1: yes
21.1281.5671.102	Operate delay (1-phase)	Settings group 1: 0 s
21.1281.5671.103	Operate delay (multi-ph.)	Settings group 1: 0 s

85-21Perm.unde \Send with		
Number	**Settings**	**Value**
21.1281.5671.140	21 Distance prot. 1.Z 1	true
21.1281.5671.140	21 Distance prot. 1.Z 1B	false
21.1281.5671.140	21 Distance prot. 1.Z 3	false
21.1281.5671.140	21 Distance prot. 1.Z 4	false
21.1281.5671.140	21 Distance prot. 1.Z 5	false

85-21Perm.unde \Operate with		
Number	**Settings**	**Value**
21.1281.5671.141	21 Distance prot. 1.pickup general	false
21.1281.5671.141	21 Distance prot. 1.Z 1	false
21.1281.5671.141	21 Distance prot. 1.Z 1B	true
21.1281.5671.141	21 Distance prot. 1.Z 3	false
21.1281.5671.141	21 Distance prot. 1.Z 4	false
21.1281.5671.141	21 Distance prot. 1.Z 5	false
21.1281.5671.141	85-21Perm.underr..receive (direct trip)	false

27 Undervolt.-V1 1

General		
Number	**Settings**	**Value**
21.151.2311.104	Current-flow criterion	Settings group 1: on
21.151.2311.101	Threshold I>	Settings group 1: 0.05 A

Stage 1		
Number	**Settings**	**Value**
21.151.481.1	Mode	Settings group 1: off
21.151.481.2	Operate & flt.rec. blocked	Settings group 1: no
21.151.481.10	Blk. by meas.-volt. failure	Settings group 1: yes
21.151.481.101	Pickup delay	Settings group 1: no
21.151.481.3	Threshold	Settings group 1: 50.600 V
21.151.481.4	Dropout ratio	Settings group 1: 1.05
21.151.481.6	Operate delay	Settings group 1: 3 s

Stage 2		
Number	**Settings**	**Value**
21.151.482.1	Mode	Settings group 1: off
21.151.482.2	Operate & flt.rec. blocked	Settings group 1: no
21.151.482.10	Blk. by meas.-volt. failure	Settings group 1: yes
21.151.482.101	Pickup delay	Settings group 1: no
21.151.482.3	Threshold	Settings group 1: 44 V
21.151.482.4	Dropout ratio	Settings group 1: 1.05
21.151.482.6	Operate delay	Settings group 1: 0.5 s

Weak infeed

Weak infeed		
Number	**Settings**	**Value**
21.1331.5821.101	Echo block time after Tx	Settings group 1: 0.05 s
21.1331.5821.102	Echo and operate delay	Settings group 1: 0.04 s
21.1331.5821.103	Echo pulse	Settings group 1: 0.05 s
21.1331.5821.104	Weak infeed action	Settings group 1: echo and WI operate
21.1331.5821.105	85-21/67N common chan.	Settings group 1: yes
21.1331.5821.106	Undervoltage threshold	Settings group 1: 50 V

87 Line diff. prot.

General		
Number	**Settings**	**Value**
21.831.2311.1	Mode	Settings group 1: on
21.831.2311.11	1-pole operate allowed	Settings group 1: yes
21.831.2311.102	Min. current for release	Settings group 1: 0.00 A
21.831.2311.104	Supervision Idiff	Settings group 1: no

I-DIFF		
Number	**Settings**	**Value**
21.831.3451.1	Mode	Settings group 1: on

Number	Settings	Value
21.831.3451.2	Operate & flt.rec. blocked	Settings group 1: no
21.831.3451.3	Threshold	Settings group 1: 0.20 A
21.831.3451.101	Thresh. switch onto fault	Settings group 1: 0.20 A
21.831.3451.6	Operate delay	Settings group 1: 0 s

I-DIFF fast		
Number	**Settings**	**Value**
21.831.3481.1	Mode	Settings group 1: on
21.831.3481.2	Operate & flt.rec. blocked	Settings group 1: no
21.831.3481.3	Threshold	Settings group 1: 3.00 A
21.831.3481.101	Thresh. switch onto fault	Settings group 1: 3.00 A

87 Stub diff. prot. 1

General		
Number	**Settings**	**Value**
21.1431.2311.1	Mode	Settings group 1: on

S-DIFF		
Number	**Settings**	**Value**
21.1431.8401.1	Mode	Settings group 1: on
21.1431.8401.2	Operate & flt.rec. blocked	Settings group 1: no
21.1431.8401.3	Threshold	Settings group 1: 0.300 A
21.1431.8401.6	Operate delay	Settings group 1: 0.3 s

S-DIFF fast		
Number	**Settings**	**Value**
21.1431.8431.1	Mode	Settings group 1: off
21.1431.8431.2	Operate & flt.rec. blocked	Settings group 1: no
21.1431.8431.3	Threshold	Settings group 1: 2.00 A

Line 1\Ciruit-breaker interaction

Protection group	Circuit-breaker group(s)
Line 1\ 21 Distance prot. 1\ Z 1	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Start auto.recl., Circuit breaker 2:Trip
Line 1\ 21 Distance prot. 1\ Z 1B	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 21 Distance prot. 1\ Z 3	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 21 Distance prot. 1\ Z 4	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 21 Distance prot. 1\ Z 5	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ 85-67N Dir. comp.\ 85-67N Dir.com	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ Switch onto fault 1\ Stage 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ External trip 1pole 1\ Stage 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 50/51 OC-3ph 1p 1\ Inverse-T 1	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ 50N/51N OC-gnd-A1\ Inverse-T 1	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ 50N/51N OC-gnd-A1\ Definite-T 1	Circuit breaker 1:Trip, Circuit breaker 2:Trip

Protection group	Circuit-breaker group(s)
Line 1\ 50 high-speed 1pol 1\ Standard 1	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ 67N GFP gnd.sys.1\ Definite-T 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 87 Line diff. prot.\ General	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Start auto.recl., Circuit breaker 2:Trip
Line 1\ 87 Stub diff. prot. 1\ General	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Blk. auto.recl., Circuit breaker 2:Trip
Line 1\ 85-21Perm.underr.\ 85-21Perm.unde	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip, Circuit breaker 2:Start auto.recl., Circuit breaker 2:Trip
Line 1\ 27 Undervolt.-V1 1\ Stage 1	Circuit breaker 1:Trip, Circuit breaker 2:Trip
Line 1\ 27 Undervolt.-V1 1\ Stage 2	Circuit breaker 1:Trip, Circuit breaker 2:Trip

Appendix 4 – Main 1 Relay Settings – Kotmale – Biyagama Line 1 – Biyagama Substation

General \Rated values

Number	Settings	Value
21.9001.101	Rated current	All: 2000 A
21.9001.102	Rated voltage	All: 220 kV
21.9001.103	Rated apparent power	All: 762.1 MVA

General \Line data

Number	Settings	Value
21.9001.149	Neutral point	Settings group 1: grounded
21.9001.112	C1 per length unit	Settings group 1: 0.905 µF/km
21.9001.148	C0 per length unit	Settings group 1: 0.905 µF/km
21.9001.113	X per length unit	Settings group 1: 0.306 Ω/km
21.9001.114	Line length	Settings group 1: 70.5 km
21.9001.108	Line angle	Settings group 1: 82.92 °
21.9001.104	Kr	Settings group 1: 2.32
21.9001.105	Kx	Settings group 1: 0.84
21.9001.106	KmR	Settings group 1: 4.98
21.9001.107	KmX	Settings group 1: 1.03
21.9001.109	Gnd.curr.ratio(MutComp)	Settings group 1: 85 %
21.9001.119	CT saturation detection	Settings group 1: yes
21.9001.120	CT saturation threshold	Settings group 1: 5.00 A
21.9001.111	Series compensation	Settings group 1: no

General \Measurements

Number	Settings	Value
21.9001.158	P, Q sign	Settings group 1: not reversed

Process monitor

Closure detec.

Number	Settings	Value
21.1131.4681.101	Operating mode	Settings group 1: Manual close only
21.1131.4681.102	Action time after closure	Settings group 1: 0.05 s
21.1131.4681.103	Min. time feeder open	Settings group 1: 0.25 s

1pol.open det.

Number	Settings	Value
21.1131.4711.101	Operating mode	Settings group 1: with measurement

Volt.criterion

Number	Settings	Value
21.1131.4801.101	Threshold U open	Settings group 1: 30 V

Fault locator		
Number	**Settings**	**Value**
21.8671.1	Mode	Settings group 1: on
21.8671.101	Start	Settings group 1: with operate
21.8671.102	Parallel-line compensat.	Settings group 1: yes
21.8671.103	Load compensation	Settings group 1: no

Mes.v.fail.det		
Number	**Settings**	**Value**
21.2671.1	Mode	Settings group 1: on
21.2671.115	Asym.fail.-DO on netw.flt.	Settings group 1: no
21.2671.113	Asym.fail. - time delay	Settings group 1: 10 s
21.2671.102	3ph.fail. - phs.curr.release	Settings group 1: 0.03 A
21.2671.103	3ph.fail. - phs.curr. jump	Settings group 1: 0.05 A
21.2671.101	3ph.fail. - VA,VB,VC <	Settings group 1: 10 V
21.2671.107	Switch-on 3ph. failure	Settings group 1: on
21.2671.106	SO 3ph.fail. - time delay	Settings group 1: 3 s

68 P.swing blk		
Number	**Settings**	**Value**
21.5311.1	Mode	Settings group 1: on
21.5311.103	Max. blocking time	Settings group 1: 2 s

68 P.swing blk \Zones to be blocked		
Number	**Settings**	**Value**
21.5311.102	21 Distance prot. 1.Z 1	true
21.5311.102	21 Distance prot. 1.Z 1B	true
21.5311.102	21 Distance prot. 1.Z 3	true
21.5311.102	21 Distance prot. 1.Z 4	true
21.5311.102	21 Distance prot. 1.Z 5	true

21 Distance prot. 1

General		
Number	**Settings**	**Value**
21.901.2311.110	Zone timer start	Settings group 1: on dist. pickup
21.901.2311.107	Dist. characteristic angle	Settings group 1: 82.9 °
21.901.2311.105	Ground-fault detection	Settings group 1: 3I0 or V0
21.901.2311.103	3I0> threshold value	Settings group 1: 0.05 A
21.901.2311.102	V0> threshold value	Settings group 1: 3.333 V
21.901.2311.104	3I0 pickup stabilization	Settings group 1: 0.1
21.901.2311.108	Loop select. with ph-ph-g	Settings group 1: block leading phase
21.901.2311.106	Parallel-line compensat.	Settings group 1: yes

Pickup Z<		
Number	**Settings**	**Value**
21.901.3661.101	Min. phase-current thresh	Settings group 1: 0.10 A
21.901.3661.102	Use ph-g load cutout	Settings group 1: yes
21.901.3661.103	R load cutout (ph-g)	Settings group 1: 42.44 Ω
21.901.3661.104	Angle load cutout (ph-g)	Settings group 1: 42 °
21.901.3661.105	Use ph-ph load cutout	Settings group 1: yes

Number	Settings	Value
21.901.3661.106	R load cutout (ph-ph)	Settings group 1: 42.44 Ω
21.901.3661.107	Angle load cutout (ph-ph)	Settings group 1: 42 °

Z 1

Number	Settings	Value
21.901.3571.1	Mode	Settings group 1: on
21.901.3571.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3571.121	Blocked if diff.prot.active	Settings group 1: yes
21.901.3571.11	1-pole operate allowed	Settings group 1: yes
21.901.3571.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3571.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3571.109	Directional mode	Settings group 1: forward
21.901.3571.102	X reach	Settings group 1: 18.337 Ω
21.901.3571.103	R (ph-g)	Settings group 1: 25.45 Ω
21.901.3571.104	R (ph-ph)	Settings group 1: 14.67 Ω
21.901.3571.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3571.110	Operate delay (1-phase)	Settings group 1: 0 s
21.901.3571.112	Operate delay (multi-ph.)	Settings group 1: 0 s

Z 1B

Number	Settings	Value
21.901.3572.1	Mode	Settings group 1: on
21.901.3572.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3572.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3572.11	1-pole operate allowed	Settings group 1: no
21.901.3572.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3572.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3572.109	Directional mode	Settings group 1: forward
21.901.3572.102	X reach	Settings group 1: 25.888 Ω
21.901.3572.103	R (ph-g)	Settings group 1: 46.6 Ω
21.901.3572.104	R (ph-ph)	Settings group 1: 25.89 Ω
21.901.3572.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3572.110	Operate delay (1-phase)	Settings group 1: 0.25 s
21.901.3572.112	Operate delay (multi-ph.)	Settings group 1: 0.25 s

Z 3

Number	Settings	Value
21.901.3573.1	Mode	Settings group 1: on
21.901.3573.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3573.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3573.11	1-pole operate allowed	Settings group 1: no
21.901.3573.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3573.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3573.109	Directional mode	Settings group 1: forward
21.901.3573.102	X reach	Settings group 1: 84.654 Ω
21.901.3573.103	R (ph-g)	Settings group 1: 99.85 Ω
21.901.3573.104	R (ph-ph)	Settings group 1: 71.96 Ω
21.901.3573.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3573.110	Operate delay (1-phase)	Settings group 1: 0.5 s
21.901.3573.112	Operate delay (multi-ph.)	Settings group 1: 0.5 s

Z 4		
Number	**Settings**	**Value**
21.901.3574.1	Mode	Settings group 1: on
21.901.3574.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3574.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3574.11	1-pole operate allowed	Settings group 1: no
21.901.3574.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3574.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3574.109	Directional mode	Settings group 1: reverse
21.901.3574.102	X reach	Settings group 1: 2.157 Ω
21.901.3574.103	R (ph-g)	Settings group 1: 6.11 Ω
21.901.3574.104	R (ph-ph)	Settings group 1: 3.67 Ω
21.901.3574.110	Operate delay (1-phase)	Settings group 1: 1 s
21.901.3574.112	Operate delay (multi-ph.)	Settings group 1: 1 s

Z 5		
Number	**Settings**	**Value**
21.901.3575.1	Mode	Settings group 1: off
21.901.3575.2	Operate & flt.rec. blocked	Settings group 1: no
21.901.3575.121	Blocked if diff.prot.active	Settings group 1: no
21.901.3575.11	1-pole operate allowed	Settings group 1: no
21.901.3575.101	Function mode	Settings group 1: ph-gnd and ph-ph
21.901.3575.114	Zone-spec. residu. comp.	Settings group 1: no
21.901.3575.109	Directional mode	Settings group 1: forward
21.901.3575.102	X reach	Settings group 1: 97.27 Ω
21.901.3575.103	R (ph-g)	Settings group 1: 96.049 Ω
21.901.3575.104	R (ph-ph)	Settings group 1: 76.964 Ω
21.901.3575.113	Zone-inclination angle	Settings group 1: 0 °
21.901.3575.110	Operate delay (1-phase)	Settings group 1: 1 s
21.901.3575.112	Operate delay (multi-ph.)	Settings group 1: 1 s

Switch onto fault 1

Stage 1		
Number	**Settings**	**Value**
21.1341.5941.1	Mode	Settings group 1: on
21.1341.5941.2	Operate & flt.rec. blocked	Settings group 1: no
21.1341.5941.6	Operate delay	Settings group 1: 0 s

Stage 1 \Configuration		
Number	**Settings**	**Value**
21.1341.5941.102	21 Distance prot. 1.Z 1	false
21.1341.5941.102	21 Distance prot. 1.Z 1B	true
21.1341.5941.102	21 Distance prot. 1.Z 3	false
21.1341.5941.102	21 Distance prot. 1.Z 4	true
21.1341.5941.102	21 Distance prot. 1.Z 5	false
21.1341.5941.102	50/51 OC-3ph 1p 1.Inverse-T 1	false
21.1341.5941.102	50N/51N OC-gnd-A1.Inverse-T 1	false
21.1341.5941.102	50N/51N OC-gnd-A1.Definite-T 1	false
21.1341.5941.102	50 high-speed 1pol 1.Standard 1	true
21.1341.5941.102	67N GFP gnd.sys.1.Definite-T 1	false
21.1341.5941.102	67N GFP gnd.sys.1.Definite-T 2	false

External trip 1pole 1

Stage 1		
Number	**Settings**	**Value**
21.291.931.1	Mode	Settings group 1: on
21.291.931.2	Operate & flt.rec. blocked	Settings group 1: no
21.291.931.11	1-pole operate allowed	Settings group 1: no
21.291.931.6	Operate delay	Settings group 1: 0.05 s

50/51 OC-3ph 1p 1

General		
Number	**Settings**	**Value**
21.221.2311.101	Emergency mode	Settings group 1: no

Inverse-T 1 \General		
Number	**Settings**	**Value**
21.221.871.1	Mode	Settings group 1: on
21.221.871.2	Operate & flt.rec. blocked	Settings group 1: no
21.221.871.11	1-pole operate allowed	Settings group 1: yes
21.221.871.26	Dynamic settings	All: no
21.221.871.8	Method of measurement	Settings group 1: fundamental comp.
21.221.871.3	Threshold	Settings group 1: 0.75 A
21.221.871.108	Type of character. curve	Settings group 1: IEC normal inverse
21.221.871.109	Reset	Settings group 1: instantaneous
21.221.871.101	Time dial	Settings group 1: 0.22

50N/51N OC-gnd-A1

General		
Number	**Settings**	**Value**
21.211.2311.101	Emergency mode	Settings group 1: no

Inverse-T 1 \General		
Number	**Settings**	**Value**
21.211.781.1	Mode	Settings group 1: on
21.211.781.2	Operate & flt.rec. blocked	Settings group 1: no
21.211.781.26	Dynamic settings	All: no
21.211.781.8	Method of measurement	Settings group 1: fundamental comp.
21.211.781.3	Threshold	Settings group 1: 0.04 A
21.211.781.108	Type of character. curve	Settings group 1: IEC normal inverse
21.211.781.109	Reset	Settings group 1: instantaneous
21.211.781.101	Time dial	Settings group 1: 0.41

Definite-T 1 \General		
Number	**Settings**	**Value**
21.211.751.1	Mode	Settings group 1: off
21.211.751.2	Operate & flt.rec. blocked	Settings group 1: no
21.211.751.26	Dynamic settings	All: no
21.211.751.8	Method of measurement	Settings group 1: fundamental comp.
21.211.751.3	Threshold	Settings group 1: 0.825 A

Number	Settings	Value
21.211.751.4	Dropout ratio	Settings group 1: 0.95
21.211.751.101	Dropout delay	Settings group 1: 0 s
21.211.751.6	Operate delay	Settings group 1: 1.1 s

50 high-speed 1pol 1

Standard 1		
Number	**Settings**	**Value**
21.981.3961.1	Mode	Settings group 1: on
21.981.3961.102	1-pole operate allowed	Settings group 1: no
21.981.3961.101	Activation	Settings group 1: on CB closure
21.981.3961.3	Threshold	Settings group 1: 2.00 A
21.981.3961.4	Dropout ratio	Settings group 1: 0.9

85-21Perm.underr.

85-21Perm.unde		
Number	**Settings**	**Value**
21.1281.5671.1	Mode	Settings group 1: on
21.1281.5671.101	Send prolongation	Settings group 1: 0.1 s
21.1281.5671.11	1-pole operate allowed	Settings group 1: yes
21.1281.5671.102	Operate delay (1-phase)	Settings group 1: 0 s
21.1281.5671.103	Operate delay (multi-ph.)	Settings group 1: 0 s

85-21Perm.unde \Send with		
Number	**Settings**	**Value**
21.1281.5671.140	21 Distance prot. 1.Z 1	true
21.1281.5671.140	21 Distance prot. 1.Z 1B	false
21.1281.5671.140	21 Distance prot. 1.Z 3	false
21.1281.5671.140	21 Distance prot. 1.Z 4	false
21.1281.5671.140	21 Distance prot. 1.Z 5	false

85-21Perm.unde \Operate with		
Number	**Settings**	**Value**
21.1281.5671.141	21 Distance prot. 1.pickup general	false
21.1281.5671.141	21 Distance prot. 1.Z 1	false
21.1281.5671.141	21 Distance prot. 1.Z 1B	true
21.1281.5671.141	21 Distance prot. 1.Z 3	false
21.1281.5671.141	21 Distance prot. 1.Z 4	false
21.1281.5671.141	21 Distance prot. 1.Z 5	false
21.1281.5671.141	85-21Perm.underr..receive (direct trip)	false

85-67N Dir. comp.

85-67N Dir.com		
Number	**Settings**	**Value**
21.1301.5761.1	Mode	Settings group 1: on
21.1301.5761.101	Send prolongation	Settings group 1: 0.1 s
21.1301.5761.102	Send delay	Settings group 1: 0 s
21.1301.5761.105	Trans. blk. pickup delay	Settings group 1: 0.02 s

Number	Settings	Value
21.1301.5761.106	Trans. blk. dropout delay	Settings group 1: 0.05 s
21.1301.5761.104	3I0 threshold rev./forw.	Settings group 1: 75 %
21.1301.5761.11	1-pole operate allowed	Settings group 1: no
21.1301.5761.103	Operate delay (1-phase)	Settings group 1: 0 s

85-67N Dir.com \Send with

Number	Settings	Value
21.1301.5761.140	67N GFP gnd.sys.1.Definite-T 1	true
21.1301.5761.140	67N GFP gnd.sys.1.Definite-T 2	false

85-67N Dir.com \Operate with

Number	Settings	Value
21.1301.5761.141	67N GFP gnd.sys.1.Definite-T 1	true
21.1301.5761.141	67N GFP gnd.sys.1.Definite-T 2	false

67N GFP gnd.sys.1

General

Number	Settings	Value
21.1111.2311.114	Polarization with	Settings group 1: V0 + IY (neutral pt.)
21.1111.2311.101	Angle forward α	Settings group 1: 338 °
21.1111.2311.102	Angle forward β	Settings group 1: 122 °
21.1111.2311.103	Min. zero-seq. voltage V0	Settings group 1: 0.770 V
21.1111.2311.115	Dir.reslt=forw.at V0<min	Settings group 1: no
21.1111.2311.104	Min.3I0 f.increas.dir.sens.	Settings group 1: 0.03 A
21.1111.2311.116	Dir.corr.at ser.comp.lines	Settings group 1: no

Definite-T 1 \General

Number	Settings	Value
21.1111.4861.1	Mode	Settings group 1: on
21.1111.4861.2	Operate & flt.rec. blocked	Settings group 1: no
21.1111.4861.114	Directional mode	Settings group 1: forward
21.1111.4861.11	1-pole operate allowed	Settings group 1: no
21.1111.4861.8	Method of measurement	Settings group 1: 1-cycle filter
21.1111.4861.130	Blocking by prot. pickup	Settings group 1: every pickup
21.1111.4861.129	Op.mode at 1p dead time	Settings group 1: blocked
21.1111.4861.112	Hold mode 1p dead time	Settings group 1: 0.04 s
21.1111.4861.115	Dynamic settings	All: no
21.1111.4861.111	Stabiliz. w. phase current	Settings group 1: 10 %
21.1111.4861.3	Threshold	Settings group 1: 0.08 A
21.1111.4861.6	Operate delay	Settings group 1: 60 s

Definite-T 1 \Blocking by

Number	Settings	Value
21.1111.4861.140	21 Distance prot. 1.Z 1	true
21.1111.4861.140	21 Distance prot. 1.Z 1B	true
21.1111.4861.140	21 Distance prot. 1.Z 3	false
21.1111.4861.140	21 Distance prot. 1.Z 4	false
21.1111.4861.140	21 Distance prot. 1.Z 5	false
21.1111.4861.140	87 Line diff. prot..Group indicat.	true

Definite-T 2 \General		
Number	**Settings**	**Value**
21.1111.4862.1	Mode	Settings group 1: off
21.1111.4862.2	Operate & flt.rec. blocked	Settings group 1: no
21.1111.4862.114	Directional mode	Settings group 1: non-directional
21.1111.4862.11	1-pole operate allowed	Settings group 1: no
21.1111.4862.8	Method of measurement	Settings group 1: 1-cycle filter
21.1111.4862.129	Op.mode at 1p dead time	Settings group 1: blocked
21.1111.4862.112	Hold mode 1p dead time	Settings group 1: 0.04 s
21.1111.4862.115	Dynamic settings	All: no
21.1111.4862.111	Stabiliz. w. phase current	Settings group 1: 10 %
21.1111.4862.3	Threshold	Settings group 1: 0.165 A
21.1111.4862.6	Operate delay	Settings group 1: 0.3 s

Definite-T 2 \Blocking by		
Number	**Settings**	**Value**
21.1111.4862.140	21 Distance prot. 1.Z 1	false
21.1111.4862.140	21 Distance prot. 1.Z 1B	false
21.1111.4862.140	21 Distance prot. 1.Z 3	false
21.1111.4862.140	21 Distance prot. 1.Z 4	false
21.1111.4862.140	21 Distance prot. 1.Z 5	false
21.1111.4862.140	87 Line diff. prot..Group indicat.	false

Weak infeed

Weak infeed		
Number	**Settings**	**Value**
21.1331.5821.101	Echo block time after Tx	Settings group 1: 0.05 s
21.1331.5821.102	Echo and operate delay	Settings group 1: 0.04 s
21.1331.5821.103	Echo pulse	Settings group 1: 0.05 s
21.1331.5821.104	Weak infeed action	Settings group 1: off
21.1331.5821.105	85-21/67N common chan.	Settings group 1: no
21.1331.5821.106	Undervoltage threshold	Settings group 1: 50 V

87 Line diff. prot.

General		
Number	**Settings**	**Value**
21.831.2311.1	Mode	Settings group 1: on
21.831.2311.11	1-pole operate allowed	Settings group 1: yes
21.831.2311.102	Min. current for release	Settings group 1: 0.00 A
21.831.2311.104	Supervision Idiff	Settings group 1: no

I-DIFF		
Number	**Settings**	**Value**
21.831.3451.1	Mode	Settings group 1: on
21.831.3451.2	Operate & flt.rec. blocked	Settings group 1: no
21.831.3451.3	Threshold	Settings group 1: 0.20 A
21.831.3451.101	Thresh. switch onto fault	Settings group 1: 0.20 A
21.831.3451.6	Operate delay	Settings group 1: 0 s

I-DIFF fast		
Number	**Settings**	**Value**
21.831.3481.1	Mode	Settings group 1: on
21.831.3481.2	Operate & flt.rec. blocked	Settings group 1: no
21.831.3481.3	Threshold	Settings group 1: 3.00 A
21.831.3481.101	Thresh. switch onto fault	Settings group 1: 3.00 A

Line 1\Ciruit-breaker interaction

Protection group	Circuit-breaker group(s)
Line 1\ 21 Distance prot. 1\ Z 1	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip
Line 1\ 21 Distance prot. 1\ Z 1B	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 21 Distance prot. 1\ Z 3	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 21 Distance prot. 1\ Z 4	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ Switch onto fault 1\ Stage 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ External trip 1pole 1\ Stage 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 50/51 OC-3ph 1p 1\ Inverse-T 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 50N/51N OC-gnd-A1\ Inverse-T 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 50 high-speed 1pol 1\ Standard 1	Circuit breaker 1:Blk. auto.recl., Circuit breaker 1:Trip
Line 1\ 87 Line diff. prot.\ General	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip
Line 1\ 85-21Perm.underr.\ 85-21Perm.unde	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip
Line 1\ 85-67N Dir. comp.\ 85-67N Dir.com	Circuit breaker 1:Start auto.recl., Circuit breaker 1:Trip

Steady State Analysis of the Power System Failure on 3rd December 2021

Annex E

February 2022

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1. Analysis of the pre-fault network

The steady-state load flow analysis of the network prior to the fault at 11:27 hours on 3rd December 2021 was simulated by the Transmission and Generation Planning Branch of the Ceylon Electricity Board (CEB). PSS/E software was used by CEB to model the transmission system in steady state. The results are shown in Appendix 1. Voltage levels of buses before the failure and their voltage variations were calculated. Table 1.1 shows simulation results compared with the actual recorded voltages of busbars. Voltage variations of busbars are within the stipulated limit of ±10% of the rated voltages of 220 kV and 132 kV, in both recorded and simulated values.

Table 1.1 – Comparison between the recorded and calculated voltages: Pre-fault

	Recorded		Calculated	
Busbar	**Voltage (kV)**	**Variation compared with the nominal voltage**	**Voltage (kV)**	**Variation compared with the nominal voltage**
Badulla	128.0	-3.0%	132.0	0.00%
Balangoda	131.3	-0.5%	128.0	-3.03%
Biyagama 132 kV	133.5	1.1%	130.4	-1.21%
Galle	124.9	-5.4%	119.6	-9.39%
Kelanitissa 132 kV	131.6	-0.3%	130.7	-0.98%
Kelaniya	131.8	-0.2%	130.3	-1.29%
Kilinochchi	130.0	-1.5%	137.3	4.02%
Kiribathkumbura	129.8	-1.7%	130.1	-1.44%
Kolonnawa	130.1	-1.4%	130.6	-1.06%
Kotugoda 132 kV	134.6	2.0%	130.0	-1.52%
Mathugama	128.9	-2.3%	124.2	-5.91%
New Anuradhapura 132 kV	131.8	-0.2%	136.7	3.56%
New Chilaw 132 kV	131.0	-0.8%	128.7	-2.50%
New Laxapana	131.8	-0.2%	132.0	0.00%
Pannipitiya 132 kV	129.3	-2.0%	120.4	-8.79%
Polpitiya	133.0	0.8%	131.6	-0.30%
Rantambe	127.9	-3.1%	132.7	0.53%
Colombo I 132 kV	131.4	-0.5%	130.4	-1.21%
Biyagama 220 kV	201.5	-8.4%	211.9	-3.68%
Kelanitissa 220 kV	206.3	-6.2%	211.8	-3.73%
Kotugoda 220 kV	203.7	-7.4%	212.6	-3.36%
Lakvijaya	218.7	-0.6%	226.6	3.00%
New Anuradhapura 220 kV	219.2	-0.4%	225.9	2.68%
New Chilaw 220 kV	210.7	-4.2%	217.5	-1.14%
Kotmale	Not Available	Not Available	220.9	0.41%

Table 1.2 compares currents of transmission lines related to the fault, prior to the failure obtained from simulation results, compared with the recorded currents of transmission lines. None of the transmission lines were observed to be overloaded prior to the fault.

Table 1.2 – Comparison of recorded and calculated currents: Pre-fault

Transmission Line	Rated Line Voltage (kV)	Recorded Current (A)	Calculated	
			Current (A)	Loading (%)
Kotmale – Biyagama Circuit 02	220	764	768.1	50.1%
Kotmale – Biyagama Circuit 01	220	754	768.1	50.1%
Kotmale – New Anuradhapura Circuit 02	220	72.6	91	12.0%
Athurugiriya – New Polpitiya	220	Not available	Not available	Not available
Athurugiriya – Polpitiya	132	208	134.4	30.4%
Kolonnawa – Kosgama	132	86	92.5	19.2%
Kolonnawa – Seethawaka	132	61	57.3	11.9%

2. Analysis after the loss of Kotmale – Biyagama Line 2

The Biyagama – Kotmale 220 kV single circuit was switched off in the PSS/E model and the steady state load flow analysis was repeated for the network, and the results as shown in Appendix 2. The voltage levels of busbars and their corresponding variations are shown in Table 2.1. Simulation results indicate that busbars would have been within the stipulated limits of ±10% of the rated voltages, except the Pannipitiya 132 kV busbar which has a voltage variation of -11.36%.

Table 2.1 – Calculated voltages: Kotmale – Biyagama 220 kV Line 2 tripped

Busbar	Voltage from the simulation results (kV)	Variation
Badulla	132.1	0.08%
Balangoda	127.6	-3.33%
Biyagama 132 kV	127.8	-3.18%
Galle	119.0	-9.85%
Kelanitissa 132 kV	128.2	-2.88%
Kelaniya	127.7	-3.26%
Kilinochchi	137.1	3.86%
Kiribathkumbura	129.1	-2.20%
Kolonnawa	128.1	-2.95%
Kotugoda 132 kV	127.4	-3.48%
Mathugama	122.3	-7.35%
New Anuradhapura 132 kV	136.4	3.33%
New Chilaw 132 kV	126.9	-3.86%
New Laxapana	131.1	-0.68%
Pannipitiya 132 kV	117.0	-11.36%
Polpitiya	130.5	-1.14%
Rantambe	132.7	0.53%
Colombo I 132 kV	127.9	-3.11%
Biyagama 220 kV	206.7	-6.05%
Kelanitissa 220 kV	206.8	-6.00%
Kotugoda 220 kV	208.0	-5.45%
Lakvijaya	226.6	3.00%
New Anuradhapura 220 kV	225.5	2.50%
New Chilaw 220 kV	214.8	-2.36%
Kotmale	221.1	0.50%

The simulation results also provided the respective currents of the transmission lines during the failure, shown in Table 2.2. The second circuit of Kotmale - Biyagama 220 kV transmission line 1 has a loading of 92%, which is substantially closer to its limit when the paralle line 2 is tripped.

Table 2.2 – Calculated currents: Kotmale – Biyagama 220 kV Line 2 tripped

Transmission Line	Rated Line Voltage (kV)	Calculated	
		Current (A)	Loading (%)
Kotmale – Biyagama Circuit 01	220	1,403.4	92.0%
Kotmale – Biyagama Circuit 02	220	Tripped	Tripped
Kotmale – New Anuradhapura Circuit 01	220	Out of service	-
Kotmale – New Anuradhapura Circuit 02	220	243.4	32.0%
Athurugiriya – New Polpitiya	220	N/A	N/A
Athurugiriya – Polpitiya	132	146.8	33.2%
Kolonnawa – Kosgama	132	66.8	13.9%
Kolonnawa – Seethawaka	132	56.9	11.8%

3. Analysis after the loss of Kotmale – Biyagama Lines 1 and 2

When both the 220 kV transmission lines from Kotmale to Biyagama were switched off, the PSS/E model did not converge during the simulation as shown in Appendix 3, indicating that the generation, remaining transmission lines and customer demand do not achieve a stable operating scenario. The collaps of the power system is probable, in this scenario.

4. Analysis after the loss of Kotmale – Biyagama Lines 1 and 2, but if other lines were available

Another scenario was simulated by adding into the model, the following 220 kV double circuit transmission lines presently under construction: (i) Kotmale – New Polpitiya (ii) Padukka – Pannipitya. Both circuits of Kotmale – Biyagame transmission line were tripped. Results of the simulation are shown in Appendix 4. The calculated voltage levels and voltage variations of the buses are shown in Table 4.1.

Table 4.1 – Calculated voltages: Kotmale – Biyagama both Lines tripped, but Polpitiya-Padukka-Pannipitiya lines available

Busbar	Voltage calculated from the simulation (kV)	Variation
Badulla	132.1	0.08%
Balangoda	128.2	-2.88%
Biyagama 132 kV	129.3	-2.05%
Galle	119.6	-9.39%
Kelanitissa 132 kV	129.2	-2.12%
Kelaniya	129.0	-2.27%
Kilinochchi	137.2	3.94%
Kiribathkumbura	130.1	-1.44%
Kolonnawa	129.1	-2.20%
Kotugoda 132 kV	128.9	-2.35%
Mathugama	124.8	-5.45%
New Anuradhapura 132 kV	136.6	3.48%
New Chilaw 132 kV	128.2	-2.88%

Busbar	Voltage calculated from the simulation (kV)	Variation
New Laxapana	131.9	-0.08%
Pannipitiya 132 kV	121.6	-7.88%
Polpitiya	131.5	-0.38%
Rantambe	132.7	0.53%
Colombo I 132 kV	129.0	-2.27%
Biyagama 220 kV	210.6	-4.27%
Kelanitissa 220 kV	210.5	-4.32%
Kotugoda 220 kV	211.4	-3.91%
Lakvijaya	226.6	3.00%
New Anuradhapura 220 kV	226.6	3.00%
New Chilaw 220 kV	216.7	-1.50%
Kotmale	221.1	0.50%

Table 4.1 shows that all the busbar voltages lie within the specified limits of ±10% of the rated voltages if the 220 kV transmission lines of Kotmale – New Polpitiya and Padukka – Pannipitiya (both lines presently under construction) were connected to the transmission network. The currents and loading levels of the transmission lines relevant to this scenario are presented in Table 4.2.

Table 4.2 – Calculated currents: Kotmale – Biyagama both lines tripped, but Polpitiya-Padukka-Pannipitiya lines available

Transmission Line	Rated Line Voltage (kV)	Simulated Results	
		Current (A)	Loading (%)
Kotmale – Biyagama Circuit 02	220	Tripped	Tripped
Kotmale – Biyagama Circuit 01	220	Tripped	Tripped
Kotmale – New Anuradhapura Circuit 02	220	79.1	10.4%
Athurugiriya – New Polpitiya	220	N/A	N/A
Athurugiriya – Polpitiya	132	240.4	54.4%
Kolonnawa – Kosgama	132	147.1	30.6%
Kolonnawa – Seethawaka	132	179.7	37.3%
Kotmale – New Polpitiya	220	771.4	41.6%
Padukka – Pannipitiya	220	588.4	38.6%

Since both voltages and loading levels are within acceptable limits, it can be concluded that with the commissioning of Kotmale – New Polpitiya and Padukka – Pannipitiya line, steady stability of the system can be maintained in a situation where both circuits of Kotmale-Biyagama line are tripped.

Appendix F: Options to provide on-site auxiliary power to LVPP

Options	Explanations	Pros and Cons
Option 1 (Single generator – new 6kV bus)	Integration of essential loads into a single new 6kV busbar per unit, which will be supplied by a new generator (GT) rated at 24 MW (3 × 8 MW) at site conditions.	Pros: • Less complexity in control and protection design. Cons: • In case of failure in the proposed generator there shall be a fast bus transfer facility to source from unit auxiliary transformer (UAT) or start/standby transformer (SST). • In case of failure or maintenance of a specific motor, the standby pump cannot be powered. • All 6 kV motor feeders must be rerouted to the new 6 kV busbar. • Significant unit outage periods while implementing this option • Expensive option
Option 2 (Single generator – T-off to both 6 kV NPB from both SSTs)	Single generator is connected to existing both 6 kV NPB from both SSTs. At a time one SST NPBs are selected for delivering power to 6 kV switchgear and other for delivering proposed generator power. The size of the minimum capacity of proposed generator is 45 MW (3 × 15 MW) at site conditions.	Pros: • No modifications to existing 6 kV switchgear. • All NPB modifications are outside the plant premises. • Electrical erections are comparatively simple. Cons: • Violation of general busbar architecture. • Only one SST is available for normal start-up/standby. • Significant modification is needed in existing protection system. • Complex commissioning as SST protection also needs to be commissioned. • Rely on FBT during blackout.
Option 2A (Two generators with two transformers on bus AA and BB with two SSTs)	Two generators are connected to a common bus and two transformers which feed two buses AA and BB. Both buses are *fed with two SSTs' power.* Minimum total capacity of proposed generators is 45 MW (3 × 15MW) at site conditions.	Pros: • No modifications to existing 6 kV switchgear. • All NPB modifications are outside the plant premises. • Electrical erections are comparatively simple. Cons: • Only one secondary winding of SST can be used at a time without paralleling the SSTs or SST other secondary winding. • Significant modification is needed to existing protection system. • Complex commissioning as SST protection also needs to be commissioned. • Rely on fast bus transfer (FBT) during blackout.

Option 3 (Single Generator -Tee Off to one 6 kV NPB from both SSTs)	A single generator is connected to existing one 6 kV NPB from both SSTs. Power delivered from SST NPBs are the same as Option 2. All bus A loads are powered directly via proposed generator while energizing the SST. Other SST secondary winding NPB is routed to busbar B side (this could be used to power the busbar B during blackouts). Minimum total capacity of proposed generators is 45 MW (3 × 15MW) at site conditions.	Pros: • No modification to existing 6 kV switchgear. • All NPB modifications are outside the plant premises. Cons: • All cons discussed in Option 2 • Needs non-selected SST shall be switched off from 220 kV. Therefore, number of starting/stopping of SST transformers will be increased. • Re-visiting of SST protection in both conditions (grid power delivery and proposed generator delivery) • If SST has a fault, GT needs to be tripped or the other SST is to be taken. In both scenarios, no healthy SST grid standby power. • Rely on FBT during blackout.
Option 4 (Three individual generators running on each unit Bus A continuously)	Three individual proposed generators are for each generator bus A loads continuously via a new 6 kV bus circuit breaker. Cable connection can be made available to bus B side too from the proposed generator for Fast Bus Transferring to the bus B in a blackout scenario. Minimum size of individual generator is 15 MW at site conditions.	Pros: • Starting / stopping is comparatively simple • Failure of one individual proposed generator does not affect the other units. Cons: • Feed water pump (BFP) 5 MW DOL switching cannot be done on to 15 MW generator. • If proposed generator fails, the unit shall be run using UAT/SST. • Needs 6 kV switchgear extensions. • Rely on FBT during blackout.
Option 5 (Single generator running continuously on each unit Bus A)	Single proposed generator is for each generator bus A load continuously. 6kV cable connection can be made available to bus B side too from proposed generator for Fast Bus Transferring to the Bus B in a Blackout scenario. Minimum total capacity of proposed generators is 45MW (3 × 15MW) at site conditions.	Pros: • Capacity is large enough for BFP 5MW DOL switching. • Protection scheme required for proposed generator is comparatively simpler then Option 6 Cons: • If the proposed or transformer failed or need maintenance all 3 units will run without reliable aux power. • Needs 6kV switchgear extension. • Rely on FBT during blackout.
Option 6 (Three generators running continuously on common bus to cater to all units Bus A)	Three proposed generators are connected to common bus to cater bus A loads continuously of all units, via two transformers. 6kV cable connection can be made available to Bus B side too from proposed generator for FBT to bus B in a blackout scenario. Minimum total capacity of	Pros: • Capacity is large enough for BFP 5 MW DOL switching. • If one proposed generator or transformer fails or needs maintenance, two units can be run with reliable power. • One redundant transformer makes easy the transformer maintenance. Cons:

	individual generator is 15 MW at site conditions.	• Protection scheme requirements for proposed generators are comparatively complex than Option 5. • Needs 6 kV switchgear extension. • Rely on FBT during blackout.
Option 7 (Two generators running continuously on common bus to cater to two units Bus A)	Two proposed generators are connected to common bus to cater to bus A loads of any two units continuously via two transformers. 6kV cable connection can be made available to Bus B other unit bus A and bus B side too from proposed generator for Fast Bus Transferring to the bus B in a blackout scenario. Minimum total capacity of individual generator is 15 MW at site conditions.	Pros: • Capacity is large enough for BFP 5 MW DOL switching. Cons: • One out of three units can be run with reliable power if one proposed generator or transformer fails or needs maintenance. • Protection scheme requirements for proposed generators are comparatively complex than Option 5. • When tripping of one proposed generator, FBT to UAT is complex. • Needs 6 kV switchgear extension. • Rely on FBT during blackout.

Option	**Explanations**
Option 8 (Separation of non-critical & critical loads)	Both 6 kV busbars A and B are to be split into two as busbar A and busbar AA, busbar B and busbar BB. All no-critical loads will be connected to busbar A and busbar B while all the critical loads will be connected to busbar AA and busbar BB. Under normal conditions, BRK A and BRK B are opened, s GT supplies all the essential loads in an islanding mode. The main advantage is that this option is that it does not rely on FBT during blackout.
Option 9 (Separation of non-critical & critical loads)	As per option 9 of the auxiliary supply, both 6 kV busbars A and B are to be split into two as busbar A and busbar AA, busbar B and busbar BB. All no-critical loads will be connected to busbar A and busbar B while all critical loadswill be connected to busbar AA and busbar BB. The main advantage is that this option needs only two GTs and does not rely on FBT during blackouts. However, the success of FBT to SST via proposed 6 breakers is uncertain during GT tripping, as GTs run in an islanded mode prior to tripping.
Option 10 (separation of non-critical & critical loads)	The configuration is identical to Option 9. However, the GTs are proposed to be operated grid connected continuously via BRK.
Option 11 (Rotary based UPS system with emergency diesel generators, EDGs)	This solution is based on EDGs which will be used to supply the auxiliary power to critical loads and the purpose of rotary UPS is to bridge the gap until the EDGs are started.

Source: CEB Technical Committee Report on Auxiliary Power Supply Design for Lakvijaya Power Station, 30 Sep 2016

Annex G

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மின்சக்தி அமைச்சு
MINISTRY OF POWER

437, ගාලු පාර, කොළඹ 03. 437, காலி வீதி, கொழும்பு 03. 437, Galle Road, Colombo 03.

My Ref. No. PE/TECH/D/03/06 | Your Ref. No. | Date 27/12/2021

Eng. M.R. Ranatunga
General Manager
Ceylon Electricity Board

Investigation into the Power System Failure on 03.12.2021

This refers to my letter of even number dated 04.12.2021 with a copy to you, appointing a committee to investigate and establish the reasons for the power system failure occurred on 03.12.2021.

The Committee requests the CEB to explain the following, as the CEB thus far has failed to provide satisfactory initial explanations to the real causes leading to the blackout on December 3, 2021, and/or due to the inconsistencies in the explanations provided by the CEB.

1. The actual cause of tripping of Kotmale-Biyagama 220 kV Line 02 on December 03, 2021, with proper technical basis and physical evidence.
2. The reason for operation of End Fault Protection while the line has undergone what is believed to be a single line to earth fault and the faulty line was already isolated from the network.
3. Explain the reason for tripping of Kotmale-Biyagama 220 kV Line 01 on December 03, 2021, after Line 02 had been isolated from both ends, with credible supporting data, and scientific justifications.
4. Explain why the end fault protection scheme was implemented without necessary safeguards, knowing that a single-line-to-earth fault may trip the entire line with lockout, even if the fault is cleared. Explain also whether this situation had prevailed since the initial installation of 220 kV protection in 2014, and if that was the case, the reason for not having experienced similar tripping in the past, given that single-line-to-earth faults are among the most common line faults.
5. Establish the reason for the operation of the backup Earth Fault relay after a substantially long duration of 22.33 seconds, despite the neutral current having become zero after 288 ms from the pickup. Explain why primary protection such as differential protection implemented on the Kotmale-Biyagama 220 kV Line 01 was not activated but earth fault protection, which is a backup protection scheme, forced the shutdown of the line.
6. Provide the records on access to relays and explain why such information is missing or incomplete.

Please consult relevant officials and provide the clarifications/ explanation in regard to above, **latest by 6th January 2022.**

If the Committee is not satisfied with the explanations provided by the CEB on the above by the due date, the Committee has the discretion to decide the next course of action.

Secretary
Ministry of Power

Copy –
Chairman, CEB

Cc: 1. Chairman, Ceylon Electricity Board.
2. Prof. Lilantha Samaranayake, University of Peradeniya - For Information pls.

Annex H

SUPPLEMENTARY REPORT
TOTAL SYSTEM FAILURE OCCURRED AT
11.27 HRS ON 03rd DECEMBER 2021

Control & Protection Branch,
Transmission Division,
Ceylon Electricity Board,
Kent Road,
COLOMBO 00900
Date: 2022.01.04

SUPPLEMENTARY REPORT

TOTAL SYSTEM FAILURE OCCURRED AT 11.27 HRS ON 03rd DECEMBER 2021

1. INTRODUCTION

A total failure occurred at 11.27hrs on 2021-12-03 involving all transmission lines, Power Stations and Grid Substations in the power system in Sri Lanka. A draft preliminary report on the total system failure occurred on 2021-12-03 prepared by the Control & Protection branch was submitted to AGM (Transmission) on 2021-12-04. (Annexure 01) Thereafter a more detailed report was prepared by Control and Protection Branch and submitted to the management on 2021-12-09. (Annexure 02) This report was also shared to the independent committee appointed by the Ministry to investigate the total failure. After the submission of Report dated 2021-12-09 to the management further investigations were carried out by the Control & Protection Branch and these findings are submitted in this supplementary report. Further the progress of implementation of remedial actions proposed in our report dated 2021-12-09 to avoid recurrence of similar incidents are also submitted in this supplementary report.

The independent committee appointed by the Ministry to investigate the Total Failure has requested further clarifications from CEB by letter no. PE/TECH/D/03/06 dated 2021-12-27. (A copy of letter is enclosed in Annexure 03.

Answers for the clarifications requested by the Ministry letter dated 2021-12-27 and related background information are also submitted in this report.

2. PROTECTION SCHEMES IMPLEMENTED AT BIYAGAMA GRID SUBSTATION AND KOTHMALE POWER STATION.

220 kV Transmission Network of CEB was developed around year 1985 under Mahawali Transmission Development Project. Around year 2000 Protection Branch recommended to rehabilitate the Protection Schemes of 220 kV Transmission Network due to frequent failure of protection relays. Accordingly, 220 kV Protection Development Project was formulated to carry out this work. The initial feasibility study of the project was carried out by Consultancy Company named PB Power of UK. Thereafter CEB received a soft loan from KfW Bank of Germany and Consultancy company named Fitchner GmbH of Germany was appointed as consultant of 220 kV Protection Development Project. The key tasks assigned to consultant were as follows.

- Preparation of Tender Specifications, basic design and Protection Setting Guideline.
- Reviewing of detail design proposed by the Contractor and Protection Relay Settings Proposed by the contractor.
- Supervision of installation, commissioning and testing of Protection Relays and Schemes.

After competitive bidding process Siemens Ltd. of India was selected as successful contractor to carry out the 220 kV Protection Development Project and all main Protection Relays were supplied by Siemens AG of Germany.

Thus, the Protection Scheme of Biyagama – Kothmale Lines was designed, commissioned and tested by Siemens Ltd. one of the leading Protection Relay suppliers in the world. Further the protection scheme design and Protection Relay Setting Proposal submitted by Siemens for Biyagama – Kothmale Lines were reviewed by consultant Fitchner, one of the leading consultancy companies in the world.

2.1. End Fault Protection

At Biyagama GSS, the End Fault Protection scheme of Siemens make is used to detect the faults occurring in between the Circuit Breaker and the Current Transformer in line bays which are not isolated by the Main Protection Relays. The End Fault Protection is an inbuilt function of the Bus Bar Protection Relay and for the proper operation of this function the Bus Bar Protection Relay shall receive the accurate Circuit Breaker status information. As per the design adopted at Biyagama GSS Circuit breaker status information is directly hard wired to control panel and thereafter it is shared to Bus Bar Protection Relay by using a contact multiplication relay and control wires. As per Relay Commissioning Test Sheets available with the Control and Protection Branch, the End Fault Protection scheme has been fully tested by Siemen's commissioning engineers for the correct operation and witness by the staff of Control and Protection Branch under 220 kV Protection Development Project. A copy of the Commissioning Test Sheet is enclosed in Annexure 04.

After the total failure the staff of Control and Protection Branch investigated the End Fault Protection Scheme of Biyagama – Kothmale Line 1 and 2 and found that the control panel is not receiving the accurate Circuit Breaker Status information and in turn the End Fault Protection Scheme is not receiving the accurate Circuit Breaker Status Information and therefore the Scheme could mal-operate. Further it was noted that the Circuit Breakers of Biyagama – Kothmale Line 01 and 02 have been replaced by new circuit breakers after the commissioning of Protection Schemes at Biyagama GSS under 220 kV Protection Development Project. The error identified in the circuit breaker wiring has now been rectified. Thereafter the control panel is receiving the accurate circuit breaker status information.

2.2. Zero Sequence Current setting adopted in Biyagama – Kothmale Line 1 and 2

In the past CEB used Zero Sequence Current setting (i.e. Earth Fault Setting) for 220 kV Transmission lines as 80 A to detect high resistance earth fault that could occur in transmission lines. These setting were reviewed by Fitchner Consultant under 220 kV Protection Development Project and accepted to use in Biyagama – Kothmale 220kV Line as well.

2.3. Steady State Zero Sequence Current in Biyagama – Kothmale Line 1 and 2

At the time of Total Failure i.e., at 11.27hrs on 2021-12-03 it was observed that unusually high Zero Sequence Current as per events and records collected from protection relays and Digital Disturbance Recorder (i.e. Ben) in Biyagama – Kothmale lines.

Qualitrol Ben 6000 Digital disturbance recorder at Kothmale PS was re calibrated by the Comcorp (Pvt) Ltd. on 2021-12-17, who are the local agent of the original equipment manufacturer. After the calibration it was identified the presence of substantial persisting zero sequence currents in transmission lines connected to Kothmale PS as seen in figure 01 and figure 02.

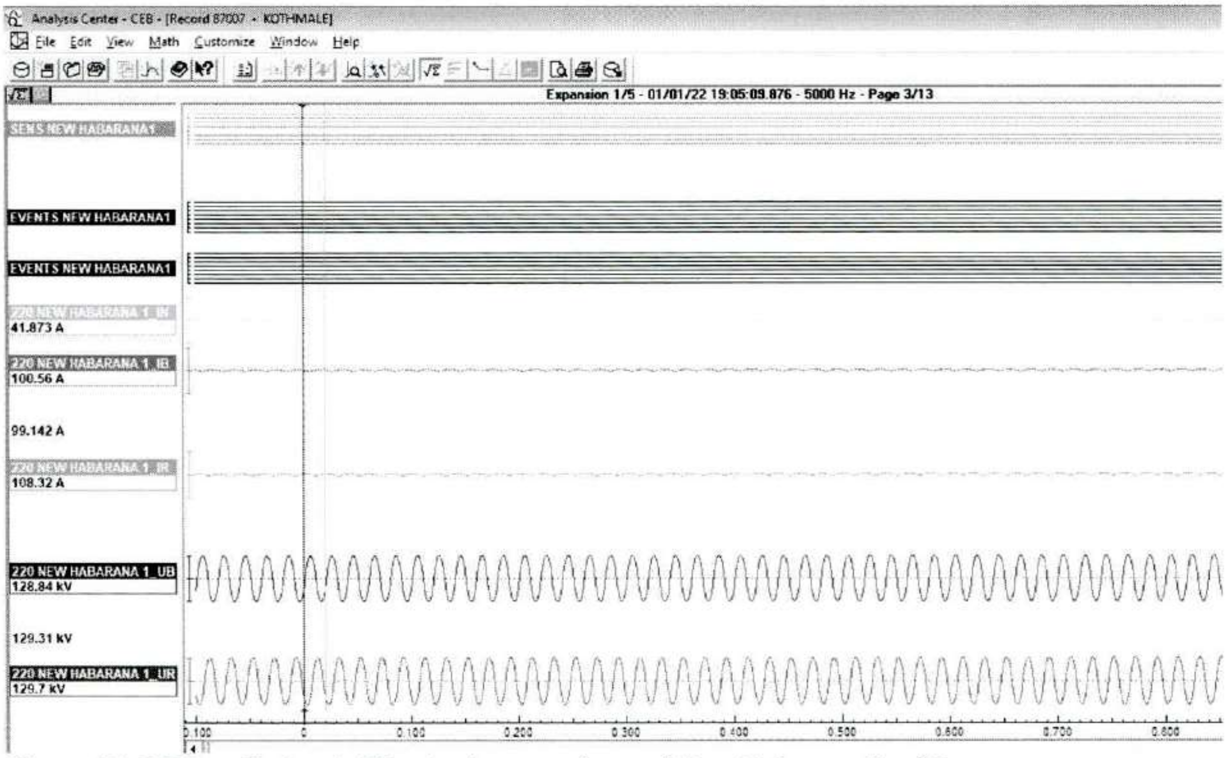


Figure 01: DDR at Kothmale PS – Analog waveforms of New Habarana line 01

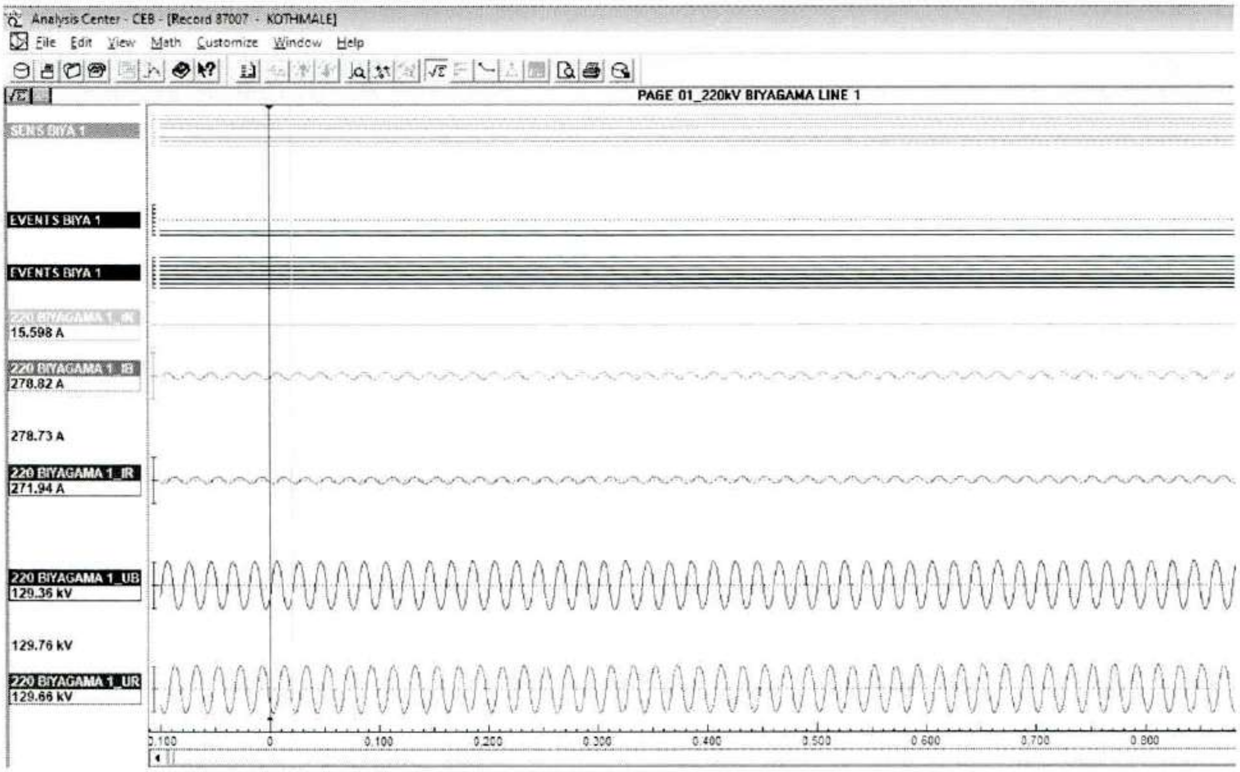


Figure 02: DDR at Kothmale PS – Analog waveforms of Biyagama line 01

Further it was found that the GPS antenna dedicated to Ben DDR has been damaged and it has been replaced.

To avoid unnecessary tripping due to persistent zero sequence currents, non directional earthfault setting was increased to 160 A in Kothmale – Biyagama Line 1 & 2 and Kothmale – New Habarana Line 1 &

2 (Previously New Anuradhapura lines). Further reset criteria was set as instantaneous instead of disk emulation which was the existing setting. This will reset the pickup as soon as the monitored analog current drops below the set value.

3. ANSWERS FOR THE CLARIFICATIONS REQUESTED BY THE MINISTRY LETTER DATED 2021-12-27

Draft answers for the clarifications requested by the Ministry letter dated 2021-12-27 prepared by Control and Protection Branch are enclosed in Annexure 05

Chief Engineer
Protection Development Unit

Chief Engineer
Protection Systems Unit

N. S. Wettasinghe

Deputy General Manager
(Control & Protection – Transmission)

Eng N. S. Wettasinghe
DGM(Control & Protection)

Enclosed:

Annexure 1 Draft preliminary report on the total system failure submitted on 2021-12-04.
Annexure 2 Preliminary report on the total system failure submitted on 2021-12-09.
Annexure 3 Letter no. PE/TECH/D/03/06 dated 2021-12-27 of Secretary, Ministry of Power
Annexure 4 Commissioning Test Sheet of Bus Bar Protection Relay at Biyagama GSS.
Annexure 5 Answers for the clarifications requested by the ministry letter dated 2021-12-27.

Annexure 1

Draft preliminary report on the total system failure submitted on 2021-12-04.

Office of the DGM (Control & Protection),
Transmission Division,
Ceylon Electricity Board,
Kent Road,
Colombo 00900.

Date: December 4, 2021

My No: DGM (C&P-Tr.)/System Failure_03_12_2021

Additional General Manager
(Transmission)

Preliminary Report on Total System Failure Occurred on 03rd December 2021

I am herewith submitting the Preliminary Report on Total System Failure Occurred on 03rd December 2021.

The recommendation of the report is appended below for your easy reference.

It is recommended to test the current transformer and inspect associated primary equipment in the Phase B of the Kothmale 220kV line 02 bay at Biyagama GSS immediately to identify the cause of the fault and replace the said current transformer if necessary. Further it is not recommended to keep the line in operation due to the possibility of repetition of the same incident.

Please grant your concurrence to carry out the above recommendations.

N. S. Wettasinghe

Eng. N.S.Wettasinghe
DGM (Control & Protection)

Eng. N.S.Wettasinghe
Deputy General Manager
(Control & Protection – Transmission)

Copy to : *DGM(AM&CM)*
DGM(O&MS-South)
DGM(SCC)

PRELIMINARY REPORT ON TOTAL SYSTEM FAILURE
AT 1127 HRS ON 03rd DECEMBER 2021

Control & Protection Branch,
Transmission Division,
Ceylon Electricity Board,
Kent Road,
COLOMBO 00900
Date: 03.12.2021

PRELIMINARY REPORT ON TOTAL SYSTEM FAILURE
AT 1127 HRS ON 03rd DECEMBER 2021

1. INTRODUCTION

A total failure occurred at 11.27hrs on 03rd December 2021 involving all transmission lines, Power Stations and Grid Substations in the power system in Sri Lanka.

2. DATE/TIMEOF THE FAILURE

Date : 03rd December 2021
Time : At 11.27 hrs

3. EQUIPMENT TRIPPINGS AND RELAY INDICATIONS

Equipment Trippings	Relay Type	Relay indications	Trip Time
Biyagama GSS - Kothmale 220kV Line 02	SIEMENS 7SL87	Line Differential Operated	11:27:13 hrs
Kothmale PS - Biyagama 220kV Line 02	SIEMENS 7SL87	Line Differential Operated	11:27:13 hrs
Kothmale PS - Biyagama 220kV Line 01	SIEMENS 7SL87	Non Directional Earth Fault	11:27:35 hrs

4. DDR RECORDS

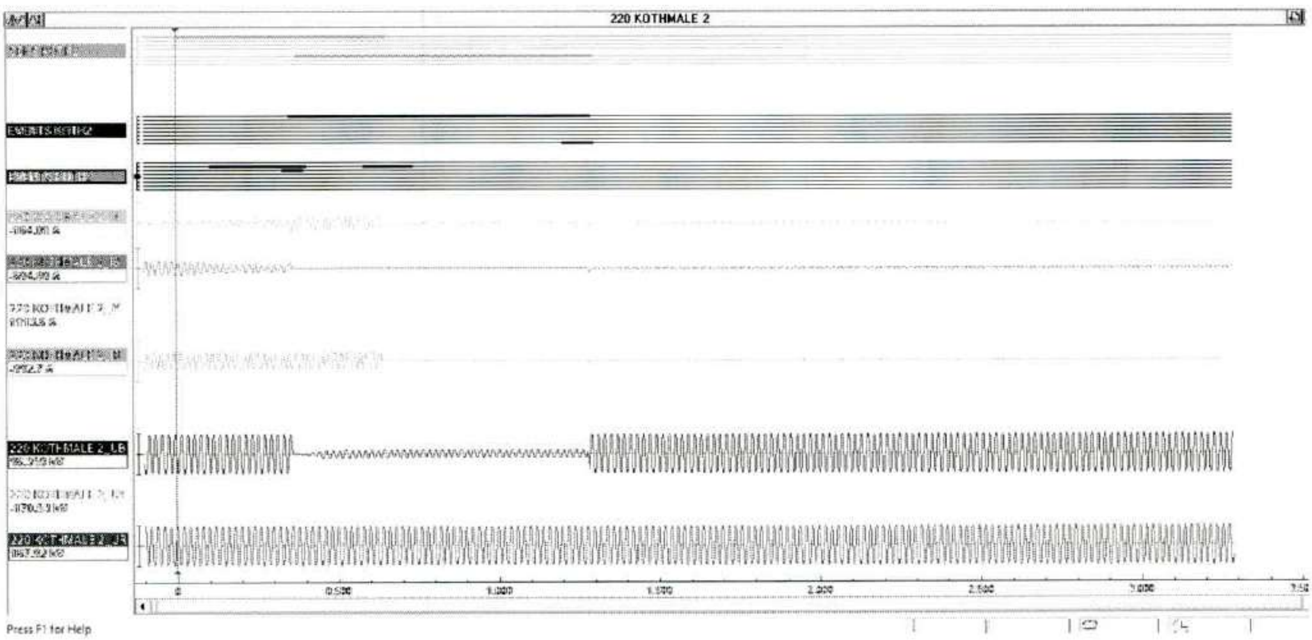


Figure 01: DDR record of Kothmale Line 2 of Biyagama GSS at 11:27:14 Hrs

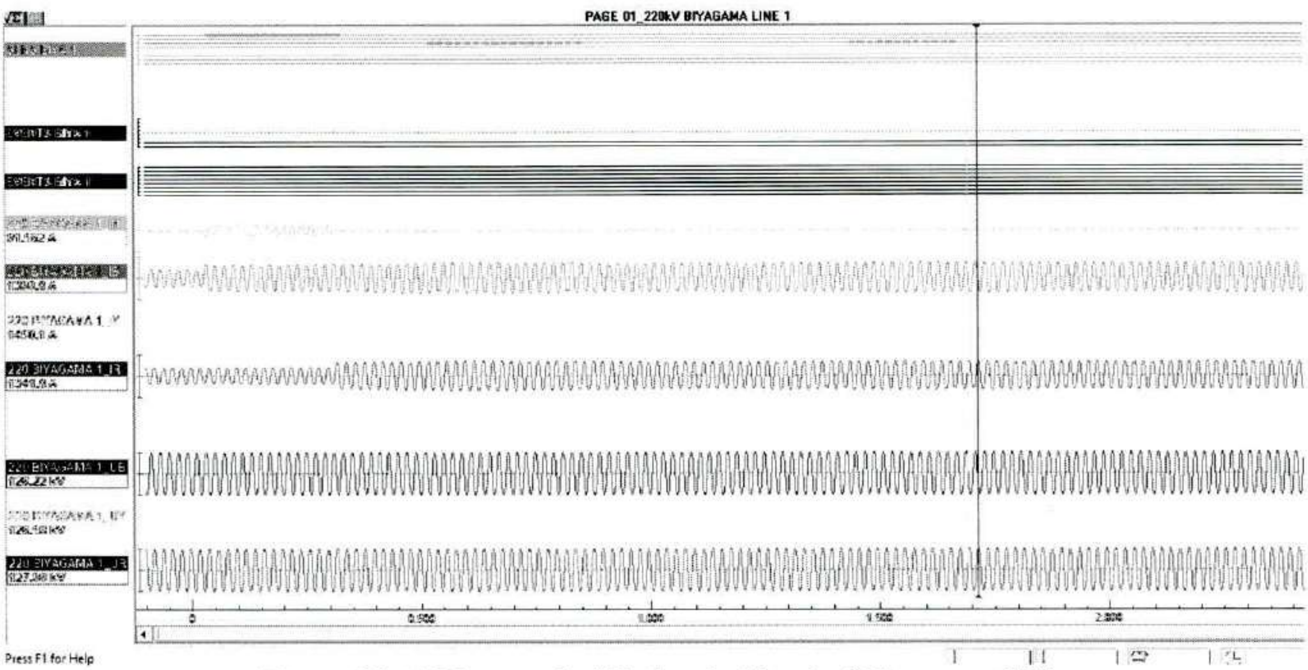


Figure 02: DDR record of Kothmale Line 1 of Biyagama GSS

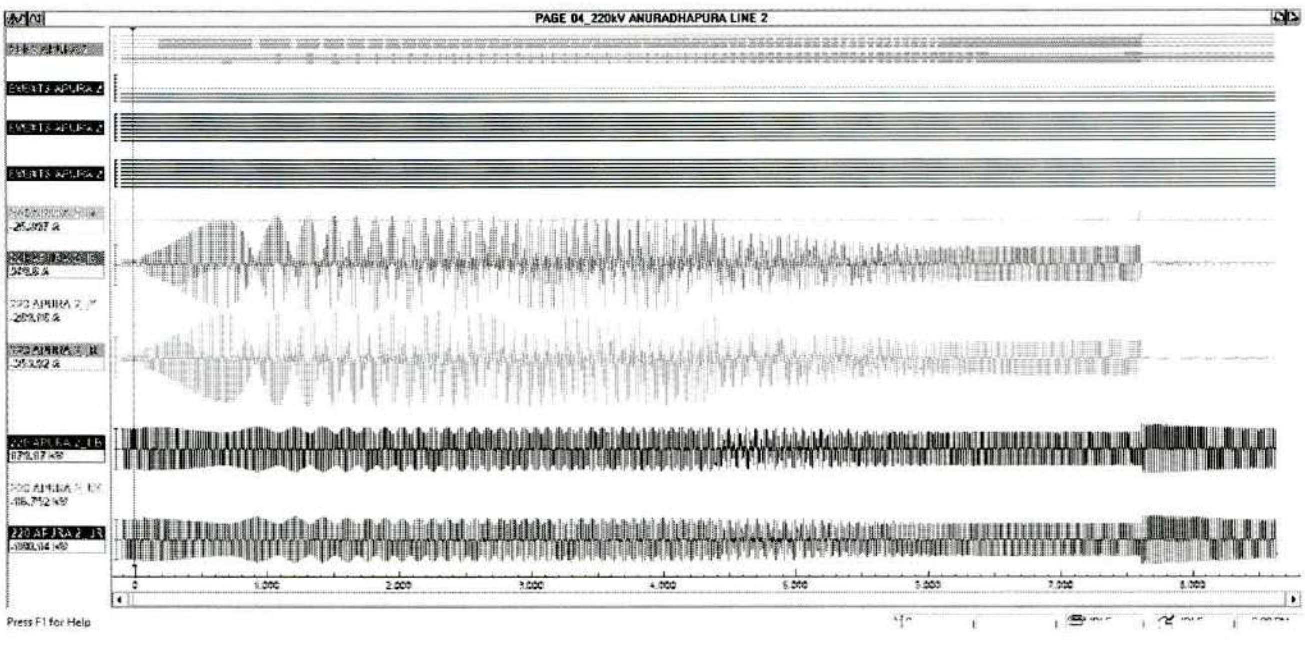


Figure 03: DDR record of New Anuradhapura Line 2 of Kothmale GSS at 11:27:35 Hrs

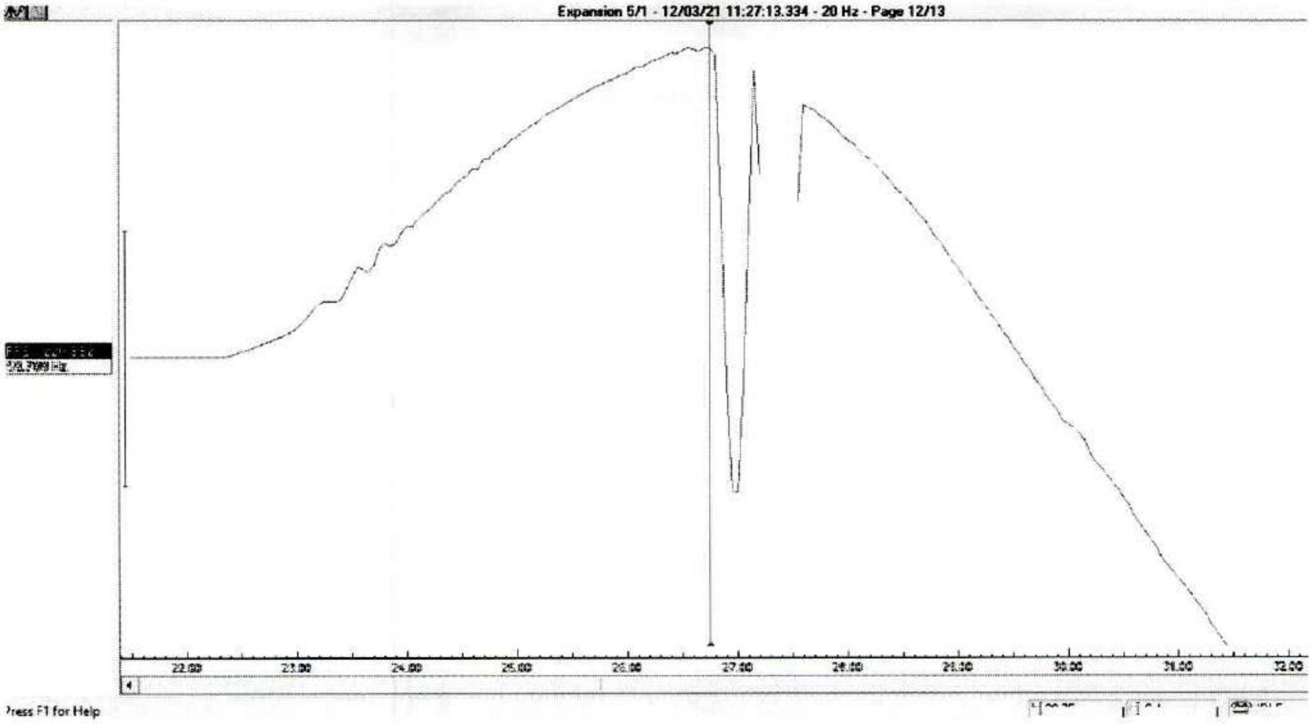


Figure 04: Frequency variation at Kothmale 220kV Bus

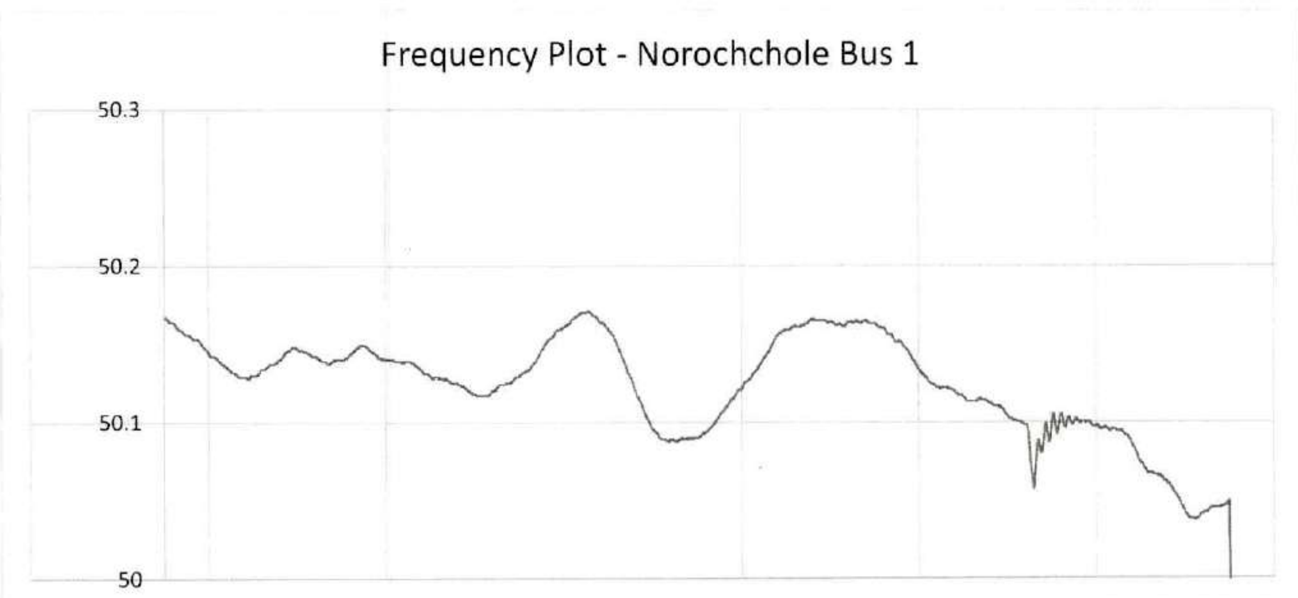


Figure 05: Frequency variation at Norochcholei GSS 220kV Bus 1 during the failure

5. OBSERVATIONS AND ANALYSIS

The sequence of incidents that took place during the system failure is summarized below.

(1) Biyagama - Kothmale 220kV Line 02 tripped due to the operation of Line Differential Protection at 11.27.13 hrs. B phase – earth fault has been detected and the B phase has tripped and reclosed from Biyagama end. Initially phase C tripped and within 288ms all three phases has tripped definitively from Kothmale end.
(2) Biyagama - Kothmale 220kV Line 01 tripped due to Non Directional Earth Fault Protection at 11.27.35 hrs from Kothmale end. It was observed the presence of persistently high neutral unbalance current exceeding 80A, which is the non directional earthfault protection setting applied in transmission lines.
(3) Subsequent to the tripping of Biyagama Kothmale lines, power swing was detected in the system and subsequent tripping of generators lead to the total system failure.

It is observed that the B phase to earth fault current of approximately 450A detected in Main 1, Main 2 relays and BEN DDR of Kothmale – Biyagama line 2. Main 1 relay is connected to Core 1 of current transformer while Main 2 and DDR are connected to core 2. Similar fault current waveforms were observed in all three devices.(figure 06) However it was observed that a similar fault current is not present in the fault records in Kothmale end. Additionally, a small zero sequence current could be observed in all connected 220kV bays at Biyagama GSS prior to the tripping of Kothmale line 02.

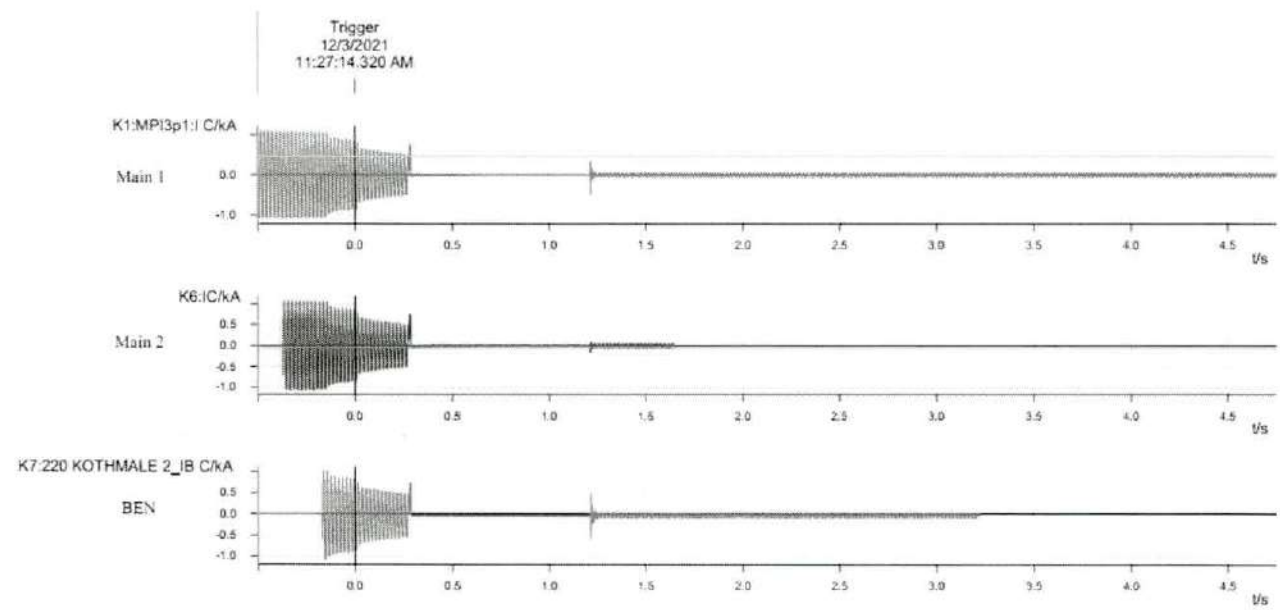


Figure 06: Current waveforms seen by Main 1 relay, Main 2 relay and DDR at Biyagama GSS – Kothmale line 2 B phase

With the tripping of Biyagama – Kothmale line 02, the current in line 01 increased marginally up to 1500A which is the overcurrent setting of the line. However Biyagama – Kothmale line 01 has tripped due to the operation of non directional earthfault protection due to the presence of an unbalance current which is greater than 80A.

6. CONCLUSION AND RECOMMENDATIONS

(1) It is recommended to test the current transformer and inspect associated primary equipment in the Phase B of the Kothmale 220kV line 02 bay at Biyagama GSS immediately to identify the cause of the fault and replace the said current transformer if necessary. Further it is not recommended to keep the line in operation due to the possibility of repetition of the same incident.

(2) It is recommended to increase the non directional earthfault setting of 80A currently used in 220kV transmission lines.

Chief Engineer
Protection Development Section

Annexure 2
Preliminary report on the total system failure submitted on 2021-12-09.

Office of the DGM (Control & Protection),
Transmission Division,
Ceylon Electricity Board,
Kent Road,
Colombo 00900.

Date: December 9, 2021

My No: DGM (C&P-Tr.)/System Failure_03_12_2021

Additional General Manager
(Transmission)

Report on Total System Failure Occurred on 3rd December 2021

This is further to my above subject letter dated 2021-12-04.

I am herewith submitting an updated version of the Preliminary Report on Total System Failure Occurred on 3rd December 2021. Please grant your concurrence to carry out the recommendations given in the report by Control and Protection branch.

N. S. Wettasinghe

Eng. N.S.Wettasinghe
DGM (Control & Protection)

Eng. N.S.Wettasinghe
Deputy General Manager
(Control & Protection – Transmission)

PRELIMINARY REPORT ON TOTAL SYSTEM FAILURE AT 11.27 HRS ON 03rd DECEMBER 2021

Control & Protection Branch,
Transmission Division,
Ceylon Electricity Board,
Kent Road,
COLOMBO 00900
Date: 09.12.2021

PRELIMINARY REPORT ON TOTAL SYSTEM FAILURE AT 11.27 HRS ON 03rd DECEMBER 2021

1. INTRODUCTION

A total failure occurred at 11.27hrs on 03rd December 2021 involving all transmission lines, Power Stations and Grid Substations in the power system in Sri Lanka.

2. DATE/TIMEOF THE FAILURE

Date : 03rd December 2021
Time : At 11.27 hrs

3. EQUIPMENT TRIPPINGS AND RELAY INDICATIONS

Equipment Trippings	Relay Type	Relay indications	Trip Time
Biyagama GSS - Kothmale 220kV Line 02	SIEMENS 7SL87	Line Differential Operated	11:27:14 hrs
Kothmale PS - Biyagama 220kV Line 02	SIEMENS 7SL87	Line Differential Operated	11:27:14 hrs
Kothmale PS - Biyagama 220kV Line 01	SIEMENS 7SL87	Non Directional Earth Fault	11:27:36 hrs
New Anuradhapura GSS – Kothmale Line 02	SIEMENS 7SL87	Distance Protection	11:27:44 hrs

4. DDR RECORDS

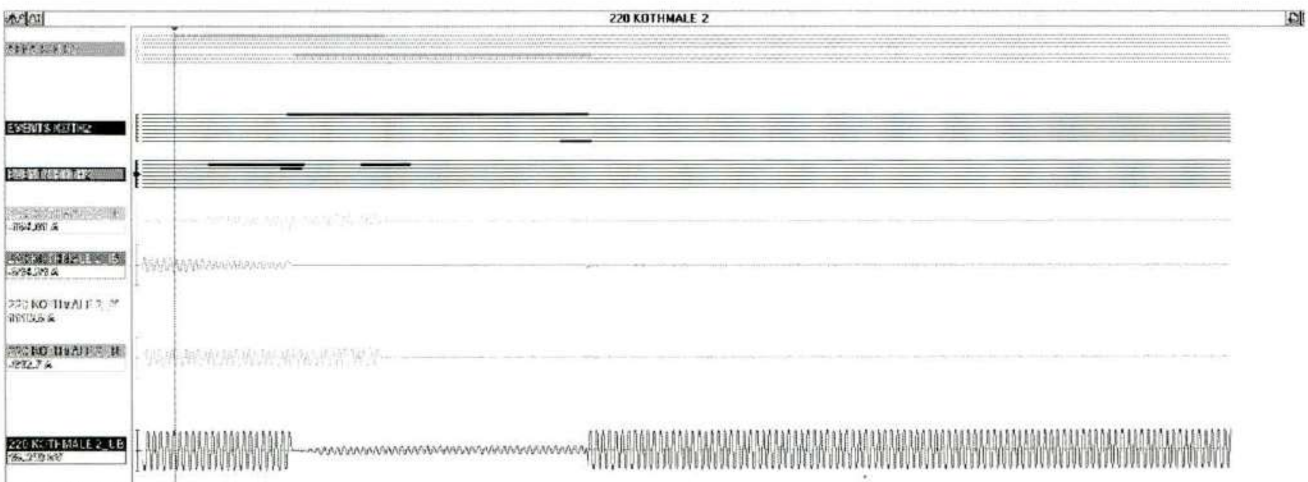


Figure 01: DDR record of Kothmale Line 2 of Biyagama GSS at 11:27:14 Hrs

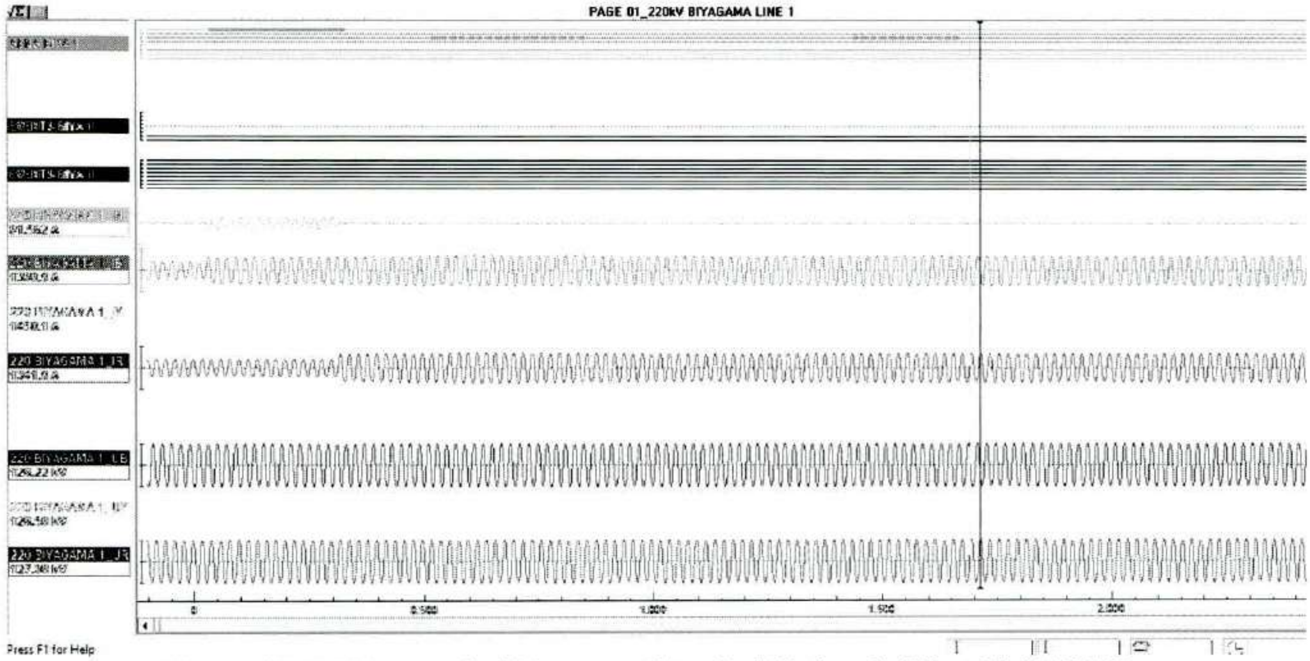


Figure 02: DDR record of Biyagama Line 1 of Kothmale PS at 11:27:14 Hrs

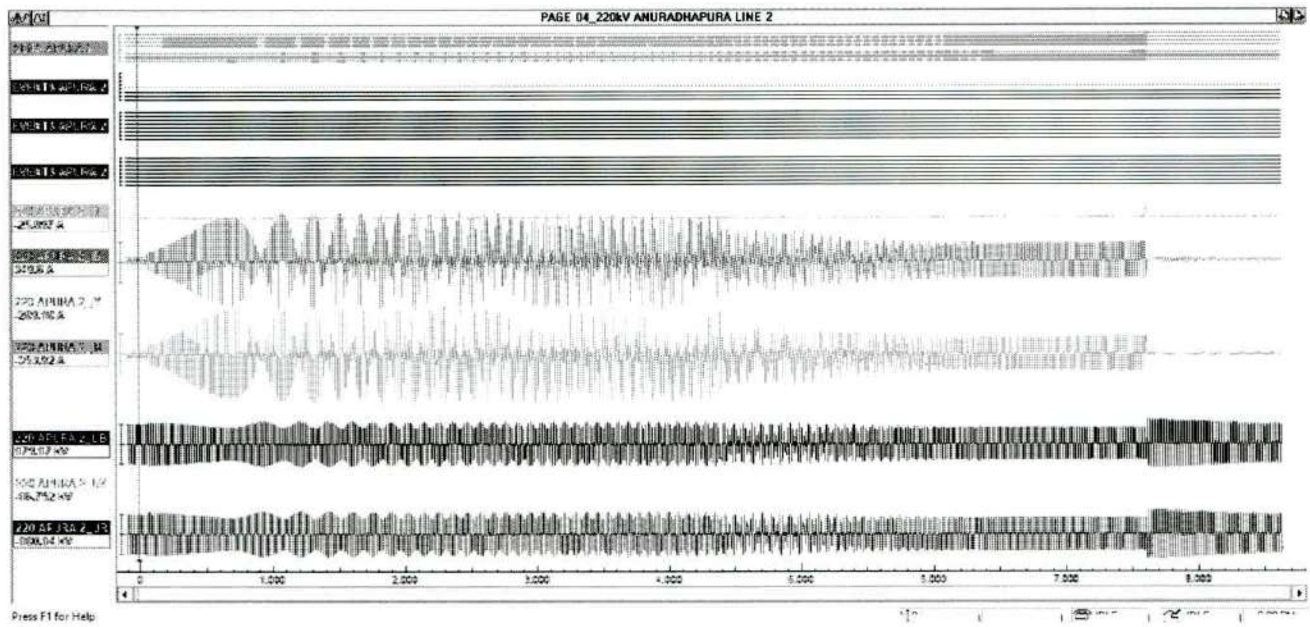


Figure 03: DDR record of New Anuradhapura Line 2 of Kothmale PS at 11:27:35 Hrs

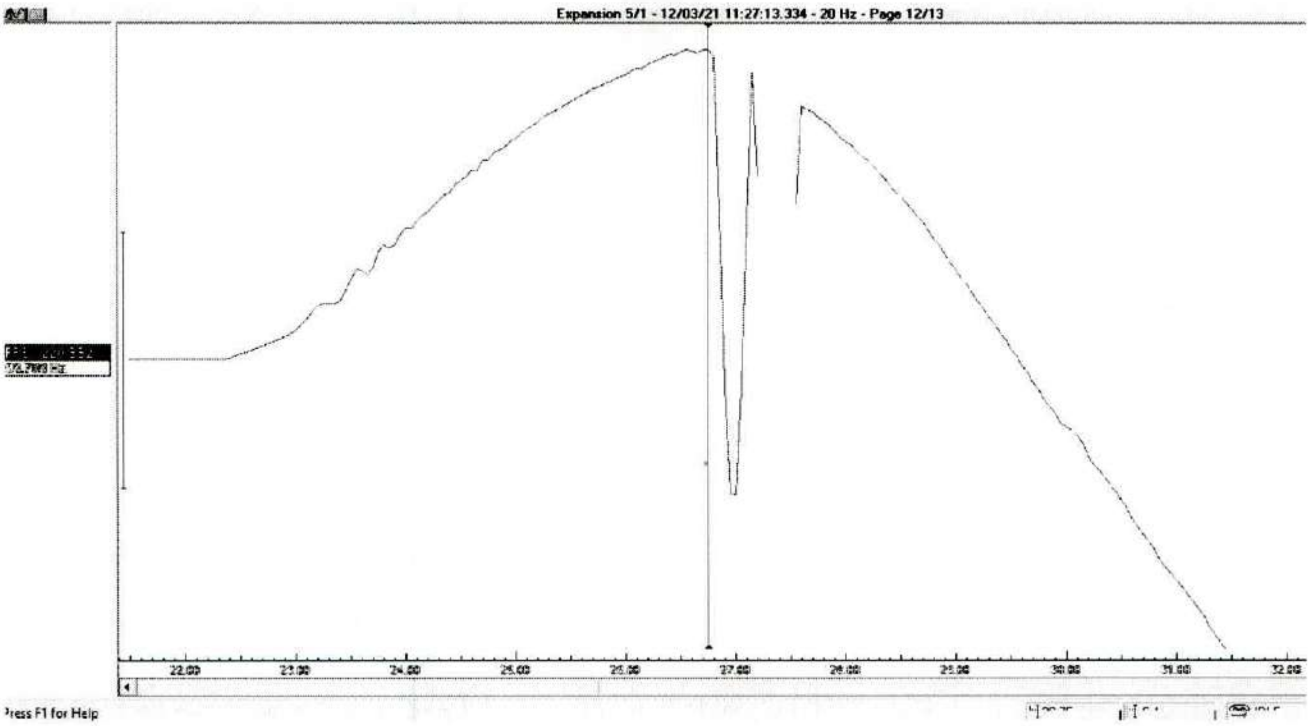


Figure 04: Frequency variation at Kothmale 220kV Bus

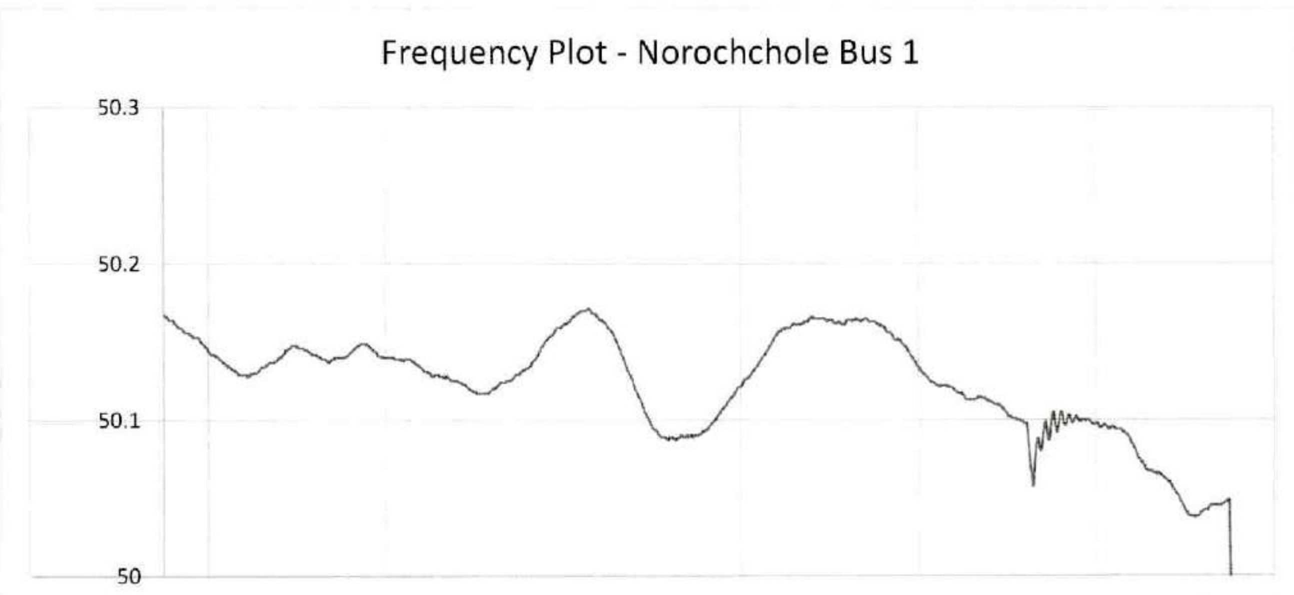


Figure 05: Frequency variation at Norochcholei GSS 220kV Bus 1 during the failure

5. OBSERVATIONS AND ANALYSIS

The sequence of incidents that took place during the system failure is summarized below.

(1) Biyagama - Kothmale 220kV Line 02 tripped due to the operation of Line Differential Protection at 11.27.14 hrs. C phase – earth fault has been detected and the C phase has tripped and reclosed from Biyagama end. Initially phase C tripped and within 282ms all three phases has tripped definitively from Kothmale end.

(2) Biyagama - Kothmale 220kV Line 01 tripped due to Non Directional Earth Fault Protection at 11.27.36 hrs from Kothmale end. It was observed the presence of persistently high neutral unbalance current exceeding 80A, which is the non directional earthfault protection setting applied in all the 132 kV and 220 kV transmission lines.

(3) After the tripping of Biyagama Kothmale line 01, power swing was detected in the system lasting approximately 6 seconds and subsequent tripping of generators lead to the total system failure.

(4) New Anuradhapura – Kothmale line 01 has tripped from New Anuradhapura end at 11.27.44 hrs due to the operation of distance protection. New Anuradhapura – Kothmale line 02 has been switched off from New Anuradhapura end due to a scheduled outage.

It is observed that the C phase to earth fault current of approximately 520A detected in Main 1, Main 2 relays and BEN DDR of Kothmale – Biyagama line 2. Main 1 relay is connected to Core 1 of current transformer while Main 2 and DDR are connected to core 2. Similar fault current waveforms were observed in all three devices (figure 06). Zero sequence current fed to the fault from Biyagama end is approximately 390A and a zero sequence current of 90A could be observed in the fault records in Kothmale end of Line 2. Additionally, it is observed that the summation of zero sequence currents observed in all connected 220kV bays at Biyagama GSS prior to the tripping of Kothmale line 02 equals the zero-sequence current flowing in Kothmale line 2. This zero-sequence current has been cleared with the tripping of phase C. Hence it is clear that there has been a primary fault in the line.

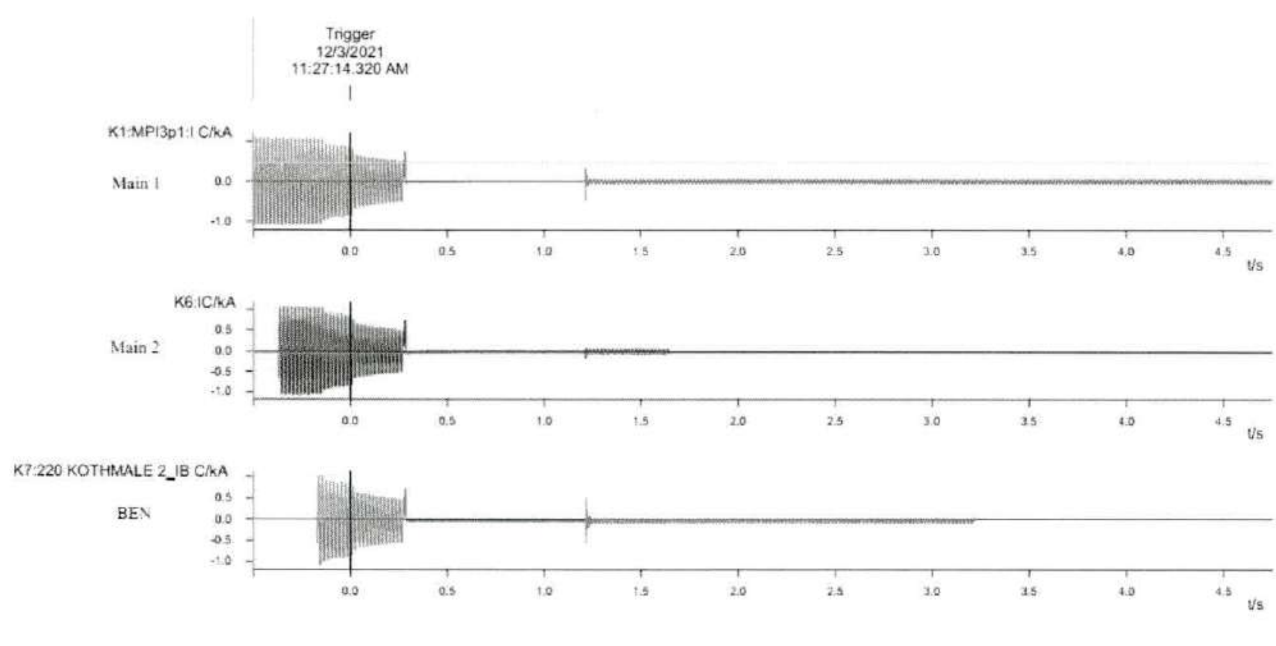


Figure 06: Current waveforms seen by Main 1 relay, Main 2 relay and DDR at Biyagama GSS – Kothmale line 2 B phase

With the tripping of Biyagama – Kothmale line 02, the current in line 01 increased marginally up to 1500A which is the overcurrent setting of the line. However Biyagama – Kothmale line 01 has tripped due to the operation of non directional earth fault protection as per the relay event log after 22s. Refer Table 01. Relay has picked up with the tripping of C phase of parallel line and remained picked up due to the presence of continuous zero sequence current which is around 80A.

Time stamp	**Relative time**	**Functions structure**	**Name**	**Value**
03.12.2021 11:27:36.938	00:00:00:22.326	Circuit breaker 1:Circuit break.	Definitive trip	on
03.12.2021 11:27:36.938	00:00:00:22.326	Circuit breaker 1:Circuit break.	Trip/open cmd. 3-pole	on
03.12.2021 11:27:36.937	**00:00:00:22.325**	**Line 1:50N/51N OC-gnd-A1:Inverse-T 1**	**Operate**	on
03.12.2021 11:27:14.917	00:00:00:00.305	Line 1:85-67N Dir. comp.:85-67N Dir.com	Pickup 3I0	off
03.12.2021 11:27:14.627	00:00:00:00.015	Line 1:85-67N Dir. comp.:85-67N Dir.com	Pickup 3I0	phs C gnd dir. unknown
03.12.2021 11:27:14.612	00:00:00:00.000	Line 1:50N/51N OC-gnd-A1:Inverse-T 1	Pickup	on

Table 01: Event record of Main 1 relay at Kothmale PS – Biyagama line 1

According to the past records of the protection relays, a persistent zero sequence current could be observed in both Kothmale Biyagama line 01 and 02. But the value of the zero sequence current of the Kothmale Biyagama line 01 is almost double the value of line 02. Same can be seen by monitoring the present relay current measurements as well. Refer Table 02.

Observations of Biyagama Line 01 at Kothmale End (Refering Relay History)					
Date & Time	Load Current(A)			Zero Sequence Current	Zero Sequence Current % w.r.t. Average Load Current
	R	Y	B		
2021.11.29_1925	648	672	672	42.143	6.346837349
2021.10.16_1513	446	459	457	27.673	6.095374449
2021.10.05_1221	473	487	488	29.094	6.027762431
2021.09.21_0733	353	360	361	22.144	6.18547486
2021.08.11_0950	595	617	618	37.413	6.133278689

Observations of Kothmale Line 01 at Biyagama End (Refering Relay History)					
Date & Time	Load Current(A)			Zero Sequence Current	Zero Sequence Current % w.r.t. Average Load Current
	R	Y	B		
2021.11.29_1925	653	675	672	38.4	5.76
2021.05.11_1849	485	499	494	27.61	5.604194858
2021.04.15_1748	287	295	288	15.71	5.417241379
2020.11.26_1806	323	329	325	17.073	5.24247697

Observations of Biyagama Line 02 at Kothmale End (Refering Relay History)					
Date & Time	Load Current(A)			Zero Sequence Current	Zero Sequence Current % w.r.t. Average Load Current
	R	Y	B		
2021.11.29_1925	658	669	654	23.235	3.518677436

2021.10.05_1221	484	489	479	16.795	3.470041322
2021.09.21_0733	359	359	351	11.918	3.344621141
2021.04.07_1521	281	281	275	10.156	3.640143369
2021.06.18_0958	687	694	682	23.394	3.401938924

Observations of Kothmale Line 02 at Biyagama End (Refering Relay History)					
Date & Time	Load Current(A)			Zero Sequence Current	Zero Sequence Current % w.r.t. Average Load Current
	R	Y	B		
2021.11.29_1925	663	672	655	24.3	3.663316583
2021.10.05_1221	494	496	484	18.47	3.759158752
2021.05.11_0649	494	497	482	19.65	4.00203666
2021.04.15_0548	291	293	281	10.33	3.58265896

Table 02: Analysis of zero sequence current in Kothmale – Biyagama line 1 & 2 with historical data

Further it is observed that a direct inter trip has been sent to Kothmale end by the operation of end fault protection in Biyagama line 02 resulting in the three-phase trip and lockout preventing the possibility of auto reclosure. It has been identified that the existing configuration of busbar protection relay (Siemens 7SS52) at Biyagama GSS detects an end fault condition when single phase is tripped which need to be investigated and rectified.

Kothmale - New Anuradhapura line 01 has tripped due to the operation of distance protection after the collapse of the system frequency which has been observed in several other line trippings involving transmission lines of 132kV network as well. It was observed that the relay has correctly blocked distance protection during the power swing condition which lasted for about 6 seconds. However it has been observed that protection relays do not operate as intended under abnormal power system frequency and voltage conditions.

6. CONCLUSION AND RECOMMENDATIONS

(1) Kothmale – Biyagama 220kV line 02 has tripped by the operation of line differential protection due to a high impedance earth fault involving the phase C of the transmission line.
(2) Kothmale – Biyagama 220kV line 01 has tripped due to the operation of non directional earth fault protection with the increase in persistent zero sequence current after the tripping of the parallel line.
(3) It is recommended to increase the existing non directional earthfault setting of 80A to 160A in all the 220kV transmission lines.
(4) It is recommended to test the primary and secondary equipment (Current Transformers and secondary cables) in both ends of the Kothmale Biyagama line 01 to identify the cause of the persistently high zero sequence current.
(5) It is recommended to investigate and rectify the end fault protection scheme of the busbar protection relay at Biyagama GSS.

Chief Engineer
Protection Development Unit

7. OBSERVATIONS OF HEAD OF BRANCH

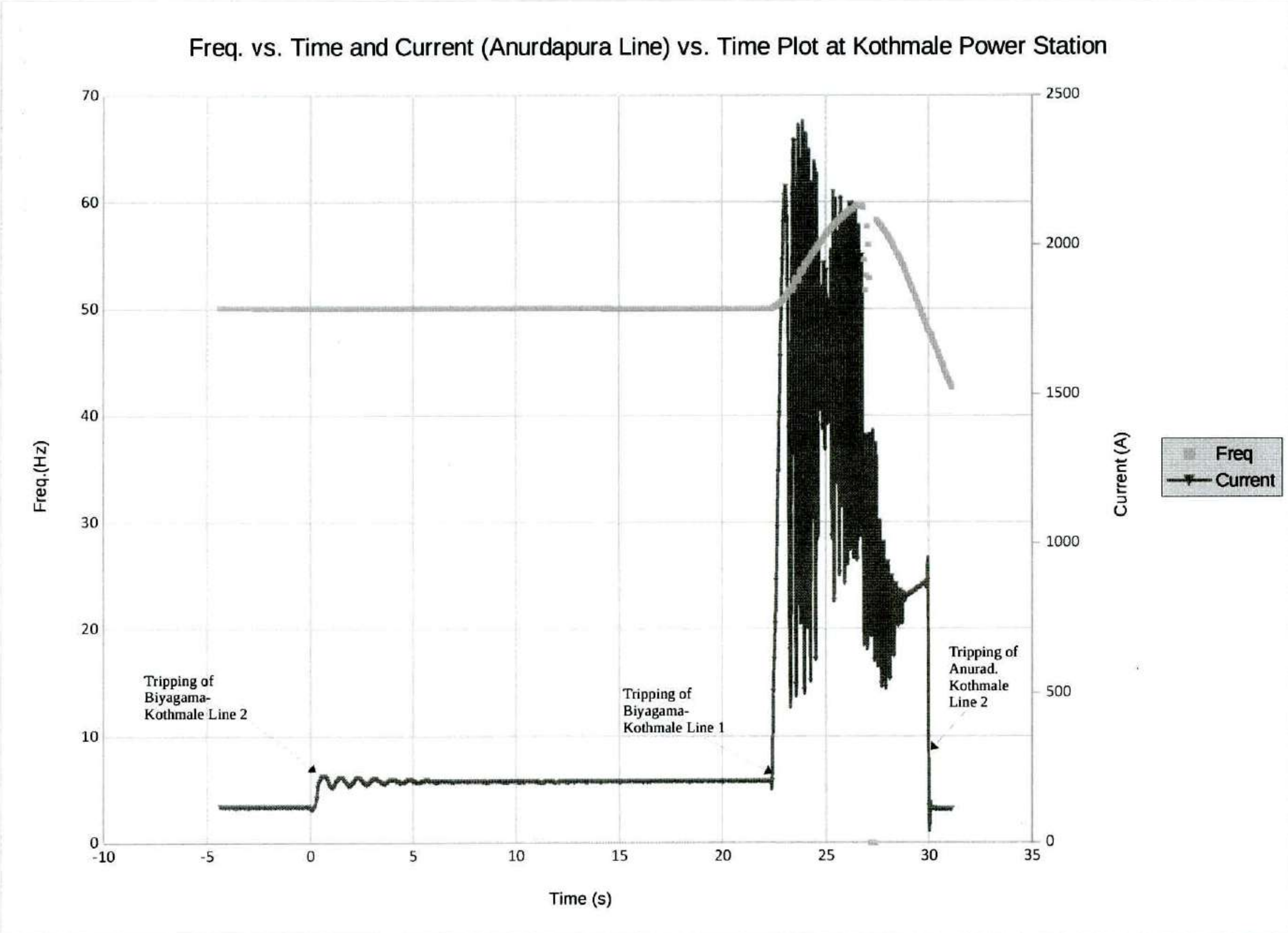
I agree with the conclusion and recommendations listed under Section 6.

The management approval is required to carry out these recommendations by staff of Control and Protection branch.

Deputy General Manager
(Control & Protection – Transmission)

Enclosed:
Annex 1 Freq vs. Time Graph at Kothmale Power Station

ANNEX 1



Freq. vs. Time and Current (Anurdapura Line) vs. Time Plot at Kothmale Power Station
70
60
50
40
30
20
10
0
-10
-5
0
5
10
15
20
25
30
35
2500
2000
1500
1000
500
0
Freq.(Hz)
Current (A)
Time (s)
Freq
Current
Tripping of Biyagama-Kothmale Line 2
Tripping of Biyagama-Kothmale Line 1
Tripping of Anurad. Kothmale Line 2

Annexure 3
Letter no. PE/TECH/D/03/06 dated 2021-12-27 of Secretary, Ministry of Power

කාර්යාලය / அலுவலகம் / Office } 2574922

ෆැක්ස් / பெக்ஸ் / Fax } 2574880, 2574743, 2574741

වෙබ් අඩවිය / இணையத்தளம் / Website } www.powermin.gov.lk

තැ.පෙ. / த.பெ. / P.O.Box } 576

F4930/21

විදුලිබල අමාත්‍යාංශය
மின்சக்தி அமைச்சு
MINISTRY OF POWER

437, ගාලු පාර, කොළඹ 03, 437, காலி வீதி, கொழும்பு 03, 437, Galle Road, Colombo 03.

මගේ අංකය / எமது இல / My Ref. No. } PE/TECH/D/03/06

ඔබේ අංකය / உமது இல / Your Ref. No. }

දිනය / திகதி / Date } 27/12/2021

Eng. M.R. Ranatunga
General Manager
Ceylon Electricity Board

Investigation into the Power System Failure on 03.12.2021

This refers to my letter of even number dated 04.12.2021 with a copy to you, appointing a committee to investigate and establish the reasons for the power system failure occurred on 03.12.2021.

The Committee requests the CEB to explain the following, as the CEB thus far has failed to provide satisfactory initial explanations to the real causes leading to the blackout on December 3, 2021, and/or due to the inconsistencies in the explanations provided by the CEB.

1. The actual cause of tripping of Kotmale-Biyagama 220 kV Line 02 on December 03, 2021, with proper technical basis and physical evidence.
2. The reason for operation of End Fault Protection while the line has undergone what is believed to be a single line to earth fault and the faulty line was already isolated from the network.
3. Explain the reason for tripping of Kotmale-Biyagama 220 kV Line 01 on December 03, 2021, after Line 02 had been isolated from both ends, with credible supporting data, and scientific justifications.
4. Explain why the end fault protection scheme was implemented without necessary safeguards, knowing that a single-line-to-earth fault may trip the entire line with lockout, even if the fault is cleared. Explain also whether this situation had prevailed since the initial installation of 220 kV protection in 2014, and if that was the case, the reason for not having experienced similar tripping in the past, given that single-line-to-earth faults are among the most common line faults.
5. Establish the reason for the operation of the backup Earth Fault relay after a substantially long duration of 22.33 seconds, despite the neutral current having become zero after 288 ms from the pickup. Explain why primary protection such as differential protection implemented on the Kotmale-Biyagama 220 kV Line 01 was not activated but earth fault protection, which is a backup protection scheme, forced the shutdown of the line.
6. Provide the records on access to relays and explain why such information is missing or incomplete.

Please consult relevant officials and provide the clarifications/ explanation in regard to above, **latest by 6th January 2022.**

If the Committee is not satisfied with the explanations provided by the CEB on the above by the due date, the Committee has the discretion to decide the next course of action.

27/12/21

Secretary
Ministry of Power

Copy –
Chairman, CEB

(2) DGM (C&P)
Pl. provide clarification / explanation with regard to above to reach me on or before 04/01/2022.
29/12/2021.

(1) AGM (Tr)
Pl send me the reply for 1 – 6 with your observations.
28/12/2021
Eng. M.R. Ranatunga
General Manager
Ceylon Electricity Board

Cc: 1. Chairman, Ceylon Electricity Board.
2. Prof. Lilantha Samaranayake, University of Peradeniya - For information pls.

Eng. P.W. Hendahewa
AGM (Transmission)

Annexure 4
Commissioning Test Sheet of Bus Bar Protection Relay at Biyagama GSS.

Site acceptance test for BUSBAR DIFFERENTIAL RELAY

PROJECT NAME: 220KV REHABILITATION

Substation: BIYAGAMA

MAKE: SIEMENS
MCU MLFB.NO: 7SS5220-5AB92-1BA0-L0R
MCU SI.NO: BF1303546368
BU MLFB NO: 7SS5251-5FA01-0AA1

PANEL: BBRP1, BBRP2
AUX.VOLTS: 220V DC
I.NOM: 1A

A) MEASUREMENT:

CT RATIO: 2500/1A

1) BU-F8710:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2475A
IL2	1A	2475A
IL3	1A	2475A

2) BU-F8711:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2473A
IL2	1A	2475A
IL3	1A	2475A

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature: (89)

3) BU-F8713.A:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2473A
IL2	1A	2477A
IL3	1A	2477A

4) BU-F8713.B:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2477A
IL2	1A	2475A
IL3	1A	2473A

5) BU-F8720:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2475A
IL2	1A	2473A
IL3	1A	2473A

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

6) BU-F8721:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2475A
IL2	1A	2477A
IL3	1A	2477A

7) BU-F8730:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2477A
IL2	1A	2475A
IL3	1A	2477A

8) BU-F8740:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2473A
IL2	1A	2470A
IL3	1A	2477A

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature: / CPO

Site acceptance test for BUSBAR DIFFERENTIAL RELAY

PROJECT NAME: 220KV REHABILITATION

Substation: BIYAGAMA

9) BU-F8750:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2475A
IL2	1A	2475A
IL3	1A	2477A

10) BU-F8760:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2477A
IL2	1A	2473A
IL3	1A	2477A

11) BU-F8770:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2475A
IL2	1A	2475A
IL3	1A	2473A

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

12) BU-F8780:

PHASE	APPLIED CURRENT	MEASURED CURRENT
IL1	1A	2477A
IL2	1A	2477A
IL3	1A	2477A

B) DIFFERENTIAL TEST:

I-DIFF>: Iset=1.32A

1) BU-F8710:

PHASE	PICKUP VALUE IN AMPS	OPTD TIME (MS)
R	1.34	27.70
Y	1.34	24.90
B	1.33	31.90

2) BU-F8711:

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

PHASE	PICKUP VALUE IN AMPS	OPTD TIME (MS)
R	1.33	43.30
Y	1.34	44.00
B	1.33	33.70

3) BU-F8720:

PHASE	PICKUP VALUE IN AMPS	OPTD TIME (MS)
R	1.33	28.80
Y	1.34	27.70
B	1.34	44.30

4) BU-F8721:

PHASE	PICKUP VALUE IN AMPS	OPTD TIME (MS)
R	1.33	43.50
Y	1.34	45.20
B	1.34	44.30

5) BU-F8730:

PHASE	PICKUP VALUE IN AMPS	OPTD TIME (MS)
R	1.34	28.80
Y	1.34	31.50
B	1.33	32.00

6) BU-F8740:

PHASE	PICKUP VALUE IN AMPS	OPTD TIME (MS)
R	1.34	30.90
Y	1.34	32.60
B	1.33	32.10

7) BU-F8750:

PHASE	PICKUP VALUE IN AMPS	OPTD TIME (MS)
R	1.34	43.60
Y	1.33	44.30
B	1.34	25.60

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

8) BU-F8760:

PHASE	PICKUP VALUE IN AMPS	OPTD TIME (MS)
R	1.33	25.60
Y	1.34	30.40
B	1.34	44.70

9) BU-F8770:

PHASE	PICKUP VALUE IN AMPS	OPTD TIME (MS)
R	1.33	43.50
Y	1.33	46.30
B	1.33	32.00

10) BU-F8780:

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

PHASE	PICKUP VALUE IN AMPS	OPTD TIME (MS)
R	1.34	28.80
Y	1.34	44.90
B	1.34	44.70

C) SENSITIVITY AND STABILITY TEST:

APPLIED CURRENT: 1A

FOR BUS ZONE-1:

1) BU-F8710 & F8711:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	197	196	196	196	0	0	ALL BAYS IN BUS ZONE-1 & BC TRIP
	Y	196	197	196	196	0	0	
	B	196	196	197	197	0	0	
THROUGH	R	0	196	0	194	0	0	NO TRIP
	Y	0	196	0	199	0	0	
	B	0	194	0	195	0	0	

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

Site acceptance test for BUSBAR DIFFERENTIAL RELAY

PROJECT NAME: 220KV REHABILITATION

Substation: BIYAGAMA

2) BU-F8710 & F8720:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	197	197	196	196	0	0	ALL BAYS IN BUS ZONE-1 & BC TRIP
	Y	196	196	197	197	0	0	
	B	198	198	198	198	0	0	
THROUGH	R	0	197	0	197	0	0	NO TRIP
	Y	0	198	0	198	0	0	
	B	0	198	0	197	0	0	

3) BU-F8710 & F8721:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	197	197	197	196	0	0	ALL BAYS IN BUS ZONE-1 & BC TRIP
	Y	196	197	196	196	0	0	
	B	196	197	197	195	0	0	
THROUGH	R	0	196	0	196	0	0	NO TRIP
	Y	0	196	0	197	0	0	
	B	0	196	0	196	0	0	

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

4) BU-F8710 & F8730:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	197	198	196	197	0	0	ALL BAYS IN BUS ZONE-1 & BC TRIP
	Y	198	197	197	197	0	0	
	B	197	197	196	196	0	0	
THROUGH	R	0	196	0	196	0	0	NO TRIP
	Y	0	196	0	196	0	0	
	B	0	197	0	197	0	0	

5) BU-F8710 & F8740:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	196	196	196	196	0	0	ALL BAYS IN BUS ZONE-1 & BC TRIP
	Y	196	197	197	197	0	0	
	B	198	198	197	197	0	0	
THROUGH	R	0	196	0	197	0	0	NO TRIP
	Y	0	196	0	197	0	0	
	B	0	197	0	196	0	0	

6) BU-F8710 & F8750:

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	196	196	196	197	0	0	ALL BAYS IN BUS ZONE-1 & BC TRIP
	Y	195	197	196	196	0	0	
	B	196	197	195	198	0	0	
THROUGH	R	0	197	0	197	0	0	NO TRIP
	Y	0	197	0	196	0	0	
	B	0	196	0	197	0	0	

7) BU-F8710 & F8760:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	198	198	198	198	0	0	ALL BAYS IN BUS ZONE-1 & BC TRIP
	Y	197	198	198	197	0	0	
	B	198	199	198	198	0	0	
THROUGH	R	0	198	0	197	0	0	NO TRIP
	Y	0	197	0	198	0	0	
	B	0	198	0	198	0	0	

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Signature:	Signature:

8) BU-F8710 & F8770:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	196	196	199	190	0	0	ALL BAYS IN BUS ZONE-1 & BC TRIP
	Y	196	196	192	197	0	0	
	B	196	194	196	198	0	0	
THROUGH	R	0	195	0	199	0	0	NO TRIP
	Y	0	196	0	197	0	0	
	B	0	196	0	194	0	0	

9) BU-F8710 & F8780:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	196	196	196	197	0	0	ALL BAYS IN BUS ZONE-1 & BC TRIP
	Y	195	197	196	196	0	0	
	B	196	197	195	198	0	0	
THROUGH	R	0	197	0	197	0	0	NO TRIP
	Y	0	197	0	196	0	0	
	B	0	196	0	197	0	0	

FOR BUS ZONE-2:

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Site acceptance test for BUSBAR DIFFERENTIAL RELAY

PROJECT NAME: 220KV REHABILITATION

Substation: BIYAGAMA

1) BU-F8710 & F8711:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	196	196	0	0	196	197	ALL BAYS IN BUS ZONE-2 & BC TRIP
	Y	195	197	0	0	197	196	
	B	196	196	0	0	195	196	
THROUGH	R	0	196	0	0	0	196	NO TRIP
	Y	0	197	0	0	0	197	
	B	0	196	0	0	0	197	

2) BU-F8710 & F8720:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	197	196	0	0	196	197	ALL BAYS IN BUS ZONE-2 & BC TRIP
	Y	197	197	0	0	196	196	
	B	196	196	0	0	195	196	
THROUGH	R	0	196	0	0	0	196	NO TRIP
	Y	0	196	0	0	0	196	
	B	0	194	0	0	0	195	

3) BU-F8710 & F8721:

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TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	198	198	0	0	196	197	ALL BAYS IN BUS ZONE-2 & BC TRIP
	Y	198	198	0	0	196	196	
	B	196	196	0	0	195	198	
THROUGH	R	0	197	0	0	0	197	NO TRIP
	Y	0	196	0	0	0	196	
	B	0	197	0	0	0	197	

4) BU-F8710 & F8730:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	196	196	0	0	196	197	ALL BAYS IN BUS ZONE-2 & BC TRIP
	Y	197	197	0	0	197	196	
	B	197	197	0	0	197	197	
THROUGH	R	0	197	0	0	0	197	NO TRIP
	Y	0	196	0	0	0	197	
	B	0	196	0	0	0	196	

5) BU-F8710 & F8740:

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TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	197	196	0	0	196	197	ALL BAYS IN BUS ZONE-2 & BC TRIP
	Y	196	195	0	0	192	196	
	B	196	196	0	0	195	197	
THROUGH	R	0	196	0	0	0	196	NO TRIP
	Y	0	196	0	0	0	196	
	B	0	196	0	0	0	197	

6) BU-F8710 & F8750:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	196	196	0	0	196	197	ALL BAYS IN BUS ZONE-2 & BC TRIP
	Y	197	197	0	0	197	196	
	B	197	197	0	0	197	197	
THROUGH	R	0	197	0	0	0	197	NO TRIP
	Y	0	196	0	0	0	197	
	B	0	196	0	0	0	196	

7) BU-F8710 & F8760:

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TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	197	196	0	0	196	196	ALL BAYS IN BUS ZONE-2 & BC TRIP
	Y	197	197	0	0	196	196	
	B	196	196	0	0	197	199	
THROUGH	R	0	197	0	0	0	197	NO TRIP
	Y	0	197	0	0	0	198	
	B	0	196	0	0	0	198	

8) BU-F8710 & F8770:

TYPE OF FAULT	PHASE	CHECK ZONE CZ		BUS ZONE BZ1		BUS ZONE BZ2		REMARK
		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	196	196	0	0	196	196	ALL BAYS IN BUS ZONE-2 & BC TRIP
	Y	196	196	0	0	196	197	
	B	196	197	0	0	197	197	
THROUGH	R	0	197	0	0	0	197	NO TRIP
	Y	0	197	0	0	0	197	
	B	0	197	0	0	0	197	

9) BU-F8710 & F8780:

TYPE OF FAULT	PHASE	CHECK ZONE CZ	BUS ZONE BZ1	BUS ZONE BZ2	REMARK

		ID (%)	IS (%)	ID (%)	IS (%)	ID (%)	IS (%)	
INTERNAL	R	197	196	0	0	197	197	ALL BAYS IN BUS ZONE-2 & BC TRIP
	Y	196	197	0	0	197	196	
	B	197	197	0	0	196	197	
THROUGH	R	0	196	0	0	0	196	NO TRIP
	Y	0	197	0	0	0	196	
	B	0	197	0	0	0	197	

D) BREAKER FAILURE PROTECTION CHECK:

CURRENT THRESHOLD FOR BF: 0.20A

1) FOR BUS ZONE-1:

A) BU-F8710: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.22S

BUS ZONE-1 TRIP TIME : 0.33S

B) BU-F8711: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.23S

BUS ZONE-1 TRIP TIME : 0.32S

C) BU-F8713.A: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.22S

BUS ZONE-1 TRIP TIME : 0.32S

D) BU-F8720: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.21S

BUS ZONE-1 TRIP TIME : 0.33S

E) BU-F8721: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.22S

BUS ZONE-1 TRIP TIME : 0.32S

F) BU-F8730: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.21S

BUS ZONE-1 TRIP TIME : 0.32S

G) BU-F8740: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.22S

BUS ZONE-1 TRIP TIME : 0.33S

H) BU-F8750: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.22S

BUS ZONE-1 TRIP TIME : 0.32S

I) BU-F8760: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.21S

BUS ZONE-1 TRIP TIME : 0.33S

J) BU-F8770: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.22S

BUS ZONE-1 TRIP TIME : 0.33S

K) BU-F8780: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.23S

BUS ZONE-1 TRIP TIME : 0.33S

2) FOR BUS ZONE-2:

A) BU-F8710: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.22S

BUS ZONE-2 TRIP TIME : 0.32S

B) BU-F8711: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.22S

BUS ZONE-2 TRIP TIME : 0.31S

C) BU-F8713.B: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.23S

BUS ZONE-2 TRIP TIME : 0.33S

D) BU-F8720: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.23S

BUS ZONE-2 TRIP TIME : 0.33S

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E) BU-F8721: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.23S

BUS ZONE-2 TRIP TIME : 0.33S

F) BU-F8730: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.23S

BUS ZONE-2 TRIP TIME : 0.34S

G) BU-F8740: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.22S

BUS ZONE-2 TRIP TIME : 0.33S

H) BU-F8750: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.23S

BUS ZONE-2 TRIP TIME : 0.33S

I) BU-F8760: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.23S

BUS ZONE-2 TRIP TIME : 0.32S

J) BU-F8770: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.22S

BUS ZONE-2 TRIP TIME : 0.32S

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K) BU-F8780: 0.21A injected with CBF START initiation via binary input

RESULT: TRIP REPEAT TIME : 0.23S

BUS ZONE-2 TRIP TIME : 0.33S

E) DIFFERENTIAL CURRENT SUPERVISION CHECK:

LIMIT VALUE-BUS ZONE : 0.10A
LIMIT VALUE-CHECK ZONE : 0.10A
TIME DELAY : 2.00S

1) FOR BUS ZONE-1:

A) BU-F8710 & F8711: Current injected with difference of 0.11A

RESULT: BUS ZONE-1 is "BLOCKED" and CHECK ZONE gave "ALARM"

B) BU-F8710 & F8720: Current injected with difference of 0.11A

RESULT: BUS ZONE-1 is "BLOCKED" and CHECK ZONE gave "ALARM"

C) BU-F8710 & F8721: Current injected with difference of 0.11A

RESULT: BUS ZONE-1 is "BLOCKED" and CHECK ZONE gave "ALARM"

D) BU-F8710 & F8730: Current injected with difference of 0.11A

RESULT: BUS ZONE-1 is "BLOCKED" and CHECK ZONE gave "ALARM"

E) BU-F8710 & F8740: Current injected with difference of 0.11A

RESULT: BUS ZONE-1 is "BLOCKED" and CHECK ZONE gave "ALARM"

F) BU-F8710 & F8750: Current injected with difference of 0.11A

RESULT: BUS ZONE-1 is "BLOCKED" and CHECK ZONE gave "ALARM"
G) BU-F8710 & F8760: Current injected with difference of 0.11A

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RESULT: BUS ZONE-1 is "BLOCKED" and CHECK ZONE gave "ALARM"

H) BU-F8710 & F8770: Current injected with difference of 0.11A

RESULT: BUS ZONE-1 is "BLOCKED" and CHECK ZONE gave "ALARM"

I) BU-F8710 & F8780: Current injected with difference of 0.11A

RESULT: BUS ZONE-1 is "BLOCKED" and CHECK ZONE gave "ALARM"

2) FOR BUS ZONE-2:

A) BU-F8710 & F8711: Current injected with difference of 0.11A

RESULT: BUS ZONE-2 is "BLOCKED" and CHECK ZONE gave "ALARM"

B) BU-F8710 & F8720: Current injected with difference of 0.11A

RESULT: BUS ZONE-2 is "BLOCKED" and CHECK ZONE gave "ALARM"

C) BU-F8710 & F8721: Current injected with difference of 0.11A

RESULT: BUS ZONE-2 is "BLOCKED" and CHECK ZONE gave "ALARM"

D) BU-F8710 & F8730: Current injected with difference of 0.11A

RESULT: BUS ZONE-2 is "BLOCKED" and CHECK ZONE gave "ALARM"

E) BU-F8710 & F8740: Current injected with difference of 0.11A

RESULT: BUS ZONE-2 is "BLOCKED" and CHECK ZONE gave "ALARM"

F) BU-F8710 & F8750: Current injected with difference of 0.11A

RESULT: BUS ZONE-2 is "BLOCKED" and CHECK ZONE gave "ALARM"

G) BU-F8710 & F8760: Current injected with difference of 0.11A

RESULT: BUS ZONE-2 is "BLOCKED" and CHECK ZONE gave "ALARM"

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H) BU-F8710 & F8770: Current injected with difference of 0.11A

RESULT: BUS ZONE-2 is "BLOCKED" and CHECK ZONE gave "ALARM"

I) BU-F8710 & F8780: Current injected with difference of 0.11A

RESULT: BUS ZONE-2 is "BLOCKED" and CHECK ZONE gave "ALARM"

F) END FAULT PROTECTION CHECK:

CURRENT THRESHOLD FOR EF: 0.20A

1) BU-F8710: 0.21A injected with CB OPEN

RESULT: END FAULT PROTECTION operated

2) BU-F8711: 0.21A injected with CB OPEN

RESULT: END FAULT PROTECTION operated

3) BU-F8720: 0.21A injected with CB OPEN

RESULT: END FAULT PROTECTION operated

4) BU-F8721: 0.21A injected with CB OPEN

RESULT: END FAULT PROTECTION operated

5) BU-F8730: 0.21A injected with CB OPEN

RESULT: END FAULT PROTECTION operated

6) BU-F8740: 0.21A injected with CB OPEN

RESULT: END FAULT PROTECTION operated

7) BU-F8750: 0.21A injected with CB OPEN

RESULT: END FAULT PROTECTION operated

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8) BU-F8760: 0.21A injected with CB OPEN

RESULT: END FAULT PROTECTION operated

9) BU-F8770: 0.21A injected with CB OPEN

RESULT: END FAULT PROTECTION operated

10) BU-F8780: 0.21A injected with CB OPEN

RESULT: END FAULT PROTECTION operated

G) BAY OUT OF SERVICE CHECK:

1) FOR BUS ZONE-1:

A) BU-F8710: Current injected in BU-F8711 with BU-F8710 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F8710 is observed.

B) BU-F8711: Current injected in BU-F8710 with BU-F8711 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F8711 is observed.

C) BU-F8713.A: Current injected in BU-F8710 with BU-F8713.A kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F8713.A is observed.

D) BU-F8720: Current injected in BU-F8710 with BU-F8720 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F8720 is observed.

E) BU-F8721: Current injected in BU-F8710 with BU-F8721 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F8721 is observed.

F) BU-F8730: Current injected in BU-F8710 with BU-F8730 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F87430 is observed.

G) BU-F8740: Current injected in BU-F8710 with BU-F8740 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F8740 is observed.

H) BU-F8750: Current injected in BU-F8710 with BU-F8750 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F8750 is observed.

I) BU-F8760: Current injected in BU-F8710 with BU-F8760 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F8760 is observed.

J) BU-F8770: Current injected in BU-F8710 with BU-F8770 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F8770 is observed.

K) BU-F8780: Current injected in BU-F8710 with BU-F8780 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-1 are tripped but no tripping of BU-F8780 is observed.

2) FOR BUS ZONE-2:

A) BU-F8710: Current injected in BU-F8711 with BU-F8710 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8710 is observed.

B) BU-F8711: Current injected in BU-F8710 with BU-F8711 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8711 is observed.

C) BU-F8713.B: Current injected in BU-F8710 with BU-F8713.B kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8713.B is observed.

D) BU-F8720: Current injected in BU-F8710 with BU-F8720 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8720 is observed.

E) BU-F8721: Current injected in BU-F8710 with BU-F8721 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8721 is observed.

F) BU-F8730: Current injected in BU-F8710 with BU-F8730 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8730 is observed.

G) BU-F8740: Current injected in BU-F8710 with BU-F8740 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8740 is observed.

H) BU-F8750: Current injected in BU-F8710 with BU-F8750 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8750 is observed.

I) BU-F8760: Current injected in BU-F8710 with BU-F8760 kept as "OUT OF SERVICE"

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RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8760 is observed.

H) BU-F8770: Current injected in BU-F8710 with BU-F8770 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8770 is observed.

I) BU-F8780: Current injected in BU-F8710 with BU-F8780 kept as "OUT OF SERVICE"

RESULT: All bays on BUS ZONE-2 are tripped but no tripping of BU-F8780 is observed.

H) BAY UNIT FAIL CHECK:

1) FOR BUS ZONE-1:

A) BU-F8710: FIBRE OPTIC LINK between BU-F8710 and MCU is removed

RESULT: BUS ZONE-1 is blocked

B) BU-F8711: FIBRE OPTIC LINK between BU-F8711 and MCU is removed

RESULT: BUS ZONE-1 is blocked

C) BU-F8713.A: FIBRE OPTIC LINK between BU-F8713.A and MCU is removed

RESULT: BUS ZONE-1 is blocked

D) BU-F8720: FIBRE OPTIC LINK between BU-F8720 and MCU is removed

RESULT: BUS ZONE-1 is blocked

E) BU-F8721: FIBRE OPTIC LINK between BU-F8721 and MCU is removed

RESULT: BUS ZONE-1 is blocked

F) BU-F8730: FIBRE OPTIC LINK between BU-F8730 and MCU is removed

RESULT: BUS ZONE-1 is blocked

G) BU-F8740: FIBRE OPTIC LINK between BU-F8740 and MCU is removed

RESULT: BUS ZONE-1 is blocked

H) BU-F8750: FIBRE OPTIC LINK between BU-F8750 and MCU is removed

RESULT: BUS ZONE-1 is blocked

I) BU-F8760: FIBRE OPTIC LINK between BU-F8760 and MCU is removed

RESULT: BUS ZONE-1 is blocked

J) BU-F8770: FIBRE OPTIC LINK between BU-F8770 and MCU is removed

RESULT: BUS ZONE-1 is blocked

K) BU-F8780: FIBRE OPTIC LINK between BU-F8780 and MCU is removed

RESULT: BUS ZONE-1 is blocked

2) FOR BUS ZONE-2:

A) BU-F8710: FIBRE OPTIC LINK between BU-F8710 and MCU is removed

RESULT: BUS ZONE-2 is blocked

B) BU-F8711: FIBRE OPTIC LINK between BU-F8711 and MCU is removed

RESULT: BUS ZONE-2 is blocked

C) BU-F8713.B: FIBRE OPTIC LINK between BU-F8713.B and MCU is removed

RESULT: BUS ZONE-2 is blocked

D) BU-F8720: FIBRE OPTIC LINK between BU-F8720 and MCU is removed

RESULT: BUS ZONE-2 is blocked

E) BU-F8721: FIBRE OPTIC LINK between BU-F8721 and MCU is removed

RESULT: BUS ZONE-2 is blocked

F) BU-F8730: FIBRE OPTIC LINK between BU-F8730 and MCU is removed

RESULT: BUS ZONE-2 is blocked

G) BU-F8740: FIBRE OPTIC LINK between BU-F8740 and MCU is removed

RESULT: BUS ZONE-2 is blocked

H) BU-F8750: FIBRE OPTIC LINK between BU-F8750 and MCU is removed

RESULT: BUS ZONE-2 is blocked

I) BU-F8760: FIBRE OPTIC LINK between BU-F8760 and MCU is removed

RESULT: BUS ZONE-2 is blocked

J) BU-F8770: FIBRE OPTIC LINK between BU-F8770 and MCU is removed

RESULT: BUS ZONE-2 is blocked

I) BU-F8780: FIBRE OPTIC LINK between BU-F8780 and MCU is removed

RESULT: BUS ZONE-2 is blocked

2) PRIMARY TEST:

A) MEASUREMENT:

Current injected on primary and measured in relay

1) BU-8710:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10

Site acceptance test for BUSBAR DIFFERENTIAL RELAY

PROJECT NAME: 220KV REHABILITATION

Substation: BIYAGAMA

L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

2) BU-8711:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10
L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

3) BU-8713.A:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10
L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

4) BU-8713.B:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10
L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

5) BU-8720:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10
L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

6) BU-8721:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10
L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

7) BU-8730:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10
L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

8) BU-8740:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

9) BU-8750:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10
L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

10) BU-8760:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10
L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

11) BU-8770:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10
L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

Site acceptance test for BUSBAR DIFFERENTIAL RELAY

PROJECT NAME: 220KV REHABILITATION

Substation: BIYAGAMA

12) BU-8780:

Phase	Current applied (A)	Primary current displayed on relay (kA)			
		IL1	IL2	IL3	3I0
L1-E	100.00	0.10	0.00	0.00	0.10
L2-E	100.00	0.00	0.10	0.00	0.10
L3-E	100.00	0.00	0.00	0.10	0.10

B) Checklist before Secondary injection Test:

Checked CT wiring as per scheme	YES
Checked AC wiring as per scheme	YES
Checked DC wiring as per scheme	YES

C) Final Checklist:

BINARY INPUTS	Checked as per Relay Assignment	OK
BINARY OUTPUTS	Checked as per Relay Assignment	OK
CB tripping checked and found		OK
Settings were checked and found		OK
Checked Alarms/Panel indications		YES
Relays found healthy		YES

Date: 03/01/2015	M/S CEB Witnessed by
Tested by: MR. JAYA VENKATESH RAJAN M/S SIEMENS LTD	Eng: MR. JANAKA MUNASINGHE
Signature:	Signature:

Annexure 5

Answers for the clarifications requested by the ministry letter dated 2021-12-27.

Annexure 05

ANSWERS FOR THE CLARIFICATIONS REQUESTED BY THE MINISTRY LETTER DATED 2021-12-27

Explanations on the points highlighted in letter "Investigation into the Power System Failure on 2021-12-03", No. PE/TEC/D/03/06 dated 2021-12-27 by the Secretary to the Ministry of Power are submitted herewith. Before the submission of specific answers for the questions raised by the committee it is relevant to familiar with the developments carried out by CEB with regard to Protection Schemes used in 220 kV Transmission Network.

Relevant Background Information

220 kV Transmission Network of CEB was developed around year 1985 under Mahawali Transmission Development Project. Around year 2000 Protection Branch recommended the rehabilitation of Protection Schemes of 220 kV Transmission Network due to frequent failure of protection relays. Accordingly, 220 kV Protection Development Project was formulated to carry out this work. The initial feasibility study of the project was carried out by the Consultancy Company named PB Power of UK. Thereafter CEB received a soft loan from KfW Bank of Germany and Consultancy company named Fitchner GmbH of Germany was appointed as consultant of 220 kV Protection Development Project. The key tasks assigned to consultant were as follows.

- Preparation of Tender Specifications, basic design and Protection Setting Guideline.
- Reviewing of detail design proposed by the Contractor and Protection Relay Settings Proposed by the contractor.
- Supervision of installation, commissioning and testing of Protection Relays and Schemes.

After competitive bidding process Siemens Ltd. of India was selected as successful contractor to carry out the 220 kV Protection Development Project and all main Protection Relays were supplied by Siemens AG of Germany.

Thus, the Protection Scheme of Biyagama – Kothmale Line 1 and 2 was designed, commissioned and tested by Siemens Ltd. one of the leading Protection Relay suppliers in the world. Further the protection scheme design and Protection Relay Setting Proposal submitted by Siemens for Biyagama – Kothmale Line were reviewed by consultant Fitchner, one of the leading consultancy companies in the world.

1. *The actual cause of tripping of Kothmale - Biyagama 220 kV Line 02 on December 03, 2021, with proper technical basis and physical evidence.*

Kothmale – Biyagama line 2 has tripped due to the occurrence of C phase to Earth fault (magnitude 520 A) in transmission line and/or connected primary equipment i.e. CT, VT. Lightning Arrester etc. This fault current has been recorded in Main 1, Main 2 relays and the BEN6000 Digital disturbance recorder. The recorded waveforms from these equipment are shown below:

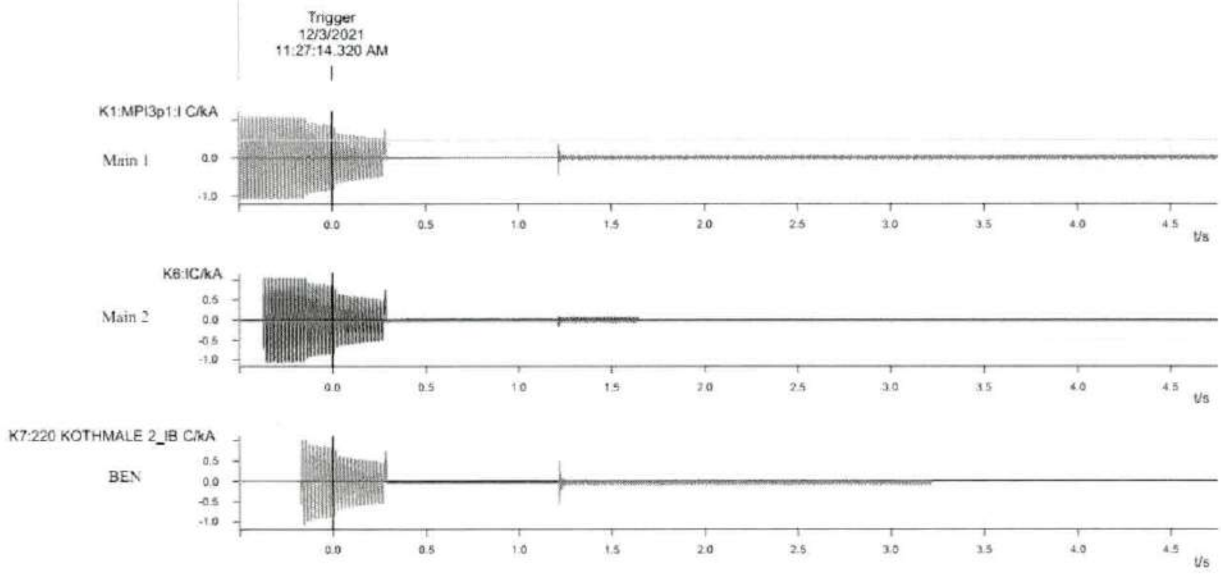

Figure 01: Current waveforms seen by Main 1 relay, Main 2 relay and DDR at Biyagama GSS – Kothmale line 2 B phase

A differential current above 400A will instantaneously trigger a tripping of the circuit breakers of both ends of the line.

Accordingly, there is sufficient information from secondary equipment to decide that there has been a fault in the primary equipment. This has to be verified by the relevant staff responsible for maintenance of primary equipment eg. staff of O&MS branch.

2. *The reason for operation of End Fault Protection while the line has undergone what is believed to be a single line to earth fault and the faulty line was already isolated from the network.*

The function of the end fault protection is to protect the zone between the current transformer and the circuit breaker when the circuit breaker is open. With line-side current transformers, the end fault protection helps to avoid an overfunction of the busbar protection if the local Circuit Breaker remained open before the fault occurred. In the absence of end fault protection such faults would only be cleared with a distance-dependent time offset by the remote end (i.e. with zone 2 time delay). If a current flow is detected when circuit breaker is open, end fault protection operates and with the available teleprotection scheme, it will issue a transfer trip command to the circuit breaker at the remote end.

During the incident on 2021-12-03, phase C – Earth fault has occurred in Biyagama – Kothmale line 02 resulting in single pole tripping of Circuit Breaker. However the circuit breaker open status input signal has been incorrectly received as all 3 poles are open and since two phases are still conducting, end fault protection has operated and a direct inter trip has been sent to the Kothmale end resulting in permanent tripping of the circuit breaker at that end. As per the schematic drawings circuit breaker open status to busbar protection panel is taken from the control panel. A series of Normally Closed contacts are used to detect opening of all three phases in the Central cubicle box of the Circuit Breaker. (Ref. figure 01) According to the schematics, Circuit Breaker open status shall be received only when all three phases are open. However due to an error in field wiring Circuit Breaker status was received incorrectly to the control panel. This has been identified and rectified on 2021-12-26 (Kothmale line 01) and on 2022-01-02 (Kothmale Line 02) respectively.

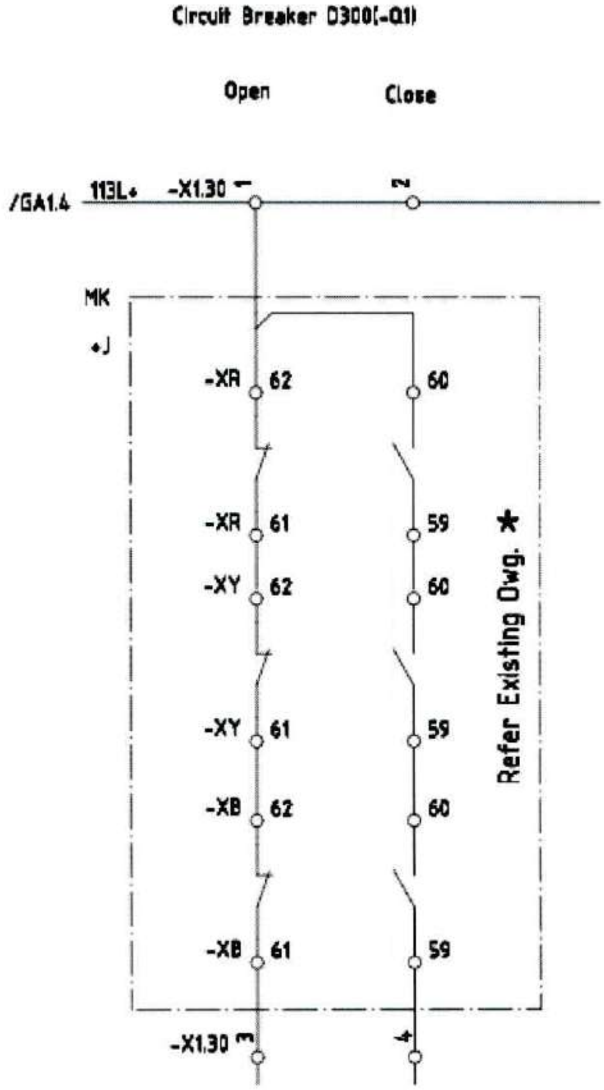

Figure 02: Circuit Breaker open status taken to the control panel from the central cubicle box of the Circuit Breaker

3. *Explain the reason for tripping of Kothmale-Biyagama 220 kV Line 01 on December 03,2021, after Line 02 had been isolated from both ends, with credible supporting data, and scientific justifications.*

Biyagama – Kothmale line 01 has tripped due to the operation of non directional earth fault protection as per the relay event log after 22s of initial pickup. Relay has picked up with the tripping of C phase of parallel line and remained picked up due to the presence of continuous zero sequence current which is around 80A.

According to the past records of the protection relays, a persistent zero sequence current is observed in both Kothmale Biyagama line 01 and 02. But the value of the zero sequence current of the Kothmale Biyagama line 01 is almost double the value of line 02. Same can be seen by monitoring the relay current measurements when line is on load without a fault as well. The value of this zero sequence current is proportional to the phase currents. With the tripping of Biyagama – Kothmale line 02, the load current in line 01 increased up to 1500A, resulting in increase of residual zero sequence current. Additionally the dropout characteristic has been set according to characteristic curve (disk emulation) with drop off at 0.9 of the set threshold (0.9 x 80A) and pickup at 1.1 times. (1.1 x 80A). The presence of such zero sequence currents could be due to line asymmetry which can cause ground directional elements to mal operate as per the research information available online. (Refer attached research document on [attached as Attachment 01 at the end of Annexure 05] Limits to the Sensitivity of Ground Directional and Distance Protection by Jeff Roberts and Edmund O. Schweitzer, III of Schweitzer Engineering Laboratories, Inc. and Renu Arora and Ernie Poggi of Public Service Company of Colorado)

The presence of this sustaining zero sequence current was further confirmed after the re calibration of the Ben 6000 digital disturbance recorder. To avoid possible recurrence of the operation of non directional IDMT earthfault protection, pickup setting was increased up to 160A, which is more than 10% of the maximum load current.

4. *Explain why the end fault Protection scheme was implemented without necessary safeguards, knowing that a single-line-to-earth fault may trip the entire line with lockout, even if the fault is cleared. Explain also whether this situation had prevailed since the initial installation of 220 kV protection in 2014 and if that was the case, the reason for not having experienced similar tripping in the past, given that single-line-to-earth faults are among the most common line faults.*

End fault protection is part of all the modern numerical busbar protection schemes. Busbar protection scheme at Biyagama Grid Substation was rehabilitated under the 220kV Protection Development Project. In the technical specification of the contract, under clause 5.12 Busbar Protection, requirement of end fault protection has been specified:

"In order to protect the dead zone between the circuit breaker and the associated current transformer, the bus bar protection should include an end fault protection."

Protection experts of Fichtner, the reputed German consultant of the project, reviewed the specification and the submitted technical design by the successful bidder, Siemens Ltd. Siemens 7SS52 numerical Bus bar protection scheme is an internationally reputed product. As per the approved design similar maloperation would not have occurred, if the circuit breaker status is received correctly during single phase operation. Site Acceptance Commissioning Test sheets of the project confirm that all required testing has been successfully carried out and the new Busbar protection scheme has been commissioned in January 2015. Inspection of field wiring in Kothmale line 1 and 2 has confirmed that the connections made in the central cubicle box of the circuit breaker are not as per the drawing. Similar errors were not present in other 220kV line bays inspected as per the availability of line interruptions. It was observed that the circuit breakers of Kothmale line 1 & 2 have been replaced after the commissioning of 220kV Busbar Protection scheme in Biyagama GSS. The error identified in the circuit breaker wiring has now been rectified.

During the period 2015-2021, there has been 13 incidents of tripping of at least one of the Kothmale – Biyagama lines, except for incidents on 2021-11-29 and 2021-12-03. Out of the 13 incidents, 10 incidents are due to actual line faults. Out of which in 5 instances, both sides have reclosed successfully.In four other instances, phase – phase faults have resulted in three phase tripping of the line, in which similar end fault protection scenario cannot be anticipated. Only in one instance single phase fault has tripped Biyagama Kothmale line 2 definitively. Even at that instance the parallel line, Biyagama Kothmale line 1 has reclosed from both ends simultaneously for a single phase fault in Y phase.

It is observed that the erroneous connections of Circuit Breaker in Kothmale Line 01 affect only for single phase faults in Phase R. Additionally the threshold value for detection of End fault protection is set at 500A. If the load currents in healthy phases are less than 500A, end fault protection will not be activated. These factors make the probability of occurrence of similar faults significantly low.

5. *Establish the reason for the operation of the backup Earth Fault relay after a substantially long duration of 22.33 seconds, despite the neutral current having become zero after 288ms from the pickup. Explain why primary protection such as differential protection implemented on the Kothmale-Biyagama 220kV line 1 was not activated but earth fault protection, which is a backup protection scheme, forced the shutdown of the line.*

Please refer the clarification for the point no. 03 above. In IEC normal inverse curve, the operation time is longer when the fault current is closer to the pickup setting. In Main 1 relay of Biyagama line 1 at Kothmale PS, setting values of non directional earth fault are 80A pickup and the time dial is 0.38sec. According tothe inverse time characteristic for a fault current of 90A, it will take 22.56 seconds for the relay to operate.. In this instance, initially non directional earthfault was picked up due to the neutral current (approximately 500A) occurred due to the tripping of R phase, which lasted for 288ms. Subsequently the zero sequence current does not drop below the drop off value (72A) until the tripping of the line after 22.33 seconds.

Inverse-T 1 \General		
Number	Settings	Value
21.211.781.1	Mode	Settings group 1: on
21.211.781.2	Operate & flt.rec. blocked	Settings group 1: no
21.211.781.26	Dynamic settings	All: no
21.211.781.8	Method of measurement	Settings group 1: fundamental comp.
21.211.781.3	Threshold	Settings group 1: 0.04 A
21.211.781.108	Type of character. curve	Settings group 1: IEC normal inverse
21.211.781.109	Reset	Settings group 1: disk emulation
21.211.781.101	Time dial	Settings group 1: 0.38

Figure 03: Non directional earth fault settings of Main 01 relay at Biyagama line 1 at Kothmale PS

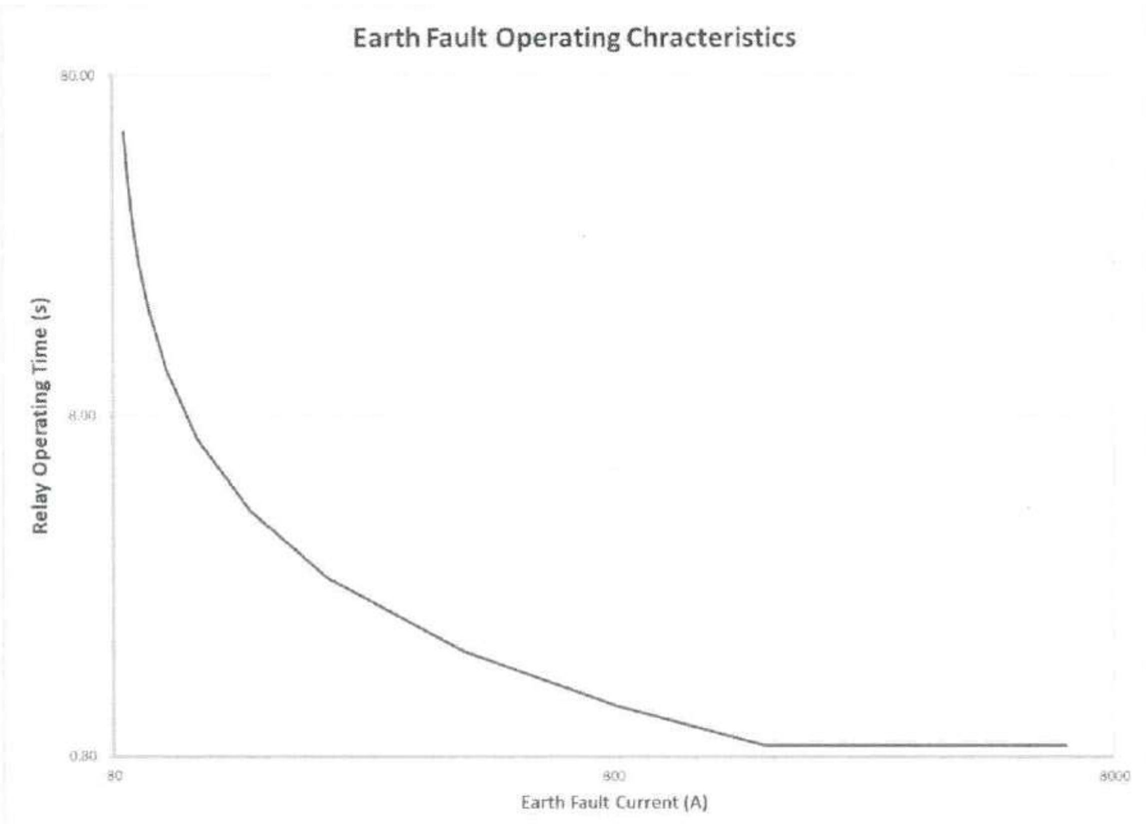

Figure 04: Operating characteristic of the Non directional earth fault protection function of Main 01 relay at Biyagama line 1 at Kothmale PS

"*despite the neutral current having become zero after 288ms from the pickup.*" – This is an incorrect statement since the neutral current of line 01 did not become zero until it trips. In the mutual line compensation wiring available in these two circuits, neutral of the parallel circuit is wired to the protection relay. Neutral current shown in Main 01 relay of line 01 is the neutral current of the line 02 which has tripped approx.. in 288ms. This could have lead to the above misleading statement.

A minimum fault current of approx.. 400A is required for line differential protection to pickup. And the distance protection will not pick up for high impedance faults (small zero sequence currents).

6. *Provide the records on access to relays and explain why such information is missing or incomplete*

All available information has been submitted to the committee including relay setting change logs, which cannot be deleted, via email and during the visit to the Kothmale PS. All the information submitted to the committee is included in the attached DVD. Alternatively these information can be downloaded from the following link: https://tinyurl.com/3aznrvzx

Main 1 relays of both ends of Biyagama – Kothmale Line 2 and Main 1 relay of Biyagama Line 01 at Kothmale end has operated during the incident on 2021-12-03. All logs are available in the submitted complete setting files of the relays. Screen shots of setting change logs of all three main 1 relays are provided below for additional information. As per the setting change logs, these relays have not been accessed to make any setting or configuration changes since 2020.12.06 (Main 1 of Biyagama Line 1 of Kothmale PS), 2019.11.20 (Main 1 of Biyagama Line 2 of Kothmale PS) and 2021-04-27 (Main 1 of Kothmale Line 2 of Biyagama PS).

However Engineers, Engineering Assistants and Electrical Superintendants of the Control & Protection Branch are authorized to access protection IEDs to download disturbance records and event logs after a failure incident to analyze the tripping. Accordingly Engineers and Electrical Superintendants of C&P branch have accessed these relays after the incident on 2021-12-29, to download failure data of that incident, which does not affect the settings or the configuration of the device in anyway.

Following is an extract from the relay manual of Siemens 7SL87 (Relay which operated in this incident) regarding the available logs:

System Functions
3.1 Indications

NOTE

Not all logs of your SIPROTEC 5 device can be deleted. These limitations apply especially to logs with relevance for security and after-sales (security log, device-diagnosis log, setting-history log).

Figure 05: Extract from the relay manual of Siemens 7SL87 regarding the available logs. (Page 83)

Following are the screenshots of the Setting History logs of relays of Biyagama – Kothmale lines which operated during the incident on 2021-12-03.

Biyagama Line 1_V16 ▸ D70_BIYAGAMA OHL#1 ▸ Process data ▸ Logs ▸ Setting-history log

Read log entries | Delete | CSV | Show values as: primary

Time stamp	Relative time	Entry number	Functions structure	Name
		(All)	(All)	(All)
03.12.2021 19:27:39.010 (3)			Setting-history log	
06.12.2020 11:23:15.451	381:19:44:37.954	3	General	Act. settings group 1
20.11.2019 15:38:37.497	00:00:00:00.000	2	General	Act. settings group 1
20.11.2019 15:38:37.497	00:00:00:00.000	1	General	DCF uploaded

Figure 06: Kothmale PS Biyagama Line 1 Main 1 Setting Change Log

Biyagama Line 2_V16 ▸ D80_BIYAGAMA OHL #2 ▸ Process data ▸ Logs ▸ Setting-history log

Read log entries | Delete | CSV | A | Show values as: primary

Time stamp	Relative time	Entry number	Functions structure	Name
		(All)	(All)	(All)
03.12.2021 19:38:24.748 (6)			Setting-history log	
20.11.2019 15:44:24.507	00:04:38:48.050	6	General	Act. settings group 1
20.11.2019 15:44:24.492	00:04:38:48.035	5	General	DCF uploaded
20.11.2019 11:11:46.492	00:00:06:10.035	4	General	Act. settings group 1
20.11.2019 11:11:46.482	00:00:06:10.025	3	General	DCF uploaded
20.11.2019 11:05:36.472	00:00:00:00.015	2	General	Act. settings group 1
20.11.2019 11:05:36.457	00:00:00:00.000	1	General	DCF uploaded

Figure 07: Kothmale PS Biyagama Line 2 Main 1 Setting Change Log

Kotmale Line 2_V16 ▸ D30_F871 ▸ Process data ▸ Logs ▸ Setting-history log

Read log entries · Delete · CSV · Show values as: primary

Time stamp	Relative time	Entry number	Functions structure
		(All)	(All)
03.12.2021 20:42:28.594 (45)			Setting-history log
27.04.2021 15:46:31.578	2140:14:34:27.014	45	General
27.04.2021 15:29:23.708	2140:14:17:19.144	44	General
29.05.2020 12:20:54.045	1807:11:08:49.481	43	General
23.01.2020 19:03:01.115	1680:17:50:56.551	42	General
27.12.2019 13:23:55.030	1653:12:11:50.466	41	General
22.05.2019 16:05:28.547	1434:14:53:23.983	40	General
16.01.2018 16:10:30.070	943:14:58:25.506	39	General
24.12.2017 12:33:18.076	920:11:21:13.512	38	General
24.12.2017 12:30:35.306	920:11:18:30.742	37	General
30.05.2017 11:45:20.532	712:10:33:15.968	36	General
26.05.2017 14:47:53.614	708:13:35:49.050	35	General
25.05.2017 12:28:27.724	707:11:16:23.160	34	General
25.05.2017 10:29:39.673	707:09:17:35.109	33	General
25.05.2017 10:11:13.794	707:08:59:09.230	32	General
31.05.2016 00:06:22.322	347:22:54:17.758	31	General
05.10.2015 02:40:58.598	109:01:28:54.034	30	-
05.10.2015 02:40:51.854	109:01:28:47.290	29	Line 1:Weak infeed:Weak infeed
05.10.2015 02:40:49.769	109:01:28:45.205	28	-
05.10.2015 02:39:40.204	109:01:27:35.640	27	General
20.09.2015 10:34:53.054	94:09:22:48.490	26	General
08.09.2015 23:21:23.402	82:22:09:18.838	25	General
21.08.2015 12:39:56.554	64:11:27:51.990	24	General
10.07.2015 13:06:54.010	22:11:54:49.446	23	-
10.07.2015 13:06:45.544	22:11:54:40.980	22	Line 1:21 Distance prot. 1:General
10.07.2015 13:06:34.444	22:11:54:29.880	21	Line 1:Fault locator
10.07.2015 13:06:24.773	22:11:54:20.209	20	Line 1:General
10.07.2015 13:06:19.679	22:11:54:15.115	19	Line 1:General
10.07.2015 13:06:15.831	22:11:54:11.267	18	-
03.07.2015 01:43:42.065	15:00:31:37.501	17	General
18.06.2015 02:31:01.270	00:01:18:56.706	16	General
18.06.2015 02:31:01.270	00:01:18:56.706	15	General
18.06.2015 02:06:11.160	00:00:54:06.596	14	General
18.06.2015 02:06:11.160	00:00:54:06.596	13	General
18.06.2015 01:59:35.279	00:00:47:30.715	12	-
18.06.2015 01:59:26.165	00:00:47:21.601	11	Line 1:85-21Perm.underr.:85-21Perm.unde
18.06.2015 01:59:12.173	00:00:47:07.609	10	Line 1:85-67N Dir. comp.:85-67N Dir.com
18.06.2015 01:59:09.743	00:00:47:05.179	9	-
18.06.2015 01:57:23.774	00:00:45:19.210	8	-
18.06.2015 01:57:13.151	00:00:45:08.587	7	Line 1:21 Distance prot. 1:Z 1
18.06.2015 01:57:00.061	00:00:44:55.497	6	Line 1:87 Line diff. prot.:General
18.06.2015 01:56:58.960	00:00:44:54.396	5	-

Figure 08: Biyagama - Kothmale Line 2 Main 1 Setting Change Log

Accordingly, it can be concluded with certainty that there have not been any changes in settings or configuration by unauthorized access to these relays.

Attachment 01

Limits to the Sensitivity of Ground Directional and Distance Protection by Jeff Roberts and Edmund O. Schweitzer, III of Schweitzer Engineering Laboratories, Inc. and Renu Arora and Ernie Poggi of Public Service Company of Colorado)

Limits to the Sensitivity of Ground Directional and Distance Protection

Jeff Roberts and Edmund O. Schweitzer, III
Schweitzer Engineering Laboratories, Inc.

Renu Arora and Ernie Poggi
Public Service Company of Colorado

Presented at the
Spring Meeting of the Pennsylvania Electric Association Relay Committee
Allentown, Pennsylvania
May 15–16, 1997

Previously presented at the
Southern African Conference on Power System Protection, November 1996,
11th Annual Conference on Electric Power Supply Industry, October 1996,
50th Annual Georgia Tech Protective Relaying Conference, May 1996,
and 49th Annual Conference for Protective Relay Engineers, April 1996

Originally presented at the
22nd Annual Western Protective Relay Conference, October 1995

LIMITS TO THE SENSITIVITY OF GROUND DIRECTIONAL AND DISTANCE PROTECTION

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INTRODUCTION

Relay designers have used analog and digital electronic technology to advance the sensitivity of protective relays while simultaneously decreasing instrument transformer burden. Today, sensitivity is generally not limited by the relays, but instead is limited by the rest of the system: system unbalance, instrument transformer accuracy and ratings, grounding practices, and source strengths.

This paper identifies these limits, analyzes them, and offers practical solutions. Some surprises in this paper include: line asymmetry can cause ground directional elements to misoperate, directional element sensitivity can be worse than the supervised overcurrent element setting, and just how much fault resistance (R_F) is really covered by various ground directional elements.

This paper evaluates sensitivity limits in the following sections:

- Ground directional element sensitivities: How much R_F coverage do various directional elements provide, and how do we calculate this resistance?
- Ground distance element sensitivities: How much R_F coverage do ground distance elements provide?
- Instrument transformers and their connections: How do voltage and current transformer magnitude and phase angle errors and saturation affect R_F coverage?
- Line asymmetry: How do untransposed lines and three-phase faults affect ground directional element fault resistance coverage?

Finally, we discuss practical field checks to determine if factors identified in this paper affect your protection scheme sensitivity and security.

DIRECTIONAL ELEMENT SENSITIVITIES

The sensitivity of a protective system might be expressed by maximum fault resistance coverage.

The sensitivities of individual relay elements depend on voltampere limits, voltage thresholds, and current thresholds. In this section, we discuss directional relay sensitivities and how different combinations of relays with differing sensitivities affect the sensitivity of the complete protective system.

Torque Limits are Frequently Expressed in Voltamperes

In an electromechanical directional element, the sensitivity is often expressed in terms of minimum voltamperes.

Microprocessor relays do not produce physical torque, but instead they frequently calculate a torque-like quantity. The magnitude of this torque-like quantity must cross a minimum threshold before the directional declaration is considered valid. This is analogous to the electromechanical implementation when the operating torque must overcome the restraint of a spring.

Reference [1] discusses many directional elements, their minimum thresholds, and security issues associated with each element. Table 1 is repeated from [1] and shows the inputs to a traditional negative-sequence directional element, and (1) shows the torque expression.

Table 1: Inputs to a Traditional Negative-Sequence Directional Element

Operating Quantity (I_{op})	Polarizing Quantity (V_{pol})
$I_{A2} \cdot (1 \angle Z_{L2})$	$-V_{A2}$

$$T32Q = |V_{A2}| \cdot |I_{A2}| \cdot \cos[\angle -V_{A2} - (\angle I_{A2} + \angle Z_{L2})] \quad (1)$$

where

V_{A2} = Negative-sequence voltage measured by the relay
I_{A2} = Negative-sequence current measured by the relay
Z_{L2} = Negative-sequence replica line impedance

T32Q is positive for forward faults and negative for reverse faults. The magnitude of T32Q must exceed a minimum torque threshold before the directional element is considered valid. This is an intentional security measure in microprocessor relays to avoid making erroneous directional decisions when the magnitude of the operating or polarizing quantity becomes too small to be a reliable measure of direction.

Voltage and Current Thresholds

The general equation for directional element torque can be expressed as $|V| \cdot |I| \cdot \cos(\Theta)$, where one example of Θ is shown in (1). Rather than require a minimum torque threshold, you could simply require a minimum $|V|$ and/or a minimum $|I|$ before considering a directional element decision as valid. If this method of security is selected, these thresholds must be selected very carefully. If the minimum $|V|$ is too high, it severely limits the directional element R_F coverage and makes the directional element useless near strong sources. On the other hand, requiring a minimum current magnitude is a very practical, efficient, and secure method of controlling directional element security.

Examples of Relay Sensitivities

Table 2 lists several published directional element sensitivities.

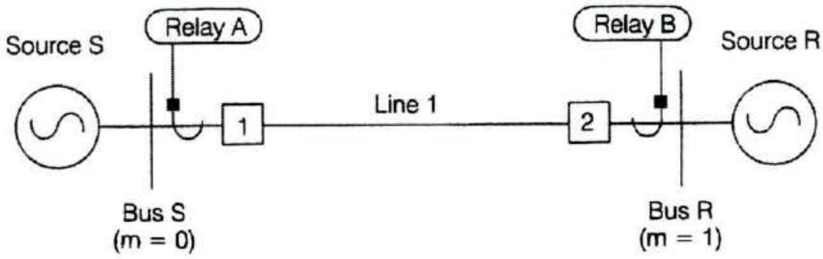
Table 2: Ground Directional Relay Sensitivities Depend on Torque, Impedance, Voltage and/or Current Limits

Directional Element	Directional Element Type	Minimum Torque or Impedance	Minimum V or I
1. SEL-321	Zero-Seq. Z (patent pending, see Appendix A)	Settable: ±64 Ω	$3 \cdot I_{A0} = 0.25$ A and $\lvert I_{A0} \rvert / \lvert I_{A1} \rvert > 0.02 - 0.5$
2. SEL-321	Neg.-Seq. Z (patented)	Settable: ±64 Ω	$3 \cdot I_{A2} = 0.25$ A and $\lvert I_{A2} \rvert / \lvert I_{A1} \rvert > 0.02 - 0.5$
3. SEL-221G/H	Zero-Seq. V	0.145 VA[1]	Pickup of 51N, 50N1 - 50N3
4. SEL-221G/H	Dual Zero-Seq.	0.145 Net Torque [VA or A^2][1]	"
5. SEL-221G/H	Zero-Seq. I	0.22 [A^2][1]	"
6. SEL-221G/H	Neg.-Seq.	0.1 VA	"
7. IRC	Zero-Seq. I	0.25 A^2	$3 \cdot I_{A0} = 0.5$ A
8. IRP	Zero-Seq. V	2 VA	$3 \cdot V_{A0} = 1$ V $3 \cdot I_{A0} = 2$ A
9. Brand X	Neg.-Seq.	0.175 VA	$V_{A2} = 1$ V $I_{A2} = 0.167$ A

Magnitude depends on ground time-overcurrent element pickup threshold. Throughout this paper, the pickup of this threshold is assumed to be 0.5 A secondary.

Directional Element Sensitivities Affect Fault Resistance Coverage

To convert directional element sensitivities into fault resistance (R_F) coverage, we must first assume a system. Consider pairs of directional elements from Table 2, applied to the 90°system of Figure 1.



Source S: $Z_{S1} = 2\ \Omega$, $Z_{S0} = 6\ \Omega$ Line 1: $Z_{L1} = 2.5\ \Omega$, $Z_{L0} = 7.5\ \Omega$ Source R: $Z_{R1} = 1\ \Omega$, $Z_{R0} = 3\ \Omega$

Figure 1: Directional Element R_F Limitation Example System Single-Line Diagram

We can perform some quick calculations, without much loss of accuracy, by realizing that R_F is much greater than that of the protected line.

Directional Element 9, AG Fault Near Bus S

This directional element requires $|V_{A2}| \geq 1$ V and $|I_{A2}| \geq 0.167$ A. Given the simplifying assumption listed above, first consider $|V_{A2}|$ at Relay A.

$$V_{A2,RELAY} = 1\ \text{V}$$

$$Z_{2EQ} \cdot I_{A2} \qquad \text{(where } Z_{2EQ} = (2\ \Omega \,\|\, (2.5 + 1)\ \Omega) = 1.27\ \Omega\text{)}$$

$$1.27\ \Omega \cdot \frac{V_A}{3 \cdot R_F}$$

$$1.27\ \Omega \cdot \frac{66.4\ \text{V}}{3 \cdot R_F}$$

Solving for R_F:

$$R_F = 28.18\ \Omega$$

These simple calculations show $|V_{A2,RELAY}| = 1$ V limits the R_F coverage to 28.18 Ω. What is $|I_{A2,RELAY}|$ measured at Relay A for $R_F = 28.18\ \Omega$?

$$I_{A2,RELAY} = \frac{66.4\ \text{V}}{3 \cdot R_F} \cdot C_{12} \qquad \text{(where } C_{12} \text{ is the current distribution factor} = \frac{(2.5+1)\ \Omega}{(2+2.5+1)\ \Omega} = 0.64\text{)}$$

$$\frac{66.4\ \text{V}}{3 \cdot 28.18\ \Omega} \cdot 0.64$$

$$0.5\ \text{A}$$

Since $|I_{A2,RELAY}|$ is three times the minimum I required, we see that $|V_{A2}| \geq 1$ V limits R_F coverage for this case.

Assuming that $|I_{A0,RELAY}|$ approximately equals $|I_{A2,RELAY}|$ at Relay A, setting a directionally-controlled ground overcurrent element below 1.5 A does not improve R_F coverage for this fault. We still must consider remote terminal faults. Setting the pickup of these ground overcurrent elements below the sensitivity of the directional element is an unnecessary security liability, especially for untransposed line applications.

Directional Element 6, AG Fault Near Bus S

This directional element requires that the negative-sequence directional element torque (T32Q) exceed 0.1 VA for forward faults.

$$\begin{aligned}
T32Q &= 0.1\ \text{VA} \\
&= V_{A2} \cdot (I_{A2} \cdot 0.64) \\
&= (I_{A2} \cdot Z_{2EQ}) \cdot (I_{A2} \cdot 0.64) \\
&= \left(\frac{66.4\ \text{V}}{} \cdot 1.27\ \Omega\right) \cdot \left(\frac{66.4\ \text{V}}{3 \cdot R_F} \cdot 0.64\right)
\end{aligned}$$

Solving for R_F:

$$R_F = 63.18\ \Omega$$

What is $|I_{A2,RELAY}|$ at Relay A for $R_F = 63.18\ \Omega$?

$$\begin{aligned}
I_{A2,RELAY} &= \frac{66.4\ \text{V}}{3 \cdot 63.18\ \Omega} \cdot 0.64 \\
&= 0.22\ \text{A}
\end{aligned}$$

Setting the pickup of a directionally-controlled ground overcurrent element less than 0.66 A does not improve R_F coverage for this fault.

Directional Element 6 has more than twice the R_F coverage as Directional Element 9.

What are the R_F limitations if the AG fault is near Bus R?

Directional Element 9, AG Fault Near Bus R

Following the same steps:

$$\begin{aligned}
V_{A2,RELAY} &= 1\ \text{V} \\
&= (Z_{2EQ} \cdot I_{A2}) \cdot C_{V2}
\end{aligned}$$

(C_{V2}, the voltage divider ratio $= \frac{2\ \Omega}{(2+2.5)\ \Omega} = 0.44$, and $Z_{2EQ} = (2 + 2.5)\ \Omega \parallel 1\ \Omega) = 0.82\ \Omega$)

$$= \left(0.82\ \Omega \cdot \frac{66.4\ \text{V}}{3 \cdot R_R}\right) \cdot 0.44$$

Solving for R_F:

$$R_F = 8\,\Omega$$

What is $|I_{A2,RELAY}|$ at Relay A for $R_F = 8\,\Omega$?

$$I_{A2,RELAY} = \frac{66.4\text{ V}}{3 \cdot R_F} \cdot C_{I2}$$

(C_{I2} is the current distribution factor = $\left(\frac{1\Omega}{(2+2.5+1)\,\Omega}\right) = 0.18$)

$$= \frac{66.4\text{ V}}{3 \cdot 8\,\Omega} \cdot 0.18$$

$$= 0.5\text{ A}$$

Again, we see that $|V_{A2}| \geq 1$ V limits the R_F coverage. For Directional Element 9 in this application, setting a directionally-controlled ground overcurrent element below 1.5 A does not improve R_F coverage for ground faults anywhere along the line.

Directional Element 6, AG Fault Near Bus R

$$\begin{aligned}
T32Q &= 0.1\text{ VA} \\
&= (V_{A2} \cdot C_{V2}) \cdot (I_{A2} \cdot C_{I2}) \\
&= (I_{A2} \cdot Z_{2EQ} \cdot 0.44) \cdot (I_{A2} \cdot 0.18) \\
&= \left(\frac{66.4\text{ V}}{3 \cdot R_F} \cdot 0.82 \cdot 0.44\right) \cdot \left(\frac{66.4\text{ V}}{3 \cdot R_F} \cdot 0.18\right)
\end{aligned}$$

Solving for R_F:

$$R_F = 17.8\,\Omega$$

What is $|I_{A2,RELAY}|$ at Relay A for $R_F = 17.8\,\Omega$?

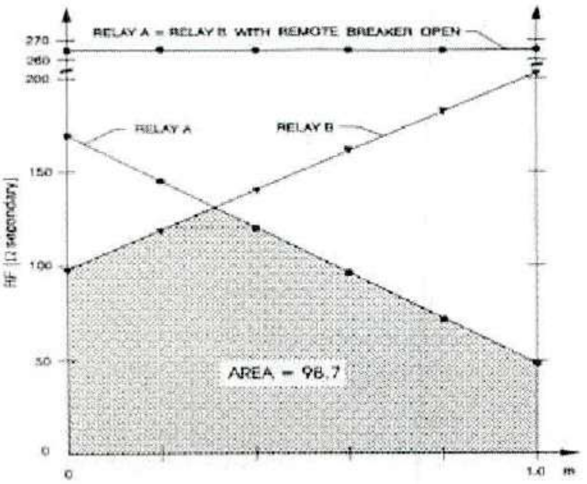
$$I_{A2,RELAY} = \frac{66.4\text{ V}}{3 \cdot 17.8\,\Omega} \cdot 0.18$$

$$= 0.22\text{ A}$$

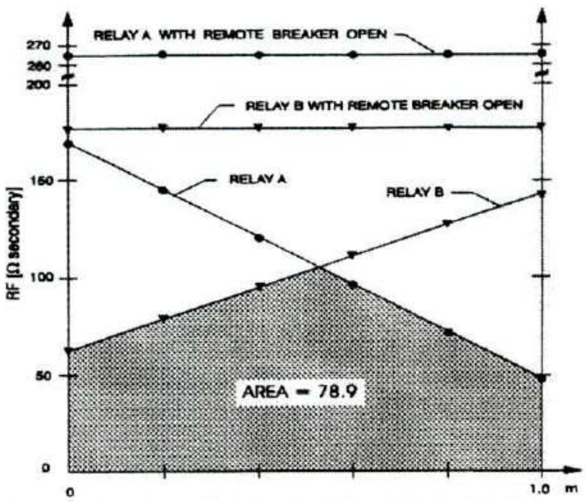
For Directional Element 6, setting the pickup of the directionally-controlled residual overcurrent element below 0.66 A does not improve R_F coverage.

We expect directional elements are installed at both ends of a two-terminal line in a looped or networked system. What is the R_F coverage of the protection system if the same or different directional elements are used in the protective relays at either line end?

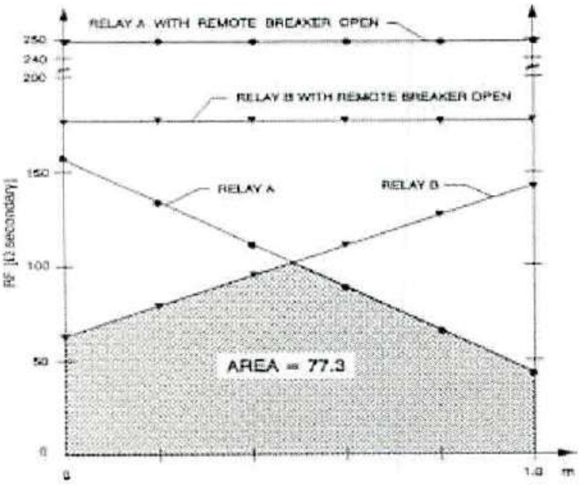
Figure 2 shows the R_F coverage for various combinations of the directional elements of Table 2 for ground faults along the line shown in Figure 1. The graphs in this figure are arranged from highest to lowest in terms of the complete protection system R_F coverage.



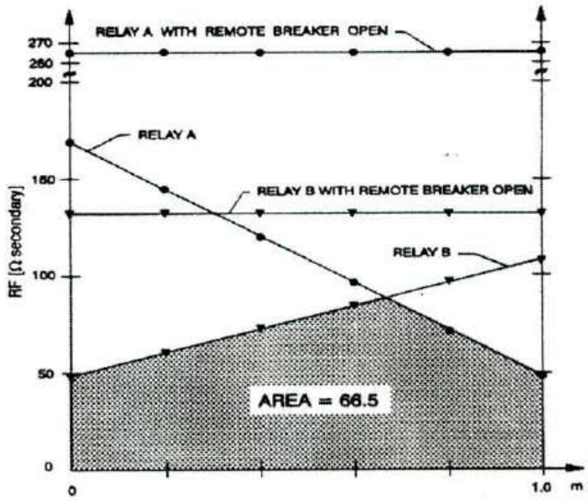
2a: Relay A = Relay B = 321



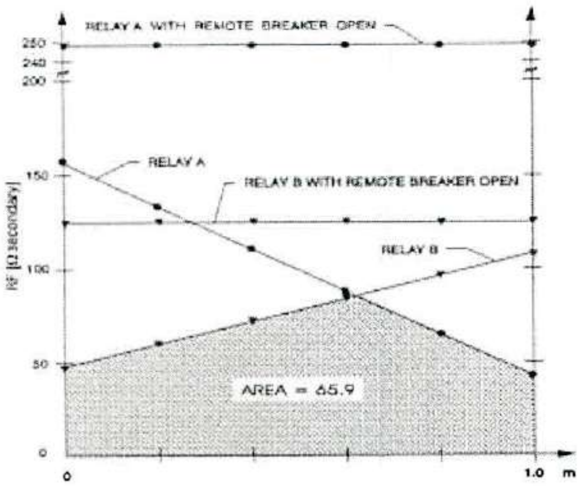
2b: Relay A = 321, Relay B = T32V 221H



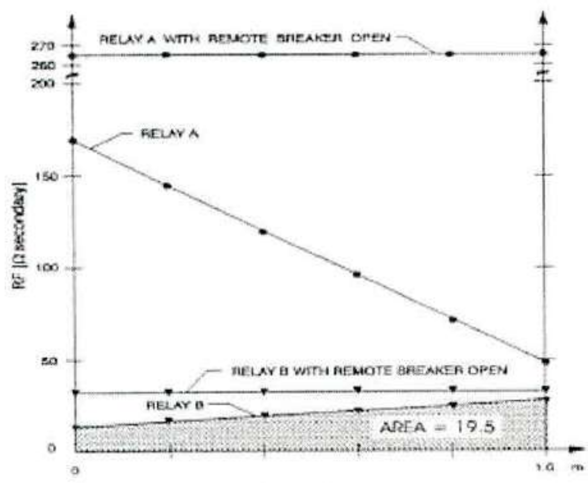
2c: Relay A = Relay B = 221H w/T32V



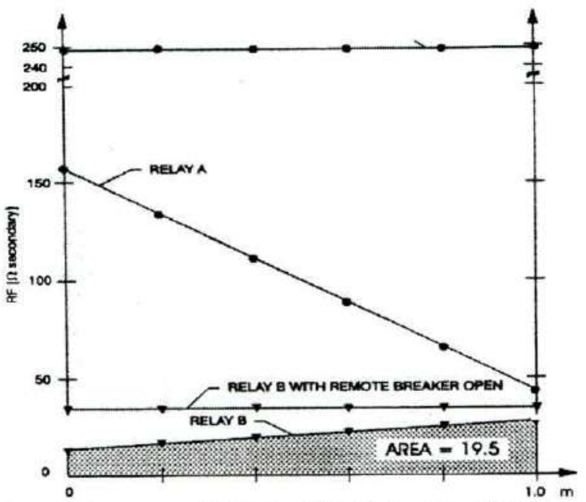
2d: Relay A = 321, Relay B = IRC



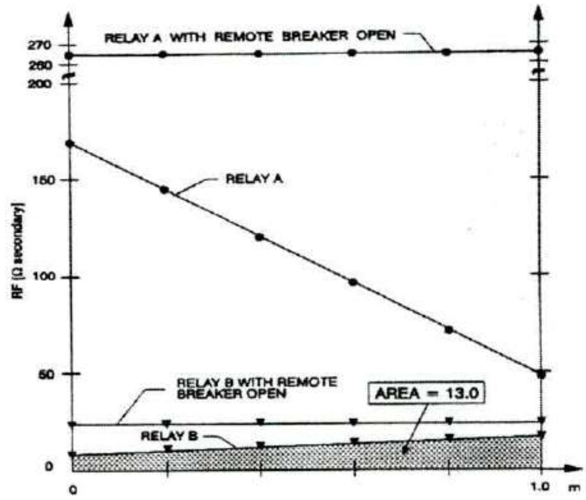
2e: Relay A = T32V 221H, Relay B = IRC



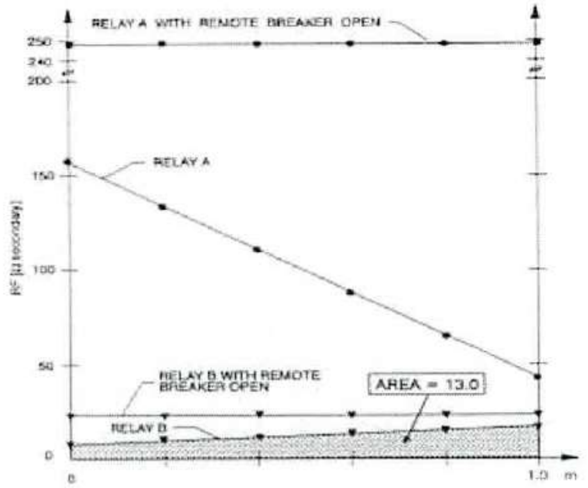
2f: Relay A = 321, Relay B = IRP



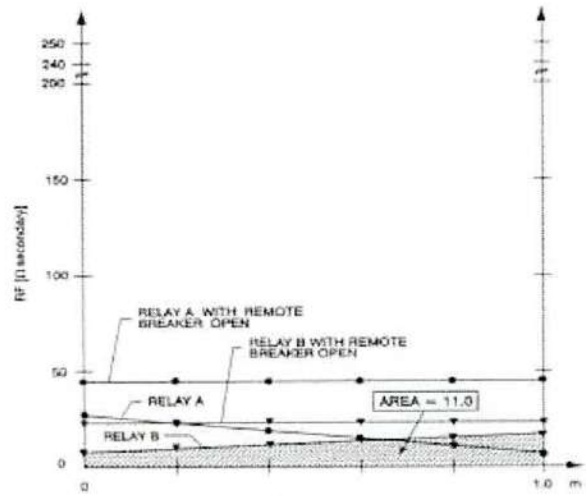
2g: Relay A = T32V 221H, Relay B = IRP



2h: Relay A = 321, Relay B = X



2i: Relay A = T32V 221H, Relay B = X



2j: Relay A = Relay B = X

Figure 2a - 2j: R_F Coverage Limitations Depend on Directional Element Sensitivity

The graphs in Figure 2 show clear differences in R_F coverage for various directional elements. Those relays with higher R_F coverage increase the dependability of the protection at that terminal. If the combination of relays improves R_F coverage (as indicated by a larger shaded area on the graphs), then the protection scheme dependability is increased. Figure 3 shows the area of the polygon formed by the R_F coverage curves for each pair of directional elements.

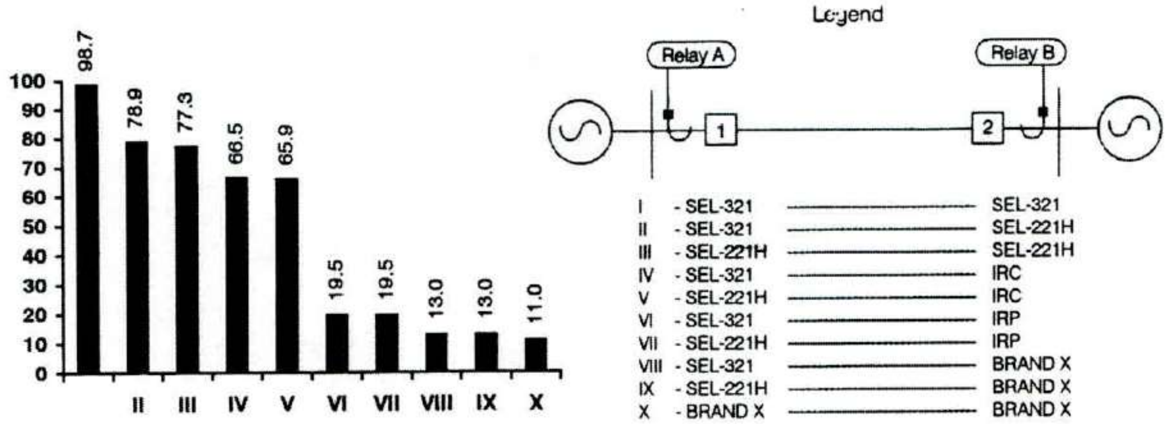


Figure 3: System R_F Coverage for Ten Relay Pairs

Figure 2.h. shows a large directional element sensitivity mismatch. The protection system R_F coverage is restricted by Directional Element 1 at Relay B for all fault locations. The maximum R_F sensed by Relay A is 48 Ω for a ground fault at the remote terminal, while the maximum R_F detectable by Relay B for the same fault location is only 18 Ω. Assume an in-section ground fault close to Bus R and that this fault has $R_F = 25\ \Omega$. Only Relay A senses this fault. Next, assume Relay A gives a time-delayed trip. Even without the infeed from Source S, Relay B still cannot sense this fault!

DIRECTIONAL ELEMENT SENSITIVITIES AND COMMUNICATION SCHEMES

This mismatch of directional element sensitivities also causes difficulties in communication-assisted tripping schemes.

Directional Comparison Block (DCB) Scheme Concerns

For security against tripping for out-of-section faults, the reverse-looking protection must sense all faults that are detectable by the remote terminal overreaching elements. However, as the graphs in Figures 2.f through 2.i suggest, there can be out-of-section high-R_F ground faults near the less-sensitive directional element terminal, when the remote terminal senses the fault as forward and the local terminal fails to make a directional declaration. Assuming directional carrier start is used, the remote terminal undesirably trips after its carrier coordination timer expires. If nondirectional carrier start is used, then this is not a concern. Here are some out-of-section fault security solutions where directional carrier start is desired:

1. Set the overreaching directional ground overcurrent element pickup thresholds no more sensitive than that of the directional element sensitivity at the remote terminal (this assumes the reverse-looking, directionally-controlled overcurrent elements have the same or lower pickup threshold as the overreaching elements of the remote terminal). These overreaching element thresholds should be set to some multiple between 1 and 1.5 times the remote terminal directional element sensitivity limit.

   The penalty for this type of security measure is less R_F coverage for internal faults.

2. Use relays at both line ends that have the same sensitivity.

Next, consider an in-section ground fault near the same less-sensitive directional element terminal, and assume non-directional carrier starting elements are used. If the less-sensitive terminal again fails to make a directional declaration, neither terminal trips high-speed because the forward directional elements never pick up to stop carrier at the less sensitive terminal. Solution 2 above resolves this problem.

Permissive Overreaching Transfer Trip (POTT) Scheme Concerns

The dependability of the POTT scheme depends on both relays at either line end sensing all in-section faults simultaneously. If either terminal fails to sense an internal fault, while the other terminal does, then high-speed tripping is defeated. The penalty for using a directional element with less sensitivity at one terminal is less high-speed R_F coverage for internal faults and time-delayed tripping for higher R_F faults.

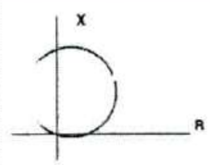
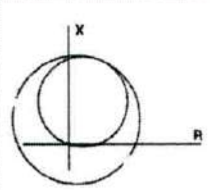
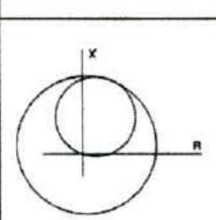
Ground Distance Element Sensitivities

Two commonly used ground distance characteristics are mho and quadrilateral. The mho characteristic is a circle, while the quadrilateral is a polygon on the impedance plane. What factors affect the R_F coverage capabilities of these distance elements?

Mho Ground Distance Elements

Ground mho elements compare the angle between $(Z \cdot I - V)$ and V_p where there are many choices for the polarizing voltage, V_p. Table 3 reviews some of the choices.

Table 3: Mho Element Polarizing Choices

Operating	Polarizing	Characteristic	General Comments
$[Z_{L1} \cdot (I) - V_A]$	V_A (self pol.)		• No expansion. • Unreliable for zero-voltage single-line-ground faults. • Requires directional element.
$[Z_{L1} \cdot (I) - V_A]$	$j \cdot V_{BC}$ (cross pol.)		• Good expansion. • Reliable operation for zero-voltage single-line-ground faults. • Requires directional element. • Single-pole trip applications require study for pole-open security.
$[Z_{L1} \cdot (I) - V_A]$	V_{a1mem} (pos.-seq. mem. pol.)		• Greatest expansion. • Reliable operation for zero-voltage ground faults. • Requires directional element. • Best single-pole trip security.

where

$I \equiv I_A + k \cdot I_R$

$I_A \equiv$ A-phase current

$V_A \equiv$ A-phase voltage

$Z_{L1} \equiv$ Pos.-seq. line impedance

$V_{BC} \equiv V_B - V_C$

$I_R \equiv$ Residual current $(I_A + I_B + I_C)$

$k \equiv (Z_{L0} - Z_{L1})/(3 \cdot Z_{L1})$

$Z_{L0} \equiv$ Zero-seq. line impedance

Of the types shown, the positive-sequence memory-polarized elements have:

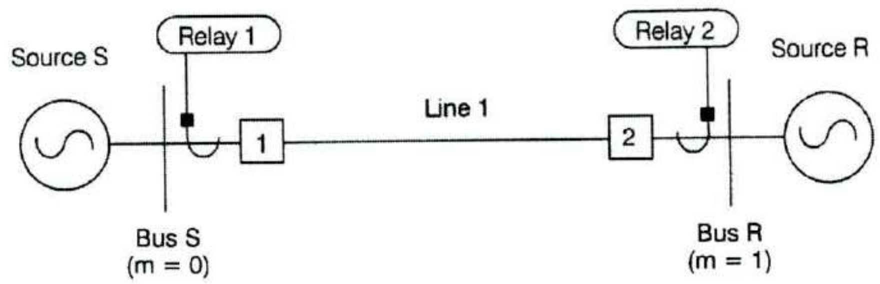
- The greatest amount of expansion for improved R_F coverage. These elements always expand back to the source.

  A common polarizing reference for all six distance-measuring loops. This is important for single-pole tripping during a pole-open period in single-pole trip applications.

Positive-Sequence Polarized Mho Ground Distance Expansion

The amount of expansion that a mho ground distance element experiences for a forward fault depends on the magnitude of the source behind the relay. The weaker the source, the greater the expansion, once the strong remote source clears. Increased R_F coverage is realized when the protected line is radial.

Table 4 summarizes the R_F coverage capability of a Zone 1 positive-sequence memory-polarized mho ground distance element at Relay 1 of Figure 4 for ground faults at m = 0, where m is the per-unit distance from Bus S. For each case, the Zone 1 reach is set for $0.8 \cdot Z_{L1}$. Table 4 shows three different local source strengths.



Source S

Strong:	ZS1=2Ω ∠90°	ZS0=6Ω ∠90°
Medium:	ZS1=7.5Ω ∠90°	ZS0=22.5Ω ∠90°
Weak:	ZS1=50Ω ∠90°	ZS0=150Ω ∠90°

Line 1

ZL1=2.5Ω ∠90°

ZL0=7.5Ω ∠90°

Source R

ZR1=2.5Ω ∠90°

ZL1=7.5Ω ∠90°

Figure 4: Single Line Diagram of Three Example Systems

Table 4: Mho Ground Distance R_F Coverage for Internal AG Faults at Bus S, by Relay 1

Source S Strength	SIR[1]	With Infeed (Remote Breaker Closed) $R_{F, MAXIMUM}$	Radial (Remote Breaker Open) $R_{F, MAXIMUM}$
Strong	1.00	2.12 Ω	3.40 Ω
Medium	3.75	2.10 Ω	6.45 Ω
Weak	20.00	1.10 Ω	16.50 Ω

[1] SIR ≡ Source Impedance Ratio = Z_{S1}/(Zone Reach)

From Table 4, mho expansion improves R_F coverage (because the detectable R_F is greater than 0 Ω). However, this R_F coverage benefit is reduced by infeed if the remote source remains strong. To see this, compare the R_F coverages of infeed verses radial. In all cases, the R_F coverage greatly improves when the remote source clears.

Quadrilateral Ground Distance Elements

The quadrilateral characteristic requires four elements:

- Reactance (top line)
- Positive and negative resistance (sides)
- Directional (bottom)

Reference [2] describes the inputs to a quadrilateral ground distance element.

Again, look at the R_F coverage for the three systems shown in Figure 4, but this time, for a Zone 1 quadrilateral ground distance element.

Table 5 summarizes the R_F coverage of the quadrilateral ground distance element described in [2] for ground faults placed at m = 0 and 0.8. The reactance reach is set to $0.8 \cdot Z_{L1}$, and the resistive reaches to ±50 Ω.

Table 5: Relay 1 Quadrilateral Ground Distance R_F Coverage for Bus S Internal AG Faults

Source S Strength	SIR	m =	Remote Breaker Closed $R_{F,MAXIMUM}$	Remote Breaker Open $R_{F,MAXIMUM}$
Strong	1.00	0.0	31.80 Ω	50.0 Ω
Medium	3.75	0.0	16.00 Ω	50.0 Ω
Weak	20.00	0.0	3.30 Ω	50.0 Ω
Strong	1.00	0.8	13.70 Ω	50.0 Ω
Medium	3.75	0.8	6.83 Ω	50.0 Ω
Weak	20.00	0.8	1.40 Ω	50.0 Ω

The quadrilateral ground distance element provides more R_F coverage, as compared to the expanded mho element. The R_F coverage of the mho and the quadrilateral elements is significantly reduced by remote source infeed. The quadrilateral element most affected is the resistance element, as would be expected. Once the remote source infeed is removed, the quadrilateral resistance element can easily measure large values of R_F.

LIMITS TO SENSITIVITY CAUSED BY INSTRUMENT TRANSFORMERS AND THEIR CONNECTIONS

Directional relays require accurate voltage and current inputs from the instrument transformer to achieve the high R_F coverages noted earlier.

Voltage Transformer (VT) Accuracies

Higher accuracy VTs reduce standing voltages (sequence voltages measured during non-fault, line-energized conditions) and improve R_F coverage. Compare the performance of two possible classes of VTs: Class 1 and Class 2. Table 6 shows that Class 1 errors are half that of Class 2 errors.

Table 6: Class 1 and 2 Maximum Magnitude and Phase Angle Errors

VT Class	Maximum Magnitude Error[1], δM	Maximum Phase Angle Error, $\delta\Theta$
Class 1	±1%	

This error is specified for $5\% \leq V_{measured} \leq 100\%$ with W, X, and Y burdens for Class 1, and Z burden for Class 2. Reference [3] further defines these burdens.

MOA is the abbreviation for Minutes of Angle. 60 MOA = 1°.

VT Magnitude and Angle Errors Create Standing Voltages

Tables 7 and 8 show the resulting standing V_{A2} and V_{A0} voltages for Class 1 and Class 2 VTs with a ratio error and an angle error from a single phase. The assumed ideal phase voltage magnitude is 66.4 V, and all phase voltages are separated by 120°.

Table 7: Standing Sequence Voltages Present for VT Ratio Errors

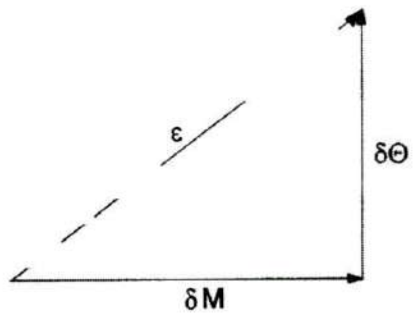
δM	$\delta\Theta$	$V_{A2}, V_{A0, Stand}$
-2%	0	0.44 V ∠ 180°
-1%	0	0.22 V ∠ 180°
0%	0	0.00 V ∠ 0.00°
+1%	0	0.22 V ∠ 0.00°
+2%	0	0.44 V ∠ 0.00°

Table 8: Standing Voltages as a Result of VT Angle Errors

δM	$\delta\Theta$	$V_{A0}, V_{A2, Stand}$
0	-1.33°	1.54 V ∠ -90°
0	-0.66°	0.76 V ∠ -90°
0	0.00°	0.00 V ∠ 0.00°
0	+0.66°	0.76 V ∠ +90°
0	+1.33°	1.54 V ∠ +90°

Each of the three VTs can have a plus or minus magnitude and/or a phase angle error. The effect of any error is to produce a standing V_{A2} or V_{A0}, even on a perfectly balanced system. The magnitude and phase angle of this standing voltage is dependent on the individual VTs and possibly their connected burdens. The standing voltage error has different effects on different faults, with different R_F on different phases.

Here is an easy way of looking at the errors shown in Tables 7 and 8. Calculate the error voltage ε, which results from the ratio and phase angle errors using the equation shown in Figure 5.



$$\varepsilon = \sqrt{(\text{magnitude error})^2 + (\text{angle error})^2}$$
$$= \sqrt{(\delta M)^2 + (\delta\Theta)^2}$$

Figure 5: ε is a Starting Point for Calculating R_F Limitations Due to VT Errors

For reliable operation for all fault types, the fault must generate V_{A2} or V_{A0} greater than two or three times that of ε. This ensures that the fault generated V_{A2} and V_{A0} overwhelms the standing voltages.

Calculate ε for the Class 1 VT using the data from Tables 7 and 8.

$$\varepsilon \quad = \quad (0.76\ V^2 + 0.22\ V^2)^{1/2}$$
$$= \quad 0.79\ V$$

Thus, for reliable directional declarations using VTs with maximum error, the ground fault must generate at least 1.58 V of $3 \cdot V_{A2}$ or $3 \cdot V_{A0}$. How much R_F coverage does this requirement allow for an in-section AG fault for the system shown in Figure 1?

AG Fault Near Bus S

Again, using the simplifying assumption listed earlier, consider $|V_{A2,RELAY}|$ at Relay A.

$$V_{A2,RELAY} = \frac{1.58\ V}{3}$$

$$\left(Z_{2EQ} \cdot I_{A2}\right) \cdot C_{V2}$$

$$\left(0.82\ \Omega \cdot I_{A2}\right) \cdot 0.44$$

$$0.82\ \Omega \cdot \frac{66.4\ V}{3 \cdot R_F} \cdot 0.44$$

Solving for R_F:

$$R_F = 15.07\ \Omega$$

What is $|I_{A2,RELAY}|$ measured at Relay A for $R_F = 15.07\ \Omega$?

$$I_{A2,RELAY} = \frac{66.4\ V}{3 \cdot R_F} \cdot C_{I2}$$

$$\frac{66.4\ V}{3 \cdot 15.07\ \Omega} \cdot 0.18$$

$$0.26\ A$$

Assuming that $|I_{A0,RELAY}|$ approximately equals $|I_{A2,RELAY}|$ at Relay A, setting a directionally-controlled ground overcurrent element no less than 0.79 A (3 · 0.26 A) ensures proper directional declarations for maximum VT errors.

The R_F coverage and corresponding $|I_{A2}|$ calculated above are worst case and somewhat discouraging. In reality, these errors can be less. The metering and event reporting features of the microprocessor relays help us understand the standing voltages so we can make the appropriate settings for the directionally-controlled ground overcurrent element pickup settings.

Current Transformer (CT) Accuracies

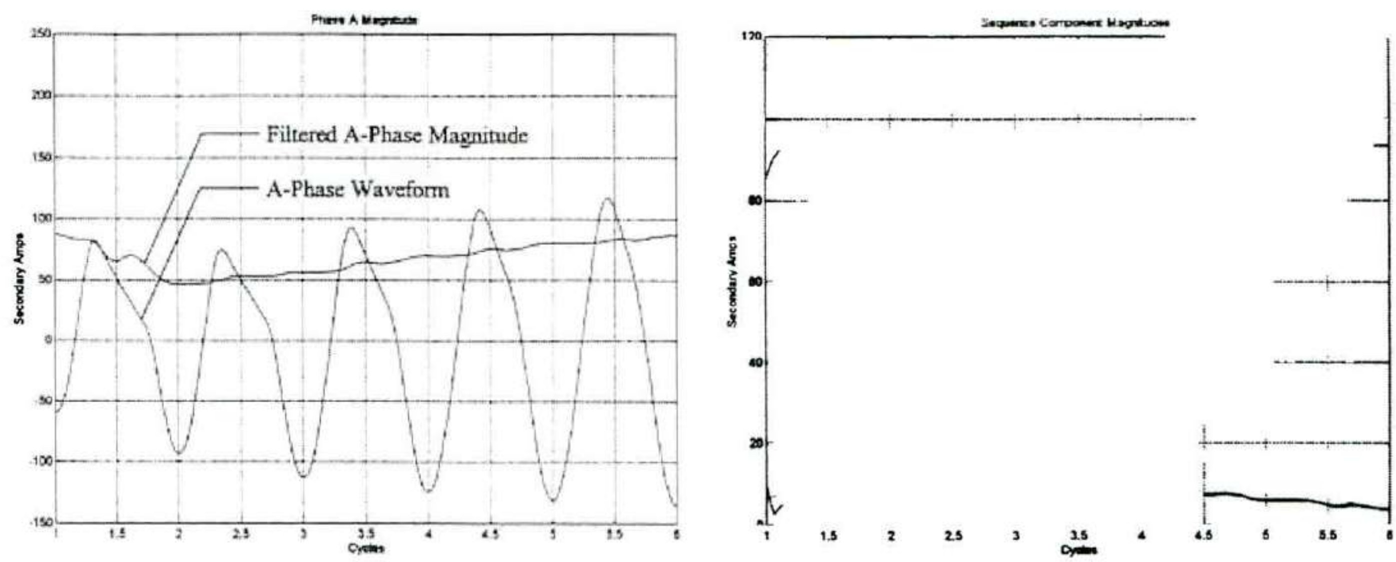
Just as we did for VTs, you could follow a similar process of evaluating sensitivity limitations caused by CT ratio and phase angle errors. The results would show that the higher the accuracy of the CTs used, the higher the R_F coverage. Other considerations for CTs are the selection of the ratio, the C-rating of the device, connected burden, and saturation.

Normally, we do not consider saturation during a discussion of high R_F ground fault detection as the associated primary currents are very small. However, achieving high R_F detection requires very sensitive directional elements. We must ensure that these elements do not pick up and do not misoperate during a close-in, three-phase fault when CT saturation is a concern. The most secure means of achieving this security is to ensure that I_{A2} and I_{A0} or the ratio of I_{A2}/I_{A1} or I_{A0}/I_{A1} are very small. Do this by selecting an adequate C-rating CT and/or reducing the connected burden.

Consider an application that has 12,000 A of primary current for a close-in, three-phase fault and that the A-phase CT has 35% remnant flux. (This assumption ensures that the A-phase CT saturates quicker than the B- and C-phase CTs. If all CTs saturate simultaneously, then no I_{A2} or I_{A0} currents are generated due to CT saturation.) Next assume that the full-winding CT ratio is 600:5, and the connected burden is 0.5 Ω ∠ 60°. The ratio for this example is such that the ideal secondary current magnitude is 100 A or 20 times the nominal rating for this fault. The available C-ratings to chose from are C200, C400, and C800.

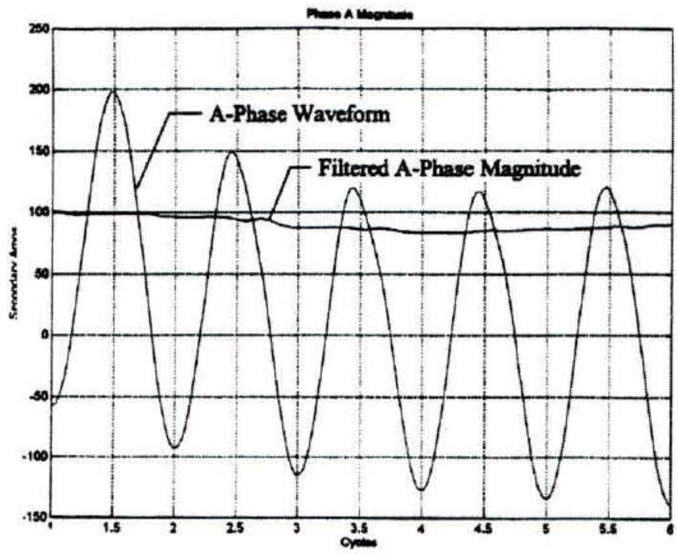
Figure 6.a shows the A-phase secondary current waveform and calculated magnitude for the conditions listed above for a C200 CT. Figure 6.b. shows the resultant I_{A1}, I_{A2} and I_{A0} current magnitudes for the same class CT. In Figure 6.a., the A-phase current magnitude is severely attenuated by the obvious saturation in the waveform. This attenuation on A-phase results in the generation of negative- and zero-sequence secondary currents, which could pick up ground overcurrent elements.

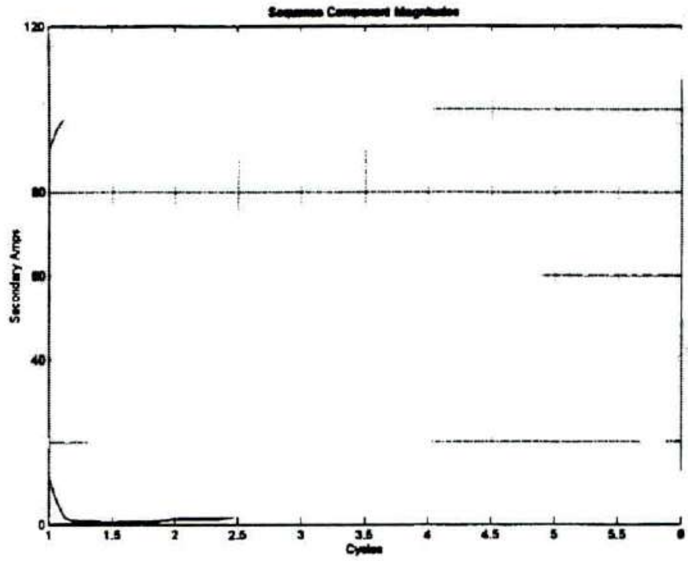
Figure 7 and Figure 8 show the performance of C400 and C800 class CTs for the same conditions as the C200 CT. The higher C-rating CT saturates less, and thereby generates less I_{A2} and I_{A0} currents for the given burden. Reducing the burden and decreasing the secondary current magnitudes also reduces saturation, and thereby allows a lower class CT to be used.



6a: A-Phase Waveform and Magnitude **6b: $|I_{A1}|$, $|I_{A2}|$ and $|I_{A0}|$**

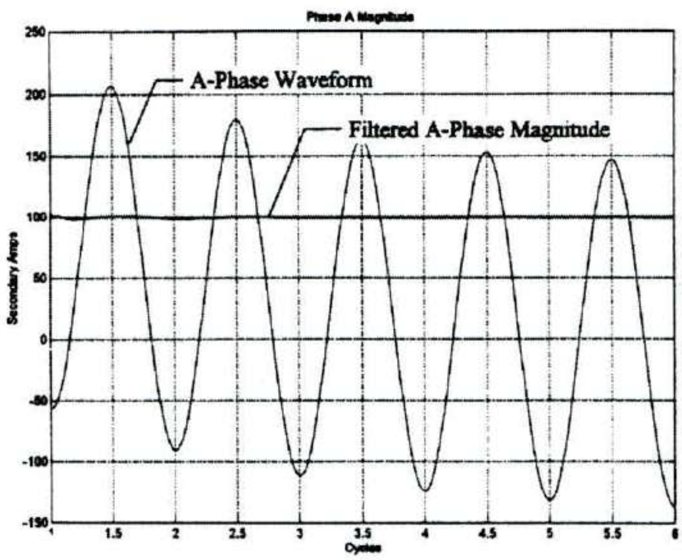
Figure 6a - 6b: C200 CT Saturation Generates Large I_{A2} and I_{A0} Currents for a Three-Phase Fault

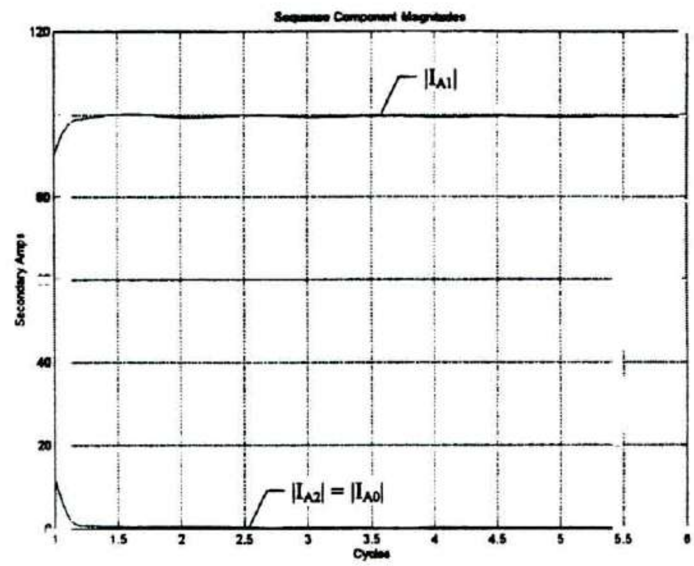




7a: A-Phase Waveform and Magnitude **7b: $|I_{A1}|$, $|I_{A2}|$ and $|I_{A0}|$**

Figure 7a - 7b: C400 CT Produces Less I_{A2} and I_{A0} Currents Than a C200 CT for the Three-Phase Fault Due to Less Saturation





8a: A-Phase Waveform and Magnitude **8b: $|I_{A1}|$, $|I_{A2}|$ and $|I_{A0}|$**

Figure 8a - 8b: C800 CT Generates Trivial I_{A2} and I_{A0} Currents

CT and VT Connection Errors Affect Directional Element Performance

In addition to requiring accurate VTs and CTs, directional relays (like all relays) require proper wiring. The following two real-world examples illustrate how simple wiring errors can affect any directional relay decision.

Do Not Ground VTs in Two Locations

VTs must be grounded in one location only. Figure 9 illustrates the voltage drops present when the VTs are grounded at the VT and again at the relay location.

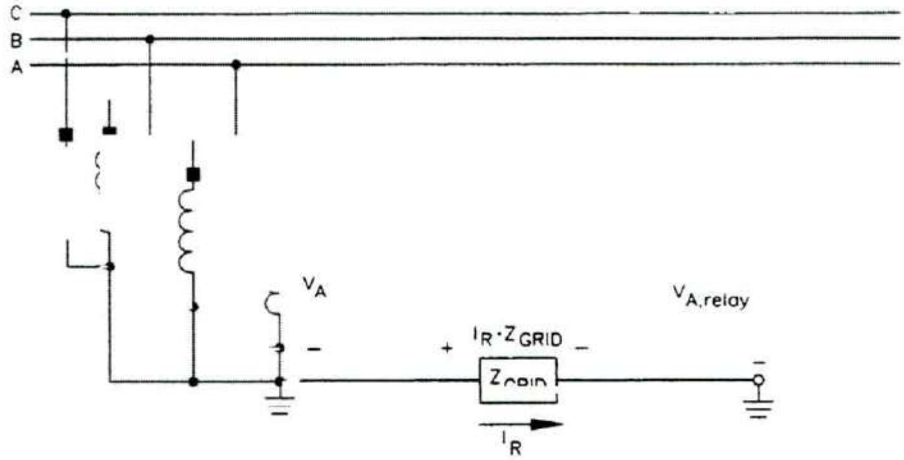


Figure 9: Grounding VTs Twice Introduces an Unwanted $I_R \cdot Z_{GRID}$ Voltage Drop

The voltage drop $I_R \cdot Z_{GRID}$ is present in all phase voltages when the VTs are grounded as shown in Figure 9 (Z_{GRID} is the ground grid impedance, and I_R is the current flowing through the ground grid). For this multiple VT ground situation, the phase voltages delivered to the relay are:

$$V_{A,relay} = V_A + I_R \cdot Z_{GRID}$$

$$V_{B,relay} = V_B + I_R \cdot Z_{GRID}$$

$$V_{C,relay} = V_C + I_R \cdot Z_{GRID}$$

How do the $I_R \cdot Z_{GRID}$ voltage drops affect the relay calculated zero-sequence quantities?

$$\begin{aligned} V_{A0,relay} &= \tfrac{1}{3} \cdot \left(V_{A,relay} + V_{B,relay} + V_{C,relay} \right) \\ &= \tfrac{1}{3} \cdot \left(V_A + I_R \cdot Z_{GRID} + V_B + I_R \cdot Z_{GRID} + V_C + I_R \cdot Z_{GRID} \right) \\ &= \tfrac{1}{3} \cdot \left(V_A + V_B + V_C \right) + \left(I_R \cdot Z_{GRID} \right) \\ &= V_{A0} + I_R \cdot Z_{GRID} \end{aligned}$$

From these calculations, $I_R \cdot Z_{GRID}$ directly affects the zero-sequence voltage measurements. If Z_{GRID} is large, this error could be substantial. The amount of error depends on $|Z_{GRID}|$ and I_R.

How do the $I_R \cdot Z_{GRID}$ voltage drops affect the relay calculated negative-sequence quantities?

$$\begin{aligned} V_{A2,relay} &= \tfrac{1}{3} \cdot \left(V_{A,relay} + a^2 \cdot V_{B,relay} + a \cdot V_{C,relay} \right) \\ &= \tfrac{1}{3} \cdot \left[\left(V_A + I_R \cdot Z_{GRID} \right) + a^2 \cdot \left(V_B + I_R \cdot Z_{GRID} \right) + a^2 \cdot \left(V_C + I_R \cdot Z_{GRID} \right) \right] \end{aligned}$$

$$= \tfrac{1}{3}\cdot\left[\left(V_A + a^2\cdot V_B + a\cdot V_C\right) + I_R\cdot Z_{GRID}\cdot\left(1 + a^2 + a\right)\right]$$

$$= V_{A2} \qquad \text{since } \left(1 + a^2 + a\right) = 0$$

From these calculations, grounding the VTs twice does not affect the negative-sequence calculations.. However, this is not an endorsement of grounding VTs twice.

Missing Current Transformer Neutral Wires Void Ground Protection

Figure 10 shows an actual accidental miswiring of the CT neutral wire circuit: the neutral return from the relay to the CTs is omitted. The information contained in the microprocessor relay event report led the protection engineer to discover the missing wire. On May 5, 1995, the transmission line experienced two faults. The first fault location read 36.19 miles, while the second event displayed a fault location of 11.93 miles. The initial fault was a phase-phase fault, while the second fault was C-ground. These two faults were separated by 0.508 seconds. The fault locations were believable as the line length is 42.5 miles. Were there two different faults at different locations so close together in time?

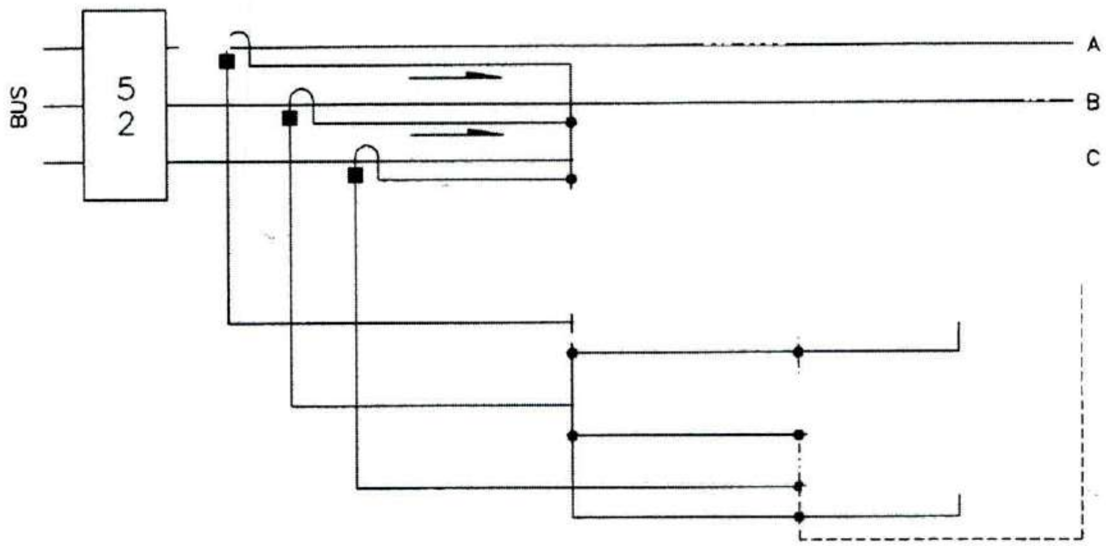


Figure 10: Missing Current Neutral Wiring Diagram

The second event looked suspicious because:

1. There was fault current in all phases, yet only one phase voltage was somewhat reduced.
2. The phase angle relationships of the currents appeared as though the system was ungrounded, yet the engineer knew the system was solidly grounded.

The event report of the microprocessor relay included the following phase voltages and currents:

$V_A = 68.1\ V_{SEC} \angle 0.0°$ $\qquad I_A = 3.1\ A_{SEC} \angle -107.3°$

$V_B = 68.9\ V_{SEC} \angle -124.1°$ $\qquad I_B = 3.3\ A_{SEC} \angle -110.7°$

$V_C = 60.2\ V_{SEC} \angle +115.0°$ $\qquad I_C = 6.4\ V_{SEC} \angle +71.2°$

From this information, we see that the A- and B-phase currents are nearly 180° out-of-phase with the C-phase current. Next calculate the negative- and zero-sequence voltages and currents:

V_{A2} = 4.38 V_{SEC} ∠ +74.7° I_{A2} = 3.15 A_{SEC} ∠ -169.9°
V_{A0} = 1.58 V_{SEC} ∠ -31.8° I_{A0} = 0.03 A_{SEC} ∠ ????°

From the calculated I_{A0}, you can immediately see that the zero-sequence ground directional and overcurrent protection was made inoperative by the missing CT neutral return wire. This point led the engineer to believe there was a problem and that the fault location for the second event was in error. A field check verified that the CT neutral wire was missing. Note that negative-sequence directional and overcurrent elements could properly sense the direction and presence of this ground fault. This is good in that the protection would operate properly, but this is bad because the wiring error could go undetected. It is extremely important to review the analog data contained in the event reports of microprocessor relays every time a fault occurs. Otherwise, problems such as this can go undetected.

Line Asymmetry Generates Unbalance

Not transposing transmission lines is common practice today. Separate communication and transmission rights-of-way, better communication circuit shielding, and reduced cost are some of the reasons to forgo the cost of fully transposing transmission lines. Eliminating transpositions also means fewer faults. Gross [4] and Lawerence [5] both cited studies that showed that 25 percent of all transmission line outages were associated with faults at transpositions.

While reducing fault exposure, non-transposition of lines results in I_{A2} and I_{A0} current flow for normal load and three-phase faults. The reason is that the self-impedances (Zaa, Zbb, Zcc) are different and mutual-impedances (Zab, Zba, Zac, Zac, Zbc, Zcb) are different. Later, we show that the magnitude of these currents is a percentage of the positive-sequence current flow and depends largely on the line conductor configuration.

While microprocessor relays have the ability to provide greater directional sensitivity than their electromechanical predecessors, we must evaluate the effect of these unbalanced currents on the sensitive directional elements.

Equations 2 through 5 from Gönen [6] represent the self- and mutual-impedances of a three-phase transmission line.

$$Z_{AB,BB,CC} = \left(R_{cond} + 0.00159 \cdot f\right) + j \cdot 0.004657 \cdot \log_{10}\left(\frac{2160}{GMR} \cdot \sqrt{\frac{p}{f}}\right) \Omega / mi \quad (2)$$

$$Z_{AB} = 0.00159 \cdot f + j \cdot 0.004657 \cdot \log_{10}\left(\frac{2160}{d_{AB}} \cdot \sqrt{\frac{p}{f}}\right) \Omega / mi \quad (3)$$

$$Z_{BC} = 0.00159 \cdot f + j \cdot 0.004657 \cdot \log_{10}\left(\frac{2160}{d_{BC}} \cdot \sqrt{\frac{p}{f}}\right) \Omega / mi \quad (4)$$

$$Z_{CA} = 0.00159 \cdot f + j \cdot 0.004657 \cdot \log_{10}\left(\frac{2160}{d_{CA}} \cdot \sqrt{\frac{p}{f}}\right) \Omega / mi \quad (5)$$

where

f	≡	system frequency [Hz]
R_{cond}	≡	resistance of the conductor [Ω/mi]
GMR	≡	geometric mean radius of the conductor [feet]
$d_{AB,BC,CA}$	≡	distance from conductor A to B, B to C, and C to A, respectively [feet]
ρ	≡	earth resistivity [Ωm]

For simplicity, we limit this review to three-phase overhead circuits without ground wires.

Equations (6) through (8) represent the voltage drops along each phase of a three-phase transmission line.

$$V_A = I_A \cdot Z_{AA} + I_B \cdot Z_{AB} + I_C \cdot Z_{AC} \tag{6}$$

$$V_B = I_A \cdot Z_{BA} + I_B \cdot Z_{BB} + I_C \cdot Z_{BC} \tag{7}$$

$$V_C = I_A \cdot Z_{CA} + I_B \cdot Z_{CB} + I_C \cdot Z_{CC} \tag{8}$$

If only positive-sequence current (I_{A1}) flows into the transmission line, then:

$$V_A = I_{A1} \cdot (Z_{AA} + a^2 \cdot Z_{AB} + a \cdot Z_{AC})$$

$$V_B = I_{A1} \cdot (Z_{BA} + a^2 \cdot Z_{BB} + a \cdot Z_{BC})$$

$$V_C = I_{A1} \cdot (Z_{CA} + a^2 \cdot Z_{CB} + a \cdot Z_{CC})$$

The positive-, negative-, and zero-sequence impedances measured due to the flow of positive-sequence current can then be represented as follows:

$$Z_{11} = \frac{V_{A1}}{I_{A1}} = \frac{\frac{1}{3}\cdot\left(V_A + a\cdot V_B + a^2\cdot V_C\right)}{I_{A1}}$$

$$\frac{1}{3}\cdot\left[Z_{AA} + Z_{BB} + Z_{CC} - \left(Z_{AB} + Z_{BC} + Z_{AC}\right)\right] \tag{9}$$

$$Z_{21} = \frac{V_{A2}}{I_{A1}} = \frac{\frac{1}{3}\cdot\left(V_A + a^2\cdot V_B + a\cdot V_C\right)}{I_{A1}}$$

$$\frac{1}{3}\cdot\left[Z_{AA} + a\cdot Z_{BB} + a^2\cdot Z_{CC} - 2\cdot\left(a^2\cdot Z_{AB} + Z_{BC} + a\cdot Z_{AC}\right)\right] \tag{10}$$

$$Z_{01} = \frac{V_{A0}}{I_{A1}} = \frac{\frac{1}{3}\cdot\left(V_A + V_B + V_C\right)}{I_{A1}}$$

$$\frac{1}{3}\cdot\left[Z_{AA} + a^2\cdot Z_{BB} + a\cdot Z_{CC} - \left(a\cdot Z_{AB} + Z_{BC} + a^2\cdot Z_{AC}\right)\right] \tag{11}$$

where

Z_{11}	≡	Self-impedance as related to a V_{A1} drop due to the I_{A1} causing the drop.
Z_{21}	≡	Mutual-impedance as related to a V_{A2} drop due to the I_{A1} causing the drop.
Z_{01}	≡	Mutual-impedance as related to a V_{A0} drop due to the I_{A1} causing the drop.

Hesse [7] showed an excellent approximation of how much negative- and zero-sequence current flows as a percentage of positive-sequence current flow. These approximations use the Z_{21} and Z_{01} quantities calculated above in conjunction with the traditional negative- and zero-sequence line impedances, Z_{22} and Z_{00}, respectively. Equations representing these approximations are:

Calculated I_{a2} due to line asymmetry: $I_{A2} = (|Z_{21}|/|Z_{22}|) \cdot I_{A1}$ (12)

Calculated I_{a0} due to line asymmetry: $I_{A0} = (|Z_{01}|/|Z_{00}|) \cdot I_{A1}$ (13)

Equations 12 and 13 show that I_{A2} and I_{A0} are proportional to I_{A1} and that the proportionality constants are ratios of impedances we can calculate. These constants are:

$$a_2 = |Z_{21}|/|Z_{22}| \tag{14}$$

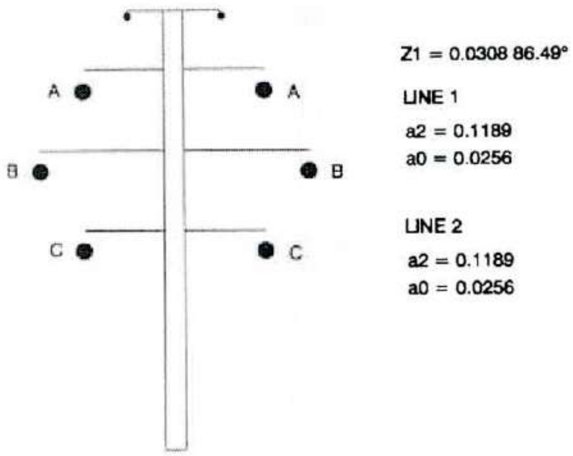
$$a_0 = |Z_{01}|/|Z_{00}| \tag{15}$$

The higher the value of a_2 or a_0, the greater the I_{A2} and I_{A0} current flow during load conditions and three-phase faults. For example, assume $a_2 = a_0 = 0.08$ and that the positive-sequence current flow due to an end-of-line three-phase fault equals 1000 A. For these conditions, the line asymmetry generates 80 A of I_{A2} and I_{A0}. If instead, the positive-sequence current magnitude was 10,000 A, then I_{A2} and I_{A0} would equal 800 A each. In both of these cases, the unbalance current magnitudes are too large to ignore. Next, we show that a_2 and a_0 are not necessarily the same.

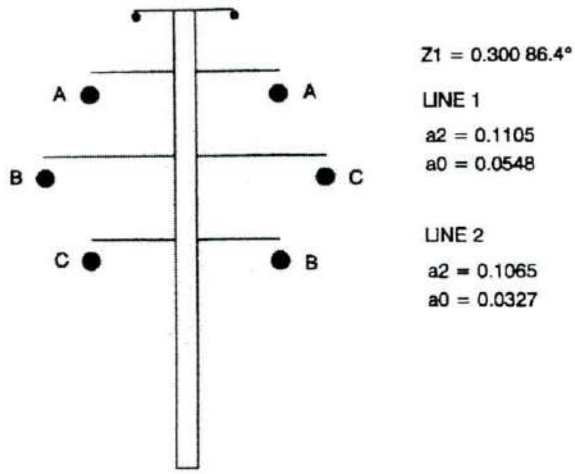
Line Configuration and Phasing - How These Affect a_2 and a_0

The magnitude of a_2 and a_0 is dependent on the line configuration. Figure 11 and Figure 12 show six different phasings each for a horizontal and a vertically configured double-circuit 345 kV transmission line. The source of this information [8] identifies the unbalance load current effects associated with these various phasings and configurations. From the figures, notice the variations of a_2 and a_0 values for each line configuration and phasing.

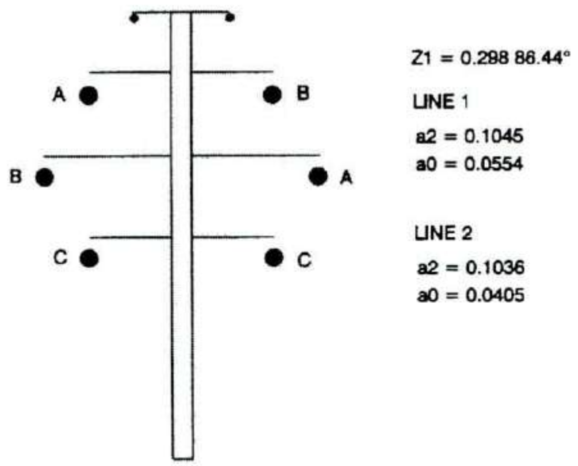
For maximum power transfer, the best phasing for either horizontal or vertical is that which produces the least positive-sequence impedance (Z1). Figure 11.f shows this configuration for the vertical tower configuration. This phasing also results in the lowest a_2 and a_0 ratios. This phasing is very attractive in that it achieves the greatest power transfer capability with the least unbalance, and it generates the least I_{A2} and I_{A0} current magnitudes for three-phase fault conditions.



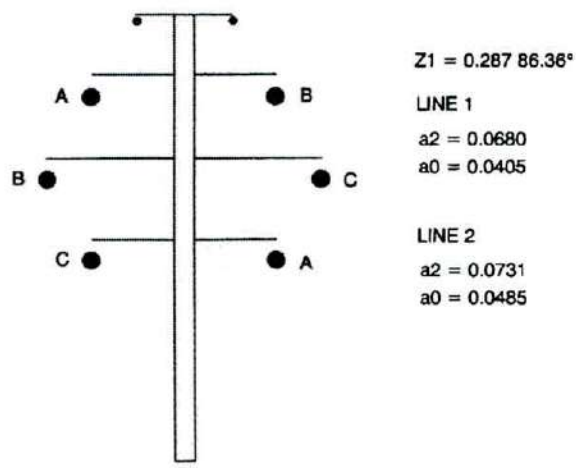
11a: ABC CBA Phasing



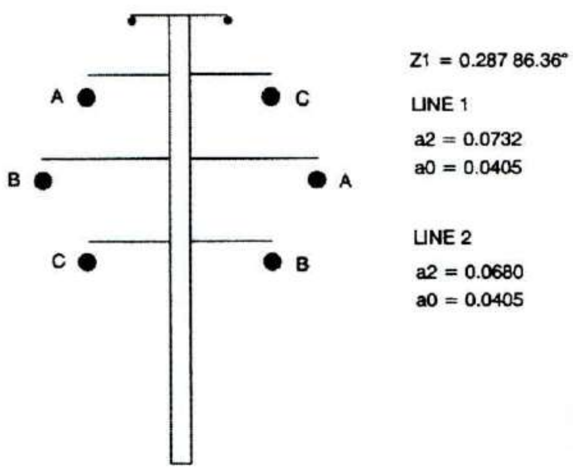
11b: ABC BCA Phasing



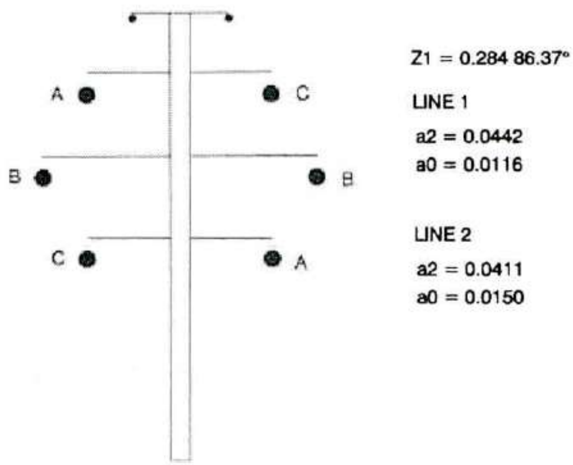
11c: ABC CAB Phasing



11d: ABC ACB Phasing



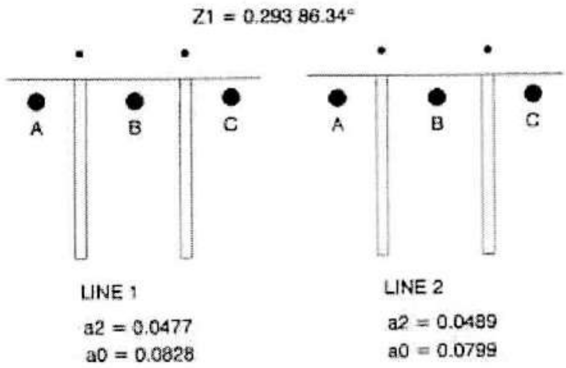
11e: ABC BAC Phasing



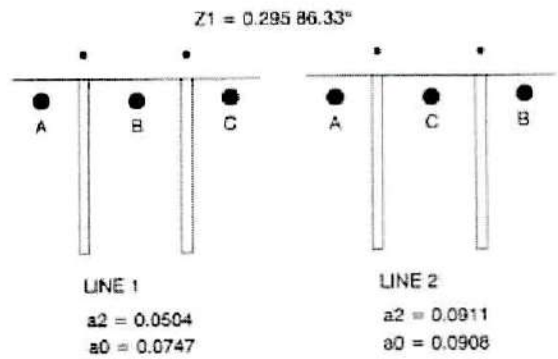
11f: ABC ABC Phasing

Figure 11a - 11f: Vertical 345 kV Tower Configuration and Six Possible Phasing Arrangements

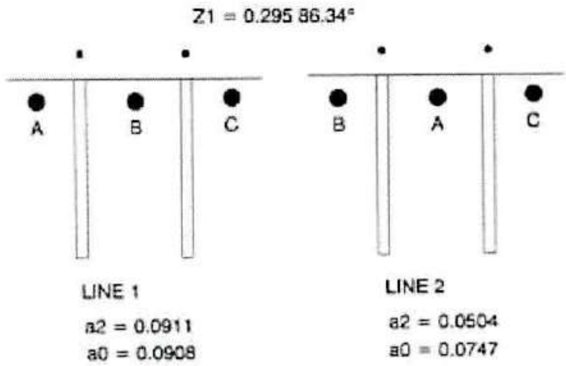
Observations about the horizontal line configuration and phasing are not as clear-cut as for the vertical configuration. For the horizontal configuration, the phasing of Figure 12.a. has the lowest magnitude of Z1 and a_2, but not a_0. Figure 12.e. shows the phasing that produces the lowest a_0 ratio.



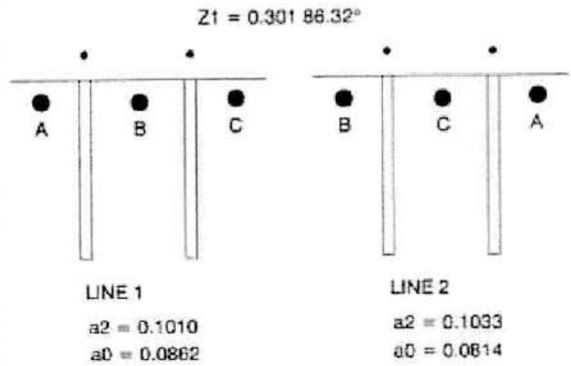
12a: ABC ABC Phasing



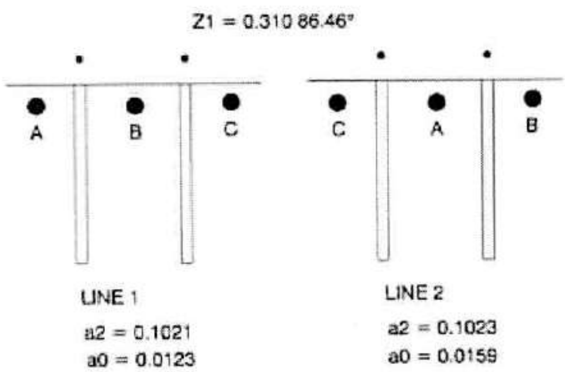
12b: ABC ACB Phasing



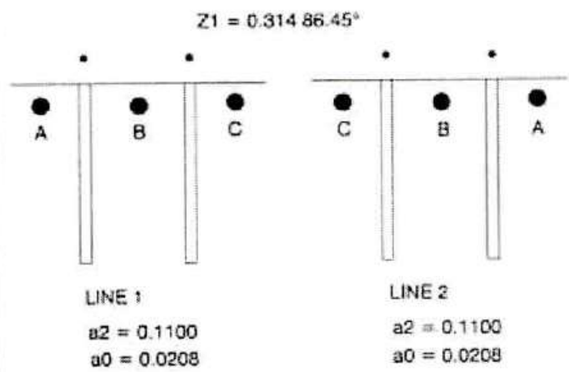
12c: ABC BAC Phasing



12d: ABC BCA Phasing



12e: ABC CAB Phasing



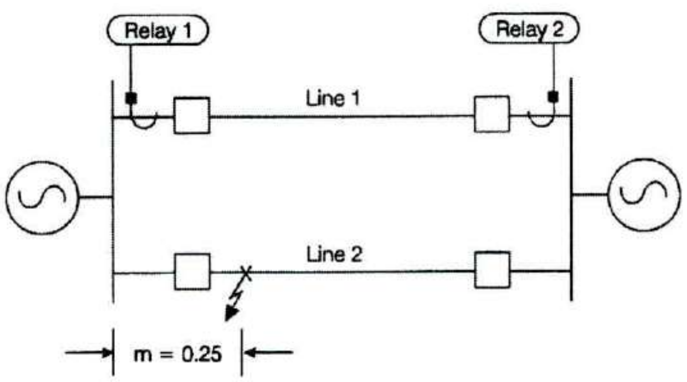
12f: ABC CBA Phasing

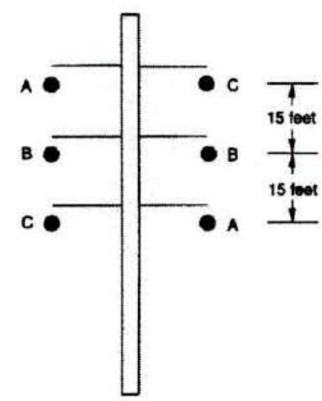
Figure 12a - 12f: Horizontal 345 kV Tower Configuration and Six Possible Phasing Arrangements

Line Asymmetry Affects Directional Elements in Communication Schemes

Line asymmetry can adversely affect the ground directional elements in a communication-assisted tripping scheme. The example shown here is a permissive overreaching transfer trip (POTT) scheme.

The single-line diagram and tower configuration are shown in Figure 13. The conductors on each circuit are 1033 MCM Ortalan ACSR. Next use Equations 2 through 5 to calculate the self- and mutual-impedances for Lines 1 and 2 to see how much unbalance the line configuration generates. Later, we show that the unbalance can penalize the POTT scheme security for the three-phase fault shown in Figure 13, unless we take precautions during the relay setting procedure.





Source S:
$Z_{S1} = 0.1\ \Omega \angle 87.1°$
$Z_{S0} = 0.1\ \Omega \angle 79.1°$

Source R:
$Z_{R1} = 0.8\ \Omega \angle 84.3°$
$Z_{R0} = 0.3 \angle 84.3°$

13a: Example System Single-Line Diagram

13b: Tower Configuration

Figure 13: Example System Single-Line and Tower Configuration

For the conductor in this example, $R_{cond} = 0.0924\ \Omega/mi$ and the GMR = 0.0402. The self- and mutual-secondary impedances of Line 1 are shown below. The voltage transformer ratio is 2000:1, and the current transformer ratio is 240:1.

$$ZL = \begin{bmatrix} (0.405 + j2.919) & (0.206 + j1.368) & (0.206 + j1.187) \\ (0.206 + j1.368) & (0.405 + j2.919) & (0.206 + j1.368) \\ (0.206 + j1.187) & (0.206 + j1.368) & (0.405 + j2.919) \end{bmatrix}$$

From these self- and mutual-impedances, calculate Z_{11}, Z_{22}, Z_{00}, Z_{21}, Z_{01}. The purpose of performing these calculations is to extract the a_2 and a_0 ratio values. The results are:

$Z_{11,22} = 1.623 \angle 82.95°$
$Z_{00} = 5.594 \angle 81.60°$
$Z_{21} = 0.121 \angle 30.0°$
$Z_{01} = 0.060 \angle -30.0°$

$a_2 = |Z_{21}|/|Z_{22}| = 0.07$
$a_0 = |Z_{01}|/|Z_{00}| = 0.01$

Comparing the a_2 and a_0 values, we see that more negative-sequence than zero-sequence current is generated for three-phase faults. Because the inputs have a greater magnitude, a negative-sequence directional element has a greater likelihood to operate than a zero-sequence directional element.

Table 9 shows the negative- and zero-sequence secondary quantities and the directional element decisions of possible sequence directional elements for Relays 1 and 2.

Table 9: Directional Element Inputs and Outputs for the Example Three-Phase Fault

	Relay 1	Relay 2	Comments
V_{A2}	0.82 V $\angle$ 67.1°	1.0 V $\angle$ -48.8°	Neg.-Seq. Voltage
V_{A0}	0.017 V $\angle$ 138.4°	0.05 V $\angle$ 63°	Zero-Seq. Voltage
I_{A2}	0.61 A $\angle$ 9.6°	0.61 A $\angle$ -170.4°	Neg.-Seq. Current
$3 \cdot I_{A0}$	0.25 A $\angle$ 122.8°	0.25 A $\angle$ -57.2°	Residual Current
I_{A1}	8.56 A $\angle$ -136.94°	8.56 A $\angle$ 43.06°	Positive-Seq. Current
T32Q	0.47 VA (forward declaration)	-0.48 VA (reverse declaration)	Traditional Neg.-Seq. Directional Element Torque
T32V	0.004 VA (no declaration, too small of a torque)	0.013 VA (no declaration, too small of a torque)	Traditional Neg.-Seq. Directional Element Torque
Z2	-1.26 Ω (reverse declaration)	1.41 Ω (forward declaration)	Improved Neg.-Seq. Directional Element
Z0	-0.2 Ω (reverse declaration)	-0.6 Ω (reverse declaration)	Improved Zero-Seq. Directional Element
a_2	0.07	0.07	$\lvert I_{A2} \rvert / \lvert I_{A1} \rvert$
a_0	0.01	0.01	$\lvert I_{A0} \rvert / \lvert I_{A1} \rvert$

How do the directional element outputs shown in Table 9 relate to the security of the Line 1 POTT scheme? For the three-phase fault shown, the overreaching Zone 2 phase distance protection at Relay 2 picks up and keys permission to Relay 1. The reverse looking Zone 3 phase distance protection at Relay 1 also picks up. It is very desirable that no forward-looking protective elements at Relay 1 pick up. For the fault shown, pilot assisted tripping of Relay 2 for the out-of-section fault shown is only blocked if no permissive signal is sent by Relay 1. The security of this scheme depends on the relays at both line ends making correct directional decisions.

From Table 9, we can see that the T32Q calculation for Relay 1 has sufficient torque to make a directional decision and that this directional decision is incorrect. If T32Q is providing the directional control for a sensitively set residual overcurrent element (call this element 67N2), the 67N2 element would key permission to Relay 2. The result of T32Q making an incorrect directional declaration for the fault shown is the tripping of both breakers on Line 1, if the 67N2 element at Relay 1 was set as sensitive as 0.25A.

The T32Q directional elements at Relays 1 and 2 misoperate for the fault shown. The T32V elements at both line ends do not operate as their torques are too small. This relates well with the smaller a_0 value calculated earlier.

The data of Table 9 shows that the impedance-based directional elements also need additional supervision. The Z2 directional elements at either line end make the correct directional declaration without additional supervision, but the Z0 directional element at Relay 2 makes an incorrect directional decision. Next, we discuss supervision methods for these and other directional elements.

Solutions

We have shown that the line asymmetry generates unbalance currents for three-phase faults and that ground directional elements can operate incorrectly. What are the solutions to this security problem, and how does each of these solutions affect sensitivity?

1 Raise the pickup threshold of the directionally-controlled overcurrent elements to a level that is above the corresponding unbalance generated for three-phase faults on an unsymmetrical line.

Raise the minimum torque thresholds for the ground directional elements so the torque threshold is not exceeded during three-phase faults on an unsymmetrical line.

3. Use a_2 and a_0 ratio factors as relay settings. If the ratio of $| I_{A2} | / | I_{A1} | \geq a_2$, then allow the negative-sequence directional element to give an output. Similarly, if the ratio of $| I_{A0} | / | I_{A1}$ $\geq a_0$, then allow the zero-sequence directional element to give an output.

Solutions 1 and 2 are really equivalent, with Solution 1 being more flexible and easier to coordinate. Fixing the torque threshold at a higher value gives you the necessary security for directional element operation during three-phase faults. The calculated ground directional element torque is $V \cdot I \cdot \cos(\Theta)$, where $\Theta = [\angle - V_{SEQ} - (\angle I_{SEQ} + \angle Z_{SEQ})]$. If we assume $\cos(\Theta) = 1$, we see that raising the minimum V or I required to calculate a directional element torque in effect raises the minimum torque threshold. Earlier, we saw the R_F limitations imposed by requiring too high of a minimum magnitude of V. This leaves raising the I required to calculate a torque. Note that this is equivalent to raising the pickup of the directionally-controlled overcurrent elements. To gain the necessary security for three-phase faults, simply raise the pickup of these overcurrent elements to a level higher than the asymmetry generated unbalance.

Solution 3 describes using the a_2 and a_0 factors calculated earlier as relay settings. Rather than calculating these factors for the purpose of calculating the maximum unbalance current magnitude, simply input these values as relay settings. For a relay that uses these settings, the directional element is not allowed to give an output until the corresponding ratio is exceeded.

How do the R_F coverage offered by Solutions 1, 2, and 3 compare? Figure 14 shows the R_F coverage for four ground directional elements at Relay 1.

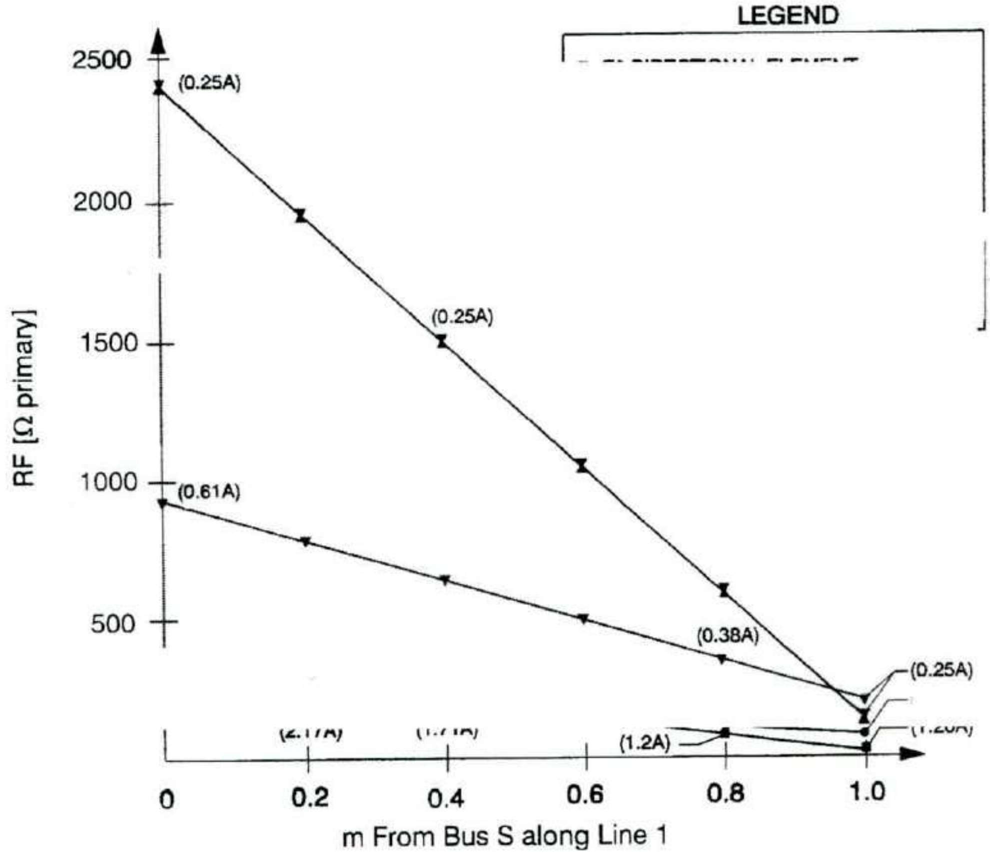


Figure 14: R_F Coverage Comparison of T32Q, T32V, Z2, and Z0 for an Asymmetrical Line

From Figure 14, the Z0 directional element R_F coverage is restricted only by $|3 \cdot I_0| \geq 0.25$ A and $a_0 \geq 0.1$. The Z2 directional element R_F coverage is confined by the a_2 ratio test, while the T32Q and T32V directional elements are limited by their minimum torque thresholds.

Observe from the data in Figure 14 that setting the pickup of any directionally-controlled ground overcurrent element less than that of the residual current level corresponding to the R_F coverage capability of the directional element is only a liability.

Practical Field Checks for Sensitivity and Secure Performance

The following list identifies field checks you can make during installation or routine checks of data captured in relay event reports.

1. **Instrument Transformer Checks:**

   a. Verify the VT and CT ratios against those marked on the instrument nameplate. Use the meter or event reporting feature to validate that the relay is receiving the expected secondary voltages and currents.

   b. Make certain that the VT circuits do not have a VT neutral fuse. Operation of this fuse guarantees VT neutral shift during ground faults. An open neutral denies the relay of zero-sequence voltage. If you find a fuse, replace it with a solid copper bar or jumper around the fuse holder.

c. Verify that the VTs and CTs are grounded in only one place.

d. Verify the proper phase rotation and phasing of the voltage and current circuits. Proper phase rotation and phasing are required for directional elements using negative-sequence quantities.

2. **Standing Voltage and Current Checks**

Verify the phase balance of the VTs and CTs by measuring the amount of V_{A2}, V_{A0}, I_{A2}, and I_{A0} during normal load conditions. Excessive negative- or zero-sequence quantities suggest excessive instrument transformer error, system unbalance, or load imbalance.

Insure that ground faults provide two to three times as much unbalance as the standing unbalance by requiring sufficient fault current to "swamp out" the standing unbalance.

3. **Adjacent Station Comparison Checks**

In new installations, you should validate the metered megawatt and megavar readings by comparing those values against other proven meters in adjacent stations.

The megawatt and megavar flows as measured at both ends of the line are opposite: one line terminal should measure megawatt flow in (out) and the remote line terminal should measure megawatt flow out (in).

4. **Line Construction Check**

Earlier in this paper, we showed that various line phasings and configurations cause differing amounts of negative- and zero-sequence current flow for normal load conditions. Determine if relay settings should be desensitized to accommodate unbalance introduced by line unbalance.

5. **Analyze Event Reports**

Analyze the valuable event report data every time. The information contained in these reports is more valuable than routine maintenance testing. In countless cases, the event report information points to one of the items discussed in this paper. This method of "testing" is far less expensive than that incurred for routine relay testing and may uncover problems that would not be discovered in the traditional testing methods. It is also more interesting and rewarding.

SUMMARY

1 Unbalance throughout the power and protection system limits protection system sensitivity. Not considering these sources of unbalance can cause relay misoperations when relays are set too sensitively. Misoperations include unwanted tripping for out-of-section faults and failure to trip for in-section faults.

2. A relay design that requires a 1 V minimum of V_{A2} (faulted-phase voltage must drop 3 V) has a severely restricted R_F coverage and causes coordination difficulties when used with more sensitive relays.

3. Properly designed quadrilateral ground distance elements can provide more R_F coverage than an expanded mho ground distance element.

4. The sensitivity of ground distance elements is greatly affected by remote infeed.

5. Raising the pickup thresholds of residual overcurrent elements is generally equivalent to increasing the directional element torque threshold as a means of tolerating standing unbalance.

6. The sensitivity of the protective system depends on individual relay sensitivities. Check VA, V, and current limits.

7. Where dissimilar relays are used at either end of the transmission line, you must coordinate the ground relays and consider the internally fixed and settable limits of critical elements.

8. Where directional carrier start is used in DCB applications, you must coordinate the directional element sensitivities at both line ends to ensure security for out-of-section faults.

9. Multiple grounds on VTs and CTs frequently cause significant zero-sequence measurement errors. Verifying that the instrument transformers are grounded in only one place is an easy step toward avoiding serious measurement errors.

10. Ratio and phase angle instrument transformer errors can limit the R_F coverage of directional elements. Knowing these errors is important to making proper ground overcurrent element pickup settings.

11. Unequal CT saturation during three-phase faults generates negative- and zero-sequence currents. Avoid saturation by using CTs with a high C-rating, and minimize cable and relay burdens. Consider putting electromechanical relays on separate CTs to reduce errors on more sensitive microprocessor relays.

12. Unbalances introduced by line asymmetry can cause incorrect directional operations. Set the ground overcurrent element pickup levels above the unbalance, and/or set a negative- or zero-sequence current to positive-sequence current ratio factor to supervise the directional element.

13. Analyze each and every microprocessor relay operation to ensure that the overall protection system is secure and reliable. This step is more important than routine testing of microprocessor relays. Get to the root of every problem, question, and uncertainty. Carefully review even normal looking operations because they often have clues useful in avoiding future trouble.

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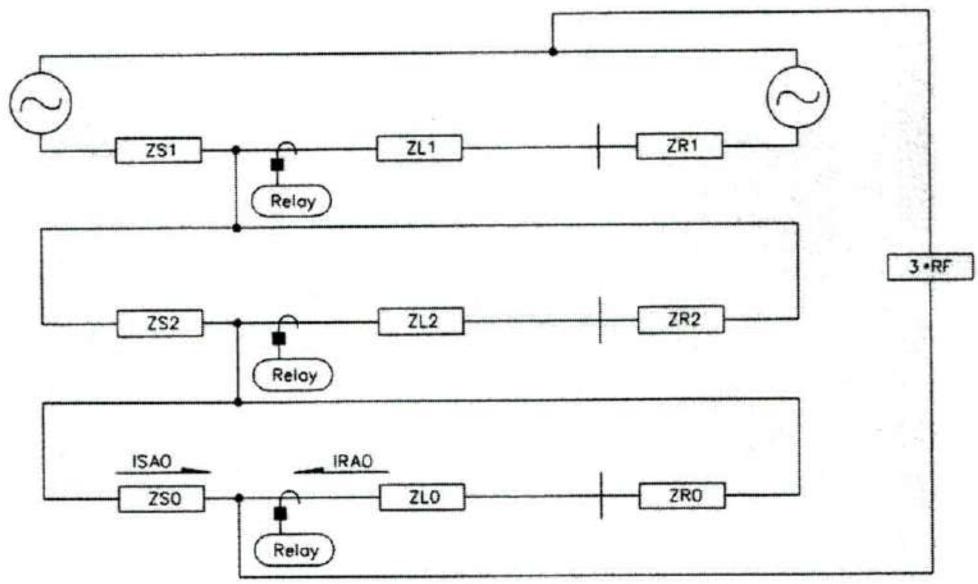
APPENDIX A

Improved Zero-Sequence Voltage-Polarized Directional Element (Patent Pending)

This appendix describes a new zero-sequence voltage-polarized directional element which overcomes dependability and security problems of traditional zero-sequence voltage polarized directional elements.

Figure A1 shows the sequence network connect for a phase-ground fault. The relay shown in the figure is monitoring all sequence currents and voltages. Zero-sequence directional elements use zero-sequence quantities only.



where:

$Z_{S1,R1}$ = positive-sequence local and remote source impedances respectively
$Z_{S2,R1}$ = negative-sequence local and remote source impedances respectively
$Z_{S0,R0}$ = zero-sequence local and remote source impedances respectively
$Z_{L1,L2,L0}$ = positive-, negative, and zero-sequence line impedances respectively
R_F = Fault resistance

Figure A1: Relay Monitors Sequence Quantities

When the zero-sequence source impedance behind the relay terminal is very strong, the zero-sequence voltage (V_{A0}) at the relay can be very low, especially for remote faults.

To overcome low V_{A0} magnitude, we can add a compensating quantity which boosts V_{A0} by $\alpha \cdot Z_{L0} \cdot I_{A0}$. The constant α controls the amount of compensation.

Equation (A1) shows the torque expression for a compensated zero-sequence directional element.

$$T32V = Re[(V_{A0} - \alpha \cdot Z_{L0} \cdot I_{A0}) \cdot (Z_{L0} \cdot I_{A0})^*] \quad (A1)$$

where:

* indicates complex conjugate

The term $(\alpha \cdot Z_{L0} \cdot I_{A0})$ adds with V_{A0} for forward faults, and subtracts for reverse faults. Setting α too large can make a reverse fault appear forward. This results when $(\alpha \cdot Z_{L0} \cdot I_{A0})$ is greater but opposed to the measured V_{A0} for reverse faults.

Relationship of the Apparent Z_0 to Fault Direction

Figure A1 shows the sequence network for a ground fault at the relay. The relay measures I_{SA0} for forward faults, and $-I_{RA0}$ for reverse faults.

From V_{A0} and I_{A0}, calculate Z_0:

Forward Ground Faults: $Z_0 = -V_{A0}/I_{SAO} = -Z_{S0}$

Reverse Ground Faults: $Z_0 = -V_{A0}/-I_{RAO} = (Z_{L0} + Z_{R0})$

This relationship is shown in Figure A2 for a 90° system.

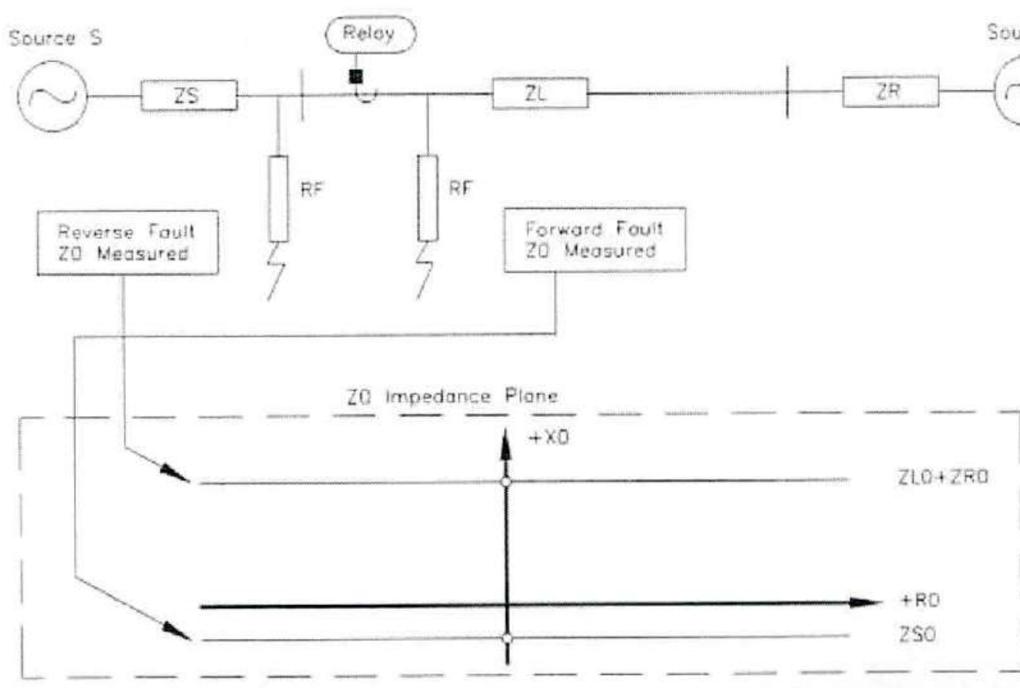


Figure A2: Zero-Sequence Source Impedance Measurement in the Zero-Sequence Plane

For the system in Figure A2, the fault is forward if Z_0 is negative, and reverse if Z_0 is positive.

Zero-Sequence Directional Element Based on Calculating and Testing Z_0

The discussion above shows that calculated Z_0 could be used to determine fault direction.

Recall the compensated directional element equation, T32V:

$$T32V = \mathrm{Re}[(V_{A0} - \alpha \cdot Z_{L0} \cdot I_{A0}) \cdot (Z_{L0} \cdot I_{A0})^*]$$

The forward/reverse balance condition for this element is zero torque. This is:

$$0 = \mathrm{Re}[(V_{A0} - \alpha \cdot Z_{L0} \cdot I_{A0}) \cdot (Z_{L0} \cdot I_{A0})^*]$$

Let $\alpha = z_0$

$Z_{L0} = 1 \angle \Theta$ where Θ is $\angle Z_{L0}$

Substituting,

$$0 = \mathrm{Re}[(V_{A0} - z_0 \angle\Theta \cdot I_{A0}) \cdot (I_{A0} \cdot 1\angle\Theta)^*]$$

Solving for z_0 results in an equation corresponding to the condition of zero-torque:

$$z_0 = \frac{\mathrm{Re}\left[V_{A0} \cdot (I_{A0} \cdot 1\angle\Theta)^*\right]}{\mathrm{Re}\left[\cdot(I_{A0} \cdot 1\angle\Theta) \cdot (I_{A0} \cdot 1\angle\Theta)^*\right]}$$

$$z_0 = \frac{\mathrm{Re}\left[V_{A0} \cdot (I_{A0} \cdot 1\angle\Theta)^*\right]}{|I_{A0}|^2}$$

Recall that the $(\alpha \cdot Z_{L0} \cdot I_{A0})$ term increases the amount of V_{A0} for directional calculations. This is equivalent to increasing the magnitude of the zero-sequence source impedance behind the relay location for forward faults. This same task is accomplished by increasing the forward z_0 threshold.

The criteria for declaring forward and reverse faults are then:

If z_0 < forward threshold, then the fault is forward

z_0 > reverse threshold, then the fault is reverse

The forward threshold must be less than the reverse threshold to avoid any overlap.

The z_0 directional element has all the benefits of both the traditional and the compensated zero-sequence directional element.

References

1. Patent Num. 5365396. Schweitzer Engineering Laboratories, Inc. "Negative-sequence directional element for a relay useful in protecting power transmission lines," 1994-11-15.

   Jeff Roberts and Armando Guzman, "Directional Element Design and Evaluation," 21st Annual Western Protective Relay Conference, Spokane, WA, October 94.

APPENDIX B

On December 20, 1994, Public Service of Colorado experienced a misoperation of the Barr Lake to Skyranch POTT scheme following a line breaker closing test into a three-phase fault on the Skyranch to Smokey Hill 230 kV line. Figure A3.a. shows the system single-line diagram.

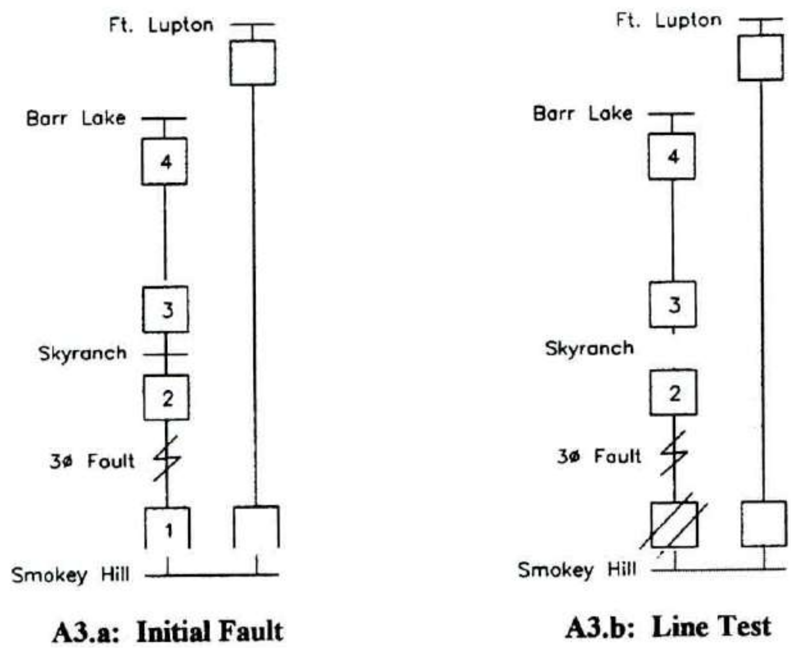


Figure A3: System Single-Line Diagram for Initial Three-Phase Fault and the Line Test Following the Initial Three-Phase Fault

Sequence of Events

Breakers 1 and 2 cleared the initial three-phase fault shown in Figure A3.a. When Breaker 2 closed to test the line (Figure A3.b. shows the system configuration during the line test), the POTT scheme on the Barr Lake to Skyranch line operated.

The relays at Breakers 3 and 4 captured event reports for this line test and subsequent misoperation. Figure A.4 shows an excerpt from the Skyranch relay.

```
5759 SKYRANCH TO BARR LAKE                Date: 12/20/94     Time: 03:08:48.325

FID=SEL-121G5-R400-V656mptrl2sy2-D891110

              Currents                        Voltages        Relays Outputs Inputs
               (amps)                           (kV)
                                                              52265L TCAAAAA DPBD5E
  IPOL      IR      IA      IB      IC      VA      VB      VC 011710 PL1234L TTTC2T
                                                              P3PNNP              A
                 •
                 •
                 •
    0     -270    -147    2235   -2356    -5.0   -11.9     2.3 M4.... ....... ....*.
    0     -212   -2605    1465     936     7.7     6.8    -3.8 M4.... ....... ....*.
    0      260     140   -2209    2326     2.9    11.1     0.5 M4.2P. ..*.... ....*.
    0      229    2601   -1427    -948    -8.3    -9.1     6.0 M4.2P. ..*.... ....*.

    0     -240    -113    2201   -2326     3.2   -11.7     1.1 M4.2P. *.**.*. .*..*.
    0      121   -1978    1272     827    26.0     4.8   -15.5 M4.... *..*.*. .*..*.
    0       -4       8   -1763    1752   -49.3    35.4    -4.1 M4.... *..*.*. .*..*.
    0     -355     770    -732    -393   -31.1   -27.2    54.3 M..... *..*.*. .*..*.

                 •
                 •
                 •
```

Figure A4: Skyranch Relay Event Report Shows 67N2 Element Picked Up When Permissive Trip Signal Present

From Figure A4, notice that the Level 2 overreaching element (67N2) used in the POTT scheme logic is picked up concurrent to the assertion of the permissive trip (PT) input. (The 67N2 element being picked up is shown as a 2 in the 67N column while the PT input assertion is shown by the * symbol in the PT column.) The 67N2 element being picked up while the PT input was asserted generated the undesirable trip.

The protective relay at Barr Lake operated correctly by detecting the forward three-phase fault shown in Figure A3 and keying permissive trip. The preferred action of the protective relay at Skyranch would be to declare this fault as reverse. However, the negative-sequence polarized ground directional element declared the fault direction forward, allowing the 67N2 element to operate. The pickup of the 67N2 element was set to 60A primary.

Non-Transposed Line Generated Unbalance

The 230 kV lines shown in Figure A3 were non-transposed. Thus, from the discussions earlier about non-transposed lines we expect there to be I_{A2} and I_R (= $3 \cdot I_{A0}$) for this three-phase fault. Using the highlighted rows from the event report shown in Figure A4, calculate the a_2 and a_0 values:

$$I_A = (2601 + j140) \text{ A pri.} \quad = 2604.8 \text{ A} \angle 3.1°$$

$$I_B = (-1427 - j2209) \text{ A pri.} \quad = 2629.8 \text{ A} \angle -122.9°$$

$$I_C = (-948 + j2326) \text{ A pri.} \quad = 2511.8 \text{ A} \angle 112.2°$$

Calculate I_{A1}, I_{A2}, and I_{A0} using I_A, I_B, and I_C:

I_{A1} = 2574.4 A

I_{A2} = 171.8 A

I_{A0} = 114.1 A

From these values, we calculate $a_2 = 0.0667$ ($|I_{A2}|/|I_{A1}|$) and $a_0 = 0.0443$ ($|I_{A0}|/|I_{A1}|$). These simple calculations using the event report data show us that every 1000 A of I_{A1} results in 66.7 A of I_{A2} and 132.9 A of I_R.

At the time of this three-phase fault, the 67N2 element pickup at Skyranch was set for 60 A primary (or 0.25 A secondary given the current transformer ratio of 240:1). Thus, the measured I_R current exceeded the 67N2 element pickup threshold during the three-phase fault. Assuming the maximum three-phase reverse fault current magnitude is 2574 A, one solution to this security problem is to raise the pickup of the 67N2 element to some value greater than 1.42 A (2574.4 A · 0.0443) to prevent this element from operating on the unbalance currents generated by the non-transposed the line.

BIOGRAPHY

Jeff Roberts received his BSEE from Washington State University in 1985. He worked for Pacific Gas and Electric Company as a Relay Protection Engineer for over three years. In 1988, he joined Schweitzer Engineering Laboratories, Inc. as an Application Engineer. He now serves as Research Engineering Manager. He has delivered papers at the Western Protective Relay Conference, Texas A&M University, Georgia Tech, and the South African Conference on Power System Protection. He holds multiple patents and has other patents pending. He is also a member of the IEEE.

Edmund O. Schweitzer, III is President of Schweitzer Engineering Laboratories (SEL), Pullman, Washington, U.S.A., a company that designs and manufactures microprocessor-based protective relays for electric power systems. He is also an Adjunct Professor at Washington State University. He received his BSEE from Purdue University in 1968 and MSEE from Purdue University in 1971. He received his Ph.D. from Washington State University in 1977.

Dr. Schweitzer is recognized as a pioneer in digital protection and holds the grade of Fellow in the Institute of Electrical and Electronic Engineers (IEEE), a title bestowed on less than one percent of IEEE members.

He has written dozens of technical papers in the areas of distance relay design, filtering for protective relays, protective relay reliability and testing, fault locating on overhead lines, induction motor protection, directional element design, dynamics of overcurrent elements, and the sensitivity of protective relays.

Dr. Schweitzer holds more than a dozen patents pertaining to electric power system protection, metering, monitoring, and control.

Renu Arora received her BSEE from Washington State University in 1985. She worked for Southern California Edison during 1986-1987. Since April 1987, she has been with Public Service Company of Colorado, where she is currently a System Protection Engineer. She is a Registered Professional Engineer in the State of Colorado. Her work includes design of protection systems for substations, transmission lines, distribution systems, and power generating plants.

Ernest Poggi received his BSEE from the University of Lowell (Lowell Tech. Institute) in 1976. He has been involved in the design and operation of power system substations and system protection equipment for 19 years with Florida Power & Light, Tri-State G&T, and Public Service Company of Colorado, where he is a Registered Professional Engineer in the State of Colorado and has participated in the IEEE subcommittee group on HVDC. He has co-authored and assisted in papers delivered to the Western Protective Relay Conference.

INVESTIGATION ON THE POWER SYSTEM FAILURE ON DECEMBER 03, 2021

FURTHER CLARIFICATIONS SOUGHT FROM CEB

The Committee investigating the total system failure on the 3rd December 2021, expects written clarifications with sufficient technical evidence from the Ceylon Electricity Board (CEB) presented to the committee in person, on the following points. The Committee expects CEB to present a unified response, covering the views and positions from all its divisions and branches. The Committee also expects full disclosure of issues and actions by CEB, related to the transmission lines and their protections systems over the period of 2015 to present.

The Committee expected comprehensive answers to the questions it posed to CEB, with all supporting documentation, data, records, etc. Regrettably, the response the Committee received from Additional General Manager (Transmission) was merely a collection of reports submitted by different branches of CEB that had failed to fully address the Committee's concerns

We make the following observation with the sincere hope that the CEB will treat the matter at hand with the gravity and urgency it deserves These observations have been compiled based on the written responses received from CEB to the Interim Recommendations in the Interim Report dated 27th December 2021 submitted to the Secretary, Ministry of Power, which has been subsequently conveyed to the CEB.

1. According to Transmission Control &Protection Branch, the phase B of Kotmale–Biyagama 220 kV transmission Line 02 tripped on the 3rd December 2021 at 11:27:14 by the operation of differential line protection, and the cause of the fault is believed to be on the primary side of protection equipment (CT, VT, Lightning Arrester, etc.). However, according to the Transmission O & M South Branch, there is no evidence of a persisting fault on the primary side. Much attention has been devoted to a "bushfire," including submission of technical papers published on the subject. However, we consider this effort by the CEB to be a feeble attempt to provide an escape route, as no evidence or technical basis of such an incident has been forthcoming. The images provided in the report of Transmission O & M South shows no signs of a bushfire, but a small fire on the ground close to the base of the 20 m high 138th tower of the line, leaving most of the potential areas green and unaffected. Had the CEB investigated the matter thoroughly, a bushfire would not have merited even a mention as a possible suspect for the alleged single-line-to-ground fault on phase B of line 2.

   It appears that the CEB has used the term "bushfire" loosely to describe a small fire lit by a villager. [The Cambridge English Dictionary defines bushfire as "a fire burning in the bush (= a wild area of land) that is difficult to control and sometimes spreads quickly." Bushfire, therefore, refers to an uncontrolled fire in the trees and bushes of scrubland (or forest)]. What CEB has referred to is possibly a bonfire lit under the line. Further, the "bushfire" theory put forward by the O&M-S Branch contradicts directly the explanation provided by C&P Branch that the cause of the tripping of phase B was a ground fault in the primary equipment.

   Therefore, the committee expects the CEB to disclose the full scenario, as one organization.

2. In page 1 of the Annexure 05, the response contains ***"Thus, the Protection Scheme of Biyagama – Kothmale Line 1 and 2 was designed, commissioned and tested by Siemens Ltd. one of the leading Protection Relay suppliers in the world. Further the protection scheme design and Protection Relay Setting Proposal submitted by Siemens for Biyagama – Kothmale Line were reviewed by consultant Fitchner, one of the leading consultancy companies in the world."***

   a. Despite glowing tribute paid to the design, commissioning, testing and review of the 220 kV protection system by world renowned entities, the CEB states that due to an error in the field wiring, the ON/OFF status of the Circuit Breaker had been received erroneously following the circuit breaker opening of phase B, leading to the operation of End Fault protection, which subsequently Locked Out Line 02 circuit breaker at the Kotmale end. Further, it is stated that the same field wiring error was identified on Line 01 as well, and the faulty wirings were corrected on the 2nd January 2022 and 26th December 2021 respectively. CEB's response also confirms that there has not been any previous operation of End Fault protection following a single phase to ground fault.

      This response by the CEB raises several important concerns:

      i. How can the field wiring of an already commissioned, tested and reviewed protection relay circuit (by world-renowned manufactures and engineering consultants in the field) develop an "error"?. CEB has not provided evidence of any subsequent modifications of the line bays in question, along with commissioning and testing reports related to such work. This situation makes it difficult to eliminate the possibility that the wiring may have been modified intentionally by someone in advance. The absence of any past record of end-fault tripping of this line reinforces the above suspicion.

         A. Please explain when the faulty wiring was first done and when it has been altered, since the protection development project of 2014.

         B. Please provide CEB internal records related to this wiring, identification of the wiring error, and internal documentation (reports, reviews, approvals) that authorized the revision to wiring. The committee requests to interview engineers or electrical superintendents who actually identified the error and did the rectification.

      ii. CEB's admission that "faulty wiring" detected on the line protection of line bays 1 and 2 have been "corrected" gives rise to a serious concern: (a) Did the C&P engineers take precautions to record such important evidence and inform their superiors of the discovery of faulty wiring, given that an investigation was ongoing? (b) Did they realize that their action would give rise to the allegation of tampering with technical evidence? (c) Have CEB authorities concerned issued instructions to C&P and O&M S branches to refrain from any modification/alteration of the relays and other transmission assets at Kotmale and Biyagama until the investigation is competed? This behavior of CEB at best can be describes as irresponsible, but is more likely to be viewed as an attempt to supply a basis for the unexplained operation of end-fault protection that eventually led to a system-wide power failure lasting six hours.

iii. The attribution of erroneous tripping of end-fault protection to faulty wiring contradicts the earlier explanation we received from C&P engineers that the end-fault protection was triggered because of a design flaw, which prevented the relay from receiving circuit breaker status of all three poles.

3.

a. The committee notes the 50N/51N OC-gnd-A1 Earth Fault settings of SIEMENS 7SL87 relay of Kotmale-Biyagama Line 01 has been 80 A on both sides. The CEB response reveals it has been increased to 160 A following the incident on the 3rd December 2021, to bring it to 10% of the rated current in the transmission line. This apparently arbitrary increase of the relay setting to 160 A calls into question the protection design by the world leading contractor Siemens, supervised by the consultant Fitchner, and implies that this value has been set wrongly (set too low) for the past 7 years. CEB engineers have not investigated the reason for observing a significant neutral current during normal operation of the line. Please clarify the basis of the previous setting (80 A) and the basis of deciding on the revised setting (160 A).

b. At the time the 3rd December 2021 incident occurred, the SIEMENS 7SL87 relay of Kotmale-Biyagama Line 02 at the Biyagama end shows its settings for 50N/51N OC-gnd-A1 Earth Fault is 150 A, while 80 A on the Kotmale end, whereas this setting for Line 01 is 80 A at both ends. Explain the basis for the difference in settings at the two ends of the same Line 02 and the technical basis for higher setting of 150 A?

4. The CEB response on page 6 of the Annexure 05 mentions that ***"In the mutual line compensation wiring available in these two circuits, neutral of the parallel circuit is wired to the protection relay. Neutral current shown in Main 01 relay of Line 01 is the neutral current of the Line 02 which has tripped approx. in 288ms. This could have led to the above misleading statement"***. Figure 1 shows the screen shot of fault records of the SIEMENS 7SL87 protection relay of the Line 01 as recorded in the relay. We may be able to accept CEB's explanation that the neutral current shown in Main 01 relay of Line 01 is the neutral current of Line 02, because it has become almost zero following Line 02 tripping.

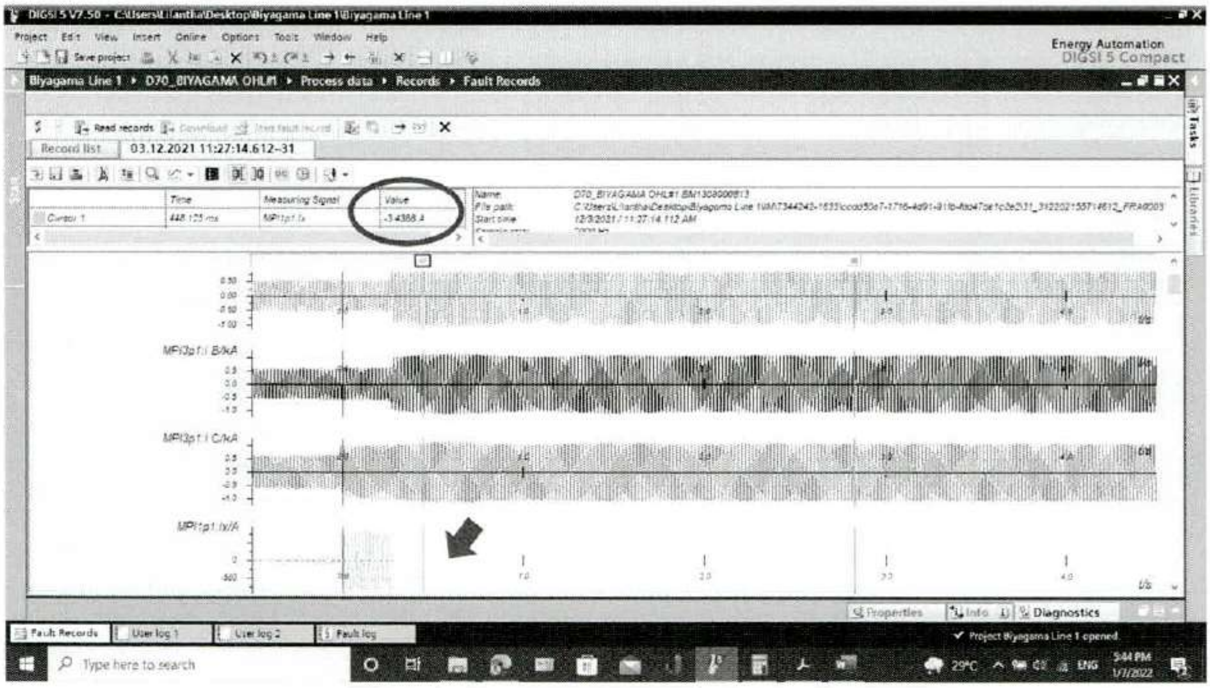


Figure 1

However, the above revelation does not explain the tripping of Line 01 on 3rd December 2021 from the operation of earth fault protection, as explained below:

Figure 2 shows the screen shot of fault records of SIEMENS 7SL87 relay as recorded in the protection relay of the Line 02. According to the above-mentioned wiring arrangement explained in the CEB response, the neutral current (bottom waveform) should be the neutral current of Line 01. We note that its peak value following Line 02 tripping is 91.213 A (rms value 64.5 A). According to the explanations given in the CEB response, the setting is 80 A and the pickup current is 10% higher than the setting (88 A) and dropout current is 10% less than setting (72 A). It is noted that the neutral current drops to 64.5 A (which is less than 72A), after 288 ms following the Line 02 tripping. Hence, the Committee finds no reason for the Earth Fault protection to operate as late as 22.33 seconds after, when the current has decreased below the dropout threshold in 288 ms. CEB should explain this issue giving reasons/justifications.

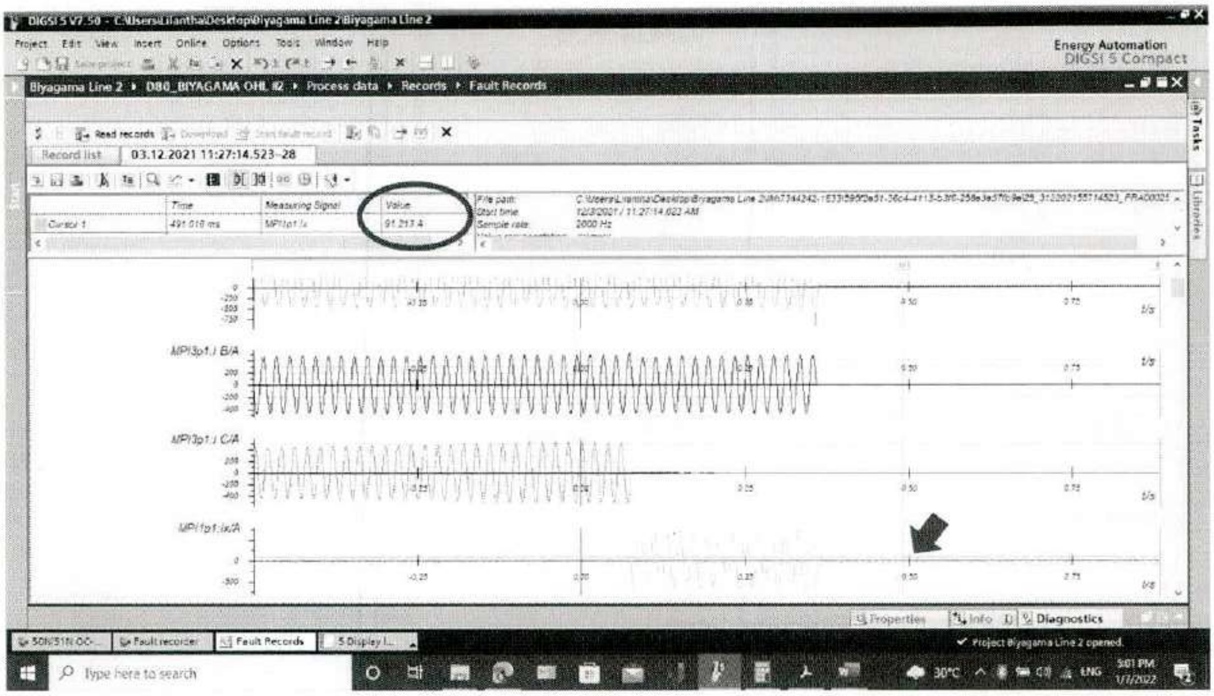


Figure 2

Signed on behalf of the committee by

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Prof. Lilantha Samaranayake / Chairman of the committee

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INVESTIGATION ON THE POWER SYSTEM FAILURE ON DECEMBER 03, 2021 FURTHER CLARIFICATIONS SOUGHT FROM CEB

Committee appointed to investigate the Total Failure requested further clarifications as follows.

- Email dated 2022-01-11 of Secretary, Ministry of Power with attached questionnaire.
- Questions forwarded by Committee during the meeting held between Committee and CEB Staff on 2022-01-12 at SCC.
- Additional questions forwarded by committee on 2022-01-13

Replies to the questions forwarded by the committee are submitted herewith.

Question 01

According to Transmission Control & Protection Branch, the phase B of Kotmale – Biyagama 220kV transmission Line 02 tripped on the 3rd December 2021 at 11:27:14 by the operation of differential line protection, and the cause of the fault is believed to be on the primary side of protection equipment (CT, VT, Lightning Arrester, etc.). However, according to the Transmission O & M South Branch, there is no evidence of a persisting fault on the primary side. Much attention has been devoted to a "bushfire," including submission of technical papers published on the subject. However, we consider this effort by the CEB to be a feeble attempt to provide an escape route, as no evidence or technical basis of such an incident has been forthcoming. The images provided in the report of Transmission O & M South shows no signs of a bushfire, but a small fire on the ground close to the base of the 20 m high 138th tower of the line, leaving most of the potential areas green and unaffected. Had the CEB investigated the matter thoroughly, a bushfire would not have merited even a mention as a possible suspect for the alleged single-line- to ground fault on phase B of line 2.

It appears that the CEB has used the term "bushfire" loosely to describe a small fire lit by a villager. [The Cambridge English Dictionary defines bushfire as "a fire burning in the bush (= a wild area of land) that is difficult to control and sometimes spreads quickly." Bushfire, therefore, refers to an uncontrolled fire in the trees and bushes of scrubland (or forest)]. What CEB has referred to is possibly a bonfire lit under the line. Further, the "bushfire" theory put forward by the O&M-S Branch contradicts directly the explanation provided by C&P Branch that the cause of the tripping of phase B was a ground fault in the primary equipment.

Therefore, the committee expects the CEB to disclose the full scenario, as one organization

CEB RESPONSE FOR QUESTION 01

Kothmale – Biyagama line 2 has tripped due to the occurrence of C phase (ABC notation) to Earth fault (Differential current of 521 A) in the primary side. The physical arrangement of primary equipment in Kothmale Lines at Biyagama GSS is shown in Annexure 1.1.viz. Transmission line, Circuit Breakers, Current Transformers, Line Isolator, Voltage Transformer, Lightning Arrester. This fault current has been recorded in Main 1, Main 2 relays and the BEN6000 Digital disturbance recorder. The recorded waveforms from this equipment are shown below:

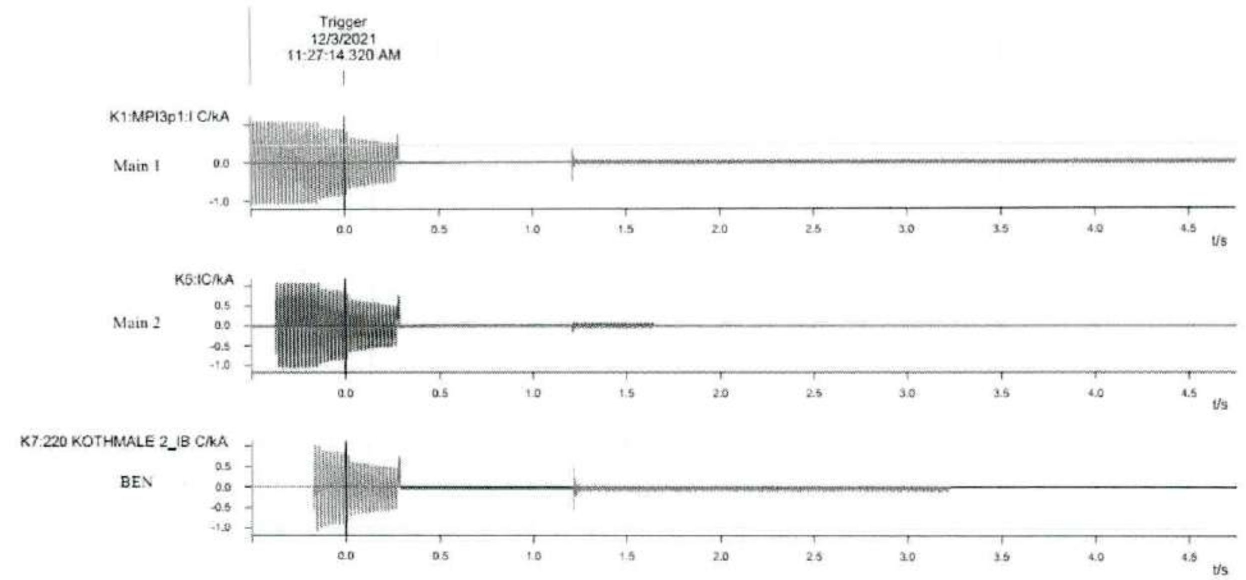

Figure 01: Current waveforms seen by Main 1 relay, Main 2 relay and DDR at Biyagama GSS – Kothmale line 2 C phase (In ABC notation)

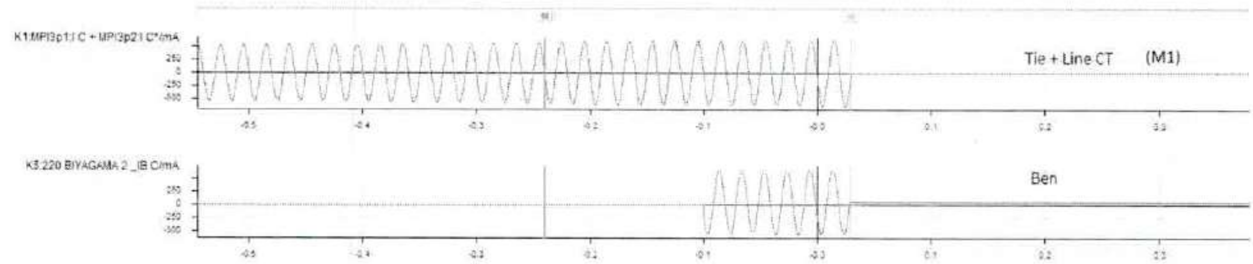

Figure 02: Current waveforms seen by Main 1 relay and DDR at Kothmale PS – Biyagama line 2 C phase (In ABC notation)

The Main 1 Protection Relay and BEN6000 Digital Disturbance Recorder at Kothmale have also recorded the fault current fed into C phase (ABC notation) to Earth fault. Screen shots of all the available waveforms of this incident recorded in different devices in both ends of the line are included in Annex 1.2.

In Figure 01 & 02, waveforms have been arranged with respect to the waveform that consist longest pre fault information. Pre fault recording of each device are as below.

M1 – 0.5 seconds memory before trigger
M2 – 0.66 seconds memory before trigger
DFR – 0.1 seconds memory before trigger

A differential current above 400A will instantaneously trigger a tripping of the circuit breakers of both ends of the line.

Zero sequence current fed to the fault from Biyagama end is approximately 431.36A and a zero sequence current of 89.91A could be observed in the fault records in Kothmale end of Line 2. Additionally, it is observed that the summation of zero sequence currents observed in all connected 220kV bays at Biyagama GSS prior to the tripping of Kothmale line 02 closely equals the zero-sequence current flowing in Kothmale line 2. This zero-sequence current has been cleared with the tripping of phase C which confirms that there has been an actual earth fault in the primary side of Biyagama Kothmale line 02. (Annexure 1.3 Detailed calculation of zero sequence currents)

Accordingly, there is sufficient information from secondary equipment to decide that there has been an actual earth fault in the primary equipment. Further the fault is a transient in nature and the faulty phase has reclosed successfully from Biyagama end. Transient faults may not leave any physical evidence and hence the digital disturbance records available in secondary equipment is used for failure analysis.

Such transient faults may be caused by flash over due to lightning, way leaves, contact with kites, surface flash over / creepage of insulators due to dust, salt etc., smoke created by fires close to the transmission line.

As per the information submitted by the DGM (O&MS South), only available physical evidence of the cause of the tripping was a man-made fire directly under the line, very close to the tower number 138 which is located 21.23km from Biyagama end. Photographic evidence of the fire is provided in Annexure 1.4.

It is noted that Phase C (bottom conductor) has tripped in this incident. Additionally, as per the witness statements the timing of the fire matches the tripping time of the transmission line. Based on the fault currents calculated distance to the fault is approximately 24.1 km from Biyagama GSS. (Fault distance calculation provided in Annexure 1.5) Accuracy of the calculation is limited due to the low fault currents involved, the errors in available line parameters and the measurement errors of CTs & CVTs. The O&MS staff has inspected the suspected range of the transmission line based on the initial calculated distance provided by the staff of C&P branch. As per calculation done by C&P Branch using the information collected from the Protection Relays the location of the fault is close to the location of fire. Considering the total length of the line, 70km, actual location of the fire lies within 5% error margin. However, fault impedance in this incident is very high. Hence flash over due to ionized air cannot be considered in this case. Likely possibility is a flashover to a nearby tree. A case study of a similar incident involving a very high resistant fault in a 525kV transmission line in Brazil is attached in annexure 1.6. (*https://ieeexplore.ieee.org/document/4982523*)

As per the data available on the faults occurred in the Biyagama – Kothmale transmission lines, it is apparent that in all trippings involving transmission line faults, which is 19 in total, at least one end has reclosed successfully. Hence all of them have been transient faults. When the line has reclosed from one end, the system operation engineer can close the breaker at the end with permanent tripping without any issue. Hence the involvement of Operation and Maintenance engineers is minimum and it is highly unlikely that there will be any physical evidence of the cause of line faults would ever be found. There are no recorded information of physical evidence for any of the above incidents.

A similar incident in which a high resistive fault, smaller than the load current, causing the operation of differential protection could be observed on 2019-10-18, in which the line has reclosed. (Figure 03)

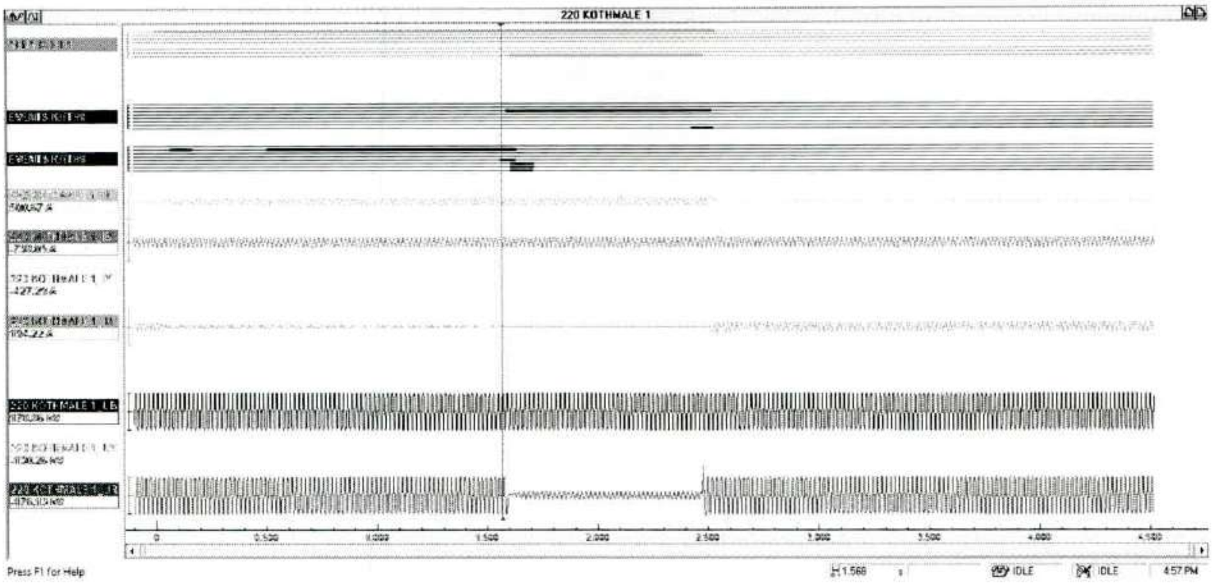

Figure 03: Ben 6000 DDR record of Kothmale line 1 at Biyagama GSS at 11:38hrs on 18.10.2019

As per the data obtained from transmission hotline maintenance unit for the period 2018-2021, there has been only 2 incidents in which the nature of the fault has been identified, out of all the trippings of the 220kV transmission lines in CEB network,

Table 01: Summary of Breakdowns -220kV Lines

No	Year	Total No of 220kV line trippings	Number of Breakdowns in which cause identified by hotline unit
1	2018	11	0
2	2019	18	0
3	2020	25	0
4	2021	28	2

Further a summary of breakdowns of all incidents involving 220kV and 132kV transmission lines is given below. This clearly demonstrate that majority of line trippings are of transient in nature and physical evidence may not be available.

Table 02: summary of breakdowns of all incidents involving 220kV and 132kV transmission lines since 2018

Year	Total no. of line transmission trippings	Number of Breakdowns in which cause identified by hotline unit	Percentage (Nature identified)
2018	300	11	3.67%
2019	247	8	3.24%
2020	185	2	1.08%
2021	210	8	3.81%

Question 02

In page 1 of the Annexure 05, the response contains **"Thus, the Protection Scheme of Biyagama – Kothmale Line 1 and 2 was designed, commissioned and tested by Siemens Ltd. one of the leading Protection Relay suppliers in the world. Further the protection scheme design and Protection Relay Setting Proposal submitted by Siemens for Biyagama – Kothmale Line were reviewed by consultant Fitchner, one of the leading consultancy companies in the world."**

a. Despite glowing tribute paid to the design, commissioning, testing and review of the 220kV protection system by world renowned entities, the CEB states that due to an error in the field wiring, the ON/OFF status of the Circuit Breaker had been received erroneously following the circuit breaker opening of phase B, leading to the operation of End Fault protection, which subsequently Locked Out Line 02 circuit breaker at the Kotmale end.

Further, it is stated that the same field wiring error was identified on Line 01 as well, and the faulty wirings were corrected on the 2nd January 2022 and 26th December 2021 respectively. CEB's response also confirms that there has not been any previous operation of End Fault protection following a single phase to ground fault.

This response by the CEB raises several important concerns:

I *How can the field wiring of an already commissioned, tested and reviewed protection relay circuit (by world-renowned manufactures and engineering consultants in the field) develop an "error"?. CEB has not provided evidence of any subsequent modifications of the line bays in question, along with commissioning and testing reports related to such work. This situation makes it difficult to eliminate the possibility that the wiring may have been modified intentionally by someone in advance. The absence of any past record of end-fault tripping of this line reinforces the above suspicion.*

A. *Please explain when the faulty wiring was first done and when it has been altered, since the protection development project of 2014.*

B. *Please provide CEB internal records related to this wiring, identification of the wiring error, and internal documentation (reports, reviews, approvals) that authorized the revision to wiring. The committee requests to interview engineers or electrical superintendents who actually identified the error and did the rectification.*

II *CEB's admission that "faulty wiring" detected on the line protection of line bays 1 and 2 have been "corrected" gives rise to a serious concern:*

(a) Did the C&P engineers take precautions to record such important evidence and inform their superiors of the discovery of faulty wiring, given that an investigation was ongoing?

(b) Did they realize that their action would give rise to the allegation of tampering with technical evidence?

(c) Have CEB authorities concerned issued instructions to C&P and O&M S branches to refrain from any modification/alteration of the relays and other transmission assets at Kotmale and Biyagama until the investigation is competed? This behavior of CEB at best can be describes as irresponsible, but is more likely to be viewed as an attempt to supply a basis for the

unexplained operation of end-fault protection that eventually led to a system-wide power failure lasting six hours.

III The attribution of erroneous tripping of end-fault protection to faulty wiring contradicts the earlier explanation we received from C&P engineers that the endfault protection was triggered because of a design flaw, which prevented the relay from receiving circuit breaker status of all three poles.

CEB Response for Question 02

It needs to be reiterated that there was no error in the wiring during the commissioning of the 220kV protection development project. The error resulted during the replacement of circuit breakers of Kothmale line 1 & 2 in March / April 2015. As per the records available since 2015, there is one similar incident in which single phase AR has not been operated from Kothmale end on 2021-05-11, due to the operation of end fault protection from Biyagama end. (Refer Annexure 2.1 for details of previous incidents)

Error in the connection can be seen in the drawing prepared for the breaker modification which is available at Biyagama GSS as well. Hence there is no ground for the assumption that the faulty wiring was an intentional act of sabotage.

As per Preliminary Report on Total System Failure dated 2021-12-03 it was proposed by Control and Protection Branch to carryout following recommendations and submitted for AGM (Transmission)'s approval.

1 It is recommended to test the current transformer and inspect associated primary equipment in the Phase B of the Kothmale 220kV line 02 bay at Biyagama GSS immediately to identify the cause of the fault and replace the said current transformer if necessary. Further it is not recommended to keep the line in operation due to the possibility of repetition of the same incident.

2 It is recommended to increase the non-directional earth-fault setting of 80A currently used in 220kV transmission lines.

Thereafter the Committee visited the Kothmale Power Station on 2021-12 11 and C &P Branch handed over the following data related to Total Failure.

1 Relay Settings, Relay Events and Oscilloscope records of Protection Relays of Biyagama – Kothmale Line 01 and 02
2 Relay Software related to above item no. (1).
3 Records collected from Digital Disturbance Recorders installed at Biyagama GS and Kothmale Power Station.

Initially the C&P staff refrained from engaging in any work at Kothmale or Biyagama GSS until the committee investigating the failure visited Kothmale PS on 2021-12-11 and collected all the required information.

After the submission of requested information to Committee, DGM(Transmission Control and Protection) requested the concurrence of AGM(Transmission) to test the End Fault Protection Scheme of Biyagama – Kothmale Line 01 and 02. Thereafter AGM(Transmission) emphasized that we have a prime duty to avoid failures similar to what happened in 2021-11-29 and 2021-12-03 and granted required permission to DGM(Control and Protection) to visit two sites i.e., Biyagama GS and Kothmale PS to take urgent measures that required to avoid repeating a similar failure again.

Accordingly, End fault protection scheme was checked after obtaining outage on 220 kV Kotmale Line 1 and Line 2 on 2021-12-26 and 2022-01-02 respectively. Until this inspection at site, the exact cause for incorrect breaker status was not confirmed. Subsequent inspection revealed that the issue is with the connections in the circuit breaker and not in the design. This issue was rectified during the outage period since it is not recommended to energize Kothmale- Biyagama Transmission line without rectifying the identified issue

The staff of C&P branch has acted in a responsible manner and informed the AGM(Transmission)/Management as mentioned above, the need to investigate and rectify the mal-operation of Protection scheme of Biygama - Kothmale Lines.

In order to correct operation of the end fault protection, accurate CB position shall be fed into the Busbar Protection relay (Siemens 7SS52). In Biyagama GS as per the drawing a series of Normally Closed (NC) contacts of CB – R phase, CB – Y phase and CB – B phase are used to detect the CB open condition when all the three phases are in open position as follows,

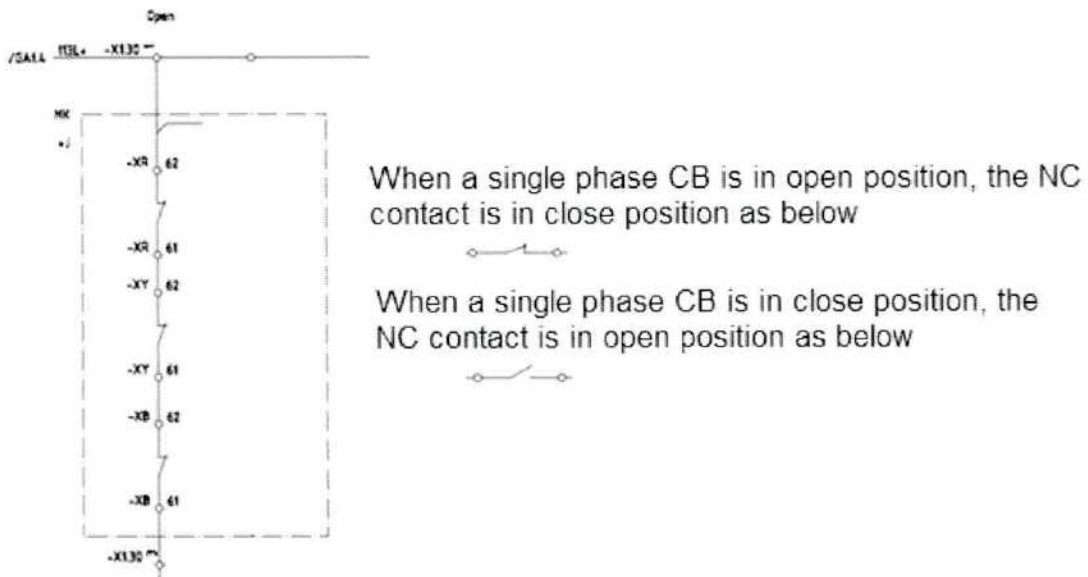

Figure 04: Connection of circuit breaker status required as per the drawing

As per the design followed at Biyagama Grid Substation the Circuit Breaker position information first received by Control panel and thereafter it is shared using a repeat relay and control wires to the Bus Bar Protection Relay. Following table illustrates the CB position received to the control panel, according to the R, Y, B actual CB positions, as per the above drawing.

Table 03: CB position received to the control panel, according to each state of R, Y, B as per the drawing

No.	Actual CB Position			Final CB position received to the relay	End Fault Protection of the relay
	R – Phase	Y - Phase	B - Phase		
1	Close	Close	Close	Close	Disable
2	Close	Close	Open	Close	Disable
3	Close	Open	Close	Close	Disable
4	Close	Open	Open	Close	Disable
5	Open	Close	Close	Close	Disable
6	Open	Close	Open	Close	Disable
7	Open	Open	Close	Close	Disable
8	Open	Open	Open	Open	Enable

From the above table it is clear that Control Panel (also Busbar Protection relay) gets the CB as open when all the three CBs are in open position (condition no. 8) and End Fault protection will only enable at this condition. In other conditions Busbar relay Binary Input will not get the voltage, hence it decides the CB is in close position and end fault protection will be disabled.

After the total failure the staff of Control and Protection Branch investigated the End Fault Protection Scheme of Biyagama – Kothmale Line 1 and 2 and found that the Control Panel is not receiving the accurate Circuit Breaker Status information and in turn the End Fault Protection Scheme is not receiving the accurate Circuit Breaker Status Information and therefore the Scheme could mal-operate. Further it was noted that the Circuit Breakers of Biyagama – Kothmale Line 01 and 02 have been replaced by new circuit breakers after the commissioning of Protection Schemes at Biyagama GSS under 220 kV Protection Development Project. This wiring issue was not identified in the other 220 kV Line bays commissioned under 220 kV Protection Development Project.

The staff of Control and Protection Branch immediately rectified the wiring issue and made available the accurate circuit breaker status information to the Busbar Protection relay.

The issues identified in 220 kV Kotmale Line 1 and Line 2 on 2021-12-26 and 2022-01-02 respectively are as follows,

<u>In 220 kV Kotmale Line 1</u>

As per the existing wiring only CB-R phase status feedback is receiving to the Control Panel and other two-phase statuses were disregarded.

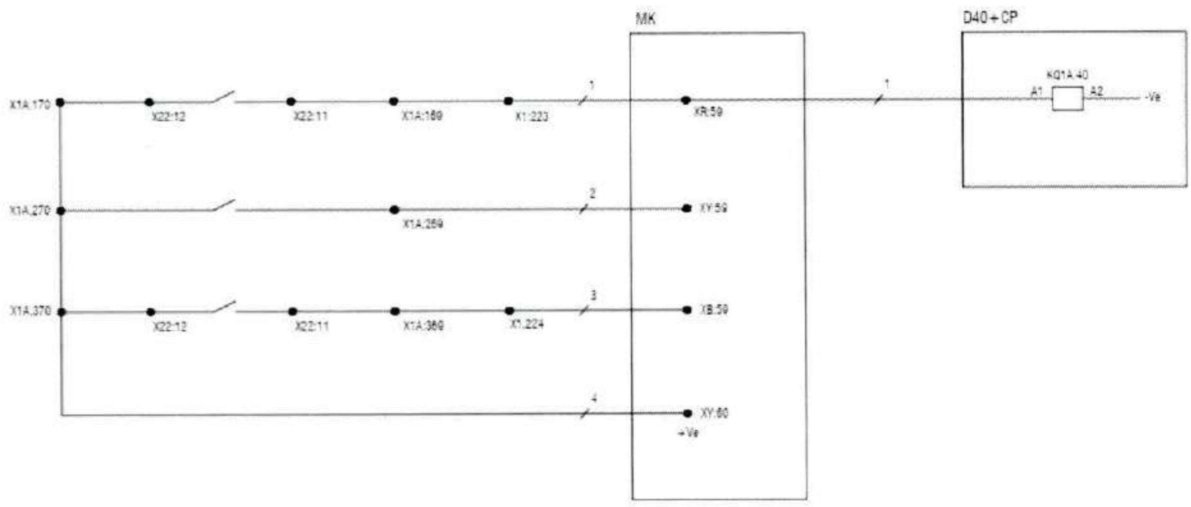

Figure 05: Existing CB close feedback to C&P relays of Kothmale line 1

So, the above table 03 is again tabulated as per above wiring,

Table 04: CB position received to the control panel, according to each state of R, Y, B as per the existing wiring in Kothmale line 01

No.	Actual CB Position			Final CB position receive to the relay	End Fault Protection of the relay
	R – Phase	Y - Phase	B - Phase		
1	Close	Close	Close	Close	Disable
2	Close	Close	Open	Close	Disable
3	Close	Open	Close	Close	Disable
4	Close	Open	Open	Close	Disable
5	Open	Close	Close	Open	Enable
6	Open	Close	Open	Open	Enable
7	Open	Open	Close	Open	Enable
8	Open	Open	Open	Open	Enable

It is clear from the above table when CB - R phase is in open position the End Fault protection will enable without considering other CB status.

In 2021-11-29 incident, after tripping of R phase CB due to R-E fault, the end fault protection operated and sent a transfer trip command to Kotmale end as per no. 5 condition of above table.

In 220 kV Kotmale Line 2

As per the existing wiring paralleling of NC (Normally Closed) contacts were used to give the opening of all three phases to the Busbar Protection relay. Please refer below drawing. This scheme is incorrect and should be serially connected as above Figure 04.

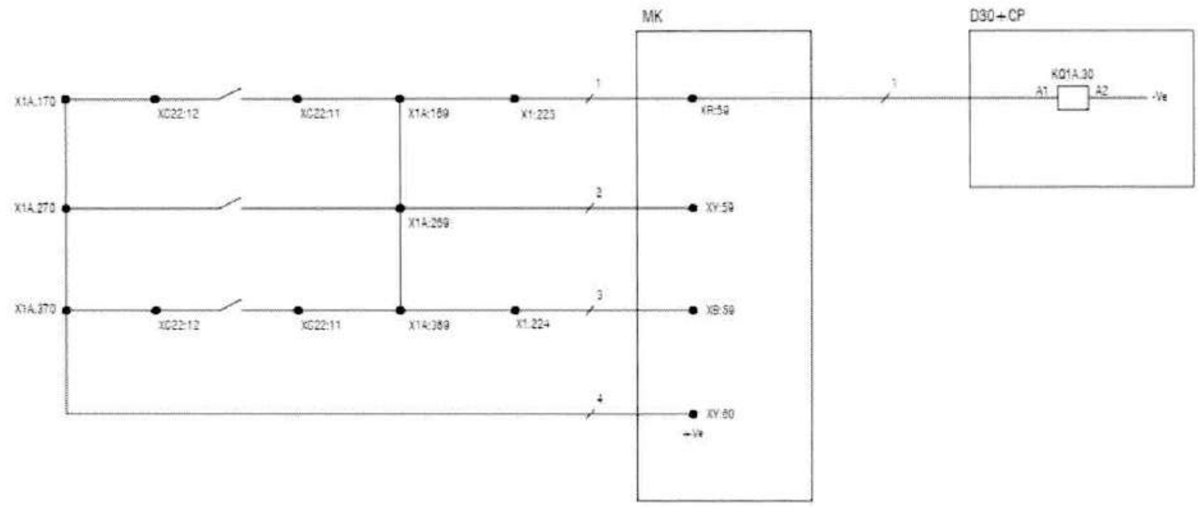

Figure 06: Existing CB close feedback to C&P relays of Kothmale line 2

So, the above table 03 is again tabulated as per above wiring,

Table 05: CB position received to the control panel, according to each state of R, Y, B as per the existing wiring in Kothmale line 02

No.	Actual CB Position			Final CB position receive to the relay	End Fault Protection of the relay
	R – Phase	Y - Phase	B - Phase		
1	Close	Close	Close	Close	Disable
2	Close	Close	Open	Open	Enable
3	Close	Open	Close	Open	Enable
4	Close	Open	Open	Open	Enable
5	Open	Close	Close	Open	Enable
6	Open	Close	Open	Open	Enable
7	Open	Open	Close	Open	Enable
8	Open	Open	Open	Open	Enable

It is clear from the above table out of eight conditions, in seven conditions the Control Panel receives that the CB is in open position and the End Fault protection will be enabled.

In 2021-12-03 incident after tripping of B phase CB due to B-E fault, the end fault protection operated and sent a transfer trip command to Kotmale end as per no. 2 condition of above table.

Explanation of 2021.05.11 incident with the above incorrect wiring

On 2021.05.11 at 18:49 hrs both Kotmale – Biyagama line 1 and line 2 tripped due to Y – E fault. In this incident the currents of the healthy phases after the tripping of Y phase exceed the required threshold of 500A to enable End Fault Protection. The healthy phases currents were more than 900 A. During this incident Kotmale – Biyagama line 1 successfully Auto Reclosed in both sides and Kotmale end of Line 2 lockout due to receiving of inter trip by operation of End fault Protection at Biyagama end.

Table 06: Explanation of operation / non operation of Endfault protection during the incident on 2021.05.11 based on above conditions

220 kV Line Name	Fault	Biyagama End	Kotmale End	
Kotmale – Biyagama line 1	Y-E at 18:49	Auto Reclosed	Auto Reclosed	As explained in above, the scheme was only considered the R-phase CB position. So, in this incident even though Y-phase is open, the Busbar relay was still receiving that the CB was in closed position. Therefore, End Fault Protection will not be enabled. (See condition 3 of Table No.04)
Kotmale – Biyagama line 2	Y-E at 18:49	Auto Reclosed	Lockout	As explained in above, the all three CB contacts were in parallel and when any one phase (Y-phase in this case) gets open the Busbar relay was identified it as the CB as open. Therefore, End Fault Protection will be enabled. (See condition 3 of Table No.05)

More details are described in Response for Question 05

<u>CEB Response Submitted for Question 02 is Summarized below.</u>

1 Biyagama Grid Substation was originally constructed by a Swedish company named ASEA under the Mahawali Transmission Project.

2 CEB received the first set of drawings for Biyagama in 1983 and the second set of As Built drawings in 1986 from ASEA. (Copy of the drawings are attached in Annexure 2.2 and Annexure 2.3)

3 As per 1983 drawing the circuit breaker open status information was brought to the Control and Protection Panel of Kothmale lines by connecting normally closed contacts of R,Y and B phases of circuit breaker in parallel.

4 As per 1986 As Built drawing the circuit breaker open status information was brought to the Control and Protection Panel of Kothmale lines by connecting normally closed contacts of R,Y and B phases of circuit breaker in series.

5 Under 220kV Protection Development Project new Control and Protection Panels were supplied for Kothmale Line 01 and 02 by Siemens in November 2014. As per As Built drawings of 220 kV Protection Development Project, Siemens has used ASEA drawings dated 1986. A new Bus Bar Protection Panel was supplied in January 2015. As per Siemens Bus Bar Protection Panel Design, the circuit breaker status information is obtained from the Control Panel. (Copy of Siemens drawings are enclosed in Annexure 2.4)

6 As per drawings available at Biyagama GSS the circuit breakers of Kothmale Line 01 and 02 have been replaced in March/April 2015. For this work ASEA drawings dated 1983 have been used. (A copy of the drawings is enclosed in Annexure 2.5)

7 When investigating the mal-operation of the End Fault Protection Scheme after the total failure occurred on 2021-12-03 by C&P Staff, it was found that the Control Panel and the Bus Bar Protection Panel are not receiving the Circuit Breaker Open status information accurately. When checking the wiring of Circuit Breaker, it was found that auxiliary contacts of R,Y and B phases of Circuit Breaker are not serially connected as required by Siemens Control Panel design and Bus Bar Protection design.

8 The wiring issue of Circuit Breakers of Kothmale Line 01 and Line 02 were corrected on 2021-12-26 and 2022-01-02 respectively by staff of Control and Protection Branch.

Question 03

a. The committee notes the 50N/51N OC-gnd-A1 Earth Fault settings of SIEMENS 7SL87 relay of Kotmale-Biyagama Line 01 has been 80 A on both sides. The CEB response reveals it has been increased to 160 A following the incident on the 3rd December 2021, to bring it to 10% of the rated current in the transmission line. This apparently arbitrary increase of the relay setting to 160 A calls into question the protection design by the world leading contractor Siemens, supervised by the consultant Fitchner, and implies that this value has been set wrongly (set too low) for the past 7 years. CEB engineers have not investigated the reason for observing a significant neutral current during normal operation of the line. Please clarify the basis of the previous setting (80 A) and the basis of deciding on the revised setting (160 A).

b. At the time the 3rd December 2021 incident occurred, the SIEMENS 7SL87 relay of Kotmale Biyagama Line 02 at the Biyagama end shows its settings for 50N/51N OC-gnd-A1 Earth Fault is 150 A, while 80 A on the Kotmale end, whereas this setting for Line 01 is 80 A at both ends. Explain the basis for the difference in settings at the two ends of the same Line 02 and the technical basis for higher setting of 150 A?

CEB Response for Question 03

As per available information a Protection Stetting Study has been carried out under SPDTP Project in 1996 by Consultancy Company – Lahmeyer International of Germany and recommended Earth Fault current setting for Biyagama – Kothmale Line as 150A. (A copy of Lahmeyer report submitted for Biyagama GS and Kothmale PS is enclosed in Annexure 3.1)

Under 220kV Protection Development Project adopted 150A for Main 1 - Siemens Protection Relay and 160A for Main 2 - Schneider Protection Relay as Earth Fault Current Setting of Biyagama – Kothmale Line 1 and 2 in year 2015. Further the minimum setting available in Schneider relay as Earth Fault current setting is160A. (A screen shot of Settings implemented under 220kV Protection Development Project is enclosed in Annexure 3.2)

Thereafter during the period July 2017 to Aug 2019 Transmission Division has developed a document named Protection Settings Standard under the leadership of Dr A P Thennekoon DGM(C&P) and had been informed to Staff of C&P Branch to follow this setting standard. Accordingly, it is recommended to use 80A for Earth Fault Current Setting of 220 kV Transmission Lines. (A copy of Protection Setting Standard is enclosed in Annexure 3.3)

Afterwards the Staff of C&P Branch has implemented the recommended Earth Fault current setting of 80A in Biyagama – Kothmale Line 1 and 2 on 2019-09-26 while carrying out the routing maintenance of Protection Panel. Due to the line outage was received for a limited period of time C&P staff have not been able to carry out this setting revision in Line 2 at Biyagama end. (A copy of Relay Test Sheet is enclosed in Annexure 3.4)

When analyzing the Total Failure occurred on 2021-12-03 it was found that large zero sequence current is flowing in the Biyagama – Kothmale Line 1 and 2 under steady state conditions and the Earth Fault current setting of 80A in Main 1 relay could result a mal-operation of the relay. Therefore, the Earth Fault Current Setting of Main 1 relay was increased to 160A by C&P Staff. (i.e. in line with Main 2 Protection Relay.) The Work Order prepared in this regard by C&P Staff is enclosed in Annexure 3.5.

Question 04

The CEB response on page 6 of the Annexure 05 mentions that ***"In the mutual line compensation wiring available in these two circuits, neutral of the parallel circuit is wired to the protection relay. Neutral current shown in Main 01 relay of Line 01 is the neutral current of the Line 02 which has tripped approx. in 288ms. This could have led to the above misleading statement".*** *Figure 1 shows the screen shot of fault records of the SIEMENS 7SL87 protection relay of the Line 01 as recorded in the relay. We may be able to accept CEB's explanation that the neutral current shown in Main 01 relay of Line 01 is the neutral current of Line 02, because it has become almost zero following Line 02 tripping However, the above revelation does not explain the tripping of Line 01 on 3rd December 2021 from the operation of earth fault protection, as explained below:*

Figure 2 shows the screen shot of fault records of SIEMENS 7SL87 relay as recorded in the protection relay of the Line 02. According to the above-mentioned wiring arrangement explained in the CEB response, the neutral current (bottom waveform) should be the neutral current of Line 01. We note that its peak value following Line 02 tripping is 91.213 A (rms value 64.5 A). According to the explanations given in the CEB response, the setting is 80 A and the pickup current is 10% higher than the setting (88 A) and dropout current is 10% less than setting (72 A). It is noted that the neutral current drops to 64.5 A (which is less than 72A), after 288 ms following the Line 02 tripping. Hence, the Committee finds no reason for the Earth Fault protection to operate as late as 22.33 seconds after, when the current has decreased below the dropout threshold in 288 ms. CEB should explain this issue giving reasons/justifications.

CEB Response for Question 04

According to the "Pickup & Dropout behaviors of the Inverse Time Curve According to IEC & ANSI" part of the technical manual of Siemens 7SL87 relay, dropout shall be initiated from 0.9 of the threshold value (Figure 07).

Pickup, Dropout, and Tripping Behavior of the Dependent Characteristic Curve According to IEC and ANSI

When the input variable exceeds the threshold value by a factor of 1.1, the inverse-time characteristic curve is processed. An integrating method of measurement totalizes the weighted time. This time results from the characteristic curve. For this, the time that is associated with the present current value is determined from the characteristic curve. Once the weighted time exceeds the value 1, the stage operates.

When the measured value falls short of the pickup value by a factor of 1.045 (0.95 x 1.1 x threshold value), the dropout is started. The pickup will be indicated as clearing. You can influence the dropout behavior via setting parameters. You can select between the following options:

- Non-delayed dropout: The summed time is deleted.
- Dropout according to characteristic curve: The summed time is reduced in relation to the characteristic curve.

The dropout according to characteristic curve (disk emulation) is the same as turning back a rotor disk. The weighted reduction of the time is initiated from 0.9 of the set threshold value.

Figure 07: Extract of 7SL87 relay manual explaining the intended pickup and drop out characteristics.

However, according to the existing fault record information, it seems that the Biyagama Line 01 7SL87 relay at Kothmale PS end didn't anyhow get dropped out at the dropout threshold mentioned above at the incident on 2021-12-03.

Due to the ambiguous nature of this incident, we have tested the earth fault characteristic of Main 1 Siemens 7SL87 relay of Biyagama line 1 at Kothmale PS end on 2022-01-09 and found out that the dropout threshold was actually at 58A when the threshold is set to 80A. Tests have been repeated and same was confirmed.

Furthermore, the same relay at Kothmale PS was tested by subjecting to the sequence of events that occurred at the abnormal tripping of Biyagama Line 01 on 2021-12-03 during the total failure too. In the simulation 480A (240mA Secondary) zero sequence current was applied for a 288ms (For the simulation of B phase opening of the parallel line) and then dropped to 70A (35mA) & steadily maintained that value (For the simulation of the state after 3 pole tripping of the parallel line). Then also the relay got tripped at elapsing a same time of around 22.35 seconds after the initial pick-up of the relay by behaving almost similarly to what had been observed in actual operation.

Then, the behavior was tested by changing the steady current in the range 88A (44mA Secondary) - 60A (30mA Secondary) with steps of 1mA secondary and relay got tripped each time elapsing same duration from the initial pick up. The tripping didn't occur only when the steady current was reduced to 29mA secondary (Test report attached in Annexure 4.1).

In addition, an interruption was taken on 2022-01-11 and 7SL87 relay of Kothmale line 01 at Biyagama GSS was tested by keeping the same settings as of the Main 01 (7SL87) relay at Kothmale end in the same line. Then also a similar behavior was observed (Test report attached in Annexure 4.2).

It seems in both the cases, the drop off was at 58A (72.5% of the setting) when the earth fault threshold has been set to 80A.

Generally, dropout characteristic of IDMT protection is not tested during commissioning since the standard test protocol for testing numerical protection relays does not include the test for drop off characteristic. (Standard test protocols employed by Siemens, ABB & NR are provided in Annexure 4.3)

At the discussion with the committee on 2022-01-12, it was recommend to do take following actions to further investigate the issue.

01 Test at least one other 7SL87 relay from the same batch
02 Test another relay from different batch
03 Request a clarification from the OEM regarding the behaviour of the Main 01 (7SL87) relay of Biyagama Line 01 at Kothmale PS end on 2021-12-03 at 11.27 Hrs

So, with the committee recommendations, C&P Branch has requested a clarification from OEM (Siemens Powe Automation Ltd) via their online help desk (email: energy.automation@siemens.com) on 2022-01-15. The copy of the request is attached as annexure 6.1

In the meantime, C&P Branch tested one of the 7SL87 relays of the same batch which was at C&P test laboratory on 2022-01-16 and found to be having identical response (Test report attached in Annexure 4.4). On the same day, two other 7SL87 relays which were of upgraded versions & installed on recently (2019) at 220kV Mannar 01 & 02 bays at New Anuradhapura GS were also tested and found to be behaving almost in identical manner. (Test reports are attached in Annexure 4.5 & Annexure 4.6)

The OEM response was received on 2022-01-18 and snapshot is attached below.

M Gmail darshana kumara <gvdkumara@gmail.com>

Ticket Nr./No.: 8-721197: Requesting Explanation on the Abnormal Operation of Non-Directional Ear... ISSUE=721197 PROJ=8

energy.automation@siemens.com <energy.automation@siemens.com> Tue, Jan 18, 2022 at 7:34 AM
Reply-To: energy.automation@siemens.com
To: gvdkumara@gmail.com

IMPORTANT: When replying, type your text above this line. --- WICHTIG: Bei Antwort, bitte Ihren Text oberhalb dieser Linie eingeben. --- IMPORTANTE: Al responder, por favor hágalo por encima de esta línea. --- IMPORTANT: Lorsque vous répondez, tapez votre texte au-dessus de cette ligne.

Smart Infrastructure - Digital Grid Customer Support - Ticket Notification

Additional Recipients: (permanent) haomapriya@gmail.com, nadunchamikara@gmail.com, sachinda.ranatunge@gmail.com, wettasin3@gmail.com

Dear Mr Kumara:

Thanks for your inquiry!
The reason for reset value=29mA is in technical data: there are two criteria:
1) 0.95*1.1*threshold value= 0.042A, the drop differential is 0.002A
2) minimum drop differential 15mA for 1A

so the greater of the drop differential (|pickup value- dropout value|) is 15mA, and dropout value is 29mA.
Dropout

The greater dropout differential (= | **pickup value - dropout value** |) of the following 2 criteria applies:

Dropout	95 % of 1.1 · threshold value
Minimum absolute dropout differential	
Protection-class current transformer	15 mA sec. (I_{rated} = 1 A) or 75 mA sec. (I_{rated} = 5 A)
Instrument current transformer	0.5 mA sec. (I_{rated} = 1 A) or 2.5 mA sec. (I_{rated} = 5 A)

If relay pickup and current drop down between 29mA and 44mA, relay will use 1.1*threshold value to calculate operate time, which is about 22.5s.

Best Regards
Ren YiQiang
Siemens Power Automation Ltd.
RC-CN EM DG SPA Pro CS CUC

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Fax:+86-2552109237
Email:ea_support.cn@siemens.com

Ticket Status: Feedback Required
Topic: Requesting Explanation on the Abnormal Operation of Non-Directional Earth Fault Protection of 7SL87 Relays
Received on: 2022-01-14 - 12:25:03

Figure 08: OEM (SIEMENS) Response on the Abnormal Operation of Non-Directional Earth Fault Protection

According to the OEM response, the dropout value of the function is determined not only by the drop out defined in the IEC standard (0.95*1.1 threshold value when set to instantaneous reset or 0.9*Threshold value when set to disk emulation reset as in this scenario) for normal inverse characteristic but also by the "Minimum Absolute Dropout Differential" applicable to internal current transformer category (1A protection class in this case) of the relay. So, when the gap of (pickup value – dropout value) according IEC specification is less than to the "Minimum Absolute Dropout Differential" value of the relay, dropout is determined by the value of the latter. The case for the Biyagama Line 01 relay at Kothmale can be summarized as below.

Non-Directional Earth Fault Threshold (Primary)	= 80A
CT Ratio	= 2000/1
Non-Directional Earth Fault Threshold (Primary)	= 80/2000 mA = 40 mA
Pickup value of the relay	= 1.1*40mA = 44 mA
Dropout Value According to the IEC Specification	= 0.9*40 mA = 36 mA
Difference between pickup and dropout values as per IEC standard	= 44 mA – 36 mA = 8 mA

Minimum Absolute Dropout Differential Value = 15 mA (1A Protection Class)

Since the difference between pickup and dropout values as per IEC standard is less than Minimum Absolute Dropout Differential Value,
Minimum Absolute Dropout Differential Value = 15 mA (1A Protection Class)
Dropout value according to "Minimum Absolute Dropout Differential" = 44 mA – 15 mA
= 29 mA

So, according to the OEM explanation, dropout value shall be 29 mA (58 A primary) and so the feedbacks received at the relay testing can be confirmed as correct.

In addition, according to the same OEM explanation the relay shall be tripped if the relay picks up & current drops down between 29mA - 44mA by using 1.1*threshold value to calculate the remaining operating time. This can be explained as below.

According to the existing fault record data of the Biyagama Line 01 tripping incident of Kothmale PS end on 2021-12-03, the 7SL87 relay was subjected to the following two states.

Table 07: Stages of available zero sequence current in Line 01

States	Subjected zero sequence current at the state (A)	Subjected time duration of the state (s)
State of only B phase (RYB Notation) of Biyagama line 02 opened state	480 (Value available at just after opening of the B phase)	0.288
State of three pole opened state of Biyagama Line 02	Approximately 70	Approximately 22

The tripping time can be derived as follows.

Calculation of Elapsed operation time as a Percentage at the first state

IEC Normal Inverse Equation for evaluating tripping time can be written as follows.

$$t = \frac{0.14 * TMS}{\left(\frac{Fault\,Current}{Threshold\,Current}\right)^{0.02} - 1} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

TMS = 0.38 as per the relay setting

Estimation of operating time (t1) if state 01 current exists until relay gets tripped

$$t1 = \frac{0.14 * 0.38}{\left(\frac{480}{80}\right)^{0.02} - 1} = 1.458 \text{ s}$$

Elapsed operating time of state 01 as a percentage of total operating time $= \frac{0.288}{1.458} * 100\,\%$

$= 19.75\,\%$

So according to the above derivation, 19.75% of total operating time has been already elapsed at the first state. So, at the second state, only 80.25 % (100% -19.75 %) of its operating time has been needed to elapse as 19.75 % of the total operating time has already gone.

Calculation of the time which the relay has to be subjected to state two values to get tripped by the Earth Fault Function

According to OEM explanation, once the current drops down between 44mA (88A Primary) and 29mA (58A Primary), the relay uses 1.1*threshold value or 88A to calculate the remaining tripping time.

So required time to be at state two to get the relay tripped(t2) = 80.25%*

$$\frac{0.14*TMS}{\left(\frac{Fault\,Current}{Threshold\,Current}\right)^{0.02}-1}$$

$$T2 = 80.25\%*\frac{0.14*0.38}{\left(\frac{88}{80}\right)^{0.02}-1}$$

$$T2 = 80.25\%*27.882 = 22.37s$$

So estimated total time for the tripping the line 01 7SL87 relay after the instant of B pole opening of Biyagama Line 02

Total Time = 0.288 + 22.37
= 22.658 s

According to the trip log, it was taken only 22.325 s to get tripped the relay. Though there is a 0.333s error in the timing, it is acceptable as the error is within the margin defined by relay tolerance limits. The snapshot of the specification of the tolerances are attached below.

Tolerances

3I0 measured via I4[83], method of measurement = fundamental component	1 % of the setting value or 5 mA (I_{rated} = 1 A) or 25 mA (I_{rated} = 5 A), (f_{rated} ± 10 %)
3I0 measured via I4[84], method of measurement = RMS value (33 % harmonics, in relation to fundamental component)	
Up to 30th harmonic	1 % of the setting value or 5 mA (I_{rated} = 1 A) or 25 mA (I_{rated} = 5 A), (f_{rated} ± 10 %)
Up to 50th harmonic, f_{rated} = 50 Hz	3 % of the setting value or 20 mA (I_{rated} = 1 A) or 100 mA (I_{rated} = 5 A), (f_{rated} ± 10 %)
Up to 50th harmonic, f_{rated} = 60 Hz	4 % of the setting value or 20 mA (I_{rated} = 1 A) or 100 mA (I_{rated} = 5 A), (f_{rated} ± 10 %)
Operate time for 2 ≤ I/I threshold value ≤ 20	5 % of the reference (calculated) value +2 % current tolerance or 30 ms

Figure 09: Specification of tolerances for inverse time earth fault function

So, according to the explanation of the OEM & the data available in the technical manual of the relay, it can be said that the operation of the 7SL87 relay at Biyagama Line 01 at Kothmale PS end on 2021-12-03 was correct according to the existing relay settings at that time.

Question 05

Submit the Failure Analysis Report for Trippings occurred in Biyagama – Kothmale Line 01 and 02 from 2015 up to now.

CEB Response for Question 05

ANALYSIS OF PREVIOUS INCIDENTS OF BIYAGAMA KOTHMALE LINES SINCE 2015

Protection equipment of Kothmale – Biyagama 220kV transmission lines were rehabilitated under the 220kV Protection Development Project in 2013-2014 and 220kV Bus bar protection at Biyagama Grid substation was commissioned in January 2015. Accordingly, all the incidents involving the tripping of Kothmale – Biyagama transmission lines are summarized below based on the Monthly failure analysis reports prepared by the Protection Development Unit during the period 2015-01-01 to 2021-12-31.

1 Complete list of incidents as per the failure analysis reports (Table 08)

Table 08: Summary of trippings of Biyagama- Kothmale lines since January 2015

Ref No	Date	Tripped Time	Station	Equipment	Line	3 ph / 1 ph Trip (fault type)	Operated Function	Observations
1	10/2/2015	18.32	Biyagama	Kothmale	1	Isolator Open	None	Accidental opening of Q11 Bus isolator
2	15/06/2015	11.36	Biyagama	Kothmale	1	3 ph (R/B)	Differential trip	AR successfully
	15/06/2015	11.36	Biyagama	Kothmale	2	3 ph (R/B)	Differential trip	AR successfully
	15/06/2015	11.36	Kothmale	Biyagama	2	3 ph (R/B)	Differential trip	AR successfully
	15/06/2015	11.36	Kothmale	Biyagama	1	3 ph (R/B)	Differential trip	Trip Lockout
3	13/3/2016	14.21	Biyagama	Kothmale	1	3 phase trip	Bus bar protection operated at Biyagama GSS	Trip Lockout
	13/3/2016	14.21	Kothmale	Biyagama	1	3 phase trip		Trip Lockout
4	10/3/2017	15.20	Kothmale	Biyagama	1	1 ph (R-E)	Differential trip	AR successfully
	10/3/2017	15.20	Biyagama	Kothmale	1	1 ph (R-E)	Differential trip	AR successfully
	10/3/2017	15.20	Kothmale	Biyagama	2	1 ph (R-E)	Differential trip	AR successfully
	10/3/2017	15.20	Biyagama	Kothmale	2	1 ph (R-E)	Differential trip	AR successfully
5	12/4/2017	16.02	Biyagama	Kothmale	2	1 ph (B-E)	Differential trip	AR successfully
	12/4/2017	16.02	Kothmale	Biyagama	2	1 ph (B-E)	Differential trip	AR successfully
6	21/4/2019	15.21	Biyagama	Kothmale	1	1 ph (Y-E)	Differential trip	AR successfully
	21/4/2019	15.21	Kothmale	Biyagama	1	1 ph (Y-E)	Differential trip	AR successfully
7	18/10/2019	11:38	Biyagama	Kothmale	1	1 ph (R-E)	Differential trip	AR successfully
	18/10/2019	11:38	Kothmale	Biyagama	1	1 ph (R-E)	Differential trip	AR successfully
8	27/5/2020	2.50	Kothmale	Biyagama	1	Data not available	Differential trip	AR successfully
	27/5/2020	2.50	Biyagama	Kothmale	1		Differential trip	AR successfully
	27/5/2020	2.50	Kothmale	Biyagama	2		Differential trip	AR successfully
	27/5/2020	2.50	Biyagama	Kothmale	2		Differential trip	AR successfully
9	5/6/2020	18.04	Kothmale	Biyagama	1	3 ph (Y/B)	Differential trip	Trip Lockout
	5/6/2020	18.04	Biyagama	Kothmale	1	3 ph (Y/B)	Differential trip	AR successfully

Table 08 Continued:

Ref No	Date	Tripped Time	Station	Equipment	Line	3 ph / 1 ph Trip (fault type)	Operated Function	Observations
10	19/11/2020	14.01	Kothmale	Biyagama	1	3 ph (R/B)	Differential trip	Trip Lockout
	19/11/2020	14.01	Biyagama	Kothmale	1	3 ph (R/B)	Differential trip	AR successfully
11	05/01/2021	14:50	Kothmale	Biyagama	2	3 phase trip	Direct Transfer Trip	Tripped while testing PLC communication
12	15/4/2021	17:48	Kothmale	Biyagama	1	3 ph (R/Y)	Differential trip	Trip Lockout
	15/4/2021	17:48	Kothmale	Biyagama	2	3 ph (R/Y)	Differential trip	AR successfully
	15/4/2021	17:48	Biyagama	Kothmale	1	3 ph (R/Y)	Differential trip	AR successfully
	15/4/2021	17:48	Biyagama	Kothmale	2	3 ph (R/Y)	Differential trip	AR successfully
13	11/5/2021	18:49	Kothmale	Biyagama	1	1 ph (Y-E)	Differential trip	AR successfully
	11/5/2021	18:49	Kothmale	Biyagama	2	1 ph (Y-E)	Differential trip	Lockout due to End fault
	11/5/2021	18:49	Biyagama	Kothmale	1	1 ph (Y-E)	Differential trip	AR successfully
	11/5/2021	18:49	Biyagama	Kothmale	2	1 ph (Y-E)	Differential trip	AR successfully
14	5/10/2021	12:21	Biyagama	Kothmale	2	1 ph (R-E)	Differential trip	AR successfully
	5/10/2021	12:21	Kothmale	Biyagama	2	1 ph (R-E)	Differential trip	AR successfully
15	29/11/2021	19:25	Kothmale	Biyagama	1	1 ph (R-E)	Differential trip	Lockout due to End fault
	29/11/2021	19:25	Biyagama	Kothmale	1	1 ph (R-E)	Differential trip	AR successfully
	29/11/2021	19:25	Kothmale	Biyagama	2	3 ph (R/B)	Differential trip	AR successfully
	29/11/2021	19:25	Biyagama	Kothmale	2	3 ph (R/B)	Differential trip	No AR due to synch fail
16	3/12/2021	11:27	Kothmale	Biyagama	1	3 ph Trip	Non Directional Earth Fault	Trip Lockout
	3/12/2021	11:27	Biyagama	Kothmale	1	Not Tripped	None	Not Tripped
	3/12/2021	11:27	Kothmale	Biyagama	2	1 ph (B/E)	Differential trip	Lockout due to End fault
	3/12/2021	11:27	Biyagama	Kothmale	2	1 ph (B/E)	Differential trip	AR successfully

Information available in the above table can be summarized as follows:

Table 09: Breakdown of incidents

Total No. of incidents during (2015-01-01 – 2021-12-31)	16
Total number of individual line trippings	23
Line Trippings where actual line fault not involved	4
Line Trippings where specific fault information (1ph/3ph) not available	2
Total number of 1 ph faults	10
Total number of 3 ph faults	7
AR successfully from both ends when 1 ph trips	7
AR successfully from both ends when 3 ph trips	2

2 Incidents where both ends have successfully Auto reclosed after tripping of single phase

There are 7 instances where the line has auto reclosed from both ends after tripping of single phase fault.

Table 10: Successful AR during single phase trippings

Ref No.	Date	Tripped Time	Station	Equipment	Line	3 ph / 1 Ph Trip	Operated Function	Observations
4	10/3/2017	15.20	Kothmale	Biyagama	1	1 ph (R-E)	Differential trip	AR successfully
	10/3/2017	15.20	Biyagama	Kothmale	1	1 ph (R-E)	Differential trip	AR successfully
	10/3/2017	15.20	Kothmale	Biyagama	2	1 ph (R-E)	Differential trip	AR successfully
	10/3/2017	15.20	Biyagama	Kothmale	2	1 ph (R-E)	Differential trip	AR successfully
5	12/4/2017	16.02	Biyagama	Kothmale	2	1 ph (B-E)	Differential trip	AR successfully
	12/4/2017	16.02	Kothmale	Biyagama	2	1 ph (B-E)	Differential trip	AR successfully
6	21/4/2019	15.21	Biyagama	Kothmale	1	1 ph (Y-E)	Differential trip	AR successfully
	21/4/2019	15.21	Kothmale	Biyagama	1	1 ph (Y-E)	Differential trip	AR successfully
7	18/10/2019	11:38	Biyagama	Kothmale	1	1 ph (R-E)	Differential trip	AR successfully
	18/10/2019	11:38	Kothmale	Biyagama	1	1 ph (R-E)	Differential trip	AR successfully
13	11/5/2021	18:49	Kothmale	Biyagama	1	1 ph (Y-E)	Differential trip	AR successfully
	11/5/2021	18:49	Biyagama	Kothmale	1	1 ph (Y-E)	Differential trip	AR successfully
14	5/10/2021	12:21	Biyagama	Kothmale	2	1 ph (R-E)	Differential trip	AR successfully
	5/10/2021	12:21	Kothmale	Biyagama	2	1 ph (R-E)	Differential trip	AR successfully

It is observed that in all off these instances either of following conditions, required to trigger end fault protection function in built in Busbar protection relay at Biyagama GSS end and send an inter trip to Kothmale end, is not satisfied:

1. The current in healthy phases after the tripping of Single phase does not exceed the required threshold of 500A
2. Circuit Breaker open status is not received when only the Y phase or B phase is tripped in Kothmale line 1 bay at Biyagama GSS.

Examples for the above two cases are shown below:

Incident 5: Tripping of Biyagama Kothmale Line 2 at 16:02 on 2017-04-12

During this instance B phase has tripped from both ends and it is observed that the currents in the healthy phases are in the range of 100A -150 A and hence even if the circuit breaker status is open it does not exceed the threshold current required to trigger end fault protection as seen in the DDR record in figure 10.

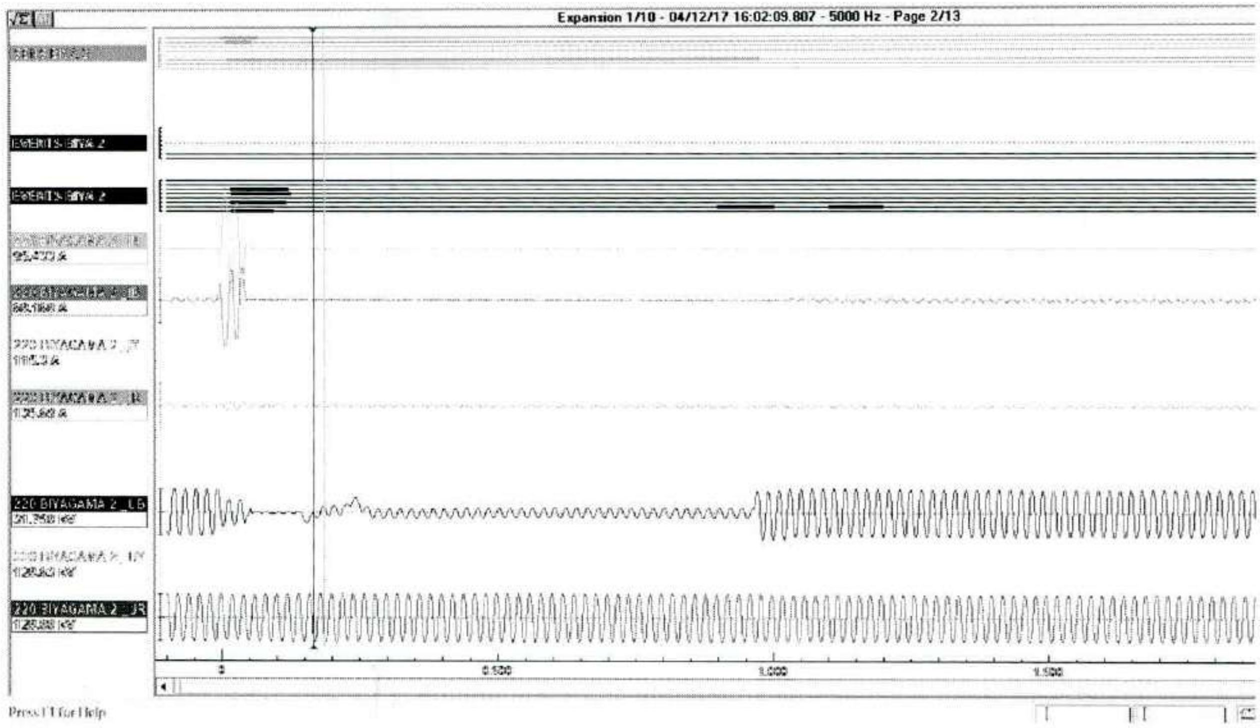


Figure 10: Ben 6000 DDR record of Biyagama line 2 at Kothmale PS at 16:02 on 2017-04-12

Incident 13: Tripping of Biyagama Kothmale Line 1 at 18:49 on 2021-05-11

During this instance Y phase of line 1 has tripped and it is observed that the currents in the healthy phases are increasing up to 900A (figure 11) yet end fault protection has not picked up since the circuit breaker status is being received as Close as per the wiring.

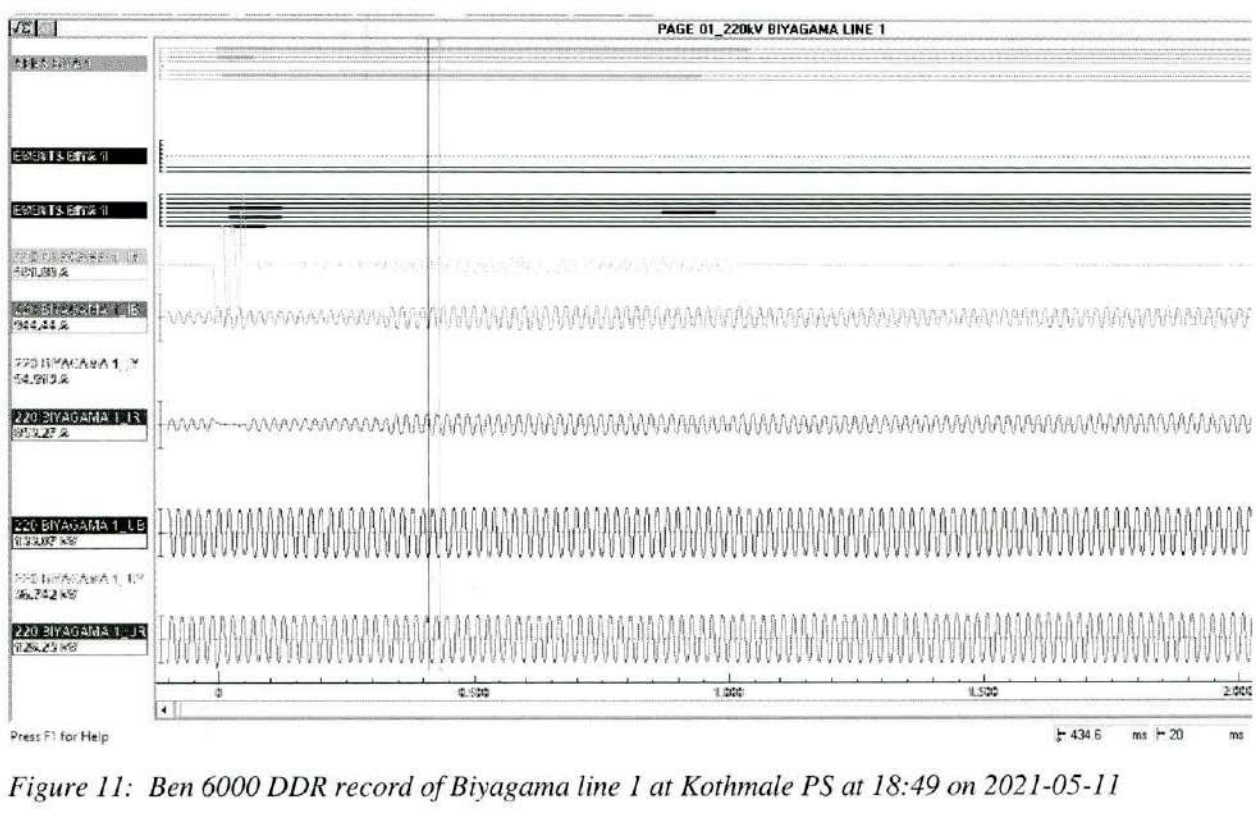


Figure 11: Ben 6000 DDR record of Biyagama line 1 at Kothmale PS at 18:49 on 2021-05-11

3 Incidents where both ends have not successfully Auto reclosed after tripping of single phase

There are 3 instances where the line has only auto reclosed from Biyagama end after tripping of only a single phase.

Table 11: Incidents of unsuccessful AR during single phase trippings

Ref No.	Date	Tripped Time	Station	Equipment	Line	3 ph /1 Ph Trip (fault type)	Operated Function	Observations
13	11/5/2021	18:49	Kothmale	Biyagama	2	1 ph (Y-E)	Differential trip	Lockout due to End fault operated inter trip from Biyagama end
	11/5/2021	18:49	Biyagama	Kothmale	2	1 ph (Y-E)	Differential trip	AR successfully
15	29/11/2021	19:25	Kothmale	Biyagama	1	1 ph (R-E)	Differential trip	Lockout due to End fault operated inter trip from Biyagama end
	29/11/2021	19:25	Biyagama	Kothmale	1	1 ph (R-E)	Differential trip	AR successfully
16	3/12/2021	11:27	Kothmale	Biyagama	2	1 ph (B/E)	Differential trip	Lockout due to End fault operated inter trip from Biyagama end
	3/12/2021	11:27	Biyagama	Kothmale	2	1 ph (B/E)	Differential trip	AR successfully

In all of the above three incidents end fault protection has operated due to the incorrect circuit breaker status received and additionally the currents of healthy phases are above the threshold current required for end fault function to be activated.

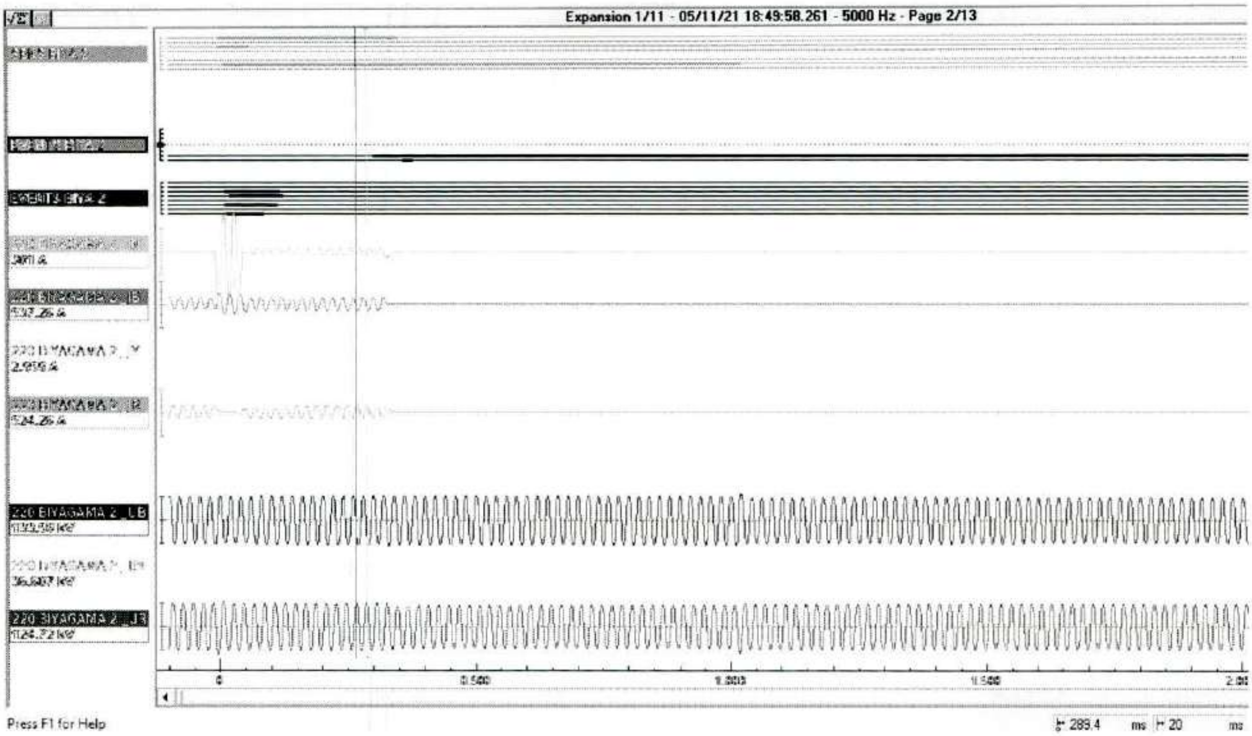


Figure 12: Ben 6000 DDR record of Biyagama line 2 at Kothmale PS at 18:49 on 2021-05-11

Records of operation of end fault protection since the installation of Siemens 7SS52 220kV Busbar protection at Biyagama GSS are available in the Fault annunciations of Busbar bay units of Kothmale line 1 & 2 bays respectively as seen in Figure 13 and Figure 14.

Fault annunciation in the bus bar bay unit of Kothmale line 01 shows 3 events in which operation of End fault protection on 2021-11-29 is one of them. Other two incidents refer to bus bar protection trip on 2016-03-13 and an event prior to commissioning of the system in 2014.

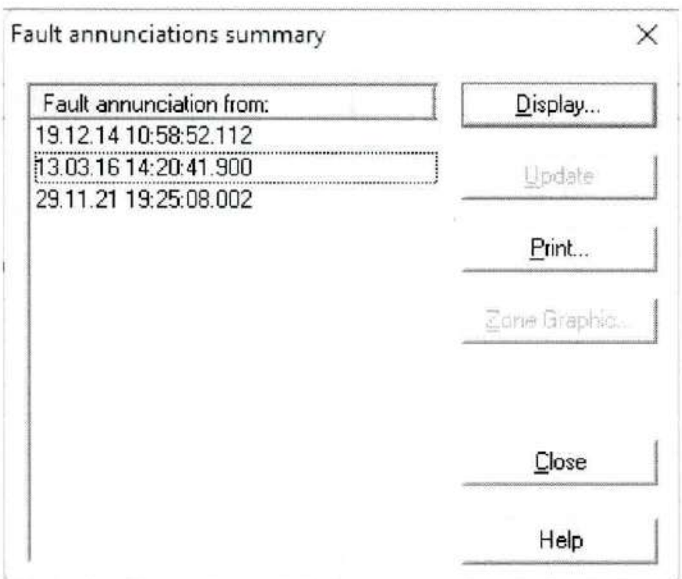
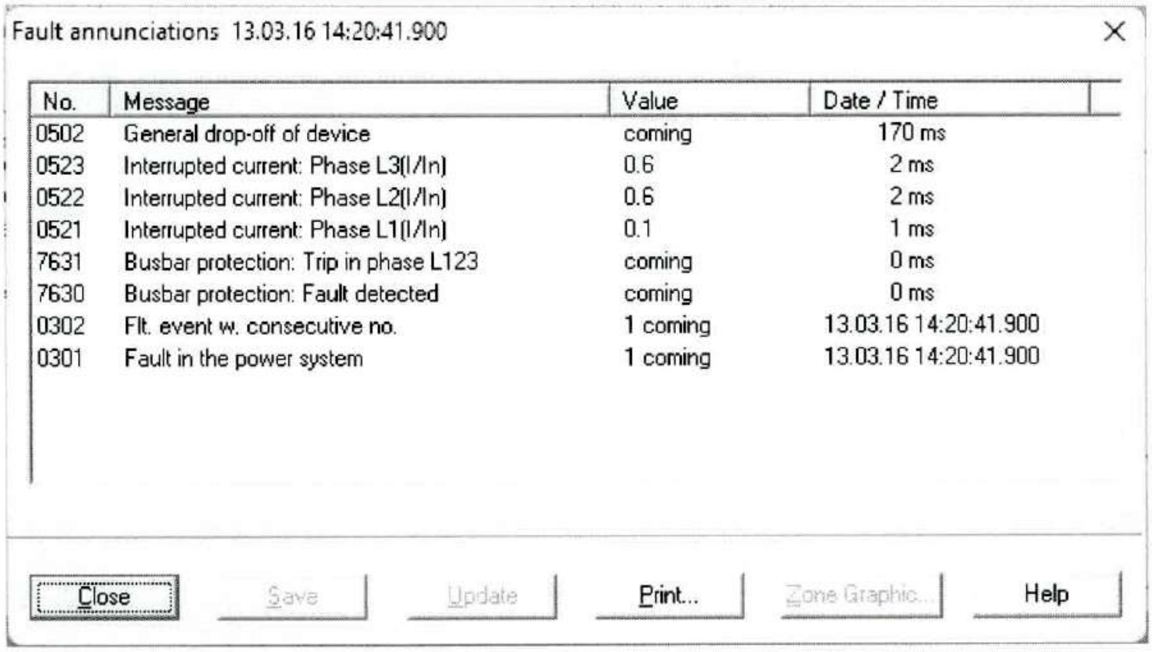


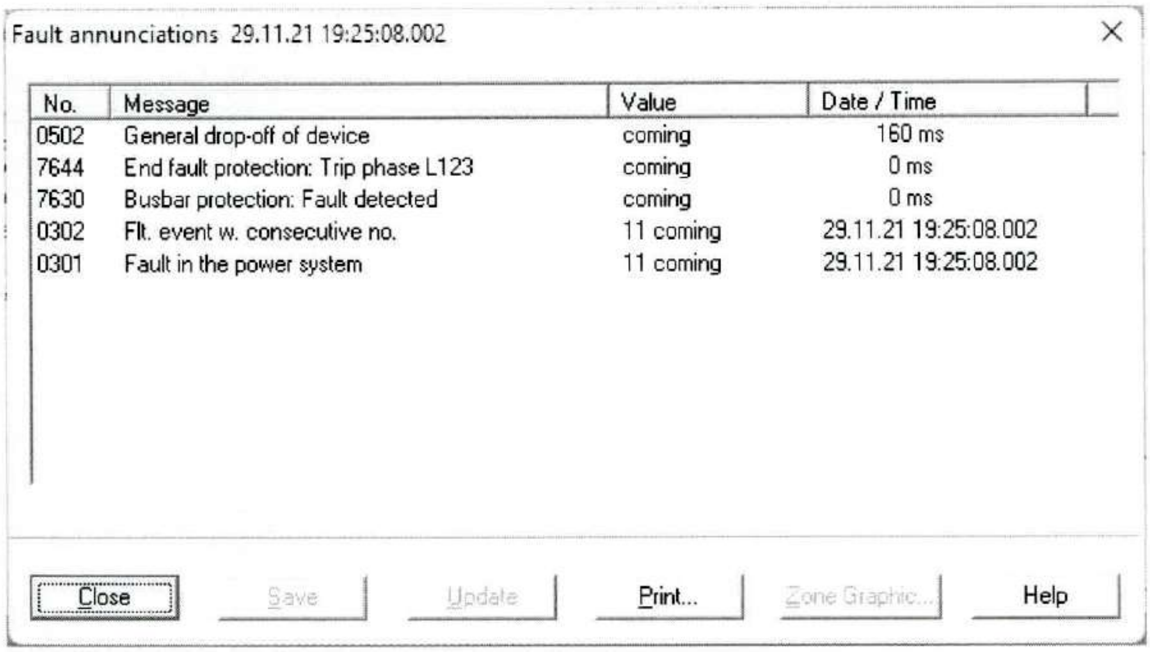
Figure 13: Busbar protection fault annunciation log of Kothmale line 01



Fault annunciations 13.03.16 14:20:41.900

No.	Message	Value	Date / Time
0502	General drop-off of device	coming	170 ms
0523	Interrupted current: Phase L3(I/In)	0.6	2 ms
0522	Interrupted current: Phase L2(I/In)	0.6	2 ms
0521	Interrupted current: Phase L1(I/In)	0.1	1 ms
7631	Busbar protection: Trip in phase L123	coming	0 ms
7630	Busbar protection: Fault detected	coming	0 ms
0302	Flt. event w. consecutive no.	1 coming	13.03.16 14:20:41.900
0301	Fault in the power system	1 coming	13.03.16 14:20:41.900

Figure 14: Operation of Busbar protection on 2016-03-13 (Incident no. 03 in Table 08)



Fault annunciations 29.11.21 19:25:08.002

No.	Message	Value	Date / Time
0502	General drop-off of device	coming	160 ms
7644	End fault protection: Trip phase L123	coming	0 ms
7630	Busbar protection: Fault detected	coming	0 ms
0302	Flt. event w. consecutive no.	11 coming	29.11.21 19:25:08.002
0301	Fault in the power system	11 coming	29.11.21 19:25:08.002

Figure 15: Operation of End fault protection on 2021-11-29 (Incident no. 15 in Table 08)

Fault annunciation in the bus bar bay unit of Kothmale line 02 shows two incidents in which End Fault has operated in both instances.

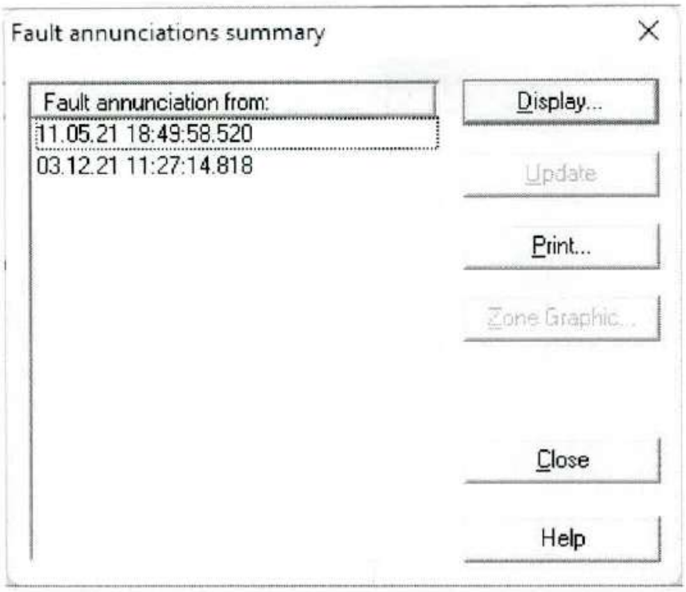


Figure 16: Busbar protection fault annunciation log of Kothmale line 02

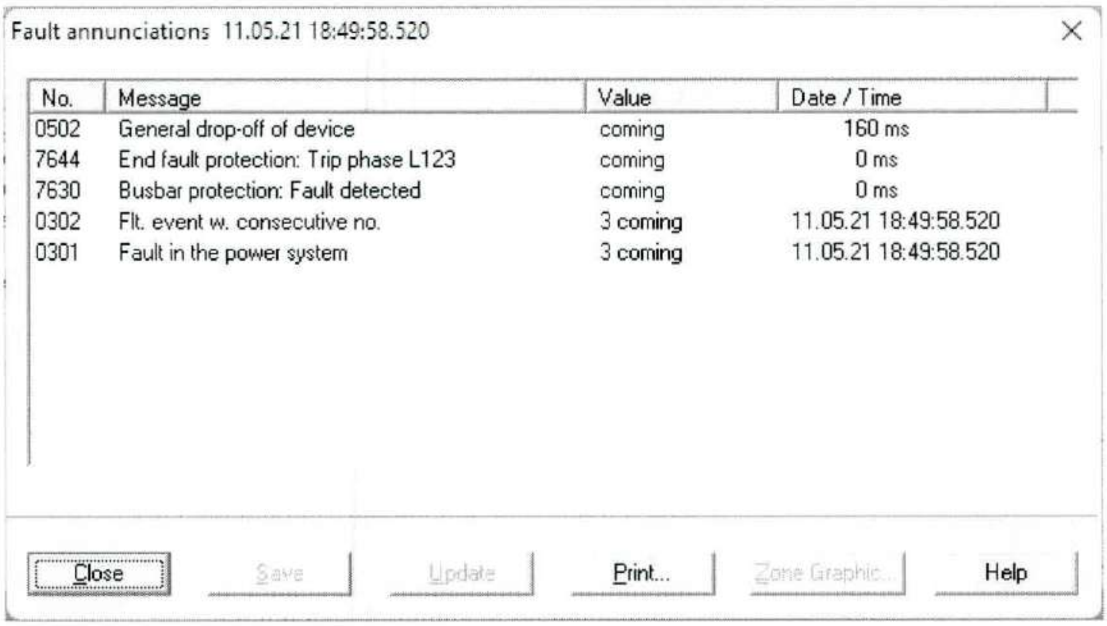


Figure 17: Operation of End fault protection on 2021-05-11 (Incident no. 13 in Table 08)

This incident confirms that the error in circuit breaker wiring has been persisting prior to the incidents on 2021-11-29 and on 2021-12-03. But it has been rare occurrence and only once it has operated since the replacement of circuit breakers in April 2015. After the incident on 2021-12-29, this issue was investigated in detail and possibility of an inter trip initiated from Busbar protection was examined, since indication of operation of end fault protection was not available in event lists of Main 1 & Main 2 protection relays or SAS. For this the events were taken from the Busbar protection relay at Biyagama GSS on 2021-12-03. However similar incident occurred on 2021-12-03 as well. After the incident it was initially determined that this was a mal operation of end fault protection scheme with a possibility of recurrence at any given time. In order to manage the situation End fault protection was disabled in all line bays at Biyagama GSS until the post fault analysis is completed. During the detailed inspection after obtaining interruptions, it was confirmed that the cause of the mal operation of end fault protection was due to incorrect circuit breaker status input received due to error in peripheral wiring of the circuit breaker. This wiring mistake has been corrected immediately in consultation with the maintenance staff.

Fault annunciations 03.12.21 11:27:14.818

No.	Message	Value	Date / Time
0502	General drop-off of device	coming	160 ms
7644	End fault protection: Trip phase L123	coming	0 ms
7630	Busbar protection: Fault detected	coming	0 ms
0302	Flt. event w. consecutive no.	12 coming	03.12.21 11:27:14.818
0301	Fault in the power system	12 coming	03.12.21 11:27:14.818

Close Save Update Print... Zone Graphic... Help

Figure 18: Operation of End fault protection on 2021-12-03 (Incident no. 16 in Table 08)

Detailed summary of line trippings since 2015 is available in annexure 5.1.

Question 06

Committee advised CEB to write to OEM and obtain a clarification for following two issues.

a *To clarify the drop off characteristics of E/F protection function of 7SL87 - Main 1 Protection Relay from Siemens.*

b *To clarify UI Login and Logout events that have occurred in P545 - Main 2 Protection Relay from Schneider.*

CEB Response for Question 06

Submission of Request for Clarification from Siemens for with regard to the drop off characteristics of E/F protection function of 7SL87 Line Protection Relay:

Staff of Control and Protection Branch submitted above clarification to online help desk of Siemens on 2022-01-14. Thereafter official request letter submitted to Siemens under the signature of AGM (Transmission) on 2022-01-15. (A copy of the documents submitted to Siemens is attached in Annexure 6.1)

Submission of Request for Clarification from Schneider with regard to the UI Login and Logout events that are occurring in P545 Line Protection Relays:

Staff of Control and Protection Branch submitted above clarification to email address given in Schneider web site on 2022-01-14. Thereafter official request letter submitted to Schneider under the signature of AGM (Transmission) on 2022-01-15. (A copy of the documents submitted to Schneider is attached in Annexure 6.1)

Question 07

Committee advised to submit Factory Acceptance Test (FAT) reports of the Siemens 7SL87 relay.

CEB Response for Question 07

A copy of Factory Acceptance Test (FAT) reports and Site Acceptance Test (SAT) reports of the Siemens 7SL87 relays installed in Biyagama – Kothmale Line 01 and 02 are enclosed in Annexure 7.1 and Annexure 7.2 respectively.

G.R.H.U. SOMAPRIYA
CE (PD)
Chief Engineer
Protection Development Unit

H. P. G. R. N. CHAMIKARA
CE(PS)TR
Chief Engineer
Protection Systems Unit

Eng N. S. Wettasinghe
DGM(Control & Protection)
Deputy General Manager
(Control & Protection – Transmission)

Enclosed:

Annexure 1.1 Arrangement of primary equipment in Kothmale Lines at Biyagama GSS
Annexure 1.2 Screenshots of waveforms of fault current recorded in different devices
Annexure 1.3 Detailed calculation of zero sequence currents
Annexure 1.4 Additional pictures received from the site of fire
Annexure 1.5 Fault distance calculation
Annexure 1.6 Very High-Resistance Fault on a 525 kV Transmission Line – Case Study (https://ieeexplore.ieee.org/document/4982523)
Annexure 2.1 Details of previous incidents
Annexure 2.2 Drawings of Biyagama GSS issued in 1983
Annexure 2.3 Drawings of Biyagama GSS issued in 1986
Annexure 2.4 Copy of Siemens drawings
Annexure 2.5 Copy of the drawing used by O&M Branch for installation of Circuit Breakers
Annexure 3.1 Protection Study report submitted by Lahmeyer International for Biyagama GS and Kothmale PS in 1996.
Annexure 3.2 A screen shot of Relay Settings implemented under 220kV Protection Development Project in 2015.
Annexure 3.3 Protection Setting Standard (Rev 0.2, Issued on August 2019)
Annexure 3.4 Relay Test sheet dated 2019-09-26
Annexure 3.5 Work Order dated 2021-12-09 related to revision of Earth Faut current setting.

Annexure 4.1 Test report of Siemens 7SL87 relay at Biyagama Line 01 at Kothmale PS

Annexure 4.2 Test report of Siemens 7SL87 relay at Kothmale Line 01 at Biyagama GSS

Annexure 4.3 Standard test protocols employed by Siemens, ABB & NR

Annexure 4.4 Test report of Siemens 7SL87 relay removed from Kothmale lines at New Anuardhapura

Annexure 4.5 Test reports of Siemens 7SL87 relay at Mannar Line 01 at New Anuradhapura GSS

Annexure 4.6 Test reports of Siemens 7SL87 relay at Mannar Line 02 at New Anuradhapura GSS

Annexure 5.1 Detailed summary of line trippings since 2015

Annexure 6.1 A copy of the documents submitted to Siemens

Annexure 6.2 A copy of the documents submitted to Schneider

Annexure 7.1 Factory Acceptance Test (FAT) reports

Annexure 7.2 Site Acceptance Test (SAT) reports of the Siemens 7SL87 relays installed in Biyagama – Kothmale Line 01 and 02

Office of the Deputy General Manager (System Control)
Ceylon Electricity Board
No 80, Parliament Road
Pelawatta
Battaramulla

Date: November 30, 2021

My Ref: DGM/SYC/ TCH/15

AGM(Transmission)

Major System Failure on 29th Nov. 2021

A Major System failure occurred on 29th Nov. 2021 at 19.25hrs. Following documents are attached herewith,

1. Preliminary report : Annexture-1
2. Under Frequency Load shading : Annexture-2
3. Frequency Plot : Annexture-3

This is for your information please.

D.S.R Alahakoon
Deputy General Manager
System Control

Deputy General Manager
(System Control Centre)
C.E.B.
No. 80, Parliament Road
Pelawatta, Battaramulla

Copy to: DGM(CS&RA) : f.i.Pl

To: DGM (System Control)

Form Revision Date 01.12.06

Preliminary Report on Major System Failure   Annexture-1

(Failures involving 5 or more GSS in entirety)

Date	29-Nov-2021
Time of failure	19:25
Weather Condition	Heavy rain and thunder

Description

Major system failure occurred at 19:25 hrs causing Nuwaraeliya, Badulla, Monaragala, Ampara, Vaunathiv and Mahiyangana GSSs to be dead. Failure initiated due to tripping of Kotmale-Biyagama cct 01 from Kotmale end, Kotmale-Biyagama cct 02 from Biyagama end due to operation of main protection followed by tripping of Kotmale-New Anuradhapura cct 02 due to O/C & E/F. (The cct 01 was released to connect New Habarana GSS). The system recovered with the operation of UFLS stage III and df/dt. Restoration of supply commenced by energizing Kotmale-Biyagama 220kV cct 02 at 19.53 hrs. Subsequently feeders were normalized as Mahaweli generation resumed.

Equipment	Tripped from	Time
Kotmale-Biyagama 220kV cct 01	Tripped from Kotmale end and A/R from Biyagama end	19:25:00
Kotmale-Biyagama 220kV cct 02	Tripped from Biyagama end and A/R from Kotmale end	19:25:00
Kotmale-New Anuradhapura 220kV cct 01	Tripped from both ends	19:25:00

Generation	Unit Nos.	Load prior to tripping	Time	Indication / Remarks
Victoria	1	81MW	19:25:00	Incoming failure
Victoria	2	80MW	19:25:00	Incoming failure
Victoria	3	80MW	19:25:00	Incoming failure
Kotmale	1	45MW	19:25:00	Incoming failure
Kotmale	2	49MW	19:25:00	Incoming failure
Kotmale	3	34MW	19:25:00	Incoming failure
Upper Kotmale	1	75MW	19:25:00	Incoming failure
Upper Kotmale	2	75MW	19:25:00	Incoming failure
Randenigala	1	62MW	19:25:00	Incoming failure
Randenigala	2	63MW	19:25:00	Incoming failure
Rantambe	1	27MW	19:25:00	Incoming failure
Rantambe	2	27MW	19:25:00	Incoming failure

Following GSS affected

Nuwaraeliya, Badulla, Monaragala, Ampara, Vaunathiv, Mahiyangana

Pre Fault Conditions

Generation at	Load (MW)
Laxapana Complex	300
Mahaweli Complex	777
Samanala Complex	201
CEB Thermal Complex	304
LVPS	530
IPP(Thermal)	108
Wind/ Solar	32

To: DGM (System Control)

Form Revision Date 01.12.06

IPP(Mini Hydro/ Biomass)	56	
Total Load	2308	at 19:25hrs
Spinning Reserve	137	6%
Frequency Control	Kotmale	

To: DGM (System Control)

Form Revision Date 01.12.06

Opening points of 132kV and 220kV system Ring connections.

Galle 132kV B/C CB	-	System Req. to maintain System reliability
Havlock-Dehiwala cable from Dehiwala end	-	System Req. to maintain System reliability
Kolonnawa - Pannipitiya both ccts from Pannipitiya end	-	System Req. to maintain System reliability
Col M - Col E cable from Col E end	-	System Req. to maintain System reliability
O/Lax- Badull ccts from O/Lax end	-	System Req. to maintain System reliability
Ukuwela 132kV Bus coupler feeding Ukuwela T/Fs from Habarana side	-	System Req. to maintain System reliability
Pannipitiya 220kV, 132kV Bus Couplers	-	System Req. to maintain System reliability
Kotugoda -Katunayake both ccts	-	Project work
Puttalam -New Anuradhapura cct 01 & 02 from New Anuradhapura end	-	System Req. to maintain System reliability
Col N-Col F cable		Released for CT replacement

Failure Sequence Summary (Initiating incident and Initial moments in summary)

Equipment/Line	Failed Time	Load	Indication/Reason
Kotmale-Biyagama 220kV cct 01	19:25:00	660A	Main protection operated
Kotmale-Biyagama 220kV cct 02	19:25:00	660A	Main protection operated
Kotmale-New Anuradhapura cct 02	19:25:00	132A	O/C & E/F
Victoria gen 01	19:25:00	81MW	Incoming failure
Victoria gen 02	19:25:00	80MW	Incoming failure
Victoria gen 03	19:25:00	80MW	Incoming failure
Kotmale gen 01	19:25:00	45MW	Incoming failure
Kotmale gen 02	19:25:00	49MW	Incoming failure
Kotmale gen 03	19:25:00	34MW	Incoming failure
Upper Kotmale gen 01	19:25:00	75MW	Incoming failure
Upper Kotmale gen 02	19:25:00	75MW	Incoming failure
Randenigala gen 01	19:25:00	62MW	Incoming failure
Randenigala gen 02	19:25:00	63MW	Incoming failure
Rantambe gen 01	19:25:00	27MW	Incoming failure
Rantambe gen 02	19:25:00	27MW	Incoming failure

Restoration Summary

Restored Duration	GSS
Restored within half an hour (0 - 1/2 hr)	0
Restored within the next half an hour (1/2hr-1hr)	0
Restored within the next half an hour (1hr-1 1/2 hr)	6
Restored within the next half an hour (1 1/2hr-2hr)	-
Restored within the next half an hour (2hr-2 1/2 hr)	-
More than 2 1/2 hr	-

Colombo Primary Restoration Summary

Primary	Interrupted Time	Restored Time	Remarks (If any)
N/A			
N/A			

	Primary	Time	GSS	Time
First Energized				
Last Energized				

To: DGM (System Control)

Form Revision Date 01.12.06

Restoration completed as follows;

GSS	Restored time (1st Attempt)
Badulla	20:30
Nuwaraeliya	20:32
Mahiyangana	20:47
Vaunathiv	20:47
Ampara	20:49
Monaragala	20:55

Comments of the SCE

Kotmale-New Anuradhapura cct 01 had been released to connect New Habarana GSS at the time of the failure.

Nilan Hemachandra

Name/Signature

Comments of the CE(SO)

Mahaweli generation is being maximized during this season due to higher inflows to the Mahaweli reservoirs while maintaining the N-1 contingency criteria of the Kotmale-Biyagama 220kV line. Total contribution from the Mahaweli generation during the failure was 30% Of total system generation and however system recovered successfully by operating the under-frequency load shedding scheme.

CE(SO) -SCC

Comments of DGM(SCC)

Failure occurred mainly due to inadequate transmission capacity. The pending Kothmale-New Polpitiya 220kV line and New Polpitiya-Hambantota 220kV line and 220/132kV switching station at Hambantota must be implemented as soon as possible to improve the transmission capacity. The System recovered with UFLS scheme.

DSR Alahakoon, DGM(System Control)

ANNEXURE - 2

Report on Operation of Under Frequency Load Shedding

Date : 29/11/2021
Time : 19:25 hrs.
Reason : Tripping of Kothmale - Biyagama Both ccts

Rejected Generation : 698 MW NOTE:

Total generation (recorded) prior to tripping: 2,308 MW

GSS	Feeder No	Stage	OFF TIME	ON TIME	LOAD / (A)	OFF TIME	ON TIME	LOAD / (A)
Athurugiriya	3	I	19:25	20:42	160			
	6	I	19:25	21:15	75			
	8	I	19:25	21:15	158			
Rathnapura	1	I	19:25	20:43	81			
Mathugama	1	I	19:25	21:20	75			
	8	I	19:25	20:49	254			
	5	II						
	10	II						
	6	III	19:25	21:20	107			
	9	III	19:25	20:58	0			
Kotugoda	13	I	Disabled					
	11	I	Disabled					
	3	II	19:25	20:17	189			
	9	IV						
	12	V or df/dt	19:25	20:17	218			
Sapugaskanda	9	I	19:25	19:38	116			
	11	I	19:25	21:19	17			
	2	II						
	4	II	19:25	21:19	136			
	7	II	19:25	19:37	130			
	6	III						
	3	IV						
	8	IV						
Kosgama	1	I	19:25	20:46	195			
	8	I	19:25	21:19	190			
	2	II	19:25	21:18	160			
	7	IV						
Ukuwela	10	I	19:25	20:51	149			
	3	II	19:25	21:23	16			
	12	df/dt	19:25	21:23	92			
	1	II	19:25	21:23	92			
Habarana	3	I	19:25	21:20	125			
	1	II	19:25	20:50	125			
	6	II	19:25	21:20	71			
	7	II	19:25	21:20	185			
	2	df/dt						
	4	df/dt						
New Galle	3	I	19:25	20:51	88			
	11	I	19:25	21:21	104			
	1	df/dt						
	6	df/dt						
	4	df/dt						
Thulhiriya	5	I	19:25	21:22	122			
	6	I	19:25	21:22	67			
	4	III	19:25	20:21	57			
	1	III	19:25	21:22	68			
	2	IV						
Matara	6	I	19:25	21:21	118			
	4	III	19:25	20:50	170			
	8	III	19:25	21:21	159			
	2	df/dt	19:25	21:21	82			
	7	df/dt						
	1	df/dt	19:25	21:21	90			
Badulla	6	I	19:25	21:05	58			
	3	III	19:25	20:53	127			
	5	III						
	1	IV						

GSS	Feeder No	Stage	OFF TIME	ON TIME	LOAD / (A)	OFF TIME	ON TIME	LOAD / (A)
Biyagama	1	I	19:25	21:14	10			
	3	III	19:25	21:12	160			
	5	III	19:25	20:54	280			
	6	III	19:25	21:12	275			
	4	IV						
	7	V or df/dt	19:25	21:16	10			
	8	V or df/dt	19:25	21:14	200			
Kelaniya	3	I	19:25	21:12	0			
	2	I	19:25	21:10	39			
	1	df/dt	19:25	20:56	0			
Belliatta	4	II	19:25	21:11	0			
	5	II	19:25	20:58	92			
	6	II	19:25	21:14	55			
Ambalangoda	2	II	19:25	21:12	170			
	3	II	19:25	20:16	135			
	4	II	19:25	21:12	90			
	6	II	19:25	20:56	135			
Kiribathkumbura	9	II	19:25	21:12	110			
	8	II	19:25	21:12	103			
	7	III						
	2	III						
	3	III						
	4	IV						
Dehiwala	7	II	19:25	20:59	140			
	6	III						
	8	III	19:25	21:00	139			
	1	IV						
	3	IV						
Rathmalana	F7	II	19:25	20:12	160			
	F9	II	19:25	20:59	285			
	F6	IV						
	F2	df/dt	19:25	20:12	115			
	F3	df/dt	19:25	20:18	120			
Veyangoda	7	II						
	3	III	19:25	21:14	245			
	4	IV						
	6	IV						
	8	V						
Panadura	3	II	19:25	21:13	114			
	2	V or df/dt	19:25	20:59	186			
	4	V or df/dt						
	5	V or df/dt	19:25	21:14	106			
N/Anu	Trinco 1 & 2	III						
Kilinochchi	2	III						
	4	III						
Aniyakanda	3	III	19:25	21:19	188			
	7	III	19:25	21:18	126			
	1	IV						
	5	df/dt	19:25	20:18	191			
Pannipitiya	3	III						
	6	III						
	9	III	19:25	21:00	196			
	10	III	19:25	21:00	14			
	2	IV						
	4	IV						
	7	IV						
	8	IV						
	5	V						
Madampe	4	III	19:25	21:16	5			
	7	III	19:25	21:16	60			
	1	V or df/dt	19:25	21:16	135			
	2	V or df/dt	19:25	21:04	205			
	3	V or df/dt						

GSS	Feeder No	Stage	OFF TIME	ON TIME	LOAD / (A)	OFF TIME	ON TIME	LOAD / (A)
Ampara	3	IV						
	5	IV						
Sub C		IV						
Sub A	1137	IV						
	14	IV						
	22	IV						
	1011	IV						
	571	IV						
Sub F	116	IV						
	54	IV						
	624	IV						
	43	IV						
	9	IV						
Sub I	18	IV						
	45	IV						
	1240	IV						
	1130	IV						
	602	IV						
Sub E	981	IV						
	10	IV						
	609	IV						
	335	IV						
Kolonnawa GIS	B1	IV						
	B2	IV						
	G1	IV						
	G2	IV						
Horana	5	IV						
	2	df/dt						
	3	df/dt	19:25	21:22	274			
	4	df/dt	19:25	21:22	174			
Pannala	3	V						
	5	V						
	7	V						
	2	df/dt	19:25	21:23	235			
	4	df/dt						
	6	df/dt						
Kurunegala	6	V						
	5	V or df/dt						
	2	df/dt						
	3	df/dt						
	4	df/dt						
S'Japura	1	df/dt	19:25	20:04	41			
	2	df/dt	19:25	21:21	53			
	4	df/dt	19:25	20:54	121			
	5	df/dt	19:25	21:22	0			
	6	df/dt						
	8	df/dt						
Bolawatta	2	df/dt						
	3	df/dt	19:25	21:21	236			
	4	df/dt	19:25	21:22	157			
	10	df/dt	19:25	21:28	259			
	8	df/dt	19:25	21:21	104			

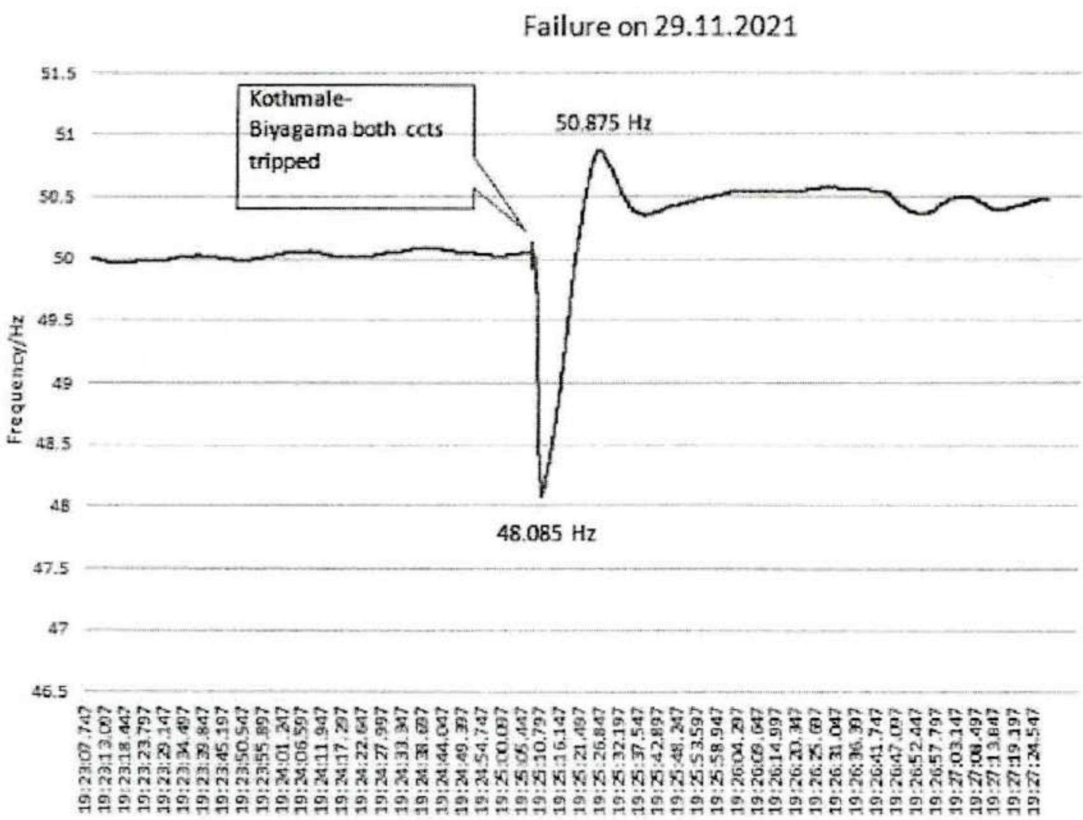
GSS	Feeder No	Stage	OFF TIME	ON TIME	LOAD / (A)	OFF TIME	ON TIME	LOAD / (A)
Katunayaka	1	df/dt	19:25	22:05	81			
	2	df/dt	19:25	22:05	56			
	7	df/dt	19:25	22:06	0			
	8	df/dt	19:25	22:06	59			
Deniyaya	1	df/dt						
	2	df/dt						
Mahiyangane	2	df/dt						
	5	df/dt						

UFLS Stage	Shedded load in [A]	Shedded load in [MW]	Shedded load as a %
Stage I	2201.0	-	0.0%
Stage II	2693.0	-	0.0%
Stage III	2376.0	-	0.0%
Stage IV	0.0	-	0.0%
Stage V	0.0	-	0.0%
Stage V or df/dt	1060.0	-	0.0%
df/dt	2540.0	-	0.0%
Total	**10870.0**	-	0.0%

Total Rejected Generation MW	698	30.2%
Total Shedded 33kV Load in [A]	10870	-
Total Shedded 33kV Load in MW	0	0.0%
Total generation (recorded) prior to tripping:	**2308**	

power factor :

Annexture-3


Failure on 29.11.2021
Kothmale-Biyagama both ccts tripped
50.875 Hz
48.085 Hz
Frequency/Hz
51.5
51
50.5
50
49.5
49
48.5
48
47.5
47
46.5
19:23:07.747
19:23:13.097
19:23:18.447
19:23:23.797
19:23:29.147
19:23:34.497
19:23:39.847
19:23:45.197
19:23:50.547
19:23:55.897
19:24:01.247
19:24:06.597
19:24:11.947
19:24:17.297
19:24:22.647
19:24:27.997
19:24:33.347
19:24:38.697
19:24:44.047
19:24:49.397
19:24:54.747
19:25:00.097
19:25:05.447
19:25:10.797
19:25:16.147
19:25:21.497
19:25:26.847
19:25:32.197
19:25:37.547
19:25:42.897
19:25:48.247
19:25:53.597
19:25:58.947
19:26:04.297
19:26:09.647
19:26:14.997
19:26:20.347
19:26:25.697
19:26:31.047
19:26:36.397
19:26:41.747
19:26:47.097
19:26:52.447
19:26:57.797
19:27:03.147
19:27:08.497
19:27:13.847
19:27:19.197
19:27:24.547

Office of the Deputy General Manager (System Control)
Ceylon Electricity Board
No 80, Parliament Road
Pelawatta
Battaramulla

Date: December 8, 2021

My Ref: DGM/SYC/ TCH/15

AGM(Transmission)

Total System Failure on 3rd Dec. 2021 at 11.27hrs.

A Total System failure occurred on 3rd Dec. 2021 at 11.25hrs. Following documents are attached herewith,

1. Preliminary report : Annexure-A
2. Recommendations/Observations : Annexure-B

This is for your information please.

D.S.R Alahakoon
Deputy General Manager
System Control

Eng. D.S. R. Ala[illegible]
D.G.M. (System [illegible])

Copy to: DGM(CS&RA) : f.i.Pl

Annexture-B

Observations/Recommendations

1. Main cause seems to be tripping of both 220kV lines from Kothmale PS to Biyagama switching station. If any alternative path for 220kV load flow this failure may not be happened. The scheduled alternative path will be from Kothmale-New Polpitiya-Padkka-Pannipitiya 220kV lines with 132kV connections from Padukka to Athurugiriya GSS. But still the 220kV connection from Kothmale PS to New Polpitiya switching station not yet completed. Also New Polpitiya to Hambantota 220kV line together with switching station at Hambantota still pending. Therefore these pending line sections together with Hambantota 220/132kV switching station progress has to be expedited and complete as soon as possible.

2. SCC has done the following real time simulations in line with the last total failure occurred on 17th Aug.2020.
   a. Restoration from Mahaweli Complex
   b. Restoration from Laxapana Complex
   c. Restoration from Samanalawewa & Kukule Power stations
   d. Auxiliary supply to LVPP from Upper Kothmale & Kothmale PS's

   From above real time simulations we have identified the problems and issues when restoring the system after a major/total failure and use this experience in this time exclusively and for each simulation SCC had prepared a comprehensive report. All shift Engineers got exposed to these trial simulations and utilized these experience for better restoration. For Colombo city restoration simulations, we have requested feeder interruptions from Colombo city, but still not granted the required permissions.

3. Colombo restoration delayed due to unavailability of reliable machines at Colombo, SCC tried to synchronize GT7 through Frame V GT's but not successful. Therefore it is highly recommended to install around 100MW of machines having black start facility and cable charging capability at Kelanitissa.

4. Auxiliary supply to LVPP within half an hour after a total failure by using Kothmale or Upper Kothmale is not practicable (although tested) and restoration is also complicated and may delay the main stream restoration and therefore an alternative arrangement has to be adopted.

5. SCC has prepared a revised restoration guideline (still in draft stage) and use this guideline for restoration. Initial loading feeders were identified during the trial simulations and informed the same to Distribution divisions earlier.

DSR Alahakoon
DGM(System Control)

Eng. D.S. R. Alahakoon
D.G.M. (System Control)

PRELIMINARY REPORT ON TOTAL SYSTEM FAILURE AT 1127 HRS ON 03rd DECEMBER 2021

System Control Branch
Transmission Division,
Ceylon Electricity Board,

Date : 12/3/2021
Time of failure : 11:27
Weather Condition : Dry

Description

Total System failure seems to be initiated with the tripping & auto reclosing of Kothmale-Biyagama cct 02 from Biyagama end, and tripping of the same circuit from Kothmale end at 11:27hrs. This was followed by the tripping of Kothmale-Biyagama circuit 01 from Kothmale end and Kothmale-N'Anuradhapura circuit 02 from N'Anuradhapura end. Rejecting of 652MW from the system as a result lead to a significant frequency drop in remaining system causing cascade tripping of remaining generators of the system lead the total system to be collapsed. The system restoration was started from Mahaweli system, Laxapana system, Samanala system and Colombo City system simultaneously. Mahaweli system and Laxapana system were synchronized from Kolonnawa GSS. Mahaweli system and Colombo City system were synchronized from Kelanithissa GSS. The above resulting system and southern system were synchronized from Mathugama GSS. All GSS s were energized at 16:47hrs.

Pre Fault Conditions

Generation data at 11:27hrs.

		Load (MW)	Mvar	
Laxapana Complex		315	43	
Mahaweli Complex		712	181	
Samanala Complex		158	51	
LVPS		538	179	
Thermal Complex		138	90	
IPP		0	0	
Small Hydro(CEB)		3	0	
Mini Hydro (IPP)		61	0	
Wind		1	0	
Biomass		2	0	
Solar		28	3	
Shunt reactive power		298	298	
Total Load		**1956**	**845**	
Spinning Reserve		155	7.9	%
Frequency Control		Kothmale unit 02		

Transmission System

Opening points of 132kV and 220kV system Ring connections.

1 Dehi - Havelock 132 kV cable from Dehi end
2 Kolon - Panni 132 kV both ccts from Kolon end
3 Mathugama-Ambalangoda both ccts from Mathu end
4 Ukuwela 132kV B/C
5 O/Laxa-N/Eliya-Badulla both ccts from O'Lax end
6 Katu-Kotu both ccts from both ends
7 Col F-Col N interconnection from both ends
8 Col E-Col M cable from Col E end
9 New Anu-Mannar cct 02 from both ends
10 Mannar-Nadukuda cct 01 from both ends
11 Pannipitiya 220kV B/C , 132kV B/C
12 Badulla-Monaragala cct from both ends
13 Puttalam-N/Anu cct 01 and 02 from N/Anu end
14 Mannar-Nadukuda cct 01 from both ends
15 N/Habarana-N/Anu cct 01 from both ends
16 Padukka-Pannipitiya both ccts from both ends

Failure Sequence Summary (Initiating incident and Initial moments in summary)

	Equipment/Line	Failed Time	Load reading at 11:27hrs.	Indication/Reason
1	Koth-Biya cct 02	11:27:13 AM	745A	Line Differential
2	Koth-Biya cct 01	11:27:35 AM	1374A	O/C / E/F
3	Kotmale Unit 01	11:27:40 AM	51MW	Over frequency
4	Kotmale Unit 02	11:27:40 AM	40MW	Over frequency
5	Kotmale Unit 03	11:27:40 AM	60MW	Over frequency
6	Lakvijaya unit 03	11:27:41 AM	270 MW	comphonent UV/OC trip
7	Lakvijaya unit 01	11:27:42 AM	268 MW	Master fuel trip
8	New Lax unit 01	11:27:42 AM	50 MW	Under frequency
9	New Lax unit 02	11:27:42 AM	50 MW	Under frequency / Gen. T/F Differential Protection
10	Polpitiya unit 01	11:27:42 AM	43 MW	Mechanical & External trip
11	Polpitiya unit 02	11:27:43 AM	43 MW	Over Speed trip
12	Athu-Thul-Polp	11:27:43 AM	210A	O/C
13	Athu-Thul-N/Polp	11:27:43 AM	408A	O/C
14	Koth-N'Anu cct 02	11:27:44 AM	817A	O/C
15	Samanawewa unit 01	11:27:44 AM	40 MW	Gen. voltage over 90%/ Over excitation limit
16	Samanawewa unit 02	11:27:44 AM	40 MW	Gen. voltage over 90%/ Over excitation limit
17	Upper Kotmale unit 01	11:27:47 AM	40 MW	Main T/F V/f operated
18	Upper Kotmale unit 02	11:27:48 AM	40 MW	Excitation system heavy fault
19	Kolon-Kosgama	11:28:13 AM	485A	O/C
20	Kolon-Seethawaka	11:28:13 AM	49A	O/C

Restoration Summary

	Restored Duration	GSS/PSS
1	Restored within half an hour (0 - 1/2 hr)	0
2	Restored within the next half an hour (1/2hr-1hr)	1
3	Restored within the next half an hour (1hr-1 1/2 hr)	3
4	Restored within the next half an hour (1 1/2hr-2hr)	9
5	Restored within the next half an hour (2hr-2 1/2 hr)	6
6	More than 2 1/2 hr	75

	Primary	Time	GSS	Time
First Energized	Sub J	12:33	Thulhiriya	12:33
Last Energized	Sub M	17:15	New Polpitiya	17:54

Unrestored or delayed equipment

Equipment	Reason/Comment
LVPS unit 01	Turbine diaphragm failure
LVPS unit 03	Turbine diaphragm failure
Kiribathkumbura-Nawalapitiya cct 02	VT failure

Comments of the SCE

Mahaweli system restoration Mahaweli system restoration was started from Kothmale unit 01, Victoria unit 01 and upper Kothmale unit 01 simultaneously towards 03 separate islands at 13:05hrs,12:27hrs and 12:53hrs respectively. The initial attempt of restoring from Kothmale-Biyagama cct 01 & 02 failed and hence the process delayed due to the operational issue of circuit breakers at Kothmale GSS. After the energization of Kothmale-Biyagama cct 02, Kothmale generators were headed towards Biyagama,Kotugoda GSSs. The Victoria generators were headed towards Randenigala ,Mahiyanganaya GSS s and Upper Kothmale generators were headed towards N'Anuradhapura, Kiribathkumbura GSSs. Upper Kothmale system could energize LVPS GSS at 15:36hrs. **Laxapana system restoration** Initial restoration from N'Laxapana generotor 01 was started at 12:37hrs and failed with the tripping of the generator at 13:12hrs. Thereafter, Laxapana system restoration was started from N'Laxapana unit 01, WPS unit 01 and Polpitiya unit 01 machines towards Athurugiriya,Kolonnawa GSS s at 13:36hrs,14:10hrs and 14:46hrs respectively. **Samanala system restoration** Samanala system restoration was started from Samanalawewa unit 02 and Kukule unit 02 simultaneously towards 02 separate islands at 12:14hrs and 13:04hrs respectively. Initial 05 attempts started from Smanalawewa generators were failed due to an issue in embedded protection scheme and hence the process delayed.6th successful grid synchronization of Samanalawewa unit 01 at 14:49hrs, could extend the supply up to N'Galle GSS through Embilipitiy,Mathara GSS s and finally failed at 16:11hrs due to the tripping of the machine. Then the entire southern system was restored through Laxapana side by 16:30hrs. Kukule both units extended the supply up to two N'Galle 132kV B/B 01. **Colombo system restoration** Colombo system restoration was stared from KPS small GT-04 and GT-02 at 12:31hrs and 14:15hrs respectively. Priority supply of Colombo city was restored initially through Sub-J and Sub-H at 12:33hrs and 13:18hrs respectively. **The entire system was restored by 16:47hrs.**

SCE

Comments of the CE(SO)

System collapsed due to rejection of 34% generation from the system and subsequent trippings of generators.Mahaweli complex were running at higher capacity due to high reservoir levels in mahaweli complex. However, N-1 contingency criteria has been satisfied in Kotmale -Biyagama 220kV double cct. Loss of 34% generation from mahaweli system lead to severe under frequency conidtion in the remaining system causing cascade tripping of generators with under frequency trip. System restoration took place without much disturbance although it took around 5 hrs. Delays in reenergizing of some transmission lines caused delay in Laxapana and Mahaweli restoraton. Colombo restoration delayed as there were no generators with adequate capacity with frequency control capability connecetd to colombo city network. It is not possible to energize the colombo city cable network initially from the Mahaweli system / Laxapana system due to voltage issues. Hence,it is highly recommanded to have Gas turbines having adequate capacity (100MW) with frequency control option in Colombo network in order to expedite the total failure restoration under present network and loading conditions

CE(SO) -SYC

Annex 01:	Generator failure and restoration summery
Annex 02:	Transmission line failure and restoration summary
Annex 03:	GSS and Colombo PSS failure and restoration summary
Annex 04:	Problems Encountered during the restoration of the failure
Annex 05:	Operation of Under frequency load shedding
Annex 02:	Frequency Plot

Annex 01: Generator Failure and Restoration summary

POWER STATION	UNIT	MW	TRIPPED AT	Unit Generation(MW) at 11:27hrs	Mvar	RELAY INDICATION / REASONS FOR TRIPPING / REMARKS	Restored at
LAXAPANA COMPLEX							
O/LAXAPANA	1	10	11:27:42 AM	10	1	BB frequency fault	15:48
	2	10	11:27:42 AM	10	1	BB frequency fault	15:46
	3	10	11:27:42 AM	10	1	BB frequency fault	15:59
	4	12.5	11:27:42 AM	12	1	Under frequency	16:10
	5	12.5	11:27:42 AM	12	1	Under frequency	16:15
N/LAXAPANA	1	57	11:27:42 AM	50	19	Under frequency	13:33
	2	57	11:27:42 AM	50	19	Under frequency / Gen. T/F Differential Protection	3:45
WIMALASURENDRA	1	25	11:27:42 AM	20	1	Under frequency	14:10
	2	25	11:27:42 AM	20	2	Under frequency	15:18
CANYON	1	30	11:27:42 AM	15	3	Gen. over active power	15:53
	2	30	11:27:42 AM	20	2	Gen. O/C/ Gen. under voltage/ Gen. over active power	16:22
POLPITIYA	1	37.5	11:27:42 AM	43	6	Mechanical & External trip	14:43
	2	37.5	11:27:43 AM	43	1	Over Speed trip	15:22
MAHAWELI COMPLEX							
KOTMALE	1	67	11:27:40 AM	51	17	GCB opened remaining at spinning mode. 81O/81U	13:05
	2	67	11:27:40 AM	39	16	GCB opened remaining at spinning mode. 81O/81U	13:58
	3	67	11:27:40 AM	60	13	Over voltage/ 81O (O/f), 81U (U/f)	14:33
UPPER KOTHMALE	1	75	11:27:47 AM	40	18	Main T/F V/f operated	12:49
	2	75	11:27:48 AM	40	18	Excitation system heavy fault	15:06
VICTORIA	1	70	11:27:42 AM	80	11	Emergency shutdown/ UF, OF, UV/ Over Speed mech. f	12:27
	2	70	11:27:42 AM	80	18	Emergency shutdown/ UF, OF, UV	15:15
	3	70	11:27:42 AM	80	10	Emergency shutdown/ Over fluxing Stage I, II	13:40
RANDENIGALA	1	60	11:27:41 AM	64	12	Over frequency	16:37
	2	60	11:27:41 AM	65	12	Over frequency	16:19
RANTAMBE	1	25	11:27:41 AM	27	5	Over current/ Over voltage/ Over frequency	16:32
	2	25	11:27:41 AM	27	5	Over frequency	16:13
UKUWELA	1	20	11:27:42 AM	20	6	No excitation / Under frequency	16:19
	2	20		0	0		
BOWATENNA		40	11:27:42 AM	39	10	Gen. O/C/ Gen. O/reactive power/ UF/ O/voltage	14:45
SAMANALA HYDRO							
SAMANALAWEWA	1	60	11:27:44 AM	40	25	Gen. voltage over 90%/ Over excitation limit	16:30
	2	60	11:27:44 AM	40	19	Gen. voltage over 90%/ Over excitation limit	16:53
KUKULE	1	37.5	11:27	38.5	7	Under frequency/ Protection electrical trip	13:04
	2	37.5	11:27	38.5	7	Under frequency/ Protection electrical trip	13:50
UDAWALAWA		4		3			
INGINIYAGALA		10					
THERMAL COMPLEX							
KPS - GT	1	16	11:27		11	Under excitation	15:38
	2	16	11:27		10	Under excitation	14:15
	3	18	11:27				
	4	16			14	Under excitation	12:31
	5	16					
NEW G.T. - KPS	7	115					
KCCP-GT		108					
KCCP-ST		55					

[redacted]

LAKVIJAYA	1	270	11:27:42 AM	268	103	Master fuel trip	-
	2	270		0	0		
	3	270	11:27:41 AM	270	100	Generatot composite LV/OC trip	-
SAPU A	1	18					
	2	18	11:27	16	10	Over Speed	16:31
	3	18					
	4	18					
SAPU B	5	10	11:27	9	5	Under frequency	16:57
	6	10		0	0		
	7	10	11:27	9	5	Under frequency	16:49
	8	10	11:27	9	4	Under frequency	17:20
	9	10	11:27	9	6	Under frequency	16:50
	10	10		0	0		
	11	10	11:27	9	6	Under frequency	16:52
	12	10	11:27	9	5	Under frequency	16:59
UTHU JANANI	1	24	11:27	17	0	Under impedance	17:20
BARGE		60	11:27	51	30	Over speed protection shutdown	
IPP							
Sojitz -KPS		165					
WCP		270					
Wind Power		125		1			
Mini Hydro		296		61	3		
Solar/ Biomass				31	1		
TOTAL GENERATION AT		11:27 hrs		1956		MW	

Annex 02: Transmission Line Failure and Restoration summary

(Only the lines that TRIPPED are mentioned below with the data of just prior to the tripping)**

Transmission Line	Tripped at	Restored at	Load	Remarks
Biyagama - Kothmale 02	11:27:13 AM	11:27:19 AM	745A	Auto reclosed
Kothmale - Biyagama 02	11:27:13 AM	13:04	745A	Differential protection operated
Kothmale - Biyagama 01	11:27:35 AM	14:16	1374 A	O/C, E/F
N'Anuradhapura - Kothmale 02	11:27:44 AM	13:34	817A	Distance protection operated
Athurugiriya - New Polpitiya	11:27:43 AM	15:59	408A	OC
Athurugiriya - Polpitiya	11:27:43 AM	13:32	210A	OC
Kolonnnawa-Kosgama	11:28:13 AM	16:06	485A	Distance protection operated
Kolonnawa-Seethawaka	11:28:13 AM	15:49	49A	Distance protection operated

Annex 03: GSS/ Switch Yard / Colombo Primaries failure and restoration summary

GSS/SY/PS	Failed at	Load	Energized at	Remarks
Victoria	11:27	241	12:27	Generation
Randenigala	11:27	122	12:40	Generation
Rantambe	11:27	54	12:47	Generation
Upper Kothmale	11:27	80	12:53	Generation
Mahiyanganaya	11:27	5.48	12:58	
Ambalangoda	11:27	28.67	13:04	
Kukule	11:27	68	13:04	Generation
Matugama	11:27	35.32	13:04	
Kotmale	11:27	157	13:05	Generation
Anu New	11:27	21.73	13:10	
Biyagama	11:27	68.79	13:10	
Ampara	11:27	35.15	13:24	
Athurugiriya	11:27	34.5	13:32	
Lax New	11:27	101	13:32	Generation
Lax Old	11:27	54	13:32	Generation
Polpitiya	11:27	86	13:32	Generation
Thulhiriya	11:27	3.5	13:33	
Sapu Gss	11:27	60.1	13:35	
Anu	11:27	15.11	13:36	
Habarana	11:27	18.47	13:54	
Badulla	11:27	9.47	14:02	
Kotugoda 132kV	11:27	32	14:08	
Kotugoda 220kV	11:27	40.72	14:08	
Vaunativu	11:27	12	14:09	
WPS PS	11:27	40	14:10	Generation
WPS GSS	11:27	16.05	14:10	Generation(Minihydro)
Naula	11:27	23.8	14:28	Generation(Minihydro)
Aniyakanda	11:27	20.12	14:29	
Kelaniya	11:27	29.39	14:31	
New Galle	11:27	57	14:34	
Ukuwela GSS	11:27	34.51	14:35	
Bowetenna	11:27	39	14:38	Generation
Polon	11:27	13.53	14:45	
Kelanithissa 132kV	11:27	26.32	14:47	
Kolonnawa Old	11:27	34.84	15:03	
Kolonnawa GIS	11:27	50.83	15:03	
Kelanithissa 220kV	11:27	0	15:05	
Veyangoda	11:27	43.24	15:08	
Kiribathkumbura	11:27	30.7	15:08	
Kurunegala	11:27	51.4	15:21	
Kerawalapitiya GSS	11:27	30.46	15:23	
Kerawalapitiya PS	11:27	0	15:23	
Sapu. Diesel	11:27	70	15:26	Generation
Norechchole GIS	11:27	1.2	15:36	Generation(Wind)
LVPS	11:27	541	15:36	Generation
Seethawake	11:27	24.55	15:36	
Pannipitiya	11:27	56.15	15:43	
Pallekele	11:27	15	15:45	
Kosgama	11:27	44.78	15:49	
Canyon	11:27	35	15:53	Generation
Vauniya	11:27	5.6	15:54	
Sri Jaya Pura	11:27	46.49	15:58	
Valachchena	11:27	11.63	16:04	
Havelock Town (A)	11:27	40.4	16:10	
Maradana	11:27	38.47	16:10	
Balangoda	11:27	5.49	16:13	
N/Chilaw 132kV	11:27	114	16:13	
Horana	11:27	41.8	16:17	

Ukuwela PS	11:27	20	16:19	Generation
Ratmalana	11:27	55.45	16:20	
Madampe	11:27	34.29	16:21	
Chilaw	11:27	36	16:21	
Kilinochchi	11:27	9.09	16:22	
Bolawatta	11:27	57.34	16:23	
Beliatta	11:27	11.86	16:24	
Sam. Wewa	11:27	80	16:24	Generation
Col. Sub E	11:27	20	16:25	
Col. Sub F	11:27	15.14	16:25	
Panadura	11:27	58.49	16:25	
Dehiwala	11:27	31.77	16:26	
Katunayaka	11:27	24.83	16:26	
Puttlam	11:27	32.36	16:28	
Maliboda	11:27	0.66	16:29	
Nuwara Eliya	11:27	1.1	16:30	Generation(Minihydro)
Chunnakam	11:27	23.66	16:32	
Maho	11:27	14.34	16:34	
Embilipitiya	11:27	13.44	16:35	
Monaragala	11:27	7.38	16:39	
Ragala	11:27	4.6	16:40	Generation(Minihydro)
Kappalthurei	11:27	7.7	16:40	
Hambanthota	11:27	22.35	16:41	
Col. Sub N	11:27	7.9	16:42	
Matara	11:27	37.92	16:42	
Trinco	11:27	24.94	16:44	
Deniyaya	11:27	2.26	16:46	
Oruwala	11:27	3.9	16:47	
Rathnapura	11:27	5.5	16:47	Generation(Minihydro)
Col. Sub M	11:27	14.4	17:13	
Col. Sub C	11:27	21.76	17:16	
Mannar	11:27	6.6	17:17	
Col. Sub L	11:27	31.5	17:26	
New Polpitiya	11:27	1	17:54	Generation(Minihydro)

Annex 04: Problems Encountered during the restoration of the failure

STATION	EQUIPMENT	PROBLEM / COMMENT	Whether a delay is caused (Y/N)
Kothmale	Biyagama cct 01	Couldnot be switched ON	Y
Kothmale	Biyagama cct 02	Couldnot be switched ON	Y
Embilipitiya	Samanalawewa cct 01	had to switch off and rectify the issue due to VT failure	Y
Kelaniya	Sapugaskanda cct 01	Couldnot be switched ON	Y
Colombo Sub L	Kelanithissa cable	Couldnot be switched ON	Y
N'Laxapana	Generator 02	Unable to start due to the operation of generator differential protcetion at the failure time.	Y
Samanalawewa	Generator 01	Synchronizing issue due to an issue in embedded protection scheme	Y
Samanalawewa	Generator 02	Synchronizing issue due to an issue in embedded protection scheme	Y
N'Anuradhapura	48V Communication DC system	Could not communicate through Hot line telephone system	Y
Nawalapitiya	Polpitiya line	Could not be energized	N

Annex 05: Operation of UFLS at the time of the failure

GSS	Feeder No	Stage	OFF TIME	LOAD / (A)
Athurugiriya	3	I	11:27	10
	6	I	11:27	30
	8	I	11:27	228
Rathnapura	1	I	11:27	41
Mathugama	1	I	11:27	0
	8	I	11:27	242
	5	II		
	10	II		
	6	III	11:27	73
	9	III	11:27	0
Kotugoda	13	I	Disabled	
	11	I	Disabled	
	3	II	11:27	321
	9	IV	11:27	202
	12	V or df/dt	11:27	78
Sapugaskanda	9	I	11:27	103
	11	I	11:27	23
	2	II	Removed	
	4	II	11:27	108
	7	II	11:27	118
	6	III		
	3	IV	11:27	227
	8	IV	11:27	0
Kosgama	1	I	11:27	215
	8	I	11:27	205
	2	II	11:27	110
	5	IV	11:27	30
Ukuwela	10	I	11:27	146
	3	II	11:27	12
	12	df/dt	11:27	104
	1	II	11:27	90
Habarana	3	I	11:27	100
	1	II	11:27	132
	6	II	11:27	50
	7	II	11:27	152
	2	df/dt	Disabled	
	4	df/dt	Disabled	
New Galle	3	I	11:27	87
	11	I	11:27	57
	1	df/dt	Removed	
	6	df/dt	Removed	
	4	df/dt	Removed	
Thulhiriya	5	I	11:27	132
	6	I	11:27	25
	4	III	11:27	38
	1	III	11:27	125
	2	IV	Removed	
Matara	6	I	11:27	87
	4	III	11:27	127
	8	III	11:27	102
	2	df/dt	11:27	80
	7	df/dt		
	1	df/dt	11:27	25
Badulla	6	I		

	3	III	11:27	22
	5	III		
	1	IV		
Biyagama	1	I	11:27	10
	3	III	11:27	170
	5	III	11:27	208
	6	III	11:27	310
	4	IV	11:27	230
	7	V or df/dt	11:27	10
	8	V or df/dt	11:27	210
Kelaniya	3	I	11:27	260
	2	I	11:27	52
	1	df/dt	11:27	290
Belliatta	4	II	11:27	0
	5	II	11:27	56
	6	II	11:27	32
Ambalangoda	2	II	11:27	69
	3	II	11:27	127
	4	II	11:27	73
	6	II	11:27	158
Kiribathkumbura	6	II		
	13	II		
	8	III	11:27	61
	9	III	11:27	69
	3	III		
	4	IV		
Dehiwala	7	II	11:27	126
	6	III	11:27	126
	8	III	11:27	123
	1	IV	11:27	47
	3	IV	11:27	183
Rathmalana	F7	II	11:27	118
	F9	II	11:27	305
	F6	IV	11:27	105
	F2	df/dt	11:27	100
	F3	df/dt	11:27	104
Veyangoda	7	II	11:27	29
	3	III	11:27	204
	4	IV	11:27	143
	6	IV	11:27	0
	8	V	11:27	60
Panadura	1	II	11:27	220
	2	V or df/dt	11:27	184
	4	V or df/dt		
	5	V or df/dt	11:27	102
N/Anu	Trinco 1 & 2	III		
Kilinochchi	2	III		
	4	III		
Aniyakanda	3	III	11:27	148
	7	III	11:27	177
	1	IV	11:27	194
	5	df/dt		
Pannipitiya	3	III		
	6	III	Off	
	9	III	11:27	208
	10	III	Off	
	2	IV	11:27	196
	4	IV	11:27	289
	7	IV	11:27	153

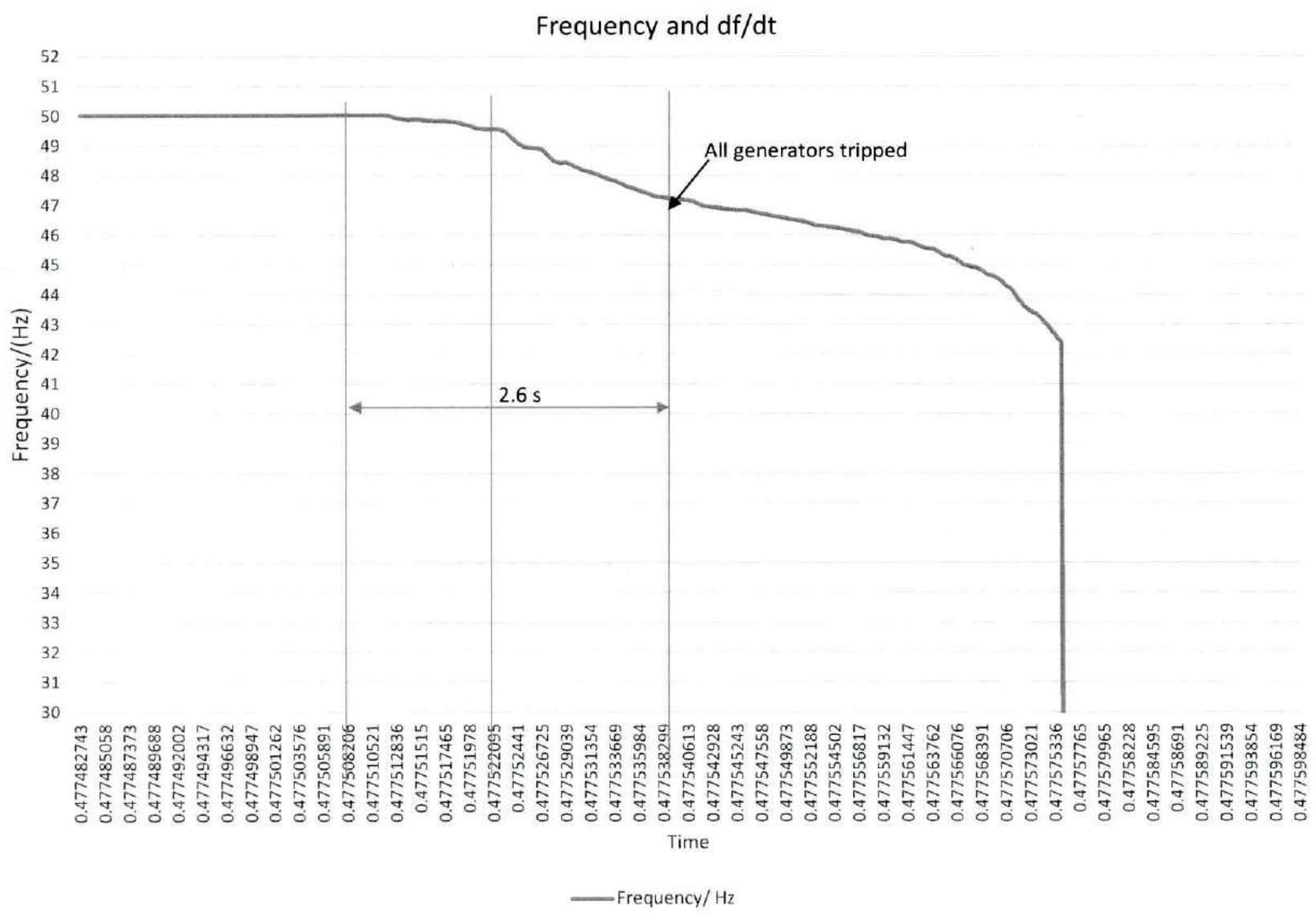
	8	IV	11:27	72
	5	V	11:27	18
Madampe	7	III	11:27	80
	1	V or df/dt	11:27	100
	3	V or df/dt	11:27	73
	5		11:27	95
	6		11:27	10
Ampara	3	IV		
	5	IV		
Sub A	1137	IV	11.27	57
(equiva 33kV Amps)	14	IV	11:27	77
	22	IV		57
	1011	IV		57
	571	IV	11:27	55
Sub F	116	IV		
(equiva 33kV Amps)	54	IV		
	624	IV		
	43	IV		
	9	IV		
Sub I	18	IV	11:27	45
(equiva 33kV Amps)	45	IV		
	1240	IV		
	1130	IV		
	602	IV	11:27	23
Sub E	981	IV		
(equiva 33kV Amps)	10	IV		
	609	IV		
	335	IV		
Kolonnawa GIS	B1	IV		
	B2	IV		
	G1	IV		
	G2	IV		
Horana	5	IV		
	2	df/dt		
	3	df/dt	11:27	346
	4	df/dt	11:27	120
Pannala	3	V	11:27	0
	5	V	11:27	151
	7	V		
	2	df/dt	11:27	212
	4	df/dt		
	6	df/dt		
Kurunegala	6	V		
	5	V or df/dt		
	2	df/dt		
	3	df/dt		
	4	df/dt		
S'Japura	1	df/dt		
	2	df/dt	11:27	115
	4	df/dt	11:27	81
	5	df/dt	11:27	127
	6	df/dt		
	8	df/dt		
Bolawatta	2	df/dt		
	3	df/dt		
	4	df/dt	11:27	134
	5	df/dt	11:27	118
	8	df/dt		
Katunavaka	1	df/dt		

	2	df/dt		
	7	df/dt	11:27	0
	8	df/dt	11:27	84
Deniyaya	1	df/dt		
	2	df/dt		
Mahiyangane	2	df/dt		
	5	df/dt		

UFLS Stage	Shedded load in [A]	Shedded load in [MW]	Shedded load as a %
Stage I	2053.0	105.6	5.4%
Stage II	2406.0	123.8	6.3%
Stage III	2371.0	122.0	6.2%
Stage IV	2442.0	125.6	6.4%
Stage V	229.0	11.8	0.6%
Stage V or df/dt	757.0	38.9	2.0%
df/dt	2040.0	104.9	5.4%
Total	**12298.0**	**632.6**	32.4%

Total Rejected Generation MW	652
Total Shedded 33kV Load in [A]	12403
Total Shedded 33kV Load in MW	638
	1954

power factor : 0.90



Frequency and df/dt
All generators tripped
2.6 s
Frequency/(Hz)
Time
Frequency/ Hz

Annex L

Office of the CE (Comm) Systems
Ceylon Electricity Board,
Kelanitissa Power Station Premises,
New Kelani Bridge Road,
Wellampitiya.

Date: December 09, 2021

My No: CMN/Systems/Admin/2021/01

Additional General Manager (Transmission)

Thro' Deputy General Manager (Communication)

Report on Communication Network Overview

This is with reference to the meeting held on 06th December at National System Control Center regarding the total failure occurred on CEB power system on 03rd December 2021.

As per your instructions, the report on communication network overview is submitted herewith please.

D G A K Wijeratna
CE (Comm. Systems)

CEB Communication Network

CEB has an island wide dedicated communication network which serves the data and voice communication requirements (operational and administration) of various branches of CEB.

Mainly two separates networks are maintained by the communication branch for providing these services

- The **SDH network** (STM-1/STM-4) with transmission capacity of 155/622 Mbit/s. This comprises of TDM based fiber optic multiplexers installed at each grid substation and power station of the CEB transmission network
- Newly implemented separate **GB Ethernet network** (with a capacity of 1 Gbps at present). This comprises of L3 routers , L2+ switches installed at various stations of CEB transmission network

Mainly following services are provided to for the National System Control Center (**NSCC**), Grid Substations (**GS**) and Power Stations (**PS**) via this communication network.

(1) Hot Line Telephone System

(2) Administrative Telephone System

(3) Supervisory Control and Data Acquisition (SCADA) System

(4) Tele-protection signaling facilities

(5) Ethernet networking facilities

(1) Hot Line Telephone System

Hot line telephone system is exclusively used for operational voice communication purposes of NSCC with other island wide GSs and PSs. This service is configured on four main Private Branch Exchanges located at four different stations and interconnected on digital trunk lines through **SDH network.**

(2) Administrative Telephone System (CEB Corporate Telephone Network)

The administrative Telephone System provides voice communications between any other grid substations, power stations and other administrative offices connected to the CEB Fiber Optic Network. Utility grade Private Branch Exchanges are installed at several grid substations and power stations and they are interconnected on digital trunk lines through **SDH network**.

(3) The SCADA System

This SCADA system is used for monitoring and controlling of the power generation and transmission network of CEB. Gateway/ RTU at each grid substation and power station are communicated with master SCADA station at NSCC via the **SDH network**. (on IEC 60870-5-104/101 protocols)

(4) Tele-Protection System

The teleprotection system is provided for satisfactory operation of HV transmission lines. The **SDH network**, direct fibers and, few Power Line Carrier links are being used as the communication media for providing fast and reliable bi-directional communication of protection commands and information between adjacent substations connected by a high voltage transmission line.

(5) Ethernet Networking Facilities

Networking facilities have been provided via the communication network for following services

- Remote accessing of Digital Disturbance Recorders (the old DDRs are connected to the **SDH network** while newly installed DDRs are connected to **GB Ethernet network**)

- Remote access of engineering workstations (EWS) of the **Substation Automation Systems** (SAS) - this service is provided via **GB Ethernet network** only.

The access to the network is via an external GB Ethernet switch or a GB Ethernet service embedded module in the fiber optic multiplexer installed at each grid substation or power station of CEB

Several security features have been implemented to safeguard the data transmission through these networks

- All the Communication Nodes (Multiplexers, PLC, Switches, Routers) are established in CEB own high security premises (Power Stations, Grid Substations and administrative offices) with proper physical security.

- Only authorized technical staff of the Communication branch can access communication equipment locally or remotely from any grid substation and power station.

- Access credentials of the communication equipment are only kept with authorized personnel of communication branch. SDH multiplexers can be accessed only through the PCs with already installed licensed Local Crafting Software.

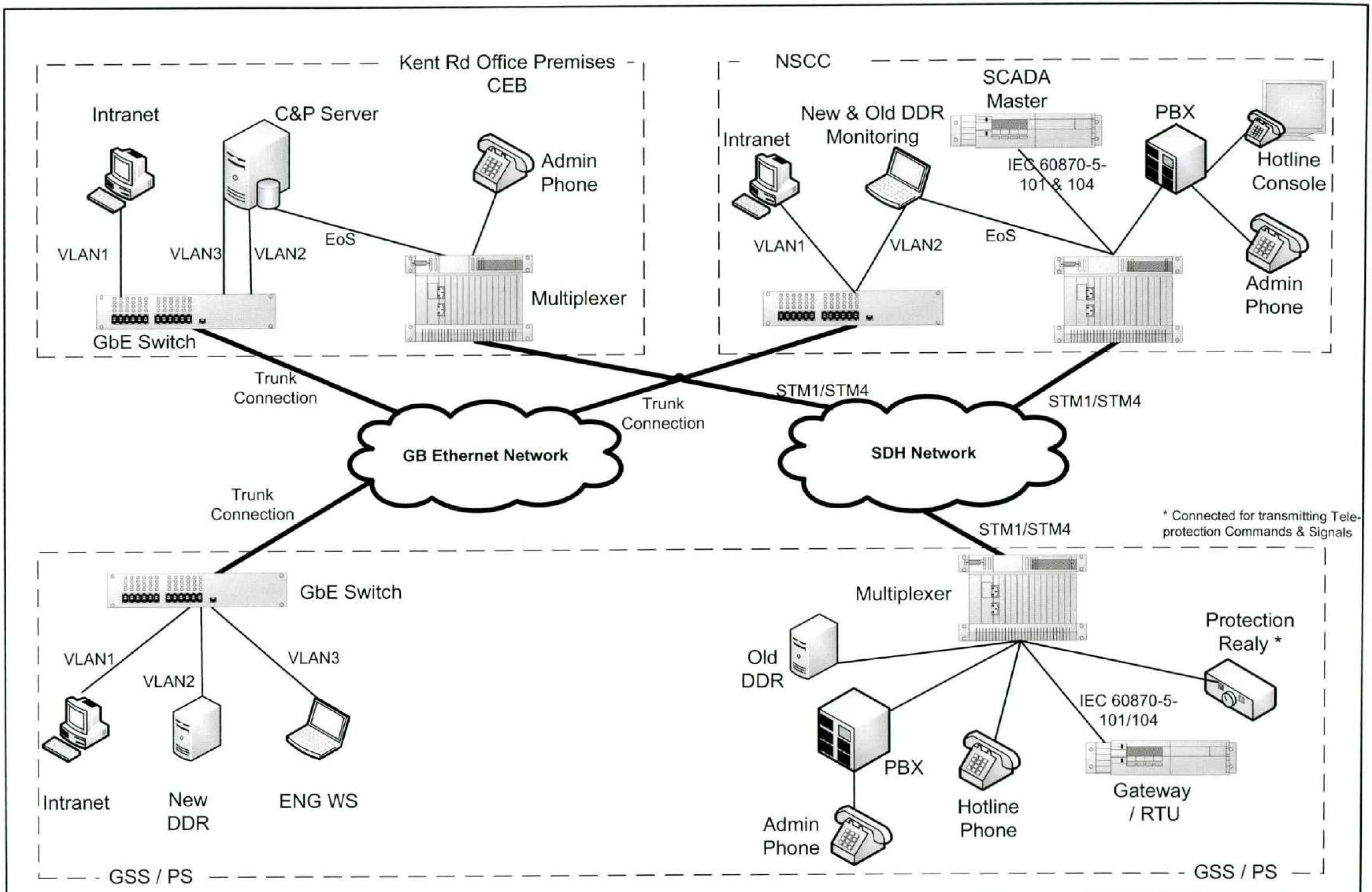
- The **SDH network** or **GB Ethernet network** is not directly connected to Internet or any other third party network.

- Logical separation of different incorporated services have been achieved though defining separate VLANs and security zones through the 1 GB backbone of the **GB Ethernet network**.

- The access to each **VLAN** is only provided for the relevant personals who use the particular service.

Only the data channels have been provided for these services via the communication network. The access control for the end equipment connected via each VLAN for remote operation is managed by each branch who use the particular service.

The attached diagram illustrates the overview of the CEB communication network.



Rev. No	Date	Description	Drawn	Approved	Overview of CEB Communication Network	Ceylon Electricity Board

[redacted]

ANNEX "A"

Office of Deputy General Manager (Tr. O & M)
Ceylon Electricity Board,
Kent Road,
Colombo 09.

Date: January 05, 2022

Additional General Manager (Transmission)

Investigation into the Power System Failure on 03.12.2021

This has reference to the Secretary, Ministry of Power's letter ref: PE/TECH/D/03/06 dated December 27, 2021 with regard to total power failure occurred on December 03, 2021.

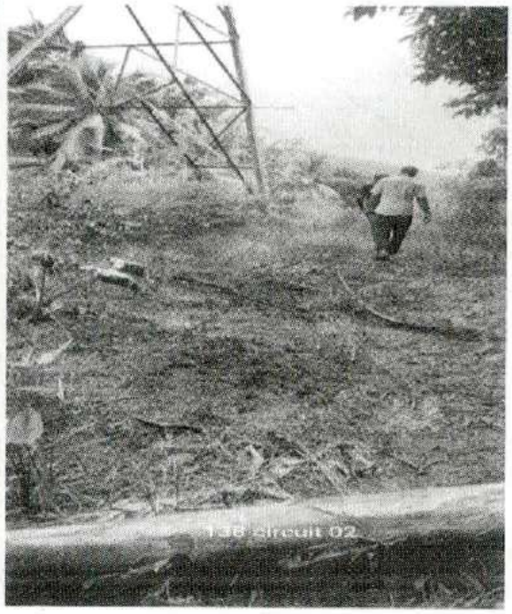
With reference to the item 1 of the said letter, please find the following clarifications.

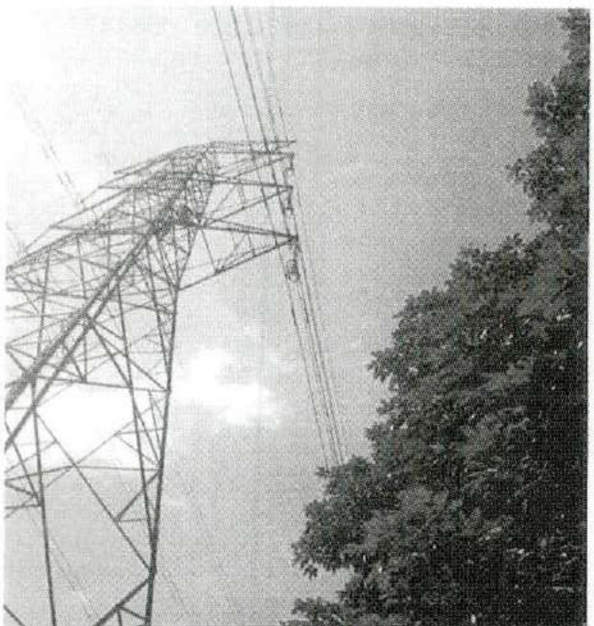
1. As per the immediate preliminary investigations, it was found that the incident has been triggered due to Kothmale_ Biyagama circuit 2 Phase C trip by line differential protection and subsequent tripping of Kothmale_ Biyagama circuit 1, Kothmale_ New Anuradhapura circuit 2 and considerable loss of generation. Please refer to the clarifications of DGM (C&P) for detailed inforn ation on the nature of the fault.
2. As informed, distance to fault was 23km (approx mately close to Tower No. 132) from Biyagama GSS. In view of rapid restoration of the system, clearance was given to National System Control Center (NSCC) for energization of the both circuits, after identifying the faults as non persisting faults. All engineers & ESS were hurried to critical grid substations to assist in restoration proceedings.
3. CE(West North) under DGM (OM-South) who is responsible for wayleave clearing of the said transmission line engaged his staff to check the suspected location on 4th and 5th December and could not find any trace of a physical fault/ Physical evidence.
4. Later, from 5th December, two additional gangs from Hot line maintenance unit also engaged for detailed inspection of insulator strings of the fault phase of the affected circuit, from tower No. 117 to 147 (31 Nos. of towers). However, the only suspected incident found, was a man made bush fire very close to tower No. 138. The photographs are attached for your ready reference (bottom conductor of this circuit was the affected Phase C).
5. Other than these, there were no physical evidences found with regard to this incident since the fault was a non persisting fault.

05/01/22
Eng. D. D. U. Dompege,
Deputy General Manager
Transmission Operation & Maintenance – South

Annex 1

Fire under the Tower no 138





ANNEX “B”

Annex N

Office of the DGM (Protection – Generation)
Ceylon Electricity Board
40/20A, Ampitiya Road
Kandy

My No: PG/11/2021-12-03/01

Additional General Manager (Generation)

Report on Power System Failure occurred on December 03, 2021 at 11:27:14.609

This report is based on the sequences of events those had occurred with the initial failure of Biyagama-Kothmale 220kV Lines on December 03, 2021 at 11:27:14.609 hrs and events & disturbance records of Digital Fault Recorders (BEN) and generator protection relays (IEDs).This contains preliminary analysis of the failure and consequent responses of generator protection IEDs to subsequent behavior of power system.

1. Sequence of Events

Table # 01 Sequence of Events *(Times are based on Biyagama Digital Fault Recorder)*

Item	Event	Time	Remarks
1	Kothmale-Biyagama Line 2 B Phase (AR Open) @ Both ends	11:27:14.609	Kothmale Ben
2	Kothmale- Biyagama Line 2 R&Y Phase Trip	11:27:14.885	
3	Kothmale-Biyagama Line 2 B Phase (AR Close) @ Biyagama end	11:27:15.533	
4	Kothmale-Biyagama Line 1 TRIP @ Kothmale end	11:27:37.005	
5	Start Frequency increase in Kothmale Grid	11:27:37.005	
6	Start Frequency Decrease in Biyagama Grid	11:27:37.024	
7	Victoria U #01 Trip (81O)	11:27:41.292	Protection Relays
8	Victoria U #02 Trip (81O)	11:27:41.294	
9	LVPP U# 03 Trip	11:27:41.331	LVPP BEN
10	LVPP BC 2/3 Trip	11:27:41.365	
11	LVPP – Anuradhapura Line 01 (Current Loss from LVPP Side)	11:27:41.365	
12	Anuradhapura – LVPP Line 01 (Current Loss from Anuradhapura ben)	11:27:41.365	ANU Ben
13	Kothmale U#02 Trip (81O)	11:27:41.381	Kothmale BEN
14	Kothmale U#03 Trip (81O)	11:27:41.381	
15	Kothmale U#01 Trip (81O)	11:27:41.399	
16	LVPP U# 01 Trip	11:27:42.033	LVPP Ben
17	LVPP BC ½ Trip	11:27:42.068	
18	LVPP – New Chilaw 01 (Current Loss)	11:27:42.068	
19	LVPP – BB 01, 02, 03 & LVPP- ANU 01 &ANU 02 – Start voltage Loss	11:27:42.068	
20	Kothmale – Anuradhapura Line 02 (Current zero)	11:27:44.554	Kothmale ben
21	Kothmale – Anuradhapura Line 02 Trip (from ANU end)	11:27:44.555	Anuradhapura ben
22	Victoria U #03 Trip (24)	11:27:44.648	Protection Relays
23	UKHPS U#01 Trip (24)	11:27:47.681	

***Time Error of Kothmale BEN recorder is 1.20sec (lag) w.r.t Biyagama BEN*

Pre Fault frequency of the system (Kothmale Unit#01 Generator) was 50.045Hz and frequency started to rise up to peak of 59.75Hz with the trip of Kothmale – Biyagama Line#01. At the same time frequency of

Lakvijaya Busbar#01 started to decrease up to 43.447Hz. It was identified that this could only be due to two alternative reasons;

- Split of Power system into two sections,
- Torsional swing between Mahaweli Complex 220kV system and Rest of the Power System including LVPP,

Protection -Generation Branch is in further analysis to confirm the exact cause of this effect that was visible at different locations of the power system.

1.1. Tripping of Victoria Generators

Protection relays of Victoria U#01 and U#02 had started over frequency pickup (53Hz) at 11:27:38:292hrs and had tripped at 11:27:41:294hrs at the setting of 53Hz, 3.0 sec. Frequency at the time of trip was 58.82Hz.

1.2. Tripping of LVPS Unit # 03

At 11:27:41.331hrs LVPP Unit#03 generator tripped on composite low voltage over current (50C) protection function. Setting of this function is as follows;

- I = 1.26pu, V = 0.6pu, V2 (negative seq.) = 0.06pu & T = 2.5sec

There was a negative sequence voltage at U#03 generator terminal during the power swing condition that occurred in the LVPS and the rest of the system. By assuming that there was torsional swing as explained earlier, presence of this negative sequence voltage is explainable. Relay of U#03 had recorded negative sequence voltage of 0.114pu (Annexure # 01).

With the tripping of Unit#03 generator breaker due to 50C, bus coupler 2/3 (X230) breaker had also opened. This is a normal practice of original equipment manufacturer to operate tripping of bus coupler for the operation of General trip of protection relays. Logic diagram of this function is annexed (Annexure #02). With the opening of CB X230, current in feed from Bus #03 to Anuradhapura Line # 01 had stopped.

1.3. Tripping of Kothmale Generators

Kothmale Unit#02 and Unit#03 had tripped at 11:27:41.381hrs and Unit#01 at 11:27:41.399 hrs due to operation of over frequency protection (81O).The setting of 81O is 53Hz, 3 sec and at the time of tripping, recorded frequency of units was 57.50Hz.

1.4. Tripping of LVPS Unit#01

LVPP Unit#01 generator tripped on composite low voltage over current (50C) protection function at the time of 11:27:42.033hrs. Setting of this function is as follows;

- I = 1.26pu, V = 0.7pu, V2 (negative seq.) = 0.08pu & T = 2.5sec

Relays had recorded negative sequence voltage of 0.104pu (Annexure # 03).

With the tripping of Unit#01 generator breaker due to 50C, bus coupler 1/2 (X130) breaker had also opened and current in feed from Bus #01 to New Chilaw Line # 01 had stopped. At the same time, voltages of all LVPS busses had started decrease.

1.5. Tripping of Other Units in Mahaweli Complex

Randenigala Unit#01 & 02 and Rantembe Unit #01 & 02 had tripped on over frequency protection and Ukuwela Unit#01 and Bowatenna Generator had tripped on under frequency protection.

1.6. Collapse of Mahaweli Complex 220kV System

After tripping of above mentioned generators in Mahaweli Complex, frequency had started to decrease and Upper Kothmale Unit#01 & 02 and Victoria Unit #03 had remained in the system, supplying power in islanded condition to eastern network through Rantembe Grid substation since over frequency (81O) protection has not been implemented in these three generators. Collapse of Mahaweli Complex 220kV network had occurred with trip of these three units due to over flux protection.

1.7. Tripping of Laxapana Complex Generators

All generators except Samanala Unit #02 generator tripped on under frequency protection. Samanala Unit #02 generator tripped transformer HV side overcurrent protection (50T).

While New Laxapana Unit#02 was in shut down sequence there was an operation of unit differential protection (87U). The reason for operation of 87U protection could be due to large internal currents drawn by main transformer due to over fluxing condition.

1.8. Tripping of Samanala Complex

Both units of KGPS had tripped on under frequency and both units of SWPS tripped on under voltage. Reason for SWPS tripping is due to low trip time which was originally set by OEM.

1.9. Tripping of Thermal Complex

All units of Sapugaskanda power plant and BMPP had tripped on under frequency protection. All units of UJPS had tripped on under impedance protection.

2. Restoration of Power System

There were no mal operation in protection system other than in SWPS. While line charging at 0.2pu voltage during the restoration, Unit#02 had tripped on under voltage (27) protection. However, this was successful when the line charging was done at 0.8pu voltage.

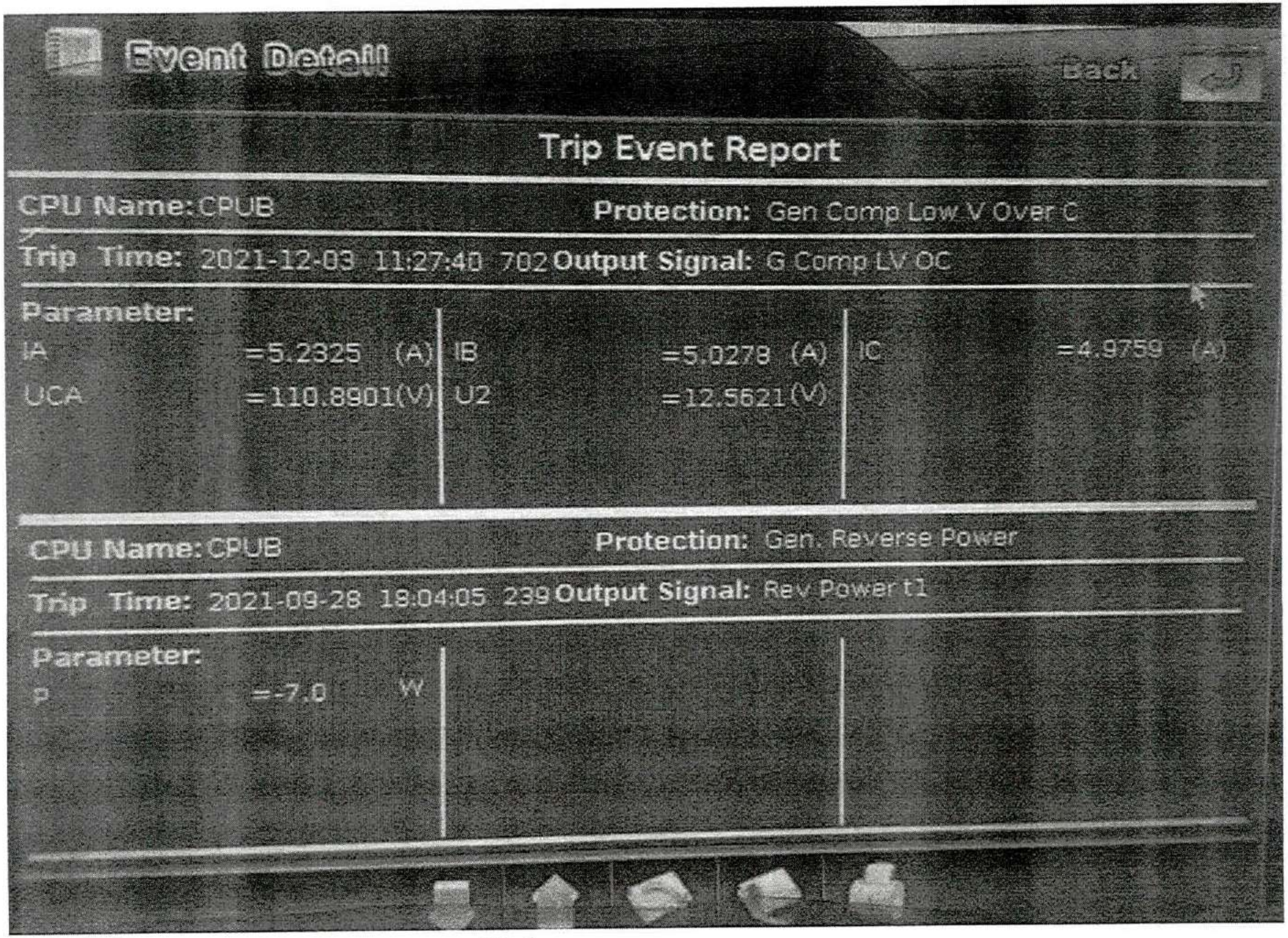
3. Recommendations

3.1. To study the possibility of torsional swing that supposed to have occurred between Mahaweli Complex and Lakvijaya Generators via Anuradhapura Line.
3.2. To study operation of 50C protection function of LVPP and obtain recommendations of OEM of protection system.
3.3. To review over fluxing setting of New Laxapana and Samanala Protection setting after discussion with AMHE and reason for operation of 50T in Samanala Unit#02
3.4. To review over frequency tripping of VPS Unit#03 and both units of UKHPS.
3.5. To study and modify line charging logic of SWPS protection System.

……………………Eng. D.N. Navaratne
DGM
(Protection Generation)

Eng. D.N. Navaratne
Deputy General Manager
Protection – Generation

Annexure # 01	- Image of LVPP Unit#03 Relay Event
Annexure # 02	- Logic Diagram of LVPP Breaker Failure Function
Annexure # 03	- Image of LVPP Unit#01 Relay Event



Annexure #01

Eng. D.N. Navaratne
DGM
(Protection Generation)

Annexure #02

Annexure #02

U_e – Transformer Undervoltage bus rated voltage (secondary value)

3) Negative-sequence voltage operating value U2g

U_{2g} is set to be able to escape from the maximum imbalance negative-sequence voltage. It is usually set to be 8% ~ 10% of the rated voltage, i.e.,

$$U_{2g} = (8\sim10)\%\ U_e$$

4) Operating time delays t1 and t_2

The zone I time delay t1 for the HV station transformer or the startup/standby transformer voltage block overcurrent protection should be set to be coordinated with the operating time of the branch overcurrent protection, i.e.,

$$t_1 = t_{fzmax} + \triangle t$$

Where,

t_{fzmax} – Longest operating time of the branch overcurrent protection

$\triangle t$ – Time step difference, it can be set to be (0.3~0.5)s

Zone II operating time $t_2 = t_1 + \triangle t$

6.41 HV side circuit breaker failure start protection

6.41.1 Composition principle

As the circuit breaker needs to trip for the reason of protection operation, there is still current at the breaker and the breaker is still closed. The breaker failure should be detected to start the special failure protection.

In DGT801U series protections, the circuit breaker failure start protection is composed of the phase current criterion, zero sequence current criterion, breaker auxiliary contact and the normally open contact of the protection tripping relay. Negative sequence current criterion can be also selected for some special conditions.

6.41.2 Logic diagram

The inputs of the protection are the breaker side CT secondary 3-phase current, sometime the zero sequence CT secondary current is introduced.

There are several logical combinations of protection which can be selected at the time of definition. The common breaker failure start protection is shown in Fig.6-41-1.

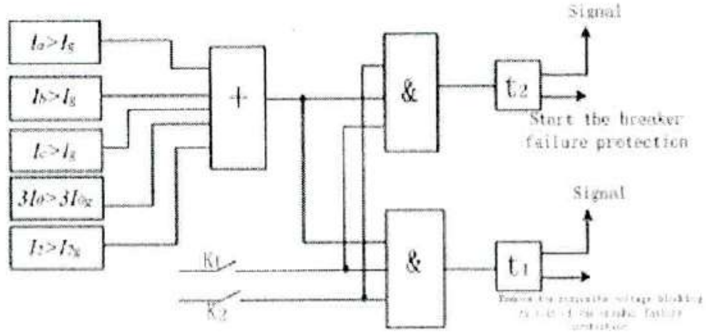


Fig.6-41-1 Logic diagram of the breaker failure start protection

Eng. D.N. Navaratne
DGM
(Protection Generation

Annexure #03

Event Detail

Back

Trip Event Report

CPU Name: CPUB   **Protection:** Gen Comp Low V Over C

Trip Time: 2021-12-03 11:27:41 302   **Output Signal:** G Comp LV OC

Parameter:

IA	=5.037	(A)	IB	=5.1744	(A)	IC	=5.3058	(A)
UCA	=97.0316	(V)	U2	=11.447	(V)			

CPU Name: CPUA   **Protection:** Gen Comp Low V Over C

Trip Time: 2021-12-03 11:27:41 759   **Output Signal:** G Comp LV OC

Parameter:

IA	=5.0339	(A)	IB	=4.7101	(A)	IC	=5.205	(A)
UCA	=106.7968	(V)	U2	=11.0113	(V)			

Eng. D.N. Navaratne
DGM
(Protection Generation)

Problems Encountered during the Restoration after the Total Failure occurred on 03-12-2021 at 11:27 hrs:

After system disturbance occurred at 11:27 hrs, Bus bar 01 & 02 in Kotmale 220kV switchyard were separated into two systems as per SCC instructions. Bus bar 01 was released for Upper Kotmale PS for energizing northern area via New Habarana Line 02 & Bus bar 02 for energizing Kotmale-Biyagama 220kV Lines.

Therefore Biyagama Line 01 had to be connected through CB 530 while Biyagama Line 02 had to be connected through CB 630.

Operation of PRV at CB 530(220kV)

After the system failure, CB 510, CB 530, CB 610 and CB 630 were opened in the Kotmale 220 kV switch yard. Therefore, an inspection was carried out to check breaker condition. There were no outer abnormalities in CB 510, CB 610 and CB 630. However in CB 530, it was observed an operation of Pressure Relief Valve (PRV in phase "Y". This is a Minimum Oil type circuit breaker.

Due to PRV operation, it was decided to further check the condition of the phase "Y" of CB 530.

CB 530 was properly isolated by opening and locking DS 531 and DS 532 and earthing CB 530. Then oil levels and nitrogen pressures were checked in all six chambers. Oil levels and nitrogen pressures were within acceptable ranges.

Then, contact resistances of all three phases were checked and they were also within the acceptable range. Physical abnormalities were also checked, especially in "Y" phase "A" side in which the PRV was operated.
Since there were no abnormalities and oil levels and nitrogen pressures were in acceptable ranges, it was decided to close CB 530

After confirming the safety of the operation of the breaker, all the alarms were reset & Biyagama Line 01 was also energized by switching On CB 530(220kV) at 14:16 hrs.

Delay of Switching on CB 630(220kV)

Protection relay alarms of Biyagama Line 02 were reset at the protection panel, "D80.RP 220kV Biyagama OHL2".

I. F871 Diff. Main-1 Relay (Siemens) alarms were reset.
II. F872 Diff. Main-2 Relay (Micom) alarms were reset.
III. Latch was reset by push button "PB for Trip Relay Reset".

This was the normal practice of resetting the alarms & no indication remained at the panels as well as control room annunciation panels.

Since the operation of CB530 (connecting to Biyagama Line 01) was delayed until proper investigation was done on CB 530, SCC asked to energize the Biyagama line 02 which was tripped from "Line Differential Protection".

Then at 12:14 hrs, Biyagama line 02 was tried to energize by switching On CB 630 but failed. This was tried several attempts from Control room mimic panel as well as from SCADA. So immediately Electrical staff attended to the fault analysis.

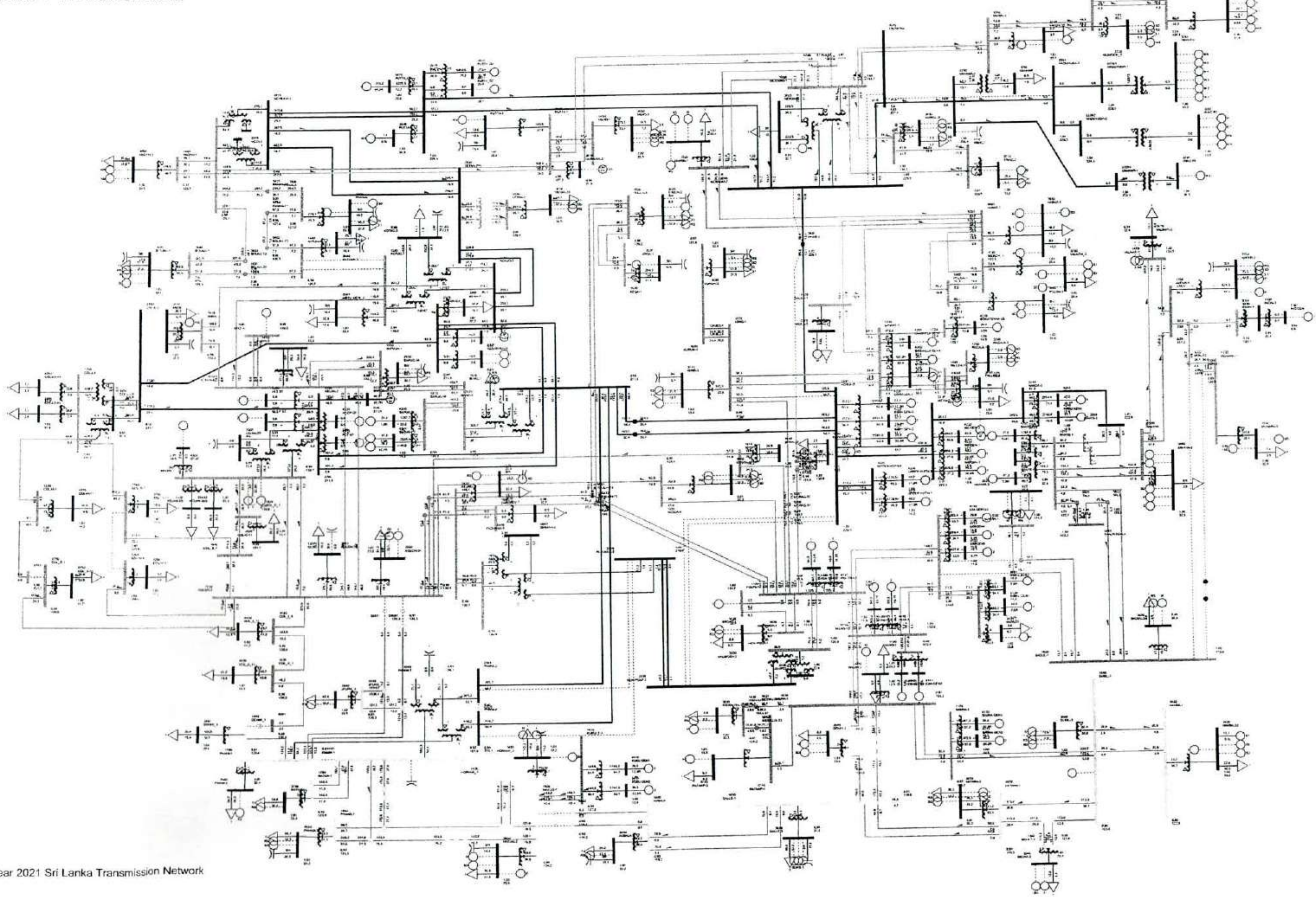
Then CB 630 was tried to manually close from + JU 482 panel and again it was unsuccessful.

This was further inspected & analyzed, and it was assumed that there should be a tripping signal coming from transmission protection panels.

In the mean time it was noticed that an Electrical Superintendent from Transmission Protection branch had been arrived to Kotmale switch yard. This situation was informed to him and then the fault was reset by him from the protection panel.

Then Kotmale-Biyagama Line 02 was connected to Kotmale switchyard at 13:01 hrs by switching On CB 630.

Appendix 1 - Pre-Fault Conditions



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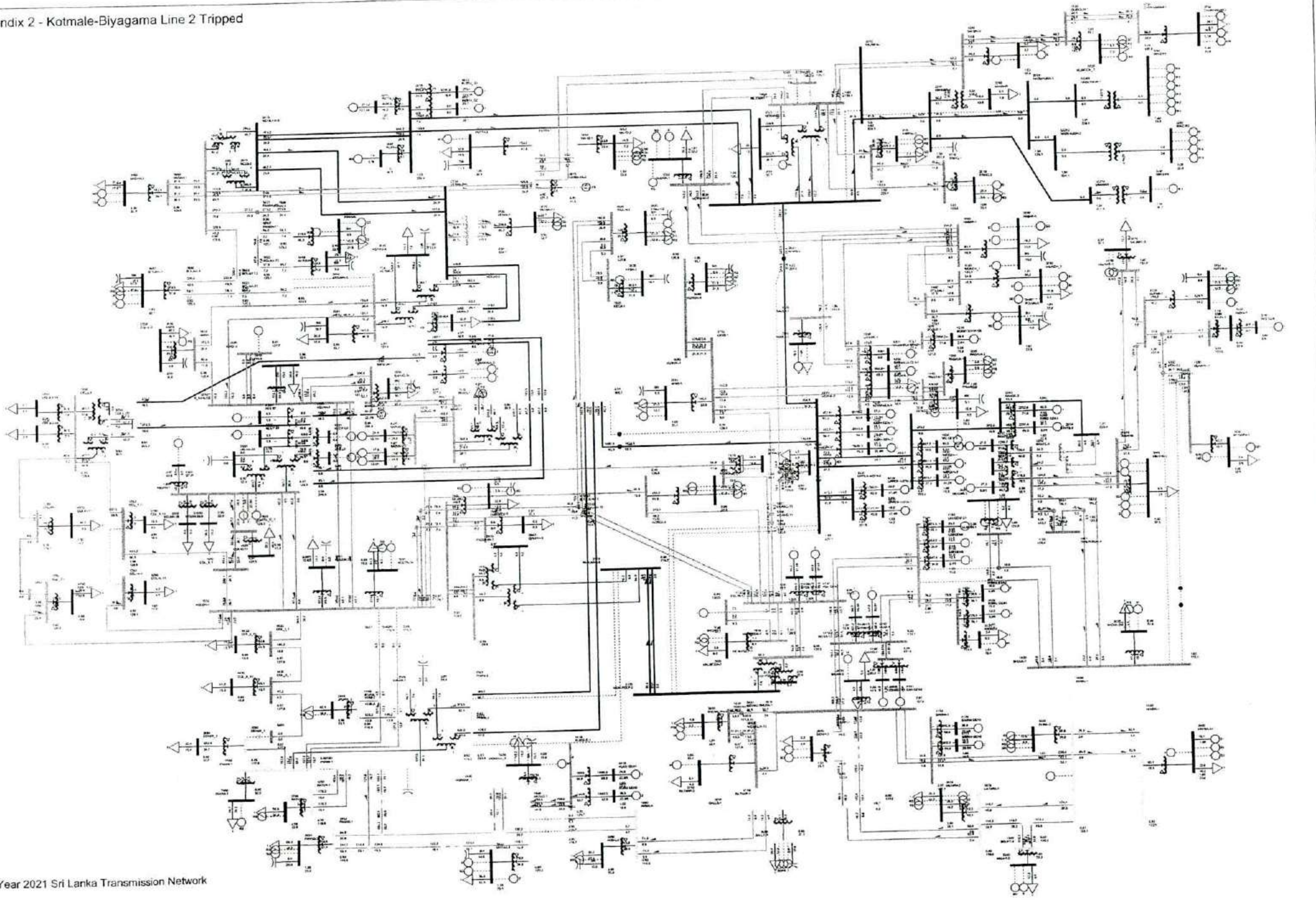
Appendix 2 - Kotmale-Biyagama Line 2 Tripped



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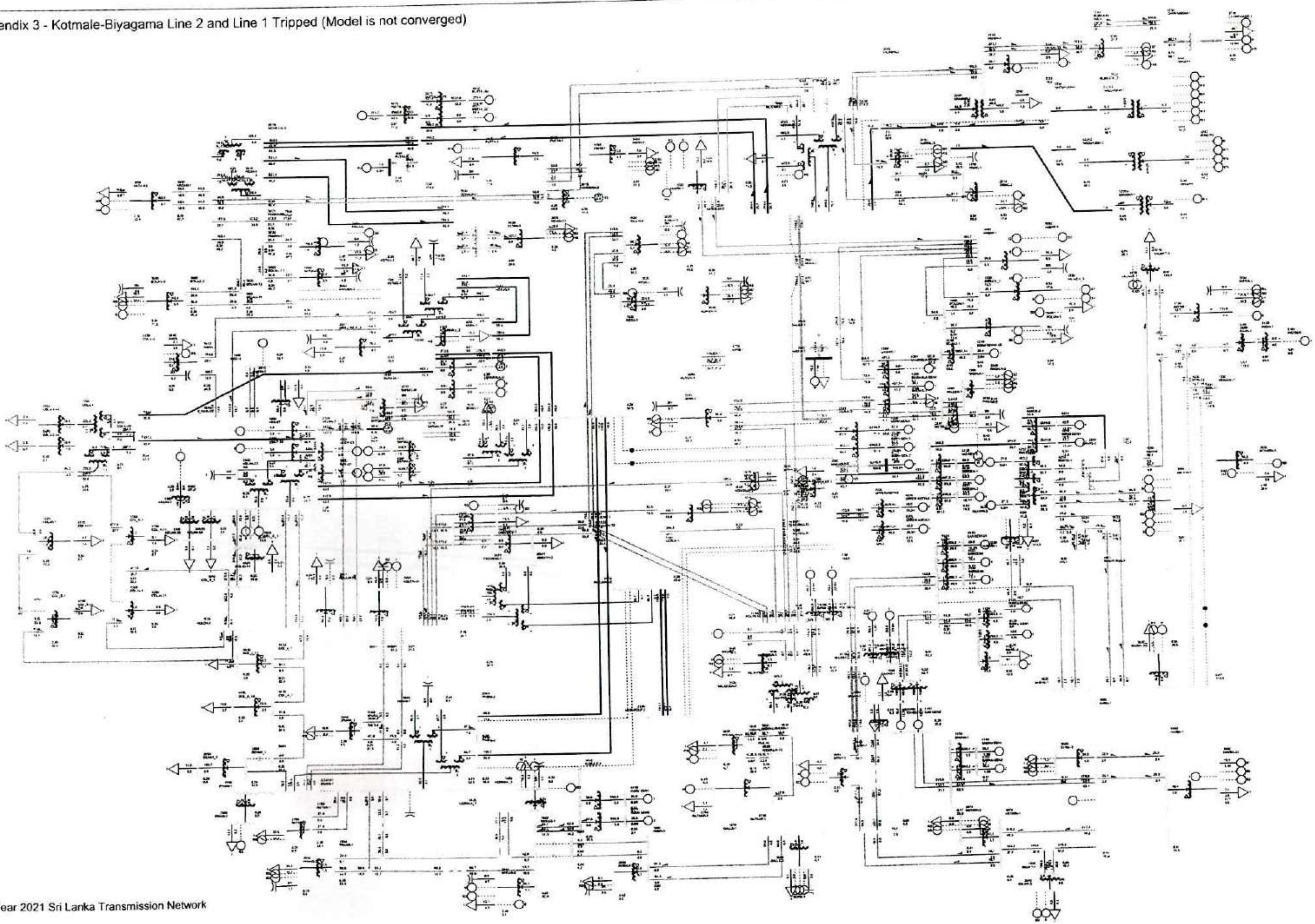
Appendix 3 - Kotmale-Biyagama Line 2 and Line 1 Tripped (Model is not converged)



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Appendix 4 - Kotmale-Biyagama Line 2 and Line 1 Tripped. Kotmale-New Polpitiya-Pannipitiya line is available.