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Design and evaluation of protection system of 50mva, 138/69/13.8kv power transformer of Bislig Substation of the National Grid Corporation of the Philippines

Tomas G Virtudez, Daxter William Gulben, Ellen Jane Gulben*, Ambrosio B Cultura II
Department of Electrical Engineering, University of Science and Technology of Southern, Cagayan de Oro, Misamis Oriental, Philippines

Abstract

Aging power transformers pose increasing risks to system reliability, safety, and continuity of supply, particularly when combined with deteriorating auxiliary components and obsolete protection systems. At the Bislig Substation of the National Grid Corporation of the Philippines, a 30 MVA power transformer that had been in service for more than 38 years exhibited signs of degradation, including on-load tap changer wear, oil leakage, and elevated dissolved gas levels. To address these concerns and support projected load growth in southern Mindanao, the transformer was replaced with a newly installed 50 MVA, 138/69/13.8 kV unit. This paper presents a case study on the design and evaluation of the protection system for the upgraded transformer, incorporating the transition from electromechanical relays to microprocessor-based protection. Using ETAP-based simulations and actual system data, the study evaluates short-circuit fault behavior, overcurrent and differential relay coordination, and arc flash hazard levels in accordance with applicable IEEE and NGCP standards. Results indicate that single line-to-ground faults govern protection design at the 69 kV level and that coordinated relay settings provide selective fault isolation while reducing arc flash incident energy. The proposed protection scheme satisfies reliability, selectivity, and personnel safety requirements for transmission substations.

Keywords: Power transformer protection, relay coordination, differential protection, arc flash analysis, fault analysis, case study

Introduction

Power transformers are among the most critical and high-value assets in transmission substations, and their reliable operation is essential for maintaining system stability, service continuity, and personnel safety. Transformer failures can result in prolonged outages, significant economic losses, and severe safety hazards, particularly in transmission-level substations supplying wide geographic areas [1]. Asset management studies further emphasize that aging transformer fleets pose increasing operational and financial risks if not proactively managed [2].

Aging transformer populations remain a major concern for many utilities worldwide. As transformers age, degradation of insulation systems, on-load tap changers (OLTCs), and auxiliary components significantly increases the likelihood of internal faults and abnormal operating conditions. OLTCs are recognized as one of the most failure-prone transformer components due to mechanical wear and arcing during tap-changing operations [4]. In addition, insulation oil deterioration and increasing concentrations of dissolved combustible gases—such as hydrogen, methane, ethylene, and ethane—are widely accepted indicators of aging and incipient transformer faults [5, 6]. Advanced protection and monitoring approaches have therefore been proposed to improve fault detection sensitivity and reduce the risk of catastrophic transformer failures [3].

At the Bislig Substation of the National Grid Corporation of the Philippines (NGCP), a 30 MVA power transformer that had been in service for more than 38 years exhibited clear signs of deterioration, including OLTC wear, oil leakage, and elevated levels of dissolved combustible gases identified through dissolved gas analysis. Although the unit was operating below its rated capacity, its advanced age and deteriorating condition posed increasing reliability and safety risks. Similar challenges associated with aging transformers and long replacement lead times have been documented in international transmission networks [1]. To address both asset condition concerns and anticipated load growth in southern Mindanao, the aging transformer was replaced with a newly installed 50 MVA, 138/69/13.8 kV power transformer.

The installation of a higher-capacity transformer necessitates a comprehensive review and redesign of the associated protection system. Transformer protection must ensure rapid and selective isolation of internal faults while remaining stable during external faults, overloads, and normal operating transients such as magnetizing inrush and over-excitation [9]. Conventional electromechanical relays, which remain in service in many older substations, offer limited adaptability and functionality compared to modern numerical relays. In contrast, microprocessor-based protection relays provide integrated protection functions, enhanced sensitivity, event recording, and improved coordination capabilities, making them suitable for transformer upgrades and substation modernization projects [10, 11].

Beyond fault detection, protection system design must also account for coordination with upstream and downstream devices, transformer short-circuit withstand capability, and personnel safety. Improper relay coordination can lead to delayed fault clearing or unnecessary transformer tripping, increasing the risk of equipment damage and elevated arc flash incident energy levels. Consequently, modern protection studies integrate short-circuit analysis, relay coordination, differential protection evaluation, and arc flash hazard assessment to ensure compliance with safety and reliability standards [7, 8].

This paper presents a detailed case study on the design and evaluation of the protection system of a newly installed 50 MVA power transformer at the Bislig Substation. Using actual NGCP system parameters and ETAP-based simulations, the study evaluates short-circuit fault behavior, impedance modeling, overcurrent and differential relay coordination, and arc flash exposure under worst-case fault conditions. The primary contribution of this work is the validation of a standards-compliant, utility-ready transformer protection scheme that satisfies reliability, selectivity, speed, and safety requirements.

Materials and Methods

This study adopts a case-study-based methodology to design and evaluate the protection system of a newly installed 50 MVA, 138/69/13.8 kV power transformer at the Bislig Substation of the National Grid Corporation of the Philippines (NGCP). The methodology integrates network modeling, short-circuit analysis, and relay coordination studies, differential protection assessment, and arc flash hazard evaluation using actual substation data and applicable protection standards.

1. Study System Description and System Model

The study system consists of a 50 MVA oil-immersed power transformer with a Y-grounded/Y-grounded/Δ configuration, supplying multiple 69 kV sub-transmission feeders and connected to two 138 kV transmission lines. All analyses were performed using the as-built transformer parameters, including nameplate impedance, voltage ratings, and cooling class, to ensure realistic representation of operating conditions, consistent with accepted transformer modeling practice [11].

A simplified single-line diagram of the Bislig Substation used for system modeling and protection studies is shown in Fig. 1.

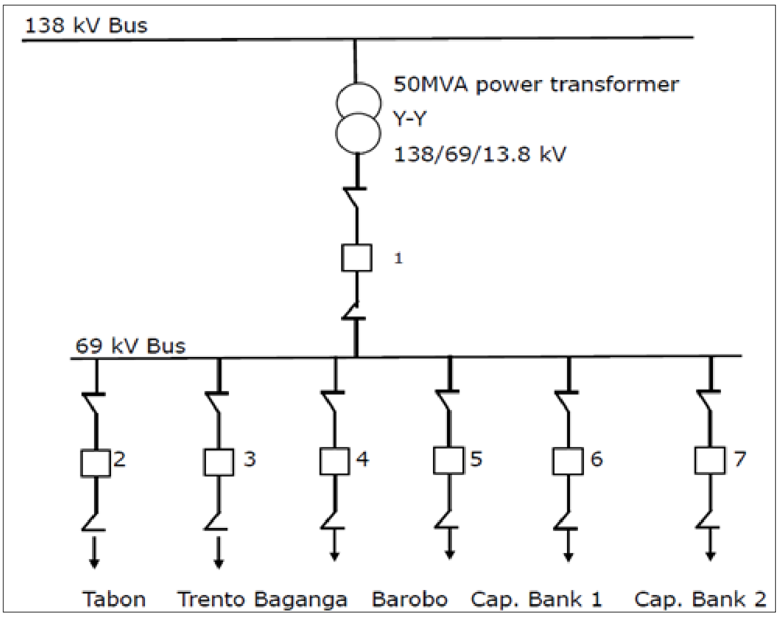

Fig 1: Simplified single-line diagram of the Bislig Substation used for system modeling and protection studies

2. Network Modeling and Load Flow Simulation

The Bislig Substation network was modeled in ETAP using a per-unit system with a common base of 100 MVA. Transmission lines, transformer impedances, feeders, and capacitor banks were represented based on available NGCP system data. Pre-fault voltage was assumed to be 1.0 p.u., and contributions from customer-owned generators and motors were neglected due to their minimal impact on short-circuit current levels.

Load flow simulations were conducted to establish the operating conditions of the transformer and 69 kV feeders under minimum, normal (optimum), and maximum loading scenarios, as defined in NGCP operational practice and consistent with standard power system analysis procedures used in transformer protection studies [10]. These simulations were used to verify bus voltage profiles, feeder loading levels, and transformer operating points, which serve as the basis for selecting protection settings and identifying worst-case operating conditions for coordination studies.

3. Short-Circuit Analysis and Fault Scenarios

Short-circuit analysis was performed to determine prospective fault currents under four shunt fault conditions: three-phase, single line-to-ground, line-to-line, and double line-to-ground faults. Faults were simulated at critical locations within the substation, particularly in front of the 69 kV feeder breakers, to capture worst-case conditions for protection coordination. The analysis approach and interpretation of fault current magnitudes are consistent with transformer protection and coordination practices described in international standards [8, 9].

Sequence network modeling within ETAP was used to represent positive-, negative-, and zero-sequence system behavior. Rather than focusing on analytical derivations, the study emphasizes the resulting fault current magnitudes and their implications on relay sensitivity, coordination, and equipment withstand capability.

4. Protection Coordination Approach

Protection coordination was designed to ensure selectivity between feeder, transformer secondary, and transformer primary protection devices. Phase and ground overcurrent relay settings were developed based on the maximum calculated fault currents, with particular emphasis on single line-to-ground faults, which govern ground protection design at the 69 kV level.

ANSI extremely inverse time-current characteristics were selected in accordance with NGCP protection philosophy. Coordination time intervals were chosen to provide adequate grading between feeder breakers, transformer secondary protection, and transformer primary protection, while accounting for circuit breaker operating times. Time-current characteristic (TCC) curves were generated in ETAP to verify coordination margins under worst-case fault conditions [9, 10].

5. Differential Protection Design Basis

Transformer differential protection was implemented using the circulating current principle to provide fast and selective protection for internal transformer faults [3, 9]. Current transformer (CT) ratios, tap settings, and pickup thresholds were selected based on transformer ratings and expected load currents. The differential protection scheme was evaluated for sensitivity to internal faults and stability during external faults and magnetizing inrush conditions. The design prioritizes secure operation under through-fault conditions while ensuring instantaneous tripping for internal transformer faults, consistent with IEEE and NGCP protection requirements [9].

6. Arc Flash Hazard Assessment Method

Arc flash hazard assessment was conducted following the methodology specified in IEEE Std 1584-2018[10] [7]. The analysis focused on selected low-voltage and medium-voltage equipment where personnel exposure is most likely during operation and maintenance activities.

Calculated fault currents from the short-circuit study and relay clearing times obtained from the coordination analysis were used as inputs to the arc flash calculations in ETAP. The objective of the analysis was to quantify incident energy levels and evaluate the impact of optimized protection coordination on reducing arc flash risk. Shown in Fig. 2 are the system model utilized in arc flash calculation in ETAP.

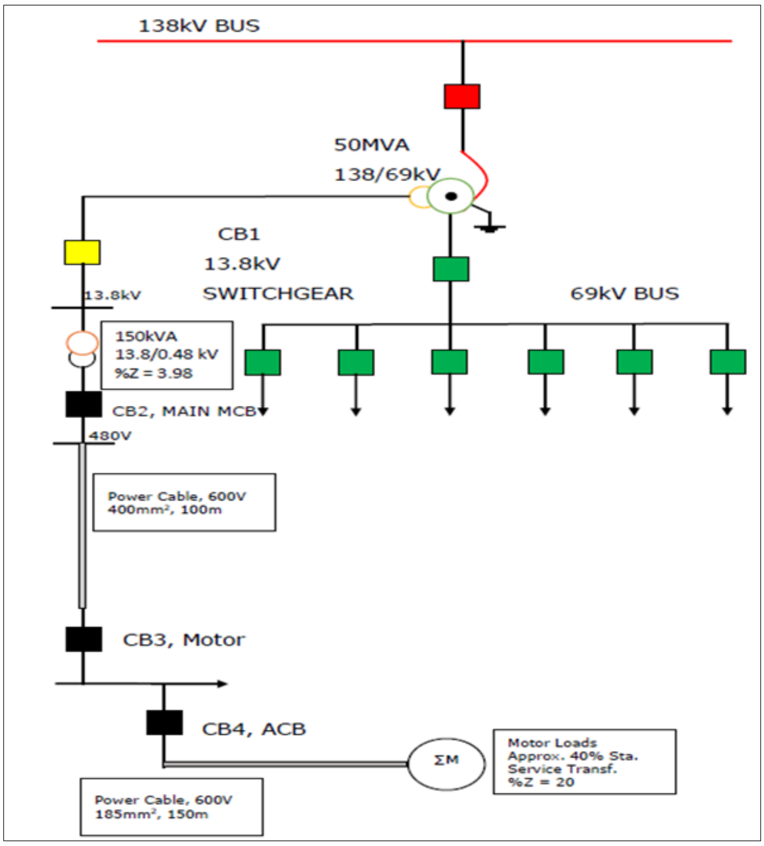

Fig 2: The arc flash system model

7. Standards and Compliance Framework

All analyses and protection settings were evaluated against applicable standards and guidelines, including IEC 60076-5 for transformer short-circuit withstand capability [8], IEEE C37.108 for transformer protection [9], IEEE C57.13 for instrument transformers, IEEE Std 1584-2018 [10] for arc flash hazard analysis, the Philippine Grid Code, and NGCP protection philosophy. Compliance with these standards ensures that the proposed protection scheme meets accepted utility and industry requirements [10, 11].

Results

This section presents and discusses the results obtained from the short-circuit analysis, impedance modeling, protection coordination assessment, differential protection evaluation, and arc flash hazard analysis for the 50 MVA power transformer at Bislig Substation. All results are based on ETAP simulations and analytical validation using actual NGCP system parameters.

1. Short-Circuit Analysis Results

Short-circuit simulations were conducted at the 138 kV and 69 kV buses to determine prospective fault levels under various fault conditions. The transient fault levels and corresponding fault currents at the 138 kV bus are summarized in Table 1, while the results at the 69 kV bus are presented in Table 2.

Table 1: Transient fault and short-circuit data at the 138 kV bus of Bislig Substation

Bislig Ss 138kV Bus	Bislig Substation			
	3-P	**L-L**	**2LG**	**1LG**
Fault Level,MVA	375.1	379.8	388.4	372.6
Fault Current, A	1764	1685	1827	1752
X / R	3.9	4.1	4.3	4.9

Table 2: Transient fault and short-circuit data at the 69 kV bus of Bislig Substation

Bislig Ss 69kV Bus	Bislig Substation			
	3-P	**L-L**	**2LG**	**1LG**
Fault MVA	190.8	194.4	243.9	245.5
Fault Current, A	1799	1722	3214	2316
X / R	4.5	4.8	5.1	5.1

The results show that single line-to-ground (SLG) faults produce the highest fault currents at the 69 kV level, reaching approximately 3.50 kA, compared with 2.38 kA for three-phase faults. At the 138 kV side, the maximum SLG fault current is approximately 1.75 kA. This behavior reflects the grounding configuration of the system and confirms that ground faults represent the most critical condition for protection design at the sub-transmission level. The calculated X/R ratios, ranging from 3.9 to 5.1, indicate a predominantly inductive system. These values have a significant impact on relay operating times and arc flash incident energy, emphasizing the importance of using worst-case ground fault conditions for coordination and safety assessments.

2. Impedance Modeling and Network Validation

Per-unit impedance modeling was performed using a 100 MVA base to normalize system parameters across voltage levels. The transformer impedance derived from nameplate data was calculated as j0.1137 p.u., while the combined source and transformer positive-sequence impedance seen at the transformer terminals reached j0.3509 p.u.. A summary of the final per-unit impedance values used in the analysis is provided in Table 3.

Table 3: Summary of per-unit impedance values for the Bislig Substation network

Source Impedance			
Source	**Z1**	**Z2**	**Z0**
Bislig Ss	j 0.23717	j 0.19288	j 0.28634

The developed positive-, negative-, and zero-sequence impedance networks are illustrated in Fig. 3. These networks were used to validate fault current calculations and to ensure consistency between analytical results and ETAP simulation outputs.

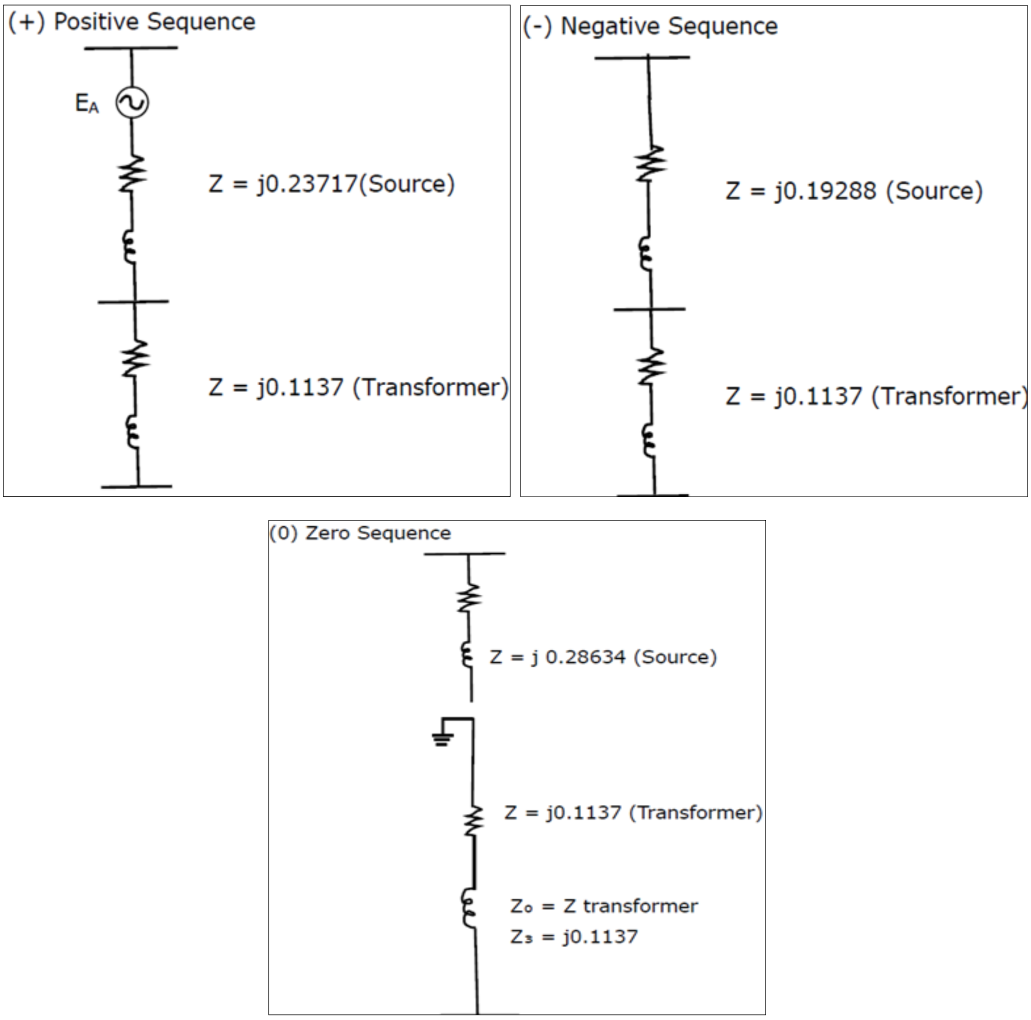

Fig 3: Positive-, negative-, and zero-sequence impedance networks of the Bislig Substation

The close agreement between analytical calculations and ETAP results confirms the accuracy of the impedance model and provides a reliable basis for subsequent protection coordination studies.

3. Validation Fault Current Evaluation at Transformer Terminals

Using the validated impedance model, fault currents were calculated for all fault types occurring in front of the 69 kV feeder breakers. The resulting fault currents at both the 138 kV and 69 kV sides of the transformer are summarized in Table 4.

Table 4: Summary of calculated fault currents at the transformer terminals

Fault Location	Bislig Ss	Fault Current (AMPS)			
		3Ø	SLG	L-L	DLG
In front of 69kV Breaker	138kV Side	1192 A	1752 A	1685 A	1187 A
	69kV Side	2385 A	3504 A	3370 A	2374 A

The results confirm that SLG faults impose the most severe stress on the protection system, reinforcing their role as the governing condition for relay setting selection and coordination. These fault current values were subsequently used to evaluate equipment withstand capability and relay performance.

4. Load Flow Analysis and Operating Conditions

Load flow analysis was conducted to establish the operating conditions of the 50 MVA transformer and associated 69 kV feeders under various loading scenarios. The objective of the load flow study is not operational optimization, but to verify voltage profiles, feeder loading levels, and transformer operating points that form the basis for short-circuit analysis and protection setting selection.

Three operating scenarios were evaluated using ETAP: minimum load, normal (optimum) load, and maximum load, consistent with NGCP operational practice. These scenarios represent typical system conditions during light loading, normal operation, and peak demand. Shown in Fig. 4 is the load flow simulation 50 MVA power transformer at Bislig Substation under normal operating conditions.

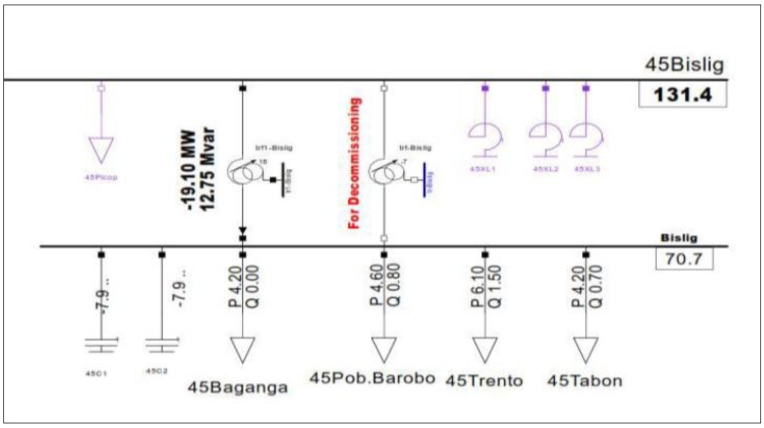

Fig 4: ETAP load flow simulation of the 50 MVA power transformer at Bislig Substation under normal operating conditions

4.1 Voltage Profile and Transformer Loading

Across all loading scenarios, the 69 kV bus voltages remained within acceptable operating limits, with voltage deviations not exceeding approximately ±2.4% from nominal values. This indicates that the transformer and feeder configuration provides adequate voltage regulation under varying demand conditions.

Under normal loading conditions, the transformer operates well below its rated capacity, confirming sufficient margin for load growth and validating the selection of a 50 MVA transformer to replace the aging 30 MVA unit. Even under maximum load conditions, transformer loading remains within acceptable thermal limits, ensuring that protection settings based on rated current values are appropriate and conservative. Table 5 shows the summary of load flow results at the 69 kV bus under minimum, normal, and maximum loading conditions.

Table 5: Summary of load flow results at the 69 kV bus under minimum, normal, and maximum loading conditions

Feeder	MW	I_min (kA)	I_norm (kA)	I_max (kA)	V range (kV)
Tabon	4.2	0.044	0.40	0.039	67.3–69
Trento	6.1	0.064	0.51	0.057	67.3–69
Baganga	4.2	0.044	0.40	0.039	67.3–69
Barobo	4.6	0.048	0.38	0.043	67.3–69

4.2 Implications on Protection Design

The load flow results confirm that the maximum operating currents under all scenarios are significantly lower than the fault currents obtained from the short-circuit analysis. This separation between load and fault current levels ensures sufficient sensitivity margin for overcurrent and differential protection elements.

Furthermore, the verified voltage profiles and transformer loading levels support the assumptions used in fault analysis and relay coordination studies. By establishing realistic pre-fault operating conditions, the load flow analysis strengthens the validity of the protection evaluation presented in the succeeding sections.

5. Terminals Protection Coordination Performance

Protection coordination analysis was carried out to ensure selectivity between feeder, transformer, and upstream protection devices. Phase and ground overcurrent relay settings for the transformer high-voltage side and 69 kV bus were developed based on the maximum calculated fault currents. A summary of the final relay settings is presented in Table 6.

Table 6: Summary of overcurrent relay settings for the transformer high-voltage and 69 kV sides

Protection Location	CT Ratio	Phase Pickup (A)	Ground Pickup (A)	Curve Type	Time Dial	Protection Role
Transformer HV Side	600/5	418	210	ANSI Extremely Inverse	0.35	Backup
Transformer LV Side (69 kV)	1200/5	837	420	ANSI Extremely Inverse	0.3	Main
69 kV Feeder – Tabon	600/5	530	265	ANSI Extremely Inverse	0.2	Primary
69 kV Feeder – Trento	600/5	530	265	ANSI Extremely Inverse	0.2	Primary
69 kV Feeder – Baganga	600/5	530	265	ANSI Extremely Inverse	0.2	Primary
69 kV Feeder – Barobo	600/5	530	265	ANSI Extremely Inverse	0.2	Primary

Ground relay pickup values were selected at approximately 50–55% of the corresponding phase pickup values, in accordance with NGCP protection philosophy. Time-current characteristic (TCC) curves generated in ETAP confirmed adequate coordination time intervals between primary and backup protection devices, ensuring fast fault isolation at the feeder level without unnecessary transformer tripping.

The ground fault coordination results are illustrated in Fig. 5, which demonstrates proper grading between feeder, transformer secondary, and transformer primary protection.

Table 6: Summary of differential protection settings for the 50 MVA power transformer

Setting	Description	Value
MVA	Transformer rated capacity	50 MVA
Vector group	Transformer vector group	YNa0d1
ICOM	Internal CT compensation	Enabled
W1CT	Winding 1 CT connection	Wye (Y)
CTR1	Winding 1 phase CT ratio	300/5
W1CTC	Winding 1 CT compensation	0
VWDG1	Winding 1 line-line voltage	138 kV
W2CT	Winding 2 CT connection	Wye (Y)
CTR2	Winding 2 phase CT ratio	600/5
W2CTC	Winding 2 CT compensation	0
VWDG2	Winding 2 line-line voltage	69 kV
CTRN1	Neutral CT ratio	1200/5
TAP1	Winding 1 current tap	3.486 A
TAP2	Winding 2 current tap	1.743 A
87P	Differential pickup current	0.30 pu
SLP1	Restraint slope 1	30%
SLP2	Restraint slope 2	60%

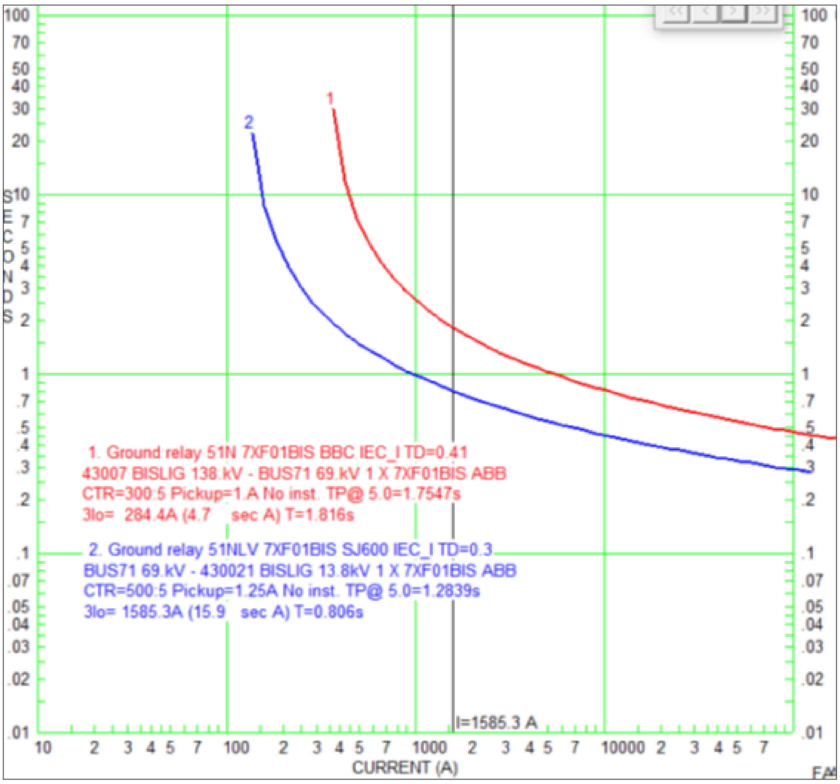

Fig 5: Ground fault time-current characteristic curves for the 50 MVA transformer protection system

6. Differential Protection Evaluation

Transformer differential protection was evaluated to ensure fast and secure operation for internal faults while maintaining stability during external faults and magnetizing inrush conditions. CT ratios, tap settings, and pickup thresholds were selected based on transformer ratings and expected load currents. A summary of the differential protection settings is provided in Table 6.

The differential protection (87T) relay settings summarized in Table 6 were selected to provide fast and selective detection of internal transformer faults while maintaining stability during external faults and magnetizing inrush conditions. Internal CT compensation and vector group correction were enabled to account for the YNa0d1 transformer configuration and CT ratio mismatch between the 138 kV and 69 kV windings. A differential pickup of 0.30 pu was chosen to ensure adequate sensitivity to internal faults while avoiding misoperation due to load current imbalance and measurement errors. The application of a dual-slope bias characteristic, with restraint slopes of 30% and 60%, enhances relay stability during high through-fault currents and potential CT saturation. These settings ensure secure operation during normal loading and external fault conditions, while enabling instantaneous tripping for internal transformer faults, thereby satisfying the fundamental protection requirements of sensitivity, security, and dependability. Simulation results indicate that the differential relay operates instantaneously for internal faults within the protection zone and remains restrained during through-faults. This confirms that the selected settings satisfy the fundamental requirements of transformer differential protection, including sensitivity, security, and stability.

7. Arc Flash Hazard Assessment

Arc flash hazard analysis was performed in accordance with the IEEE STD 1584-2018[10] methodology to evaluate personnel exposure under fault conditions. Incident energy levels were calculated at selected locations within the Bislig Substation using the available short-circuit currents and the corresponding relay clearing times obtained from the finalized protection coordination study. The calculated incident energy values and associated personal protective equipment (PPE) categories are summarized in Table 7.

Table 7: Arc flash incident energy levels at selected locations in the Bislig Substation

Location / Equipment	System Voltage	Fault Current (kA)	Clearing Time (s)	Incident Energy (cal/cm²)	PPE Category	Remarks
138 kV Transformer HV Side	138 kV	1.75	0.35	1.2	Category 1	Low incident energy due to fast upstream protection
69 kV Transformer LV Side	69 kV	3.5	0.3	3.8	Category 2	Governing SLG fault condition
69 kV Feeder Breaker – Tabon	69 kV	3.37	0.2	2.9	Category 2	Primary feeder protection
69 kV Feeder Breaker – Trento	69 kV	3.37	0.2	2.9	Category 2	Similar feeder characteristics
69 kV Feeder Breaker – Baganga	69 kV	3.37	0.2	2.9	Category 2	Coordinated with transformer LV relay
69 kV Feeder Breaker – Barobo	69 kV	3.37	0.2	2.9	Category 2	Worst-case feeder arc exposure

The results indicate that arc flash incident energy levels vary significantly across substation locations, primarily as a function of fault current magnitude and protection clearing time. At the 138 kV transformer high-voltage side, the incident energy remains relatively low at 1.2 cal/cm², corresponding to PPE Category 1, due to the lower fault current level and rapid operation of upstream protection. In contrast, higher incident energy values are observed at the 69 kV level, where single line-to-ground faults produce the highest fault currents. The transformer low-voltage side exhibits the maximum incident energy of 3.8 cal/cm², establishing it as the governing condition for arc flash exposure within the substation.

For the 69 kV feeder breakers, incident energy levels are consistently maintained at approximately 2.9 cal/cm² (PPE Category 2) as a result of effective primary feeder protection and coordinated relay settings. These values confirm that optimized protection coordination, particularly reduced fault clearing times at the feeder level, plays a critical role in limiting arc flash severity. Overall, the arc flash assessment demonstrates that the proposed protection scheme not only ensures reliable fault isolation but also significantly enhances personnel safety by maintaining incident energy levels within manageable limits across all evaluated locations.

8. Engineering and Operational Implications

The overall results demonstrate that the proposed protection system for the 50 MVA transformer at Bislig Substation satisfies key protection design requirements, including reliability, selectivity, speed, and safety. The dominance of SLG faults underscores the importance of accurate ground fault modeling and coordination, while the effective performance of the differential protection scheme ensures rapid isolation of internal transformer faults. These findings provide practical guidance for protection engineers involved in transformer upgrades and substation modernization projects within NGCP and similar transmission networks.

Conclusions

This paper presented a comprehensive design and evaluation of the protection system for a newly installed 50 MVA, 138/69/13.8 kV power transformer at the Bislig Substation of the National Grid Corporation of the Philippines. Using actual system data and ETAP-based simulations, the study assessed fault behavior, impedance modeling, relay coordination, differential protection performance, and arc flash safety under worst-case operating conditions.

Short-circuit analysis results show that single line-to-ground faults dominate the protection design at the 69 kV level, producing the highest fault currents and therefore governing relay pickup selection and coordination requirements. Per-unit impedance modeling and sequence network validation confirmed the accuracy of the developed system representation and provided a reliable basis for fault current evaluation.

The protection coordination study demonstrated that the selected phase and ground overcurrent relay settings achieve adequate selectivity between feeder, transformer, and upstream protection devices. Ground relay pickup values set at approximately 50–55% of phase pickup levels, together with appropriately graded time-current characteristics, ensured fast fault isolation without unnecessary transformer tripping. Differential protection evaluation confirmed instantaneous operation for internal transformer faults while maintaining stability during through-fault and inrush conditions.

Arc flash hazard assessment further showed that optimized relay coordination significantly reduces fault clearing times and incident energy levels at critical substation locations, thereby enhancing personnel safety and compliance with electrical safety requirements. Overall, the proposed protection scheme satisfies the fundamental protection design criteria of reliability, selectivity, speed, and safety, and is fully compliant with NGCP protection philosophy and applicable IEEE and IEC standards.

The findings of this case study demonstrate that a systematic, standards-based approach to transformer protection design can effectively support substation modernization efforts and asset upgrades in transmission networks. The methodology and results presented in this work provide practical guidance for protection engineers involved in similar transformer replacement and protection upgrade projects.

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