ABSTRACT While the world’s power distribution system resembles an intricate web-like structure, the most conventionally implemented distribution mechanism is the radial distribution system (RDS) where connection points for each distribution line are normally kept open. However, disadvantages regarding the traditional system have led to active research on establishing the networked distribution system (NDS), in which multiple circuits are interconnected with electricity as well as high-speed communication systems. The NDS offers multiple advantages including increased facility utilization, increased hosting capacity, and higher terminal voltage. Conversely, an unsolved issue prevails as the existing protection coordination method designed for the RDS is inadequate for fault occurrences in the NDS due to inaccurate fault direction identification. Hence, there is an urgent need for an alternative protection coordination method that allows high precision fault direction identification through communication. Moreover, the application of various existing technologies is hindered as the distance relay protection coordination algorithm malfunctions in situations where distribution lines are of short length, loads are dispersed onto multiple lines, and integration of distributed generation (DG) is frequent. Therefore, this paper presents a fault direction identification method that uses the waveform of the fault current based on long short-term memory (LSTM) neural network and a communication-based protection coordination scheme that can be applied in fault situations within an NDS.

INDEX TERMS Protection coordination, distribution system, closed-loop system, networked distribution system, fault direction, long short-term memory, deep learning neural network

I. INTRODUCTION

While the radial distribution system (RDS) is designed to supply the annual peak load since the maximum load is only required for a relatively short period during the year, the facility utilization rate is rather modest [1]–[3]. Facility utilization is anticipated to deteriorate due to the recent surge in distributed generation (e.g., solar power, wind power generation, etc.) and an increase in electric vehicle charging stations which induce large fluctuations in load. In addition, failures in distribution lines of the RDS result in a power outage lasting 3 to 5 minutes among all connected areas including those intact until the faulty section is disconnected, and an alternative power supply is provided to the sound sections (i.e., the load-side line in the faulty section).

As an attempt to resolve the shortcomings of the RDS, the closed-loop system (CLS), an alternative approach that connects two unidirectional ends within the RDS, was introduced and subsequently demonstrated in distribution systems. Conversely, implementations of the approach failed to expand due to two major drawbacks [8], [9]. First, if a failure occurs at the substation, the load of both lines is supplied from the remaining intact substation, resulting in a reduced utilization rate of 50%. Second, the integration of distributed generation (DG) is not permitted within the CLS as the presence of multiple transformers for DG leads to malfunctions in the existing protection coordination algorithm.

Apart from the time-current curve (TCC)-based protection coordination method developed for the RDS, a protection coordination method utilizing a high-speed communi-
the bus, or when the distance between protection devices is
applied to spot loads, where the load is only connected to
the proposed methods, distance relay can be successfully
multiple methods using directional relay and distance relay
unsuitable for accurately distinguishing the faulty section.
Point, protection coordination methods built for the RDS are
lines. Since the fault direction differs depending on fault
currents rush to the fault point from multiple connected
when a fault occurs within the NDS, the resulting fault
openings of the circuit breakers of the power system result
in a power outage of large-scale. Several fault direction esti-
mation techniques applicable to existing distribution power
systems have been studied. A method of estimating the
direction of a fault using the phase difference between the
voltage and current of the distribution line is the most widely
used method in the real distribution system [31]. The Using
phase difference method frequently malfunctions due to the
influence of three-phase ground fault, short circuit fault,
or distributed generator that occurs near the voltage/current
measurement point. The using only the phase of the cur-
rent method calculates and compares the phase immediately
before and after the fault detection by frequency or time-
frequency analysis. Due to harmonics or disturbances, this
approach is prone to fail to estimate the fault direction and
necessitates the employment of additional digital filters to
filter DC components created by incipient faults [32]–[34].
The current differential relay method, which is a method of
detecting the position and direction of a fault using the
magnitude or polarity of a current, is a protective cooperation
method mainly used in a transmission system and has very
high reliability [35]. This method is particularly effective for
spot load systems, but cannot be used if there is a load or
distributed power source in the section between protective
devices, such as distribution systems, due to the underreach
effect. Recently, methods for automatically estimating the
fault direction of complex grids by adding machine learning-
based techniques were investigated [36]–[38], however, these
approaches are in the early stage in the research and the
applied power distribution network is limited to RDS or CLS.

Hence, in this paper, a novel protection coordination
method for the NDS based on long short-term memory
(LSTM), which learns and estimates the time series data of
the fault current waveform according to the time of occur-
rence, location, and condition of the fault is presented. The
Recurrent Neural Network (RNN) is an efficient time-series
data analysis model developed to model the relationship
between input patterns when a correlation exists between the
elements prior to and following the time-series data. LSTM
is an algorithm that compensates for the limitations observed
for the RNN, in that the preservation of information decreases
as the distance from the current point increases. Because
a separate structure determines whether to store historical
time series data, LSTM shows excellence in the retention

| TABLE 1. Comparison between distribution line operation methods. |
|------------------------|-----------------|-----------------|-----------------|
| Scheme                | RDS             | CLS             | NDS             |
| Reliability           | Low             | Intermediate    | High            |
| Initial Cost          | 1               | 1.2~1.3         | 1.1             |
| Complexity of Design/Operation | Low          | Intermediate    | High            |
| Utilization Rate      | Low             | Intermediate    | High            |
| Areas of Application  | All             | Suburban~       | Urban Areas     |
| Communication         | Unnecessary     | Required        | Required        |

sufficient. On the other hand, distance relay is inapplicable
in situations where load and renewable energy sources are
simultaneously connected to distribution lines of short length
(1~10km) due to the underreach.

Upon fault detection, the previous protection coordination
method developed for the CLS allows the identification of
direction, shares information regarding the fault via
communication, determines the faulty section, and finally
isolates the faulty section. However, if the protection co-
ordination method fails in determining the fault direction,
which is a principal factor in identifying the faulty section,
the circuit breaker malfunctions. Consequently, simultaneous
openings of the circuit breakers of the power system result
in a power outage of large-scale. Several fault direction esti-
mation techniques applicable to existing distribution power
systems have been studied. A method of estimating the
direction of a fault using the phase difference between the
voltage and current of the distribution line is the most widely
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for the RNN, in that the preservation of information decreases
as the distance from the current point increases. Because
a separate structure determines whether to store historical
time series data, LSTM shows excellence in the retention

A comparison between existing distribution systems and
the NDS is presented in Table 1. In comparison to the RDS
and CLS, the operation of the NDS can improve facility
utilization through load sharing (or distributed resource shar-
ning). In addition, the NDS can alleviate the occurrence of
voltage fluctuations due to DG which is often encountered
in situations where load and renewable energy sources are
simultaneously connected to distribution lines of short length
(1~10km) due to the underreach.

Despite the advantages, NDS is yet to be implemented
as the distance from the current point increases. Because
a separate structure determines whether to store historical
time series data, LSTM shows excellence in the retention

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of relevant information [39]. Utilization of the LSTM algorithm is anticipated to yield significant reductions in error when determining fault direction, which is the major cause for circuit breaker malfunction issues in the existing CLS protection coordination algorithm. To verify the performance of the proposed algorithm, possible fault scenarios have been demonstrated in two distribution lines.

The remainder of this paper is organized as follows. Section II provides a problem formulation of existing protection coordination algorithms. In Section III, a novel LSTM-based distribution system protection coordination scheme is presented. An experimental simulation setup and corresponding results are discussed in Section IV. The paper is concluded in Section V.

II. PROBLEM FORMULATION

A power system protection algorithm is largely divided into four steps: fault detection, fault re-assessment, identification of fault direction and faulty section, and subsequent blocking. A protection device detects a short circuit fault through the measured current and voltage fails to exceed the threshold value after fault current detection, the incident is considered a failure in direction identification, and a trip signal is not issued. Subsequently, the circuit is automatically opened if the fault is not resolved within 200 ms. In short, if there is any uncertainty regarding the detected fault, the presumed fault is expected to be resolved through other sections. Conversely, if the fault persists, the circuit breaker is opened to ensure the stability of the system. Table 3 shows the minimum threshold value for fault direction identification in the CLS protection coordination algorithm. In the protection cooperation algorithm, the symmetric component threshold is set higher than the individual symmetric component thresholds of the DOCR to increase reliability when determining the direction of the fault current within a quick response time.

Then, the relay determines the fault direction by comparing the phase angle relation of the symmetric current components to voltage components. Fig. 1 illustrates the vector diagram and relation between different phasors in the short fault and the ground fault. Relays have an adjustable relay characteristic angle (RCA), which is the angle of the current compared to the angle of the voltage at which the relay operates with maximum sensitivity. In the event of a short circuit failure, \( I_1 \) is typically highly lagging. The direction of the fault current is determined by calculating the torque of the relay internal voltage (\( V_1 \)-RCA) and \( I_1 \). The torque product indicates the direction of fault current flow: a positive torque defines a forward fault and a negative torque defines a reverse fault. Therefore, the fault direction is calculated by comparing \( I_1 \) with the positive area within \( \pm 90^\circ \) of the RCA. As for the ground fault, the direction of the fault current can be estimated in a similar manner after the \( V_0 \) is inverted (different RCA setting for \( I_0 \)) [40].

In succession to identifying the fault direction, each circuit breaker transmits a trip signal to the connected circuit breaker in the direction corresponding to the fault current via communication. Conversely, a block signal is transmitted to the connected circuit breaker in an opposite direction of the fault current. If trip signals are received from connected circuit breakers on each side, the circuit breaker is considered to be located in the faulty section, and the circuit is instantaneously opened. Fig. 2 shows the application of the existing CLS protection coordination method to a fault occurring between line 4 of circuit breaker A and line 1 of circuit breaker B. For the case of circuit breaker B in Fig. 2, since trip signals were received from both sides, it is regarded as a fault and only the breaker connected to line 1 is opened. The load of the branch

### TABLE 2. Minimum Symmetrical component threshold of DOCR.

| Component | Description | Criteria |
|-----------|-------------|----------|
| 3I1       | Direction Identification of Positive Sequence | 0.5 A |
| 3I0       | Direction Identification of Zero Sequence | 0.25 A |
| V0        | Direction Identification in Short Circuit | 3.33% of \( V_{\text{normal}} \) |
| 10/11     | Direction Identification in Ground Fault | 9% of 10/11 |

### TABLE 3. Minimum Symmetrical component threshold within the CLS.

| Component | Description | Criteria |
|-----------|-------------|----------|
| V1        | Direction Identification in Short Circuit | 0.2 p.u. of \( V_{\text{rated}} \) |
| I1        | Direction Identification in Ground Fault | 20% of \( I_{\text{op}} \) |
| V0        | Direction Identification in Ground Fault | 0.1 p.u. of \( V_{\text{rated}} \) |
lines does not experience a power outage.

However, there are two major limitations regarding the approach. First, when complete ground faults or short circuits are to occur in high proximity to a protection device, the fault direction cannot be determined as the magnitude of the fault resistance is small. Thus, the fault area fails to be minimized. In specific, for occurrences of 3-phase ground faults and 3-phase short circuits, if the fault resistance is low (0.1Ω or less), V0 and V1 converge close to “0 V”, and thus the threshold value is not exceeded. For this case, fault direction is determined using the phase of the memory voltage measured 3 cycles earlier. However, since the memory voltage phase is a value at a steady-state and not a faulty state, the algorithm may malfunction if the phase of the I0 overlaps with the boundaries of fault direction identification. Second, the presence of multiple transformers for the integration of DG within a power system may lead to failures when using the algorithm. When a fault occurs, the fault current partially flows to the high-voltage side of the DG integrating transformer (Yg-∆ connection). Therefore, while the I0 is detected, the V0 does not exceed the threshold, and thus the direction identification fails.

A case in which the protection device malfunctions due to a fault occurring in a separate line of the CLS is demonstrated in Fig. 3. In the presence of DG integration, if a failure occurs in a different line (CB3) connected to the same main transformer, I0 flows to three separate paths: bus 2-9, bus 11-8-9, bus 11-8-7-6-5-4-3-9. As a result, I0 measured at each circuit breaker is relatively small, and thus V0 falls below the threshold value. As the fault direction cannot be identified, the circuit breaker consequently malfunctions, resulting in a wide area power outage due to simultaneous openings of multiple circuit breakers.

III. PROPOSED PROTECTION COORDINATION ALGORITHM

A. FAILURE SITUATION CASES

In bidirectional power distribution systems (e.g., CLS and NDS), the fault direction may be influenced by three major factors associated with the fault location and phase. First, the fault direction is highly dependent on the fault location (i.e., the power supply side (Upstream) or the load side (Downstream) of the protection device). Second, the fault direction depends on the phase sequence of the fault (i.e., a positive or negative phase sequence). Third, the direction of the fault current is divided into two cases regarding the difference in detection time (i.e., occurrence and detection may occur within the same half-cycle, or the fault current may be detected in the next half-cycle). In specific, if a fault current occurs near the zero-crossing point of the cycle, the fault current may fail to exceed the threshold. In this case, the fault current is expected to be detected in the subsequent half-cycle. The phase sequence and direction of a current in response to a fault situation is demonstrated in Table 4. The red line indicates the normal current (load current) waveform in absence of a fault, the blue line indicates the waveform of the fault current, and the green line indicates the phase sequence detected from the feeder remote terminal unit (FRTU).

The normal current direction (Cnorm) is calculated by the phase difference between the voltage and the current monitoring for each circuit breaker in the distribution feeder system as follows:

$$C_{\text{norm}} = \cos\{ (\angle V_{5C} - RCA) - \angle I_{5C} \}$$  (1)

where $\angle V_{5C}$ and $\angle I_{5C}$ are the phases of voltage and current at a steady-state before pickup 5 cycle, respectively. In this paper, the direction from the inside to the outside of the circuit breaker is defined as a forward direction as in the existing method. Each circuit breaker transmits a trip signal in the forward direction and a blocking signal in the reverse direction.
When a fault is picked up, the polarity of the current ($Pol_{pu}$) and the before the half cycle ($Pol_{hc}$) are extracted and compared as follows:

$$Pol_{pu} = i$$
$$Pol_{hc} = \frac{1}{32} \sum_{t=ZC_{n+1}}^{ZC_{n+1}} i_t$$ \hspace{1cm} (2)

The sampling rate of the distribution feeder system used for protection cooperation is 3,840 Hz which is 64 samples per one cycle. Therefore, the average value of the current during the half cycle (32 samples) is calculated as the polarity before the half cycle of fault pickup. $ZC_n$ and $ZC_{n+1}$ represent the time duration at which the current crosses zero. The number of $i_t$ should be more than 20 in order to reduce errors in transient conditions including inrush current, measurement errors, and DC components. Then, the direction of the fault current is opposite that of the normal current if the two polarities are the same, and the direction of the fault current is the same as that of the normal current if the two polarities are different. As result, it is feasible to determine the fault direction in the distribution system only using the fault current waveform. The proposed approach to estimate the fault direction can be uniformly applied regardless of the fault type, and all symmetric current components.

**B. LSTM-BASED FAULT CURRENT DETERMINATION ALGORITHM**

An LSTM-based solution for time-series fault data analysis is presented in Fig. 4. The solution consists of layers of feature engineering, predictive model development, model optimization, and systematic evaluation.

LSTM input layer: Features of the current waveform input data are extracted. When a fault occurs within the NDS, the protection coordination sequence of each circuit breaker operates. To determine the direction of the fault current, three parameters measured by the circuit breaker have been...
selected as inputs: the direction of current flow at steady-state ($C_{norm}$), the polarity at fault detection ($Pol_{pu}$), and the polarity of the preceding half cycle ($Pol_{hc}$). The correlation between the fault direction and the steady-state current direction can be assessed by comparing the polarities of the fault detection point and the preceding half-cycle of the point of detection. The steady-state current direction is extracted through phase differences of the voltage and current among the 5 cycles preceding fault detection. Accordingly, three time-series parameters are extracted for the inputted current signals in the LSTM input layer.

LSTM Hidden Layer: The hidden layer accepts data received from previous levels. Each hidden layer is the actual representation layer of the feature. The output of the previously hidden layer becomes the input of the next hidden layer. Through iteration, the weights of the hidden layer are continuously adjusted until the network converges.

LSTM output layer: The outputs of the LSTM network are the estimated fault direction and fault detection time for each circuit breaker.

Evaluation layer: After the last optimized parameters are applied to the LSTM estimation network, an optimal prediction result is obtained by calculating the mean squared error between the predicted data and the original data.

The time series dataset for LSTM network training was collected by 8 different fault current simulation cases. 8 fault case simulations were conducted to accumulate input data by altering the fault current from the minimum fault current detection value (400 A) to the most extreme case, the 3-phase fault (10 kA). The parameters of the LSTM network are adjusted and optimized using the adaptive moment estimation (ADAM) method. 128 mini-batch-sized feature data are randomly extracted for training. In addition, we set the initial learning rate to 0.001, the gradient decay factor to 0.9, and the squared gradient decay factor to 0.999.

C. PROTECTION COORDINATION ALGORITHM

The complete protection cooperation algorithm using the proposed method is shown in Fig. 5 including the LSTM architecture, training, and fault direction estimation. The protection device of the system constantly monitors zero- or positive-sequences through the method of the symmetrical coordinate of the voltage and current. If a fault is detected whilst monitoring, the polarity at the point of detection is derived for direction identification, and the polarity of the mean value of current for the half-cycle preceding pick-up is then derived. Subsequently, based on the fault direction result derived from the LSTM network, the faulty section is determined through data sharing with the connected circuit breaker. If a fault is present within the identified section, it is immediately opened to minimize the faulty section. Finally, information on the status (e.g., circuit open, blockage failure, etc.) of the protection device is transmitted to the connected circuit breaker to decide whether the protection coordination had worked, and a backup sequence is prepared.

IV. PERFORMANCE EVALUATION

A. SIMULATION SETUP

1) Target System

As shown in Fig. 6, the proposed protection coordination scheme was tested in the power distribution system of the IEEE 14-bus in which the distribution system voltage and frequency were modified to 22.9 kV, 60 Hz [3], [41]. Systematic parameters including power source, transformer, and distribution line are shown in Table 5.

Benchmark examples (e.g., power source, transformer, distribution line, etc.) registered in PSCAD’s knowledge base have been used as the system parameters, and the PSCAD/EMTDC was utilized as the simulation tool. Parameters of the two transformers have been equally set since circulating currents, which may occur during parallel operation of transformers, are not considered in this paper. A spot load of 7 MVA and a 1 MVA distributed power source
are connected to each bus, and a distributed load of 1 MVA is connected to each line. The total load of the system is 57 MVA, and if power is normally supplied from DG, each transformer will supply 25 MVA.

2) Result in Normal Fault Situation
The duration for fault processing in the proposed protection coordination scheme is approximately 84 ms: the time required for pick-up following fault occurrence is 16.67 ms (60 Hz, 1 cycle), the average response time (i.e., time from pickup to direction identification and logic processing) is 20 ms, the average duration for the N:N communication between the connected protection devices is 5 ms, the average auxiliary relay operation time is 8 ms, and the average blocking time (i.e., contact opening and arc extinguishing time) is 34 ms. Based on this information, the duration from fault occurrence to the faulty section blocking according to the type and location of the simulated fault is summarized in Table 6. In Table 6, 1-4 DL refers to the distribution line connecting bus 1 and bus 4. Each fault was simulated at the 50% point of a distribution line connecting two buses. Regarding a general fault situation, the protection coordination was successful as only the circuit breakers at both ends of the failure point were opened.

B. FAULT SCENARIO 1; THE FIRST DRAWBACK OF CLS PROTECTION COORDINATION
The operation of a circuit breaker in response to an occurrence of a ground fault in a separate line from the same bank (i.e., an external fault) was simulated. After connecting a distributed load of 5 MVA to one bus of the target system, the ground fault was simulated and repeated for all buses. When using the existing CLS protection coordination, it was demonstrated that while the protection devices of the target system should not be triggered since an external fault had occurred, because the $I_0$ was picked up while the $V_0$ failed to exceed the threshold value (3.33% of 13.2 kV; 440 V) the result was instead a failure direction identification. On the other hand, when using the proposed method, the direction was successfully determined, and block signals between the protection devices resulted in the inactivity of protective devices.

C. FAULT SCENARIO 2; THE SECOND DRAWBACK OF CLS PROTECTION COORDINATION
Table 7 shows the results for the application of existing and newly proposed protection coordination methods to simulations of a 3-phase ground fault or a 3-phase short circuit occurring right in front of the protection device of each line. When incorporating the existing method, the circuit breakers indiscriminately opened due to a failure in determining the fault direction, resulting in a wide area power outage. However, when applying the proposed protection coordination method, only the circuit breakers in the faulty section were opened, and protection coordination was successful.
Among the multiple fault cases, the voltage and current (R2 and R13) were additionally measured for a fault occurring in front of R13 in a line connecting buses 1 and 6. The results which are depicted in Table 8, indicate that R2 successfully identified the 3-phase ground fault and the fault direction. In opposition, R13 failed to identify the fault direction as the V0 was 140 V while the I0 was picked up. Likewise, for the occurrence of a 3-phase short circuit, R2 operated normally, while R13 failed to do so as the V1 was measured to be 80 V. An alternative may be to modify the threshold value, but further research is inevitable since different values will need to be applied depending on the power system.

V. CONCLUSION

When a fault occurs within the traditional dendritic power distribution system, a power outage is inevitable in sound areas as a time delay occurs during the processes of faulty section isolation and provision of alternative power supply to sound sections. Conversely, the faulty section is automatically isolated in the NDS, preventing occurrences of power outages within sound sections, and thereby ensuring enhanced reliability. Existing protection coordination methods designed for the RDS are inapt for the NDS, and existing communication-based protection coordination methods possess critical limitations. Hence, in this paper, a modified direction identification method has been proposed for the application to the NDS.

The proposed direction identification method is distinct from other conventional protection coordination algorithms as fault direction is determined solely through current waveforms. Since the phase difference between voltage and current is not required, the novel method is indeed anticipated to resolve drawbacks associated with existing methods and to bring about a number of benefits. In short, the proposed method holds the capacity of identifying a fault direction within a short time frame regardless of the magnitude of the voltage element, distribution line length, load type, or presence of DG integration within a power system. Future empirical studies on the NDS are planned to be conducted using the intelligent electronic device (IED) following optimization through real-time simulation (Hardware in the loop simulation, HILS).

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