Adaptive Protection of Distribution Systems with DERs Considering Consumer and Generation Profiles

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Abstract—**Distributed Energy Resources (DER) penetration has a significant impact on the distribution protection system. Current flow during short-circuit and load flow depend on DERs' operating state, generated power, and short-circuits contribution as well as consumer loads. The more DER integration leads to more challenge to maintaining DER, feeder, and substation protections sensitive, selective, with fast response, and optimum reliability.**

The IEEE 34 Node Test Feeder used and extended by addition of photovoltaic, wind, and energy storage DERs. Consumer loads and DER's generation were extended from static values to typical load and generation profiles, which examined daily, weekly, and seasonal patterns. Protection device settings were calculated selectively in the absence of DERs. Using the method of Protection Security Assessment (PSA), automatically evaluate the correct operation of protection devices in case of different fault scenarios. Three-phase and single-phase metallic faults are applied to validate protection system security. The PSA reassessed DER contribution and influence on protection selectivity. Adaptive rules should fix identified miss-coordinations by modifying protection settings or feeder automation logic. This paper applied adaptive rules to improve protection settings.

The PSA method and adaptive rules assumed for implementation in an Advanced Distribution Management System (ADMS).

Keywords— Protection, adaptive, DER, PSA, generation profile, consumer profile, CTI, TCC

I. Introduction

Development of *Distributed Energy Resources* (DER) has been rapidly growing and mostly connected to low voltage and medium voltage of distribution systems via inverter. Regarding the protection manner, the short circuit contribution during normal and fault condition of DER penetration to the distribution network must be taken account. Several issues are appeared due to distributed and volatile power sources of DERs connection, as mention in [1]. Multidirectional current flow short circuit contribution is the main consideration towards the DERs connection. Autoreclosers false, sympathetic, or blinding [2] must be avoided during the presences of DERs. Nowadays, the loads are becoming more dynamic and using more power electronics so that furthermore the load profiles changing should be considered [3]. Whether the profiles of DERs generation will be examined in a variety of seasonal as well.

To coordinate and review the protection system of distribution network, plotting curve on the *Time Coordination Charts* (TCC) is a complexity method whenever the network is changing over time. Whereas, in every different switching status and DER volatile outputs, the protection system condition should be regularly checked. It means protection engineers should coordinate and analyze several TCCs and confirm correct operation of protective devices in their distribution network area. This process is time-consuming, needs sufficient protection engineers, and becomes frustrating. Adaptation of settings in some of these scenarios is possible which need protection engineers to reconfirm new protection settings.

The PSA method [3] simulates automatically all faults scenarios with volatile DER generation and loads for different network switching conditions. Correctly operation or vulnerabilities of protection coordination are ranked automatically and reported to protection engineers in a colored matrix visualization. Due to time-saving through simulation and automation, the PSA method can reconfirm the plausibility of protection settings changes faster. Accordingly, protection engineers can focus better to solve protection system vulnerabilities.

This paper studies protection system vulnerabilities due to DERs distributed nature and due to DER volatile outputs. Vulnerabilities are identified by the PSA method. Adaptation of protection settings is made through predefined coordination rule for *Coordination Time Interval* (CTI). The IEEE 34 Node Test Feeder is used as network study model and enhanced by DERs with sample profiles for generation [4] and load [5].

II. Methodology

The definition of adaptive protection is still debatable without any agreement in the industry. It is necessary to calculate the protection settings of an adaptive protection system in either off-line or on-line manner and to identify the required functionalities of adaptive protection [6].

This study initially considers disconnecting DERs from the network model. Three-phase and single-phase short-circuit faults along distribution feeders are simulated and evaluated by the PSA method. Then DERs are deemed to be connected with constant maximum generation for PSA evaluation. Finally, volatile DERs' output and their impact on protection settings sensitivity, coordination, and speed are evaluated. Fig. 2 shows the workflow for protection settings assessment and adaptation.

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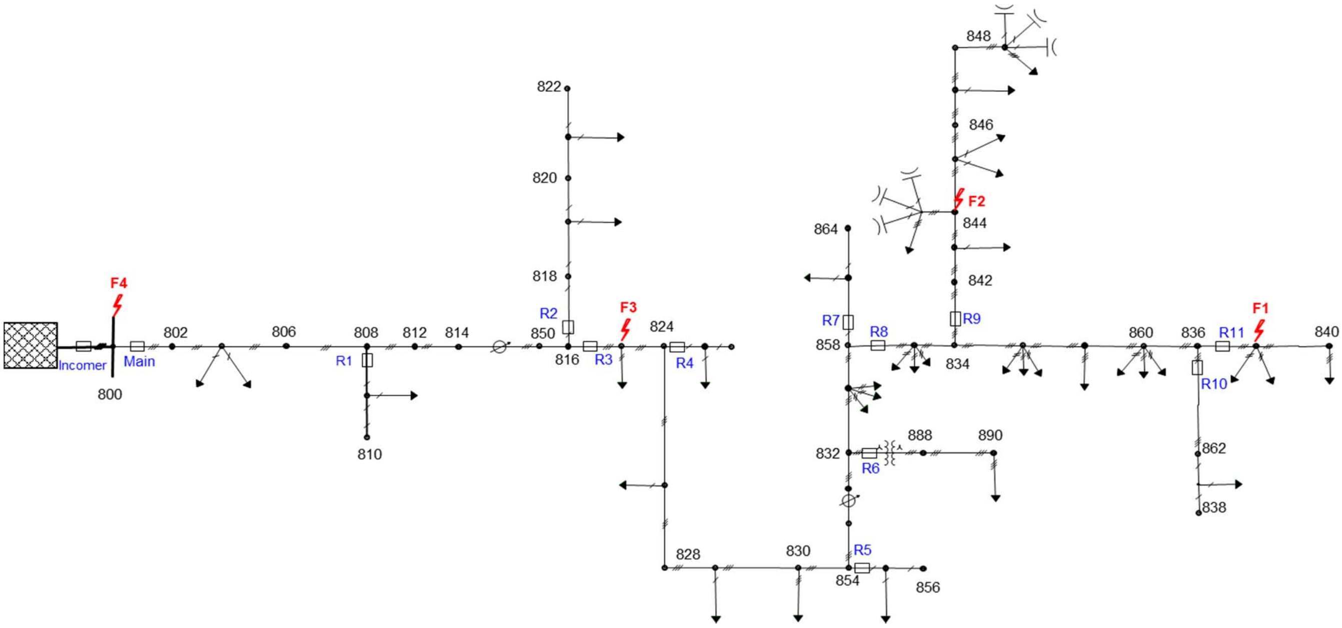


Fig. 1 Enhanced IEEE 34 Node Feeder Test Model for short-circuit and protection simulation

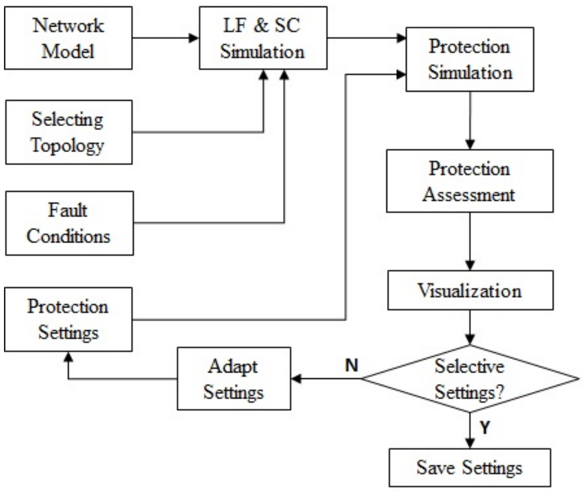


Fig. 2. Workflow for protection settings assessment and adaptation

A. Study Network Model

The IEEE 34 node test feeder with load data [7] was modeled unbalanced in our simulation software. The upstream network modeled as a balanced solidly grounded equivalent voltage source with 3-phase short circuit capacity of 200MVA. X/R=7.1, R0/R1=3.5, X0/X1=2.0.

Load flow and short-circuit analyses with three-phase or single-phase faults studied on the test model. Then, Protection devices were added, as shown in Fig. 1. Incomer relay, main relay, and R1 to R11 relays are either the main feeder sectionalizers feeder or reclosers on each lateral branch from the main feeder. Fig. 1. shows all the protection devices as non-directional overcurrent type with the optional possibility to activate additional directional overcurrent stage.

B. Protection Device Settings and Simulation

All protection devices were considered as relays with the IEC normally inverse characteristic curve. Protection relay operation time to trip in the presence of fault current is according to the following equation:

$$\boldsymbol{t_{Trip}} = \boldsymbol{T_p} \frac{\mathbf{0.14}}{\left(\frac{\boldsymbol{I_F}}{\boldsymbol{I_P}}\right)^{\mathbf{0.02}} - \mathbf{1}} \tag{1}$$

Where $\boldsymbol{t_{Trip}}$ is relay tripping time, $\boldsymbol{T_p}$ is time multiplier setting (TMS) parameter, $\boldsymbol{I_F}$ is fault current, and $\boldsymbol{I_P}$ is relay pickup current parameter. Parameters $\boldsymbol{I_P}$ and $\boldsymbol{T_p}$ are relays settings while fault current depends on the network model and short-circuit fault condition. The settings $\boldsymbol{I_P}$ should be higher than the maximum load current that measured by the current transformer of the relay with enough safety factor:

$$\boldsymbol{I_P} = \boldsymbol{SF} * \boldsymbol{I_{max.load}} \tag{2}$$

The safety factor (SF) value commonly used is 1.1.

Load flow study determines the maximum load at each protection device. With this input, the relays pick-up current setting ($\boldsymbol{I_P}$) can be calculated. Relays' time multiplier setting ($\boldsymbol{T_p}$) depends on fault current contribution at relay location and time coordination among relays to clear a fault selectively. Therefore, short circuit calculation is a mandatory calculation parameter input to determine relays' time multiplier setting.

To find maximum short circuit at relay locations, a 3-phase fault observation like F1 to F4 in Fig. 1 placed at the nearest point to each relay location. To find the minimum short circuit, a two-phase fault observation placed on the main feeder line end or on the feeder lateral section ends.

In the case with absences of DERs on the test model, protection devices were timely coordinated considering coordination with predefined CTI=0.3s between each relay coordination pairs. Relay settings were calculated based on the maximum load current, and the maximum or minimum short-circuit current at relay locations. Resulted settings for pickup current and time multipliers were added to relays on the test model. This enables the test model for protection simulations needed for PSA evaluations.

In the case with the presence of multiple DERs on the test model, current flow during normal and short-circuit conditions depend on the volatile value of loads and DER generations and operating status of DERs (On/Off). Volatile value of loads and DER generations were modeled as typical hourly load and generation profiles in each season. We considered all DER as connected in our test model. In utility grids, a higher number of simulations may be required to find maximum load current, and maximum/minimum short-circuit current to calculate protection setting at relay locations. DER connection points also have protection devices need coordination in time.

C. Protection Security Assessment (PSA)

Initially, a fault scenario and a network area are defined by the user. We considered the 3-phase short-circuit fault scenario, along with the entire test model in Fig. 1 considering faults on all buses and nodes and every 10% of all lines. The PSA method places all fault scenarios and simulates protection relay behaviors until a fault be cleared.

Then, PSA automatically determines network zones. Each zone is a group of distribution network elements with a boundary consisting set of relays responsible for clearing that zone faults. The combination of fault scenarios, fault locations in entire of each zone is simulated automatically using out study test model. The PSA automatically evaluate how each fault scenario is cleared in each zone of the protection devices. Correct relay operation (selective) are marked with green, more relay operation (over-function) or less relay operation (under-function) are marked with yellow or orange colors. Faults cannot be cleared by relays marked with RED. Results aggregated in a colored matrix like where rows indicate zones of protections, and columns are fault location along the line for the given fault scenario.

D. Analysis of PSA results

The PSA result matrix is the protection engineers start point to conduct an in-depth analysis for PSA identified vulnerabilities. Protection engineers should develop rules or methods to improve identified vulnerabilities either through adapting protection relay settings or adding new protection functions, e.g., directional overcurrent. We adapted and optimized relay settings during this study wherever needed.

III. CASE STUDY

The IEEE 34 node test feeder with 24,9 kV primary distribution system was performing in this study. This radial distribution feeder has 2,04 MW typical residential load and unbalances feeder character. This actual feeder was located in Arizona and used overhead line conductor configuration with single-phase and three-phase variety loads. The power transformer of substation rate is 2500 kVA by 69 kV/24.9 kV is connects to node 800 (not shown in Fig. 1). At the one lateral a transformer supplies the low voltage of 4.16 kV three-phase loads. This feeder also has two voltage regulator and numbers of shunt capacitors. [7]

The protection system simulated on the main line and in every lateral branch. Overcurrent relay selected as thirteen devices spread on the feeder as primary and backup protection. This simulation performs differences of protection behavior before DER connected into the grid and how identified miss-coordination protection by PSA during DERs penetration. Generation and customer characteristic during a year described by four season daily profiles were considered.

A. Basic Configuration Without DERs

Fig. 1 shows the basic configuration operates with only one power source and protection relay along applied on the main line and laterals. The load flow simulation was carried out at the maximum static load condition. Corresponding maximum load current at each relay location used to calculate relays' current pick up setting ($\boldsymbol{I_P}$). Maximum and minimum short-circuit current identified and based on their relays' time multiplier ($\boldsymbol{I_P}$) were calculated and coordinated manually. Table I shows the summary and resulted relay settings.

TABLE I. SIMULATION AND SETTING: BASIC CONFIGURATION

Relay	I max load (A)	Isc max (A)	Isc Min (A)	Setting	
				Ip (A)	tTrip (s)
Incomer	51.98	6280.01	4944.22	57.18	1.30
Main	51.98	5243.88	483.17	57.18	1.00
R1	1.22	925.81	766.37	1.34	0.15
R2	12.79	539.94	190.00	14.07	0.15
R3	39.92	685.21	217.60	43.91	0.70
R4	3.09	475.53	380.91	3.40	0.15
R5	0.31	334.62	446.01	0.34	0.15
R6	11.91	161.20	56.05	13.10	0.15
R7	0.14	283.18	280.81	0.16	0.15
R8	24.21	325.82	201.65	26.63	0.40
R9	16.49	325.82	200.12	18.14	0.15
R10	2.05	315.33	212.94	2.26	0.15
R11	2.29	315.00	201.05	2.52	0.15

TABLE II. ASSESSMENT RESULT WITH SINGLE-PHASE FAULTS

16 Routes, 16 Selective, 0 Not Cleared, 0 Underfunction, 0 Overfunction, 0 Not calculable

Zones	Start	End	1 %	10 %	20 %	30 %	40 %	50 %	60 %	70 %	80 %	90 %	99 %
Zone 1	R8	Distributed Load 816-824	1,276	1,238	1,201	1,167	1,134	1,1	1,066	1,032	0,997	0,962	0,93
Zone 2	R11	Distributed Load 858-834	0,37	0,542	0,541	0,54	0,538	0,537	0,535	0,534	0,533	0,531	0,53
Zone 3	R3	802	1,326	1,23	1,177	1,122	1,065	1,006	0,96	0,96	0,96	0,96	0,96
Zone 4	Main	800	1,33	1,33	1,33	1,33	1,33	1,33	1,33	1,33	1,33	1,33	1,33
Zone 5	R10	838	0,18	0,18	0,18	0,18	0,18	0,18	0,18	0,18	0,18	0,18	0,18
Zone 5	R10	N285	0,18	0,18	0,18	0,18	0,18	0,18	0,18	0,18	0,18	0,18	0,18
Zone 6	R9	848	0,207	0,207	0,207	0,207	0,208	0,208	0,208	0,209	0,209	0,209	0,21
Zone 6	R9	N278	0,207	0,207	0,207	0,207	0,208	0,208	0,208	0,209	0,209	0,209	0,209
Zone 6	R9	N257	0,207	0,207	0,207	0,207	0,207	0,207	0,207	0,207	0,207	0,207	0,207
Zone 7	R7	864	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43
Zone 8	R6	890	0,62	1,224	1,33	1,389	1,451	1,515	1,582	1,651	1,724	1,801	1,873
Zone 8	R6	N286	0,62	1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219
Zone 9	R2	822	0,73	0,73	0,73	0,73	0,73	0,73	0,73	0,73	0,73	0,73	0,73
Zone 10	R5	856	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43
Zone 11	R4	826	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43	0,43
Zone 12	R1	810	0,73	0,73	0,73	0,73	0,73	0,73	0,73	0,73	0,73	0,73	0,73

Time coordination relay pairs are R11, R10, R9 with R8; R4, R5, R6, R7, R8 with R3; R1, R2, R3 with the Main Relay; and the Main with Incomer relays. Each relay coordination pairs were set with a time multiplier to insure 0.3s of CTI for operation time between down- and up-stream relays. Relay operation time increases respectively from lateral reclosers toward sectionalizers, main feeder relay, and substation incomer relay.

PSA method applied with three-phase and single-phase short-circuit faults simulation. Table II shows the PSA results with single-phase faults. PSA result matrix cells were marked in green for every zone. It represents that the calculated protection settings for the basic configuration can clear the fault in every possible location in Fig. 1 successfully. Numbers in colored columns are fault clearing time.

B. Configuration With DERs at Maximum Generation

In this case, three DER types were added to the basic configuration: wind, battery, and PV.

TABLE IV shows the protection settings. Comparing to the case in Table I, the short-circuit values increases by a factor from 1.05 to 1.53. DERs were considered at maximum load for calculation of relays' pickup current setting. is the PSA results and shows the effect of DERs on protection system selectivity.

TABLE III. ASSESSMENT RESULT WITH DER CONNECTION AND THREE PHASE FAULT: BEFORE ADAPTIVE PROTECTION

16 Routes, 1 Selective, 7 Not Cleared, 2 Underfunction, 1 Overfunction, 5 Not calculable

Zones	Start	End	1 %	10 %	20 %	30 %	40 %	50 %	60 %	70 %	80 %	90 %	99 %
Zone1	R8	Distributed Load 816-824	12,163	12,178	12,201	12,222	12,243	12,262	12,282	12,301	12,319	12,336	12,351
Zone2	R11	Distributed Load 858-834	0,497	0,493	0,492	0,491	0,49	0,488	0,487	0,486	0,485	0,484	0,483
Zone3	R3	802	0,664	11,203	11,271	11,477	11,483	11,491	11,504	11,525	11,569	11,69	11,747
Zone4	Main	800	1,33	1,33	1,33	1,33	1,33	1,33	1,33	1,33	1,33	1,33	1,33
Zone5	R10	838	1,682	x	x	x	x	x	x	x	x	x	x
Zone5	R10	N285	1,682	1,682	1,683	1,683	1,683	1,683	1,683	1,684	1,684	1,684	1,684
Zone6	R9	848	1,65	1,654	1,658	1,662	1,666	1,67	1,674	1,678	1,682	1,686	1,691
Zone6	R9	N278	1,65	1,653	1,657	1,661	1,664	1,668	1,672	1,675	1,679	1,683	1,686
Zone6	R9	N257	1,65	1,651	1,652	1,653	1,654	1,655	1,656	1,657	1,659	1,66	1,661
Zone7	R7	864	x	x	x	x	x	x	x	x	x	x	x
Zone8	R6	890	0,437	0,362	0,415	0,443	0,471	0,499	0,528	0,557	0,586	0,616	0,644
Zone8	R6	N286	0,437	0,36	0,36	0,36	0,36	0,36	0,36	0,36	0,36	0,36	0,36
Zone9	R2	822	x	x	x	x	x	x	x	x	x	x	x
Zone10	R5	856	x	x	x	x	x	x	x	x	x	x	x
Zone11	R4	826	x	x	x	x	x	x	x	x	x	x	x
Zone12	R1	810	x	x	x	x	x	x	x	x	x	x	x

The DERs have the same rating of 350 kW and installed into the network via inverters. Typically, there was no significant short circuit contribution feeds to the system by the inverters. The contribution current ranges from 1.1 to 1.5 times of rated current [8]. We considered the contribution factor of 1.2 in this study. Even though DERs had no significant fault current impact, they could significantly change the load current and direction at relay locations. Fig. 3 shows the miss-coordination routes after DERs connection to the distribution feeder. Relay setting in highlighted areas cannot selectively protect the network.

Only one zone of protection (zone 2) can clear its fault selectively. However, several zones of protection cannot clear their faults (zone 5, 6, and 8). Their area was containing DER generation with insufficient protection that cannot clear their faults after overcurrent relay R10, R9, and R6 tripping. In some zone of protection under-function (zone 1 and 3) and over-function (zone 4) were identified. During the fault condition, DERs contributes current, which flows probably with contrary direction with lateral relay behavior (R6, R9, R10). Consequently, those relays cannot detect any fault through them.

Fig. 4 shows the operation status of protection devices. It is an example of over-function of protection system. Whenever DERs contribution on the branch, the fault F2 was cleared successfully by relay R9. But sectionalizers R8 and R3, as well as the main feeder protection, tripped additionally. Eventually, a new adaptive rule should be selectively adequate the short circuit disturbance.

Following considered to improve protection system performance in this study:

1. Activating and setting directional overcurrent protection in lateral autoreclosers as well as feeder sectionalizers. This rule used to overcome multi-directional short-circuit current flow between DERs and main substation during a fault condition.
2. Re-setting the undervoltage and overcurrent relays, as integrated protection of DERs, which is only overload function implemented before. During the contribution of DER, both overcurrent and undervoltage were coordinated selectively as main and backup protection respectively. DERs protection was coordinated with lateral auto-reclosers operation time.
3. Recalculating and coordinating protection settings along the main line and branches with adaptive rules. Each rule is valid for a specific equipment type, network topology, and protection devices location. This step was examining every possibility combination of DERs connection. The maximum condition was considered (all DERs connected) due to maximum current contribution.

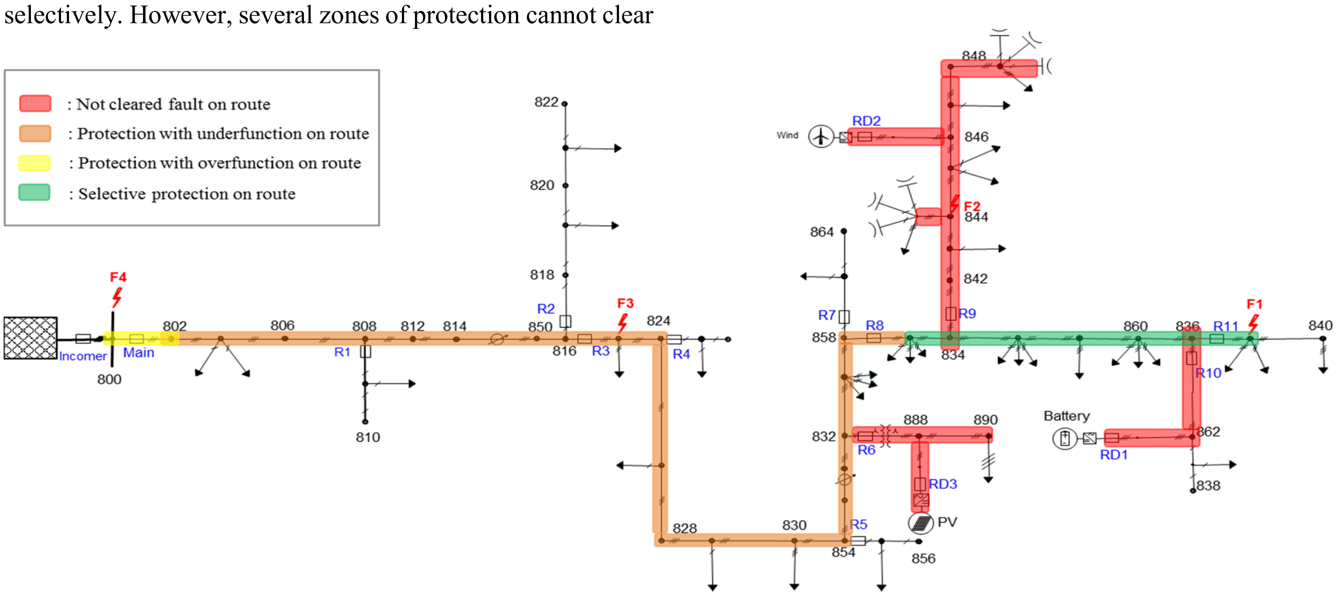


Fig. 3. Miss-coordination routes during DERs penetration

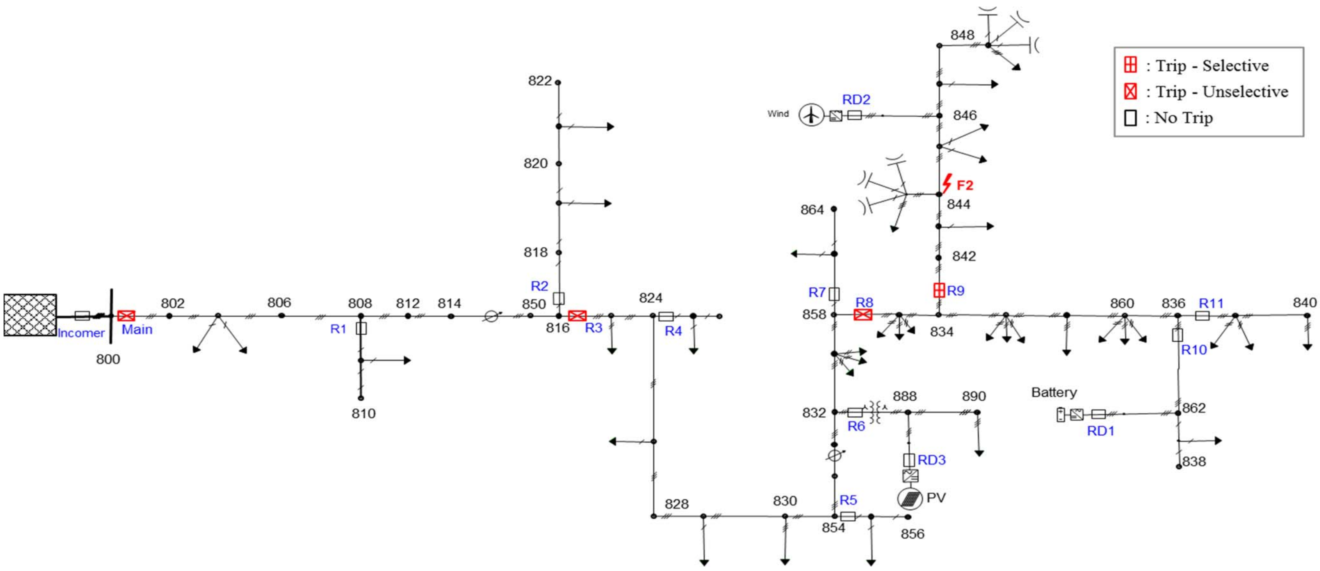


Fig. 4. Unselective conditions during a fault in lateral in the existing protection setting

Table IV shows the protection settings. Comparing to the case in Table I, the short-circuit values increases by a factor from 1.05 to 1.53. DERs were considered at maximum load for calculation of relays' pickup current setting.

TABLE IV. SIMULATION AND SETTING: DERS INTEGRATION

Relay	I max Load (A)	Isc max (A)	Isc Min (A)	Setting	
				Ip (A)	tTrip (s)
Incomer	17,32	6475,04	4944,22	19,05	1,60
Main	17,32	5438,91	483,17	19,05	1,30
R1	1,21	925,81	694,24	1,34	0,30
R2	12,42	874,51	190,00	13,66	0,30
R3	6,03	880,25	217,60	6,64	0,70
R4	3,10	475,53	466,09	3,41	0,30
R5	0,30	334,62	446,01	0,33	0,30
R6	5,73	260,24	56,05	6,30	0,30
R7	0,12	663,82	225,70	0,14	0,30
R8	7,37	527,54	201,65	8,10	0,40
R9	7,79	519,51	200,12	8,57	0,15
R10	2,05	505,69	212,94	2,26	0,15
R11	2,22	505,00	200,45	2,44	0,15
Bat	10,70	505,69	212,94	0,24	0,08
Wind	10,70	504,86	201,65	0,24	0,08
PV	10,84	260,24	117,82	0,24	0,20

Directional overcurrent relay activation is applicable wherever at the protection device location current flow in two direction be possible. To preserve DERs from destruction risk, it requires to adapt overcurrent relay setting as main protection and under-voltage protection as a back-up relay, refers to IEEE 1547-2018 [9]. Directional overcurrent protections were applied in lateral auto-reclosers R6, R9, and R10 which cover their protection zones. The same were activated for R3 and R8 as their direct following protection zones for a fault in main substation. In this case, the feeder main was influenced with maximum DER short-circuit contribution to the main substation fault.

The protection assessment method was repeated to verify the new setting applied in the model. The assessment results show in Table V, were improved significantly due to the reduction of the weak point along with the network.

TABLE V. ASSESSMENT RESULT WITH DER CONNECTION AND THREE PHASE FAULT SIMULATION: ADAPTIVE

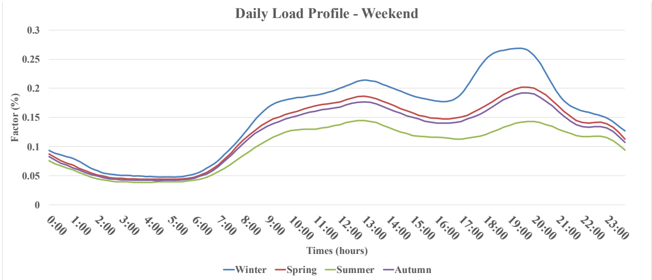
16 Routes, 8 Selective, 0 Not Cleared, 2 Underfunction, 1 Overfunction, 5 Not calculable

Zones	Start	End	1 %	10 %	20 %	30 %	40 %	50 %	60 %	70 %	80 %	90 %	99 %
Zone 1	R8	Distributed Load 816-824	1,53	0,977	0,951	0,921	0,89	0,882	0,887	0,872	1,53	0,452	0,687
Zone 2	R11	Distributed Load 858-834	0,511	0,505	0,504	0,502	0,501	0,499	0,497	0,496	0,494	0,492	0,491
Zone 3	R3	802	0,686	0,659	0,658	0,658	0,657	0,656	0,655	0,653	0,648	0,637	0,631
Zone 4	Main	800	0,759	0,76	0,761	0,761	0,762	0,763	0,764	0,765	0,766	1,39	1,39
Zone 5	R10	838	0,631	x	x	x	x	x	x	x	x	x	x
Zone 5	R10	N285	0,631	0,631	0,631	0,631	0,631	0,631	0,631	0,631	0,631	0,631	0,631
Zone 6	R9	848	0,552	0,674	0,674	0,674	0,674	0,674	0,674	0,674	0,674	0,674	0,676
Zone 6	R9	N278	0,552	0,674	0,674	0,674	0,674	0,674	0,674	0,674	0,674	0,674	0,674
Zone 6	R9	N257	0,552	0,552	0,674	0,674	0,674	0,674	0,674	0,674	0,674	0,674	0,674
Zone 7	R7	864	x	x	x	x	x	x	x	x	x	x	x
Zone 8	R2	822	x	x	x	x	x	x	x	x	x	x	x
Zone 9	R5	856	x	x	x	x	x	x	x	x	x	x	x
Zone 10	R4	826	x	x	x	x	x	x	x	x	x	x	x
Zone 11	R1	810	x	x	x	x	x	x	x	x	x	x	x
Zone 12	R6	890	1,53	1,53	1,53	1,53	1,53	1,53	1,53	1,53	1,53	1,53	1,53
Zone 12	R6	N286	1,53	1,53	1,53	1,53	1,53	1,53	1,53	1,53	1,53	1,53	1,53

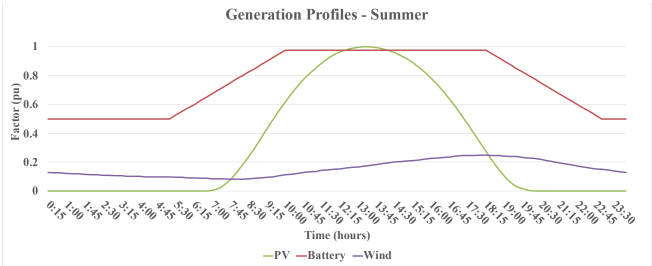
C. Protection Setting Considering The Profiles.

Load and generation profiles consideration are applying before the fault simulation executed. Typical daily profiles in the residential area [4] [5] were applied as a sample form to examine their effect into the network. The study uses weekend profiles as the highest load contribution to the system as the worsts case. All variety season possibly approaches as real generation condition. Fig. 5.a showing the highest energy consumption was in the winter, while the lowest in the summer. The sample generation profile in summer shows in Fig. 5.b.

Applied sample profiles for DERs had no significant impact on short circuit current flow. The assessment result also shows the identical behavior with TABLE V. We should mention that this conclusion is only valid for our simple test model. For a complicated distribution feeder, the effect of load and generation profiles on protections should be validated through repeating of the PSA method, e.g., for each hour and each season.



(a)



(b)

Fig. 5. Sample daily profile for the load (a) and generation (b)

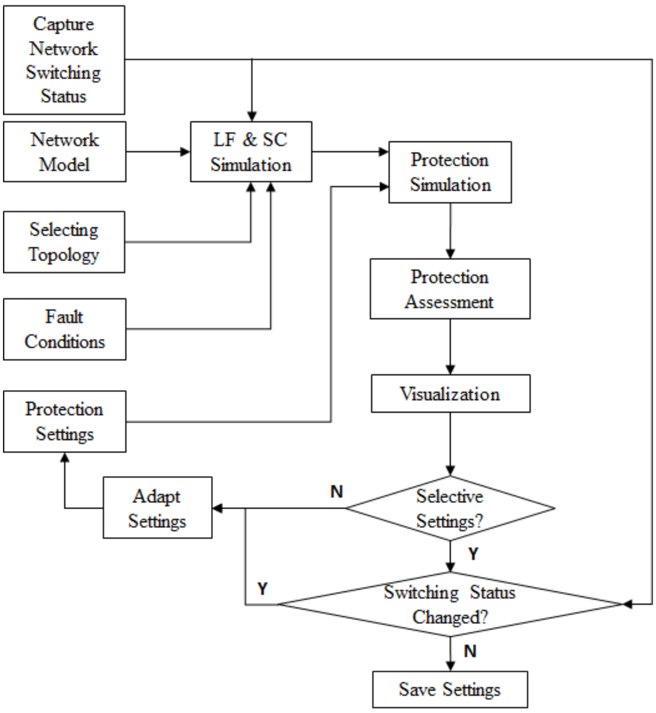


Fig. 6. Automated Adaptive Protection System

IV. Automated Adaptive Protection System

Customer load, DERs generation & availability, as well as the distribution configuration, are changing over time. This dynamic situation directly influences the protection devices [10]. Depends on distribution utility visions, the manual process of reading, computing, evaluating, and uploading protection settings into the protection device can be automated. Automated adaptation of protection setting like shown Fig. 6 could be available in the next generation of ADMS systems [11]. Intelligent Electronic Devices (IEDs) could receive resulted in optimized settings through a communication infrastructure with standard protocols [6].

V. Conclusion

The IEEE 34 node test feeder was modeled an enhanced for load flow, short-circuit, and protection simulation. The resulted study test model tuned for selective protection settings in absences of DERs. And next case presence of DERs with maximum generation output was considered. We observed the short-circuit magnitude increased slightly. But load current with or without DERs has considerable differences. We observed both effects could cause the wrong operation of protection relays. Observed vulnerabilities were removed by the improvement of protection settings and the addition of directional overcurrent functions.

The PSA method automatically identified and visualized protection settings weaknesses. This facilitates protection coordination analysis for protection engineers and gives them more time to focus on protection settings adaptation.

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