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Mitigate the Effect of Distributed Generators Connected to Distribution System

Saleh Khairullah Oraibi, Rasyidah Mohamad Idris*

Faculty of Electrical Engineering, Universiti Teknologi Malaysia, 81310 UTM Skudai, Johor, Malaysia.

*Corresponding author: rasyidahidris@utm.my

Abstract: This paper proposes using two methods, the conventional method and the curve time grading methods, to study and mitigate the effect of connecting the distributive generators to the IEEE15 bus distribution system. The main contribution of this work is that they are simple and applicable to all types of medium-sized networks and **a** havehigh speed to obtain results, compared with other methods that require the use of complex programs and require a long time to implement and get results. This is achieved by using some simple and uncomplicated equations with almost total dependence on ETAP software. ETAP program is used for analyzing and checking the results obtained, where the operating time and TMS value of all relays in the system are calculated in case the distribution generators are not connected, and for ensuring the quality of coordination by Etap software, then the distributive generators are connected, their effects are studied, and the relays are coordinated again by the two previous methods. The conventional method applies to all topologies, but it requires accuracy in transferring information and takes a longer time to obtain results compared to the curve time grading method, which in its work depends entirely on the use of star view from Etap curves characteristics; its effects are more accurate and can be obtained in less time. The methods mentioned enabled the engineers and technicians to control electrical systems connected to distribution generators by getting curacy results.

Keywords: distributive generators, relay coordination, overcurrent relay.

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1. INTRODUCTION

Due to the environmental effect of fossil fuels and their expensive production and extraction cost, man has resorted to alternative energy sources, including wind and solar energy distribution generators[1].

Connecting these alternative sources led to reducing pollution in the environment, improving voltage, and reducing losses in the system because these sources are small in size and quick to install, which makes it easy to install them in places with relatively small areas and close to consumption sources[2]. However, despite all these benefits, they cause some Harmonic problems and poor coordination between the protection relays in the system. Many studies have suggested a set of solutions to this problem[3]. Overcurrent relays are required to respond as soon as possible to electrical disturbances to improve the stability of synchro generators. Backup relays may not be able to connect to main relays in overcurrent protection systems that do not include interfaces for backup relays. This issue may be solved using [4] suggestion of a highly reliable method to defend against overcurrent. Starting with a set of rules and communication channels, criteria are established for finding pairs where backup relays do not react to failures at certain fault sites. Metaheuristics and determinism are used to create a new optimization technique[5]. Increased short circuit range in transmission and distribution networks caused by (DG) penetration into the electrical grid poses technical challenges and jeopardizes the system's safety[6]. Directed overcurrent relays will produce miscoordination issues when DGs are attached to looping power supply systems (DOCR)[7]. DG units are coupled to resistive superconducting fault current limiters (SFCL) to obtain optimum protection system settings, as described in [8]. Methods like [9] employ exact calculations and extensive descriptions of the network's components to imitate its transient state. A Simulink model was used to simulate the network at every step of the coordinating process. A new approach that considers the transitory change in topology for collecting and signaling backup relays OTs has also been designed. Once upon a time, there was a coordination technique between IEEE 8-bus and IEEE 30-bus[10]. Overcurrent relays may now be configured by an adaptive protection scheme (APS) assumption, thanks to a novel two-stage optimization approach described in [11]. The Fault Current Limiter (FCL) is optimized in the first phase to maintain the currency of the fault within the thermal capabilities of Circuit Breakers (CBs), regardless of whether Distributed Generation manufactured them or not (DG)[12]. As a result, systems that aren't prepared to manage these new power sources may have problems, including power flow in the wrong direction or drastic shifts in fault current levels. In [13], changes are made to the real-world distribution system safety concept to guarantee that the protective devices always perform correctly and reliably to avoid short circuits from occurring[14]. DOCR's objective function was modified in [15]to improve coordination. To ensure optimum relay coordination, the DOCR uses a modified version of the Manta Ray Foraging Optimization (MRFO) approach's modified objective function and code. The algorithm was applied to the nine and fifteen-bus test systems for testing purposes[16]. Changing the DG's size affects the amount of power it gives and affects how the system's current values flow. This is explained more fully below in [3] and [17]. Different Algorithms were used to lessen DG effects and estimate TSM values required to disconnect relays from the system and appropriately eliminate discoordination from power distribution systems. Articles [18] and [12]employ mathematical algorithms like PSO or GA, which are excellent tools for reducing the amount of error and time required to do a task at its optimum level of quality.

These studies mentioned are considered the most wonderful, but they need knowledge of using specific computer software such as MATLAB and other complex systems[19]. Connecting the distribution generator leads to a change in the current flowing in the design,

When a fault occurs, the fault current will be much greater than the current if the distributed generator is not connected, and this causes coordination problems between the main and support relays[20]. Most of this effect is to reduce the operating time of some relays and increase it for others, which causes a difference in the discrimination time interval[21].

Keeping the discrimination time interval between the main and back relay within the required limits is one of the most difficult challenges; two quick methods have been proposed to solve this problem.

The proposed methods apply to medium-sized systems containing several distribution generators, whereby these methods can reformat the system in a relatively short time and operate the system with the presence of the distribution generator,

The first method is the conventional method with the use of a set of equations to resetting the system, and the second method, which is considered one of the practical methods that can be implemented on any distribution system by changing the value of the relay's operating current and making the difference between the main and back up current very large, and that depends totally on Etap Software changes using curves for new action points while keeping a constant discrimination time interval between main and backup relays.

2. METHODOLOGY

2.1 15 IEEE bus system

The proposed system as a case study is the IEEE 15 bus distribution system at 11 kV with a grid of 15 MVA and x/r =7; the buses are connected by a transmission line as illustrated in "Figure 1" with x and r values shown in Appendix A., and the bus load can be shown in Appendix B. The system is coordinated by using the equations that will be explained in the conventional method. The impact of distributed generators can be studied when two distribution generators with the values shown in Table 1 are connected to the system as shown in Figure 2, and by using the following approaches, the system will coordinate with the distribution generator connection.

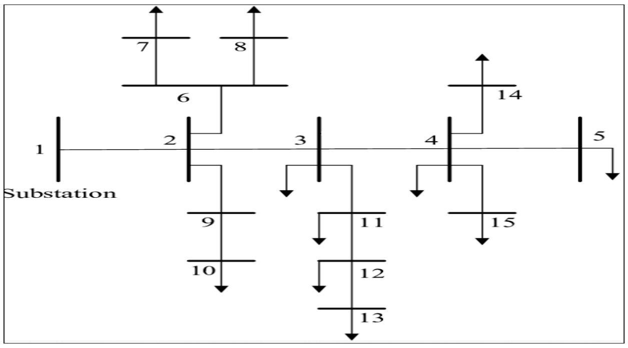

Figure 1. IEEE 15 Without distribution generators.

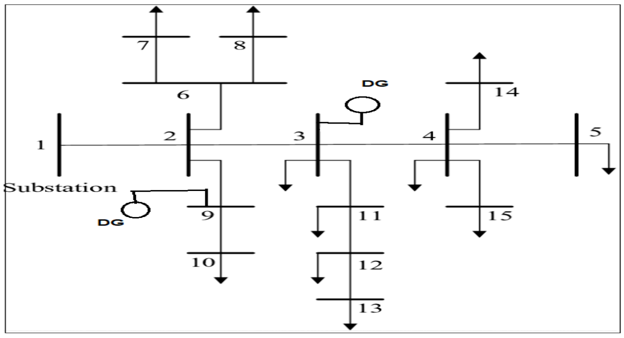

Figure 2. IEEE 15 With distribution generators.

Table 1. Distribution generators Information.

	MW	MA	KV	PF%	position
DG 1	1.2	1.412	11	85	3
DG 2	1.2	1.412	11	85	9

2.2 33 IEEE bus system

This system will utilize the IEEE 33 bus distribution system in Figure 3, which comprises 33 buses interconnected via an overhead line network. The system is connected to a 100 MVA grid with an impedance (X/R = 7) and a 33 kV voltage. Our relays will be Alstom P139 protection device overcurrent directional relays with normal inverse curves and ALSTOM-FX 11-72.5, 36KV, 2500 A circuit breakers.

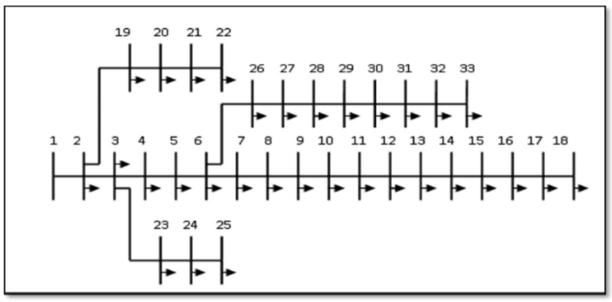

Figure 3. IEEE 33 bus system without distributed generators.

The operating time values of all relays will be calculated using the traditional method. Then the distributional generators with the matters mentioned in Appendix F are connected as in Figure 4. The distribution generators' effects on operating time and the time difference between the main and supporting relay are studied. The curves method reduces the impact of connecting distribution generators on the system.

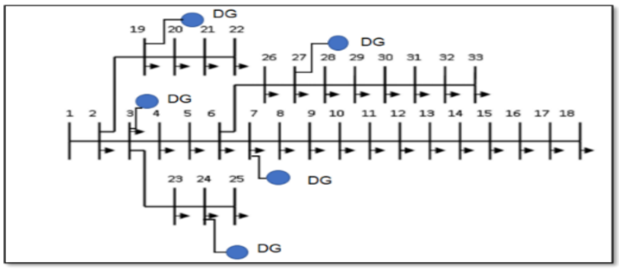

Figure 4. IEEE 33 bus system without distributed generators.

2.3 Conventional Method

The conventional method [22] depends on a set of equations and data from the system under study, such as the fault current values near and far bus from the relay to be reformatted.

The load flow specifications in the Etap software can be used to obtain the current flow under normal conditions, which limits the values of the current transformers and circuit breakers for each line in the system.

The normal load current values can be obtained from Equation (1).

$$I = \frac{S}{v\sqrt{3}} \tag{1}$$

According to Equation (2), the value of the pick-up setting for any relay can be estimated based on the usual current flowing through the line and the size of the current transformer (CT) connected to that relay.

$$Ps > \frac{In}{CT} * 100 \tag{2}$$

The relay has a specific current called relay setting current (RSI), representing the operating current for the relay, which can be obtained by Equation (3).

$$RSI = \frac{PS}{100} * \mathrm{CT} \tag{3}$$

Two values are needed to determine the TMS value of the relay, the first representing the operating time (R ot) and the second representing the relay characteristics operating time (R cot), according to Equation (4).

$$TSM = \frac{R\ ot}{\mathrm{Rcot}} \tag{4}$$

Each relay's operating time depends on the previous running time of the last relay, and adding the discrimination time interval keeps a constant time difference between the main and backup relays. Relay characteristics operating time represents the operating curve for each relay; since the research relays are normally inverse, the relay characteristics time can be represented by Equation (5).

$$\mathrm{R\ cot} = \frac{0.14}{((If/RSI)^{0.02} - 1)} \tag{5}$$

The flow chart in Figure 5 is used to obtain all the parameters for all t.

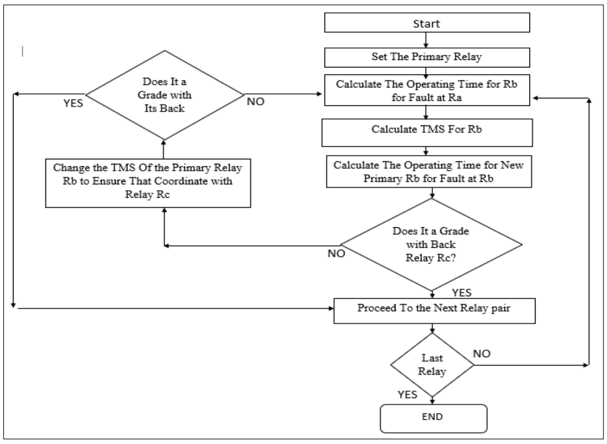

Figure 5. Flow chart for the conventional method.

2.4 Curve time grading method

The current has an inverse relationship with the operating time. Thus, a high wind will turn on an overcurrent relay faster than a low one. Inverse Definite Minimum Time (IDMT) relays are another name for inverse time[23]. The working duration of both overcurrent definite-time and overcurrent inverse-time relays must be altered to guarantee that the relay nearest to the fault trips before any other protection; this method is known as time grading.

The normal current in the system, which can be obtained by using the load flow characteristics of Etap, determines the values of the circuit breaker and current transforms that can be used in the system, which is usually greater than the value of the normal current. The overcurrent relay will activate when the system current surpasses 120 percent of the rated normal current (e.g., 200/5 A) since currents are monitored using current transformers with primary and secondary coils (e.g., 200/5 A).

The proposed method is dealing with changes in the values of the pick-up current for the backup relay to create a high gap of pick-up current values between the main and backup relays can be done by changing the RSI values of the backup relay so that it can keep the discrimination time interval between the relays within the required values, which in our research is 0.4second. A plug setting regulates the relay's activation current, and a time setting controls the relay's run duration.

2.2.1 Operating curve characteristic modeling

Changing the operating curve for the backup relay and keeping the main relay curve unchanged ensures that the time difference between the main and backup relay is equal to the discrimination time interval, as shown in Figure 6. The resulting curve can determine the TMS value, operating time, and the pickup current for a relay, and by the same procedure, the other parameters for all relays can be obtained.

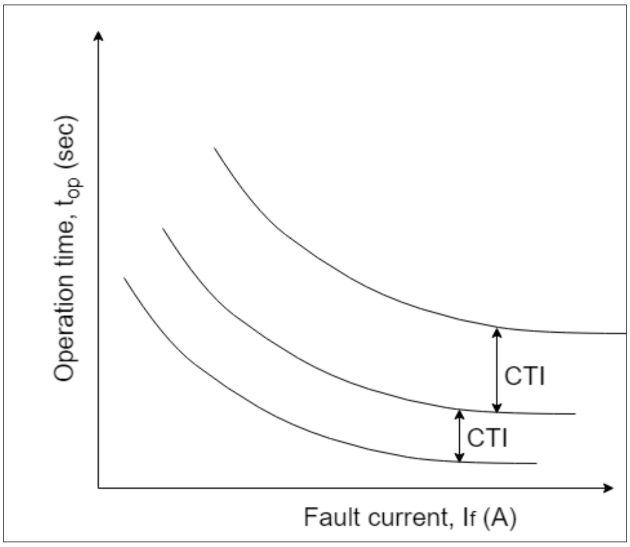

Figure 6. Relay operating curve characteristics.

3. RESULTS AND DISCUSSION

3.1 IEEE15 bus without distribution generators.

The system shown in Figure 1 is used as a case study without distribution generation.

The flow chart in Figure 5 and the Equations (1-5). It can be used to obtain values of the TMS, R cot, and Rot, and the result can be shown in Table 2.

Table 2. IEEE 15 parameters without distribution generators.

	CT	PS	RSI A	If(A)	R cot(S)	Rot (S)	TMS
R1	300	1	300	735	7.07	1.57	0.2
R2	200	1	100	689	5.58	1.27	0.22
R3	100	1	100	628	3.74	0.5	0.135
R4	50	0.5	25	628	1.83	0.105	0.05
R5	75	0.75	56.25	647	2.79	0.504	0.18
R6	50	0.5	25	647	2.08	0.104	0.05
R7	50	0.5	25	647	2.08	0.104	0.05
R8	75	1	75	667	3.13	0.518	0.165
R9	50	0.75	37.5	667	2.36	0.118	0.05
R10	100	0.75	75	647	3.17	0.906	0.285
R11	75	0.75	56.25	610	2.86	0.521	0.181
R12	50	0.75	37.5	610	2.43	0.121	0.05
R13	50	0.5	25	629	2.1	0.105	0.05
R14	50	0.5	25	629	2.1	0.102	0.05

From Table 2, it can be checked that there is a good sequence of the relays operating, and the time difference between the main and backup relays is about 0.4 sec, which means the system is coordinated perfectly.

3.2 IEEE 15bus system with distribution generators.

The distribution generators with the data in Table 1 are linked to the IEEE 15 bus system, as seen in Figure 2, and as such, the operating times of the relays will change, which will cause a mismatch in the system's coordination or may isolate some components that are not affected by the fault area, which will reduce the system's reliability because the fault current will continue to flow in the faulty point because there is no protection device in the other direction of the current flow. That leads to high losses in the system and necessitates quick action to isolate the fault problem. The new parameters of all relays in the system when the distribution generators are connected can be illustrated in Table 3.

Table 3. IEEE 15 parameters with distribution generators.

	CT	PS	RSI A	If(A)	R cot(S)	Rot (S)	TMS
R1	300	1	300	1736	7.07	1.76	0.2
R2	200	1	100	1632	5.58	1.01	0.22
R3	100	1	100	1326	3.74	0.374	0.135
R4	50	0.5	25	1052	1.83	0.105	0.05
R5	75	0.75	56.25	1736	2.79	0.408	0.18
R6	50	0.5	25	1230	2.08	0.104	0.05
R7	50	0.5	25	1230	2.08	0.104	0.05
R8	75	1	75	1586	3.13	0.461	0.165
R9	50	0.75	37.5	1294	2.36	0.118	0.05
R10	100	0.75	75	1416	3.17	0.69	0.285
R11	75	0.75	56.25	1246	2.86	0.412	0.181
R12	50	0.75	37.5	1110	2.43	0.121	0.05
R13	50	0.5	25	1174	2.1	0.105	0.05
R14	50	0.5	25	1174	2.1	0.102	0.05

As seen in Table 3, many relays now operate at different times due to the effects of bidirectional current, which also increases fault current in the system. For example, relay 2, the main relay for relay 1, operates at 1.01 seconds, while relay 1 runs at 1.76 seconds, meaning that their discrimination time interval equals 0.75 seconds and is not close to 0.4 seconds. As a result, the system will experience miscoordination and some other problems.

4. COORDINATION FOR IEEE 15 BUS SYSTEM WITH DISTRIBUTION GENERATORS.

The top priority when distribution generators are connected is relay coordination because it can reduce losses, prevent isolation of areas free of fault points, and improve the dependability of the electric network. Several relay coordination strategies have been proposed, and two will be selected for comparison in this study.

4.1 The conventional technique

There are many current sources in the design when the distribution generators are connected to the system; two relays must be used in some lines, such as between buses 2-3 and 2-8.

If a fault occurs in this region, there will be more than one main and backup relay. The normal current passing through the lines of the system when distribution generators are connected will be approximately the same current when they are not connected, so the current transformer CT, circuit breaker CB, pick-up setting Ps, and pick-up current for relays RSI will not be changed.

The change will be in the fault current, R cot, R ot, and TSM values, which can be obtained by using the Equations (1–5), and the results will be as in Table 4.

Table 4. New setting for IEEE 15 parameters with distribution generators.

	CT	PS	RSI A	If(A)	R cot(S)	Rot (S)	TMS
R1	300	1	300	1736	7.742	1.535	0.198
R2	200	1	100	1632	4.02	1.232	0.3
R2a	200	1	100	1632	7.47	1.521	0.205
R3	100	1	100	1326	2.9	0.484	0.183
R4	50	0.5	25	1052	1.69	0.1	0.05
R5	75	0.75	56.25	1736	2.115	0.485	0.225
R6	50	0.5	25	1230	1.67	0.085	0.05
R7	50	0.5	25	1230	1.67	0.085	0.05
R8	75	1	75	1586	2.575	0.49	0.19
R8a	75	1	75	495	3.639	1.535	0.421
R9	50	0.75	37.5	1294	1.8	0.09	0.05
R10	100	0.75	75	1416	2.313	0.874	0.377
R11	75	0.75	56.25	1246	2.19	0.496	0.226
R12	50	0.75	37.5	1110	1.92	0.1	0.05
R13	50	0.5	25	1174	1.68	0.084	0.05
R14	50	0.5	25	1174	1.68	0.084	0.05

From Table 4, it can be observed that all relays operate in perfect sequence and the discrimination time interval between the main and backup relay is about 0.4; for example, relay 10 is main and works at 0.874 seconds while its backup is relay 2 which operates at 1.232 seconds. Therefore, the time difference between them is 0.358 seconds.

This approach enables the engineers to control the system when connected to the distribution generators, even when the penetration of the distribution generators is changed, as shown in Table 5.

The percentage of the permissible penetration drop in the system is about 50%, whereby decreasing penetration to levels less than this percentage will cause miscoordination.

When the penetration of the distribution generators is decreased to 50%, it will cause incoordination cases in two positions for R2a and R8a, but all other relays operate in sequence and with an acceptable time difference.

4.2 The Curve time grading technique

The main and backup relays operate sequentially when the IEEE 15 bus system is coordinated properly without DG. The discrimination time between them is about 0.4 seconds, as shown from the star view characteristics in Etap as in Figure 7.

Table 5. New setting for IEEE 15 parameters with penetration is.50%.

	CT	PS	RSI A	If(A)	R cot(S)	Rot (S)	TMS
R1	300	1	300	1736	7.742	1.535	0.198
R2	200	1	100	1632	4.02	1367	0.3
R2a	200	1	100	1632	7.47	5562	0.205
R3	100	1	100	1326	2.9	542	0.183
R4	50	0.5	25	1052	1.69	0.1	0.05
R5	75	0.75	56.25	1736	2.115	0.542	0.225
R6	50	0.5	25	1230	1.67	0.11	0.05
R7	50	0.5	25	1230	1.67	0.11	0.05
R8	75	1	75	1586	2.575	0.529	0.19
R8a	75	1	75	495	3.639	2374	0.421
R9	50	0.75	37.5	1294	1.8	0.11	0.05
R10	100	0.75	75	1416	2.313	0.972	0.377
R11	75	0.75	56.25	1246	2.19	0.542	0.226
R12	50	0.75	37.5	1110	1.92	0.11	0.05
R13	50	0.5	25	1174	1.68	0.1	0.05
R14	50	0.5	25	1174	1.68	0.1	0.05

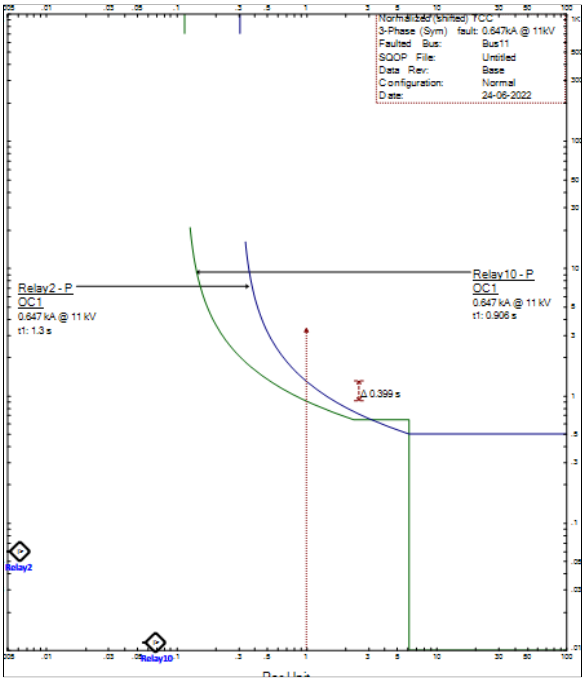

Figure 7. Operating time curve for relays 10 and 2 without distribution generators.

Figure 7 shows the operating curve for R 2 and R10 without DG, and the discrimination time interval between them equals 0.399.

When the distribution generators are connected, the time interval between the relays will not be 0.4, and the obtained time is usually less than the discrimination time interval, as shown in Figure 8 (the CTI is 0.313 seconds), which leads to incoordination in the system. The time grading method is used by changing the position of the back relay curve and keeping the curve of the main in such a way that the difference in time between the two curves is equal to the discrimination time interval.

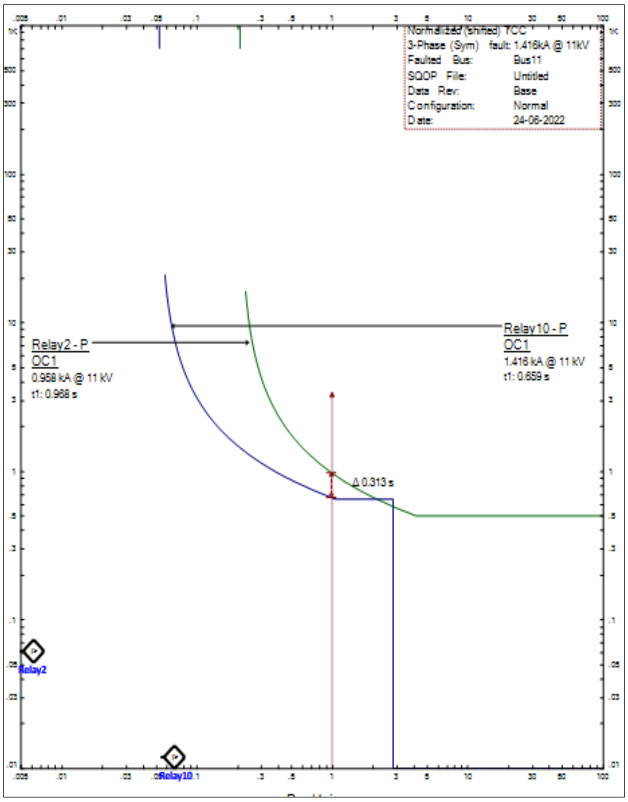

Figure 8. Operating time curve for relays 10 and 2 with distribution generators.

Figure 8 shows the operating curve for R 2 and R10 with DG, and the discrimination time interval between them is equal to 0.313, which is less than 0.4 and causes miscoordination between the relays when a fault has occurred.

The result for the IEEE 15 bus distribution system connected to the distribution generators using the curve grading time technique is shown in Table 6.

Table 6. New setting for IEEE 15 parameters with DG By using the curves grading time approach

	CT	PS	RSI A	If(A)	R cot(S)	Rot (S)	TMS
R1	300	1	300	1736	7.742	1.548	0.2
R2	200	1	100	1632	4.02	1.211	0.3
R2a	200	1	100	1632	7.47	1.486	0.199
R3	100	1	100	1326	2.9	0.522	0.18
R4	50	0.5	25	1052	1.69	0.1	0.05
R5	75	0.75	56.25	1736	2.115	0.464	0.22
R6	50	0.5	25	1230	1.67	0.085	0.05
R7	50	0.5	25	1230	1.67	0.085	0.05
R8	75	1	75	1586	2.575	0.49	0.2
R8a	75	1	75	495	3.639	1.524	0.419
R9	50	0.75	37.5	1294	1.8	0.09	0.05
R10	100	0.75	75	1416	2.313	0.867	0.375
R11	75	0.75	56.25	1246	2.19	0.4927	0.225
R12	50	0.75	37.5	1110	1.92	0.1	0.05
R13	50	0.5	25	1174	1.68	0.084	0.05
R14	50	0.5	25	1174	1.68	0.084	0.05

"Table 6" shows that the operating time and TMS values are approximately near the same ones obtained using the conventional approach. It is clear when comparing "Figures 11 and 12".

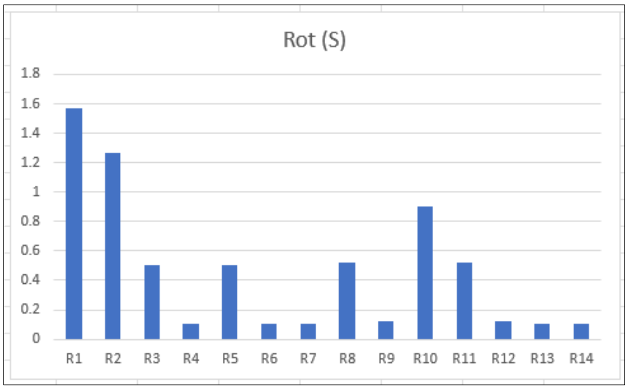

Figure 9. Relays operating time without distribution generators.

Figure 9 illustrates the operating time for the relays in the system without DG, and it can be observed that the highest working time is for relay 1 because of its location near sources.

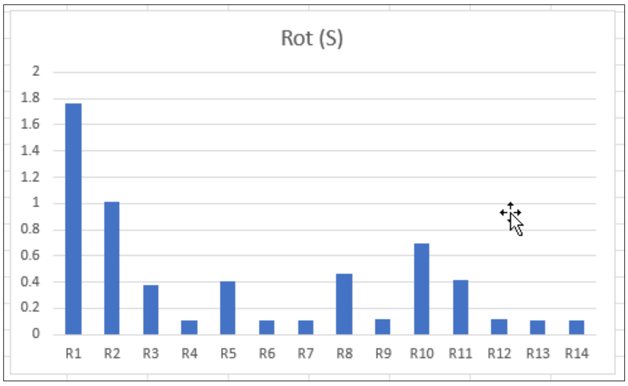

Figure 10. Relays operating time with distribution generators.

Figure 10 shows that operating time for relays with distribution generators is decreased because of the bidirectional current flow provided by distribution generators, which will cause discordance in the system.

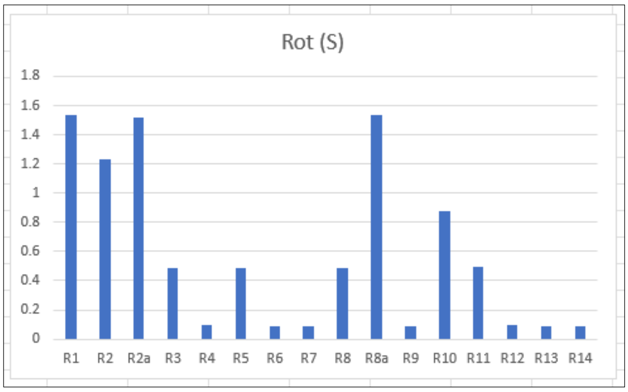

Figure 11. New relays coordinate time with distribution generators by the conventional approach.

Figure 11 shows that the conventional method was perfect for coordinating the system when the distribution generators are connected and the discrimination time interval for all main and back relays is within the required limit.

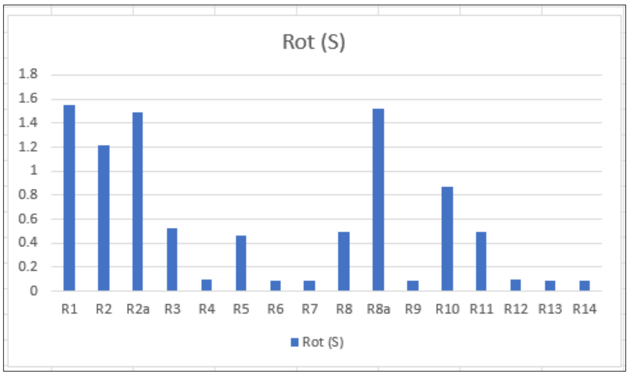

Figure 12. New relays are coordinating time with DG by curve grading time approach.

Figure 12 shows the operating time for all relays obtained by the curve time grading method with DG, and the time difference is kept constant between the main and backup relays.

The time required to complete the curve grading approach is usually less than the conventional method and depends totally on the Etap software, which enables the engineers to obtain the exact parameters for all relays and improve the system's reliability.

5. IEEE 33 BUS SYSTEM

5.1 IEEE 33 bus without distribution generators.

Current transformer values for each line, pick-up current, dial time, and pick-up setting Ps for each relay can be calculated using equations (1-5) and excel, as shown in Table 7.

Table 7. Plug setting, TSM, RSI, CT, Rot) in each relay for the 33 IEEE 33 bus system without distribution generators.

Relay	PS	C T	RSI	TSM	OT	Relay	PS	C T	RSI	TSM	OT
R1	1	800/5	800	0.6823	6.134	R17	0.75	25/5	18.7	0.05	0.077
R2	1	600/5	600	0.8772	5.792	R18	1	150/5	150	0.458	1.28
R3	1	400/5	400	1.1369	5.43	R19	1	150/5	150	0.315	0.886
R4	1	400/5	400	1.054	5.07	R20	1	50/5	50	0.254	0.488
R5	1	400/5	400	0.97	4.73	R21	0.75	50/5	38	0.05	0.088
R6	1	250/5	250	1.187	4.33	R22	1	150/5	150	0.326	0.917
R7	1	250/5	250	1.077	3.98	R23	1	125/5	125	0.1985	0.52
R8	1	250/5	250	0.971	3.61	R24	1	125/5	100	0.05	0.12
R9	1	225/5	225	0.914	3.23	R25	1	125/5	125	1.094	2.88
R10	1	125/5	125	1.0498	2.84	R26	1	125/5	125	0.942	2.49
R11	1	125/5	125	0.9	2.46	R27	1	125/5	125	0.791	2.097
R12	1	125/5	125	0.755	2.06	R28	1	100/5	100	0.69	1.704
R13	1	75/5	75	0.7369	1.66	R29	1	75/5	75	0.5894	1.308
R14	1	50/5	50	0.638	1.27	R30	1	75/5	75	0.41	0.91
R15	0.75	50/5	38	0.4748	0.875	R31	1	75/5	75	0.229	0.511
R16	0.75	50/5	38	0.258	0.476	R32	1	75/5	75	0.05	0.111

The time difference between the main and backup relays is around 0.4 seconds, which indicates that the system is completely coordinated. It is possible to confirm that the relays are running in the proper sequence.

5.2 IEEE 33 bus without distribution generators.

Two regions will connect the distributive generators of the under-researched system shown in “Figure 13”. The first is a current one-way region, and the second is a multi-way current region.

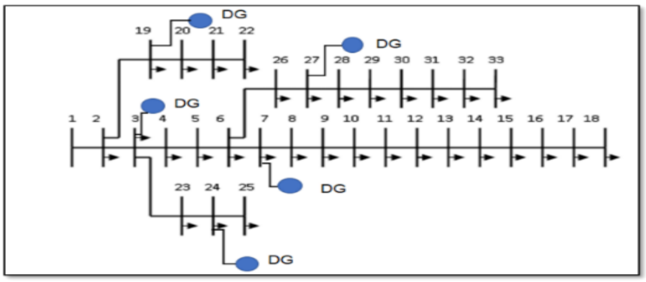

Figure 13. IEEE 33 bus system without distributed generators

In a one-way region, the current comes from all the sources of generation combined, so the calculation of the TMS values and the operating time for each relay does not differ from the case of not connecting the distributive generator, except that the current passing through the fault point for each case is greater than the current in the case of not connecting the distribution generators, and after calculating the required values, they can be summarized in Table 8.

While in the multi-way current region, to control the current flowing through each line from each side of the power sources, we must use two directional overcurrent relays in each line, which will allow us to carefully isolate the faulty component from the rest of the system while avoiding isolating areas that are too far away from the fault. It is necessary to recalculate the TMS and operating time for each relay on both sides of the line to maintain coordination between the relays, and the main relay may have more than one backup relay. The results of the computations, which also used the relay coordination equations, are shown in Table 8 and Figure 14.

5.3. Mitigate the effect of distributed generators by using the curve time grading technique

Relying on the same steps followed with the 15-bus system and applying them to the 33-bus system and using the same method, the operating time and TMS values shown in Table 9 can be obtained.

6. CONCLUSION

Distributive generators have a major role in reducing the environmental effect of generating electrical energy and reducing losses when connected to places of high consumption. However, it affects the protection devices used in the system. It caused a change in the operating time of the relays, which led to the difference in the proposed time difference between the main and back relays, which causes a discoordination between these relays when the fault occurs, which affects the system's reliability and increases losses. Many studies have been suggested to reduce the effect of distribution generators on electrical systems, and each has its advantages and disadvantages in terms of the speed of obtaining results, the difficulty of applying them in practice, or the complexity of using software to solve these methods. The first is conventional, and the second is curve time grading, as the two methods were applied to the IEEE 15 and 33 IEEE bus systems. The traditional method was good for obtaining results and achieving the required time difference between the relays. Still, it is not very easy and involves accuracy and time to get results. In contrast, the second method was simple and completely dependent on the ETAP program, with faster access to results and a wider possibility of controlling the accuracy of the results.

Table 8. Plug setting, TSM, RSI, CT, Rot) in each relay for the 33 IEEE 33 bus system with distribution generators.

R	PS	C T	RSI	DTS	Rot	R	PS	C T	RSI	DTS	Rot
R1	1	800/5	800	0.6	5.523	R17	0.75	25/5	18.7	0.05	0.064
R2	1	600/5	600	0.979	5.123	R18	1	150/5	150	0.616	1.3
R2a	1	600/5	600	0.44	2.604	R18a	1	150/5	150	0.9744	5.523
R3	1	400/5	400	1.387	4.96	R19	1	150/5	150	0.4257	0.8732
R3a	1	400/5	400	0.547	3.04	R20	1	50/5	50	0.3112	0.4765
R4	1	400/5	400	1.287	4.64	R21	0.75	50/5	38	0.05	0.0765
R4a	1	400/5	400	0.6237	3.44	R22	1	150/5	150	0.422	0.892
R5	1	400/5	400	1.187	4.24	R22a	1	150/5	150	0.839	5.1622
R5a	1	400/5	400	0.6969	3.84	R23	1	125/5	125	0.247	0.498
R6	1	250/5	250	1.461	3.97	R23a	1	125/5	125	1.052	5.562
R6a	1	25/5	250	0.819	4.24	R24	1	125/5	100	0.05	0.098
R7	1	250/5	250	1.46	3.645	R25	1	125/5	125	1.36	2.74
R8	1	250/5	250	1.3	3.278	R25a	1	125/5	125	0.81	4.24
R9	1	225/5	225	1.187	2.9	R26	1	125/5	125	1.207	2.436
R10	1	125/5	125	1.247	2.525	R26a	1	125/5	125	0.88	4.64
R11	1	125/5	125	1.05	2.419	R27	1	125/5	125	1.047	2.0539
R12	1	125/5	125	0.99	2.035	R28	1	100/5	100	0.9	1.671
R13	1	75/5	75	0.924	1.654	R29	1	75/5	75	0.7428	1.28
R14	1	50/5	50	0.78	1.261	R30	1	75/5	75	0.511	0.884
R15	0.75	50/5	38	0.573	0.862	R31	1	75/5	75	0.28	0.4867
R16	0.75	50/5	38	0.306	0.464	R32	1	75/5	75	0.05	0.0867

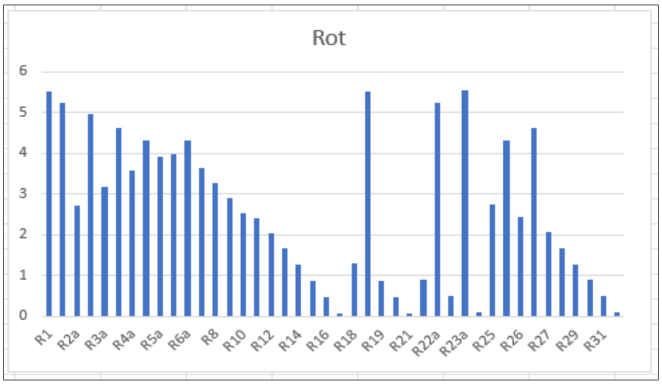

Figure 14. 33 IEEE New relays coordinate time with distribution generators by the curve time grading technique.

Table 9. Plug setting, TSM, RSI, CT, Rot) in each relay for the 33 IEEE 33 bus system with distribution generators by the curve time grading technique.

Relay	Pick up a step (STEP)	C T	Pick up current (RSI)(A)	Time Dial (TMS)	Rot	Relay	Pick up a step (STEP)	C T	Pick up current (RSI)(A)	Time Dial (TMS)	Rot
R1	1	800/5	800	0.59	5.512	R17	0.75	25/5	18.7	0.05	0.064
R2	1	600/5	600	0.955	4.3	R18	1	150/5	150	0.616	1.29
R2a	1	600/5	600	0.45	2.63	R18a	1	150/5	150	1	5.523
R3	1	400/5	400	1.4	4.95	R19	1	150/5	150	0.4257	0.8732
R3a	1	400/5	400	0.572	3.16	R20	1	50/5	50	0.3112	0.4765
R4	1	400/5	400	1.254	4.55	R21	0.75	50/5	38	0.05	0.0765
R4a	1	400/5	400	0.65	3.6	R22	1	150/5	150	0.422	0.892
R5	1	400/5	400	1.145	4.29	R22a	1	150/5	150	0.839	5.24
R5a	1	400/5	400	0.715	3.95	R23	1	125/5	125	0.3	5
R6	1	250/5	250	1.42	3.96	R23a	1	125/5	125	1.052	5.562
R6a	1	25/5	250	0.854	4.29	R24	1	125/5	100	0.05	1
R7	1	250/5	250	1.45	3.654	R25	1	125/5	125	1.36	2.74
R8	1	250/5	250	1.3	3.278	R25a	1	125/5	125	0.81	4.33
R9	1	225/5	225	1.186	2.9	R26	1	125/5	125	1.207	2.436
R10	1	125/5	125	1.254	2.56	R26a	1	125/5	125	0.88	4.64
R11	1	125/5	125	1.04	2.42	R27	1	125/5	125	1.1	2.1
R12	1	125/5	125	0.99	2.035	R28	1	100/5	100	0.9	1.671
R13	1	75/5	75	0.924	1.654	R29	1	75/5	75	0.75	1.28
R14	1	50/5	50	0.78	1.261	R30	1	75/5	75	0.511	0.884
R15	0.75	50/5	38	0.573	0.862	R31	1	75/5	75	0.3	0.5
R16	0.75	50/5	38	0.306	0.464	R32	1	75/5	75	0.05	0.0867

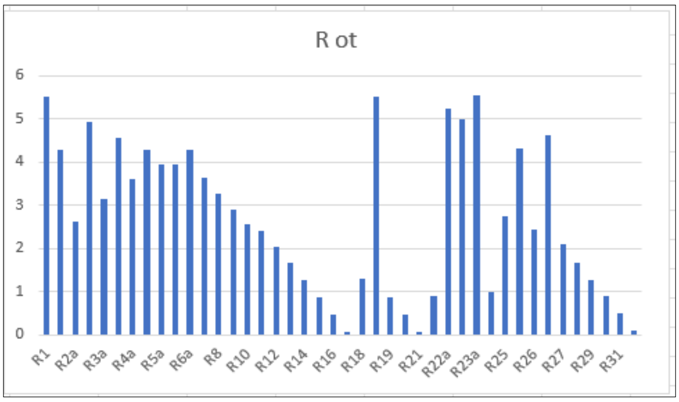

Figure 15. 33 IEEE New relays coordinate time with distribution generators by the curve time grading technique.

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APPENDIX

Appendix A
Branch Connections
% Impedance, Pos. Seq., 100 MVA Base

LINE	FROM	TO	R	X	Z	Y
Line1	Bus2	Bus1	38.18	46.42	60.1	0.001001
Line3	Bus3	Bus2	38.18	46.42	60.1	0.001001
Line5	Bus4	Bus3	57.27	69.63	90.16	0.001502
Line7	Bus5	Bus4	76.36	92.84	120.21	0.002003
Line9	Bus9	Bus2	57.27	69.63	90.16	0.001502
Line10	Bus10	Bus9	57.27	69.63	90.16	0.001502
Line11	Bus11	Bus3	38.18	46.42	60.1	0.001001
Line12	Bus12	Bus11	38.18	46.42	60.1	0.001001
Line13	Bus13	Bus12	38.18	46.42	60.1	0.001001
Line14	Bus14	Bus4	38.18	46.42	60.1	0.001001
Line15	Bus2	Bus6	76.36	92.84	120.21	0.002003
Line16	Bus6	Bus7	19.09	23.21	30.05	0.000501
Line17	Bus6	Bus8	19.09	23.21	30.05	0.000501
Line19	Bus4	Bus15	38.18	46.42	60.1	0.001001

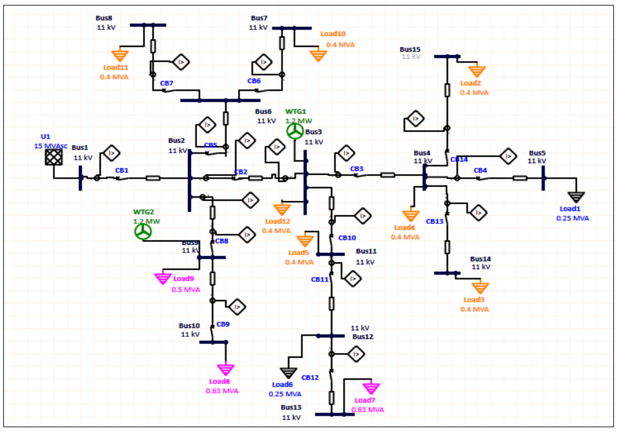
Appendix B
Bus Input Data

BUS	VOLTAGE	Mw	Mvar
Bus3	11	0	0
Bus4	11	0	0
Bus3	11	0.4	0
Bus4	11	0.4	0
Bus5	11	0.25	0
Bus6	11		
Bus7	11	0.4	0
Bus8	11	0.4	0
Bus9	11	0.5	0
Bus10	11	0.63	0
Bus11	11	0.4	0
Bus12	11	0.25	0
Bus13	11	0.63	0
Bus14	11	0.4	0
Bus15	11	0.4	0

Appendix C
Generation bus distribution generators

bus	Kv		MW	Mvar	PF
Bus1	11	Swing			
Bus3	11	Mvar/PF Control	1.2	-0.744	-85
Bus9	11	Mvar/PF Control	1.2	-0.744	-85
			2.4	-1.487	

Appendix D
IEEE 15 bus system in Etap



APPENDIX E
33 IEEE Branch connections

				R	X	Z	Y
Line1	Line	Bus2	Bus1	0.37	1.12	1.18	0.0025650
Line13	Line	Bus3	Bus2	0.37	1.12	1.18	0.0025650
Line14	Line	Bus4	Bus3	0.37	1.12	1.18	0.0025650
Line15	Line	Bus5	Bus4	0.37	1.12	1.18	0.0025650
Line16	Line	Bus6	Bus5	0.37	1.12	1.18	0.0025650
Line17	Line	Bus7	Bus6	0.74	1.24	1.44	0.0023561
Line18	Line	Bus8	Bus7	1.48	2.47	2.88	0.0047122
Line19	Line	Bus9	Bus8	0.74	1.24	1.44	0.0023561
Line20	Line	Bus10	Bus9	0.74	1.24	1.44	0.0023561
Line21	Line	Bus10	Bus11	0.74	1.24	1.44	0.0023561
Line22	Line	Bus11	Bus12	0.74	1.24	1.44	0.0023561
Line23	Line	Bus12	Bus13	0.74	1.24	1.44	0.0023561
Line24	Line	Bus13	Bus14	0.74	1.24	1.44	0.0023561
Line25	Line	Bus14	Bus15	0.74	1.24	1.44	0.0023561
Line26	Line	Bus15	Bus16	0.74	1.24	1.44	0.0023561
Line27	Line	Bus16	Bus17	0.37	0.62	0.72	0.0011781
Line28	Line	Bus18	Bus17	0.74	1.24	1.44	0.0023561
Line29	Line	Bus19	Bus2	0.15	0.25	0.29	0.0004712
Line30	Line	Bus20	Bus19	0.74	1.24	1.44	0.0023561
Line31	Line	Bus21	Bus20	0.74	1.24	1.44	0.0023561
Line32	Line	Bus21	Bus22	0.74	1.24	1.44	0.0023561
Line35	Line	Bus3	Bus23	0.15	0.25	0.29	0.0004712
Line36	Line	Bus24	Bus23	0.74	1.24	1.44	0.0023561
Line37	Line	Bus25	Bus24	0.74	1.24	1.44	0.0023561
Line39	Line	Bus6	Bus26	0.15	0.25	0.29	0.0004712
Line40	Line	Bus26	Bus27	0.37	0.62	0.72	0.0011781
Line41	Line	Bus27	Bus28	0.74	1.24	1.44	0.0023561
Line42	Line	Bus29	Bus28	0.74	1.24	1.44	0.0023561
Line43	Line	Bus30	Bus29	0.74	1.24	1.44	0.0023561
Line44	Line	Bus31	Bus30	0.37	0.62	0.72	0.0011781
Line46	Line	Bus31	Bus32	0.37	0.62	0.72	0.0011781
Line47	Line	Bus32	Bus33	0.74	1.24	1.44	0.0023561

Appendix F
IEEE 33 Distribution generators information

	MW	MV	KV	PF	EFF	RPM	BUS
WTG 1	6.5	7.647	33	85%	95%	1500	7
WTG 2	3.5	4.118	33	85%	95%	1500	19
WTG 3	3.15	3.706	33	85%	95%	1500	27
WTG 4	1	1.176	33	85%	95%	1500	3
WTG 5	3.15	3.706	33	85%	95%	1500	24

Appendix G
IEEE 33 bus system in Etap