Effect of Distributed Generation on Protective Device Coordination in Distribution System

Muhammad Rehan Farooqi , M Eng Student at University of Waterloo ECE Department.
Supervisor Professor Doctor T.S Sidhu, ECE Department
University of Western Ontario

1. Introduction.

The incorporation of Distributed generation (D.G) into power systems can offer many major advantages. However, besides its various benefits, distributed generation can cause various negative impacts; careful assessment is required to evaluation that system reliability and security are conserved following DG integration.
Among these issues, protection coordination is a major concern as it directly affects continuity of service and reliability of service. The Distribution systems are generally considered to be ready to support small DG installations without much change. Furthermore, justifying strategies can then be identified to improve any potential problems. As we will be discussing hereafter, the addition of DG to the distribution network may prevent the protective device from detecting a fault, which is supposed to be within its protection zone. It may also result in the loss of coordination between two protective devices. It is important to understand that this depends strongly on the type of DG, its size, and location in the network. [1]

2. Typical Distribution System Topology.

The distribution system is designed to be Radial in nature that is they are fed from a single power source. Protection is based on time-over-current relays and fuses reclosers and sectionalizes that are coordinated with each other, So that the device near the fault will clear the fault first and minimize the duration and extent of interruptions. It is so automated to safely clear faults and get customers backing service as quickly as possible. Now days with larger Integration of DG to the system, which brings about complications? And we have to consider how this type of generation can be safely and reliably interconnected.
Fortunately, due to the robustness of the existing design practices, the distribution system can handle a little and limited amount of DG interconnection without or some modifications. It is this robustness of the existing design that has allowed us to move into the a new era of interconnection based on standards such as IEEE 1547-2003 without major design changes to the system. However, as the integration of these Distributed generation are increased, we will eventually cross the threshold where changes in design and control practices are required at all levels of the power system. [1]

3. Today's Current Distribution System Protection Practices.

Over-current protection is a major device of Distribution systems Protection. Proper Over-current protection allows temporary faults to be quickly cleared from the system and permanent faults (failed cable sections or failed equipment) to be isolated in a manner that minimizes the number of customers impacted as well as the extent of the damage that occurs during the fault. Over current protection involves coordinated operation of many devices, such as Circuit breakers, relays, re-closers, sectionalizing switches, and various types of fuses. All of the devices are coordinated based on the various time current characteristics curves, relay pickup settings (where applicable), and fuse melting /damage curves.
Essentially all radial distribution systems, protection is predicated on the principle that power (and fault current) flows from the substation out to the loads. There are no other sources of fault current. New sources of fault currents that can change the direction of flow. [2]

4. Effect Of Distributed Generation On Distribution System Form Protection Point Of View

1. Cause new fault current paths to exist that weren't there before,
2. It increases the fault current magnitudes, and redirect ground fault currents in ways that can be problematic for certain types of over current protection schemes.
3. In addition, the time duration it takes to clear DG fault sources from the line may be somewhat longer than the utility source alone.
4. All of these issues are usually insignificant with low penetration DG environments, but at high penetration, they can require serious design upgrades to the power system to avoid problems summarized in Table 1.

Table 1

Description of Fault Contribution Condition	Issues Related to Condition
Increased Fault Current Magnitudes on the System Due to DG Fault Contributions	1. Can cause fault levels to exceed interrupting device rating. 2. Can change fuse and circuit breaker coordination parameters. 3. Increased conductor damage and/or distribution transformer tank rupture risk for faults (due to higher magnitude).
Changes in Direction of Fault Current Flows or Additional New Flows not Present Before Addition of DG	1. May cause sympathetic trip of reclosers or circuit breakers. 2. Can desensitize ground fault relaying protection. 3. Can cause network protectors to operate when they do not need to. 4. Can confuse automatic sectionalizing switch schemes.
Increased Time to Clear All of the Various DG Contributions Compared to Utility Source Alone	1. Increased conductor or equipment damage during fault (due to longer duration arcing or current flow). 2. Temporary faults may not be cleared as efficiently, defeating reclosing objective.

5. Types of Fault Current contributors.

5.1 Combustions Engine.

This the worst offending distribution-Generation connected energy sources with regards to injected fault currents are rotating synchronous generators. These types inject more than twice as much fault current per unit of rated capacity as compared to the solid-state inverter devices. Internal combustion engines (ICE) and combustion turbines (CT), which usually use rotary are the largest fault current injectors per unit of rated capacity.

5.2 Converters.

Inverter: Interfaced power sources such as PV, fuel cells, Wind Turbines and some Micro turbines are more justifying forms of DG than their synchronous rotating generator cousins. However, at high levels of distribution-connected DG penetration, even relatively benign inverter technology can still lead to problems.

6. DG Hosting Capacity In Distribution With Respect To Protection System.

In an existing network designed without Considering the presence of any DG, some modifications may be necessary with DG present. In order to determine the maximum allowed Penetration of DG into an existing network, Different indices can be formulated, corresponding to varying degrees of modification, for which varying amount of DG can be accepted. These indices are the base for determination of the so- called **'hosting capacity'.**

The modification indexes suggested hereunder are rather straight forward, from the situation when modification is not required (M0) to the situation when a new system design is required (M5). The applied modification index is partly a consequence of the decided performance, partly a consequence of the existing situation and the actual design of the network.

TABLE 2

Different Modification Index for Different Hosting Capacity with Dg and Protection of Distribution Networks.

Modification index	Description
M0	No modification
M1	Changes in metering
M2	Changes in relay protection settings
M3	Changes in protection schemes
M4	Changes in Dimensioning of lines and equipment
M5	Changes in system structure

7. Generalized Assessment Algorithm.

Different types of energy sources can be utilized in DG systems; however, the impact on the protection of the distribution system is dependent on whether the interfacing scheme is based on the direct coupling of rotary machines, such as synchronous or induction generators, or whether the DG system is interfaced via a power electronic converter.

The generalized assessment method relies on breaking the DG impact on distribution system protection to a number of sub-studies. Namely, they are: loss of coordination, de-sensitisation, nuisance fuse blowing, bi-directional relay requirements, and over voltage studies. Figure 1 summarizes the methodology. **[4]**

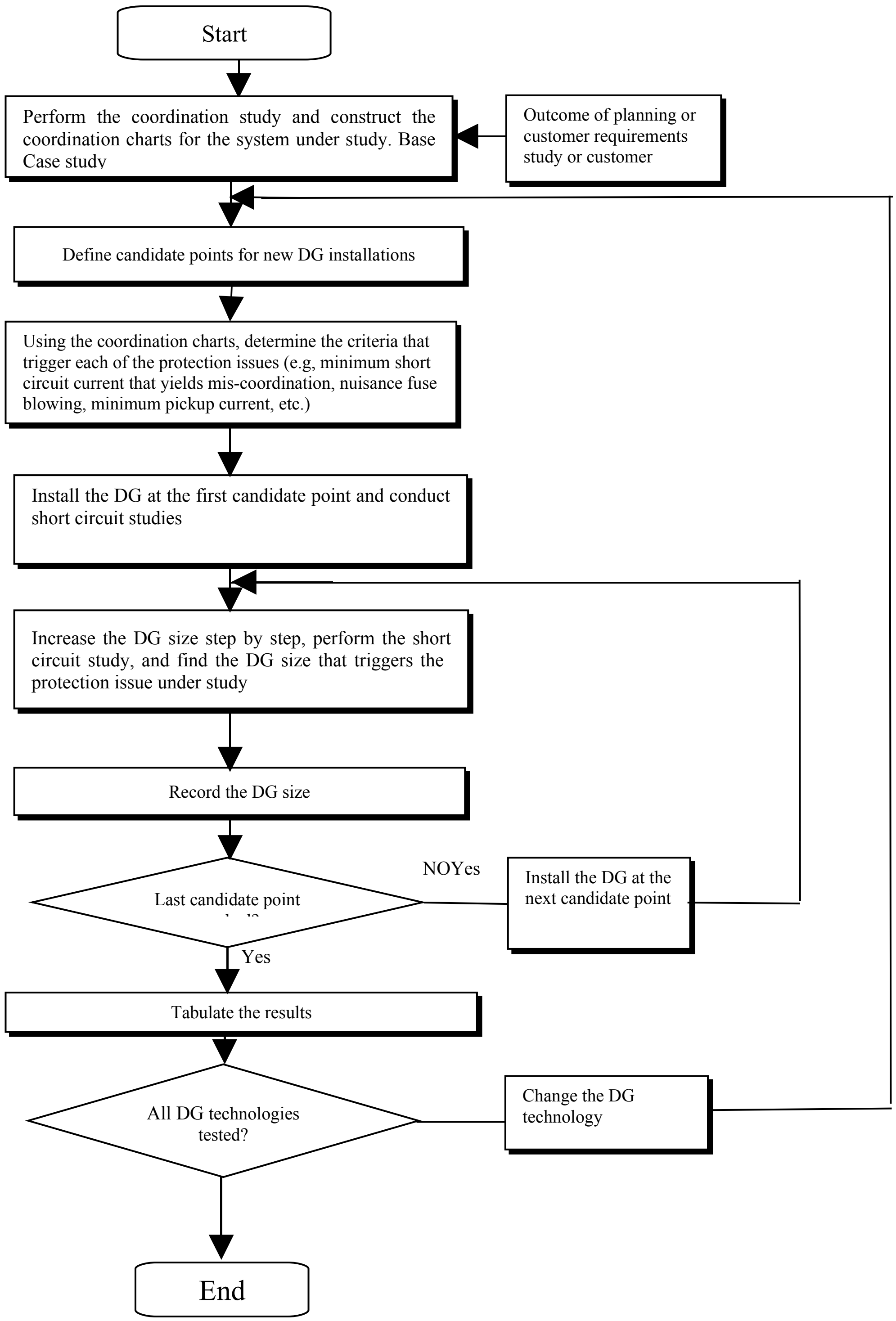
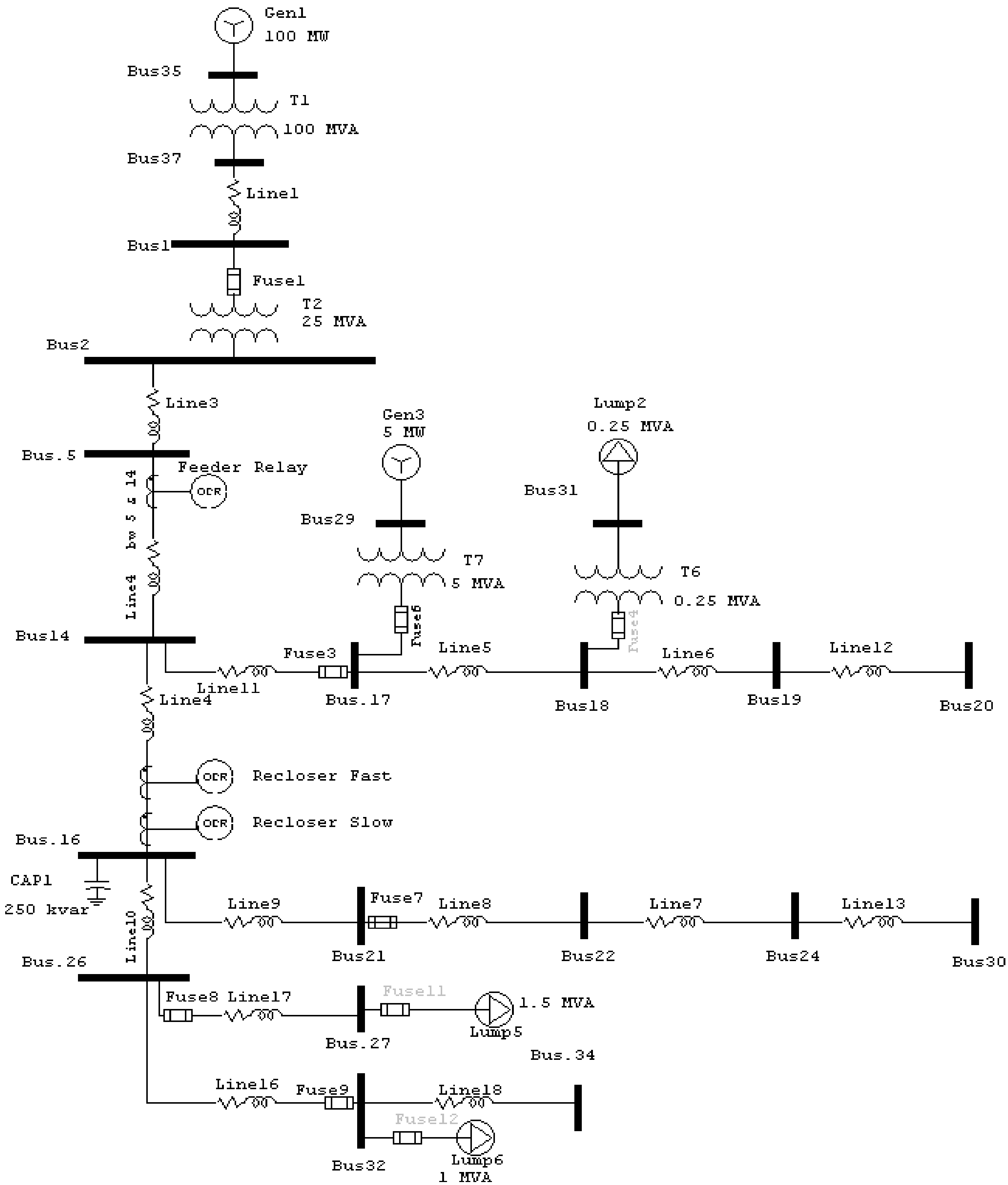


Figure 1

8 Distribution System Investigated.

The distribution system selected for this project is an 13.9kV multi-grounded Suburban distribution circuit with several laterals. Three phase feeding multiple loads. The power Flow and One line diagram is shown in Figure 2 The Total load supplied by one the Feeder out of Four feeders is shown in detail and the rest are some what identical. **[3]**

Figure # 2 Single line Diagram.



The total load of feeder is nearly Max of 5MW and 1 MVARS. circuit is summed up and concentrated at the Bus as shown in the one line. The values of the equivalent concentrated loads are given in Table 3.

Table # 3

Bus #	Total Load Present Load in Amps.
Bus 18	**22**
Bus 17	**44**
Bus 21	**22**
Bus 22	**44**
Bus 27	**44**
Bus 32	**44**

8.1 Overview of Solution

Simulations of the cases outlined above are conducted using ETAP Software, which model the system in balanced networks. Every case has been saved as a self-contained study file. To calculate short-circuit currents in each branch of the system, fault flow analysis is used. With this analysis, it is possible to obtain short-circuit current in each section when a fault is on a specific location on the network.

ETAP is used to check the fault current magnitude against the characteristics of the relay, which is supposed to clear it for different operating conditions. It was also used to check the coordination of two separate relays under different fault conditions, for different operating scenarios.

8.2 Study Procedure

The procedure I used for the This Project is based on the Above mentioned assessment Algorithm.

1. Simulation of the distribution network selected for the study using ETap, with out including the embedded distributed generation source. Called as the Base case.

2. Conduction of a fault flow analysis for a selected fault location, without the inclusion of distributed generator.

3. Conduction of a fault flow analysis for a selected fault location, with the inclusion of a directly connected synchronous distributed generator.

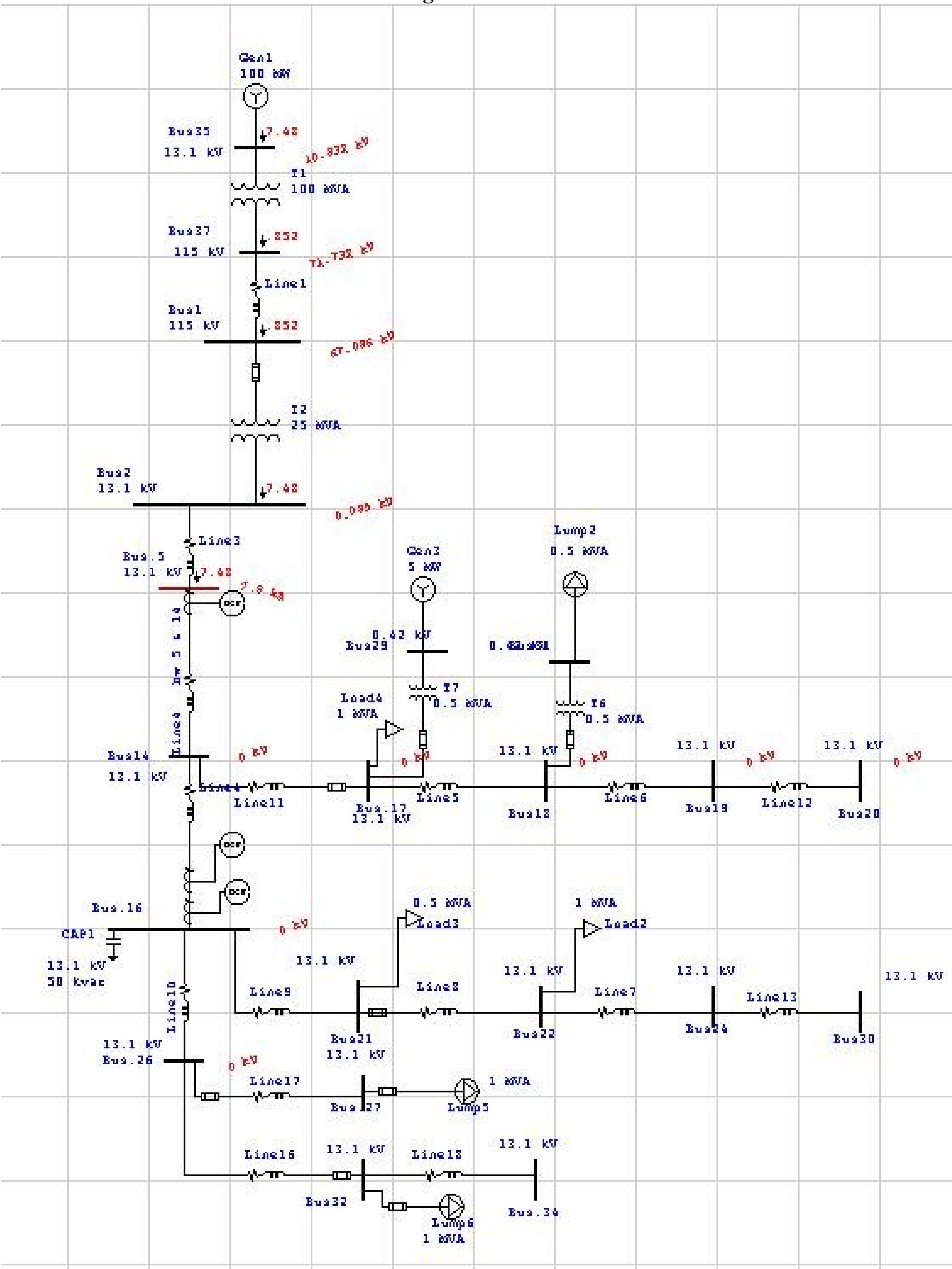
3. Compare the current seen by the relay against its assumed time current characteristic using ETAP.

8. **Rural Distribution System Protection Coordination [3].**

Short circuit analysis was performed on the rural distribution system given in Figure 4. The maximum short circuit current was around 7.5kA for three phase bolted fault at the feeder head end.
A. Details of Study Case.

Distribution substation as shown in Figure 1. This is supplied from a 115 kV line through a 15/20/25 MVA transformer protected by a high-side fuse. The fault values are to calculated in amperes at 13.09 kV for solid faults at the locations shown.

Figure # 3



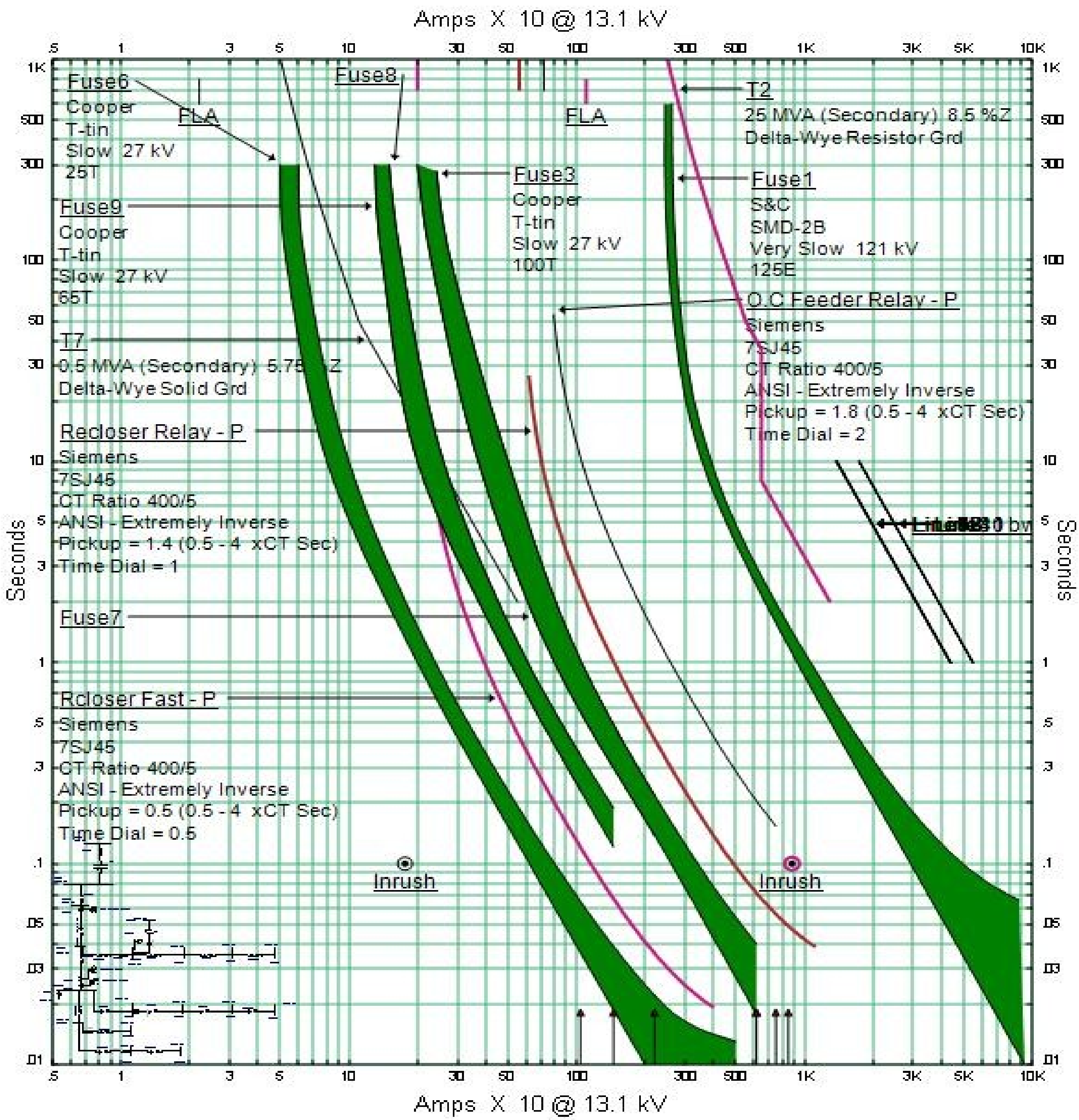
Gen1
100 MW
Bus35
13.1 kV
7.48
T1
100 MVA
Bus37
115 kV
.852
Line1
Bus1
115 kV
.852
T2
25 MVA
Bus2
13.1 kV
7.48
Line3
Bus.5
13.1 kV
7.48
Line4
Gen3
5 MW
Lump2
0.5 MVA
0.42 kV
Bus29
T7
0.5 MVA
T6
0.5 MVA
Load4
1 MVA
Bus14
13.1 kV
0 kV
Line11
Bus.17
13.1 kV
Line5
Bus18
Line6
Bus19
Line12
Bus20
Bus.16
CAP1
13.1 kV
50 kvar
0.5 MVA
Load3
1 MVA
Load2
Line9
Line8
Line7
Line13
Bus21
Bus22
Bus24
Bus30
Line10
Bus.26
Line17
Bus.27
Lump5
1 MVA
Line16
Line18
Bus32
Bus.34
Lump6
1 MVA

9.1 Substation Transformer Protection.

we begin at the high-side fuse, the setting and coordination of the protection are as follows. The maximum load for the 25 MVA tap is **25,000/ SQ. Root (3) x 115 = 125.5 A at 115 kV**

We had selected the 125E fuse for the transformer primary Protection . Its operating close to 250 A is 600 Sec, which should override cold-load and magnetizing inrush transients. The characteristics are plotted on log-log fuse coordinate paper (Figure 4).

Figure #4



Complete Relay Coord.

The amperes at 13 kV side of Transformer is calculated in order to show the Coordination on same voltage level , so the 125E fuse in the 115 kV circuit is plotted at

115/13.09=8.79 times the manufacturer's curves.

Thus, the 600 sec minimum-melt current of 250 A becomes 250 x 8.79 = 2196 A for balanced currents.
Whereas phase-to-phase faults on the 13 kV side are 0.866 of the three phase fault value, the current in one phase on the primary is the same as the three-phase fault value. However, the primary fuse sees only 0.577 of the secondary one-per-unit current for 13 kV phase-to-ground faults. The transformer through-fault over current limit curve is plotted as shown in figure# 4 the transformer is protected satisfactorily against thermal damage.

9.2 Fuse

The 65T and 100T fuses selected on the basis of the loads served from the taps are shown plotted in Figure 5 from the manufacturer's curves. The left curve is minimum melt, and the right maximum clearing.
The maximum load through the recloser is **Max Load = 230 A.**

9.3 Recloser.

A recloser was selected. with a minimum trip rating of 560 A phase, slightly more than twice the load needed to override cold load with a safety factor. The time characteristics units are plotted for the timed and the instantaneous operations. **In this term paper I Simulated Recloser with the Help of E.I O.C relay as the Actual reloser is not available in this limited licensed version of ETAP.**

To provide this instantaneous tripping, phase can be applied to breakers to supplement the time units. Reclosers have either a fast or slow time-current characteristic, of which only one at a time can be used. Several attempts can be made, usually 1-3. The particular number and sequence is based on many local factors and experiences.

9.4 Current Transformer Selection.

The maximum load through the breaker and relays at the 13 kV bus is 330 A. Thus, the CT ratio of 400:5 will give a secondary current of 330/80 = 4.13A.

9.5 Over current Relay

Extremely inverse time over current relays provide good coordination with the fuses and the recloser. Selecting tap 9 provides a phase relay pickup of 9 x 80 = 720 A, just over twice the maximum load needed to override a cold load.

9.6 Fuse-saving

This is used to avoid fuse operations for transient faults and, thereby, avoid long outages for crews to replace them. This is accomplished by a second instantaneous unit set to overreach the fuse and, in the hope to clear transient faults before the fuse can operate. An instantaneous recloser is attempted and, if successful, service is restored. The instantaneous unit is locked out, thereby permitting the fuse to clear a continuing fault. An industry survey by the IEEE showed that 81% use this for phase faults and 61% for ground faults.

Thus, for fuse-saving at the breaker, as in Figure 4, the instantaneous units could be set to operate for fault 2, but not for fault 1, or at 5374 A phase, However, it is important that the instantaneous unit and breaker clear faults before the fuse is damaged (minimum melt) or blown. Figure 5 shows that the 100T fuse will be damaged at about 5000 A after about 0.03 sec (1.8 cycles at 60 Hz). Thus, the fuse will blow before the breaker opens; therefore, fuse-saving is not applicable at the breaker.

Fuse-saving is applicable at the recloser when operating on its fast or instantaneous curves. For faults on the laterals beyond Bus faults (21,27, or 32), the` recloser will trip and recloser once or twice as programmed. If the fault is transient and cleared, service will be restored without a fuse operation. after this, the recloser operates on its slow curves, and the fault is cleared y the proper fuse on the laterals or by the recloser for faults on the feeder.

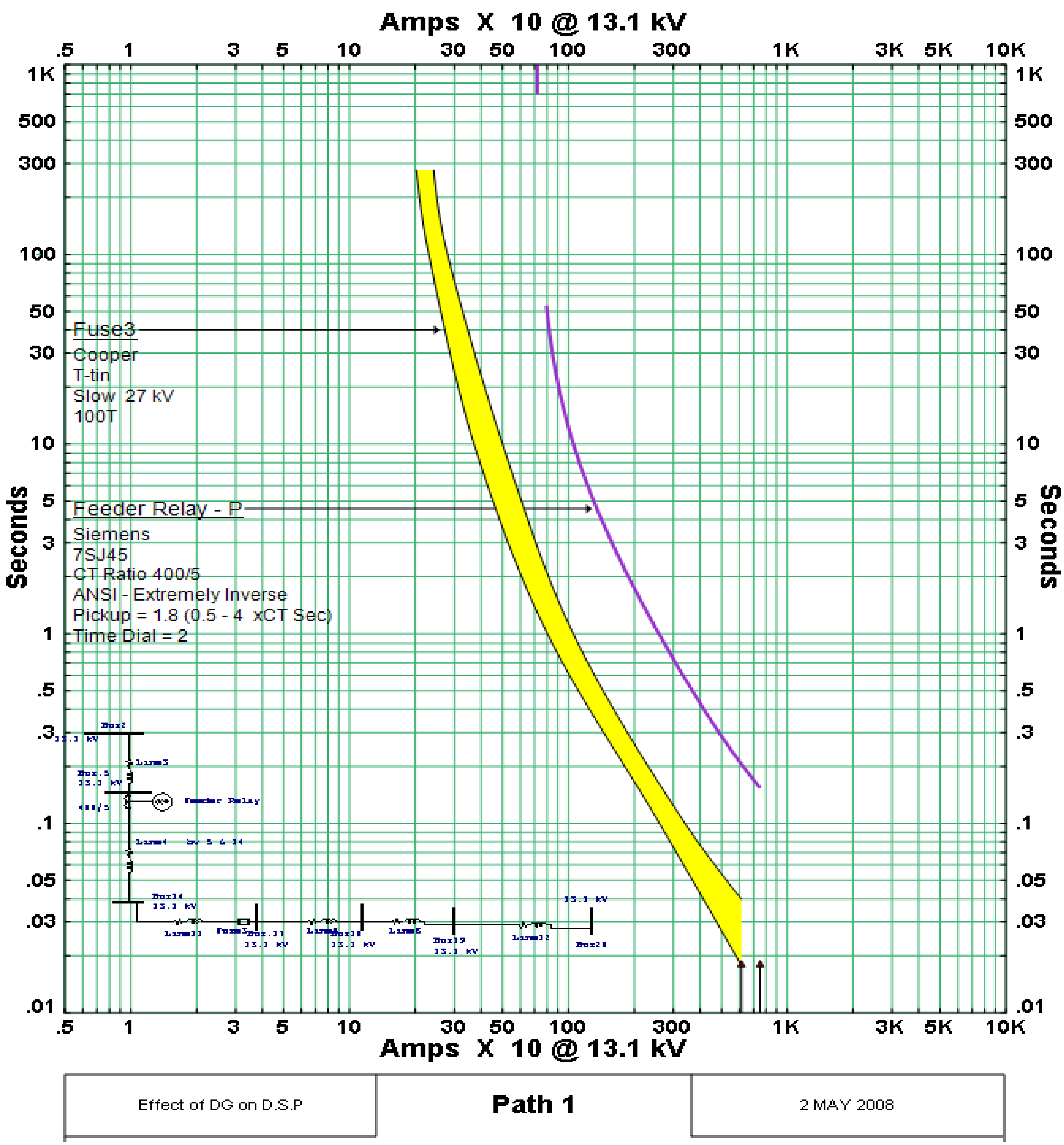
9. **Path Selection. [4]**

In order to analysis of the given case we start with making paths of circuits which are as follows.

9.1 Path 1: From Station Bus 5 to Bus 14 to 20.

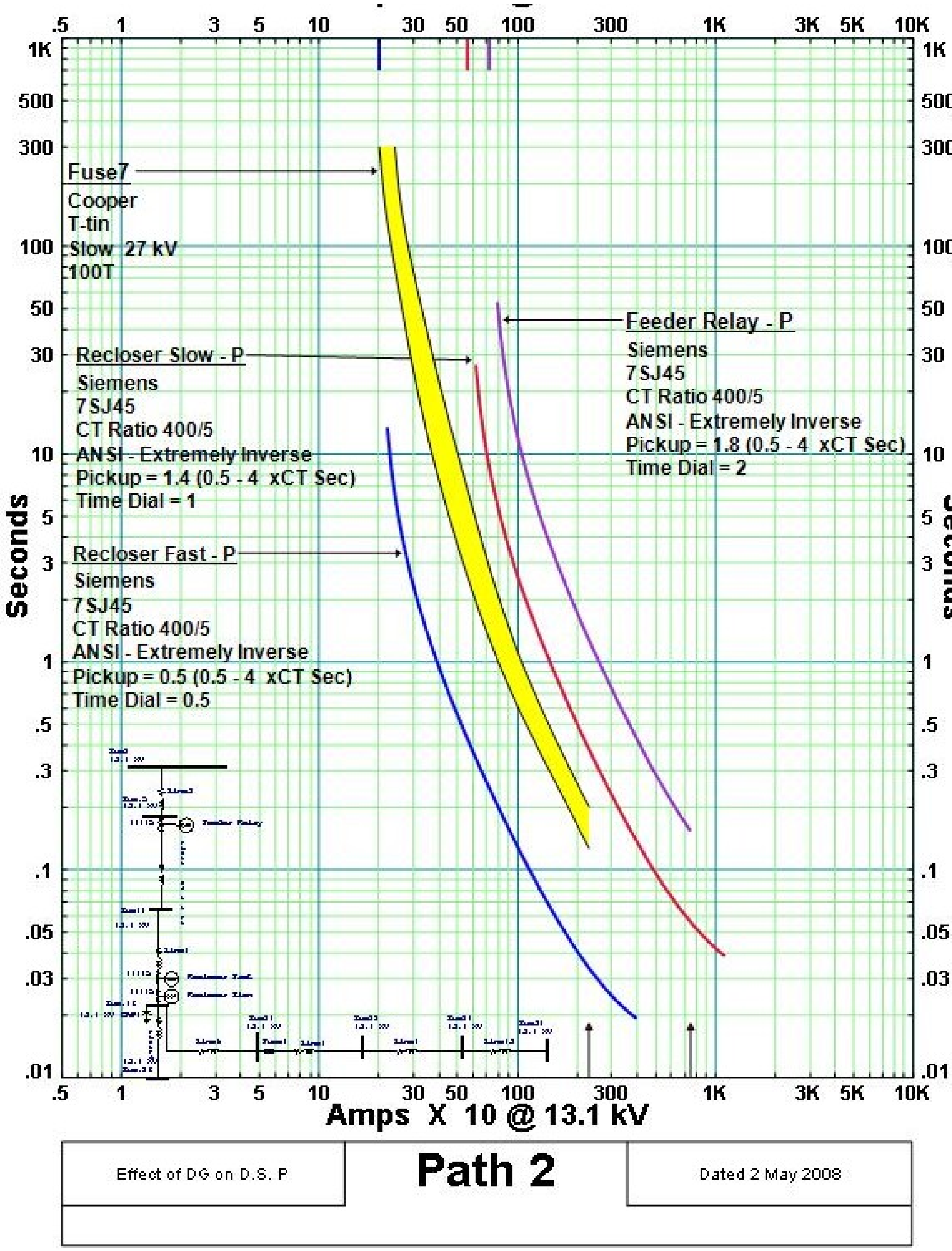
This circuit starts from the main substation Bus 1 and extends towards bus 14 . This path includes the main feeder relay, and the transformer at bus 17. Figure 6 shows the one line diagram as well as the protective device coordination chart for this path. As seen in Figure 6, the fuse F1 (125 E) for primary transformer was chosen such that it will not operate for transformer inrush current values and at the same time coordinates with the transformer damage curve. Also, the majority of the through-fault curve of transformer (T17) (including the damage point, which is at the end of the curve is located over the clearing curve of the fuse. This guarantees safe operation of the transformer under through-fault conditions.

This path is protected by Over current relay and **no fuse-saving is applicable at this Path**.



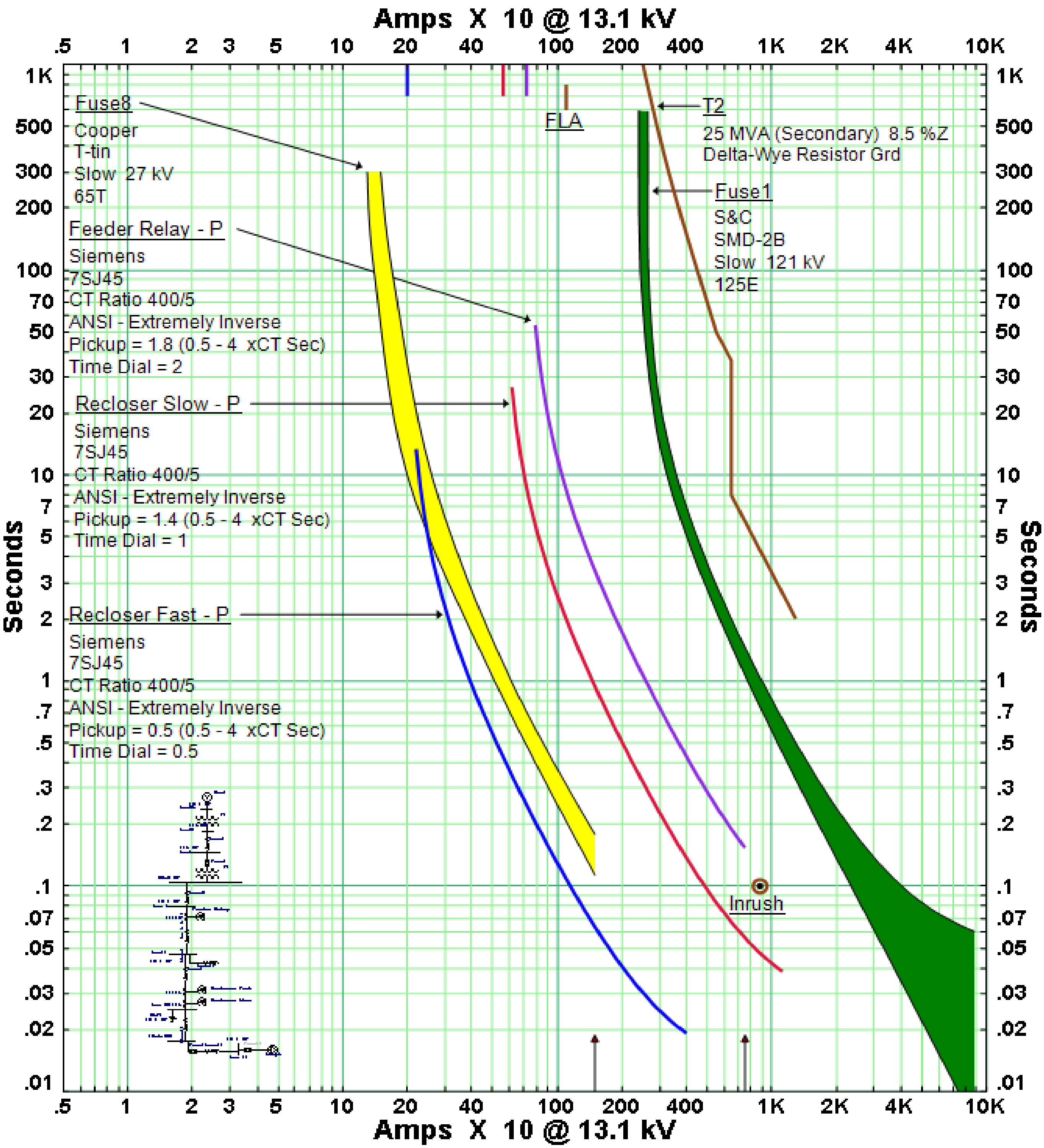
9.2 Path 2: From Station Bus 5 to Bus 24.

This circuit starts from the main substation and extends towards load Bus 24. This path includes the main feeder relay, the recloser, and the main lateral fuse (F7) Figure 6 shows the one line diagram as well as the protective device coordination chart for this path. For this three-phase lateral, the maximum short circuit current is around 2217A. The band-limited coordination between the recloser and the fuse is very sufficient for the maximum short circuit at the fuse location in this case. Furthermore, the upstream relay totally coordinates with the slow curve of the recloser.



9.3 Path 3: From Station Bus 5to Bus 30.

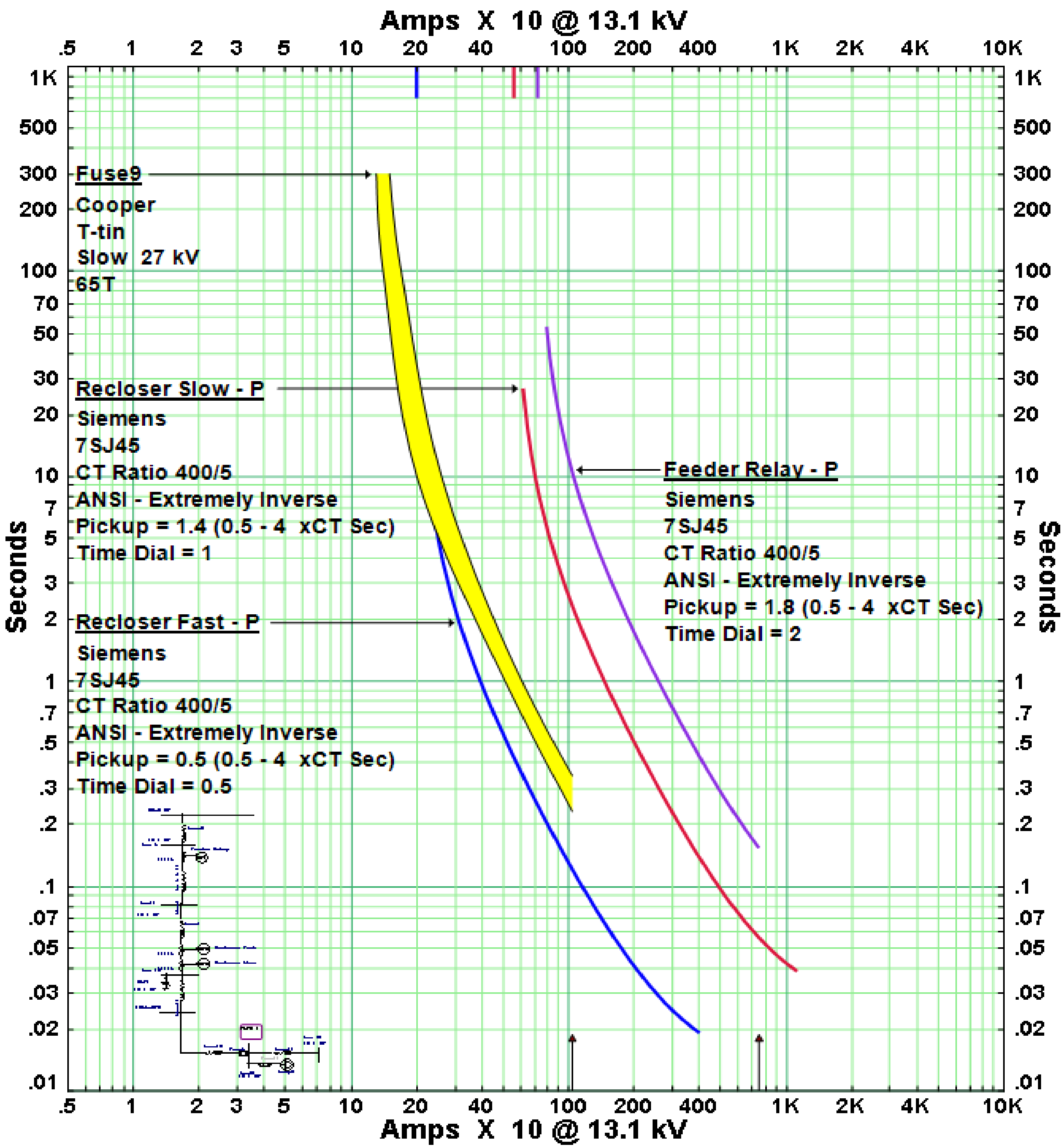
Coordination along this path is similar to Path 2 with 1467 A short circuit current at the fuse location. The band-limited coordination between the recloser and the fuse is very sufficient for the maximum short circuit at the fuse location in this case. Furthermore, the upstream relay totally coordinates with the slow curve of the recloser as shown in figure 4.



Effect of DG on D.S.P	**PATH 3**	05-04-2008

9.4 Path 4: From Station Bus 5 to Bus 34.

Coordination along this path is similar to Path 2 with 1045 A short circuit current at the fuse location. The band-limited coordination between the recloser and the fuse (F32) is very sufficient for the maximum short circuit at the fuse location in this case. Furthermore, the upstream relay totally coordinates with the slow curve of the recloser as shown in Figure #7.



Effect of DG on D.S.P	**PATH 4**	05-04-2008

10 Impact Studies And A Generalized Method To Assess The Impact Of DG On System Protection.[4]

A number of protection issues, such as loss of coordination, de-sensitization, nuisance fuse blowing, bidirectional relay requirements , should be addressed in order to See the impact of DG penetration. In this section, a generalized method to assess the impact of DG on distribution system protection is developed. To simplify the study, each protection impact is studied individually to determine the penetration limit that triggers this issue. Summarized in the Following tables.

WITH OUT DG		WITH DG					
Fault at Bus #	Isc 3 PHASE		DG RATING MW	Utility Isc 3 PHASE	DG Isc 3 PHASE	Total 3 PHASE	Delta in Isc
5	7.455	DG- LOCATION BUS # 17	5	7.45	1.25	8.7	1.245
16	4.405			4.13	0.75	4.88	0.475
17	6.16			6.16	1.3	7.46	1.3
21	2.2			1.96	0.353	2.313	0.113
26	1.457			1.27	0.232	1.502	0.045
32	1.045			0.906	0.165	1.071	0.026
5	7.455		10	6.44	1.66	8.1	0.645
16	4.405			3.87	1.46	5.33	0.925
17	6.16			6.16	2.74	8.9	2.74
21	2.2			1.75	0.658	2.408	0.208
26	1.457			1.12	0.422	1.542	0.085
32	1.045			0.792	0.298	1.09	0.045
5	7.455	DG -LOCATION BUS # 21	5	7.455	0.922	8.377	0.922
16	4.405			4.41	1.01	5.42	1.015
17	6.16			6.06	0.807	6.867	0.707
21	2.2			2.2	1.3	3.5	1.3
26	1.457			1.26	0.289	1.549	0.092
32	1.045			0.89	0.204	1.094	0.049
5	7.455		10	7.45	1.47	8.92	1.465
16	4.405			4.41	1.71	6.12	1.715
17	6.16			6.01	1.28	7.29	1.13
21	2.2			2.2	2.76	4.96	2.76
26	1.457			1.16	0.449	1.609	0.152
32	1.045			0.807	0.313	1.12	0.075
5	7.455	DG- LOCATION BUS # 32	5	7.45	0.623	8.073	0.618
16	4.405			4.4	0.671	5.071	0.666
17	6.16			6.09	0.554	6.644	0.484
21	2.2			2.04	0.311	2.351	0.151
26	1.457			1.46	0.967	2.427	0.97
32	1.045			1.05	1.3	2.35	1.305
5	7.455		10	7.45	1	8.45	0.995
16	4.405			4.41	1.1	5.51	1.105
17	6.16			6.05	0.875	6.925	0.765
21	2.2			1.95	0.489	2.439	0.239
26	1.457			1.46	2.22	3.68	2.223
32	1.045			0.733	1.12	1.853	0.808

11.1 Impact Assessment

In normal operation, protection devices are coordinated such that the primary protection operates before the backup can take action. Interconnecting the DG increases the short circuit level. Depending on the original protection coordination settings along with the size, location and type of the DG, uncoordinated situations may be yielded. In these situations, the backup operates before the primary, which results in nuisance tripping to some of the loads.

11.2 The impact of DG on the loss of coordination.

Consider the given system, with a 5 MVA synchronous-type DG connected at bus 21 through a Gnd Wye (pri)/Delta (sec)Y interconnection transformer. the coordination chart for the coordination path from the utility to bus34 . As shown in Figure 7, the short circuit current at bus 32 before installing the DG was 1.045K A, so, the recloser and the fuse are fully coordinated at this value of Short circuit current. For the coordination chart in Figure 7, the coordination is maintained up to a short circuit current level equals to 4000A, which is the intersection point between the fast curve of the recloser and the clearing curve of the fuse. If the short circuit current is increased beyond this limit, the coordination between the recloser and the main lateral fuse will be lost.
In our case with the addition of Two DGs at Bus 21 and Bus 27 the total fault current of 837 amps flows from both the DGs and 732 Amps flow from Utility. The Total Amps which Flows from Fuse F 9 is 1500 Amps . The Recloser will only see the 732 amps and Will not see the Current from both the DGs. The Recloser will operate in 0.25Sec, and the Fuse F 9 operated in 0.18 Sec with a Fault current of 1500 Amps as Shown in the Figure # 7. This is the Case of Miss coordination and the Fuse Saving has been Lost.

The fuse coordination and sympathetic tripping examples discussed in the preceding material are but a few of the fault current issues we need to worry about. Other problems
caused by fault current contributions include operation of network protectors, confusion of sectionalizing switch fault sensing circuits, improper logging of faulted circuit indicator devices, and exceeding breaker interrupting ratings. All of these fault-current related issues are essentially problems associated with high-penetration distribution connected DG environments (either through aggregation of many small energy source sites or a few large sites).

11.3 Loss of Sensitivity.

The limit of low of Sensitivity is high the Simulations show that the Two DGs with Capacity of 10 Mva are installed at Bus 14 and 17 the Total fault current was 14000 Amps and the Over Current relay Sense only 7.01 Amps and trip the Breaker in 1.06 Sec. Although the Fault current is 14000 Amps.

11.4 Bidirectional.

Low-penetration environments rarely, if ever, need to worry about any of these issues. The fact that to date the penetration level of DG on most feeders is very low explains why these issues have not been a widespread problem. As seen in the below case the Bi Directionality is not seen with a low Penetration of DGs, The Simulation shows that Two DGs with the Capacity of 15 MVA Each are installed at Bus 14 and 17 With the Total Fault current of 7340 Amps for a fault on bus 2 on an Another feeder Which cause the Over Current to Trip falsely. The detail of Protection Coordination is shown in the Table below.

Dg location	DG #1 MVA	DG #2 MVA	DG Isc	DG Isc Total	Utility ISC	Total IS	Recloser Isc	Recloser Time	Fuse Isc	Fuse Trip Time	Comments.
Bus # 21	5MVA		0.167	0.837	0.732	1.5	0.732	0.25	1.5	0.18	Miss Coordinatio
Bus # 27		5MVA	0.67								
Bus # 21	5MVA		0.287	1.257	1.27	2.5	1.27	0.09	2.5	0.05	Miss Coordinatio
Bus # 32		5MVA	0.968								
Bus # 17	10MVA		3.72	5.2	7.01	14	NA	NA	NA	1.06	Loss of Sensitivit
Bus # 14		10MVA	3.27								
Bus # 14	15MVA		3.62	7.34	7.53	14.87	OC Amps	NA	NA		Bi- Directionality
Bus # 17		15MVA	3.72				7.53				

12 Conclusions And Recommendations

The coming of high-penetration DG to the power system will force a reevaluation of the strategy that the industry is currently using for integration of DG and other types of DG resources. The increasing presence of DG on the system will force a move from the current strategy, which essentially involves integrating DG onto the system as a “passive” or “neutral” player with the minimum impact possible, to a strategy that involves the “active participation” of DG resources with system power dispatch operations, voltage regulation, reactive power balance, reliability management (intentional islanding), and service restoration operations.

With the changing role of DG will come major changes in the utility system protection, controls, and equipment configurations that must be utilized. The DG equipment itself will also need to change—inverters, synchronous generation and induction generators will need more communication ports, transfer trip capability, reactive power features, and new modes of operation such as intentional islands and micro grids.

I conclude that changes in design and practices and operating modes will be necessary to create a 21st century power system with a high-penetration of DGs.

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