Using modeling techniques to determine the protection and control requirements for distributed generation networks.

M.Sc Thesis

Course Title: Energy and the Environment

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Acknowledgements

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Introduction

Renewable energy is being promoted as the way forward to meet worldwide energy needs in the near future. The renewable technologies have come to the fore due to the recognition by government's world wide that future energy requirements may not be met due to the depletion of fossil fuels, coal, oil and natural gas. The UK is expected to completely deplete known reserves of natural gas in the next 12 years [1] at current extraction rates. The energy white paper compiled by British Energy states that 70% of the UK electricity requirements would be met by natural gas generation. This raises questions regarding reliability, as the natural gas will be imported. Another reason driving renewable energy generation is climate change; it is believed that use of fossil fuels to produce electricity is producing green house gases such as Carbon Monoxide, Carbon Dioxide and Nitrous oxide. These gases are released into the atmosphere from the electricity generating stations, and it is believed that the gases are contributing to the depletion of the ozone layer, which results in the suns radiation being trapped in Earth's atmosphere with the resulting effect of a global surface temperature increase.

Governments worldwide have come together to address the issues of fossil fuel depletion and climate change while energy needs increase globally. This consultation has resulted in energy targets being applied to each country to increase use of renewable energy technology and decrease dependence on fossil fuels. The UK target is 10% renewable generation by 2010 and 20% by 2020 [2]. In Scotland the target is 18% by 2010 [3] and 40% by 2020 [3]. The UK government is providing incentives to developers to connect the generation to the electricity grid such as 10 year guaranteed selling tariffs. The developed sources of renewable generation that are currently being connected are wind-power, off shore wind-power, tidal energy, biomass, and solar power. The most common technology being connected to the grid currently is wind turbines. The system operators of the transmission and distribution network are trying to connect as much renewable generation as possible as they are obliged under the renewable energy obligation to produce a percentage of their generation by carbon free sources. If they do not meet their carbon free generation targets they must pay a fee to compensate for the electricity not produced using a renewable source this currently stands at £30/MWh [2]. Therefore it is in the interest of the system operators to aid in the connection of the renewable generation.

The distribution system in Scotland is in the form of radial networks, in England it is mostly radial, but there is a section in the Midlands operated by Manweb that operates as a ring configuration. The distribution network has historically been passive i.e. flow of electricity has been from the generating centres at transmission level to the lower distribution networks at lower voltage. With the introduction of renewable generation many of the connections are at distribution level, which can introduce a bi-directional flow of power through the distribution network. The connections are made at distribution level because much of the best natural resource for use with these technologies is within rural areas; this is particularly true of wind-power generation in Scotland. Another consideration for a developer is the cost of connection for the generation. The higher the connection voltage the more expensive the connection as the network is required to be more secure at higher voltage.

The aim of this project has been to determine the effect on the electrical protection settings and performance when embedded generation (in this case a small wind farm) is added to a distribution network. The network topology chosen for the project was a radial network, as it is typical of the network configuration at distribution level in Scotland and much of the current wind-power development is happening in rural areas of Scotland. The protection chosen for the first part of the project was an overcurrent protection relay with Inverse Definite Minimum Time (I.D.M.T.) as this is typical of the protection employed on most distribution feeders. The network was modeled in PSS/E Power System Simulator for Engineering [4]; it is a 10-feeder network from 132kV to 11kV [diagram 1]. The study of the protection system has been confined to the 11kV feeders, as this is where it is assumed that the distributed generation would be connected. It is assumed that the overcurrent or fuse protection on the load feeders grades with the main feeders on the same busbar. The second section of the thesis proposes a method of employing directional protection on the same radial network to ascertain whether directional protection could be a primary or backup protection to the IDMT protection to ensure all faults are cleared. The third section of the thesis will provide a synopsis of the current developments with loss of mains and the reasons why this protection is important to the safe operation of wind farms. Section 4 of the thesis will provide a budget cost for the connection of a wind Turbine to the distribution network.

Section 1

1.1 Method

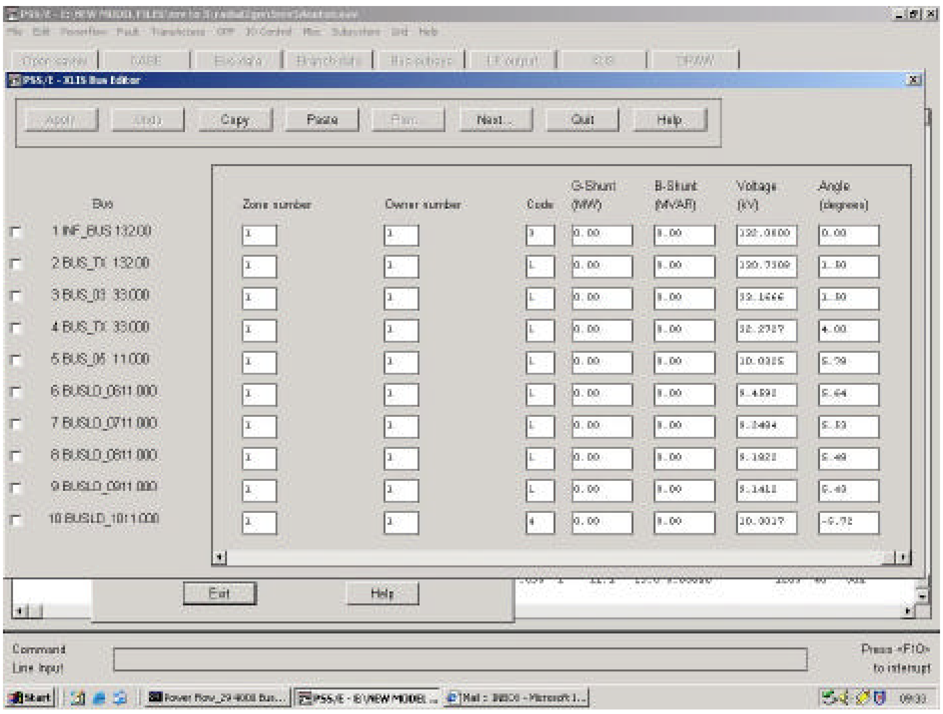
This chapter will investigate the changes required if any when distributed generation is added to a previously passive network. The majority of the data used for the network was taken from other models; the remaining information was taken from manufacturers catalogues. Firstly a passive network was created in PSS/E [4], a loadflow and fault analysis for a 3-phase fault was run within PSS/E [4]. These results were used to calculate settings for the protection assumed to be on the 11kV distribution network. The protection relay used for secondary injection was an overcurrent relay with earthfault capability. The settings within the relay were changed to represent each feeder on the 11kV network. An injection test set was used to inject the results of the fault levels gained from the fault study into the relay. The trip times of the relay were recorded and the wind turbine data was added to the network. The load flow and fault study was run again within PSS/E for 1, 2, 3 and 5 wind turbines connected to each of the 11kV feeders. The resulting fault levels were injected into the protection relay and the trip times recorded. A comparison is made of the trip times for each configuration to investigate what changes if any would be required to ensure the distribution network remained operational with distributed generation as part of the distribution network.

1.2 Equipment Description

These pages will provide a description of the equipment used during the project.

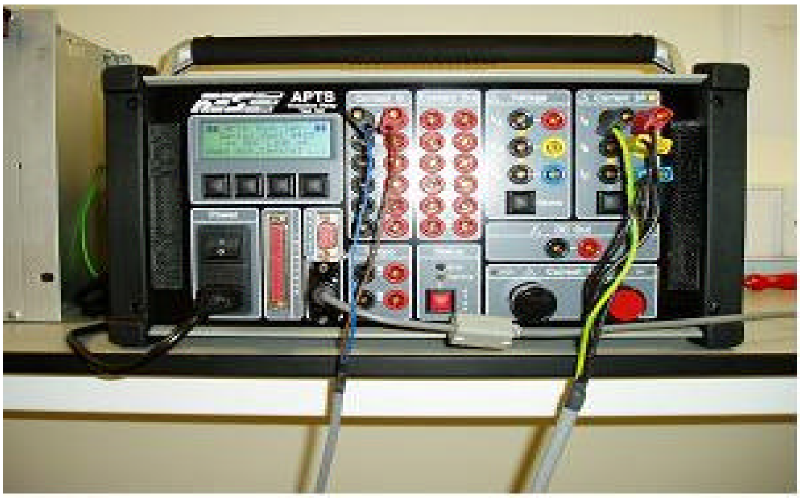
1.21 PSS/E – Power System Simulator for Engineers

PSS/E [4]; is a software package used to model and simulate electrical networks. The network is defined in a windows or text based environment by choosing parameters such as number of busbars, cable impedance and length, generator power and impedance etc. The network once defined, can then be solved to determine the loadflows within the network. Faults can also be placed on the network to determine fault levels throughout the network. PSS/E V29.2 Loadflow was used to model and simulate the distribution network used for this project.



1.2.2 APTS - Automatic Protection Test Set

Relay Engineering Services APTS test set [5] is a secondary injection test set used primarily to test protection relays. Secondary injection refers to the secondary side of the measuring transformer attached to the protection relay. The test set is used to inject the protection relay with current and voltages at secondary transformer level to test the functionality of the relay. The relay converts these values to the primary value equivalent. The fault levels used for the secondary injection were taken from PSS/E [4].



1.2.3 Laptop Computer

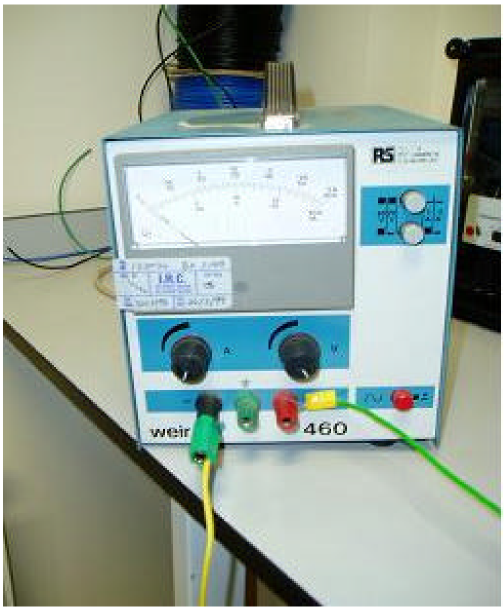
The laptop computer is used to drive the APTS test set [5]. Injection current and voltage values are input within the APTS software on the laptop and transferred to the test set by a parallel port connection.

1.2.4 Areva Micom P122 Relay

This relay is an overcurrent and earthfault protection relay manufactured by Areva [6]. This relay is used to detect the occurrence of an abnormal condition involving current and send a signal to a circuit breaker or equivalent to interrupt the fault. These relays are multifunctional and can also be used for undercurrent trip, trip circuit supervision and automatic reclose, as well as overcurrent protection, and in addition they provide a records feature which records fault current levels during a disturbance. This relay was injected with fault currents in order to analyse the trip time patterns.

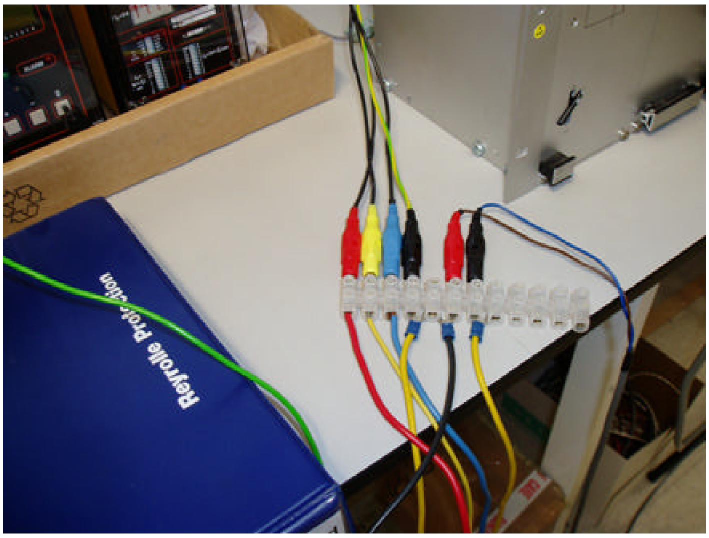
1.2.5 Auxiliary Power Supply

This is a dc power supply that was used to provide the auxiliary power to the protection relay.

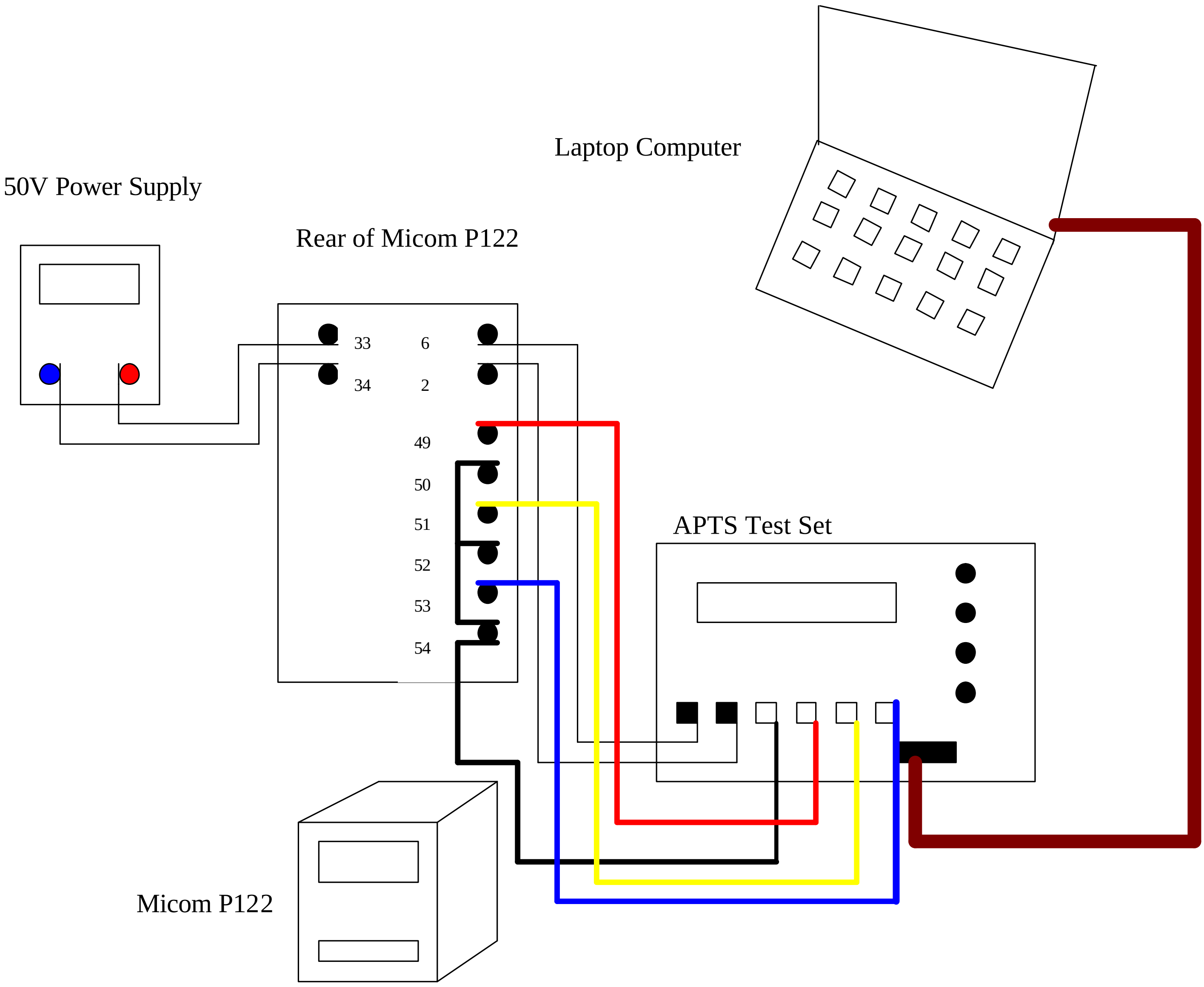


1.26 Power wiring 2.5mm

These cables were used to connect the auxiliary supply to the relay and the relay to the test set.



Equipment Connection Diagram *Figure 1*



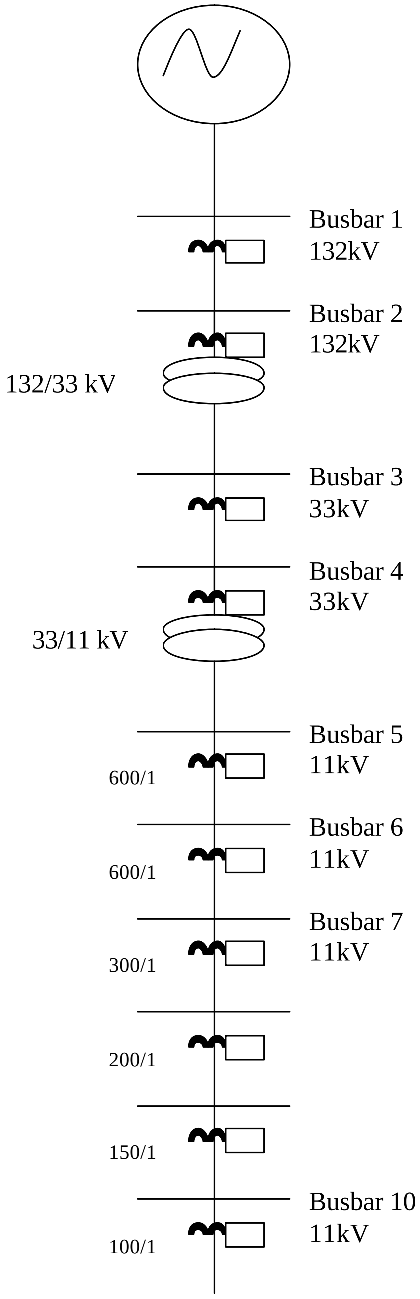
1.3 Network Description

Wind turbines are built mostly in rural areas to enable capture of the greatest possible wind resource. The configuration of the model for PSS/E [4] was based on this premise but with connection of the wind turbines at 11kV instead of 33kV. This is more difficult as the utility companies only allow voltage level limits of between +/- 10% of the nominal value. The parameter values used to model the radial network were taken from different sources. The generator and transformer data were taken from another working model and the cable data and wind turbine data were found from manufacturer catalogues. The load data was taken from a working model and used to represent a rural community with local shopping and some local businesses. The load on feeder 6 was modeled for a commercial load, feeder 7 and 8 were modeled for rural residential load and the load on feeder 9 and feeder 10 was modeled to represent a small shopping complex. Network diagram is represented in figure 2.

The network has 3 voltage levels within the network and 10 branches. The configuration consists of the main generator connected to a 132kV busbar at the top of the network and the loads are all connected at 11kV. Initially no distributed generation was connected to the network. Is has been assumed that an IDMT relay is connected at each feeder; these are not modeled within PSS/E [4]. A loadflow analysis and fault analysis were carried out on the PSS/E [4] model; these values were used to calculate settings for the IDMT [4] relays connected to the feeders on the 11kV network.

Network Diagram

Figure 2



Inverse Definite Minimum Time Settings			
Busbar	Iset	In	T.M.S.
10	0.87	100	0.125
9	0.9	150	0.225
8	0.87	200	0.325
7	0.96	300	0.375
6	0.75	600	0.425
5	0.83	600	0.55

1.31 Load Flow

The model was created in PSS/E [4] and checked for consistency using the TREE tool within PSS/E [4]. The load flow was then calculated using the Gaussian analysis tool within PSS/E [4].

The results display the power flow through the network and the voltage at each busbar. The current load flow was used to determine the current transformer settings that would be used with relays. These voltage and current levels are tabulated below. The complete loadflow results are listed within appendix B.

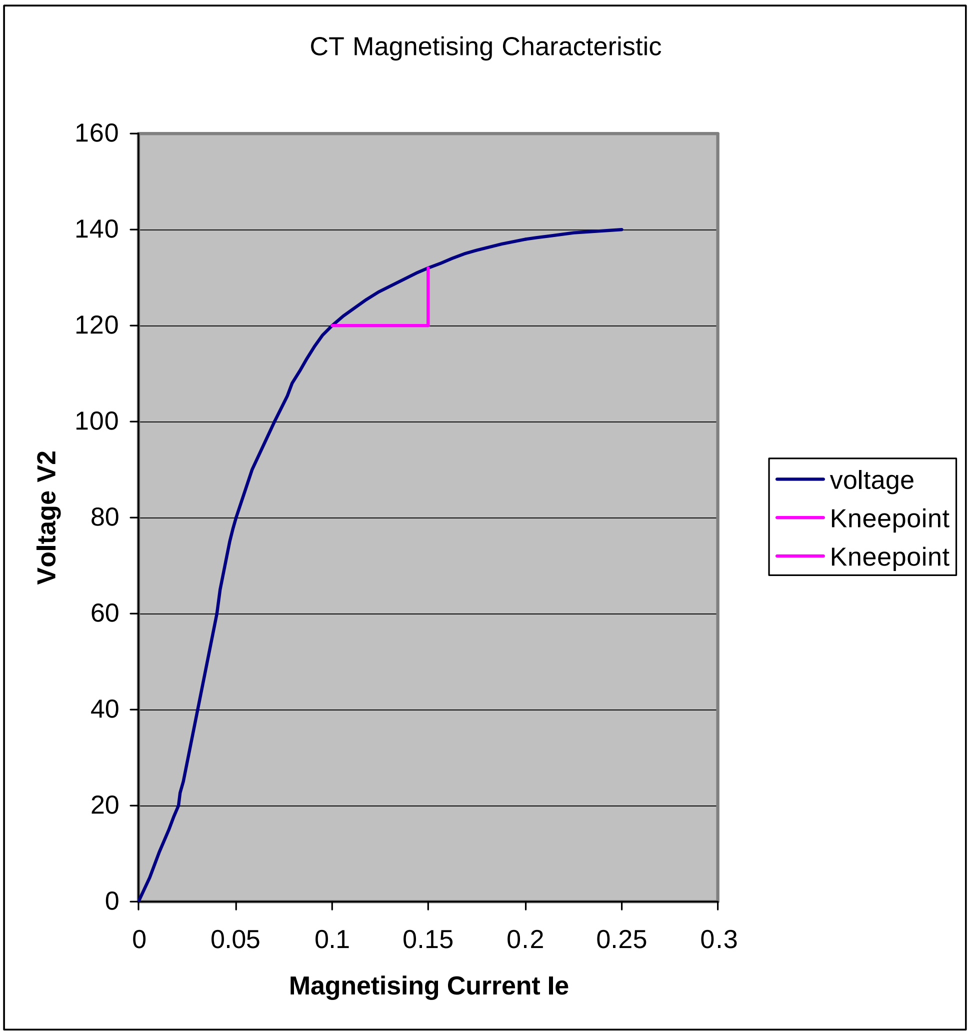
Busbar	1	2	3	4	5	6	7	8	9	10
Voltage kV	132	130.6	33.91	33.2	11.32	10.76	10.52	10.43	10.35	10.3
Angle ?	0	0.1	-2.7	-2.9	-5.3	-5.5	-5.6	-5.6	-5.7	-5.7
Loadflow A	52	52	52	196	560	560	240	152	99	53
Load	-	-	-	-	-	320	88	53	46	53
CT Ratio	-	-	-	-	600/1	600/1	300/1	200/1	150/1	100/1

Figure 3

1.32 Current Transformers

The current transformer ratios were based on the system maximum loading conditions at the time of analysis. In practical situations account would be taken of future load increases, this would be carried out to reduce the cost of equipment when increase/decrease in load requirements occurred. The choice of current transformer will also depend on the burden being placed on the CT, the short time factor, the accuracy limit factor, and the knee point voltage. The burden is the load placed on the CT, for example the burden for a 1 Amp at 5VA would be 5 Ohms; the error of the CT will increase with a greater burden on the current transformer. The short time factor is the amount of current above rated level that the CT can withstand without damage to the CT, this would apply during a fault situation were the current flowing through the CT will be many times the rating. The short time factor is normally expressed as a multiple of the rating and will also have a withstand time associated with it. The accuracy limit factor is a measurement of the accuracy of the CT at a multiple of rated current. The CT would typically be described as a 5P20 this means 5% accuracy at 20 times rated current. Values of accuracy limit factor and short time rating are documented within the British and European Standards, for measurement transformers the British Standard is BSEN60044-1 1999 [7] [8]. Finally the knee point voltage is used as a measure of the ratio error of the CT. The magnetizing current is essentially a measure of the error within the CT, it is very small at rated values but steadily increases as the burden on the relay increases, this results in a decrease in the accurate measurement ability of the CT and increases the probability of high induced voltages across the CT, this can lead to overheating and insulation breakdown.

Figure 4



CT Magnetising Characteristic
Voltage V2
0
20
40
60
80
100
120
140
160
0
0.05
0.1
0.15
0.2
0.25
0.3
Magnetising Current Ie
voltage
Kneepoint
Kneepoint

1.33 Voltage

The voltage steadily decreases as we move down the radial network away from the generation source. This is expected as the impedance increases with distance, therefore the voltage drop from the generator source is increased. In a practical situation the voltage on a network must be controlled and operate within an upper and lower limit. A prospective owner/operator of distributed generation must comply with the standards that the utilities work to. Engineering Recommendation G59/1[9] states the operational voltage limits that equipment connecting to the Grid must operate within. This standard states that the voltage limits can be +/-10% of the nominal voltage level. This is a more difficult condition to meet at a lower voltage; this could be one reason to connect distributed generation at 33kV, although the connection charge to the utility is greater. There are methods employed to increase or decrease the voltage level to within the voltage limit required. These methods include tap changing transformers, inductive or reactive compensation, and using the generators themselves to produce or absorb VArs depending on the line voltage.

1.34 Fault Conditions

Fault calculations were carried out within PSS/E [4] to ascertain the fault level at each busbar. This value could then be used to calculate the plug setting and the time multiplier setting for an overcurrent fault at each feeder within the 11kV network. The calculated plug setting and the time multiplier setting would be the settings used throughout the project as a benchmark, as one of the aims of the project is to ascertain what changes to the feeder protection would be required when distributed generation is added to the network. The fault level calculation was carried out for a 3-phase fault. This is the most onerous fault condition in terms of fault level that equipment could be exposed to. The maximum fault level was calculated for a 3-phase fault at each busbar using the fault calculation software within PSS/E [4]. Within PSS/E [4] different impedances can be specified for the positive and negative and zero sequence networks for fault calculation. The sequence impedances were made equal for the fault calculation models used within PSS/E during the project [10].

The 3 phase fault levels calculated are listed in the table below, only the fault levels from busbar 5 to 10 will be displayed from now on as the analysis is focused on the 11kV network. The full file is displayed within appendix B2.

Busbar	5	6	7	8	9	10
Fault Level A	4254.5	3400.1	2701.9	2382.8	2045.1	1726.5

Figure 5

1.35 Grading Margin

To continue supplying power to sections of the network when there is a fault lower down the network the overcurrent relays on feeder 5 to 10 must discriminate with each other. This means that for a fault on busbar 10, the relay at busbar 10 must operate first before the relay at feeder 9. This is very important in order to keep the disruption to the network to a minimum. Therefore a grading margin is employed between each set of relays. The grading margin can be calculated using different formula depending on the relay type. The different formula, provide approximately the same answer. The calculation used for the grading margin in the experiments for the project was taken from the G.E.C. Protection Relay Application Guide (P.R.A.G.) [14] and consists of four main criteria, circuit breaker operation time, the overshoot time of the relay, errors within the relay and CT's and the contact gap which is the period of time allowed to ensure that a relay still has a short distance to travel when the fault is cleared by the relay with which it is discriminating.

E_r = Relay timing Error

E_{ct} = Allowance for CT ratio error

t = Nominal operating time of relay nearest the fault

t_{cb} = Circuit breaker interrupting time

to = relay overshoot time

ts = Safety margin (s)

$$t' = [2E_r+E_{ct}/100]*t + t_{cb} + to + t_s \text{ (s)}$$

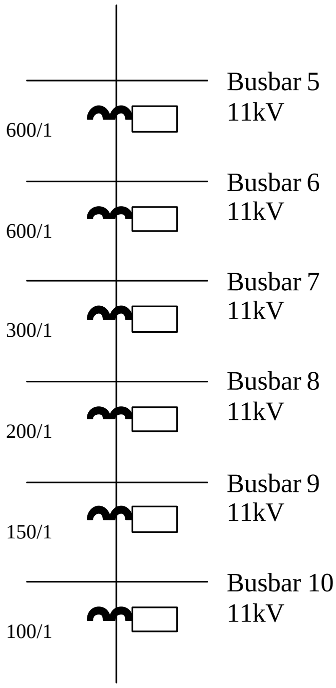
$$t' = 0.075*0.1+0.1+0.05+0.05$$

$$t' = 2.75 \text{ seconds}$$

The values used within the calculation were taken from P.R.A.G. [14] and were approximate, an extra 0.25s was added for errors within the approximation, therefore the minimum, grading margin required between relays operation is 0.3 seconds.

Network Diagram 11kV Distribution Network

Figure 6



1.36 IDMT Calculation for Relay Settings

The plug setting and the time setting multiplier for each relay on the 11kV feeder network must now be calculated, to enable injection of the overcurrent relay with secondary current representations of the primary fault level. The calculations for the IDMT settings were based on the induction disc standard inverse operating curve for a GEC induction disc relay [15]. These settings were then adapted to the Micom setting structure. The microprocessor relay has a similar curve to the induction disc relay but the setting criteria within the relay are slightly different. The Micom uses Iset instead of plug setting. The Iset setting can be defined to 0.01 of the CT ratio, the T.M.S. in the Micom relay is defined in steps of 0.225.

The formulas used for the calculations are:

Formula 1

Plug Setting (P.S.) = Fault level/ (20*Sec.CT Value*ct prim/ct sec)

Formula 2

Plug Setting Multiplier (P.S.M.) = Fault level/ (Plug Setting*Sec.CT Value*CT Prim/CT sec)

Formula 3

T characteristic (Tchar) = 0.14/ (p.s.m.$^{0.02}$-1)

Formula 4

Time multiplier setting (T.M.S.) = Trequired/Tchar

The plug setting can be set in steps of 0.25 and the T.M.S. can be set in steps of 0.125. The trip time required for the relay on feeder 10 is 0.25 seconds; therefore relay 9 must trip in 0.55 seconds. The setting process begins by calculating the setting for the relay on feeder 10.

Feeder 10 - IDMT Settings

P.S.

=1726.5/ (20*1*100/1)

P.S. = 0.86

Closest plug setting is 1.00.

TChar

$=0.14/ (17.265^{0.02}-1)$

Tchar = 2.39 s

P.S.M.

= 1726.5/ (1*1*100/1)

P.S.M. = 17.265

T.M.S.

= 0.25/2.39

T.M.S. = 0.105

Closest plug setting is 1.00.

Feeder 9 - IDMT Settings

P.S.

=2045.1/ (20*1*150/1)

P.S. = 0.68

Closest plug setting is 0.75.

TChar

$=0.14/ (18.18^{0.02}-1)$

Tchar = 2.34 s

P.S.M.

= 2045.1/ (0.75*1*150/1)

P.S.M. = 18.18

T.M.S.

= 0.55/2.34

T.M.S. = 0.235

The minimum time required for the relay to operate is 0.55 seconds.

Feeder 8 - IDMT Settings

P.S.	**TChar**
=2382.8/ (20*1*200/1)	=0.14/ ($13.6^{0.02}$-1)
P.S. = 0.6	Tchar = 2.61 s
Closest plug setting is 0.75.	

P.S.M.

= 2382.8/ (0.75*1*200/1)

P.S.M. = 13.6

The plug setting multiplier and trip time is now calculated for a fault at feeder 9.

P.S.M.	**TChar**
= 2045.1/ (0.75*1*150/1)	=0.14/ ($18.18^{0.02}$-1)
P.S.M. = 18.18	=2.34s

The minimum time required to trip the feeder relay at 8 can now be calculated and from the trip time the time multiplier setting.

Treq	**T.M.S**
=2.34*0.235+0.3	=0.85/2.61
=0.85s	=0.326

Feeder 7 - IDMT Settings

P.S.	**P.S.M.**
=2701.9/ (20*1*300/1)	= 2701.9/ (0.75*1*300/1)
P.S. = 0.45	P.S.M. = 10.6
Closest plug setting is 0.5.	

There would be no load discrimination between relay 7 and relay 8, as both relays will start to operate at 150Amps. Therefore the Plug setting at 7 shall be increased to 0.75.

TChar

$=0.14/ (10.6^{0.02}-1)$

Tchar = 2.9 s

The plug setting multiplier and trip time is now calculated for a fault at feeder 8.

P.S.M.	**TChar**
= 2382.8/ (0.75*1*200/1)	$=0.14/ (15.89^{0.02}-1)$
P.S.M. = 15.89	=2.46s

The minimum time required to trip the feeder relay at 7 can now be calculated and from the trip time, the time multiplier setting.

Treq	**T.M.S**
=2.46*0.326+0.3	=1.1/2.9
=1.1s	=0.38

Feeder 6 - IDMT Settings

P.S.	**P.S.M.**
=3400.1/ (20*1*600/1)	= 3400.1/ (0.5*1*600/1)
P.S. = 0.28	P.S.M. = 9
Closest plug setting is 0.5.	

The relay 6 will not begin to creep until 300A: relay 7 will begin to creep at 225A. Discrimination is okay.

TChar

$=0.14/ (9^{0.02}-1)$

TChar = 3.12 s

The plug setting multiplier and trip time is now calculated for a fault at feeder 7.

P.S.M.	**TChar**
= 2701.9/ (0.75*1*300/1)	$=0.14/ (12.01^{0.02}-1)$
P.S.M. = 12.01	=2.75s

The minimum time required to trip the feeder relay at 6 can now be calculated and from the trip time, the time multiplier setting.

Treq	**T.M.S**
=2.75*0.38+0.3	=1.345/3.12
=1.345s	=0.43

Feeder 5 - IDMT Settings

P.S.

=4254.5/ (20*1*600/1)

P.S. = 0.35

Closest plug setting is 0.5.

P.S.M.

= 4254.5/ (0.75*1*600/1)

P.S.M. = 7.6

There would be no load discrimination between relay 6 and relay 5, as both relays will start to creep at 300 Amps. Therefore the Plug setting at 5 shall be increased to 0.75.

TChar

=0.14/ ($7.6^{0.02}$-1)

TChar = 3.05 s

The plug setting multiplier and trip time is now calculated for a fault at feeder 6.

P.S.M.

= 3400.1/ (0.5*1*600/1)

P.S.M. = 11.33

TChar

=0.14/ ($11.33^{0.02}$-1)

=2.81s

The minimum time required to trip the feeder relay at 5 can now be calculated and from the trip time, the time multiplier setting.

Treq

=2.81*0.43+0.3

=1.51s

T.M.S

=1.51/3.05

=0.5

1.37 Calculating Iset for Micom relay

To adapt the settings calculated for an induction disc relay to the settings required for the Micom relay required calculating the Iset setting using the Micom standard inverse equation. This equation is:

$$t = T*(k/ (I/I_s)^{?} -1$$

t = trip time

T = time multiplier setting

k = 0.14 (Standard Inverse)

I = value of measure current

Is = programmed pick up value (fault level)

? = 0.02

All of the parameters had already been calculated except the Iset setting, which is the current value programmed within the relay that will activate the timed overcurrent function within the Micom relay. Activation of this function does not necessarily result in a trip operation. An example of the calculation for feeder 10 is shown below; similar calculations were carried out for the remaining feeders.

$$t = T*(k/ (I/I_s)^{?} -1$$

First re-arrange formula in terms of I_s.

$$I_s = I / {}^{?}?((k*T/t) +1)$$

Now calculate Is.

= 1726 / (0.02? ((0.14*0.125/0.25)+1))

= 58.64 Amps.

1.371 Modifications to Iset Value

This Iset value was too low for the Iset setting as the load expected on the radial feeders was 53Amps and if the loading increased slightly and was constant over a long time period the relay would eventually trip. Therefore the Iset value was increased to 0.87In, which would be 87 primary amps. Increasing the Iset value increased the operation time of the relay. The difference in operation times can be viewed in the results summary. The calculated value of Iset and the actual value for the remaining feeders are summarized below. The calculations are within appendix C1.

Feeder	Iset Calculated	Iset Setting
5	0.62	0.83
6	0.66	0.75
7	0.88	0.96
8	0.88	0.87
9	0.85	0.9
10	0.59	0.87

Figure 7

1.38 Summary of IDMT setting

	Calculated Setting		Relay Settings	
Feeder	P.S.	T.M.S.	Iset	T.M.S.
5	0.75	0.5	0.83	0.55
6	0.5	0.43	0.75	0.425
7	0.5	0.38	0.96	0.375
8	0.75	0.326	0.87	0.325
9	0.75	0.23	0.9	0.225
10	1	0.104	0.87	0.125

Figure 8

The grading margin between relay 6 and relay 5 is less than the 0.3 seconds grading margin calculated. This was due to the network configuration, only the cable impedance contributed to the difference between the current flow reaching feeder 6 and the current flow from busbar 5, as there was no load attached to busbar 5. Although attempts were made to improve the trip times by changing parameters within the network, these were not successful and the trip times could not be increased. This would not be acceptable for a radial feeder on a distribution network on the electricity grid, for a 3-phase fault at maximum fault level both relays would operate.

On the next page is a graph of the operating characteristics of each overcurrent feeder relay. The calculations for the graph are detailed in appendix B.

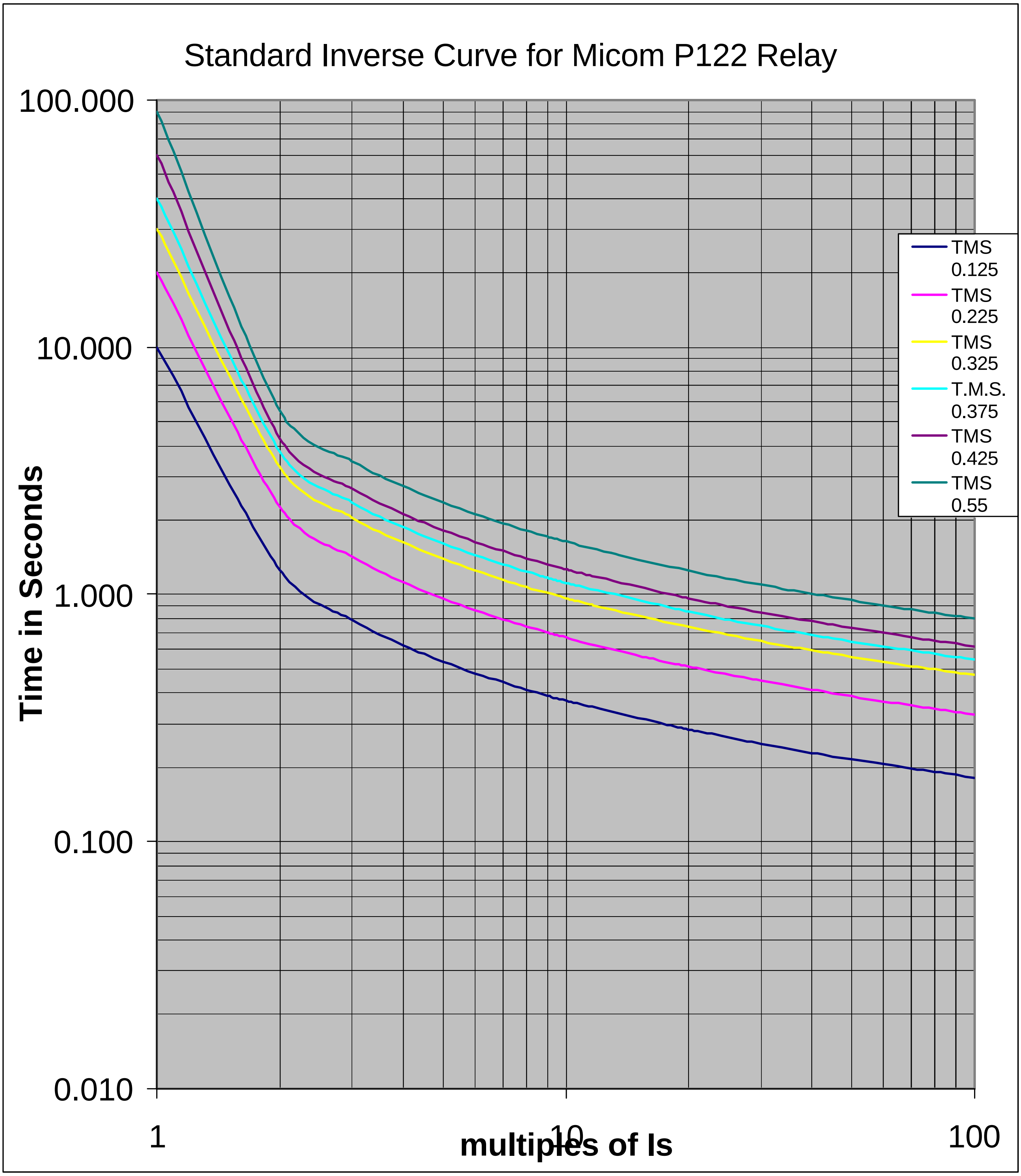

Standard Inverse Curve for Micom P122 Relay
100.000
10.000
1.000
0.100
0.010
Time in Seconds
1
10
100
multiples of Is
TMS 0.125
TMS 0.225
TMS 0.325
T.M.S. 0.375
TMS 0.425
TMS 0.55

Figure 9

1.4 Secondary Injection of Micom P122

Aim

The aim is to operate the relay by injecting current at the fault level provide by the PSS/E [4] model and to produce a trip time for each relay from feeder 5 – 10. The operation times of the Micom P122 should be similar to the operation times calculated for the IDMT settings. The times will be used as base values for comparison with the trip times when distributed generation has been added to the network, this will aid in deciding whether the relay settings, relay type or current transformers require to be changed.

Method

There are four pieces of equipment used in the following experiments, the laptop, the injection test set [5], a power supply, and an overcurrent relay. The laptop was used for the APTS software; values of current were input into the software on the laptop. The APTS test set [5] was used to inject secondary values of current into the overcurrent relay. The power supply was used as an auxiliary power supply to power the overcurrent relay; the APTS test set [5] could also have been used. The overcurrent relay was injected with current from the APTS test set [5]; the IDMT settings and current ratios were set on the relay.

The equipment was connected as shown in *figure 1.* 2.5mm cable was used to wire up the equipment. The experiment used 3-phase current; therefore the three current phases on the injection test set were wired up to the CT inputs on the relay. The tripping contact on the Micom relay was wired up to the digital inputs of the injection test set. This facilitated measurement of the operating time of the relay for current injection.

Once the equipment was wired and checked the auxiliary power supply was turned on, this powered up the Micom P122. The calculate settings and CT ratio could now be set on the relay. This experiment did not require many of the functions available within the relay, so these were disabled through the menu system of the relay. The functions that were enabled were I>, Iset function and the t> T.M.S. function within Protection Group 1, the earth fault function was disabled as earth faults are not within the scope of this investigation. The CT ratio, both primary and secondary values were set within the configuration menu. A tripping contact was enabled within Automatic Control menu to operate when I> operated. The power was turned on at 230v ac socket outlet for the APTS test set [5]. The test set remained on but off-line until the APTS software was loaded on the laptop. The laptop can operate on battery power or mains 230v ac.

Current injection could now take place at each of the IDMT feeder settings and CT ratios calculated. Each Injection of current was carried out twice to ensure consistency of the tripping times. The Micom relay was set up with the settings from feeder 10. The APTS software was operated on manual current injection. The relay would be injected with multiples of the secondary current transformer values; for feeder 10 the injection current would be 17.26 amps.

This was repeated again to check the tripping times were consistent. The relay settings were changed to represent the next relay on the radial network and so on until all of the relay settings had been tested and operation trip times recorded.

1.41 Results

The results of the trip tests are shown below.

Relay	Injected Fault Level	Expected Trip Time	Actual Trip Time	Time margin
10	1727 A	0.25 seconds	0.298 seconds	
9	2045A	0.55 seconds	0.579 seconds	0.281
8	2383 A	0.85 seconds	0.859 seconds	0.28
7	2702 A	1.1 seconds	1.160 seconds	0.301
6	3400 A	1.34 seconds	1.456 seconds	0.296
5	4255 A	1.51 seconds	1.772 seconds	0.316

Figure 10

1.42 Operation Time Measurement Errors

The difference in calculated operation time and measured operation time is due mainly to slight changes being required for Iset to compensate for the load on the feeders. The increased settings have resulted in an increase in operation time, which has been to the benefit of the feeders closer to the generator and to the detriment of the feeders at the bottom of the network. The other factors affecting the measured operation time of the Micom relay is the time measured by the injection test set. The trip time recorded by the test set is the total time for operation. This includes the trip contact operating time and the Micom relay operating time, which has a +/- 2% measurement error. The trip contact operating time for a Micom relay is 7ms. The information regarding measurement error and trip contact operating time can be found in the operation manual for the Micom P122 [16]. A breakdown of the components of the measured operation time by the injection test set is shown below:

Micom P122 Relay Parameters

$t = T*(k/ (I/I_s)^{?}$ -1

t = trip time

T = time multiplier setting

k = 0.14 (Standard Inverse)

I = value of measure current

Is = programmed pick up value (fault level)

? = 0.02

$t = 0.125*(0.14/1727/87)^{0.02} - 1$

t =0.284 seconds

+/-2% error band = +/-0.00568

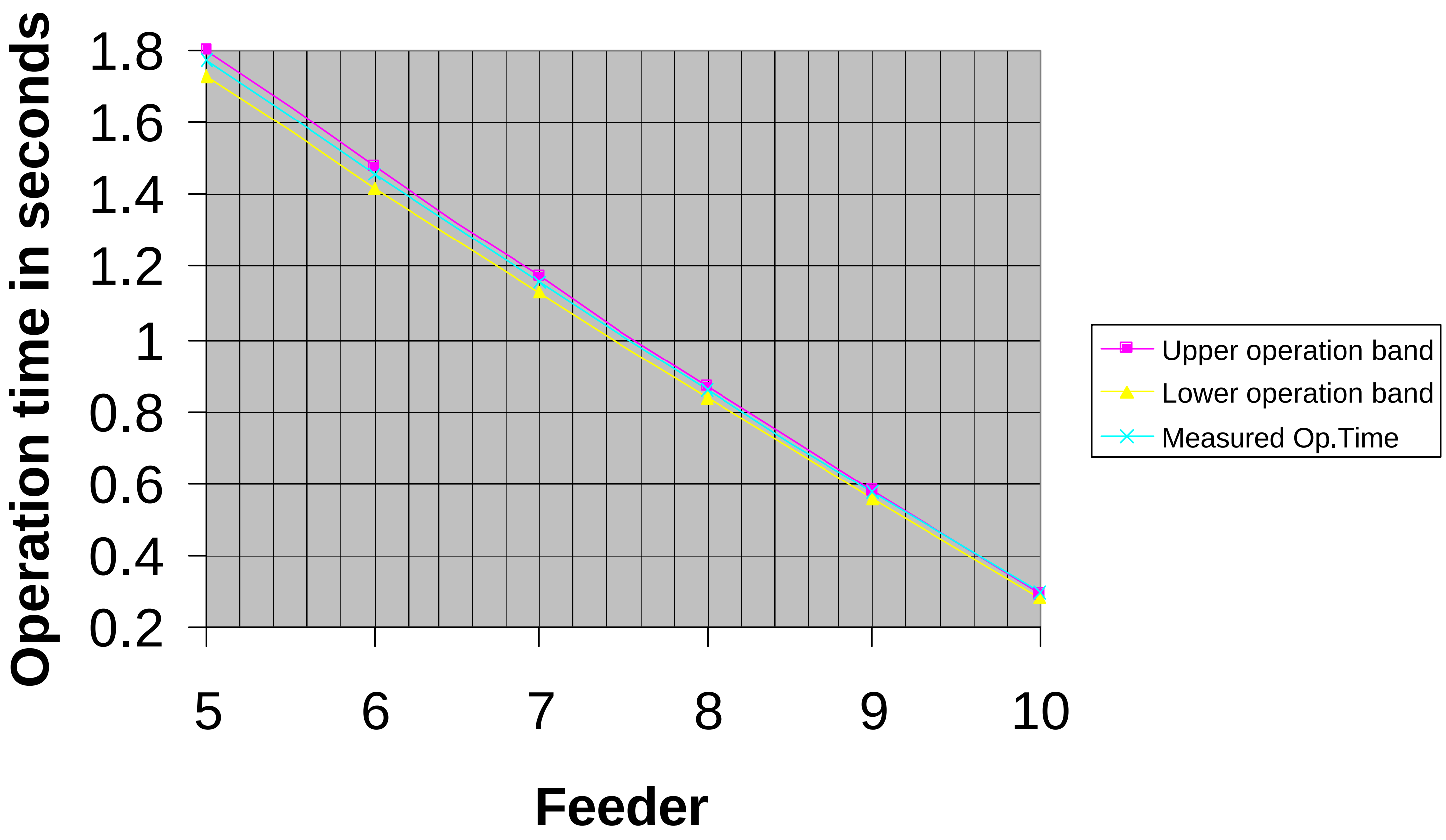
t is between 0.278 seconds and 0.29 seconds.

Add the contact operation time, which is 7ms.

t is between 0.285s and 0.297 seconds

The operation time measured by the injection test set was 0.298 seconds. The graph depicts the operational time band of the Micom relay for feeder 5 to feeder 10. The operation times are within the error band from feeder 8. For feeder 9 the measured value is higher than the error band by 0.001 seconds. It can be accepted that the measured values are a good approximation to the calculated operation time of the relay, and these values will be used from this point as a means of evaluating the differences for the relays when embedded generation is added. The Graph and the calculations used to produce it are within appendix C2.

Figure 11



Operation time in seconds
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
5
6
7
8
9
10
Feeder
Upper operation band
Lower operation band
Measured Op.Time

1.5 Radial Network with Distributed Generation

We will now consider the case where distributed generation is added to the network. The aim of these experiments is to determine the impact on the overcurrent protection relays when distributed generation is connected to the radial network. This has been investigated in terms of the physical placement of the distributed generation on the radial network and the amount of generation on the network. The analysis will look at the operation times of the relays and whether they would operate and maintain the margin. Possible solutions for the case when the margin is not maintained will also be discussed. The conclusions of the experiments will be stated and any further investigative work that could be performed will be proposed.

1.51 Method

The distributed generation modeled within PSS/E [4] was a wind farm. The wind turbines were modeled within PSS/E [4] as a generation source. The turbine modeled was a 2.3MW turbine the reactive power and the impedance of the turbine were taken from a manufacturer's catalogue. The turbine was connected to the 11kV feeder by a 690V/11kV two winding transformer. One turbine was connected to the appropriate busbar, this represented 2.3MW of generation. The connections were then checked using the TREE tool within PSS/E [4], and then the load flow was performed. The results of the loadflow were recorded in a text file for analysis. A 3-phase fault was then placed on each busbar with the wind turbine connected. For the fault study the negative sequence and zero sequence components were made equal to the positive sequence. The fault level on all 11kV busbars was recorded for each fault. The fault study results were saved in a text file.

The PSS/E [4] model was then modified to represent two turbines connected to the same feeder. Doubling the value of the power output and the impedance of the turbine achieved this. The loadflow and fault analysis were then performed for a 3-phase fault at each busbar. The results were recorded in a text file. This was then repeated for 3 turbines and 5 turbines respectively, 5 turbines being the maximum amount of generation required to supply the load. This process was then repeated for each busbar on the 11kV network. In each case the distributed generation would be removed from the preceding busbar to be connected to the next busbar further up the network. Once all the fault level data had been collected, the overcurrent relay was set with the settings calculated in the previous section for each 11kV feeder and the relay was injected with the fault levels recorded in the text file.

It has been assumed for this analysis that the overcurrent protection is on the feeder side of the circuit breaker and not the busbar side. PSS/E [4] loadflow can produce two fault levels for each feeder, a fault level at the busbar, and a fault level at 100% down the feeder cable. The fault level value chosen for the secondary injection has been the busbar fault level as this is higher because of less impedance. This is inaccurate, as it has been assumed that the protection is feeder side of the circuit breaker therefore for the protection to see the fault, the fault would have to be a cable fault down the feeder, which would result in a smaller fault level, as there would be more impedance in the circuit. It has been assumed that the fault is on the feeder although in actuality in PSS/E [4] the fault is on the busbar. This could be an area for more research to provide a more accurate model.

It is assumed that when the distributed generation is connected to a busbar that is a lower busbar (i.e. closer to 10). The fault level from the wind turbines will not contribute to the fault level seen by the IDMT relay on the faulted feeder, the relay will only see the fault level contribution from the main generation source. It has also been assumed that a fault on a feeder where there is a wind turbine connected to that busbar will see both the fault level from the main generation source as well as the fault level from the distributed generation.

1.52 Wind Turbine Parameters

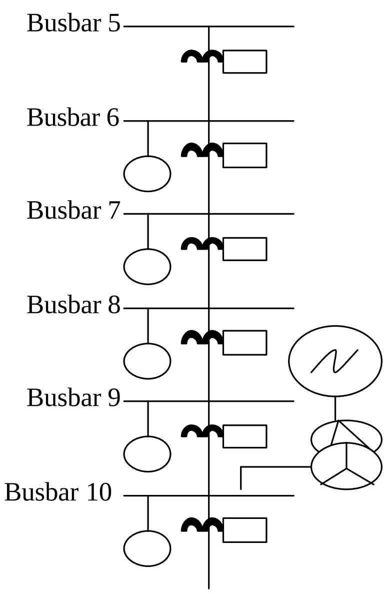
This table provides the parameters used in the wind generator model within PSS/E [4] to represent the power output from the wind turbine. These parameters were changed to represent a change in the number of wind turbines connected to the busbar in the model. The remaining parameters not shown here were used to describe the connections of the wind generator model to the busbar. These parameters include the base value, the resistive and reactive transient values, which were represented by the PSS/E [4] default values. The resistance and reactance of the generator is represented within PSS/E [4] as the Parameter - Zsource. The stator resistance and reactance in the table below represent Zsource.

Parameters for the Connection of Wind Turbines at Busbar 5,6,7,8,9&10				
	Power		**Stator**	
No. Of turbines	Real MW	Reactive MVArs	Resistive p.u.	Reactive p.u.
1	2.3	1.209	0.0063	0.1605
2	4.6	2.418	0.0126	0.321
3	6.9	3.627	0.0189	0.4815
5	11.5	6.045	0.0315	0.8025

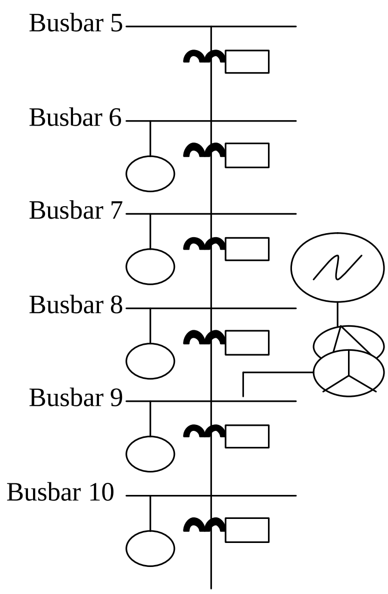
Figure 12

Wind Turbine Connection Diagrams

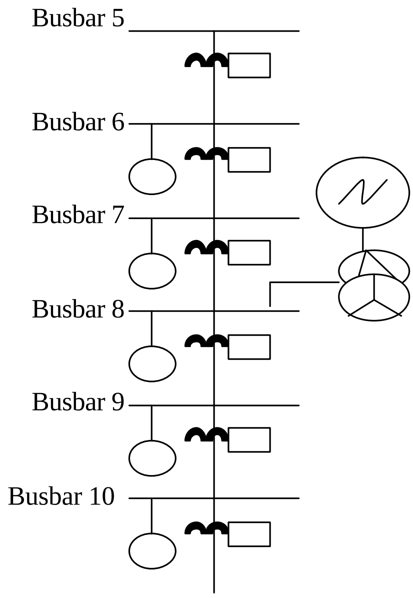
Figure 13



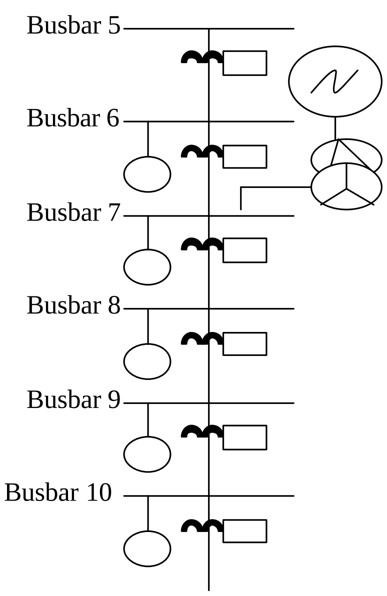
Connection at Busbar 10



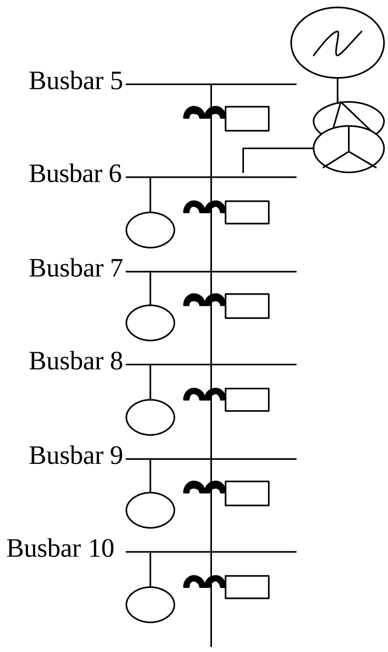
Connection at Busbar 9



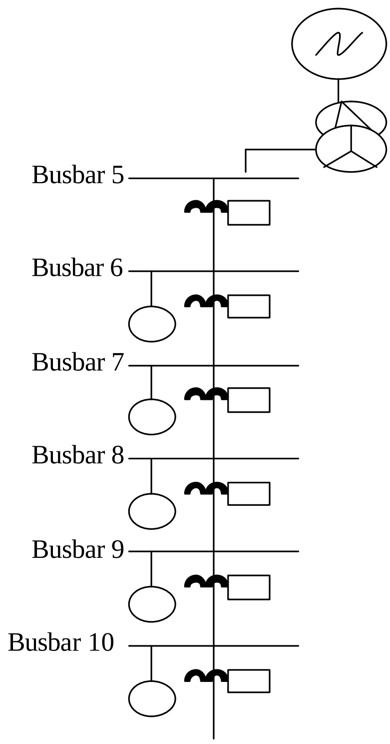
Connection at Busbar 8



Connection at Busbar 7



Connection at Busbar 6



Connection at Busbar 5

1.53 Loadflow

The network loadflow is displayed below for feeder 10 and 5. The connections to the remaining busbars show the same trends as those displayed below. Busbar 101 is the busbar connected to the windfarm and busbar 102 is connected to the 690/11kV transformer, this is required by PSS/E [4] to create the network model. Although in practice the transformer and windfarm would be connected to the substation busbar as the incoming and outgoing feeder circuits. The +ve loadflow denotes the loadflow from the main source of generation connected to the 132kV busbar. The –ve loadflow denotes the flow from the distributed generation. The results from the load flows are held in text files in appendix D.

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<u>Loadflow with Wind Turbines Connected on the Network</u>

Figure 14

1 Wind Turbines connected to Busbar 10												
Busbar	1	2	3	4	5	6	7	8	9	10	102	101
Voltage kV	132	123.8	32.91	31.72	11.11	10.95	10.86	10.85	10.91	9.911	9.911	0.69
Angle ?	0	-3.3	-9.5	-12.8	-18.4	-19.9	-21.2	-21.7	-21.7	1.4	1.7	2.5
Loadflow A	122	122	206	206	587	587	295	239	221	221	230	3263
2 Wind Turbines connected to Busbar 10												
Voltage kV	132	130.8	32.69	31.98	10.61	10.10	9.926	9.891	9.891	9.951	9.976	0.69
Angle ?	0	0.4	-1.4	-0.8	-2.2	-0.3	1.6	2.6	4.5	6.6	7.1	8.6
Loadflow +ve (A)	57	57	216	216	616	616	386	361	361	373	--	--
Loadflow A-ve	--	--	--	--	--	--	--	361	373	391	391	5549
3 Wind Turbines connected to Busbar 10												
Voltage kV	132	130.5	33.28	32.42	10.62	10.0	9.746	9.662	9.608	9.611	9.626	0.69
Angle ?	0	0.6	-1.5	-0.7	-2.2	0.3	2.9	4.6	4.9	9.8	10.4	12.1
Loadflow +ve (A)	72	72	266	266	758	758	529	495	488	493	--	--
Loadflow (-ve) (A)	--	--	--	--	--	--	495	488	493	503	6822	503
5 Wind Turbines connected to Busbar 10												
Voltage kV	132	130.4	33.26	32.27	10.2	9.575	9.387	9.374	9.451	9.674	9.740	0.69
Angle ?	0	1.0	-0.4	1.2	0.8	5.7	11.0	14.3	18.7	24.1	25.2	28.9
Loadflow +ve (A)	104	104	370	370	1053	1053	909	902	910	927	--	--
Loadflow -ve (A)	--	--	--	--	--	--	--	910	927	949	12861	949
CT Ratio	--	--	--	--	600/1	600/1	300/1	200/1	150/1	100/1	--	--

<u>Loadflow with Wind Turbines Connected on the Network (</u>Pg2)

Figure 14A

1 Wind Turbines connected to Busbar 5												
Busbar	1	2	3	4	5	6	7	8	9	10	102	101
Voltage kV	132.0	130.0	33.2	31.99	10.06	9.484	9.273	9.207	9.167	0	10	0.69
Angle ?	0	1.1	-1.0	0.6	-0.6	-0.7	-0.8	-0.9	-0.9	0	0.4	1.8
Loadflow A+ve	119	119	419	419	1185	574	212	111	52	0	900	0
Loadflow A -ve	--	--	--	--	900	212	111	52	0	0	900	12193
2 Wind Turbines connected to Busbar 5												
Voltage kV	132	130.2	33.14	32.04	10.05	9.473	9.263	9.197	9.156	0	10.01	0.69
Angle ?	0	1.2	-0.4	1.4	1.0	0.9	0.8	0.7	0.7	0	2.1	4.2
Loadflow A+ve	119	119	420	420	1190	575	212	111	52	0	--	--
Loadflow A–ve	--	--	--	--	969	212	111	52	--	0	969	13127
3 Wind Turbines connected to Busbar 5												
Voltage kV	132.0	130.4	33.07	32.04	10.03	9.459	9.249	9.182	9.141	0	10.02	0.69
Angle ?	0	1.3	0.2	2.3	2.6	2.5	2.3	2.3	2.3	0	3.8	6.5
Loadflow A+ve	121	121	427	427	1208	576	212	112	52	0	--	--
Loadflow A–ve	--	--	--		1048	212	112	52	--	0	1048	14202
5 Wind Turbines connected to Busbar 5												
Voltage kV	132.0	130.7	33.17	32.27	10.03	9.459	9.248	9.182	9.141	0	10.06	0.69
Angle ?	0	1.5	1.5	4.0	5.8	5.6	5.5	5.5	5.4	0	7.2	11.2
Loadflow A+ve	134	134	466	466	1320	576	212	112	52	0	--	--
Loadflow A ve	--	--	--	--	1263	212	112	52	--	0	1263	17116
CT ratio	--	--	--	--	600/1	600/1	300/1	200/1	150/1	100/1	--	--

1.54 Observations from Loadflow Results

In general, the loadflow increases with the increasing number of turbines. This is true no matter where the turbine is connected within the 11kV network. The CT ratio is no longer adequate at busbar 5, 6, and 7 for two or more wind turbines connected to busbar 10. The current transformer at busbars 10, 9, and 8 would require to be increased for any number of turbines connected to busbar 10. The loadflow through busbars 9 and 8 are very similar and the loadflow through feeder 10 is higher than the loadflow at busbar 9 or busbar 8. This is unusual as in a passive radial network the loadflow would be highest through the cables connected to busbar 1 and lowest at busbar 10. This ensures the 11kV network is more difficult to grade as you could require a larger current transformer for the overcurrent relay on feeder 10 than at feeder 9.

Busbar 10 was switched off for the loadflow carried out on busbars 8, 7, 6 and 5 because the loadflow results were displaying a loadflow from busbar 10 when the distributed generation was connected higher up the network. The network was checked repeatedly for a rogue connection at busbar 10 but this was not the case, the model was also recreated with no former connection to busbar 10 instead of an amendment but this also did not work. Although busbar 10 was switched out of the network for the remaining loadflow calculations and displayed results, this did not stop the loadflow flowing from the bottom of the network. In retrospect it would have been better to leave
busbar 10 in the network as there was a load connected to this busbar and by removing busbar 10 the loadflow results were decreased.

Generally the higher the distributed generation connection moves closer to the middle of the network the higher the loadflow contribution from the wind turbines to the network. This is due to the distributed generation 'seeing' smaller impedance closer to the middle of the network. As the distributed generation connection moves closer to busbar 5, the current transformers required by the overcurrent relays on feeder 5, 6 and 7 require to be increased. The current transformers at feeder 8, 9, and 10 can still be used but the relay settings may require slight adjustment.

The power factor angle becomes more reactive the greater the amount of distributed generation. On the grid this can be corrected by using power factor correction capacitors or inductors. The power factor is more balanced the closer the distributed connection is to the middle of the network and it seems to become much more reactive the closer to the bottom of the network.

The general trend with the voltage is that the voltage increases with increased number of turbines close to the transformers, as tap changers are regulating the vo ltage. In the 11kV network increased amounts of distributed generation connected to the network leads to lower voltage levels on the network. If the voltage fell enough this could lead to non-compliance with G59/1[9] which states the operational voltage level of the network with distributed generation connected.

1.5.5 Fault Analysis

The fault analysis was run for 1, 2, 3, and 5 turbines connected to each of the 11kV busbars. The fault levels produced from the analysis were injected into the P122 Micom relay [6] to ascertain the trip times. These times were recorded in tables and were compared against the trip times without distributed generation connected to the network to ascertain whether connecting distributed generation to the network adversely affected the protection relay criteria on the network. The tables of results on the following pages show the fault levels for 1 wind turbine connected to each of the 11kV busbars. Increasing the number of turbines connected to each busbar increases the fault level at each feeder. This is reflected in a reduction of time to trip the relay. All of the PSS/E [4] fault level files are displayed in text format within appendix E. The tables of results on the results pages adequately highlight the problems that connection to distributed generation can cause to a previously passive network. Therefore only 1 turbine connection has been shown within the main body of the thesis.

The fault level can consist of two components, a contribution from the main generation source, denoted (a) and a contribution from the distributed generation denoted (b). This is illustrated within the fault level table cells. Where (a+b) is displayed in the table cells there is a contribution from the main generation source and the distributed generation source. The fault levels are displayed within PSS/E [4] in polar form. To calculate the total fault level when there was an (a) and (b) component, the fault levels were converted to rectangular co-ordinates added and converted to polar form once again. The fault level magnitude was injected into the P122 Micom relay [6].

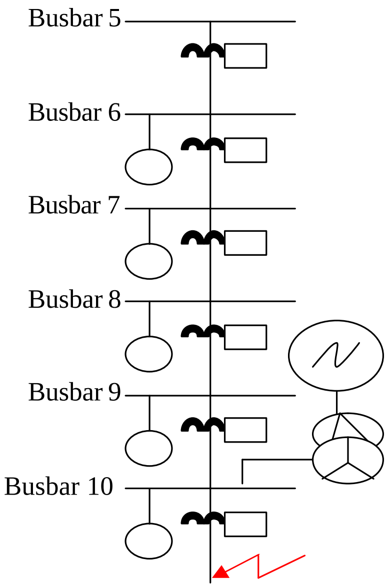
The ** denotes no injection into the relay by the test set. The injection test set can inject up to a maximum of 35A per phase, this means 35 times Iset. Where the fault level was above 30 times Iset the secondary injection was not injected as it was felt that the test set was being operated close to its limits.

The – denotes no fault flow through the relay current transformers at this feeder. Remembering it has been assumed that the current transformers are on the feeder circuit and not on the busbar circuit, therefore any fault current flow from the wind turbines attached to a busbar will not be 'seen' by the current transformers of the downward feeder unless the fault is downstream of the distributed generation.

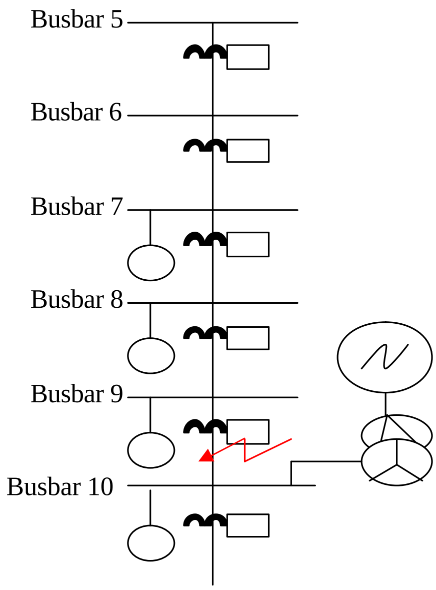
As already stated busbar 10 was switched off for the loadflow analysis of busbars 8, 7, 6 and 5 as there was current flow upstream from busbar 10 when there was no generation source attached. The fault level studies were kept consistent with the loadflow in this respect.

Fault Diagrams for Wind Generation connected to Busbar 10

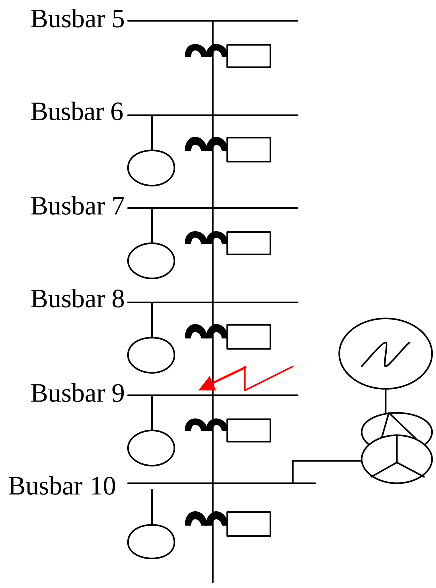
Figure15



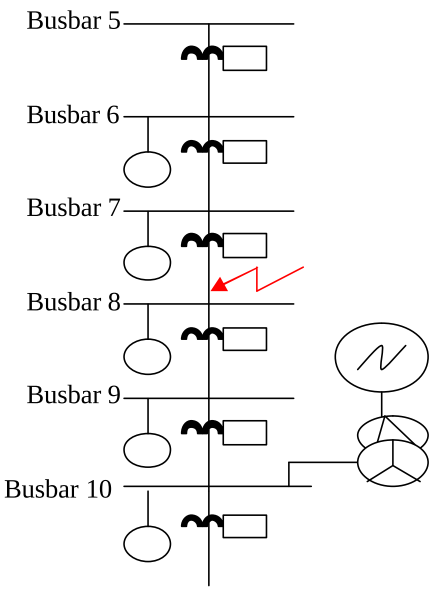
Fault on Feeder 10



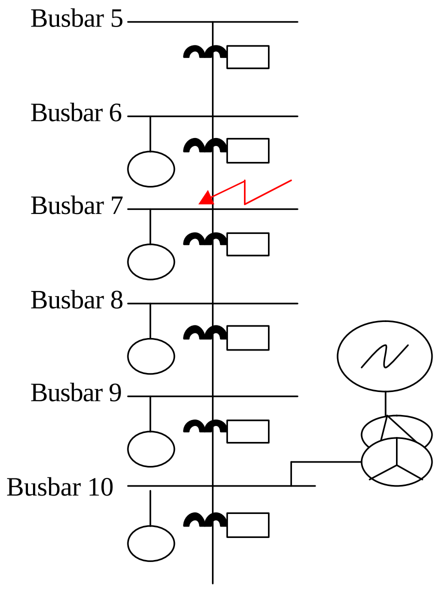
Fault on Feeder 9



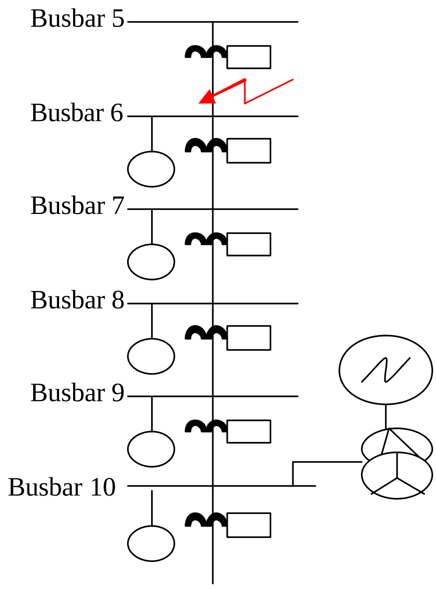
Fault on Feeder 8



Fault on Feeder 7



Fault on Feeder 6



Fault on Feeder 5

Fault Level Results with Wind Generation connection at Busbar 10

1 Turbine connected to busbar 10 , fault on feeder 10						
Relay	10	9	8	7	6	5
Fault Level (A)	9468 a+b	1712 a	1729a	1767a	1958a	1958a
Trip Time (S)	**	0.62	0.983	1.439	2.016	2.8
1 Turbine connected to busbar 10 , fault on feeder 9						
Relay	10	9	8	7	6	5
Fault Level (A)	-	2022a	2031a	2057a	2217a	2217a
Trip Time (S)	-	0.58	0.917	1.325	1.854	2.558
1 Turbine connected to busbar 10 , fault on feeder 8						
Relay	10	9	8	7	6	5
Fault Level (A)	-	3518b	2361a	2374a	2497a	2497a
Trip Time (S)	-	0.516	0.863	1.233	1.725	2.369
1 Turbine connected to busbar 10 , fault on feeder 7						
Relay	10	9	8	7	6	5
Fault Level (A)	-	2923b	2904b	2681a	2769a	2769a
Trip Time (S)	-	0.518	0.799	1.16	1.624	2.222
1 Turbine connected to busbar 10 , fault on feeder 6						
Relay	10	9	8	7	6	5
Fault Level (A)	-	2284b	2259b	2239b	3383a	3383a
Trip Time (S)	-	0.554	0.879	1.268	1.461	1.987
1 Turbine connected to busbar 10 , fault on feeder 5						
Relay	10	9	8	7	6	5
Fault Level (A)	-	1894b	1865b	1839b	1806b	4235a+b
Trip Time (S)	-	0.594	0.951	1.407	2.133	1.776

Figure 16

Fault Level Results with Wind Generation connection at Busbar 9

1 Turbine connected to busbar 9 , fault on feeder 10						
Relay	10	9	8	7	6	5
Fault Level (A)	5419a+b	5419+1117	1154a	1221a	1497a	1497a
Trip Time (S)	**	**	1.195	1.81	2.468	3.483
1 Turbine connected to busbar 9 , fault on feeder 9						
Relay	10	9	8	7	6	5
Fault Level (A)	-	10325a+b	2139a	2166a	2339a	2339a
Trip Time (S)	-	**	0.899	1.291	1.794	2.471
1 Turbine connected to busbar 9 , fault on feeder 8						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	2482a	2497a	2631a	2631a
Trip Time (S)	-	-	0.847	1.2	1.672	2.293
1 Turbine connected to busbar 9 , fault on feeder 7						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	4036b	2818a	2913a	2913a
Trip Time (S)	-	-	0.74	1.139	1.58	2.158
1 Turbine connected to busbar 9 , fault on feeder 6						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	2879b	2853b	3551a	3551a
Trip Time (S)	-	-	0.802	1.132	1.425	1.94
1 Turbine connected to busbar 9 , fault on feeder 5						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	2257b	2225b	2183b	4434a
Trip Time (S)	-	-	0.878	1.274	1.873	1.736

Figure 17

Fault Level Results with Wind Generation connection at Busbar 8

1 Turbine connected to busbar 8 , fault on feeder 9						
Relay	10	9	8	7	6	5
Fault Level (A)	-	6054a+b	6080a+b	1529a	1773a	1773a
Trip Time (S)	-	**	0.738	1.564	2.16	3.016
1 Turbine connected to busbar 8 , fault on feeder 8						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	10481a+b	2470a	2602a	2602a
Trip Time (S)	-	-	**	1.21	1.683	2.308
1 Turbine connected to busbar 8 , fault on feeder 7						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	5816b	2788a	2882a	2882a
Trip Time (S)	-	-	0.74	1.144	1.591	
1 Turbine connected to busbar 8 , fault on feeder 6						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	3685b	3515a	3515a
Trip Time (S)	-	-	-	1.017	1.434	
1 Turbine connected to busbar 8 , fault on feeder 5						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	2707b	2656b	4391a
Trip Time (S)	-	-	-	0.811	1.159	1.664

Figure 18

Fault Level Results with Wind Generation connection at Busbar 7

1 Turbine connected to busbar 7 , fault on feeder 9						
Relay	10	9	8	7	6	5
Fault Level (A)	-	4530a+b	4551a+b	4615a+b	1544a	1544a
Trip Time (S)	-	0.515	0.739	0.933	2.412	3.399
1 Turbine connected to busbar 7 , fault on feeder 8						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	6969a+b	7011a+b	2042	2042a
Trip Time (S)	-	-	0.739	0.852	1.958	2.715
1 Turbine connected to busbar 7 , fault on feeder 7						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	10817a+b	2831a	2831a
Trip Time (S)	-	-	-	**	1.602	2.195
1 Turbine connected to busbar 7 , fault on feeder 6						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	-	3455a	3455a
Trip Time (S)	-	-	-	-	1.446	1.965
1 Turbine connected to busbar 7 , fault on feeder 5						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	-	3214b	4321a
Trip Time (S)	-	-	-	-	1.499	1.759

Figure 19

Fault Level Results with Wind Generation connection at Busbar 6

1 Turbine connected to busbar 6 , fault on feeder 9						
Relay	10	9	8	7	6	5
Fault Level (A)	-	3190a+b	3206a+b	3251a+b	3531	1475
Trip Time (S)	-	0.516	0.771	1.071	1.43	3.54
1 Turbine connected to busbar 6 , fault on feeder 8						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	4306a+b	4333a+b	4583a+b	1732
Trip Time (S)	-	-	0.741	0.956	1.268	3.074
1 Turbine connected to busbar 6 , fault on feeder 7						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	5767	5975	2080
Trip Time (S)	-	-	-	0.862	1.133	2.68
1 Turbine connected to busbar 6 , fault on feeder 6						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	-	11594	3492
Trip Time (S)	-	-	-	-	0.963	1.956
1 Turbine connected to busbar 6 , fault on feeder 5						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	-	-	4365a
Trip Time (S)	-	-	-	-	-	1.748

Figure 20

Fault Level Results with Wind Generation connection at Busbar 5

1 Turbine connected to busbar 5 , fault on feeder 9						
Relay	10	9	8	7	6	5
Fault Level (A)	-	2475a+b	2488a+b	2526a+b	2754a+b	2755a+b
Trip Time (S)	-	0.54	0.847	1.197	1.6	2.224
1 Turbine connected to busbar 5 , fault on feeder 8						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	3128a+b	3149a+b	3340a+b	3341
Trip Time (S)	-	-	0.778	1.085	1.47	2.204
1 Turbine connected to busbar 5 , fault on feeder 7						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	3875a+b	4022a+b	4023a+b
Trip Time (S)	-	-	-	0.998	1.345	1.821
1 Turbine connected to busbar 5 , fault on feeder 6						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	-	6242	6242
Trip Time (S)	-	-	-	-	1.115	1.5
1 Turbine connected to busbar 5 , fault on feeder 5						
Relay	10	9	8	7	6	5
Fault Level (A)	-	-	-	-	-	12593
Trip Time (S)	-	-	-	-	-	1.242

Figure 21

1.5.6 Observations from Fault Analysis

Connections at Busbar 10

Connection of distributed generation at the bottom of the network increases the loadflow and fault level flowing through this busbar and feeder. Generally the current transformer for the feeder relay would be required to be increased to match the new loadflow. The loadflow results for distributed generation connection at busbar 10 show similar loadflow through busbar 9 and 10, this could make providing new settings for relay 10 difficult as the current setting for both relays would be similar. For a fault on feeder 10, the remaining 11kV feeders will see fault contribution from the main generation source only and because of the impedance down the network these fault levels are much smaller than the fault level on feeder 10.

For a fault on feeder 8 the fault level seen by the relay on feeder 9 is higher than the fault level on feeder 8. The fault level through the current transformers to the fault on feeder 8 is from the main generation source whereas the fault level through the current transformers on feeder 9 is from the wind-power source. In this case the relay at feeder 9 operates at 0.516s and trips the associated circuit breaker before feeder 8 operates, feeder 8 will operate at 0.863s resulting in loss of supply to busbar 9 and busbar 8. This will result in the power being cut off to loads down stream of the fault; this is the same as what would be expected in a traditional radial network.

Connection of Wind Generation higher up the 11kV distribution network

With the connection of the wind-turbines moving up the network more changes are required to the feeder protection on the 11kV network. This is due to higher loadflow from the combined generation sources. The fault levels on the 11kV network will increase. The most dramatic increase of fault level is closest to the wind-turbine connection. As the connection of generation moves up the network the fault levels are more consistent. In general the operation times of the relays with regard to grading margin seem to have improved with the connection of distributed generation.

The contribution from the wind-turbines can be of a transient nature therefore the network could operate over periods where the network flow is passive and not active. This could affect the operation of the relay when the settings have been modified as the operation fault level that the new settings were based on may never be achieved under passive operation.

1.6 Conclusions

Section 1 has investigated the connection of distributed generation to a previously passive network and the effects the power flow from the distributed generation has on the protection settings. The relay used for these experiments was a Micom P122 overcurrent relay [6]. The IDMT element was used in the relay with a standard inverse curve. A comparison was made between the trip times of the relay when different amounts of generation were added to the network and for different connections points on the 11kV network. Although some of the data used in the PSS/E [4] model was fictitious some general conclusions can be drawn.

Connecting distributed generation to a previously passive network, will always necessitate a new look at the existing protection, and associated equipment to determine the changes to equipment sizes such as current transformers and changes to protection settings. Changes will always be required even when the power flow from the distributed generation is small. Generally placing the connection of the distributed generation higher up the network is better due to a smaller differential increase of fault level between all of the feeders. This will necessitate smaller changes to the protection and it may be possible to employ the same equipment but with different settings. Cognizance also must be taken of the short term rating of the current transformers. In the British and European Standards [7], the short term rating of a current transformer does not normally exceed 20 times secondary rating. In some of the tables on the previous pages the fault level was 30 times rating in these cases the current transformer would have saturated and could result in permanent damage to the current transformer and damage to the protection relay. It must also be taken into account that the protection relays that would be associated with the distributed generation have not been taken into account within these experiments. The distributed generation could be tripped off the network before making a contribution to the fault, also it would depend where on the feeder the fault was as the overcurrent relay looking down the feeder may not ‘see’ the distributed generation contribution to the fault.

1.7 Alternative methods of providing protection of a radial distribution network with distributed generation connected.

A solution would be to have a relay that operated with two sets of settings depending on load criteria. If the load flow increased above a certain level the protection relay would determine that there was more generation on the network and would change to a second set of operational settings. There would be operational considerations with a relay that could manage this, could it operate with one set of current transformers if the settings were very different? How long would it take to change between settings, would it be able to ride through transients on the network that could temporarily affect loadflow? Although there are some relays that can operate on different settings given different operating criteria such as a distance relay, typical overcurrent protection is not that sophisticated. Therefore another solution is required. It has been proposed that employing differential protection on a radial network will ensure swift clearance of a fault when distributed generation is connected to the network. The main problem with employing differential protection on a radial distribution network is the communication that is required between the two relays requires pilot cable or a fibre cable run between the two relay points. Most radial networks do not have the pilot wire or fibre laid in the ground or on overhead cables and it is very expensive to accomplish this on an existing network. The next section will look at using directional relays to protect a radial network with distributed generation connected as an alternative to differential protection.

Section 2

2.1 Introduction

It was demonstrated in Section 1 that adding distributed generation to a previously passive network will necessitate changes to the overcurrent protection employed on the network. Even when these changes are employed it may no longer be possible to grade the overcurrent protection on the radial network. Protection engineers within the electricity industry generally believe that the only reliable form of protecting a radial network with distributed generation on the network is to employ differential protection. The general principle of differential protection is that the current flow through the relay at one end of the feeder should match the current flow through the relay at the other end of the feeder. The current circulation method [8] by Merz Price is the most well known. When there is no existing communication medium within the network providing communications can be very time consuming in planning permission getting access to cable routes and expensive to retrofit having to dig up (if laid in ground) the cable routes. This section will consider an alternative to employing differential protection in addition to an overcurrent relay on a radial feeder.

Section 2 will explain how a directional relay is configured and its setting and operating criteria. Where the relays should be placed on the radial distribution network and how they would achieve clearance of faults in addition to an overcurrent relay on the 11kV feeder.

2.2 Operating Principles of a Directional Relay

Directional relays can be used where there is a bi-directional fault current flow in the distribution network. In a radial distribution network without distributed generation connected this would not be the case but with distributed generation there will be bi-directional flow of current. Directional relays use a current and voltage input for each phase, a current and voltage transformer representing each phase provide these signals. The voltage signal is used as the reference and therefore is represented within the relay as having angle 0º. Using the voltage waveform as a reference the current waveform can be used for calculation of the power factor angle for the relay. This angle will depend on the types of load on the radial network. The calculated characteristic angle is used to determine whether the power flow is 180º out of phase with the settings if this is the case the power flow is in the reverse direction. When using this relay all equipment that can affect the characteristic angle must be taken into account such as transformers for example dy11, so that this displacement can be figured into the settings values. If not considered the relay could be made too sensitive and trip on a load flow that is not in the reverse direction.

2.3 Setting Principles of KCEG142

The directional relay proposed for the use on a radial network with distributed generation is a KCEG142. This is a protection relay manufactured by Areva Transmission and Distribution [6]. This relay is a digital multifunction relay, based on an induction disc principle but with a digital processor and liquid crystal display. The relay is capable of measuring overcurrent and earthfault, directional overcurrent, and earthfault, under frequency and undervoltage and thermal overload and has L.E.D. indication for a trip condition or fault condition.

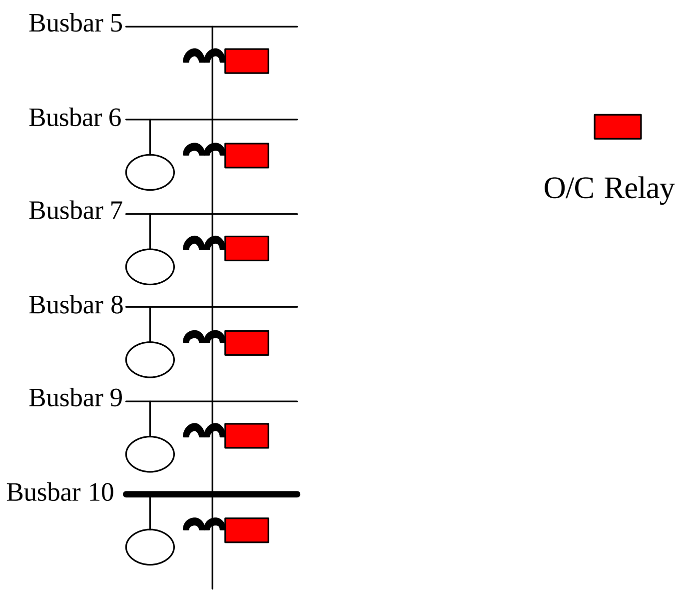
The elements of the relay that must be set for fault injection by secondary injection are the system data, phase fault protection group 1, and relay mask. The system data element contains information on the relay serial number, type of communication that the relay will use when communicating remotely, software within the relay, frequency that the relay will operate at. Within the phase fault protection group 1 element the overcurrent settings and directional overcurrent settings can be set. There is a two-stage overcurrent function that can be set with time delay and curve type available and a 3-stage directional overcurrent element with time delay. The characteristic angle for the directional element is also set within the phase fault element The undervoltage relay settings can also be set within this element. Once the settings have been entered into the relay via the menu the output relays can be set. The output relays are set within the relay masks element. The relay masks element is a list of functions that can make the output relays operate. The relay masks are using logic '1' high 'on', '0' low 'off ' the functions, once set within the relay govern what condition will make the relay trip or alarm. For an output trip on directional current I>Rev and CB>trip would be set high.

2.4 Placement of Directional Relays on Radial Network

There are two possibilities discussed here for using directional relays on the radial network. The first possibility is to connect the directional relay at the top of the distributed generation feeder before connecting to the radial network busbar. The relay would be required to operate on an instantaneously on reverse direction only for a fault condition. This would disconnect the distributed generation from the radial network. This would result in a fault on the radial network being fed from the main source of generation connected to Busbar 1; minimal change would be required within the 11kV radial network as the fault levels would be similar to a network without distributed generation. The overcurrent settings would have to be checked to ensure that account was taken of the increased loadflow provided by the distributed generation, to ensure an overload trip did not occur. The problem with this method is that all of the loads on the network will be tripped off; as both sources of supply will be lost (this is assuming the fault is on the 11kV network and not on the distributed generation feeders).

11kV feeder Network

Figure 22



The second method is to place directional relays on feeders 9, 8, 7 and 6 and at the closest position to the 11kV connection on the distributed generation feeder. The relays will be placed next to the overcurrent relays but the relays will only operate on reverse fault flow. The relays will have operational settings such that the directional relay at 6 will have an instantaneous trip setting and the time multiplier setting will increase as the relay position moves closer to Busbar 10. The directional relay on the distributed generation feeder will have the largest time multiplier setting.

<u>11kV feeder Network with Directional Relays</u>

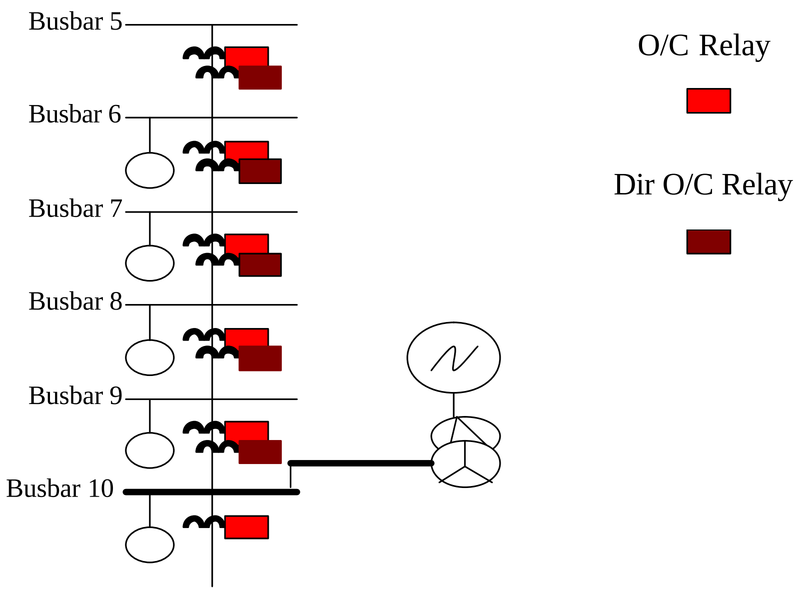


Figure 23

<u>Fault on Feeder 5 with Distributed Generation Connected to Busbar 10</u>

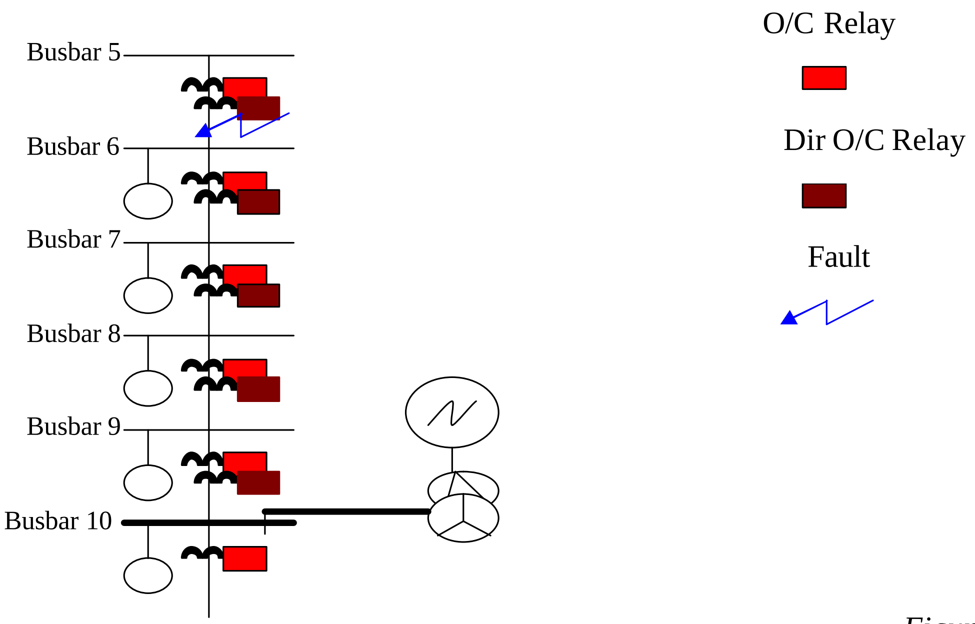


Figure 24

Consider a fault on feeder 5 with distributed generation connected to Busbar 10. For a fault at feeder 5 the directional relay at relay 6 should operate first, this would cease fault flow up the radial network. The fault level flowing through the overcurrent relay at 5 would increase as the impedance of the whole network has decreased due to the operation of relay 6. The overcurrent relay at relay 5 would then operate and clear the fault. This is known as cascade tripping. Using this technique the loads in the 11kV network would still be operating on the radial network.

As the fault moves down the network the relay above the fault would operate on overcurrent protection and the relay below the fault would operate on a directional setting. For a fault occurring on feeder 9 the overcurrent relay at 9 would operate first with the directional relay on the distributed generation feeder providing back up to remove the distributed generation. For a fault at feeder 10, the fault flow would be the combined flow from the main generation source connected to Busbar 1 and the flow from the distributed generation. Therefore a directional overcurrent relay is not required on this feeder.

2.5 Distributed Generation Connected Higher up the radial network

When the distributed generation connection is placed higher up in the radial network less directional relays are required. A fault that occurs further down the network will have fault flow from only one direction and can therefore be cleared by the overcurrent relay. A fault that occurs higher up the network than where the distributed generation is connected shall require the use of directional relays as well as overcurrent relays to clear the feeder with minimal interruption. This would operate in a similar manner to that already discussed in the last paragraph.

Fault on Feeder 9 with Distributed Generation Connected to Busbar 7

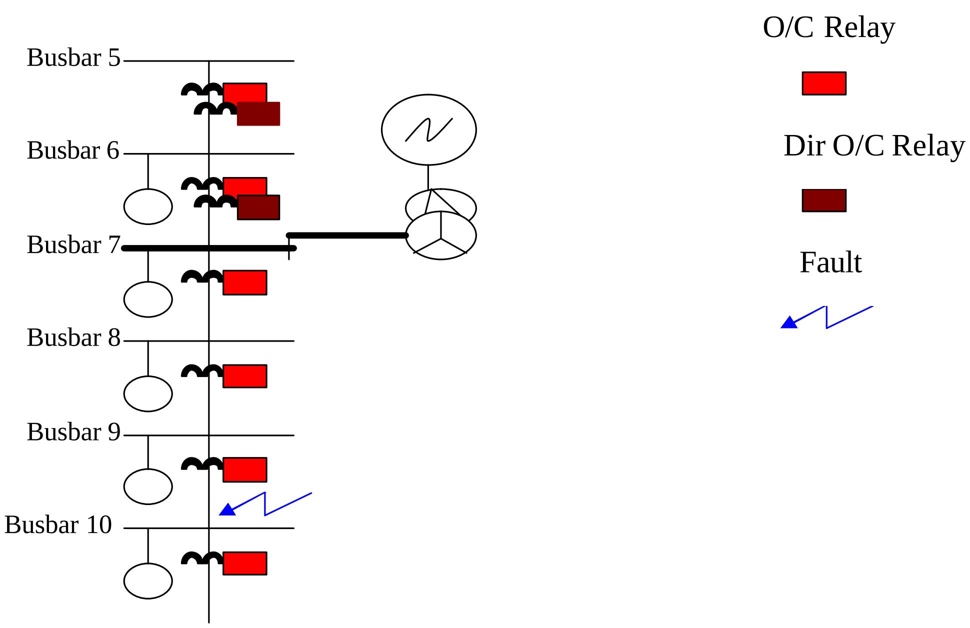


Figure 25

2.6 Conclusion

Section 2 has looked at the use of a directional overcurrent relay to operate for abnormal conditions such as faults when distributed generation has been connected to a radial distribution network. The use of directional relays has been provided as an alternative to differential protection as the communication medium between the differential relays can be expensive to retrofit on an existing distribution network. This section has looked at the setting criteria required to operate the relay.

The conclusions from section 2 are that directional relays can be used in conjunction with the existing overcurrent protection on the network to operate and clear a fault causing minimal disruption to the radial network. This can be achieved by placing directional relays on each feeder that is higher up the network than the distributed generation. The distributed generation feeder will also have a directional relay placed at the closest point to the busbar connection on the radial network. The directional relays will be set using a time-delayed characteristic, which only operates for a reverse current flow up the network. The characteristic angle within the directional relay will be set for a fault taking into consideration any transformers in the current path where a phase shift has been employed. The directional relay highest up the network will be set with the shortest time and so on down the radial network, with the directional relay on the distribution feeder being set with the longest time. All relays further down the network than the distributed generation will only require an overcurrent relay as a fault that occurs on one of these feeders will have fault current flow from one direction only. This will include the feeder relay whose cable is attached to the same busbar as the distributed generation.

2.7 Further Work

Further work using directional relays would be to use the fault levels calculated in PSS/E [4] to find out if it is possible to set both overcurrent and directional overcurrent relays so that they operate as suggested. The fault levels calculated within PSS/E [4] will not show the increased fault level that the overcurrent relay would operate on when the directional relay has tripped i.e. cascade tripping.

Section 3

3.1 Introduction

This section presents an overview of current loss of mains protection and the possible future developments. Loss of mains protection must be employed when connecting to the utilities distribution network, this protection is specified in engineering recommendation G59/1[9] and is specified by the utilities in the UK when a connection to the distribution network is required. This protection protects both the distribution network and the main transmission network by disconnecting the distribution network and any generation connected to it from the main utility network when a disturbance or fault occurs.

Loss of mains protection is a topical area of discussion with regard to distributed generation. This is mainly due to the consideration of safety that arises when distributed generation is employed within a distribution network. When a fault occurs on the main electricity grid the distribution network within the fault area is disconnected. The distributed generation on the distribution network will continue to operate and supply power to loads on the islanded distribution network. The distributed generation is normally privately owned and run therefore communication between the local utility and the owner could be sporadic.

There are four main issues that arise from operating the distribution network in islanded mode. The loads within the distribution network may not be matched the generating capability and could result in voltage dipping on the network, which would affect industrial process on the distribution network. This would have result in negative publicity for the owner and utility, as the distribution network and generation sources would be viewed as unreliable. When the distribution network is removed from the network by opening circuit breakers, the earth connection for the distributed generation is also severed. Distributed generation normally has the earth connection for the distributed generation provided via the grid earth connection. If a fault occurred on the distribution network with the earth connection severed. The distribution network could suffer circulating fault current through the current phases. Reconnection to the main grid will be required when the fault on the grid has been cleared. The distribution network having operated in isolation from the electricity grid could then be out of phase, have smaller or larger frequency, have mismatched voltage magnitude or may be out of phase sequence with the grid. Synchronization has to be achieved between the distribution network and the main grid before the islanded distribution network can be reconnected to the main grid. This could require temporary load shedding in the distribution network or shutting down and restarting the distributed generation on the network. The most important consideration of loss of mains and distributed generation is the issue with the safety of personnel. When the distribution network is islanded from the grid during a grid fault, it could be assumed that the distribution network is dead when in fact it is still live due to the distributed generation providing power to loads. It is possible that operational personnel could be working on sections of the distribution network that are live when this is not intended due to a breakdown in communication between the private owner/operator and the utility. It is possible for an incident involving injury to operational personnel due to lack of knowledge of the present state of the network.

Loss of mains protection can be divided into two categories of protection, passive protection, and active protection. Passive protection monitors the system and operates on the result of monitoring the system. Active Loss of mains protection will interact with the operation of the utility grid.

3.2 Types of Loss of Mains Protection – Passive Technique

Transfer Trip [11] – This method of protection monitors the auxiliary contacts of the grid circuit breakers. When a change of contact status is detected on one of the grid circuit breakers a trip signal is sent to the interconnection circuit breaker located between the main grid network and the distribution network to trip the interconnection circuit breaker thus separating the main network from the distribution network. This is probably the simplest method of protecting against Loss of mains but to employ this technique requires communication between the main grid and the distribution network i.e. a (S.C.A.D.A.) Supervisory Control And Data Acquisition system is required. This is expensive to retrofit to an existing system therefore if the pilot cables are not available another method must be employed.

Over/under Frequency and Over/under Voltage [11] – This technique monitors variations in the voltage magnitude and frequency of the system. Any quick change in loading i.e. such as when islanding occurs will affect the speed and voltage of the generator until a new energy equilibrium is found. This is an effective technique when smaller generators are employed on the distribution network but can be ineffective if the generation source is large and by islanding the distribution the generator can easily cope with the islanded load also larger generators have automatic voltage regulation to compensate quickly for any changes in load which could adversely effect the frequency or voltage of the generator.

Reverse Power Protection [11] – This protection can be used where the generation on the distribution network is not being used to export electricity to the grid. When the distribution network is islanded, power will flow from the generator to the local utility loads on the islanded network. A reverse power relay can only be used when there is a unidirectional flow of power.

Rate of Change of Frequency Relay (R.O.C.O.F) [11] **-** This is one of the most popular techniques for achieving loss of mains protection for distributed generation. This technique is based on the premise that a change in load or generation will occur immediately after islanding of the network. The R.O.C.O.F. relay monitors the voltage on the network and operates after a time delay if the voltage sine wave exceeds a preset value. The R.O.C.O.F. relay is difficult to set. If the voltage waveform value were too low the relay would nuisance trip and if the relay is set to high the relay may not operate for a disconnection condition. These relays are also known for nuisance tripping due to a remote disturbance on the network.

Phase Displacement Monitor [11] **-** This technique is related to the R.O.C.O.F. relay in that any changes in displacement are due to a change in the operating frequency of the electricity grid. The phase displacement also monitors the voltage waveform. These relays operate very quickly but they are very difficult to set just like the R.O.C.O.F.

3.3 Types of Loss of Mains Protection – Active Technique

Reactive Export Error Detected (R.E.E.D.) [11] **–** This relay interfaces with the generators control system to force the generator to produce an amount of reactive power, this can only be maintained when the generation is connected to the main utility grid. This relay has a time delay to allow for fluctuations in the power system. This relay can detect loss of grid even when there is no load change due to circuit breaker switching. However this relay can become less effective if power factor correction is used to maintain the reactive power level of the distributed generation close to unity power factor and the relay operating time is between 2 and 5 seconds.

System Fault Level Monitor [11] **-** This technique uses measurements of the source impedance at the interconnection circuit breaker to determine whether a fault condition the main grid has occurred. By measuring the short circuit current and reduction in supply voltage when a shunt inductor is placed briefly across the supply using point on wave triggered thyristor switches. These switches activate just before a zero in the current waveform, which causes a short pulse of current to flow through the shunt inductor. A trip signal will be sent if the utility system fault level disagrees with the measured value. A disadvantage of this system is that it can cause introduce flicker into the network.

Combined Capacitor /Reactor Technique [11] **–** This technique uses the fact that a capacitor connected across the local load when the distributed generation is operating independently of the main utility network the voltage level will rise and the frequency decreases. The opposite is true of an inductor placed across the local load. Using a combination of both capacitor and inductor, due to the counteraction properties they have together loss of grid can be detected while maintaining the voltage magnitude and frequency close to their previous levels.

3.4 Future Developments

Rate of Change of Voltage & Rate of Change of Power Factor [13] – This technique use a combination of rate of change of voltage and rate of change of power factor to detect loss of mains when the load is similar to previous generator load after islanding. Using the rate of change of voltage relay technique loss of mains can be detected when the islanded load is very similar to the previous generator load but with rate of change of voltage alone a fault condition is also detectable. Combining rate of change of voltage with rate of change of power factor the condition can only be loss of mains.

Power Measurement [12] – This technique uses current and voltage measurement at the generator terminals to calculate instantaneous power. The instantaneous power calculated is then used to calculate rate of change of power. This is achieved by integrating the instantaneous power over a moving period of time. When the absolute value of integrated power exceeds the set value a trip signal is sent from the relay.

3.5 Conclusion

Loss of mains protection is required under the UK Engineering recommendations G59/1[9] when an owner/operator of a distributed generation plant would like to connect their generation to the distribution grid. This protection is required by a distributed generation scheme to ensure detection of loss of mains so that the generation source can be isolated from the local utility loads and to ensure the safety of operational personnel working on the distribution network. Many of the techniques discussed will provide detection of loss of mains under certain conditions; no current method will detect loss of mains for all possible conditions. As distributed generation connection to the utility's network is set to increase current techniques should be reviewed and consideration should be given to combining two or three of the most reliable techniques within one relay to cover all possible scenarios. This relay could work on a voting system where two out of three techniques within the relay would have to detect an island before a trip signal would be sent. This would decrease nuisance tripping and decrease the possibility of a generator continually generating power for the island.

Section 4

Budget Cost for connection of 1 Wind Turbine to Utility

Cost of 1 Turbine	£1,250,000.00
Cabling Cost (1 km Length)	£22,000.00
Switchgear at Substation 4 Section	£60,000.00
Transformer	£6850.00
Cost of Connection to Utility @ 11kV [16]	£20,000.00
Cost of G59/1 Protection	
Neutral Voltage Displacement Relay	£494.00
Loss of Mains relay df/dt	£1775.00
Shunt Trip Coils	£120.00
Primary and Secondary Fuses	£140.00
11kV /110V Voltage Transformer	£900.00
Protection Relay Cubicle	£1500.00
Protection on Turbines	
Overcurrent Relay	£725.00
Current Transformer /Set	£345.00
Labour for Fitting Protection Relays and Panel	
2 Men for 5 days for 10 Hr /Days £35.00/ Hr	£3500.00
Testing and Commissioning 1 Man 1 Day 10 Hrs @ £40.00 Hr	£400.00
Total Cost	£1,368,749.00

* These costs do not include costs for 11kV switchgear installation.

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