

CSIRO CLUSTER PROJECT #3

*A report on quantification of network benefits
from the deployment of Distributed Generation*

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Table of Contents

Table of Contents	1
Executive Summary of Benefits of DG to Networks.....	1
Chapter 1 Benefits for Voltage	5
1.1 Voltage stability	5
1.2 Impacts of Large-Scale DG Integration on the VSM	9
1.3 Voltage profile	12
1.4 QUT contributions to DG as a feeder voltage, power factor and harmonic correction device	14
References	21
Chapter 2 Benefits for Reliability	26
2.1 Benefits for reliability	26
2.2 Reliability benefits of distributed generation as a backup source	27
2.3 Reliability issues of DG	28
2.4 Reliability evaluation of distributed generation based on operation modes	30
2.5 Reliability benefits of distributed generation on heavily loaded feeders	32
2.6 QUT contributions to optimizing DG including its reliability benefit	35
References	42
Chapter 3 Protection Issues.....	45
3.1 Impacts on fault characteristics of power systems	45
3.2 Impacts on the operations of protective relays	47
3.3 Impacts on protection coordination	48
3.4 New protection technology considering the impacts of DGs	49
3.5 New protection technology developed by QUT considering the impacts of DGs	53
3.6 Implication for DG penetration into networks	66
References	73
Chapter 4 Benefits of DG with respect to Losses	75
4.1 Introduction	75

4.2 Methods for estimating network losses with DG	75
4.3 Distributed generation contribution to losses	76
4.4 Reported studies on distributed generation impacts on losses.....	77
4.5 Network benefits with DG	78
4.6 Realistic facts in quantification of network benefits	86
4.7 Summary.....	87
4.8 Conclusions	87
References.....	88
Chapter 5 Bringing the benefits together: Optimized DGs into networks	89
5.1 Structure for optimization.....	89
5.2 Optimizing impact on reliability, network reinforcement investment, and losses	91
5.3 Design of network incorporating DG benefits.....	95
Reference	99
Chapter 6 Overall comments and summary of contributions.....	100
6.1 Methodology	Error! Bookmark not defined.
6.2 Innovation	Error! Bookmark not defined.
Reference	101

Executive Summary

The benefits of DG to networks

Distributed generation (DG) represents decentralized generation of electricity, and is usually close to the loads and generally interconnected to the utility distribution system.

DG could save considerable costs in deferring network upgrades, improving system reliability and voltage profile, reducing energy losses, and providing blackout starting power. At the same time, DG could also lead to some challenges to power system operation and control due to its volatile features.

More specifically, DG has the following advantages:

1. DG can improve the efficiency of providing electric power. It is known that transmitting electricity from a power plant to a user wastes around 4 to 9 percent of the electricity losses.
2. DG could provide benefits in the form of more reliable power.
3. DG is helpful for improving the power quality.
4. DG is helpful for improving power transmission, and aids the entire grid by reducing demand during peak times and by minimizing network congestion. DG can contribute to deferring transmission upgrades and expansions.
5. DG helps reduce the terrorist targets since DGs are distributed and small-scaled.
6. The wide use of DGs could reduce emissions.
7. DG can provide emergency power for public services, such as hospitals, airports, military bases.
8. DG is helpful for increasing the diversity of energy sources. The increasing diversity could avoid the economy from price shocks, interruptions, and fuel shortages.

The benefits of distributed generation were summarized in a 2007 report prepared by Department of Energy (DOE), USA (http://www.oe.energy.gov/epa_sec1817.htm), and the matrix shown below was also given in the report.

There are four main areas of DG benefits to networks addressed in this report as listed below:

- voltage profile and power factor improvement
- contributions to reliability
- overcoming the barrier to using DG in protection
- impact of DG on losses

These areas of network impact are integrated into a tool for numerical appraisal of design of networks incorporating DG's. The optimization based on genetic algorithms modified particle swarm optimization is able to determine an optimal investment in distribution systems choosing between line

upgrades, switch capacitors, tap changers and Distributed generation appraised on the basis of reliability changes, investment cost and loss reduction.

Table 1. The Matrix Representing Distributed Generation Benefits and Services

		Benefit Categories							
		Energy Cost Savings	Savings in T&D Losses and Congestion Costs	Deferred Generation Capacity	Deferred T&D Capacity	System Reliability Benefits	Power Quality Benefits	Land Use Effects	Reduced Vulnerability to Terrorism
DG Services	Reduction in Peak Power Requirements	✓	✓	✓	✓	✓	✓	✓	✓
	Provision of Ancillary Services –Operating Reserves – Regulation – Blackstart –Reactive Power	✓	✓	✓	✓	✓	✓	✓	✓
	Emergency Power Supply	✓	✓			✓	✓		

T&D= transmission and distribution.

Methodology

The novel developments that have permitted quantification of these developments follow a similar pattern for the four basic areas. For voltage control, the limitation of existing standards and algorithms is illustrated. The essence of the problem is formulated in a mathematical model. An algorithm is proposed which addresses the problem and this is validated by simulations on models of representative sections of distribution networks. In this case existing tools inject power from inverters at unity power factor and when there is no local load then the voltage rise can exceed device ratings and the device trips. One can correct the voltage from an inverter by adjusting the reactive injection from the inverter. The difficulty is that a strong potential exists for oscillations between voltage controllers particularly inverter based. The solution process developed extends concepts of droop control of generation with the flexible control of inverters. This work was supported in part by CSIRO flagship funding and some of the motivation was developed by discussions with utilities and manufacturers. No similar work on voltage control and dynamic oscillations has appeared as part of journal publications or key conference publications but constitutes a breakthrough to a major problem inflicting utilities at the moment.

The process of reliability improvement using schedulable distributed generation has been investigated by QUT and other researchers. The key contribution in this project has been to show the strong relative benefit of reliability in motivating investment in distributed generation. The analysis

here is for the case where the system does not have strong possibilities of cross connects between feeders [11]. In highly meshed urban systems the reliability is obtained by providing alternative connection to other feeders. In more rural areas the option to connect to another feeder is a very expensive option and the DG solution can become an attractive investment. This project has investigated the change over point between cross connect solutions and DG and provided a guidance on the process of incorporating reliability into an overall investment strategy. The optimal investment strategy and the role of cross connects has been supported by the CSIRO flagship funding.

One very complex issue has been the protection strategy for incorporating distributed generation system within networks. This issue acts more as a barrier to DG connection than a direct network benefit. It is easy enough to protect the DG element from system faults and to protect the network supply transformer but the issue is to ensure reliable detection of network faults both for the purposes of avoiding excess damage to the lines and cables but to achieve required levels of public safety. The public safety issue arises because a conductor on the ground may have a high fault impedance and only part of the fault current is supplied by the substation and part can come from DG. The development partly funded by the flagship project includes development in protection algorithms [4] and fully funded in fault interpretation [1-3,5].

Innovation

The overall aim of the project has always been focused on determination of siting and sizing of distributed generation. On a pure energy cost basis it frequently is not justifiable to invest in distributed generation in Australia. Where the waste heat can be used locally and displaces high cost energy purchases then local generation can become attractive. For most of Australia energy costs are not dominated by heating so aspects that drive DG in Europe become not so attractive in Australia. On the other hand Australia has a high cost sparse distribution network for large numbers of customers. The equivalent cost for delivery of energy to outback Queensland customers 10years ago was 70c/kWhr while the consumer cost in the city was 15c/kWhr and the bulk energy cost was around 3c/kWhr. For generation back into the grid for highly connected networks the appropriate reward would be at the cost of displaced energy 3c/kWhr. If the generation was guaranteed to be present at the peak time for the high cost areas of the network the appropriate reward for generation should be closer to the 70c/kWhr. This illustrated that for certain types of generation it is important to consider the network benefits and the easiest economic cases for DG may be on the fringe of grid until a substantial carbon price raises the reward level more generally. In order to quantify these benefits particularly for reliability the DG must often run when required in combination with other DGs. The network benefit must be traded against increased generation cost if there are sites with substantial changes in generation cost or efficiency. Overall these units must be permitted to run and support voltage if major benefits are to be obtained hence a significant effort has been spent to ensure that protection and voltage control strategies would be acceptable to utilities.

The key innovations that have arisen from this project have been

- to support some of the developments in voltage control and thus provide a basis for a new generation of inverters for distribution networks.

- to develop strategies to interpret faults on networks in the presence of DG and to partly support developments in inverse time admittance relay developments as a method to ensure public safety though reliable detection of faults on networks with DG.
- of itself losses constitute approximately 7% of the generated power in Australia. Distributed generation which places the generation close to the load can reduce those losses. However the generation cost of DG's is frequently much larger than central generation costs so this 7% loss benefit does not of itself drive much investment in DG. When the major benefit is in voltage control and reliability then the loss benefit can help get the project over the line.
- to determine optimal investment in networks across a range of options including DG against multiple selection criteria, a new optimization tool has been developed. This tool addresses the variation of loading levels and the discrete and nonlinear nature of the optimization. Existing tools such as pure genetic algorithms (GA) or particle swarm optimizations (PSO) have been found to be unable to cope with the highly quantized nature of distribution system optimization which is often expressed as selection of one of a set of standard sizes for transformers or cables. The most successful tool has been a combination of GA modified PSO. The process of iteration across multiple load levels is another innovation which raises the performance above anything currently available.

Overall the project has contributed to the removal of two key barriers to the wider adoption of DGs and has provided tools to quantify the appropriate investment levels justifiable for a utility to invest in DG. This quantification of value would potentially form the basis of a reward mechanism for third party DG owners to seek a reward from utilities.

Six chapters are included in this report. The benefits of DGs on reliability enhancement, voltage improvement, and loss reduction are addressed in Chapters 1, 2 and 4 respectively, while the impacts of DGs on protective relays are presented in Chapter 3. In Chapter 5, the overall benefits of optimized DGs into networks are examined, while in Chapter 6 overall comments and summary of contributions presented.

Chapter 1 Benefits for Voltage

Some distributed generation technologies in the distribution system can control voltage profiles by injecting or absorbing reactive power, and even improve overall system voltage quality as well as voltage stability.

1.1 Voltage stability

The voltage stability index can usually be derived from the P-V curve [Hedayati et al. 2008; Xi Chen and Wenzhong Gao, 2008; Gil et al. 2009]. Bifurcation analysis is also used in [Hedayati et al. 2008]. By adding DG units in the bus most sensitive to voltage collapse, the voltage profile can be improved, the power loss reduced and the power transfer capacity increased. A typical 34-bus distribution network is used to test the method. In [Xi Chen and Wenzhong Gao, 2008], the overall impact of adding DG (fuel cell) to the modified IEEE 14 bus test case is studied. Different DG placements are compared in terms of power loss, load ability and voltage stability index. The Fast Voltage Stability Index (FVSI) and Line Stability Factor (LQP) for voltage stability contingency analysis are compared. In [Gil et al. 2009], the VSM (Voltage Stability Margin) is improved by connecting DG units at a particular bus. The index is extended to DGs connected at a group of buses. The proposed BVI (Bus VSM Improvement Index) is calculated with different DG penetration in the IEEE RTS96 24-bus test system. The BVI remains relatively stable for penetration levels from 0% to 20%. The installations of DG provide reliable support for contingencies and can improve the VSM by 45% to 60% during the peak load period; however when the load is too low or too high, the VSM improvement is not obvious. In [Kumar and Selvan, 2009], DG units are optimally deployed in the distribution network with genetic algorithm. The location of DG is initially selected according to the voltage stability index. The fitness function consists of energy losses plus the weighted voltage deviation of every bus. The method is tested with a 25-bus Indian system, a 33-bus and a 69-bus radial distribution network. Simulation results show that the SI (voltage stability index) decreases as the load level increases. The load increasing factor is evaluated for two different scenarios with or without DG in [Fujisawa and Castro, 2008]. In [Hemdan and Kurrat, 2008], it is discussed how the locations and capacities of DG units enhance the voltage stability; the influence on different feeders in the distribution network is also analyzed. Different types of DG are studied. A static voltage stability margin (SVSM) is used to determine the locations of DG [Chen et al. 2006], and the load increase is considered in this model. The GA optimizer however will greatly increase the computational cost when there are more nodes.

In [Nasser G. A. et al. 2008], the effect of DG capacity and location on voltage stability enhancement of the radial distribution system is investigated. It was found that the location of the DG has a significant impact on the voltage stability over its capacity, and voltage stability should be taken into account as a goal when dealing with the optimum allocation of DG.

In [Lin Wang et al. 2006], a new network-facilitated voltage stability control strategy is presented for distribution systems connected to distributed generations (DGs). The strategy aims to increase power system operation security during normal conditions and to save a distribution system from imminent voltage collapse due to contingencies. When implementing the strategy, state-of-the-art digital signal processing (DSP) technology is used for determining correct voltage stability controls, and modern computer networking technology is utilized for monitoring power system operating states and transmitting data and stability control commands.

The voltage stability of the investigated network is tested by applying some disturbances in both the high and the low-voltage networks in [Ahmed M et al. 2005]. Fig. 1 shows the voltage response to the abovementioned 150ms fault at bus (B2). All DG units contain suitable reactive power controllers to regulate their performance. Since these units are located near the load centre, some improvements in the performance are achieved, especially for the load during the short circuit.

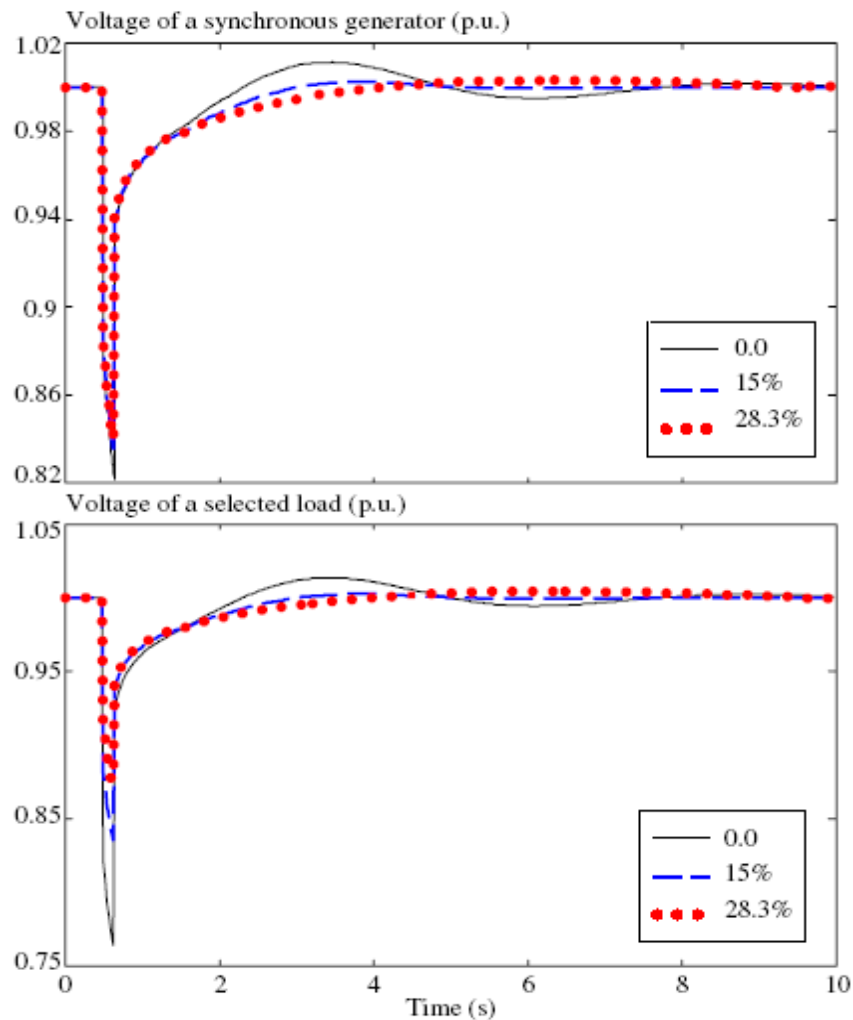


Fig. 1. Voltage variation of one of the synchronous generators and a selected load as a result of a three-phase fault in the high-voltage network

Fig. 2 illustrates the voltage response to a 10Mvar load switching at bus (B1) in the high-voltage network. The increase in the penetration level of the DG units causes more damping to the voltage in both the low- and the high- voltage parts. In addition, lower steady-state voltage deviations are achieved at load terminals when the DG sources are used near them. However, the steady-state voltage deviations at the generator terminals are lower when no DG units are used. Due to the higher capacity of synchronous generators without DG units, they can achieve better local voltage support at their terminals. Therefore, the synchronous generators compensate for the reactive-load switching with lower terminal-voltage deviations.

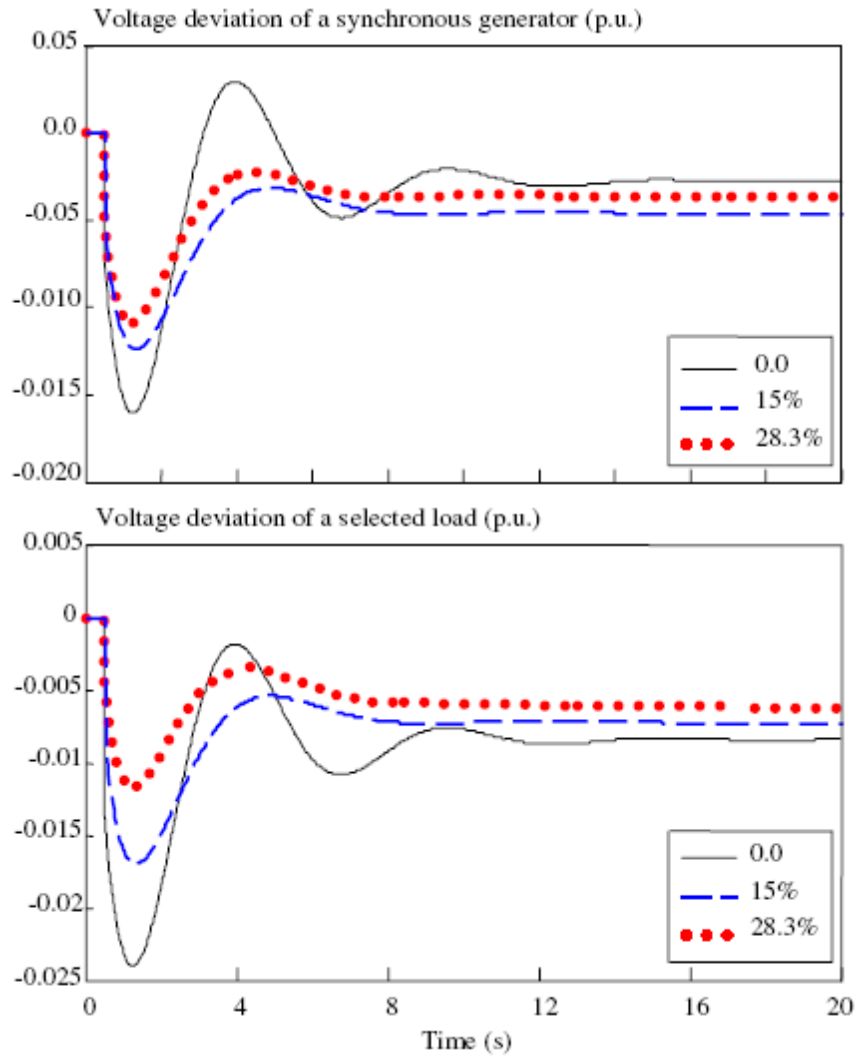


Fig. 2. Voltage deviation of one of the synchronous generators and a selected load as a result of switching a load of 10Mvar in the high-voltage network

Fig. 3 shows the voltage deviation at two load nodes when a load of 1Mvar is switched on at the terminals of the first load of them. The second load node is about 2km away from the switching point. A large voltage decrease occurs at the switching point when the DG units are not utilized. This voltage decrease is significantly reduced when the 28.3% penetration level is considered. The other load terminals in the distribution system also incorporate some

improvements in the voltage profiles when DG units are used. The voltage decrease and the relative improvements in the voltage profiles at these terminals vary depending on their relative locations with respect to the switching point.

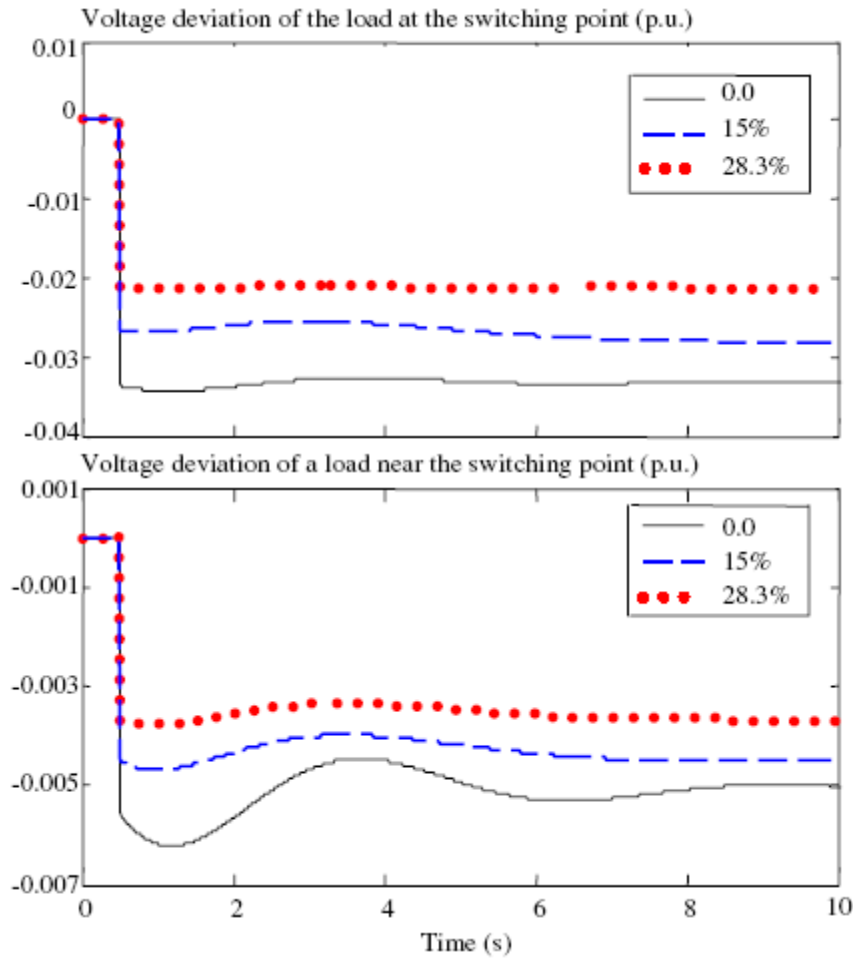


Fig. 3. Voltage deviation at two load terminals as a result of a switching a load of 1Mvar in the low-voltage network

Generally, the analysis of the system performance with regard to voltage stability shows that DG can support and improve the voltage profiles at load terminals. This can extend the stability margin of dynamic loads, i.e. induction motors, which can lose their stable operating point with large voltage dips.

The research work in [H. A. Gil et al. 2009] is focused specifically on how large amounts of DG may influence the Voltage Security Margin (VSM) of the transmission grid during normal operations and under contingencies. Bus-based indices are developed, which provide information about the relative influence of aggregated customer-owned DG on the voltage security of the grid. The study relies on a systematic voltage stability analysis for different DG penetration scenarios and locations across the grid. A study of the influence of the daily system load cycles and type of contingencies is also provided, which sheds light on the actual effectiveness of aggregated DG for reinforcing the transmission grid against voltage collapses. It was found that such contribution

may change considerably depending on the location of the aggregated DGs. It was also found that the actual support received from the aggregated DGs during contingencies depends largely on both the precontingency system load level and the post-contingency voltage security margin.

1.2 Impacts of Large-Scale DG Integration on the VSM

A. Contribution of DG to the system VSM

Relative to the current operating point, the VSM is defined as the ‘distance’ to the point of voltage collapse, usually parameterized with respect to a reference system load. In this work, the VSM is measured as the actual loading, λ , (in MW) at the point of voltage collapse (a zero reference load is assumed). Voltage collapses are strongly connected to Saddle-Node Bifurcation (SNB) points, as shown in Fig. 4.

With this in mind, the first direct measure of how DG contributes to the system VSM is to carry out an incremental voltage stability analysis for different realistic DG penetration scenarios, and compare the results to a base-case with no DG. Such incremental analysis will tell not only how the VSM is improved (or worsened) in absolute terms (in MW), but will also provide information about the best locations for aggregated DG from the voltage security point of view.

Here, a “Bus VSM Improvement Index” or BVI_i is proposed. This index is a measure of how given MW of aggregated DG at bus i (P_{DG_i}), improves the system VSM from a base-case MW loading λ_0 to a new MW λ_i relative to the amount of aggregated DG being integrated. Thus:

$$BVI_i = \frac{\lambda_i - \lambda_0}{P_{DG_i}} \quad (1)$$

The proposed index indicates the percentage VSM improvement of every kW of DG connected at a particular bus. For instance, a BVI_i of 0.71 indicates that the system VSM improves by an amount equal to 71% of the total DG installed at bus i . Note that the index can be either positive, greater than one, zero or even negative, as the results will show.

The contribution from a given combination of DGs (or the totality of them) may also be estimated with an expression analogous to (1). For instance, for a given subset Ω of buses with DG one can determine a BVI_Ω as follows:

$$BVI_\Omega = \frac{\lambda_\Omega - \lambda_0}{\sum_{\Omega} P_{DG_i}} \quad (2)$$

Where the denominator indicates the total DG capacity contained in the bus subset Ω . The issue of whether a subset’s BVI_Ω can be expressed in terms of the sum of the individual indices BVI_i of all DGs contained in the subset depends on whether the response of the network with respect to the VSM is nearly linear, at least for small DG penetrations. Intuition says that the larger DGs (in MW) should have more weight on the index BVI_Ω for the set to which the DG belongs. Hence, if one defines a weight factor γ_i as:

$$\gamma_i = \frac{P_{DG_i}}{\sum_{\Omega} P_{DG_i}} \quad (3)$$

Then, it could be assumed that:

$$BVI_{\Omega} = \sum_{\Omega} \gamma_i BVI_i \quad (4)$$

If (4) holds true, the superposition principle can be applied and the estimation of the combined contribution from aggregated DGs at different buses is considerably simplified. This assumption will be later confirmed, especially when generators are below their active and reactive power output limits and for small DG penetration levels.

Although the result from (4) is certainly not general for large DG penetration, it implies that in certain cases the estimation of the VSM improvement by any combination of aggregated DGs could be simplified by estimating individual BVI_i for each bus and then adding them up to obtain the combined contribution. This operation would only require one voltage stability analysis for each bus in set Ω , instead of requiring a study for each possible combination inside the set of buses under analysis, which may be rather large for large scale grids.

B. Effect of Contingencies

Estimating the system VSM would be of little use if all generation and power delivery equipment were guaranteed to operate with 100% reliability all the time. System operators are therefore interested not only about how aggregated DGs improve the VSM on normal operating conditions, but also about how those DGs will support the system during transmission line outages.

DG interconnection standards usually require DG to disconnect whenever the voltage at the point of interconnection drops below a certain threshold for a predetermined period of time. In these conditions, a large tripping of large amounts of DG will certainly worsen the system voltage and angle response during the contingencies. However, if the DGs manage to “ride through” the distribution-level voltage oscillations provoked by certain transmission line outages, DGs can actually help the system survive the outage. The latter can be better explained with the help of Fig. 4. Thus, during normal operation at a given hour of the day (with all generation and delivery equipment operating as intended) the system operates at point A. Assuming that the loads are constantly powered (as is typically the case in voltage stability studies due to load recovery characteristics), if a transmission line contingency occurs, the system will stabilize at the new operating point represented by B along a PV-curve that includes the output from the DGs. If a further scenario with no DGs in operation is considered (the left-most curve), the system might experience a voltage collapse.

Note in Fig. 4 that the DGs would not provide any assistance on a contingency if the load is greater than λ_2 . Similarly, for loads below level λ_1 , the system might survive the contingency regardless of the presence of DGs, depending on angle stability issues.

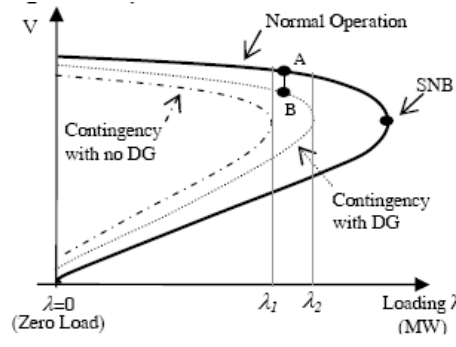


Fig.4. PV-curves for different contingency and DG scenarios

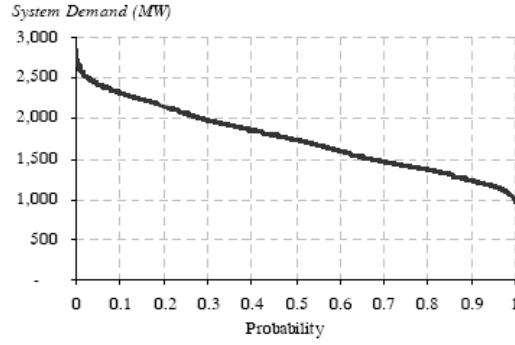


Fig.5. Load duration curve

Therefore, although DGs may actually improve the reactive power supply across the transmission grid, from a voltage stability perspective, their most important contribution during contingencies actually takes place on the load interval between λ_1 and λ_2 . This load interval is referred to as the “DG assistance” interval. Since the system load is constantly fluctuating over a wide range during the day, one way of determining the probability that the load falls within the interval given by λ_1 and λ_2 is to consider a system’s normalized Load Duration Curve (LDC) as depicted in Fig. 5.

Hence, a normalized LDC function $LDC(d)$ will yield the probability p that the load will be above a certain value d , i.e.:

$$p \left[\lambda \geq d_0 \right] = LDC(d_0) \quad (5)$$

Similarly, defining α as a function with the probability that the load will fall between d_0 and d_1 , then:

$$\alpha(d_0, d_1) = p \left[\lambda_1 \geq d \geq d_0 \right] = LDC(d_0) - LDC(d_1) \quad (6)$$

Note that $LDC(d_0) > LDC(d_1)$ whenever $d_0 < d_1$. For instance, according to the LDC shown in Fig. 5, the probability that the load is higher than 2,000 MW is:

$$p \left[\lambda \geq 2,000 \right] = LDC(2,000) = 0.287 \quad (7)$$

The probability that the load will be between 2,000 MW and 2,200 MW is:

$$\alpha(2,000, 2,200) = LDC(2,000) - LDC(2,200) = 0.287 - 0.171 = 0.116 \quad (8)$$

Observe that the probability $\alpha(d_0, d_1)$ in (6) may have considerable small values, especially for higher demand levels.

The main idea here is that the actual contribution from DGs upon contingencies should consider not only the contribution to the VSM in MW, but also the chance that the system load will be within the “DG assistance” interval given by the postcontingency VSM with and without DG, i.e. the λ_2 and λ_1 values, respectively, in Fig. 4. The next section will clarify these concepts and will help understand better the actual effectiveness of large amounts of DG in preventing a voltage collapse upon large-scale contingencies.

1.3 Voltage profile

A method that can regulate the line voltage within voltage limits and can reduce the electrical flickers of wind turbines is proposed in [Y. Kubota et al. 2002]. In [T. Ackermann and V. Knyazkin, 2002], the problem of improving voltage quality by changing the locations and capacities of DG units is discussed. It is concluded that the impact of DG depends on the penetration level of DG as well as on the DG technologies.

The authors of [Carastro et al. 2006] discussed the application of a shunt active power filter with energy storage to stabilize voltage and eliminate harmonics. The control method based on the state space pole-placement design shows good performance with zero steady state error given plant variation. In [Karlsson et al. 2005], the voltage droop controllers of power electronic converters are presented and can operate well in both the stand-alone mode and when rotating sources are included in the DG system. The proposed controller is tested by simulation and experiments in [Karlsson et al. 2005].

In [Qiu Sun et al. 2009], the impact of DG’s locations and capacities on voltage profile in power distribution networks is discussed. Two typical load distribution models - uniform and isosceles load models - are established to analyze the voltage profile on the feeder quantitatively. Regarding the simulation, it is shown that the voltage profile could be influenced by the location and capacity of DG, which should be well planned to ensure the static voltage of each node within the permitted range.

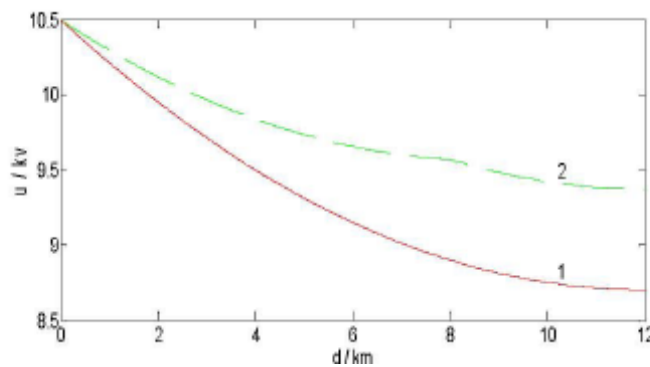


Fig.6. Voltage profile of feeder with a uniform load before and after DG is injected

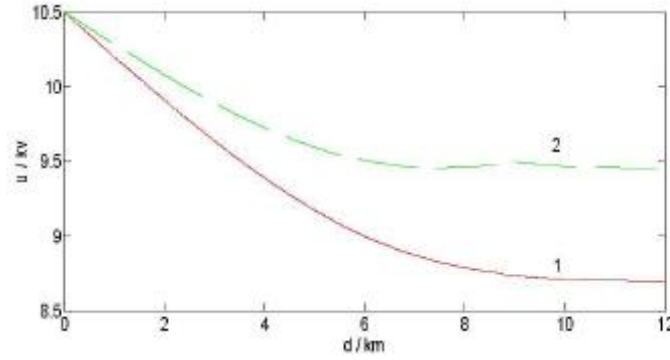


Fig.7. Voltage profile of feeder with an isosceles load before and after DG is injected

In Figure 6 and 7, curve 1 and curve 2 represent the voltage profile without DG and with DG respectively. It can be observed that DG can provide voltage support to pull up the low voltage at the end of the feeder. The effect of DG is more obvious when it is near the end of the line.

In [R. R. Londero et al. 2009], the impact of DG with different penetration levels on steady-state voltage profile and voltage stability of power systems is addressed. It is found that voltage profile is improved by utilizing DG with respect to the steady-state analysis. With more power from the DG units, the voltage stability margin is also improved. However, the DG penetration levels do not impact voltage at DG terminals.

Fig. 8 shows system voltage profile to high load for the main buses in the corridor between the main generator (bus 6420) and the DG (bus 5170). The results show that as the DG penetration level increases, the system voltage profile also increases.

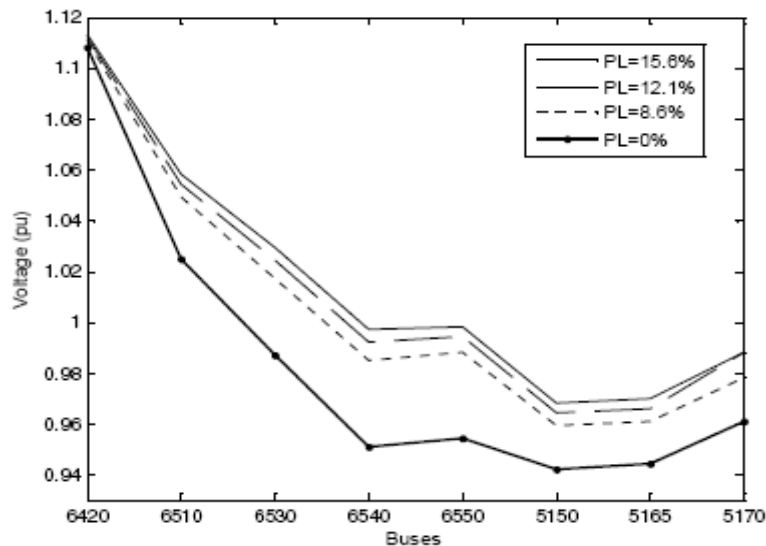


Fig.8. Steady-state voltage profile for different DG penetration levels.

Fig. 9 shows the voltage stability PV curve at bus 5210 (138kV) for different DG penetration levels to high demand, considering constant power loads. Although the active and reactive power supplied by the DG was kept constant during the simulations, which means that

only the main generation assumes the increase in system demand, the results show that the presence of the DG improves the system voltage stability margin. It can be explained because the DG provides active and reactive power to local loads, decreasing system losses and increasing the system voltage stability limit.

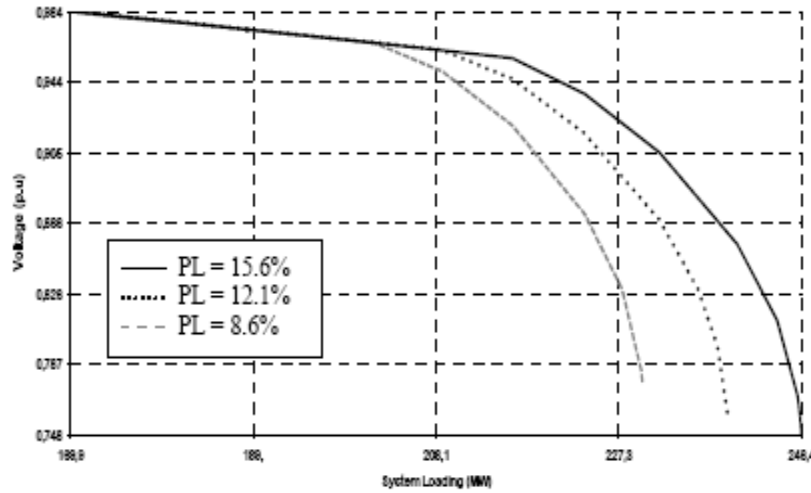


Fig.9. PV curves for different DG penetration levels considering constant power load.

1.4 QUT contributions to DG as a feeder voltage, power factor and harmonic correction device

Inverter based DG systems such as PV, fuel cells, microturbines all are theoretically capable of affecting the system voltage. The difficulty that is facing many utilities at the moment is the voltage rise on feeders with high levels of PV installation. With low occupancy during the day with high PV power input the voltage rises causing the PV inverters to trip. The vision presented here is for all inverter connections to be grid positive in having a hierarchy of tasks within the rating of the connection inverter

1. Export of the required real power
2. Export or import of reactive power to control voltage and/or power factor
3. Suppression of system harmonics

The present regulation for inverters for PV connection focus on real power export, insists on unity power factor and sets limits on harmonic creation. There are three main aspects to the research innovation covered here.

1. The first one is the development of a voltage control process such that sets of inverters can contribute to feeder voltage control without risk adverse interactions between the controllers. The next step reviews the power factor implications of voltage control.
2. For perfectly reactive lines then a flat voltage profile with each voltage at exactly the reference level, the power factor at the start of the feeder is unity which implies lower cost for the supply transformer or equivalently maximized feeder rating at peak load. For real distribution lines with substantial resistance the voltage profile needs to be shaped to get the unit power factor at the transformer but can be part of the same form of voltage controller.

3. The final aspect is the control of harmonics. Inverters are capable of current tracking which means that they can absorb no harmonics. They can operate in voltage control mode which means they must absorb all harmonics at that point of the network. The research result here is that the inverter control can be changed on line to control the extent of harmonic absorption dynamically such that the troublesome low order harmonics can be absorbed up to the device rating without detriment to real or reactive power tasks.

A Voltage Control with multiple inverters

In [G Ledwich et al, 2010], an analysis has been presented on impacts of multiple site reactive power compensation for distribution feeder voltage support. Initially, a radial distribution feeder with multiple DSTATCOMs is modelled in MATLAB and tested with proportional-only controllers. The test results obtained with proportional-only controllers demonstrated that the steady state voltage profile of the feeder is dependent upon the proportional gain of the controllers, i.e. a higher proportional gain yielded a better voltage profile. An increase of proportional gains in order to further improve the steady state voltage profile resulted in voltage oscillations and system failure.

TABLE I
PARAMETERS USED IN SIMULATION STUDY WITH PROPORTIONAL
CONTROLLER

Variable	Value
Source voltage (V_S)	1 pu
Reference voltage (V_{ref})	1 pu
Total line impedance (Z_{Line})	(0.24+0.4j) pu
Total load impedance (Z_{Load})	(2.7+1.2j) pu
Proportional gain of the controller (k_p)	0.5
Number of buses	5

The developed model is tested for five DSTATCOMs in the network. A time domain simulation is carried out on MATLAB with a 0.02 s time step. The parameters used for the simulation study is listed on Table I. Fig. 10 shows the variation of voltages at buses 1, 3 and 5 with time and Fig. 11 shows the steady state voltage magnitudes at different buses along the feeder with and without DSTATCOM operation. It is observed that the steady state voltage profile of the feeder is improved by the DSTATCOM action. It is also clear that the steady state voltage errors are reduced with increased gain. If the gain of the controller is further increased to $k_p = 1$, the system response becomes oscillatory and the control system becomes unstable as illustrated in Fig.12. It is also observed that these voltage oscillations are getting larger with the bus number. In other words, the farthest bus from the substation experiences the largest oscillations. There is a maximum value for the proportional gain before the system becomes unstable. Low proportional gains on the other hand, result in higher steady state voltage errors and poor voltage profile along the feeder even when the DSTATCOMs have spare reactive power capacity.

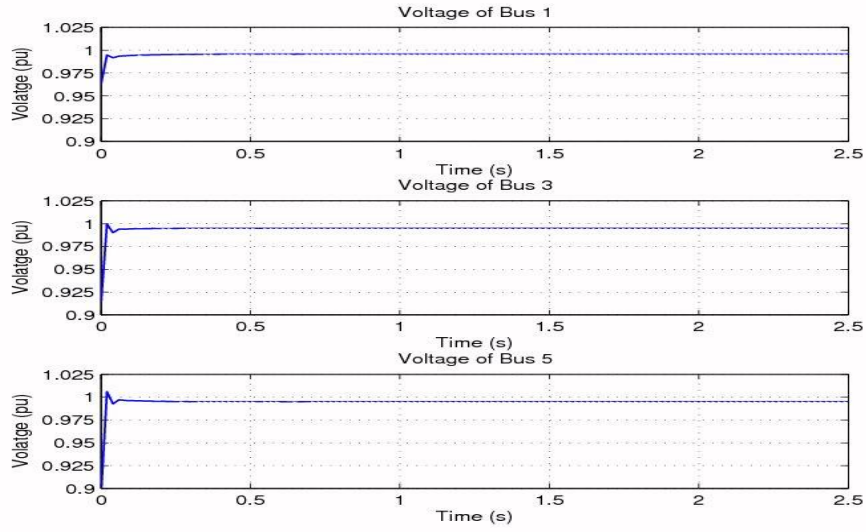


Fig. 10. Bus voltage variation with proportional controller

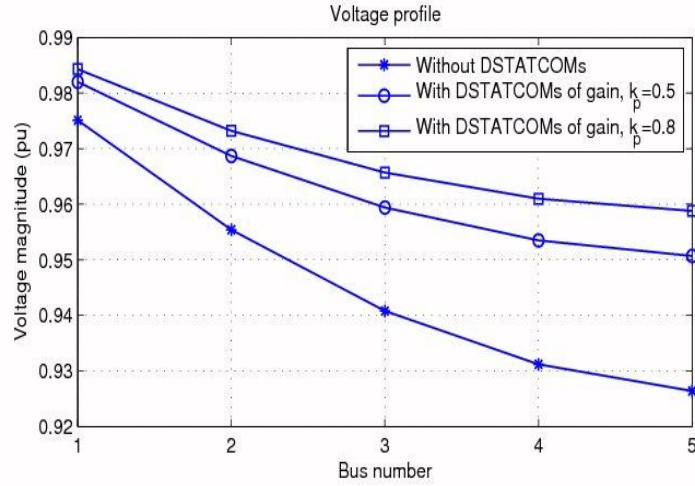


Fig. 11. Steady state voltage profile of the feeder

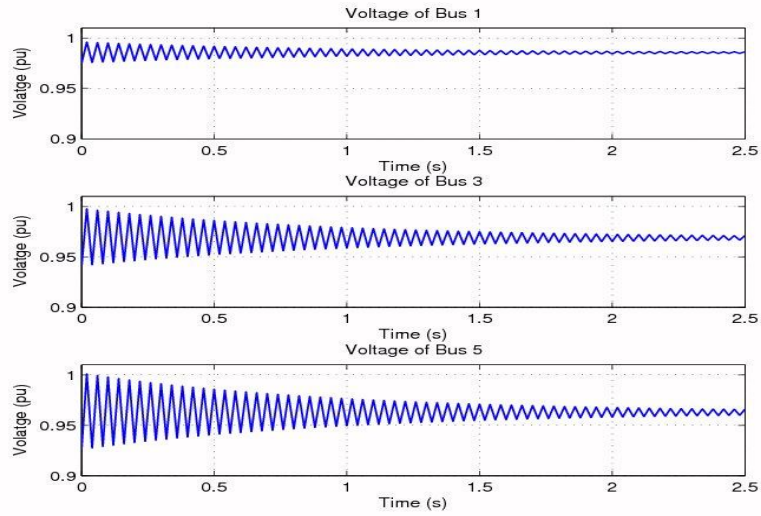


Fig. 12. Bus voltage variation with high proportional gains ($k_p = 1$)

As a result, the DSTATCOMs are proposed to operate on their respective steady state droop lines in order to obtain the highest gain for voltage correction. An integral controller is used to force the operating point on to the steady state droop line. The control strategy has shown enhanced sharing of reactive power among DSTATCOMs.

A mathematical model of a radial distribution feeder connected with multiple DSTATCOMs that are controlled by the proposed control strategy is developed. Eigenanalysis has been conducted to predict the degree of DSTATCOM interaction and to develop the criteria for controller design. These results showed that the dynamic interactions between DSTATCOMs are likely to occur under lightly loaded conditions. In other words, the system is more stable for heavily loaded conditions than for lightly loaded conditions. It also showed that increasing the number of DSTATCOMs has a higher chance of causing dynamic interactions between two adjacent DSTATCOMs.

The steady state bus voltage versus total load admittance plots showed that the feeder capacity can be improved by a significant percentage with the operation of multiple DSTATCOMs. Nevertheless, this percentage is dependent upon the rating and the droop coefficient of DSTATCOMs. Smaller droop coefficients ensure higher utilization of DSTATCOMs at all operating conditions. The daily load profile must be considered when determining the number of DSTATCOMs, their positions and ratings. An Eigenanalysis must be carried out to determine the controller gains for stable operation. Although higher integral gains assure quicker steady state operating points, such higher gains may also introduce a higher degree of interaction between adjacent DSTATCOMs.

Eigenvalue analysis of the system matrix is useful to predict the level of interaction among DSTATCOM controllers and the system instability. There are 10 Eigen values for this system. These Eigen values are plotted on Fig. 13 for an integral gain range from 1 to 3 with 0.1 increments. A similar Eigen value analysis is performed for the same radial feeder when the total load is equally distributed at 10 different locations and each location is connected with a DSTATCOM (a 10 bus system). Fig. 13 shows that there is a maximum or boundary integral gain before the system becomes unstable. This boundary integral gain is plotted on Fig. 14 for both 5 and 10 bus systems against the total load admittance. These plots demonstrate that both systems become more sensitive to integral gain under light loading conditions and the 10 bus system becomes unstable at smaller integral gains than the 5 bus system. In other words, the system is vulnerable to an increase of integral gains when the DSTATCOMs are situated much closer to each other.

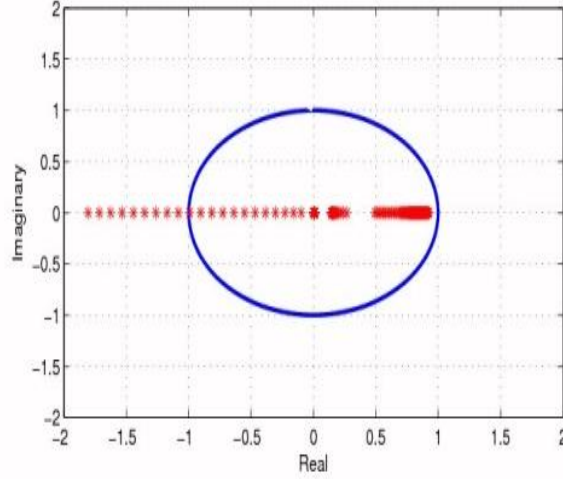


Fig. 13. Eigen value locus with varying integral gain for 5 bus system

Alternatively, the boundary integral gain can be found by repetitive time domain simulations with gradual increments of integral gain. In this process, the boundary integral gain is identified with voltage oscillations. Boundary integral gains obtained in this manner for few randomly selected loads matched well with the values of Fig 14.

The paper has only presented and discussed the test results for uniformly distributed DSTATCOM cases to illustrate the performance of the proposed control scheme. However, a test with two DSTATCOMs at the same bus demonstrated that the control system managed to maintain the bus voltage without any conflicts between the two controllers. Thus, the proposed control system is likely to be equally robust for non-uniformly distributed DSTATCOMs.

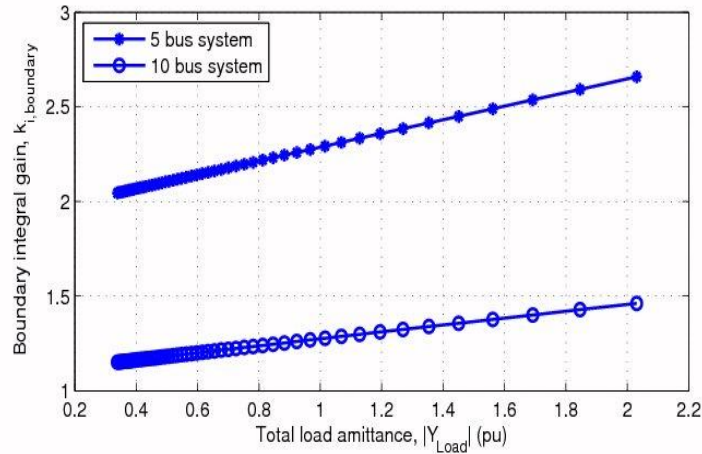


Fig. 14. Boundary integral gains versus total load admittance

B DSTATCOM for distribution line enhancement: power factor issues

Distributed small power electronic converters can be added to customer premises to inject reactive power to assist with voltage profiles and/or power factor. In [L. Perera et al] an effort is made to examine whether there is a fundamental conflict between voltage control and power factor control.

For feeders which are approaching a loading limit based on voltage, a substantial enhancement of 4 times loading (in one example) becomes possible through the use of voltage controllers. In this case the only criterion applied was keeping the voltage above 0.95p.u. A total load of $0.8907 - 0.3959i$ p.u. required a total Q injection of .638 p.u. for a line with an impedance angle ($R+jX$) of 60° .

The rating of lines and the line losses can be minimized if the power factor is kept close to unity through all line segments and transformers. For purely reactive lines then this corresponds to a flat voltage profile. However the resistance in distribution lines can be quite significant thus even if the current is in phase with the voltage, the voltage across the line segment is $I*(R+jX)$ and thus there will be a significant voltage drop along the line even for the unity power factor current. If the voltage remains within the required bounds then the reactive capability of inverters could be used to make line current in phase with line voltage thus minimizing energy losses in the line. One aspect about implementing such a control would be that the line current phase would need to be communicated from the power line going down the street to the controlling inverter in customer premises. If we have a pure voltage control strategy then there is no need for remote measurements only the voltage at the terminals of the inverter system.

The aim of this paper is to show that parameters of a voltage control scheme (identical for all inverters in the feeder) can be adjusted such that the power factor at the supply end of the feeder approaches unity power factor while the reactive capacity of the inverters is used towards the far end of the line particularly if the voltage is approaching the limit of $\pm 5\%$ error. The seven cases in this paper are of a radial feeder with inverters at each bus. Each uses an integral to droop line controller but the reference voltage, the droop line gain and the shape of the droop line are varied.

Therefore, power factor or voltage control can be implemented without stability concerns using the integral to droop line. If the line was pure reactive there is no conflict between voltage and power factor control. The unity power factor design is achieved by a voltage control to 1pu down the feeder with a shallow droop line for tight voltage control. When the line impedance is 30o from pure reactive, then this tight voltage control to 1p.u. will yield a current that is lagging by approximately 30o. In the seven examples of this paper, a loose voltage control to steeper droop line and a reduced voltage reference can give reduced line losses and achieve close to unity power factor at the beginning of the feeder. There is a reduced level of loading support to maintain the voltage profile in this scenario. Adding a nonlinear droop line which provides a substantially greater level of reactive support as the voltage approaches 0.95p.u. increases the constraints on the control stability but constrains the voltage droop at the end of line while maintaining it closer to unity power factor at the line source.

C Tuning Harmonic Absorption of Voltage Source Converters

In [G Ledwich and L Perera], a method is developed for controllable harmonic absorption using hysteretic controlled state feedback converters operating in power systems. The analysis is able to confirm the expected dynamic performance through eigenvalue analysis of the system with controller. The control is able to select between very low harmonic absorption by

emphasizing current tracking or a high level of absorption by emphasizing voltage tracking. The robustness of the LQR based hysteretic design is able to be clearly shown using the eigen-analysis tool developed in this paper. The analysis process can be easily extended to include multiple converters that are connected to multiple buses of a power system.

In this paper, the converters are assumed to consist of ideal dc voltage source supplying a voltage of V_{dc} to a VSC. The structure of the VSC is shown in Fig. 15. The VSC is set as an H-bridge supplied from a dc bus. The resistance R_T represents the switching and transformer losses, while the inductance L_T represents the leakage reactance of the transformers. The filter capacitor C_f is connected to the output of the transformers to bypass switching harmonics, while L_f represents an added output inductance of the DG system. Together L_T , C_f and L_f form an LCL or T-filter.

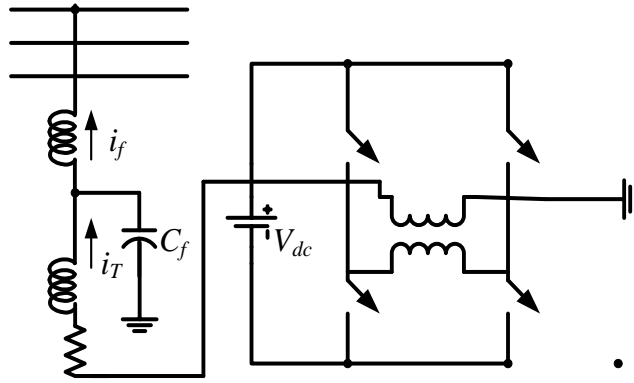


Fig. 15. Converter structure.

The equivalent circuit of the converter is shown in Fig. 16. In this, $u \cdot V_{dc}$ represents the converter output voltage, where u is the switching function and is given by $u = \pm 1$. The main aim of the converter control is to generate u . From the circuit of Fig. 2, the following state vector is chosen $z^T = [v_c \ i_f]$.

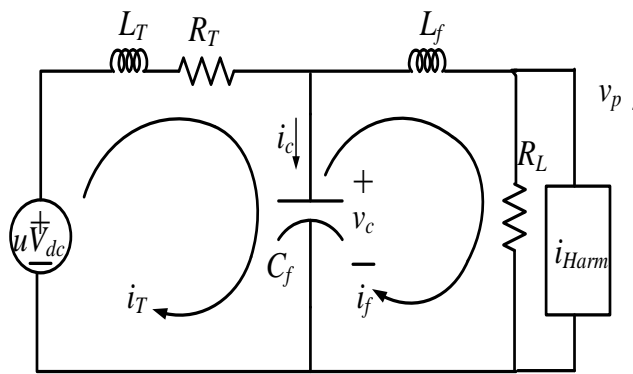


Fig. 16. Single-phase equivalent circuit of VSC.

The results in Fig 17 show that over the range considered the real component of the two eigenvalues is always negative. Thus the LQR design process with the state feedback is able to ensure stability of this system even with the use of the sliding line transformation.

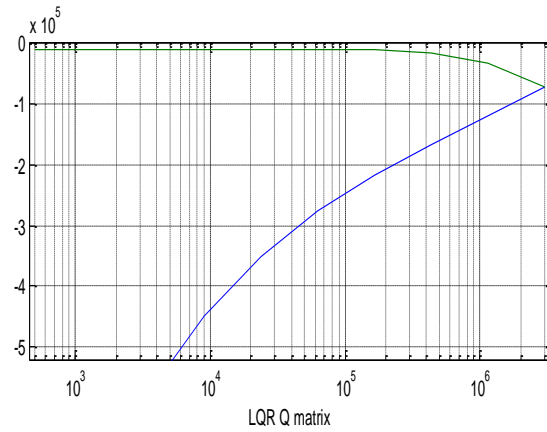


Fig. 17. Eigenvalues of hysteretic system

Inverters for PV applications have real power control as the main task. A secondary task can be the control of voltage on feeders by the export of reactive power which can take up more of the remaining inverter capacity. The harmonic properties can then be tackled but the extent of absorption needs continual cycle adjustment to ensure device rating is not exceeded. Tunable harmonic correction can be based on correction of the waveform distortion on the previous cycle. For random or burst distortion the process designed in this paper adjusts the relative harmonic impedance and will be operative even for sudden changes in the system distortion as in arc furnaces. When there are multiple converters then they can have a form of droop line sharing of harmonic absorption provided that the harmonic impedance is finite.

Conclusions

Because of their distributed nature, distributed generation can make substantial differences to customer voltage in the distribution system. With inverter based DG such as photovoltaic panels their reactive capacity can be made to work co-operatively as a dispersed voltage controller using a new tool “integral to droop line control”. This same tool can be set such that the peak loadability of feeders can be improved through improving power factor at the transformer supplying LV lines. Incorporating this tool not only removes the barrier to adoption that voltage issues are becoming but it can contribute to the peak line loading.

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Chapter 2 Benefits for Reliability

The goal of a power system is to supply electricity to its customers economically and reliably. It is important to build and maintain a reliable power system because outages can incur severe economic damages to the utility and its customers.

In Australia, electric power utilities have been restructured and divided into separated generation, transmission and distribution companies. The responsibility of maintaining the reliability of the overall power system is shared by all involved companies instead of by a single utility only.

Distributed generation (DG) is normally defined as the small generation units (<10 MW) installed in distribution systems. The applications of DG include combined heat and power, standby power, peak shaving, grid support, and stand-alone power. The DG technologies include photovoltaic, wind turbines, fuel cells, small and micro-sized turbine packages, internal combustion engine generators, and reciprocating engine generators.

In this chapter, the impacts of DG on power system reliability will be discussed in relation to the following five aspects.

2.1 Benefits for reliability

Power system reliability is usually defined as the ability of the power system to withstand sudden disturbances, such as electric short circuits and unanticipated loss of system facilities, while delivering electricity to customers with certain standards and in the amount needed. Power system reliability and power quality are closely related to each other. Reliability is often affected by power quality.

Different DG technologies have different features. Solar PV and fuel cells connected to the grid by inverters are characterised by zero inertia, while wind turbines are usually asynchronous generators. DG units connected to the weak point of the grid will increase the fault severity and consequently lead to voltage fluctuation and worsened stability.

1) Power supply reliability

An actual distribution network is studied in [Jahangiri and Fotuhi-Firuzabad, 2008 A. P. Agalgaonkar et al. 2006]. Three system indices, SAIDI (system average interruption duration index), CAID (customer interruption duration index) and AENS (average energy not supplied) are compared with 3 cases. The three indices in [Jahangiri and Fotuhi-Firuzabad, 2008] are also used in [Waseem et al. 2009], but more complicated factors, such as the location, size, and the aggregation of DG, are also considered. In [Atwa and El-Saadany, 2009], the SAIDI is improved by adding wind turbines in the island operation mode. The improvement of reliability however will be limited when the wind power penetration increases to a certain level. The distribution network is divided into several sections in [In-Su Bae and Jin-O Kim, 2007; In-Su Bae and Jin-O Kim, 2008]. The connection matrix of DG and the relationship between different sections are

used to calculate SAIFA (system average interruption frequency index), SAIDI, MAIFI (momentary average interruption frequency index), EENS (expected energy not supplied). These index values are obtained for different cases.

2) Distribution network optimization with reliability constraints

In [Mitra et al. 2006], the cost of the network is optimized by the PSO (particle swarm optimization) algorithm while the stability index is added to the objective function as the penalty function. The optimization method is tested by a 22 node distribution network. PSO is proven to be better than dynamic programming. In [Haghifam et al. 2008], the optimization function is defined by three parts: the capital cost of DG, the operational and maintenance (O&M) cost of DG and the energy loss reduced. The technical risk objective function is the probability of overloading of substations and transmission lines, and the probability of over/under voltage. The economic risks are compared using the costs of meeting customer energy demand in two scenarios with and without DG. Both the technical and economic risks are evaluated by fuzzy inequalities (since it is difficult to assign a true/false value to constraints like the voltage). The problem is formulated with all the above three objectives. The power generated by DG units is constrained. The Pareto-optimal DG placement plan is implemented by NSGA-II(non-dominant sorting genetic algorithm) in a 9 node distribution network in MATLAB environment. There are many other Pareto-optimal DG placement strategies which can be selected by planners taking into account their experiences or the conditions of the distribution network.

2.2 Reliability benefits of distributed generation as a backup source

The power system especially at the distribution level is vulnerable to failures and disturbances caused by bad weather or human errors. Having distributed generation (DG) as backup power sources can improve the system reliability. Therefore, distributed generation is expected to play a key role in the residential, commercial and industrial sectors of the power system.

In [Waseem, I., Pipattanasomporn M. and Rahman S., 2009], research work has been done on a residential distribution system with DG. Research findings include:

- Installing DG on the traditional distribution feeders that do not have disconnections on the main line will not improve system reliability. Adding disconnections on the main line will maximize the contribution of DG as backup generators and increase system reliability. With disconnections, DG can supply the loads disconnected from the substation in case of section or distributor lateral failures.
- The best location of DG is at the end of the line considering reliability improvement. Once the outage area is isolated, downstream customers can be supplied by DG, while upstream customers can be served by the substation.
- Installing small-scale DG units instead of a large-scale distributed generator can improve system reliability, depending on the locations of DG, the number of customers and load

levels. Reliability will be improved if DG units, especially the ones with large capacities, are located closer to the end of lines.

- Installing one large capacity DG unit or several small DG units of the same size at the same location will not cause a significant difference in the overall system reliability. However, the reliability will be improved for the load points at which multiple DG units are installed. This is because if a unit fails, other DG units can still serve the load.

2.3 Reliability issues of DG

Distributed generation has the potential to improve reliability of electricity services, because it is placed closer to demand centers. Having more units in operation will reduce the reliance on a small number of large generators, and alleviate transmission and distribution network congestion, which are obvious advantages over centralized generation. In [Pascal, J and Olyksy A, 2008], the related reliability issues of DG are well presented.

For a stand-alone system without grid support, the outage probability is very high and in general, the resulting reliability is lower than supplying the load with the main grid, because the probability of losing several units is definitely higher than losing the whole grid. With grid-connected distributed generation, the above concerns are reduced because the customer can rely on the grid when their private units are unavailable. As noted above, the cost of using DG to generate electricity is higher than using conventional generators, unless cogeneration technology is employed.

Grid interconnection is also an issue that must be considered when examining the systems with a high penetration level of distributed generation. Traditionally, electricity flows in only one direction, from generators through the grid to consumers. Distributed generation places generators within the grid and requires the DG units and the grid to be run in parallel and in a coordinated manner. Several different types of DGs for generating electricity are introduced in [Pascal, J and Olyksy A, 2008].

A. Power Generation from Wind

The energy outputs of wind turbines depend mainly on wind speed. This relationship between wind speed and wind power can be described by the power curve. The most commonly used probability distribution to model wind speed is the Weibull distribution, as detailed in [Pascal, J and Olyksy A, 2008].

The correlations between the wind speeds at different locations should also be considered. Simulating the correlated wind speeds at different locations with the Rayleigh distribution is an important task. If the probability density function of wind speed is chosen, the probability density function of power generated by wind turbines can be assessed analytically or based on Monte Carlo simulation.

The key parameter for describing the availability of a generator is its capacity factor. The capacity factor is defined as the ratio of the actual output of a generator over a period of time and

its output if it had operated at full nameplate capacity over the entire time. Existing studies show that wind power stations usually have a relatively lower capacity factor.

The capacity factor of conventional plants varies between 50% and 90%. Typical aggregated capacity factors (annual average) of wind turbines (onshore) are in the range of 20%-35%, depending primarily on wind conditions, but also on the wind turbine design (rotor size with respect to generator size).

In [Pascal, J and Olyksy A, 2008], a problem addressed on integration of wind energy is how much installed wind capacity statistically contributes to the guaranteed capacity at peak load. This firm capacity part of installed wind capacity is called *capacity credit*. Capacity credit is not a term that refers to how much wind power is actually replaced and should not be confused with the displacement of power from other power sources. The contribution of variable-output wind power to system security – in other words, the capacity credit of wind – should be quantified by determining the capacity of conventional plants displaced by wind power, whilst maintaining the same degree of system security with unchanged loss of load probability (LOLP) in peak periods.

Despite the differences of wind conditions and system characteristics between European countries, capacity credit studies give similar results. For small penetration levels, the relative capacity credit of wind power will be equal or close to the average production of wind power plants (load factor). It is proportional to the load factor at peak load.

With increasing penetration levels of wind energy in the system, its relative capacity credit becomes lower. However, this does not mean that less capacity can be replaced. It means that a new wind turbine in a system with high wind power penetration levels will substitute less compared to the first turbines in the system.

B. Power Generation in PV Systems

The outputs of solar photovoltaic systems depend mainly on the intensity of solar radiation, which changes randomly during the day. The power output of solar PV, similar to that of wind turbines, can be considered a random variable, in which the probability density function strictly depends on the density function of solar radiation intensity.

The probability density function of radiation intensity can be estimated from historical data. Log-normal distribution, beta distribution, and Weibull distribution are all suitable for modelling solar radiation .

Correlations of solar radiation at different locations do not need to be considered. The probability density function of solar radiation intensity can be assumed not to be changed significantly over the studied area.

The density function of solar radiation intensity and the density function of the power produced by PV systems can be estimated with statistical estimation methods. The power produced by photovoltaic cells with area A and efficiency η is expressed in [Pascal, J and Olyksy A, 2008] as:

$$P(r) = rA\eta \tag{1}$$

Where r is the intensity of solar radiation.

C. Power Generation in Small Hydro Power Plants

Energy production in the hydroelectric power plant mainly depends on water flows, which can be characterized by fast variations. To model the energy production of a hydroelectric power station, in [Pascal, J and Olyksy A, 2008], it is deemed necessary to find a suitable density function for water flow – a widely used distribution (probability density function) does not exist – and then introduce a probability density function for solar power.

The probability density function of the water flow q can be obtained from historical data. When we know the probability density function of the water flow, then density function of solar power output P can be analytically estimated, basing on the following equation:

$$P(q) = qh\eta\rho g \quad (2)$$

Where: h – effective head, η – overall efficiency of the power station, ρ – water density, g – acceleration due to gravity.

The locations of hydro stations usually depend strictly on the locations of water sources.

D. General Remarks

It should be emphasized that the electric energy produced by wind turbine, solar PV and small hydro-turbines are random variables. It is therefore necessary to describe their characteristics with probability distributions. However, in some cases uncertainty will also be influenced by the selection of appropriate probabilistic models (density functions) for modelling the uncertain factors. Renewable power plants can significantly contribute to decreasing the dependency on fuels, and consequently decreasing energy import. Through energy sources diversification, they can also improve energy security.

Increasing penetration of renewable energy sources can be thought to support the system reliability to some extent, which however should be verified on each level of the electric power system. Note that renewable energy sources and distributed generation can potentially cause a number of problems and dangers in power systems.

2.4 Reliability evaluation of distributed generation based on operation modes

Techniques for analyzing distributed generation connected to the distribution system are different from the techniques for existing large-scale generation connected to the transmission system. Since the distribution system is a radial network, while DG units have relatively smaller capacities than conventional generators, it is important to find out how far emergency power can reach after failures occur. Some customers may lose their connections to the substation or DG after the failure. Even though a partial connection still remains, customers may still experience outage if the capacity of DG is insufficient. DG recovers disconnected areas sequentially according to their distances. Depending on the restoration protocol, the restoration area is

determined generally by comparing the rated capacity of DG with the sum of peak load customers [Chowdhury, Agarwal and Koval, 2003; Choi, 2006]. In [In-Su Bae and Jin-O Kim, 2007], it can be evaluated by using the time-varying power of DG and the load duration curve of customers. However, the application of the load duration curve is restricted to fuel-based DG units since the load chronology is more appropriate for renewable DG, which is not reliably dispatchable.

Due to the failure, the system configuration is changed, and restoration order also should be modified. To describe the connections between customers and resources, [In-Su Bae and Jin-O Kim, 2007] proposes connection matrices which have the information regarding the system configuration and restoration sequences when the failure occurs at any position in the distribution system.

Traditional reliability indices considered only sustained interruptions. The start-up time of DG should be taken into account for the reliability evaluation of the distribution system including DG. If the start-up time is sufficiently short, customers will experience a very short interruption, otherwise they will suffer a sustained interruption. Various resources recovering loads have influence on reliability indices, such as the duration and frequency of sustained or momentary interruptions, depending on the operation mode of DG. Due to the complexity of all situations, the reliability has been evaluated under different assumptions.

Generally, DGs can be classified into peak and standby units, according to their purpose. The purpose of installing the peak unit is to obtain profits through high electricity prices. The electricity prices vary frequently, depending on the demand and the availability of generation assets. One strategy for DG owners is to use DG during peak load periods, when the power from the transmission system is more expensive. The price of spot electricity can be assumed, generally, to be proportional to the load, and it may be plotted as the dotted line in Fig. 1. In this figure, the fuel cost is assumed to be constant during the year. Then, it can be said that it is efficient to run DG, only when the electricity price is higher than the fuel cost. The total running time in a year can be approximated by comparing these two values, as shown in Fig. 1.

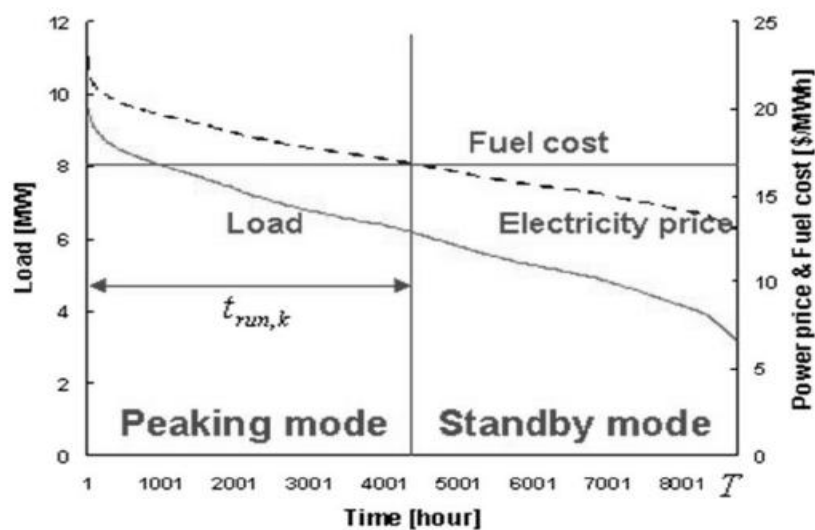


Fig. 1. Operation mode of DG (In-Su Bae and Jin-O Kim, 2007)

The standby unit is installed to provide emergency power and prevent outage when the failure occurs. The standby unit does not run in the normal state, and is connected to the distribution system in emergency only. The interruption duration would be reduced to the start-up time of this standby unit.

Another classification criterion for DG is based on its operation mode. Even though DGs is installed as peaking units, it can be used in standby mode when stopped. It is then identical to the standby unit. Vice versa, the standby unit can also be used in peaking mode. By switching between these modes, we can take advantage of both peaking and standby units. In mixed mode operation, it is important to know whether this DG unit is running or stopped at the time of failure. The load duration curve is used not only to know the total running time of DG, but also to identify the operation state of DG, because the load duration curve rearranges the time in descending order of the load.

The starting failure of DG in peaking mode does not need to be considered, because peaking mode is the state in which DG is providing electricity already. DG in the standby mode can recover loads that have been disconnected, only when it succeeds in its start-up.

In [In-Su Bae and Jin-O Kim, 2007], an analytical technique using the load duration curve to evaluate reliability is proposed. The proposed techniques include the characteristics of DG, such as the peaking and standby modes and their mixed operation mode. The equations in this paper are developed for the purpose of general application in connection matrices. Impact factors and parameters are expressed as a function of time, such that the precise evaluation of reliability is possible for distribution systems with versatile system states.

2.5 Reliability benefits of distributed generation on heavily loaded feeders

In planning a distribution system the DG can contribute to losses, voltage profile and reliability. As discussed in [Le et al 2008] the strongest benefit is often found to be the improvements in system reliability.

In [Brown, 2007], distributed generators are loosely defined as sources of energy connected to distribution systems. They are much smaller than traditional centralized generators, ranging from several kilowatts to approximately 10 megawatts. The main advantage of DG units is their close proximity to the loads that they serve. It is this close proximity that makes reliability improvement work.

The most common application of DG is for backup generation [Brown, 2007] to improve reliability for a single customer. After experiencing an interruption, backup generators are started to supply electricity to critical loads. For critical and sensitive loads, backup generators can be combined with batteries and inverters to ensure uninterruptible power supply. After an interruption occurs, loads are immediately transferred to batteries and inverter. The capacities of batteries are designed to serve critical loads until the generator can reach its full speed.

Another important application of DG is peak shaving. During the periods of high demand and/or high prices, on-site generators are started up to serve part of the local loads. In addition to reducing customer energy costs, peak shaving can also improve system reliability by reducing overall feeder loading.

In [Brown, 2007], it is pointed out that another application of DG that is becoming increasingly important is referred to as net metering, where local generation can exceed local demand and consequently power will be sold back into the distribution system. Energy that is fed back into the system is metered and a customer's energy bill will be determined based on the difference between the energy from the distribution system and the energy supplied to the distribution system. Net metering impacts distribution reliability because it changes the power flow characteristics of distribution feeders [Willis and Rackliffe, 1994]. Consider a ten mile feeder serving ten megawatts of uniformly distributed load. All of the ten megawatts will flow from the distribution substation and will gradually decrease until the end of the feeder is reached (Fig. 2).

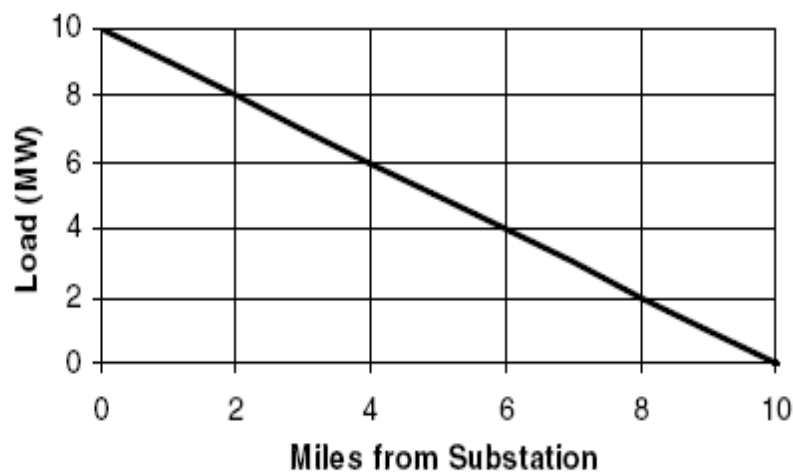


Fig. 2. Feeder loading without DG (Brown, 2007)

Several other scenarios are also studied in [Brown, 2007]. One scenario is to consider the impact of placing a four megawatt DG unit at the midpoint of this feeder (Fig. 3). In this situation, power metered at the beginning of the feeder is six megawatts rather than the total load of the feeder. This can be deceptive since load transfers are often based on metered data at the substation, but may be constrained by more heavily loaded sections downstream of the DG unit. Moreover, DG can hide load growth and cause load forecasting and planning difficulties [Willis and Scott, 2000; Taylor, Willis, and Engel, 1997; Dugan, McDermott, and Ball, 2000]. If the load growth of the feeder is not recognized due to the installation of DG, and is allowed to grow too large, loss of a DG unit during peak loading can result in equipment overloading and consequently outages.

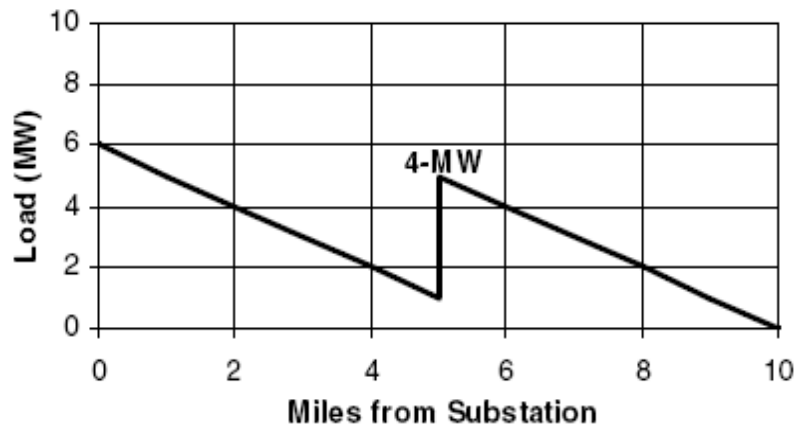


Fig. 3. Feeder loading with 4-MW DG at midpoint (Brown, 2007)

In [Brown, 2007], it is argued that if the output of a DG unit is greater than the downstream feeder load level, power will flow from the DG location towards the substation (Fig. 4). Somewhere along this path there will be a point where no current flows. The opportunity to improve reliability is more accessible if the no current point becomes closer to the substation, but the probability of operation and protection coordination difficulties increases as well. Having a no current point upstream of the substation transformers is generally unacceptable since it will cause reverse power flow into the transmission system.

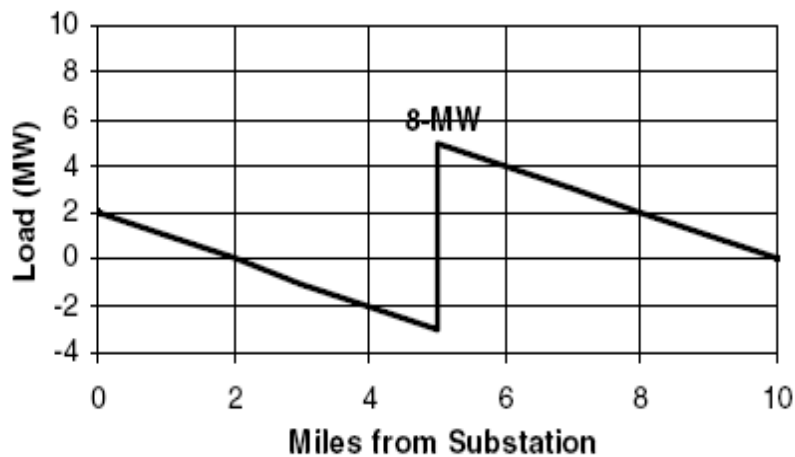


Fig. 4. Feeder loading with 8-MW DG at midpoint (Brown, 2007)

If the power flow from a DG unit towards the substation is large enough, the equipment near the DG unit may experience higher loading than with no DG. Consider the example in Fig. 1 in which there is normally two megawatts of load, eight miles away from the substation. If an eight megawatt DG unit is placed at this point, six megawatts of power will flow towards the substation—three times of the normal loading. If the equipment is not designed properly, it can become overloaded and cause reliability problems.

2.6 QUT contributions to optimizing DG including its reliability benefit

Reliability of a power system decides the quality of power supply and consumers' satisfaction. It is necessary to perform comprehensive assessment of power system reliability.

Due to the liberalization of electricity markets and the unbundling of generation, transmission and distribution sectors, concerns about the present and future reliability levels arise. There is increasing interest in the detailed investigation of power system reliability issues, especially taking into account the whole power system.

To achieve a sustainable energy supply, a large number of requirements should be satisfied: climate compatibility, sparing use of resources, low risks, social fairness and public acceptance. Moreover, it should also be able to facilitate innovation and help create jobs. Numerous worldwide and regional studies indicate that renewable energy sources are capable of meeting these requirements. Relevant global and national future scenarios show substantial increases in the share of renewable energy sources. It is becoming increasingly clear that faster expansion of renewable energy systems is a prerequisite of a sustainable energy future.

If properly installed and operated, DG can improve both end-user satisfaction and grid reliability. By analyzing the influences of distribution generation we can propose an assumption that the energy production from renewable energy sources will be the major uncertainty for the energy industry.

Therefore, QUT has done a lot of work in this area. For example, [I. Ziari et al, 2009] reports the initial steps of research on planning of rural networks for MV and LV. In this paper, two different cases are studied. In the first case, 100 loads are distributed uniformly on a 100 km transmission line in a distribution network and in the second case, the load structure become closer to the rural situation. In case 2, 21 loads are located in a distribution system so that their distance is increasing, distance between load 1 and 2 is 3 km, between 2 and 3 is 6 km, etc). These two models to some extent represent the distribution system in urban and rural areas, respectively. The objective function for the design of the optimal system consists of three main parts: cost of transformers, and MV and LV conductors. The bus voltage is expressed as a constraint and should be maintained within a standard level, rising or falling by no more than 5%.

In this paper, a heuristic and random-based method called Particle Swarm Optimization (PSO) algorithm is used for planning of a simple distribution system. This tool is used in case 1 for a simple uniform load case and an analytical method, nonlinear programming (NLP), is utilized for the second case showing an increased realism of customer demand. The programs are written and run in Matlab.

In case 1, a distribution system with 100 loads located 1 km apart from each other, is considered. Based on the number of candidate transformers, up to nineteen different cases for optimization are assessed. Fig. 5 demonstrates the optimal location of transformers versus the number of candidate transformers. This simple case shows that roughly uniform spacing of transformers is optimal for this form of modelling. For example, the optimal location of 5

transformers for the uniform load case can be seen in Fig. 5 as being 10%, 29%, 48%, 69% and 89%.

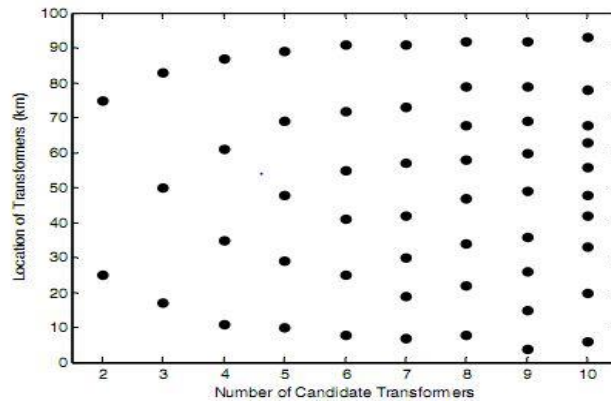


Fig. 5. Location of transformers versus the number of candidate transformers

For the case 2 (21 Nonlinear spaced load), a simple linear form of a rural area is modelled. 21 transformers are selected as candidates with variable size and location in the tested distribution system. Fig. 6 shows the structure of loads in the system and the calculated transformers location. The first point is that the optimal design corresponds to only 9 transformers being employed even though 21 possible sites were examined.

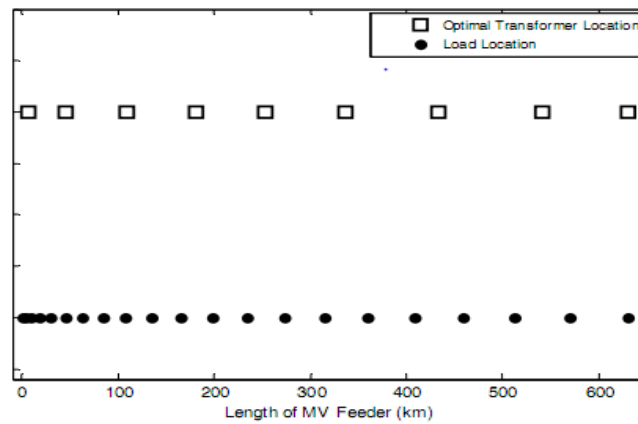


Fig. 6. Location of loads and Transformers

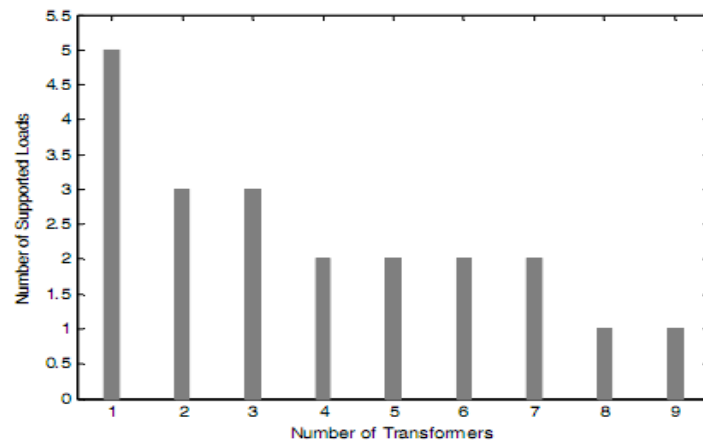


Fig. 7. The number of loads supported by transformers

As shown in Fig. 7, the optimal solution for the first transformers provides support for 5 loads.

Increasing the demand for electrical energy, tight restriction on expanding distribution lines to supply remote areas and system reliability are three main issues which have increased the desirability of DGs in recent years. Although, use of DGs can lead the distribution network to lower loss, higher reliability, etc, it can also apply a high capital cost to the system. This demonstrates the importance of finding the optimal size and placement of DGs. Although minimizing the power loss and improving the reliability simultaneously will yield a better solution than optimizing individually, only a few papers have investigated the combination of these elements. From the reliability point of view, consideration of load shedding leads the optimization to more realistic condition.

As a result, in [I. Ziari et al, 2010], the placement and sizing of DG in distribution networks are determined using optimization. The objective is to minimize the loss and to improve the reliability at lowest cost. The constraints are the bus voltage, feeder current and the reactive power flowing back to the source side. The placement and size of DGs are optimized using a combination of Discrete Particle Swarm Optimization (DPSO) and Genetic Algorithm (GA). This increases the diversity of the optimizing variables in DPSO not to be trapped in a local minimum. To evaluate the proposed algorithm, the semi-urban 37-bus distribution system connected at bus 2 of the Roy Billinton Test System (RBTS), which is located at the secondary side of a 33/11 kV distribution substation, is used. The results illustrate the efficiency of the proposed method.

To validate the proposed method, the 11 kV semi-urban distribution system connected to bus 2 of the Roy Billinton Test System (RBTS), as shown in Fig. 8, is studied. This 37-bus test system has 22 loads located in the secondary side of a (33/11 kV) distribution substation. The characteristics of the test system are given in Table I.

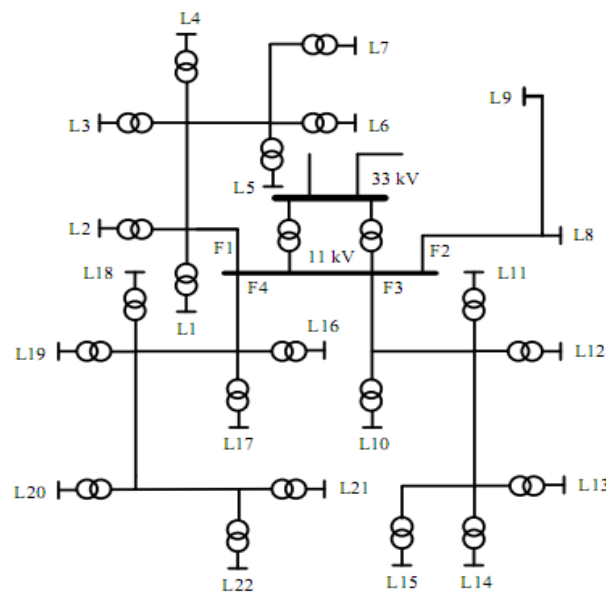


Fig. 8. Distribution System for RBTS Bus 2

TABLE I
CHARACTERISTICS OF THE TEST SYSTEM

No. of Loads	Customer Type	Load Points	Average Load Level
9	Residential	1-3,10-12,17-19	0.50 MW
5	Commercial	6-7,15-16,22	0.45 MW
6	Government	4-5,13-14,20-21	0.57 MW
2	Industrial	8-9	1.10 MW

As shown in Fig. 8, 22 loads located in the first test system are composed of 9 residential loads and 6 government loads located at feeders F1, F3 and F4, 5 commercial loads located at feeders F1 and F4, and 2 industrial loads located at feeder F2. The total average load in this network is 12.37 MW and the total peak load is 19.8 MW.

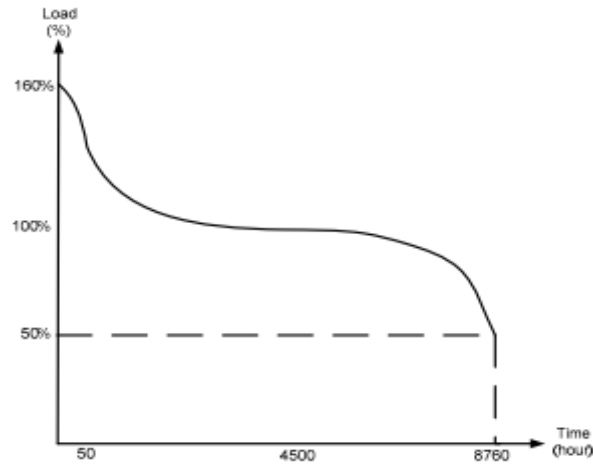


Fig. 9. Load duration curve used in the testing distribution system

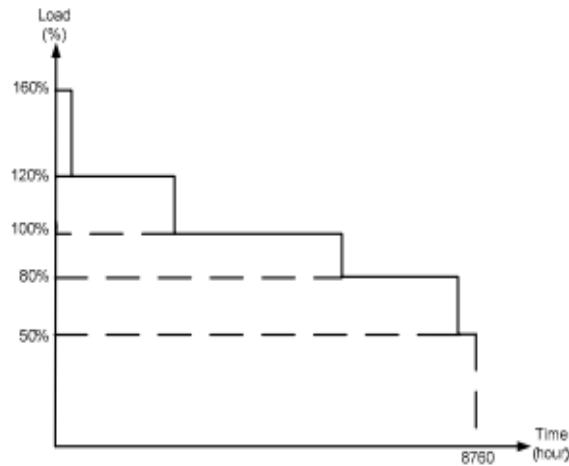


Fig. 10. Approximation of load duration curve

The load duration curve of this test system is shown in Fig. 9. To deal appropriately with this curve, the most complex way is to study the network and solve the problem for every point. This way leads the program to very slow computation time. The easiest and fastest way is to

approximate this curve with 2-3 levels which might be inaccurate. In this paper, to implement a compromise between accuracy and computation time, this curve is approximated with 5 load levels as shown in Fig.10; however, using sensitivity analysis to find the optimal load level number can be included in the future. As shown in Figure 10, the load is peak for 2% of a year and lowest for 3% of a year. The average load is drawn from the network for 40% of a year. For 30% and 25% of a year, the load level is 120% and 80% of the average load, respectively.

TABLE II
PARAMETERS VALUE USED IN THE TEST

Parameters	Value
k_{PL}	168000 S/MW
C_{INSTAL}	400000 S/MVA
$C_{O\&M}$	45 S/MWh
r	9.15 %
T	30 Years
W_{SAIDI}	5×10^6

In this case study, it is assumed that the cost per kWh is different for different load levels, 3 ¢ for 50% and 80% of the average load, 6 ¢ for 100%, 8 ¢ for 120%, and 10 ¢ for peak load level. This is because of the energy source employed and the fuel consumed in each load level. In 50% and 80%, the coal-based sources are used. For 100%, the gas-based source is also assumed added. For 120% and 160%, the wind and solar energies should be also employed respectively to supply the loads. The other parameters are shown in Table II. The DGs are assumed in discrete size, a multiple of 300 kW. As shown in Table II, the SAIDI weight factor is 5×10^6 . As mentioned before, to calculate this index, the number of customers should be multiplied by the cost per unit time of an interruption which is provided by the local electrical company. For example, if the number of customers is 12000 in the test system and the cost per 1 minute interruption is assumed 7\$, the SAIDI weight factor is calculated 5.04×10^6 ($12000 \times 60 \times 7$) in which 60 is to convert hour to minute. As seen in Table II, the SAIDI weight factor in this paper is presumed 5×10^5 . It is clear that by decreasing/increasing this factor, the importance of reliability in the objective function, so the optimal number/size of DGs will decrease/increase. Therefore, this factor can also be multiplied by a coefficient to adjust the importance of reliability.

TABLE III
DGs LOCATION AND RATING (MW) FOR AVERAGE ALL LOAD LEVELS

		BUS NUMBER														
		3	4	6	7	9	10	20	21	23	29	31	32	34	35	36
LOAD LEVEL	50 %	0	0.3	0.6	0	0	0.9	0.3	0.3	0.9	0.3	0	0.3	0.3	0.6	0.3
	80 %	0	0.6	0.6	0.6	0	1.2	0.6	0.9	0.9	0.6	0.6	0.6	0.3	0.6	0.3
	100 %	0.6	0	0.9	0.9	0	1.2	0.6	1.2	1.5	0.6	0.6	0.6	0	1.5	0
	120 %	0.6	0.6	0.9	0	1.2	1.2	1.2	1.2	1.5	0	0.6	0.9	0.3	0.9	1.2
	160 %	0	0.6	0.9	0.6	1.2	0.9	1.2	1.2	1.8	0.6	0.6	0.9	0.3	1.5	1.2
OPTIMIZED DGs		0.6	0.6	0.9	0.9	1.2	1.2	1.2	1.2	1.8	0.6	0.6	0.9	0.3	1.5	1.2

As observed in Table III, 15 DGs should be installed at buses 3, 4, 6, 7, 9, 10, 20, 21, 23, 29, 31, 32, 34, 35, and 36 with ratings 0.6, 0.6, 0.9, 0.9, 1.2, 1.2, 1.2, 1.2, 1.8, 0.6, 0.6, 0.9, 0.3, 1.5, and 1.2 MW, respectively. When the load level is 50%, 11 DGs with total rating of 5.1 MW located at buses 4, 6, 10, 20, 21, 23, 29, 31, 32, 34, 35, and 36 is the optimal condition. 13 DGs with total rating of 8.4 MW, 11 DGs with total rating of 10.2 MW, 13 DGs with total rating of 12.3 MW, and 14 DGs with total rating of 13.5 MW for 80%, 100%, 120% and 160% of the average load respectively should also be installed to meet the minimize the loss, to maximize the reliability and to meet the constraints. The highest level of DG is related to the peak load and the lowest level is related to the 50% loading. Table IV illustrates a comparison between the outputs before and after the installation of DGs for all load levels.

TABLE IV
COMPARISON OF OUTPUTS BEFORE AND AFTER INSTALLATION OF DGs (\$)

		With DGs		Based on Average Load		Without DGs	
		LOSS COST	INTERRUPTION COST	LOSS COST	INTERRUPTION COST	LOSS COST	INTERRUPTION COST
LOAD LEVEL	50%	2.722×10^3	1.751×10^7	7.748×10^3	1.682×10^7	5.316×10^3	2.640×10^7
	80%	9.049×10^4	2.573×10^8	1.158×10^5	2.523×10^8	2.001×10^5	3.961×10^8
	100%	3.631×10^5	3.367×10^8	3.631×10^5	3.367×10^8	8.216×10^5	5.281×10^8
	120%	3.737×10^5	2.089×10^8	4.144×10^5	2.445×10^8	9.715×10^5	3.300×10^8
	160%	1.466×10^5	2.956×10^8	1.907×10^5	3.794×10^8	4.102×10^5	3.961×10^8
TOTAL		9.766×10^4	8.499×10^8	10.92×10^4	8.883×10^8	2.41×10^5	1.32×10^9

As observed in Table IV, after installation of DGs, the loss and interruption cost decrease. The total cost decreases from M\$1322.41 to M\$850.88. This difference, M\$471.53, is much more than the total cost of DGs, M\$64.63. Considering this table, the loss and interruption costs at 160% of the average load are less than at 100% and 120% loading. This occurs since the duration of peak load level is much less than 100% and 120% levels (see Fig. 10).

The 11 kV semi-urban distribution system connected to bus 2 of the Roy Billinton Test System (RBTS) is studied to evaluate the proposed methodology. The results are finally compared with the no DG condition and the benefits of installing DGs are illustrated. The high levels of considerations of practical issues increase the applicability in realistic distribution system planning.

After a wide area blackout or local outage, the power system concerned should be restored as soon as possible. The power system restoration process after a global blackout could be divided into three phases: the black-start phase, the network reconfiguration phase and the load restoration phase. Among these three phases, the black-start phase is defined as the one in which the black-start units, after a large-area blackout, supply power to the non-black-start units without the help of other systems and then gradually expand the re-supplied areas until the entire power system is restored. Thus, the black-start process is the first stage for quickly restoring power supply, and optimizing the black-start schemes is one of the most significant issues having impacts on the system restoration speed.

Power system restoration after a large area outage involves many factors, and the procedure is usually very complicated. A decision-making support system could then be developed so as to find the optimal black-start strategy. In order to evaluate candidate black-start strategies, some indices, usually both qualitative and quantitative, are employed. However, it may not be possible to directly synthesize a value for those indices, and different extents of interactions may exist among these indices. In the existing black-start decision-making methods, qualitative and quantitative indices cannot be well synthesized, and the interactions among different indices are not taken into account. The vague set, an extended version of the well-developed fuzzy set, could be employed to deal with decision-making problems with interacting attributes. Given this background, the vague set is first employed in [Shunqi Zeng et al, 2010] to represent the indices for facilitating the comparisons among them. Then, a concept of the vague-valued fuzzy measure is presented, and on that basis a mathematical model for black-start decision-making is developed. Compared with the existing methods, the proposed method can deal with the interactions among indices and more reasonably represent the uncertain information. Finally, an actual power system is served for demonstrating the basic features of the developed model and method.

The basic framework of the support system for black-start decision-making includes three functional modules, i.e., development, verifications and selection/optimization of black-start strategies. The support system will search the topological database according to the locations of black-start units. Then, all possible black-start schemes will be generated automatically by ascertaining the power plants to be restarted and possible supplying paths to restart them. Afterwards, a series of technical verifications will be done to check the black-start schemes, including self-excitation analysis of the black-start units, over-voltage verifications, system frequency verifications, examinations of low frequency oscillation and transient stability. Finally, an optimal black-start scheme will be selected from the candidate schemes after verifications.

The black-start decision-making method based on vague-valued fuzzy measures could be described in this paper as follows:

The initial value of each index in the candidate black-start schemes should first be specified, and then be transferred into vague values. The weights associated with indexes and the values associated with interactions are given by domain experts, and the Sugeno integral operator based on the non-additive measure is next used for nonlinear aggregation. Suppose that the set of evaluation indices is denoted by $C = \{c_1, c_2, \dots, c_n\}$, and the values of indices $X = \{x_1, x_2, \dots, x_n\}$ with $x_i = (t_i, f_i) \in L$. The vague-valued weight of each subset in C is $\tau_{P(C)} = (\tau_t, \tau_f)$, so the value of the comprehensive evaluation of the candidate scheme can be calculated as

$$V = S(x_1, x_2, \dots, x_n) \quad (3)$$

The domain experts' accumulated appraisal can be determined after each expert's appraisal value is obtained by using Eqn. (3). Suppose that there are K domain experts participating in the selection/optimization of black-start schemes as denoted by a set $E = \{e_1, e_2, \dots, e_K\}$, and the weights associated with each subset of E is $\tau_{P(E)} = (\tau_t, \tau_f)$, then if the

calculated comprehensive evaluation of the scheme by expert e_k is denoted as V^k , then the group decision-making appraisal value is given as

$$\bar{V} = S(V^1, V^2, \dots, V^K) \quad (4)$$

The group decision-making appraisal values of all the schemes can be obtained by Eqns. (3) and (4).

In summary, the basic procedure of the developed black-start decision-making method can be described as follows:

- 1) Each index value associated with the candidate black-start schemes is transformed into a vague value, and then normalized;
- 2) The weights associated with evaluation indexes and the interactions among the subsets in the index set C should be ascertained by domain experts, and be expressed as vague values;
- 3) The comprehensive evaluation V_i^k of the black-start scheme i by expert e_k is determined with the Sugeno integral operator;
- 4) The group decision-making appraisal value \bar{V}_i of the scheme i by the whole group of experts is determined with the Sugeno integral operator.
- 5) All the group decision-making appraisal values for all candidate schemes can be obtained by repeating Steps 3) and 4).
- 6) All the group decision-making appraisal values of the schemes are ranked according to their merit order.

The vague set theory based black-start decision-making approach is developed for optimizing the power system restoration procedure in this work. The proposed method is based on a group decision-making model, and could better model the practical decision-making procedure. In the developed method, the interactions among various indices could be taken into account, and the vague set can better model fuzzy information than existing methods. It is demonstrated by case studies that the interactions among various indices could have significant impacts on the evaluation results of the black-start schemes, and hence cannot be overlooked.

Conclusions

Reliability is one key issue that can be addressed by Distributed Generation. The optimization of distribution design considered in this chapter show that reliability is a strong component of the benefit of DG for areas that are not highly meshed. It is largely this reliability benefit which may indicate that the best case of DG apart from combined heat and power for cold countries can be at the fringe of grid in rural areas.

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Chapter 3 Protection Issues

Traditionally the distribution system is operating in a radial configuration, and its power flow and short-circuit current are flowing with one direction only. The inclusion of DGs in a distribution network could change the flowing direction of power flow and short-circuit current, and as a result the traditional protective scheme is no longer applicable. As DG capacity increases in the distribution system, the issue concerned with protective relay system design and coordination will become more and more challenging. Basically, there are two ways to solve the problem. The first one is to appropriately coordinate the relay settings of the existing protective relay to achieve a cost-effective outcome, but this may not be always possible. The second one is to replace protective devices, but this will incur large amount of investments, and may not be cost-effective. In [H. Yang et al. 2010], a new method is presented for optimal coordination of overcurrent relays for distribution systems with distributed generations based on differential evolution algorithm. In [M. Dewadasa et al], a fold back current control and admittance protection scheme is developed for a distribution network containing DGs. The methods presented in [H. Yang et al. 2010] and [M. Dewadasa et al] respectively represent the two ways to solve the issue associated with the protective system in a distribution system with DGs.

3.1 Impacts on fault characteristics of power systems

3.1.1 Short-circuit current level

[Stefania Conti, 2009] has shown how short circuit currents may increase due to the contribution of DGs. In [Stefania Conti, 2009], it is proposed that fault currents increase mainly depending on a number of factors, such as capacity, penetration, technology, interface and connection point of DG, as well as other parameters such as system voltage prior to the fault, etc. In future, it will become impossible to neglect the fault level increase in the presence of DG.

In [Martin Geidl, 2005], a detailed analysis for fault current is illustrated. Phase-phase or phase-earth faults normally lead to an overcurrent which is significantly higher than the operational or nominal current. For overcurrent protection, the fault current has to be distinguishable from the normal operational current.

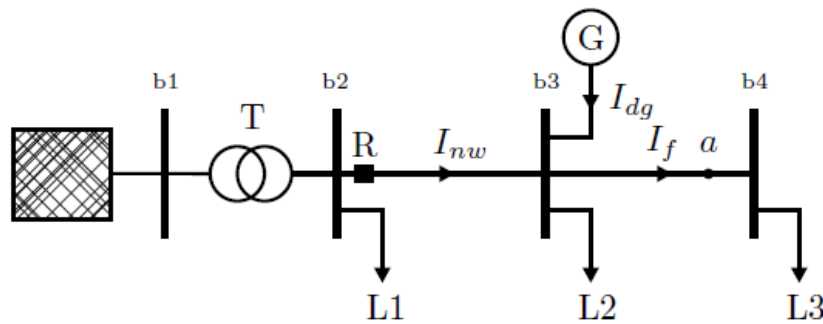


Fig. 1. Short circuit at a . Current from transmission network I_{nw} , current from embedded generator I_{dg} [Martin Geidl, 2005].

Fig. 1 shows a distribution feeder with a DG that supplies part of the local loads. Assuming a short circuit at point a , DG will also contribute to the total fault current

$$I_f = I_{nw} + I_{dg} \quad (1)$$

But the relay R will only sense the current coming from the network infeed I_{nw} . The relay detects only a part of the real fault current and may therefore not trigger properly. The situation is tougher especially for high impedance faults (HIF) that overcurrent protection with inverse time-current characteristics may not trigger in sufficient time. Another influence of DG on fault currents is that DG can also affect the current direction. If a short circuit occurs at bus $b2$, the fault current contribution from DG will pass the relay in the reverse direction. That may cause problems if directional relays are used.

Above all, DG can affect the following issues of short circuit faults:

- 1) Amplitude
- 2) Direction
- 3) Duration (indirectly)

3.1.2 Reverse power flow and voltage profile

Traditionally, power usually flows from the network with higher voltage levels to the one with lower voltage levels, i.e. from transmission to distribution grids. However increased DG units may reverse power flows from the low-voltage grid into the medium-voltage grid.

Radial distribution networks are usually designed for unidirectional power flow, from the infeed downstream to the loads. Existing directional overcurrent relays are designed according to this principle. With a DG on the distribution feeder, the load flow situation may change. In [Martin Geidl, 2005], it is mentioned that if the local production exceeds the local consumption, power flow will change its direction. The value of power flows are also changed, which proposes severe challenges to traditional relay protection calculation schemes.

In [Martin Geidl, 2005], it is proposed that DG always affects the voltage profile along a distribution line. DG may cause a violation of voltage limits and additional voltage stress for the equipment. Fig. 2 illustrates the voltage gradient along a distribution feeder with and without embedded DG. The power flow direction is related to the sign of the voltage gradient. In this situation, the power flow direction between bus $b2$ and $b3$ is changed due to the infeed at bus $b3$. DG can also influence the voltage profile in a positive way and turn into a power quality benefit, especially in highly loaded or weak networks.

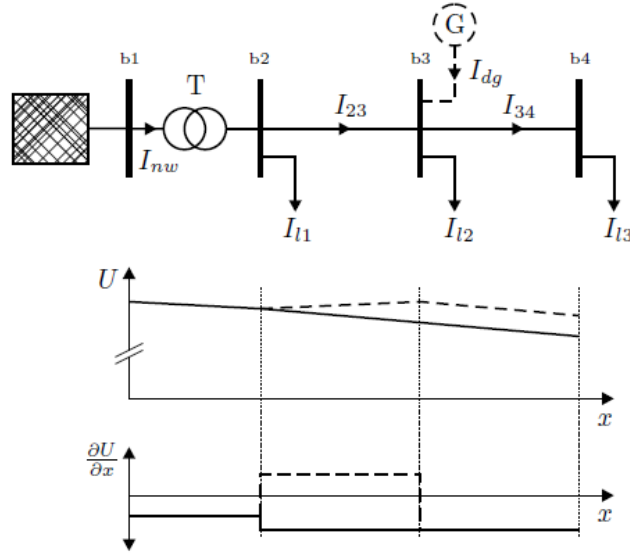


Fig. 2. Voltage profile and gradient on a distribution feeder with and without contribution of generator G . Solid line: $I_{dg} = 0$, downstream power flow; dashed line: $I_{dg} > I_{l2} + I_{l3}$, reverse power flow between $b2$ and $b3$ [Martin Geidl, 2005]

3.2 Impacts on the operations of protective relays

In [Jinfu Chen et al., 2009], the effects of DG on the operations of protective relays (PR) are classified into the following three types:

3.2.1 Protection fault operation

As shown in Fig. 3, due to the influence of DG, the short-circuit current measured by protection relay $B2$ will increase when short circuit fault occurs at the tail end of line BC . The larger the capacity of DG, the larger the short circuit current I_{B2} will be. If I_{B2} is larger than the current protection I section setting value, fault operation of protective relay will happen.

Another situation involving the fault operations of protective relays is shown as follows: as shown in Fig. 4, the reverse current provided by DG will be detected by $B1$, which may cause the fault operation of $B1$ and the resection of line with DG.

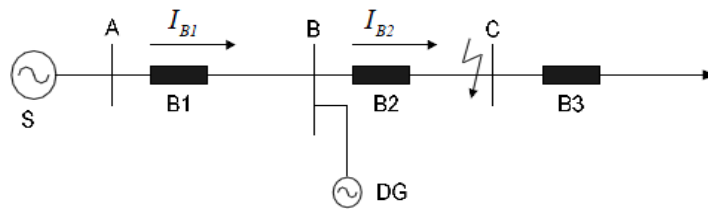


Fig. 3. The influence of DG on downstream protection of the line [Jinfu Chen et al. 2009]

3.2.2 Lower protection sensitivity

Compared with the original distribution network, the fault current detected by protection device $B1$ will decrease when short circuit fault occurring at the tail end of line BC . With the increase in the capacity of DG, the fault current detected by protection device $B1$ will decrease rapidly. Meanwhile, the overcurrent protection sensitivity will be obviously reduced.

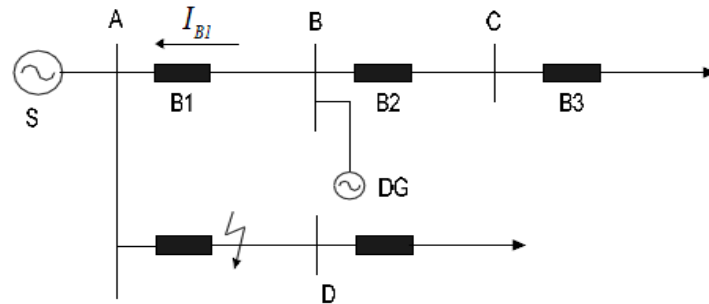


Fig. 4. The influence of DG on upstream protection of the line [Jinfu Chen et al. 2009]

3.2.3 Failed to identify the fault

As shown in Fig. 5, a DG is connected to the end of the distribution network. The short circuit current is possibly less than the maximum load current. As a result, the fault cannot be removed.

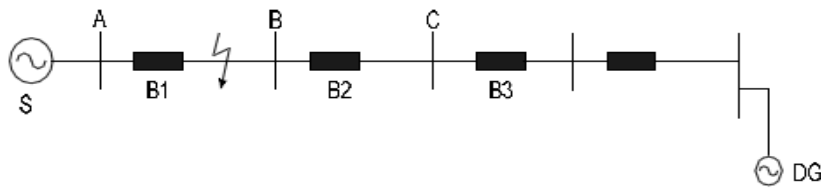


Fig. 5. Failed to identify the fault because of the influence of DG [Jinfu Chen et al. 2009]

3.3 Impacts on protection coordination

“Traditional distribution system has been radial, i.e. characterized by single source and hence the time coordination between protective devices is designed on basic assumption of system to be radial” [Brahma, S. M., and Girgis, A. A., 2004]. After connecting DG, part of the system may no longer be radial, which means the coordination might not hold. The effect of DG on coordination will depend on size, type and placement of DG [A. A. Girgis and S. M. Brahma, 2001].

Radial distribution systems usually employ non-directional overcurrent relays (inverse or definite time), reclosers and switch fuses in their protection systems [Tales M. de Britto, 2004]. Because these devices do not take the flow direction into account, they may fail in cases where DGs contribute to the fault. An approach for evaluating the protection coordination is to analyze the time by current curves of the devices involved in the part of the network where the fault occurred. The main protection is the one which is closest to the fault point, and backup protection

is the next, between the fault and the source. Backup protection should isolate the fault only in the cases the main protection fails to operate.

In [A. A. Girgis and S. M. Brahma, 2001], it is stated that installation of DGs in an existing radial distribution system affects the protection coordination as follows:

- 1) “Devices downstream of the last DG will never see fault current for an upstream fault. If these devices can handle the increased fault current due to penetration of DG, there will not be any problem coordinating them.”
- 2) “If devices see fault currents for upstream faults. There are two possibilities:
 - a) If they see the same fault current for a fault downstream as well as for a fault upstream, coordination will be lost.
 - b) If they see different currents for a downstream or upstream fault, there is a margin available for coordination to remain valid. If disparity in fault currents seen by devices is more than the margin, coordination holds. Therefore, coordination is likely to hold if DG fault injection is higher.”
- 3) “For fuse-recloser coordination, there is also a margin available for coordination to remain valid. In this case, if the disparity in fault currents seen by these devices is less than the margin, coordination holds. Therefore, coordination is likely to hold if DG fault injection is less.”

3.4 New protection technology considering the impacts of DGs

Protection schemes for distribution systems have been traditionally designed assuming that the system is radial, with a single source feeding the network of downstream feeders. Due to the connection of DG into modern distribution system, the impact of DG on protection coordination makes protection design more complicated. A precise and effective protection system plays an important role in reducing the unnecessary tripping of connected DGs, and supporting rapid network restoration. For clear organization and illustration, the protection systems with impacts of DGs taken into account are categorized into two kinds: the conventional and Artificial Intelligent approaches.

3.4.1 Conventional approaches

One of the major impacts of a DG on a feeder in distribution system is that the DG will contribute to the fault current in the fault situation [Baran et al. 2005]. To address the protection design, methods to estimate the contribution of DGs to fault currents are needed. In [Baran et al. 2005], a method to capture the inverter interfaced distributed generator (IIDG) behavior during a fault is developed. The presented model is used to extend the traditional fault analysis method for distribution system, so that IIDGs can be represented in the analysis. Fault current contributions of IIDG are capable to be estimated under both balanced and unbalanced fault conditions.

In [Brahma et al. 2004], the current contributions from all sources (the main source and all DGs) are employed for the protections to identify the fault section. At first, a fault in DG or in the system can be distinguished by checking if the sum of the current contributions from all

sources is equal to zero, similar to a current differential protection scheme. Every source can be represented as a voltage source behind Thevenin impedance. If the fault point shifts from one bus to the adjoining bus, for a given type of fault, Thevenin impedance to a given source can either increase or decrease. Thus, the faulted section can be identified as the section for which the measured current contribution from each source all lie between contributions from that source for the same type of fault on the two connected buses to this section.

In an automatic telecontrol environment of distribution system, some fault sensing devices might not send the required information to the control system after a fault event due to a communication system failure. For the sake of overcoming this difficulty, a software procedure for fault location is presented in [Conti et al. 2009], making use of the directional information of fault sensing devices. When a fault occurs on a feeder, firstly, a numbering procedure is performed to encode the fault sensing devices according to the directional information and their locations. Then, based on the appropriate numbering of the devices installed in the faulted feeder and on the acquirement of fault current direction, the fault location procedure is able to find the minimum part of the network in which the faulted section is located, even in the case of insufficient information such as when an alarm missing due to communication channel failure.

A new protection scheme for distribution systems with DG is proposed in [S. A. M. Javadian and M.-R. Haghifam, 2008]. In the proposed scheme, systems protection is performed through a computer-based relay which is installed in sub-transmission substation. The relay determines the system status after it receives the required network data, and if a fault occurs it diagnoses its type and location, and finally issues proper commands for protection devices to clear the fault and to restore the network. In [Al-Nasseri et al. 2006], the micro-source output voltages are monitored and then transformed from a-b-c axis to d-q axis. Any disturbance at the micro-source output due to a fault in the network will be reflected as disturbances in the d-q values; the abc-dq transformation of the system voltage can therefore be used to detect the occurrence of a short circuit fault. By comparing measurements at different locations, the difference between the faults in different zones of protection associated with a particular micro-grid network is obtained. This scheme makes the over-current protection selective. In [X. Z. Wang, 2006], methods are proposed to use the reactor and DG capacity permit to restrict fault current. The simulation results show the validity of the two measures.

3.4.2 Artificial intelligence-based approaches

Existence of multi-sources in fault condition and its impact on protection coordination makes the establishment of an accurate mathematic model for fault diagnosis for distribution system with DG a complex task. In order to solve this problem, AI-based approaches such as Artificial Neural Network (ANN) [Rezaei et al. 2008, Bretas et al. 2006], Petri Net [Calderaro et al. 2007, Calderaro et al. 2009] and Muti-agent Technology (MAT) [Zeng et al. 2004, Rajapakse et al. 2006, Perera et al. 2006] have been developed in recent years.

1) Optimization-based approaches

In [Zeineldin et al. 2006] directional over current relays are used to protect the system with DG units that are connected to the grid or operated in a micro-grid. Since the relay protection calculation problem is an MINLP (Mixed Integer Nonlinear Programming) problem, the settings of relays and coordination relations are optimally calculated using a modified PSO (Particle Swarm Optimization) algorithm. Since it is impossible to select a setting for the relays that can satisfy both grid connected and micro-grid operation modes; a viable solution for micro-grid protection could be: a central protection unit is required to change the settings of relays based on the system configuration. In [Chaitusaney S and Yokoyana A. 2005], the reclosers and fuses are coordinated by restricting the DG injection current. The method is tested in a simple and typical distribution network. By applying the method proposed in [Chaitusaney S and Yokoyana A. 2005], the energy cost from the utility and DG, as well as the cost from the unserved energy, are evaluated without losing the coordination of protection in [Chaitusaney S and Yokoyana A. 2005]. Simulation results show that with a proper DG capacity, both the energy cost and the outage cost are reduced. In [SO C W and LI K K, 2002], the Time Coordination Method is proposed and can coordinate the over current relays to protect the ring-fed distribution network with distributed generation. The modified Evolutionary Programming technique is employed.

Some constrained conditions are proposed in the following papers. The DG capacity is maximized by genetic algorithm in [Jinfu Chen et al. 2009], and the optimization problem is constrained by the reliability of relay protection in the distribution network. A 34 bus radial distribution network is presented to prove the effectiveness of the method. However the protection reliability constraints are based on the analysis of the entire set of relay settings, which restrict the method to being applied in all distribution networks. In [Wang Lingfeng and Singh Chanan, 2008] the recloser placement together with DG placement is solved by calculating two reliability indices: weighted aggregation of SAIDI (system average interrupted duration index) and SAIFI (system average interruption frequency index). The ACS (ant colony system) is used for optimization. The algorithm is tested with a 69-bus and a 394-bus distribution network. The comparative study is carried out between GA (genetic algorithm) and ACS in this paper as well. The reliability model of an asymmetric, three-phase, non-radial distribution feeder equipped with capacity-constrained DG is developed in [Pregelj et al. 2006]. The model is used to quantify the potential reliability improvement due to the intentional islanded operation in parts of the feeder. A GA optimizer for optimal placement of reclosers and DG units on such a feeder is developed and successfully tested on two models of distribution feeders.

2) ANN-based approaches

The ANNs are suitable for modelling complex relationships between inputs and outputs or to find patterns in data. The greatest advantage lies in their ability to learn from samples and generate the result for inputs not seen in the training phase, without any explicit analytical model.

In [Rezaei et al. 2008], an online ANN-based fault section estimation approach for protection system is developed. First, offline calculations including the flow and short circuit analysis are carried out. The current contribution from each source to each type of fault at each step point is required for the training of the neural network. Normalized proportion of current

contribution from all sources using a maximum of three-phase fault current will be used as input and fault distance from every source as output of neural network. To deal with nonlinearities, a feed forward four-layer neural network is employed for rapid fault section estimation in an online environment.

Fault diagnosis in the situation of high impedance fault (HIF) is a very difficult task, especially when DGs are connected to the feeder. In [Bretas et al. 2006], an ANN-based HIF detection, identification, and location scheme for protection system of power distribution feeders with DG is proposed. The fault detection and identification routine is based on the symmetrical components of the 1st, 2nd, 3rd and 5th harmonics of the current signal, measured at the feeder's substation terminals. These components feed an ANN whose outputs indicate the fault presence and the fault type. Then, two ANNs, one trained for phase faults and other for ground faults, are employed for fault location. It is capable for obtaining precise fault locations for both linear low impedance and non-linear high impedance faults.

3) Petri Nets-based approaches

Petri net is a powerful tool, which enables the users to graphically design and monitor complicated process-based activities in a simple yet comprehensive manner [Calderaro et al. 2007].

When a fault occurs on a section in distribution network with DG, relay failure due to miscoordination of protection systems will lead to an extended outage range. Thus, relay failure detection is an important issue in protection system design. In [Calderaro et al. 2007, Calderaro et al. 2009], Petri Nets-based methods are proposed in order to support distribution network operator (DNO) to detect failures or wrong protective device operations. In [Calderaro et al. 2009], a marked deterministic timed Petri net is established to model the feeder overcurrent relay, the DG protective device and the protected line. Based on the concepts of transition failure and place failure in Petri net, relay failure can be detected. An algebraic approach using Galois Fields (GF) simple matrices manipulation is employed for identifying mixed transition and place failures.

4) MAT-based approaches

MAT, a distributed artificial intelligence technology, provides a framework for coordinating intelligent behavior among autonomous intelligent agents. A multi-agent system (MAS) can be thought of as a group of interacting agents working together to achieve a set of goals. The protection system is a summation of coordinated relays located in various parts of the distribution system with DG penetration. Digital relay can be viewed as an intelligent agent called "a relay agent", which is capable of interacting with other relay agents and performing tasks of fault diagnosis with autonomy and cooperation [Zeng et al. 2004]. The different issues among MAT-based approaches mainly lie in the function of relay agents and how relay agents cooperate to finish the fault diagnosis task.

In [Zeng et al. 2004], each relay agent can autonomically accomplish its own tasks for fault detection as follows: Fault features are extracted by wavelet packet transform, and the

obtained spectral energies of the wavelet components are employed to train a multi-layer feed-forward neural network to distinguish between fault and normal operational conditions. The fault section can be identified, according to the sign of fault harmonic energy obtained in the fault detection procedure of each relay agent.

In [Rajapakse et al. 2006, Perera et al. 2006], the function for the relay agents is fault direction determination. Discrete Wavelet Transformation (DWT) is used to extract Wavelet Transform Coefficients (WTC) of the high frequency transient information in current signals. For each relay agent, whether a fault is internal or external (i. e. the fault direction) can be distinguished by the sign of WTCs of the modal transformed currents. With the fault direction information received from all relay agents, the fault section can be identified as follows: if an internal fault is detected by a relay agent, the busbar which this relay agent is located in is the fault section; on the other hand, the line encircled by relay agents that detect external faults is the fault section.

3.5 New protection technology developed by QUT considering the impacts of DGs

However, the rapid increase in the number and capacity of distributed generators has also brought some problems to power system operation and control. Whether the abovementioned advantages of DGs can be achieved or not depends heavily on whether these problems could be properly resolved, and one important issue from these problems is the coordination of protective devices. Traditionally the distribution system is operating in a radial configuration, and its power flow and short-circuit current are flowing in one direction only. The inclusion of DGs in a distribution network could change the direction of power flow and short-circuit current, with the result that the traditional protective scheme may no longer achieve its task. As the the number and capacity of DGs in the distribution system increases, the issues concerned with the protective relay system design and coordination will become more and more challenging. It is expected that replacing protective devices will incur a large amount of investment, and may not be a cost-effective way. Instead, the problem may be able to be solved by appropriately coordinating the relay settings of the existing protective relays to achieve a cost-efficient outcome at least for low levels of penetration of DGs.

When a fault occurs on a section or a component in a given power system, if one or more protective relays (PRs) and/or circuit breakers (CBs) associated do not work properly, or in other words, a malfunction or malfunctions occur with these PRs and/or CBs, the outage area could be extended. As a result, the complexity of the fault diagnosis could be greatly increased. The existing analytic models for power system fault diagnosis do not systematically address the possible malfunctions of PRs and/or CBs, and hence may lead to incorrect diagnosis results if such malfunctions do occur. Given this background, based on the existing analytic models, an effort is made in [Wenxin Guo et al, 2010] to develop a new analytic model to take into account the possible malfunctions of PRs and/or CBs, and further to improve the accuracy of fault diagnosis results. The developed model does not only estimate the faulted section(s), but also

identifies the malfunctioned PRs and/or CBs as well as the missing and/or false alarms. A software system is developed for practical applications, and realistic fault scenarios from an actual power system are served for demonstrating the correctness of the presented model and the efficiency of the developed software system.

The main contributions include the following three aspects:

- a) A new form of the FH is presented, including the information about “the actual states of section(s) in the outage area (healthy or faulted)”, as well as “the actual operating states of PRs and CBs (normal or malfunctioned)”.
- b) A novel criterion is presented (i. e., the objective function of the optimization problem) with malfunctions of PRs and CBs taken into account. Here, the key issue is to determine the expected states of PRs and CBs corresponding to a given FH. The fault diagnosis model to be developed could not only estimate fault section(s), but also identify the malfunctioned PRs and CBs, as well as the incorrect and missing alarms.
- c) Based on the developed fault diagnosis model, a software system is designed and implemented to meet the requirements of actual power systems. The developed software package has been employed by Guangdong Power Dispatching Center in south China. Actual fault scenarios are employed to demonstrate the feasibility and efficiency of the developed model and approach.

The framework of the developed analytic model-based approach for power system fault diagnosis is shown in Fig. 6.

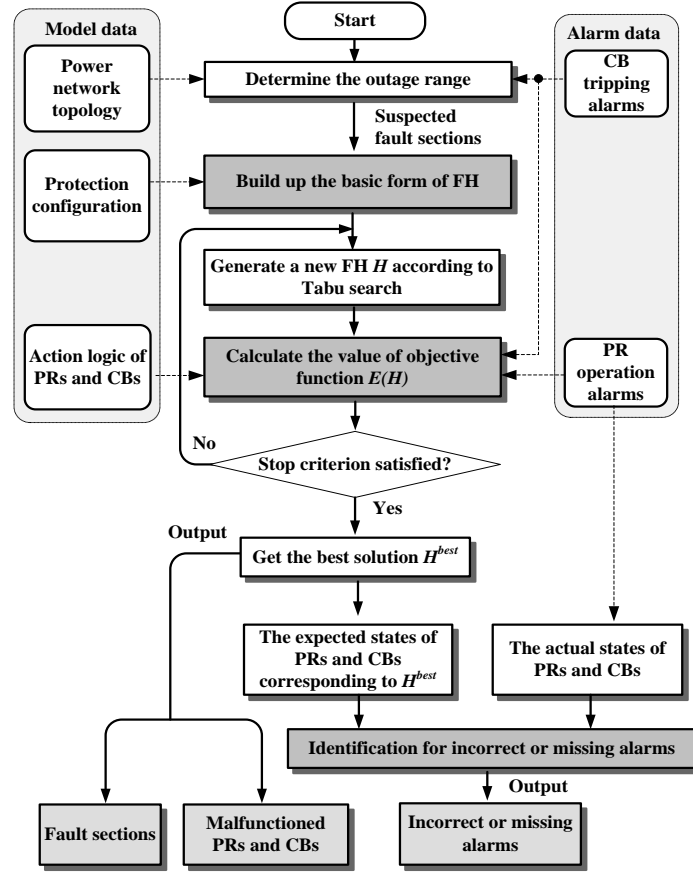


Fig. 6. The framework of the developed fault diagnosis method

The objective function $E(H)$ reflects the credibility of a FH denoted by H . A smaller $E(H)$ suggests a higher credibility of H . Thus, the power system fault diagnosis problem could be formulated as an optimization problem, with the objective of finding a FH (or FHs) that minimizes $E(H)$. $E(H)$ is determined by the following procedure:

If H is an unreasonable FH, H must not be a correct solution of the fault diagnosis problem. Thus, once H is an unreasonable FH, $E(H)$ should be assigned a large value such as $E(H)=100000$, so that an unreasonable FH will, in any case, not be the optimal solution of the fault diagnosis problem.

If H is a reasonable FH, $E(H)$ is determined as follows:

$$\begin{aligned}
 E(H) &= w_1 \left(\sum_i^{n_r} |\Delta r_i(H)| + \sum_j^{n_c} |\Delta c_j(H)| \right) + w_2 |H| \\
 &= w_1 \left(\sum_i^{n_r} |r_i - r_i^*(H)| + \sum_j^{n_c} |c_j - c_j^*(H)| \right) + w_2 \left(\sum_k^{n_d} |d_k| + \sum_i^{n_r} (|f_{ri}| + |m_{ri}|) + \sum_j^{n_c} (|f_{cj}| + |m_{cj}|) \right)
 \end{aligned} \tag{2}$$

The above equation consists of the following two parts:

- 1) The discrepancy index: $\sum_i^{n_r} |\Delta r_i(H)| + \sum_j^{n_c} |\Delta c_j(H)|$.

- 2) This index reflects the discrepancy between the expected and actual states of PRs and CBs, i.e., $|\Delta r_i(H)| = |r_i - r_i^*(H)|$ and $|\Delta c_j(H)| = |c_j - c_j^*(H)|$.

Here, r_i represents the actual state of the i th PR, and $r_i = 0$ or 1 corresponds to the nonoperational or operational state; c_j represents the actual state of the j th CB, and $c_j = 0$ and 1 corresponds to the tripped (open) or non-tripped (closed) state; $r_i^*(H)$ represents the expected state of the i th PR corresponding to H . If the i th PR should not operate, $r_i^*(H) = 0$, otherwise $r_i^*(H) = 1$; $c_j^*(H)$ represents the expected state of the j th CB. If the j th CB should not be tripped off, $c_j^*(H) = 0$, otherwise $c_j^*(H) = 1$.

As shown in Fig. 7, based on the developed method, a software package is developed for actual applications in utility companies. Two data sources are included:

- a) The IEC 61970 based EMS (Energy Management System) provides an integrated solution through defining a CIM (Common Information Model) for electric primary equipments and standardizing a GID (Generic Interface Definition), which provides access to SCADA systems for obtaining CB tripping alarms. The single-line diagrams of the power network concerned and each substation are exported from the IEC 61970 based EMS, with a standard graphic format namely SVG (Scalable Vector Graphics).
- b) The Fault Information System (FIS) provides the PR configuration information and the real time PR operating alarms.

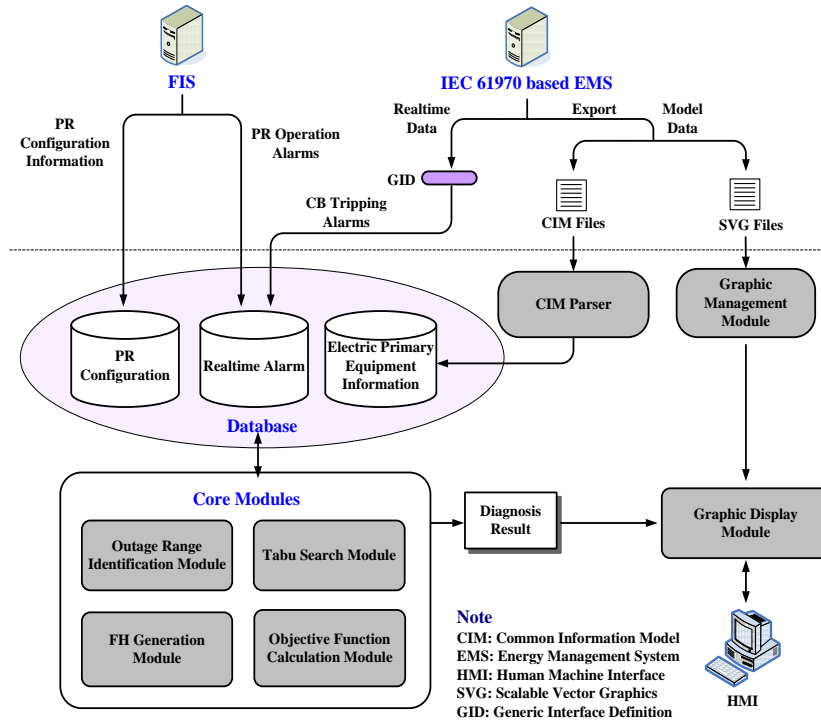


Fig. 7. The framework of the developed software system

Based on the existing analytic model-based methods, a novel analytic model is presented for power system fault diagnosis with malfunctions of protective relays and circuit breakers taken into account. The developed model could not only estimate the fault sections, but also identify the malfunctioned protective relays and circuit breakers, as well as the incorrect and missing alarms. With the application of GPS clocks in recent years to synchronize the data acquisition of SOE (Sequence of Events), a time tagging accuracy of about 1 ms could be achieved. A software package is developed for actual applications in power utility companies. It is demonstrated by many actual fault scenarios of an actual power system in China that the developed model is correct, and the method efficient. The proposed method does not employ the temporal information of alarm messages, and future efforts will concentrate on this.

In [Lihong Wei et al, 2010], an accurate and effective technology for fault diagnosis of a high voltage transmission line plays an important role in supporting rapid system restoration. The fault diagnosis of a high voltage transmission line involves three major tasks, namely fault type identification, fault location and fault time estimation. The diagnosis problem is formulated as an optimization problem in this work: the variables involved in the fault diagnosis problem, such as the fault location, and the unknown variables such as ground resistance, are taken into account as optimization variables; the sum of the discrepancy of the approximation components of the actual and expected waveforms is taken as the optimization objective. Then, according to the characteristics of the formulated optimization problem, the Harmony Search, an effective heuristic optimization algorithm developed in recent years, is employed to solve this problem. Test results for a sample power system have shown that the developed fault diagnosis model and method are correct and efficient.

Some improvements are made in this work:

- a) The variables being solved for the fault diagnosis problem such as the fault location, and the unknown variables such as the ground or arc resistance are used as optimization variables. Consequently, fault type, fault location, fault time and indefinite variables can be obtained at the same time.
- b) The formulated problem is a mixed integer programming one with both discrete and continuous valuables. The Harmony Search (HS), an effective heuristic optimization algorithm developed in recent years, is employed to solve this problem.

As shown in Fig. 8, FDHVTL is formulated as an optimization problem with the following two key points:

- a) The variables being solved for the fault diagnosis problem such as the fault location, and the indefinite variables such as ground resistance are used as optimization variables;
- b) The matching degree of the waveforms, i.e., the discrepancy between the actual and the expected waveforms, is employed as the optimization objective. The actual and the expected

waveforms are produced with Digital Fault Recorder (DFR) and Matlab Simulink, respectively.

HS is employed to solve the established optimization problem.

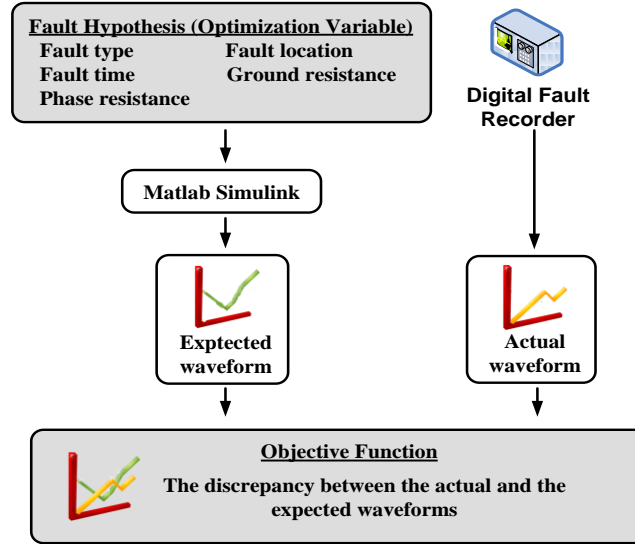


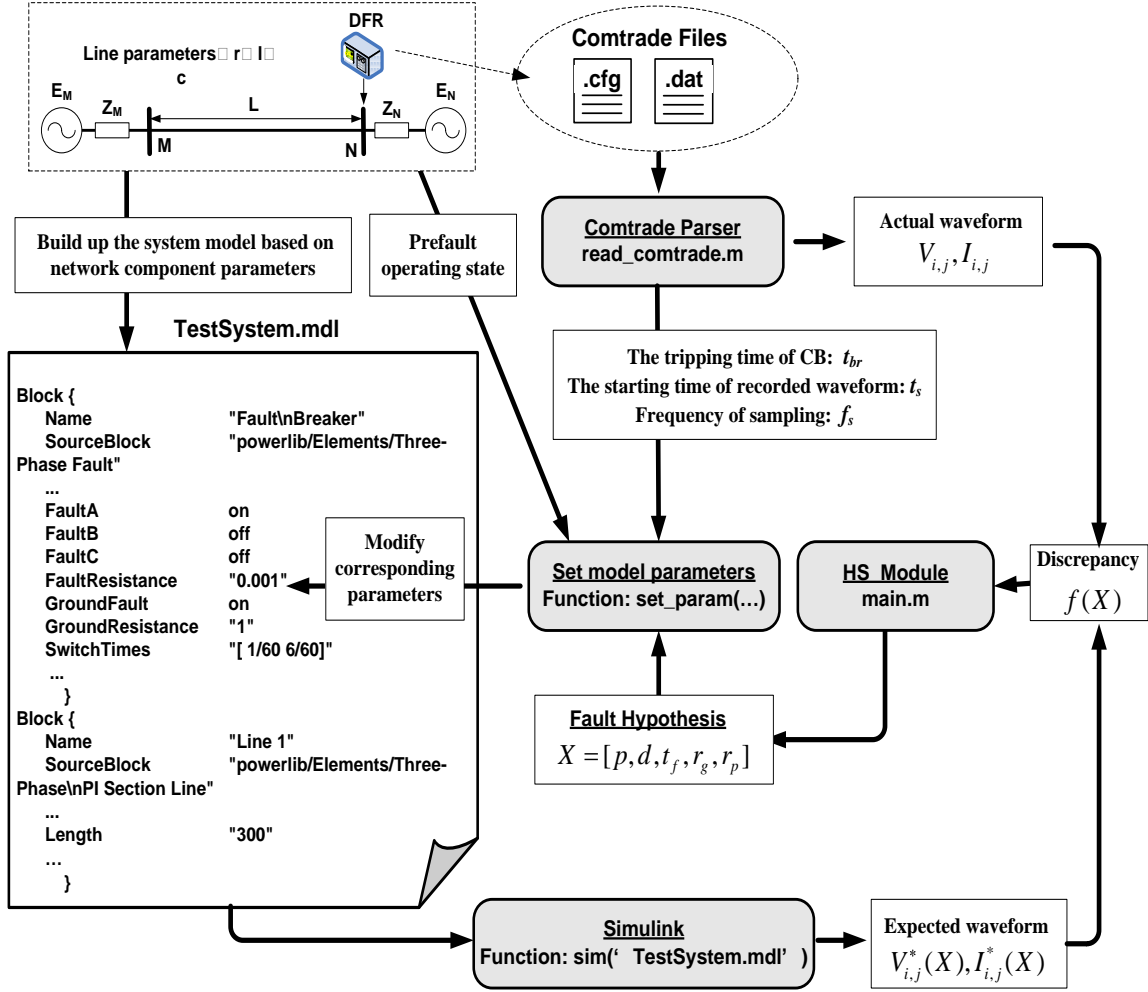
Fig. 8 The flowchart of the HVTL fault diagnosis based on waveform matching

The waveform matching is made between the actual waveforms derived from the DFR and the expected waveforms produced from the simulation studies. M points in the actual and the expected waveforms in $[t_s, t_{br}]$ are sampled respectively. An objective function which reflects the discrepancy between the actual and the expected waveforms is given as follows:

$$f(X) = f(p, d, t_f, r_g, r_p) = \sum_{i=A,B,C} \sum_{j=1}^M |V_{i,j} - V_{i,j}^*(X)| + \sum_{i=A,B,C} \sum_{j=1}^M |I_{i,j} - I_{i,j}^*(X)| \quad (3)$$

Where $i = A, B$ or C represents phase A, B, or C, respectively; j is the j th sampling point ($j \in \{1, 2, \dots, M\}$); $V_{i,j}$ and $I_{i,j}$ are the sampling points of the during-fault voltage and current respectively, which are obtained from DFR in an actual fault scenario; $V_{i,j}^*(X)$ and $I_{i,j}^*(X)$ are the sampling points of the during-fault voltage and current respectively, which are produced by simulation studies corresponding to a given fault hypothesis X .

Implementation of the fault diagnosis system is shown in Fig.9.



Note: The M-file "read_comtrade.m" is used to parse the Comtrade format file; the model file of Matlab Simulink "TestSystem.mdl" is employed to model the test power system; sim('*.mdl') is a Matlab function used to simulate the model file *.mdl.

Fig. 9 The implementation of the fault diagnosis system

By taking the fault type, fault location, fault time, ground resistance and phase resistance as the optimization variables and employing the matching degree between the actual and the expected waveforms as the optimization objective, FDHVTI is then formulated as a mixed integer programming problem. The Harmony Search, an efficient heuristic optimization algorithm developed in recent years, is employed to solve the developed optimization formulation. It is demonstrated by simulated fault scenarios of a sample system that the developed model is correct and the HS based method is computationally quite manageable. Because this tool is designed for application to high voltage transmission confusing issues such as high load harmonic currents or nonlinear arc faults are able to be avoided.

A flood of alarm messages in an automatic digital substation makes the monitoring task a significant challenge for the operators in a remote control centre, especially under fault scenarios. An on-line intelligent alarm processing system is developed based on the architecture of the digital substation in [Lihong Wei et al]. First, real-time alarms are classified according to

the IEC 61850 standard, in order to provide synthesized and organized alarms for the alarm processing procedure in the next step. Then, a new and systematic alarm processing approach for digital substations is developed. Two modules, i.e., the generation of candidate hypotheses and the truth evaluation for the hypotheses, are included in the developed approach, and these two modules are operating in parallel in on-line implementation. This approach could not only determine the fault/disturbance cause but also the missing or false alarms, but also the causes of the false alarms. According to actual application requirements, an on-line intelligent alarm processing system is developed and applied in the Xingguo substation—the first digital substation in Jiangxi province, China. Finally, an actual alarm processing scenario serves to demonstrate the presented alarm processing method as well as the developed software system.

With the support from Jiangxi Electric Power Research Institute in China, an on-line intelligent alarm processing system for the 110kV Xingguo digital substation is designed and implemented in this work. The major contributions of this work are as follows:

- 1) Based on the architecture of the digital substation, real-time alarms are classified according to the IEC 61850 standard.
- 2) For on-line implementation in digital substations, a new and systematic alarm processing approach is presented. Two modules, i.e., the generation of candidate hypotheses and the truth evaluation for the hypotheses, are included in the developed approach. These two modules are operating in parallel in on-line implementation:
 - In the module for the generation of candidate hypotheses, the related candidate hypotheses are organized in the same hypothesis set.
 - In the module for the truth evaluation of the hypotheses, a systematic alarm processing approach based on logic analysis is presented. Consequently, not only the fault/disturbance cause, but also the missing or false alarms, could be identified. Moreover, the causes of the false alarms could also be identified by analyzing the alarms associated with the secondary devices, i.e., the protection devices and communication devices.
- 3) According to the requirement of the actual project, a software package is developed by using the proposed on-line intelligent alarm processing approach, and has been successfully applied in the Xingguo substation, the first digital substation in Jiangxi province, China. Finally, an actual alarm processing scenario is presented to demonstrate the presented alarm processing model as well as the developed software system.

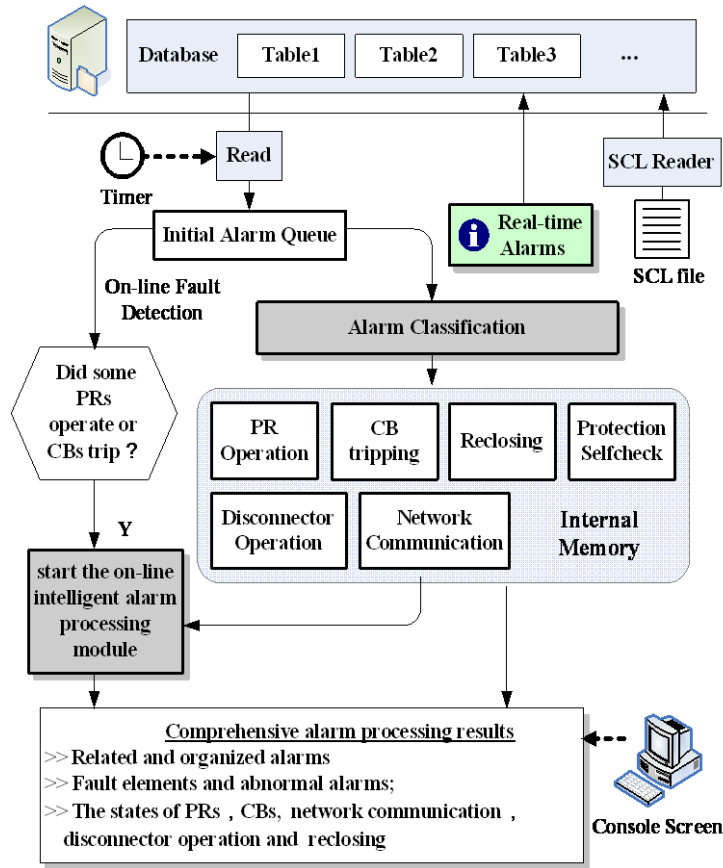


Fig. 10. The framework of the proposed system

The developed framework for the on-line intelligent alarm processing system in this work is based on the architecture of a digital substation as shown in Fig. 10. At the system initialization stage, the alarm configuration is automatically written into the database by analyzing the Substation Configuration Description Language (SCL) file. When a fault/disturbance takes place, the received alarms will be put into the real-time database first, and then into the initial alarm queue. Based on the IEC 61850 standard, the alarms in the initial alarm queue are classified in order to provide layered and organized alarms for the alarm processing procedure. When PRs operate or CBs trip, the module of on-line intelligent alarm processing will be activated. Consequently, the comprehensive alarm processing results are displayed on the operator's console screen with the following details:

- 1) Related alarms are listed by groups so as to help the operators organize the real-time alarms clearly.
- 2) Faulted elements are identified to assist the operators rapidly restoring the network, especially under complicated fault scenarios.

Based on the architecture of digital substations, a systematic alarm processing approach and further an on-line intelligent alarm processing system are developed in this work. The developed software system can not only classify the real-time alarms according to the IEC 61850

standard, but also find out the cause of a fault/disturbance, missing or false alarms as well as the causes of the false alarms' occurrences. It is demonstrated by many test examples and actual scenarios that the proposed approach is correct and the developed software system can meet the requirements of on-line alarm processing in actual power systems.

Fault diagnosis and accident treatment in substations have play an important role in maintaining power system security and reliability. Some substation diagnosis models and methods have been proposed to address this problem, by using technologies such as the expert system, artificial neural network, Petri network, agent technology, rough sets, and using information obtained from protective relays and circuit breakers. In addition, substation diagnosis models and methods are usually related with those models and methods used for the fault diagnosis of individual transmission and transformation equipment, such as the transformer diagnosis model based on three chromatographic level correlation analysis, and the wavelet theory based transmission line fault diagnosis model using fault recorders. It can be seen that most of the currently available substation fault diagnosis models only employs the information of protective relays and circuit breakers, or fault features of a single device. In other words, the existing models and methods, due to employing only local information, have difficulty in achieving an accurate diagnosis for complex faults with uncertainties, including multiple consecutive failures, malfunctions of protective relays and/or circuit breakers, missing or false alarms, and sensor errors, to name a few.

Given this background, a Cause-and-Effect based fault diagnosis model is developed in [Zhiwei Liao et al] by introducing the Root Cause Analysis approach and taking into account the technical features of digital substations such as the substation structure and the data/information flows,. Based on the logic relationship between the parent node and the child node such as the transformer/circuit breaker/transmission line, and between the root cause and child cause in the diagnosis model, the Dempster/Shافر evidence theory is used to integrate different types of fault information so as to implement an hierarchical, systematic and comprehensive diagnosis. An actual fault scenario is used for demonstrating the developed approach in diagnosing malfunctions of protective relays and/or circuit breakers, missing or false alarms, and other frequently encountered faults at a digital substation.

A root cause analysis based fault diagnosis system for digital substations is shown in Fig. 11, $S(CN) = \{CN_1, CN_2, CN_3, CN_4, CN_5\}$ and $S(F) = \{c_1, c_2, c_3, c_4, c_5\}$ denote the child nodes and the child causes of transformers, circuit breakers, lines, bus and secondary system (DC power supply, network communications and security devices).

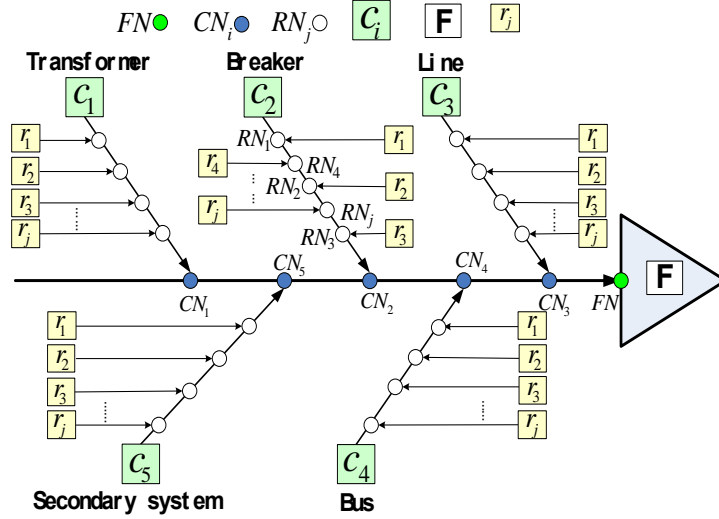


Fig. 11. The framework of the RCA-based fault diagnosis system for digital substations

The following is the explanation to each component in the diagram:

- 1) F : a problem node to be solved as a specified fault in a substation .
- 2) c_i : a child cause of F and a basic reason of a specified fault, such as a transformer or line fault. $p(c_i)$ denotes the fault probability caused by c_i . $S(F) = \{c_1, c_2, \dots, c_i\}$ is the child cause set which could trigger F .
- 3) r_j : a root cause of F and a fundamental reason of a specified fault in the power system, such as the faults caused by the transformer arc or a single phase line grounding fault. $p(r_j | c_i)$ denotes the fault probability caused by r_j which belongs to c_i . $G(c_i) = \{r_1, r_2, \dots, r_j | r_j \in c_i\}$ is the root cause set that belongs to the basic cause c_i . For example, c_2 is a line fault, $r_1 \in c_2$ is a single phase grounding fault which belongs to the root cause of a line fault.
- 4) FN : the only one parent node for the diagnosis system. $FN = (D, M, O)$, indicating that the parent node is composed of three elements D , M and O . D represents the composition of the access modes to obtain the required information from the source, $D \subseteq D_e = \{d_1, d_2, \dots, d_n\}$, and D_e is the collection of all possible n modes. $M = \{m_1, m_2, \dots, m_p\}$ denotes the available fault diagnosis methods applicable at the node. $O = \{[c_i, p(c_i)] | (i = 1, 2, \dots, q)\}$ is the diagnosis output, where $c_i \in O$, q is the number of the reasons (c_i), $p(c_i)$ denotes the fault probability caused by c_i . Thus, FN denotes the basic diagnosis functions.
- 5) CN_i and RN_j : the child nodes and the root nodes. Like FN , they are constituted by three elements D, M, O . Furthermore, they can give a more detailed diagnosis result based on FN . Thereinto, $S(CN) = \{CN_1, CN_2, \dots, CN_i\} \in FN$, with $S(CN)$ denoting the set of the child nodes, which all belong to FN ; $S(RN \in CN_k) = \{RN_1, RN_2, \dots, RN_j\}$ is the set of root node RN which belongs to the child node CN_k .

- 6) The node functions of FN , CN_i and RN_j are independent. With the node definition given in 4), it can be seen that all nodes are independent in obtaining the needed diagnosis information, selecting the appropriate diagnosis methods, and analysing fault reasons of each node.
- 7) The causes between c_i and r_j are complementary. For instance, the child cause $S(F) = \{c_1\}$ and its root cause $r_1 \in c_1$ can be used as each other's complementation and verification.

Based on the fault diagnosis model presented before, a software package has been developed and applied in the 110 kV Xingguo digital substation, the first of its kind in Jiangxi Province, China. In the given numerical examples here, the power outage area is enclosed by the dotted lines as shown in Fig. 12.

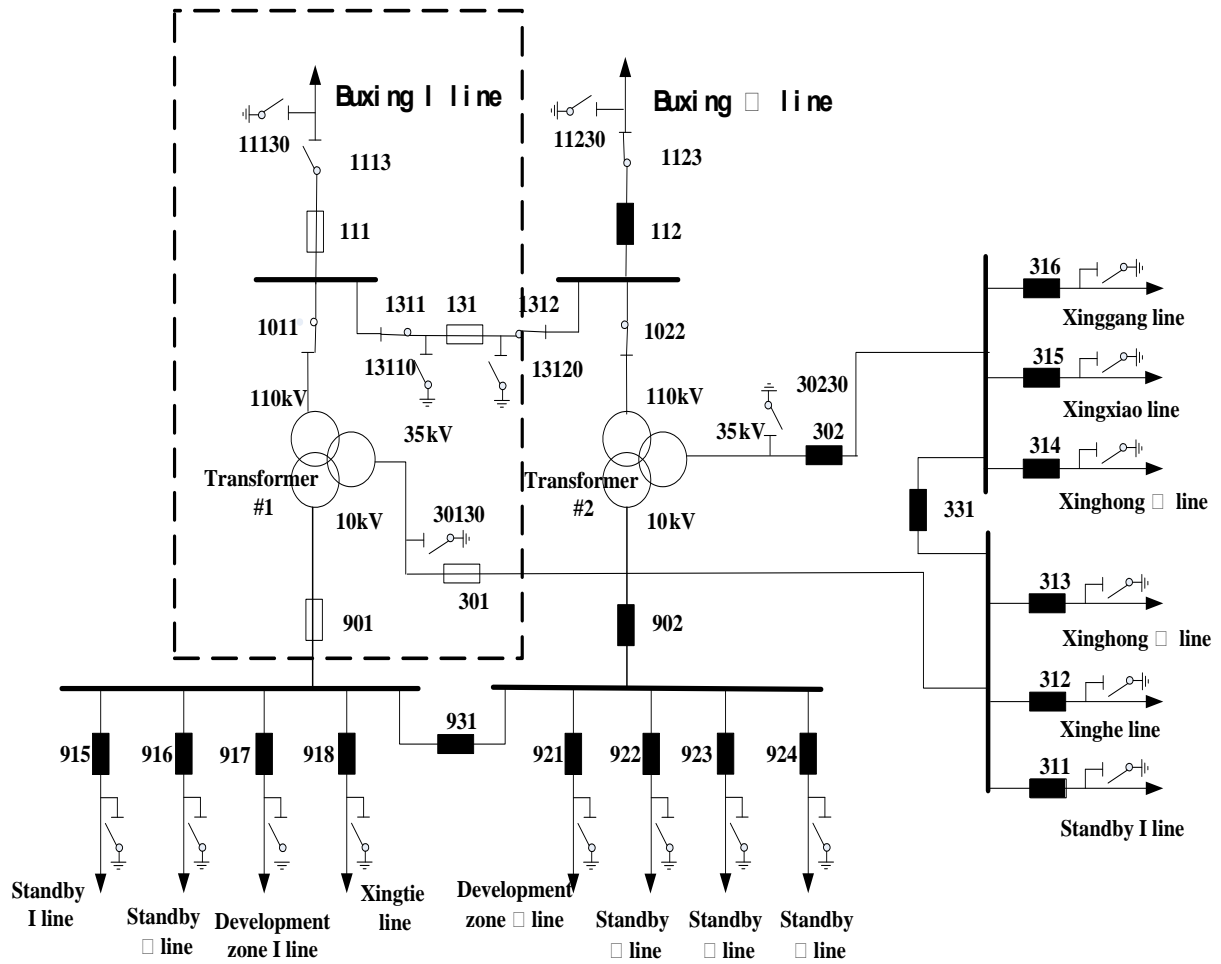


Fig. 12. The connection scheme of the 110 kV Xingguo digital substation

The coil current and switch signal waveform of the circuit breaker numbered 111 is obtained by mode d_3 as plotted in Fig. 13. The recorded fault curves of Buxing-I line is obtained by mode d_3 as plotted in Fig. 14.

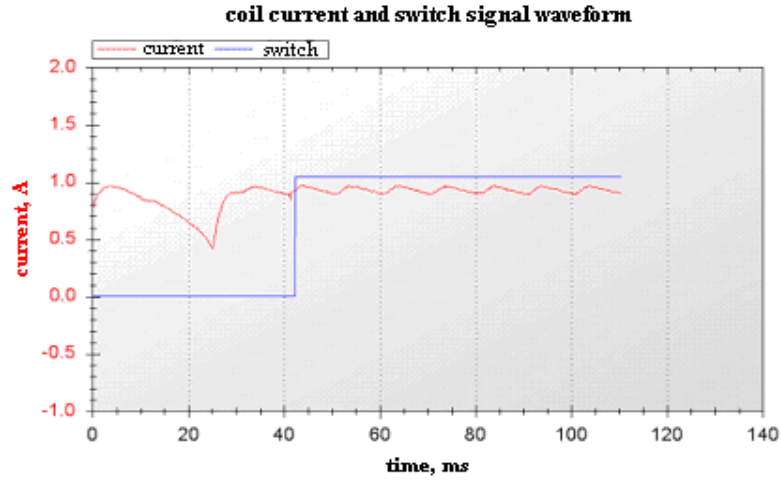


Fig. 13. The coil current and switch signal waveform of the circuit breaker numbered 111 obtained by mode d_3

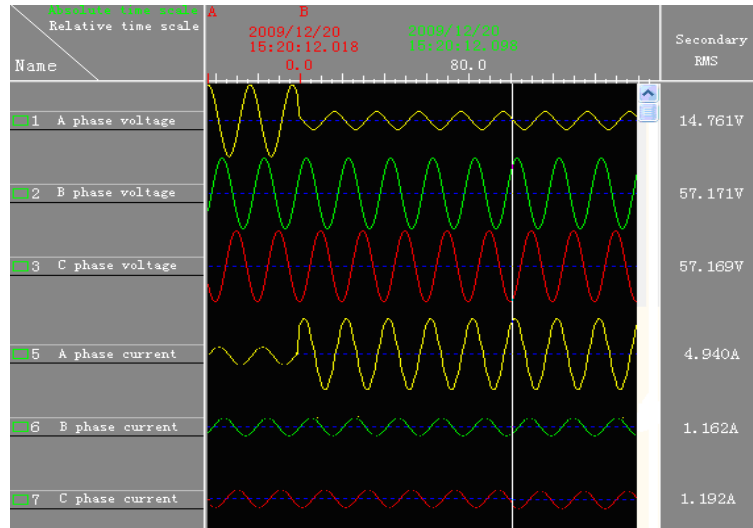


Fig.14. The fault recording curves of Buxing I line obtained by mode d_3

By systematically considering the structure and technical features of digital substations, a Root Cause Analysis based approach is presented to diagnose faults of transmission and transformation equipments of digital substations. The well-established Dempster/Shافر evidence theory is applied for analyzing the comprehensive fault information of transmission and transformation equipments so as to find the root cause. The developed fault diagnosis software system can be used to diagnose various faults often encountered in substations, including malfunctions of protective relays and/or circuit breakers, and missing or false alarms. The fault diagnosis system can be implemented in a hierarchical structure for multi-level information integration. An actual fault scenario is served for demonstrating the effectiveness of the proposed fault diagnosis software system. The performance of the developed software tool has been verified in practical applications.

3.6 Implications for DG penetration into networks

The concern about climate change has led to the development of more sustainable energy based on renewable sources, such as solar, wind, mini-hydro and bio-fuels. This push is starting to spread the power generation over the distribution networks in the form of distributed generation and will lead to increase in the DG penetration level significantly in the near future. These DGs can provide benefits for both utilities and consumers in terms of transmission losses, deferral in capital investment and reliability.

Islanded operation, protection, reclosing and arc extinguishing are some of the challenging issues related to the connection of converter interfaced distributed generators (DGs) into a distribution network. The isolation of upstream faults in grid-connected mode and fault detection in islanded mode using overcurrent devices are difficult. In the event of an arc fault, all DGs must be disconnected in order to extinguish the arc. Otherwise, they will continue to feed the fault, thus sustaining the arc. However, the system reliability can be increased by maximising the DG connectivity to the system; therefore the system protection scheme must ensure that only the faulted segment is removed from the feeder. This is true even in the case of a radial feeder as the DG can be connected at various points along the feeder. In [M. Dewadasa et al, 2009] , a new relay scheme is proposed which, along with a novel current control strategy for converter interfaced DGs, can isolate permanent and temporary arc faults. The proposed protection and control scheme can even coordinate with reclosers. The results are validated through PSCAD/EMTDC simulation and MATLAB calculations.

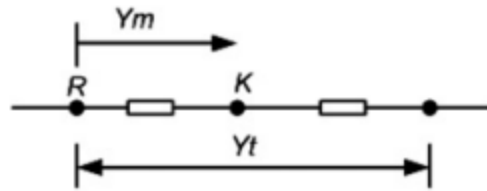


Fig. 15. Protected radial feeder

The new inverse time relay is proposed based on the admittance of the protected line. A radial distribution feeder, as shown in Fig. 15, is considered to explain the new relay fundamentals. It is assumed that the relay is located at node R and the point K is an arbitrary point at the protected feeder. The total admittance of the protected line segment is denoted by Y_t and measured admittance between the points R and K is denoted by Y_m . Then the normalised admittance (Y_r) can be defined in terms of Y_t and Y_m as

$$Y_r = \left| \frac{Y_m}{Y_t} \right| \quad (4)$$

This normalised admittance is used to obtain an inverse time tripping characteristic for the relay. The general form for the inverse time characteristic of the relay can be expressed as

$$t_p = \frac{A}{Y_r^p - 1} + k \quad (5)$$

Where A , r and k are constants, while the tripping time is denoted by t_p .

The relay tripping characteristic for $A = 0.0047$, $r = 0.08$ and $k = 0$ is shown in Fig.16.

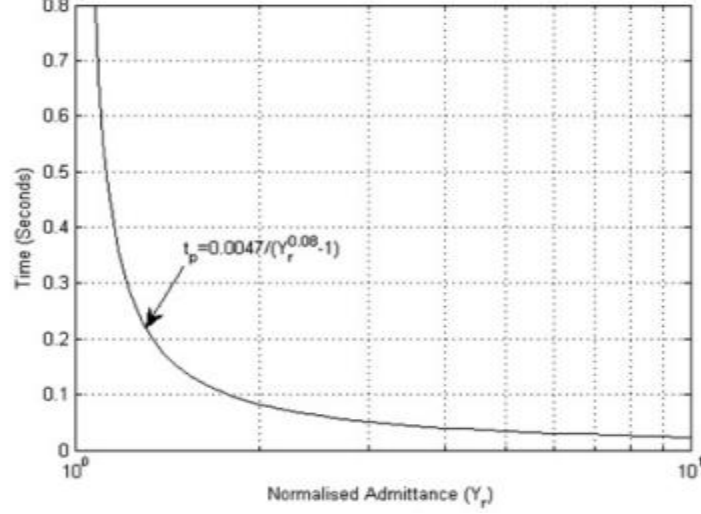


Fig.16. Relay tripping curve

A current fold back control for a converter interfaced DG is proposed in this paper. This control strategy helps in the arc extinction while maintaining sufficient current levels to aid fault detection. The converter nominally operates in voltage control mode. Once a fault is detected, it switches to fold back current control mode. The three-phase structure of the converter which is used in this paper to implement the proposed control strategy is shown in Fig.17. It contains three H-bridge converters that are supplied a common DC bus containing the DG. Three single-phase transformers are connected to the three converters to provide isolation and voltage boosting.

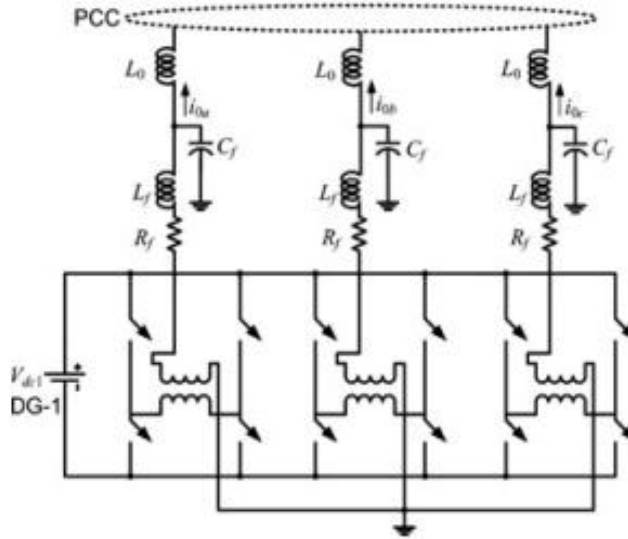


Fig. 17. Converter structure and control

In the Fig.17, L_f is the leakage reactance of the transformer, R_f is the transformer losses and L_o is the output inductance of the DG-converter system. The filter capacitor C_f is used to bypass the switching harmonics and the voltage across the capacitor is denoted by v_c .

All in all, a new inverse time admittance relay characteristic and a new fold back control strategy for converter interfaced DGs are discussed in this paper. The relay has the ability to isolate both the permanent faults and transient arc faults from upstream and downstream side of the faulted segment when fold back current limited DGs are present in the network. Therefore proposed protection scheme enhances reliability during islanded operation, assuming that the DG generation is sufficient to supply the load demand. Furthermore, reclosing possibilities are considered to increase the reliability further.

The proposed converter control strategy is capable of maintaining a DG connected to the network after a fault and does not require its immediate disconnection. Moreover, the fault ride through capability of a converter can be increased indirectly because of the proposed fold back current limit. Furthermore, the arc will self-extinguish and the system will self-restore if the DGs utilise the proposed controller.

The protective relay coordination refers to the ability to select appropriate relay setting values so that they can meet the basic requirements for protective relays, namely, selectivity, speed, sensitivity and reliability, under different kinds of faults. An appropriately coordinated protection system could isolate faults quickly, and maintain the operation of the remained healthy part of the system. Directional overcurrent relays are widely employed in distribution systems, and hence it is very important to investigate the coordination problem when using this kind of protective relays. Some research work has been done in this area, but in most of the existing methods linear or nonlinear programming approaches are employed for this purpose. Only continuous variables could be handled in these approaches, and the results thus obtained have to be rounded off to the nearest discrete value. Hence the optimality of the coordination result cannot be maintained.

Given this background, the optimal coordination problem of overcurrent relays is revisited and formulated as a mixed integer nonlinear programming problem (MINLP) in [Hui Yang et al, 2010]. In the formulation, the pickup current setting is a discrete variable, while the time setting multiplier is continuous. As each protective relay in the distribution system must be properly coordinated with the adjacent relays, the coordination of the protection system could be very complicated. In this paper, the well-established differential evolution (DE) algorithm is employed to solve this problem. The above mentioned problem of rounding the optimal solution of continuous variables in existing methods could be avoided in the presented DE-based method. The mathematical model of the directional overcurrent relay coordination problem is formulated first with the objective of minimizing the operating time of protective relays. Then, the DE algorithm is briefly introduced. Finally, a numerical example is served for demonstrating the proposed approach.

To facilitate the presentation, a general non-linear programming model is introduced first:

$$\text{Min } f(x) \quad (6)$$

$$\text{s.t. } g(x) = 0 \quad (7)$$

$$h_{\min} \leq h(x) \leq h_{\max} \quad (8)$$

Where, $f(x)$ is the objective function; x is the variables to be determined; $g(x) = [g_1(x), \dots, g_m(x)]^T$, m is the number of equality constraints; $h(x) = [h_1(x), \dots, h_r(x)]^T$, r is the number of inequality constraints; h_{\max} and h_{\min} are respectively the vectors of the upper and lower bounds for the inequality constraints, $h_{\min} = [h_{1\min}, \dots, h_{r\min}]^T$, $h_{\max} = [h_{1\max}, \dots, h_{r\max}]^T$.

As for the optimal coordination problem of protective relays in distribution systems, the objective is actually to minimize the operating time of relays under the constraints of selectivity, sensitivity, reliability and relay characteristic curves. This problem could be formulated as an optimization model:

$$\min_{x \in X} f(x, p) \quad (9)$$

$$\text{s.t. } t = g(x) \quad (\text{relay characteristic function}) \quad (10)$$

$$h(x) \leq 0 \quad (\text{coordination constraint}) \quad (11)$$

$$x_{\min} \leq x \leq x_{\max} \quad (\text{relay settings constraint}) \quad (12)$$

$$t_{\min} \leq t \leq t_{\max} \quad (\text{operating time constraint}) \quad (13)$$

Where, $f(x)$ is the objective function; x is the variables to be determined, i.e., relay settings parameters, X is the set of available settings; p is a set of perturbations or fault conditions in a specified zone; t is the operating time of a relay.

In the above optimization model, eqn. (11) represents the selectivity constraint used to maintain the selectivity between the primary protection and backup protection; eqn. (12) represents the sensitivity constraint used to make sure that a relay could operate when a fault happens within its protection range by appropriately setting the relay parameters; eqn. (13) represents the reliability constraint used to guarantee that when a fault happens within a relay's protection range, the relay must operate within the bounds of the operating time. In summary, the optimal coordination problem of protective relays is to minimize the operating time of relays with these constraints respected.

In this section, a sample system is slightly modified for demonstrating the developed approach, as shown in Fig. 18. The system shown in Fig. 18 is a 10kV distribution system with 5

buses and 8 protective relays. A distributed generator is installed at the end of feeder B. There are 2 circuit breakers, i.e. one at the public power supply point and the other at the distributed generation supply point. The DE algorithm is employed to obtain the optimal time setting multiplier (TM) and pickup current setting value (IP) of the directional overcurrent relay. The formulated model consists of 16 variables with 8 discrete variables and 8 continuous variables by employing the proposed method; however there will be 72 variables with 8 discrete variables and 64 continuous variables if the existing method is used. It should be pointed out that the proposed method can be applied to larger and more complicated distribution systems with multiple DGs.

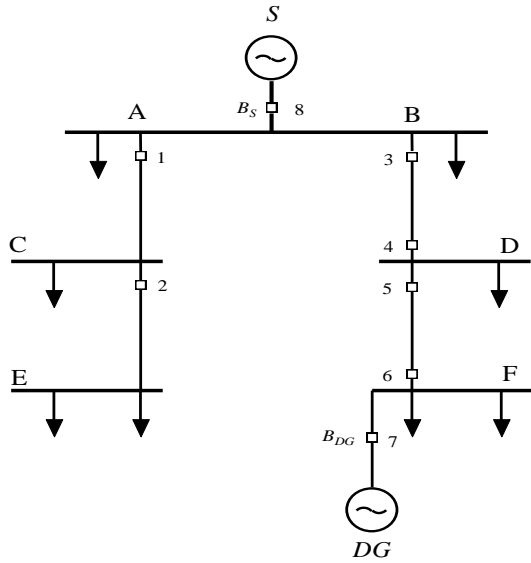


Fig. 18. The sample distribution system

The optimal objective value and the objective value of a given individual in each generation are shown in Fig. 19; the mismatched number of protective relays in the best individual and a given individual are shown in Fig. 20; the TM1 of relay #1 of a given individual is shown in Fig. 21.

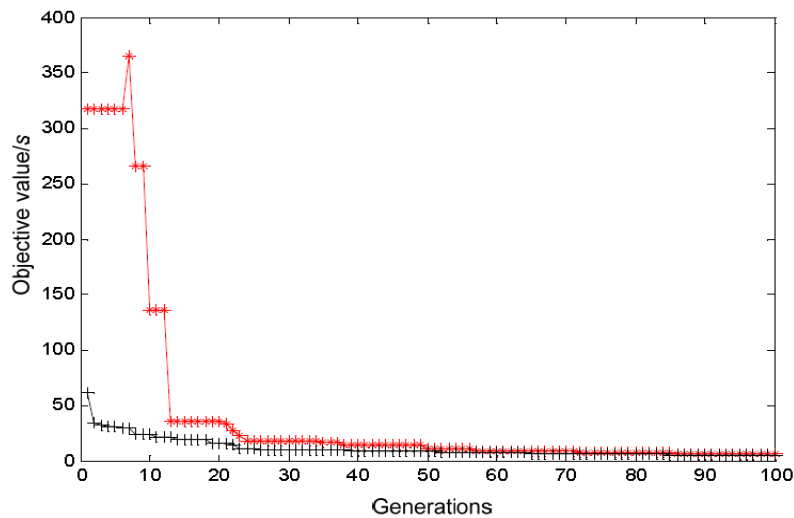


Fig. 19. The objective value of the best individual and that of a given individual

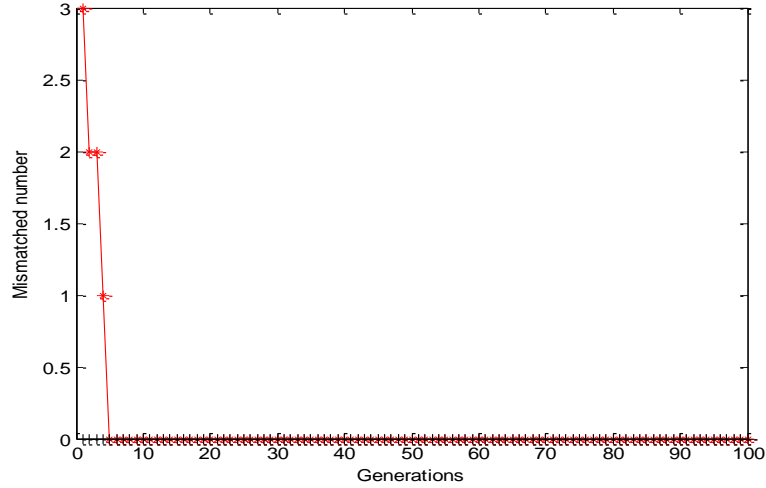


Fig. 20. The mismatched number of protective relays in the best individual and a given individual

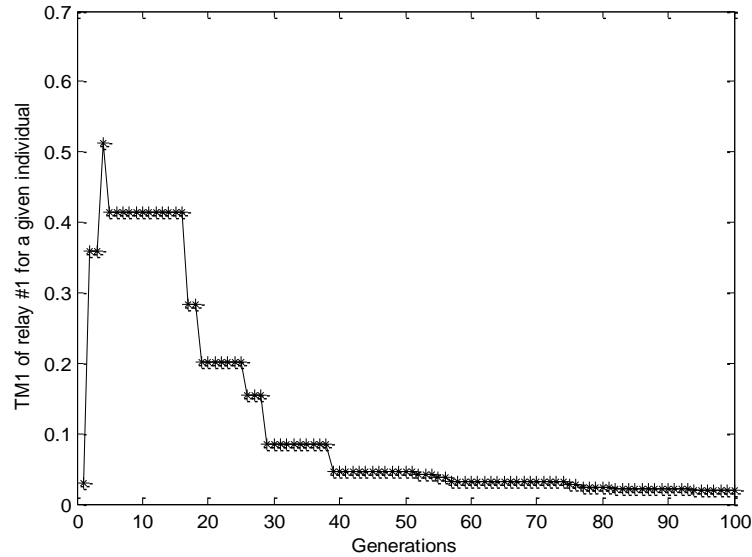


Fig. 21. TM1 of relay #1 for a given individual

The line with cross marks in Fig. 19 represents the objective value of the best individual, while the line with stars represents the objective value of a given individual. It can be found that the optimal objective value and the objective value of a given individual are improved obviously from generations 1 to 30. In Fig. 20, the mismatch of protective relays between the best individual and a given individual is shown; the black line with cross marks represents the mismatch of the best individual in each generation, while the line with star labels represents the mismatch of a given individual in each generation. It can be seen from Fig. 20 that the best individual meets the coordination constraints in the whole evolution process of the DE algorithm, and a given individual could also meet the coordination constraints after several generations. In Fig. 21, the changes of TM1 of relay #1 for a given individual is shown. The results for the protective relay coordination become stable after 40 generations. Distributed generations

could bring many benefits in economic, technological and environmental aspects, but at the same time result in a lot of challenges, of which one of the most important ones is the coordination of protective relays. When DGs are connected into a distribution system, both the direction and distribution of the power flow and fault current in the distribution system could change significantly, so the traditional protection scheme could no longer properly work, and hence new protection schemes are demanding.

Therefore, the optimal coordination problem of protective relays in distribution systems with distributed generations is formulated as a mixed integer nonlinear programming problem in [Hui Yang et al, 2010], and solved by the well-established DE algorithm. The feasibility and efficiency of the proposed method has been demonstrated by a sample system.

Conclusions

This chapter addresses a looming barrier to the increased use of DG in networks. The presence of DG's can produce errors in the operation of protection systems with faults not being seen or excessive amounts of the network being switched out in the event of line faults. There are two approaches presented here, one is the optimization of the relay settings of existing overcurrent relays to extend the robustness of existing systems of DG's. The second approach is to modify the nature of the relay to an admittance relay which is compatible with overcurrent relays but better at distinguishing line faults in the presence of DGs.

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Chapter 4 Benefits of DG with respect to Losses

4.1 Introduction

Energy losses occur due to transferring energy across power networks. They are caused by resistance of conductors and the presence of magnetic material in equipment. Power losses increase the overall cost of producing the energy demand because additional generation is needed to compensate for energy losses. Losses also increase the power flow across networks because of higher energy demands. Increase in energy demand leads to install higher rated equipment which in turn increases the cost of equipments and price of electricity.

The power losses can be divided into two categories – technical and commercial losses. Technical losses occur due to the characteristics of network equipment, supply, and demand whereas the commercial losses occur during measurements of electricity flows (or metering errors). In the UK, technical and commercial losses in average accounts make up 7% of electricity transported across distribution networks. In USA, US-wide transmission and distribution losses account for 9.5% in 2001 due to stressed utilisation and congestion of power transport corridors (Digest of United Kingdom Energy Statistics, <http://www.dti.gov.uk/energy/inform/dukes/>, GridWorks, 2009).

The technical losses vary with time due to varying magnitude of currents resulting from consumption levels. There are losses which do not vary with time. They are referred to as fixed losses. For example, in a transformer iron losses do not vary with time and come under fixed losses. Some of the power losses occur due to dielectric and sheath materials of equipment. They are not so much concerned in power loss analysis because of their relatively small contribution to power losses.

The power loss is one of the elements that indirectly contribute to global warming due to additional generation producing greenhouse gasses.

4.2 Methods for estimating network losses with DG

One of the important facts in the analysis of power losses in distributed generation (DG) connected networks is the modelling of the output characteristics of DG. If the DG concerned has no frequency or voltage controls within its facility or they are not allowed to participate in voltage and frequency controls but operate as a base load plant, then the DG can be regarded as a negative load. It can be modelled as $(-P, -Q)$ load within the load flow formulation for the time interval (for example half an hour) that is considered for the assessment. On the other hand, the DG output can be modelled as a generator with fixed active power output within the power flow formulations. In both circumstances, the varying output has to be taken into account when evaluating over a time period. This can be modelled by applying time series to the DG output. For example, if a wind plant output for the time interval t_1 is P_1 , then the wind plant under base network operating condition models as $(-P_1, -Q_1)$. This process continues for the whole time period. A similar process is followed for modelling load variation at buses. In order

to improve the accuracy and to model realistic operating conditions, contingencies can also be modelled and with the sequential Monte Carlo simulation routines, the power losses can be estimated for a specific confidence level. There are others methods in which the power losses are calculated through analytical approaches considering probabilistic models. For example, the probability of having a particular level of DG output can be calculated and then used to calculate the likelihood of having the magnitude of power losses at a particular time interval. These models are constrained by analytical feasibility when applied to large distribution networks (Agalgaonkar and Kulkarni, 2003, Jayaweera et al., 2007, Hegazy and Hashem, 2003).

The total cost of losses can be estimated using the same method but incorporating the cost of energy production to meet the losses at each sample in the Monte Carlo simulation. These calculations should incorporate cost of power losses comes through necessary upgrading of equipment, DG contribution to environmental impacts, and metering losses. However, the published literature has yet to capture those additional elements into cost calculation models.

4.3 Distributed generation contribution to losses

Most distribution networks are traditionally designed as radial networks. The central generation supplied the load through passive networks. This is the prime reason the losses increase with an increase in network consumption. Aging network assets, operating distribution networks closer to the rated limits, and increased ambient temperature effects have contributed to further increase the technical losses.

With the development DG technologies, the trend in supplying the loads from central generation is changing. Because DG units are placed at or as near to the local loads as possible, the need for central generation to supply the load is reducing. This contributes to reduction in power losses in the network. Therefore, the DG not only reduces the need for central generation, but also reduces need for equipment upgrade driven by power losses.

However, the real contribution from DG to reduce power losses is complex because of type of DG technology, their characteristics, their availability at particular operating conditions (such as high peaks) and their resource locations. In addition, some of the DG technologies produce intermittent power output and increase the need for backup power supply for increased energy security.

At some operating conditions, if the load to be supplied by DG is low (due to network and operating constraints) then DG contribution to reduction of power losses is low. On the other hand, if the DGs directly support a large load, then the power losses that would otherwise have occurred in the system are saved. These suggest the value of optimal placement of DGs for reduction in power losses and the complexity in arguing DG as a source of reduction of power losses. (Mutale et al., 2000, Moises and Matos, 2004, Wang and Nehrir, 2004, Quezada et al., 2006)

Therefore, it is vital to perform quantitative assessment in order to justify realistic benefits of reducing losses by DG. Reference (Kashem et al., 2006) proposes a quantitative

approach to minimise power losses in a distribution feeder appropriately considering distributed generator sizes at locations and operating points.

Although there are some limitations to minimise power losses under all operating conditions, they can be mitigated with rapidly advancing ICT and smart control technologies. They will come into effect in the foreseeable future. For example, strategically controlling the output of DG mix, backup power supply, and network configuration through smart control technologies enable us to mitigate most of the above barriers. In such a context, the distributed generation should be able to provide relatively positive contributions to reduce losses irrespective of network configuration, DG resources constraints, and other barriers.

4.4 Reported studies on distributed generation impacts on losses

There are published literatures that address the DG contribution to power losses in radial distribution networks. The common theme of these literatures is that the DG contributes to decrease power losses up to the threshold capacity of DG connection and increase beyond the threshold.

However, above arguments are not always true in some of the networks when considered distribution network components within voltage groups. Such a development is reported in reference (EA Technology, 2006) considering typical distribution network models in the UK. Fig. 1 shows the reported results in a rural network model. There are four scenarios in Fig. 1 where the 1st scenario has no DG contribution, and 2nd through 4th scenarios respectively have increased installed capacities of DG. The reference (EA Technology, 2006) argue that the DG contribution to reduce losses are not always significant and depends on the type, complexity, and connection points of DG.

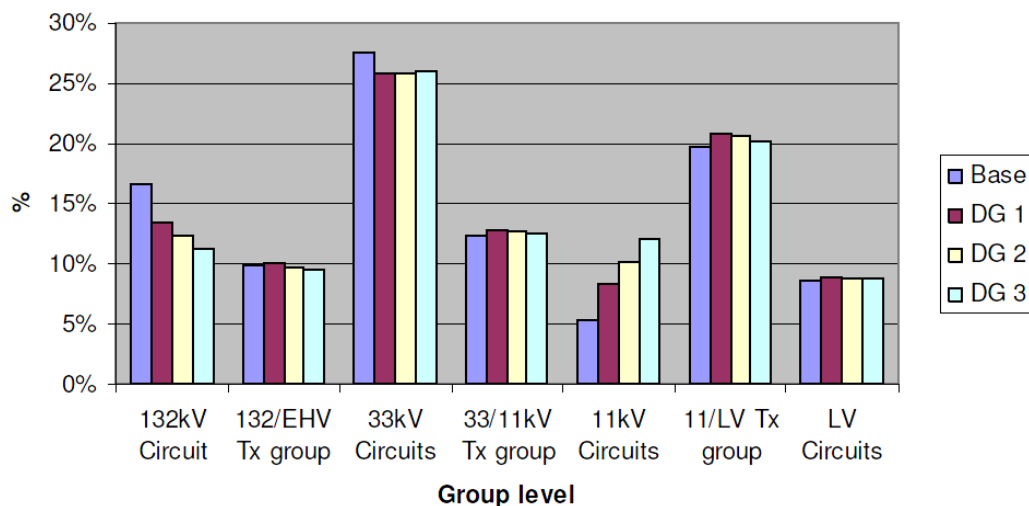


Fig. 1. A comparison of power losses in a rural network model through voltage groups (EA Technology, 2006)

Fig. 2 shows another aspect of power losses in a mixed urban/ rural network model. It suggests that circuit groups 132kV and 33kV and transformer group 132kV reduces power losses with the increase in DG capacity. However, they are proportionate to the level of increase in DG. The DG 3 scenario has the largest contribution to reduce losses. It is interesting to note that the DG 3 scenario contribution to losses are significantly increased at 11kV circuit group. These results show the complexity in arguing that the distributed generation proportionately contribute to reduce/ increase power losses in a network and suggest the need for case specific detailed assessment .

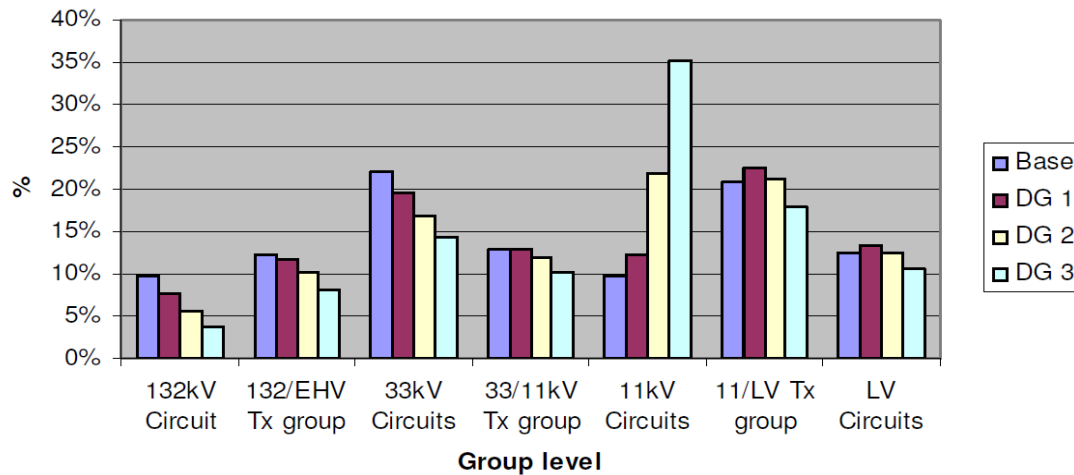


Fig. 2. A comparison of power losses in a mixed urban/rural network model using voltage groups (EA Technology, 2006)

4.5 Network benefits with DG

Network benefits of DG are categorised into two parts. They are:

- (a) Technical benefits with varying network access
- (b) Economical benefits with value based placement of DG

These two benefit factors are investigated in detail in this part of the research. The case study (a) is based on sequential simulation on a rural distribution network model and the case study (b) is based on probabilistic models on Roy Billinton test system (Billinton and Jonnavithula, 1996).

Case study (a) – Investigation of technical benefits with varying network access of DG

This part of the case study was performed at CUT directly supported by this CSIRO project using a model of a rural distribution. Wind power generation was considered as the DG source in this study. Fig. 3 shows the network which has wind plants, diesel plants, and the grid supply as power generating or supplying resources. The network peak active and reactive power demand are 7.6MW and 1.5MVAR respectively. Network demand fluctuations are modelled with time series of loads at nodes. The load growth effects are not incorporated for the assessment

however; they will be added within the next deliverables. Wind plant output characteristics are also modelled with time series of wind plant output.

There are four scenario groups in this study. They are shown in Fig. 3 as ‘wind site A connection’, ‘wind site B connection’, ‘wind site C connection’, and ‘Wind site D connection’. Each network access group represents four supplementary scenarios. Each of these supplementary scenarios has installed capacity of wind plant ranging from 0MW to 4MW, where zero wind installed capacity represents the base case. The study aimed at connecting wind plants through a single site at a time. For example, if the ‘wind plant C connection’ is in active then the wind plants connected through other sites are disconnected from the network.

The network demand can be supplied by the diesel unit, grid, and wind plant. However, the wind plant acts as a base load plant and any deficit of generation is supplied by the diesel plant or the grid. Intermittency of power output of wind plants is compensated by either diesel or grid in-feed.

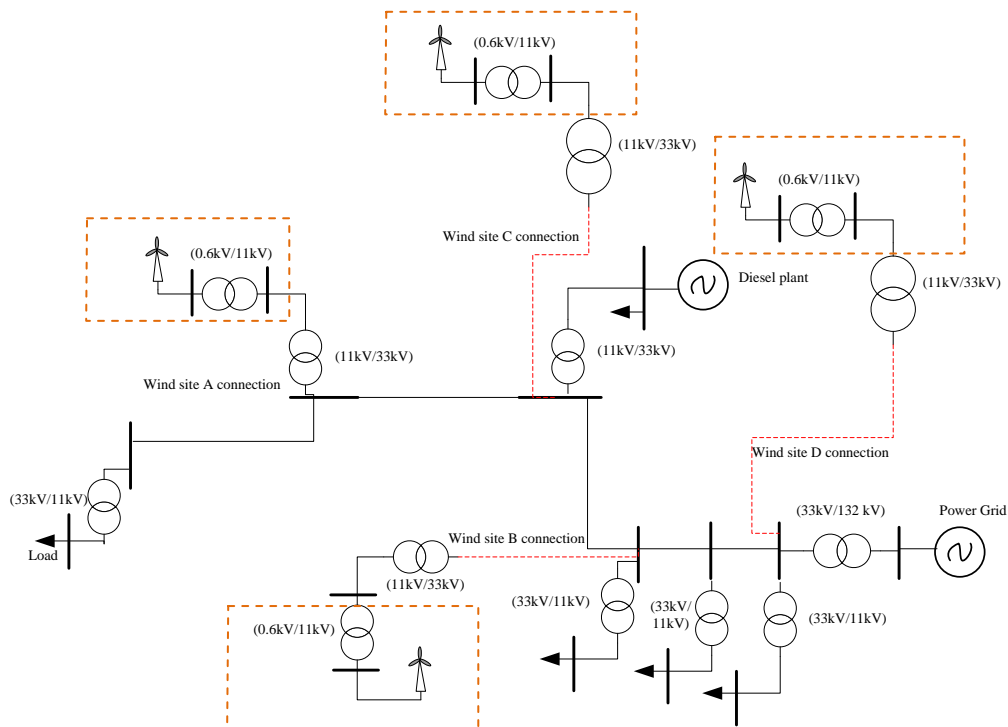


Fig. 3. A model of a rural distribution network

Fig. 4 and 5 show the results of contribution of the wind power integration capacity on active and reactive power losses. It is obvious from the results that the wind plants connected through rural downstream feeders contribute to reduction of power losses. However, the level of reduction in power losses varies with the point of interconnection of the plants. In this study, wind plants connected through ‘site C’ sees the largest reduction in power losses. This group reduces 0.8% of active power losses and 8% of reactive power losses at the 4MW wind penetration capacity (53% in Figs. 4&5) compared to the base case power losses. The groups A

and C follow a similar pattern in reducing the active and reactive power losses. Both of these groups reduce active and reactive power losses by 0.9% and 9% respectively at the wind capacity of 4MW compared to the base case power losses. However, the connection made through ‘site D’ has a different level of contribution as it is near the upstream feeders and the most loads are connected at downstream feeders. This group reduces active and reactive power losses by 0.2% and 2% respectively at the wind capacity of 4MW compared to the base case power losses.

The study only focused on power losses with increased connection of wind plant generating capacity. However, if the analysis is concerned with reliability and other network operability aspects then there is possibility to further limit the penetration capacity of wind. This is because they can limit the wind power generation transport capacity due to network and operational constraints. In that context, an economical assessment including life cycle costs may need to be taken into account to differentiate the wind plants’ real contribution to reduction of losses.

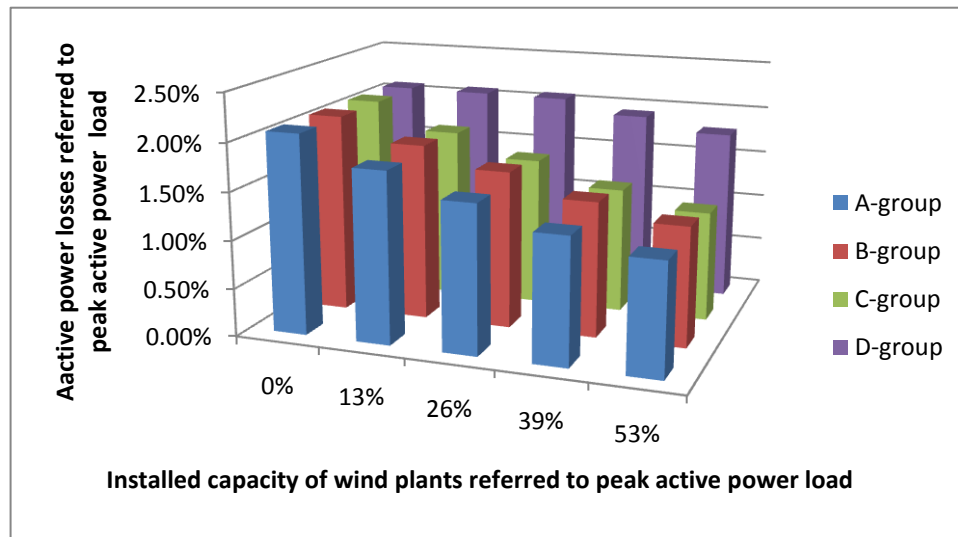


Fig. 4. Active power losses with increased connection of wind power generation

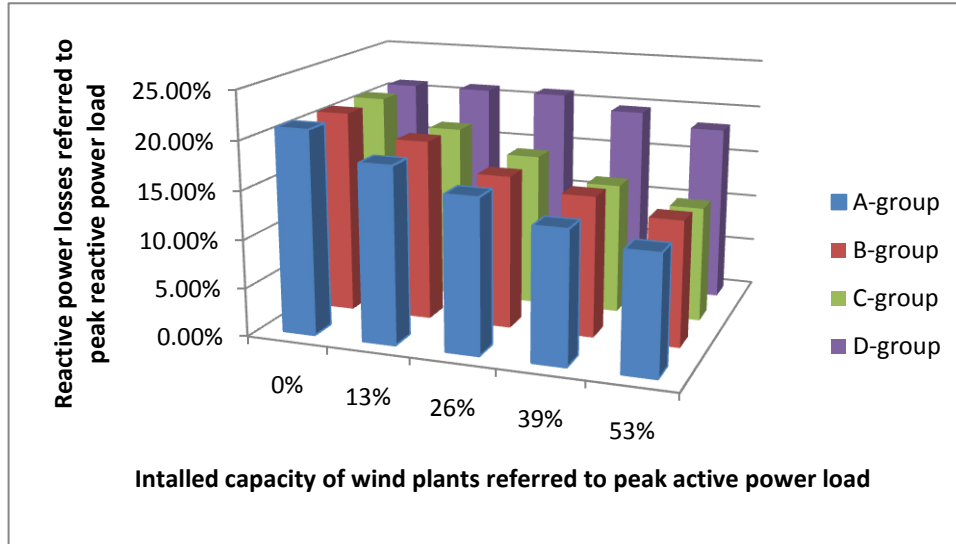


Fig. 5. Reactive power losses with increased connection of wind power generation

In scrutinising the results in Figs. 4&5, it is clear that for this particular network, the wind plants contribute to reduction of power losses to some extent if the point of interconnection of wind plants is downstream, near the major loads, and the network is radial. Varying these conditions may affect the wind power generation contribution to reduce losses. Thus, the geographic location of wind plants and penetration capacity determine the wind plants' contribution to reduce power losses.

Considering all these facts, one can argue that the DG contribution to reduce power losses is complex and case base and detailed analysis are required to come to a robust conclusion for a particular network.

The unique contribution of this part of the research is that DG does not necessarily reduce the power losses in a distribution network however; there can be operating points in which the increased penetration of DG reduces power losses to some extent. The case study presented above suggests that one should not look at DG only through the power losses that directly come through power transportation over the distribution network assets. This is because the level of reduction in power losses are fairly low when compared to the connected load in the system. However, if the real energy utilisation comes into effect rather than reduction in power losses as argued above, then the tangible benefits of DG are expected to be increased. Therefore, it is advised to incorporate energy transformation models into the benefit calculation formulae and then assess and compare the unique benefits of DG in a distribution network. This would provide the realistic value for DG.

Case study (b): Investigation of economical benefits with value based placement of DG

Fig. 6 shows the single line diagram of RBTS bus no. 6, which was chosen as the test case for this part of the research. This bus meets the requirement of being a weak grid system that is far away from the generation. The loads on this bus represent a diverse mix such as farm loads along with residential and commercial loads (Billinton and Jonnavithula, 1996). For this investigation, factors such as cost of additional reactive power support and reliability is considered in addition to cost due to distribution system losses. These are expected to be the potential cost elements that vary if DG location is changed. The required reactive power compensation was determined by trial and error to maintain voltage regulation within 4%.

Adding in DG sources to the distribution network potentially improves the voltage profile at that point and at surrounding buses. Depending on the location of the reactive power injection, it affects the amount of extra compensators required in the system. Hsu and Chen (Chungshih and Mo-Shing, 2000) propose an iterative technique for finding the required reactive power compensation by compensating the node with the worst voltage regulation to bring it within the required range. In this study, the reactive support for the network operating condition is determined by trial-and-error method. The total distribution system losses are obtained by using a Newton-Rhapson load flow technique. Normalised plots of all three curves are shown in Fig. 7.

The Fig. 7 indicates that less reactive power support is required if the DG is in proximity to the weak voltage areas since the DG source provides the necessary reactive power. Additionally, in some cases, real power losses are greater than the instance when no DG is used in the system. This is because the distance of the DG is very large compared to load, and this offsets any benefit gained by alleviating the load.

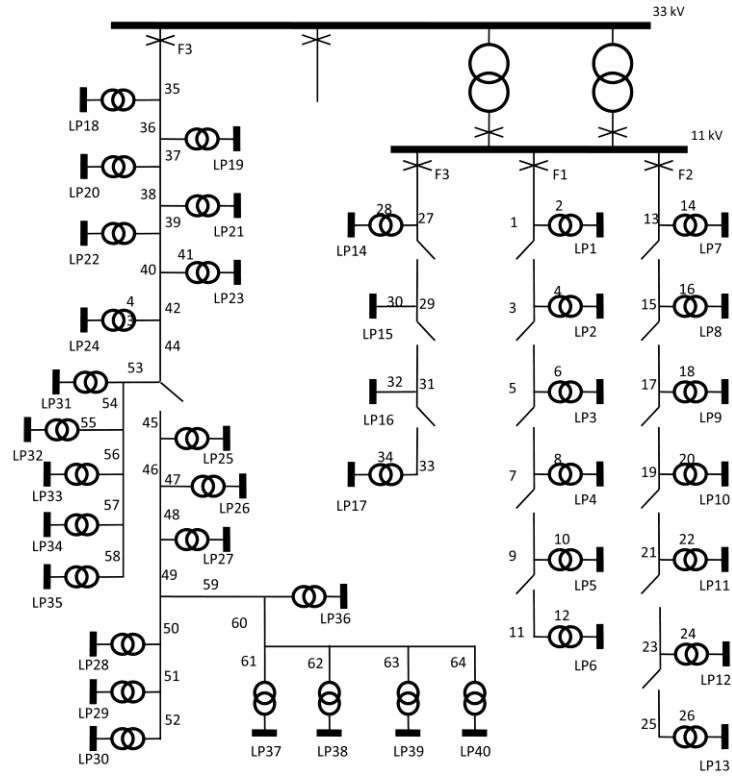


Fig. 6. Single line diagram of RBTS bus no. 6 (Billinton and Jonnavithula, 1996)

It is clearly observed that reactive power support and power losses are much more sensitive to location compared to reliability. However, none of these were optimised at the same DG location. In fact the optimum location for reliability where the cost was 40% of the cost without DG was a very poor location in terms of reactive power compensation (100% additional compensation is required in comparison to compensation requirement without DG). Therefore, the true optimum benefit location would ideally be at the location where the three curves intersect. This appeared to be close to branch number 35. Cost of each factor reduced to approximately 52% of the cost when no DG was in the system.

The analysis of the value based location also needs to account for how much each element impacts on the overall cost. For example, if the cost of reactive power support is very high compared to the cost of outages, then it is likely that at the optimum location the reactive power requirement will be minimised rather than outaged.

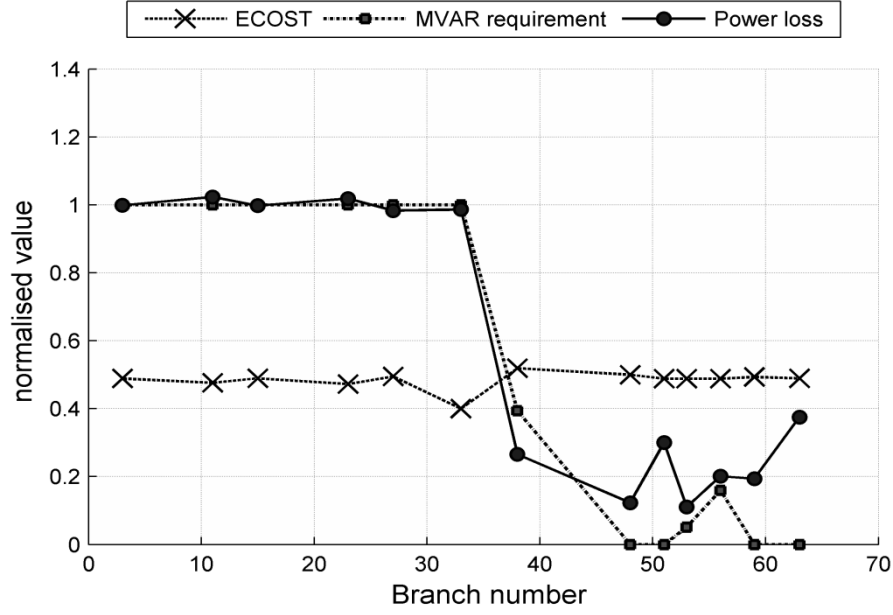


Fig. 7. Comparison of cost variations of power losses, reactive power requirement, and reliability

Costs were attached to each factor as per unit cost. Reactive power cost was considered in terms of \$/kVAR and real power losses cost was in \$/kWh. Outage costs were obtained directly from ECOST values. Chowdhury and Islam (Chowdhury and Islam, 2007) propose the use of ECOST as a measure of reliability. ECOST is the expected outage cost of the system as a whole. ECOST is calculated as follows.(Chowdhury and Islam, 2007)

$$ECOST = \sum_{k=1}^{NLP} \left[\sum_{j=1}^{NC} L_k f_j c(d_j) \right] \quad (1)$$

Where:

NLP is the number of load points in the system

NC is the number of contingencies (system states) that are being considered.

L_k is the load interrupted at load point k due to contingency j

f_j is the frequency of contingency j

$c(d_j)$ is the normalised cost of the outage of duration d_j . $c(d_j)$ can be obtained from the customer damage function (CDF). The CDF approximates the outage cost per unit of load interrupted (per MW) as a function of outage duration.

The sum of all three costs was considered at each location, relative to the total cost when no DG was used. The curve shown in Fig. 8 is for a per unit cost of \$0.01/kWh and \$0.01/kVAr for real power loss and reactive power compensation respectively.

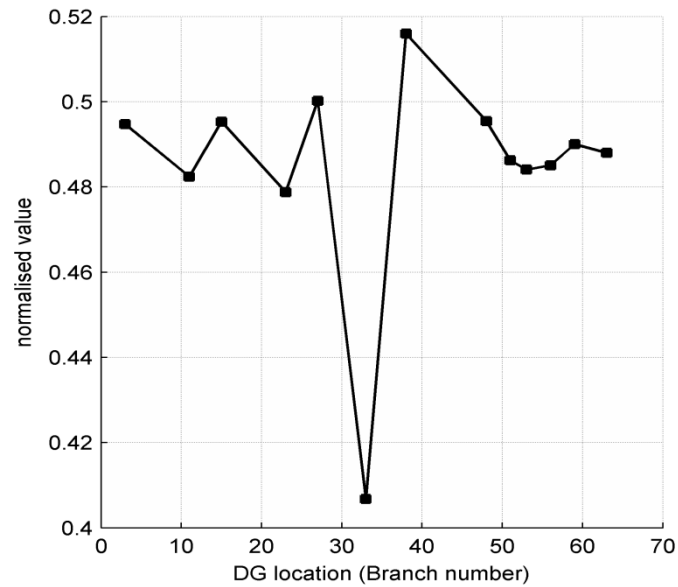


Fig. 8. Variation of overall cost for low cost of reactive power compensation and power losses

In Fig. 8, the value based curve is almost exactly the same as the curve for the outage cost (ECOST). Therefore, due to the relatively low importance of reactive power supports costs and real power loss costs, the selection of optimum location was dominated by the outage cost. In the next curve (Fig 13), the associated costs were much higher in comparison to the reliability cost (\$1/kVAr and \$0.01/kWh).

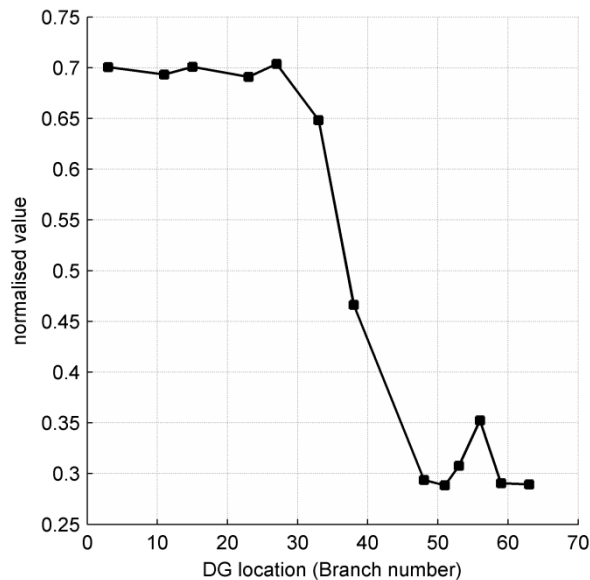


Fig. 9. Variation of overall cost for high cost of reactive power compensation and low cost of power losses

In this curve, the shape was clearly dominated by the reactive power requirement. This is because cost of reactive power requirement was much higher than cost of power losses. If the cost of power losses is high (\$0.01/kVAr and \$1/kWh), then the shape of the curve would be dominated by the power losses as shown in Fig. 10.

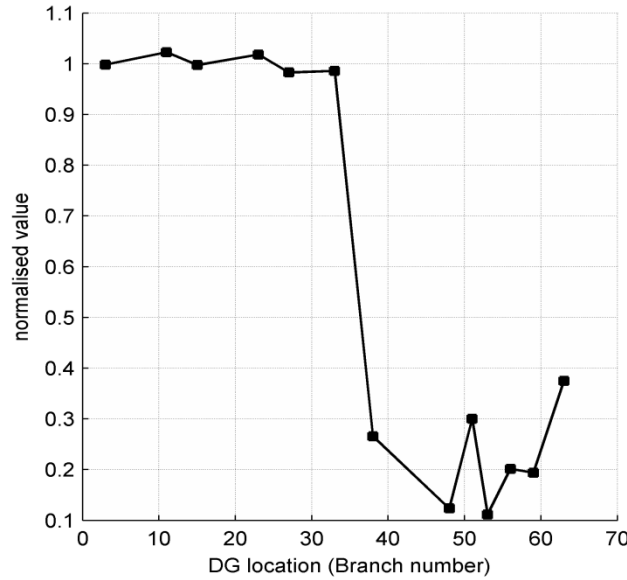


Fig. 10. Variation of overall cost for low cost of reactive power compensation and high cost of power losses

It is important to note that using an overall value based approach does not necessarily provide a balanced trade-off between all the benefit factors that considered. Thus, appropriate weighting of each benefit factor is necessary in order to determine benefit of DG on a power network. For example, there are distribution networks in which the reliability is more important than the other benefits. Operating philosophy of distribution networks are also varied. Reliability of urban distribution networks can be crucial than a rural network. In such context, the benefit of DG can be network specific and case base analysis may be required in order to make robust conclusions.

4.6 Realistic facts in quantification of network benefits

Due to the uncertainties and complexities in wind data, most literature provides averaged values of DG contribution to power losses. However, the vital signal from DG may be hindered by many small effects that are sustained for a significant period of time. For example, at a particular time interval in a day the DG may contribute to increase power losses. There may be other time intervals where the DG contributes to reduce power losses. However, when all of them are averaged, the resulting figure may not reflect the real contribution from DG on power losses because persistent low values of power loss components may suppress others that contribute to increase losses when the sequential simulation is used to assess power losses. This may give a wrong signal because significantly high power losses even within short time intervals may

contribute to higher costs of operation at specific operating conditions. These operating conditions can be initiated through network uncertainties and constraints. Such effects could be minimised if the weighting factors are taken into account for the assessment tools at respective time intervals.

On the other hand, the quantification of cost of losses through life cycle cost of equipment would give a better indication of real contribution to power losses from DG in distribution networks. This is because varying losses ultimately affects the life cycle of network equipments.

Therefore, it is important to trace the DG contribution to power networks through recursive life cycle of equipment and allocating weighting factors that minimises biasness for the quantification of network benefits (losses) with DG.

4.7 Summary

Distributed generation affects power losses in transmission and distribution networks; however, DG plants should be placed optimally and coordinated dynamically in order to improve benefits. Not all distributed generators produce firm power output and need backup power for intermittency that disturbs the firm power output. DG plants can also be placed as mixes at strategic locations as possible to reduce power losses.

Published literature captures the power losses deterministically, statistically, and probabilistically. The common theme of most literature is the distributed generation reduce power losses however, it may not be true always. Therefore, case specific analysis considering many benefit factors is necessary in order to justify realistic value of DG for a particular distribution network.

Case studies are performed to study technical and economical benefits of DG. The study suggests that appropriate weighting of benefit factors are necessary for the realistic assessment of network benefits with DG.

4.8 Conclusions

Published literature evidences a clear gap in quantification of network benefits of losses, thus, there is a clear opportunity in this area for further research.

Performed investigations suggest that the DG integration can potentially improve the network benefits. However, benefits are not unique and weighting of each category of benefit is necessary to assess realistic value of benefits of DG in a distribution network.

Distributed generation contribution to network benefits of losses is complex and case base analysis is required for the robust quantifications. Recursive quantification of varying power losses and its effects on life cycle of equipment through Monte Carlo simulation can potentially enhance the knowledge of realistic benefits of DG in distribution networks.

The power loss terms can often be a very small component in motivating DG installation but an important one to quantify correctly.

Remarks

Some of the above facts will be taken into account in delivering remaining objectives of the project (“A software simulation of generation-optimized controller incorporating start up costs” and “Life cycle costing and greenhouse gas abatement”). The pending project report will also address sensitivity of energy optimised DG on reduction of power losses.

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Chapter 5 Bringing the benefits together: Optimized DGs into networks

There is a growing interest in DG as an alternative for supplying electric power to customers. Worldwide, the current trend of electricity market deregulation is leading to continuous growth in the number of DGs connected to utilities' distribution networks for a number of reasons: i) electricity market rules encouraging competition and simplified connection, ii) advances in new technologies, and iii) increasing system capacity needs. Both electric utilities and customers are users of DG as both can gain advantages. For a utility, DG could be used as an additional option to meet load growth and to relieve transmission constraints. From the perspective of the end-user customers, DG could offer higher power quality and overall reliability at a competitive power cost. In order to maximize the DG benefits, DGs need to use the existing utilities' transmission and distribution systems to transfer their generated power from one location to another. However, with the aim of effective integration of DGs into utilities' networks, several requirements, such as voltage regulation, loss of main protection, and the sustainability of DGs following disturbances on the associated network need to be satisfied. Selected use of DG can provide system benefits including improved power quality, reduction in central generating station reserve requirements, and reactive power support. Grid-supported DGs can provide the transmission capacity release, reduction in network losses, and avoidance or postponement of high investment costs for network upgrades.

5.1 Structure for optimization

A. The chance constrained programming framework

Some uncertainties such as the uncertain output power of a plug-in electric vehicle (PEV) due to its stochastic charging and discharging schedule, that of a wind generation unit due to stochastic wind speed, and that of a solar generating source due to the stochastic illumination intensity, volatile fuel prices and future uncertain load growth, could lead to some risk in determining the optimal sitting and sizing of DGs in distribution systems. Given this background, under the chance constrained programming (CCP) framework, a new method is presented to handle the risks brought by these uncertainties in the optimal sitting and sizing of DGs in [Zhipeng Liu et al, 2010].

As a branch of stochastic programming methods, CCP can accommodate constraints with stochastic variables included, and makes decisions before stochastic variables are actually observed. Moreover, CCP allows that the decision-making procedure does not satisfy some constraints, but must satisfy the constraints with a given probability, i.e., the so-called confidence interval. The general form of a CCP problem can be described as

$$\begin{cases} \min & \bar{f} \\ \text{s.t.} & \\ & \Pr f(X, \xi) \leq \bar{f} \geq \alpha \\ & \Pr g_j(X, \xi) \leq 0 \geq \beta \quad (j=1,2,\dots,n) \end{cases} \quad (1)$$

Where: X is a k -dimension decision-making vector; ξ is a set of stochastic variables with known probability distributions; $g_j(X, \xi) \leq 0 \quad (j=1,2,\dots,n)$ are stochastic constraints; $f(X, \xi)$ is the objective function; \bar{f} is the optimal value of the objective function with the given confidence interval β ; α and β are both the given confidence intervals; $\Pr\{\cdot\}$ represents the probability of the event included in $\{\cdot\}$.

The major components of the CCP based optimal sitting and sizing of DGs in distribution system planning are outlined in Fig.1.

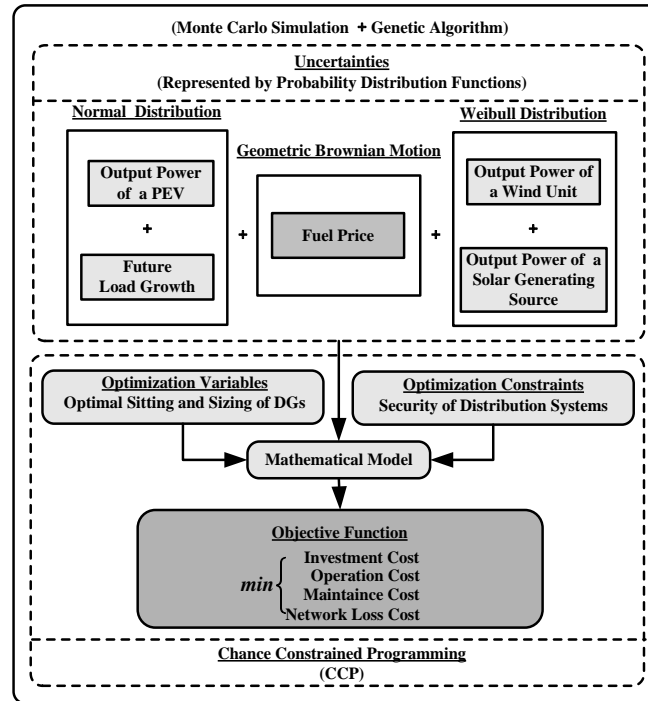


Fig. 1. The flowchart of the developed CCP based method for optimal sitting and sizing of DGs in Distribution Systems

B. The deterministic programming framework

In this framework, some deterministic mathematical models are employed to formulate the optimal sitting and sizing of DGs, and generally the mathematical models such obtained are mixed-integer nonlinear programming ones with multiple variables and constraints included.

In [Zhipeng Liu et al, POWERCON 2010], the Modified Primal-Dual Interior Point Algorithm is employed to determine the sizing of DGs with the objective of optimizing the voltage profile at every bus. In [I. Ziari et al, TENCON 2009], a Discrete PSO (DPSO) is employed to solve the Optimal Allocation of Sectionalizers and Cross-Connection (OASCC) problem. In [I. Ziari et al, AUPEC 2009], a heuristic and random-based method called Particle

Swarm Optimization (PSO) algorithm is used for planning of a simple distribution system. This tool is used in case 1 (100 identical spaced Loads) for a simple uniform load case and an analytical method, nonlinear programming (NLP), is utilized for the second case (21 Nonlinear spaced loads) showing an increased realism of customer demand. In [I. Ziari et al, PES General Meeting 2010], the placement and sizing of DG in distribution networks are determined using a combination of Discrete Particle Swarm Optimization (DPSO) and Genetic Algorithm (GA).

Otherwise, in [Acharya N. et al, 2006], an efficient and analytical approach is developed for DG allocation in primary distribution networks with the objective of minimizing network losses. However, this approach may fail to find the global optimal solution sometimes. In [Gandomkar M. et al, 2005], an algorithm combining the Genetic and Tabu Search approaches is presented for DG allocation in radial distribution networks. The calculation results of a simple and small system indicate that this algorithm is better than genetic algorithm based approach. In [Singh D. et al, 2005], a genetic algorithm based approach is employed for the sitting and sizing of DG from the perspective of a generation company. In [C. S. Wang et al, 2004], analytical methods are presented to determine the optimal location of a DG in radial as well as networked systems with the minimization of the network loss as the objective; in [K. H. Kim et al, 2008], the fuzzy goal programming is employed to determine the optimal placement of DGs for loss reduction and voltage improvement in distribution systems. A simple yet conventional iterative search technique is combined with the Newton-Raphson load flow method for finding the optimal sizing and placement of DGs in [S. Ghosh et al, 2010], and the modified IEEE 6-bus, IEEE 14-bus and IEEE 30-bus test systems are employed to demonstrate the developed method. In [T. Gözel and M. H. Hocaoglu, 2009], an equivalent current injection based loss sensitivity factor is used to determine the optimal locations and sizes of DGs by an analytical method with the minimization of the total power losses as the objective. A new approach is proposed in [M. M. Elnashar, 2010] to optimally determine the locations and sizes of DGs in a large mesh-connected system.

5.2 Optimizing impact on reliability, network reinforcement investment, and losses

The impact of DGs on reliability, network reinforcement investment and losses is optimizing in form of the objective function among all the optimization mathematical methods proposed by QUT. For example, a mathematical model of CCP is developed with the minimization of DGs' investment cost, operating cost and maintenance cost as well as the network loss cost as the objective, security limitations as constraints, the sitting and sizing of DGs as optimization variables in [Zhipeng Liu et al]. The mathematical model is described below:

$$\begin{aligned}
\min f &= \chi C^I + \gamma C^O + \tau C^M + \varsigma C^L \\
&= \sum_{t=1}^T \left\{ \chi \sum_{i=1}^{N_{DG}} \left[E_{DG_i}(t) C_{DG_i}^I(t) P_{DG_i}^N(t) - P_{DG_i}^N(t) \right] \right. \\
&\quad + \gamma \sum_{i=1}^{N_{DG}} E_{DG_i}(t) C_{DG_i}^O(t) T_{DG_i}(t) P_{DG_i}^N(t) \\
&\quad \left. + \tau \sum_{i=1}^{N_{DG}} E_{DG_i}(t) C_{DG_i}^M(t) T_{DG_i}(t) P_{DG_i}^N(t) + \varsigma C^L(t) \Delta W_h(t) \right\}
\end{aligned} \tag{2}$$

Where $\chi + \gamma + \tau + \varsigma = 1$; χ, γ, τ and ς are weighting coefficients; T is the total number of years in the planning period; C^I, C^M, C^O are respectively the investment cost, maintenance cost and operating cost of DGs, and C^L is the network loss cost, in the planning period; $E_{DG_i}(t)$ represents the optimization variable included in the planning scheme, $E_{DG_i}(t) = 0/1$ denotes that there will not be /there will be a DG built at node i in year t ; $P_{DG_i}^N(t)$ and $P_{DG_i}^N(t-1)$ are the installed capacities of DGs at node i in year t and year $t-1$, respectively; $\Delta W_h(t)$ is the energy loss of the distribution system in year t ; N_{DG} is the number of candidate DGs to be installed in the distribution system; $T_{DG_i}(t)$ is the equivalent generation hours of the DG at node i in year t ; $C_{DG_i}^I(t)$ is the per unit capacity investment cost of the DG at node i in year t ; $C_{DG_i}^O(t)$ is the per unit operating cost of the DG at node i in year t ; $C_{DG_i}^M(t)$ is the per unit maintenance cost of the DG at node i in year t .

Specifically speaking, for a renewable DG, $C_{DG_i}^O(t) = 0$; for a fuel-based DG, its operating cost is mainly composed of the fuel cost, and $C_{DG_i}^O(t)$ can be obtained by the above equation. For a plug-in electric vehicle (PEV), its operating cost is determined by its charging and discharging cost. The per unit capacity operating cost of a PEV can be obtained as

$$\begin{aligned}
C_{DG_i}^O(t) &= \frac{C^L(t) r_{DG_i}^C(t) T_{DG_i}^C(t) + C^L(t) r_{DG_i}^{C*}(t) T_{DG_i}^{C*}(t)}{T_{DG_i}(t)} \\
&\quad - \frac{C^G(t) r_{DG_i}^D(t) T_{DG_i}^D(t) + C^G(t) r_{DG_i}^{D*}(t) T_{DG_i}^{D*}(t)}{T_{DG_i}(t)}
\end{aligned} \tag{3}$$

Where $T_{DG_i}(t) = T_{DG_i}^C(t) + T_{DG_i}^{C*}(t) + T_{DG_i}^D(t) + T_{DG_i}^{D*}(t)$; $T_{DG_i}^C(t) (T_{DG_i}^{C*}(t))$ is the charging time of the PEV at node i in year t at the valley load (other periods); $T_{DG_i}^D(t) (T_{DG_i}^{D*}(t))$ is the discharging time of the PEV at node i in year t at the peak load (other periods); $C^L(t) (C^G(t))$ is the retail price (on-grid price) in year t ; $r_{DG_i}^C(t) (r_{DG_i}^{C*}(t))$ is the electricity price adjustment coefficient for charging at the valley load (other periods) in year t ; $r_{DG_i}^D(t) (r_{DG_i}^{D*}(t))$ is the electricity price adjustment coefficient for discharging at the peak load (other periods) in year t .

To encourage the owners of electric vehicles to take part in the centralized dispatching, i.e. charging in valley/off-peak periods and discharging in peak periods, the electricity prices adjustment coefficients for charging and discharging as represented by $r_{DG_i}^C(t) (r_{DG_i}^{C*}(t))$ and $r_{DG_i}^D(t) (r_{DG_i}^{D*}(t))$ can be employed.

In [I. Ziari et al , TENCON 2009], the main goal is to minimize the objective function composed of the capital cost and reliability cost. The capital cost is related to the sectionalizers and cross-connection and the reliability cost is assumed to be proportional with a reliability index, SAIDI.

As mentioned, the employed objective function consists of two main parts: Capital cost and reliability cost. The following equation expresses the employed objective function formulation:

$$OF = W_{SAIDI} \times SAIDI + SwitchCost \quad (4)$$

Where, OF and W_{SAIDI} are the objective function value and the $SAIDI$ weight factor. $SwitchCost$ is the total costs of sectionalizers and cross-connection. It should be noticed that the cost of cross-connection is assumed to be proportional with its length. The System Average Interruption Duration Index (SAIDI) is calculated as:

$$SAIDI = \frac{Sum\ of\ All\ Customer\ Interruption\ Durations}{Total\ Number\ of\ Customers\ Served} \quad (5)$$

As observed, SAIDI shows the average outage duration for each customer. This index is measured in either minutes or hours.

In [I. Ziari et al, AUPEC 2009], the objective function used in this problem consists of the allowing costs: transformers, MV and LV conductors.

$$OF = TotalC_T + TotalC_F + TotalC_C \quad (6)$$

Where, OF is the objective function .

The total cost of transformers can be obtained as:

$$TotalC_T = \sum_{j=1}^{NT} C_{Tj} \quad (7)$$

Where, NT is the number of transformers.

The LV conductors cost can be calculated as:

$$TotalC_C = \sum_{k=1}^{NC} C_{Ck} \quad (8)$$

Where, NC is the number of LV conductors.

In [I. Ziari et al, 2010], the objective of this study is to minimize the sum of distribution line loss, the peak power (which applies an additional investment for using high rating equipment) and the reliability along with the costs for installation, operation and maintenance of DGs. Limits on the bus voltage, feeder current and the reactive power flowing back to the source side are set as constraints so that they maintained within a standard range. The constraints are added to the objective function using penalty factors so that if they are satisfied, this constraint term will be zero; otherwise, a large number is added to the objective function which will then ensure rejection of that solution. Given these points, the objective function is defined as follows:

$$OF = C_{INSTAL} + \sum_{t=1}^T \frac{C_{O\&M} + C_{INTERRUPTION} + C_{LOSS}}{(1+r)^t} \quad (9)$$

Where OF is the objective function which is the NPV (net present value) related to the total cost, C_{INSTAL} is the total installation cost for DGs, $C_{O\&M}$ is the total operation and maintenance cost for

DGs, $C_{INTERRUPTION}$ is interruption cost, C_{LOSS} is the loss cost, r is the discount rate, and T is the number of years in the study timeframe. The DG cost is formulated as:

$$\begin{aligned} C_{DG} &= C_{INSTAL} + \left(\sum_{T=1}^T \frac{1}{(1+r)^T} \right) \cdot C_{O\&M} \\ C_{INSTAL} &= \sum_{j=1}^{NDG} C_{1j} \cdot P_j \\ C_{O\&M} &= \sum_{t=1}^{LL} \sum_{j=1}^{NDG} C_{2j} \cdot P_j \cdot T_t \end{aligned} \quad (10)$$

Where NDG is the number of DGs, P_j is the rating of DG j , LL is the number of load levels, T_t is the duration of the corresponding load level, C_{1j} is the installation cost per kW for DG j , and C_{2j} is the operation and maintenance cost per kW for DG j . As observed in above equation, the installation cost of a DG is assumed proportional with its rating and the operation and maintenance cost is assumed proportional with the DG energy (kWh).

The interruption cost can be calculated by multiplying the number of customers, the average interruption duration per customer and the cost per unit time of an interruption. This second element can be identified with SAIDI which is the average interruption duration per year per customer. The interruption cost is so obtained as:

$$\begin{aligned} C_{INTERRUPTION} &= \sum_{t=1}^{LL} NC \times SAIDI \times CI \times \frac{T_t}{8760} \\ C_{INTERRUPTION} &= \sum_{t=1}^{LL} W_{SAIDI} \times SAIDI \times \frac{T_t}{8760} \end{aligned} \quad (11)$$

Where NC is the number of customers, CI is the cost of interruption per hour for a customer and W_{SAIDI} is the SAIDI weight factor. The loss cost is expressed as follows:

$$\begin{aligned} C_{Loss} &= k_L \cdot T_{Loss} + C_{PL} \\ T_{Loss} &= \sum_{t=1}^{LL} T_t \cdot T_{Loss_t} \\ T_{Loss_t} &= \sum_{l=1}^{NL} Loss_{t,l} \\ Loss_{t,l} &= R_{Line_l} \cdot I_{Line_{t,l}}^2 \end{aligned} \quad (12)$$

Where k_L is the cost per kWh of losses, T_{Loss} is the total annual loss in kWhr, LL is the number of load levels, T_t is the duration of load level t , T_{Loss_t} is the total loss value for load level t , N_L is the number of transmission lines, $Loss_{t,l}$ is the loss in line l for load level t , R_{Line_l} is the line resistance in line l , $Line_{t,l}$ is the current of line l for load level t , and C_{PL} is the peak power loss cost.

The peak power loss occurs when the load level is at peak. Reduction of the line loss by the DGs in the peak load can prevent additional investment for using high rating equipment. This additional investment is called the peak power loss cost and is assumed to be proportional to the peak power loss and defined as.

$$C_{PL} = k_{PL} \cdot T_{Loss_{LL}} \quad (13)$$

Where k_{PL} is the saving per MW reduction in peak power loss.

5.3 Design of network incorporating DG benefits

To design of network incorporating DG benefits in network, QUT has been paying attention to the research on the optimal sitting and sizing of DGs, such as [Zhipeng Liu et al, 2010], [Zhipeng Liu et al, POWERCON 2010], [I. Ziari et al, PES 2010], [I. Ziari et al, AUPEC 2010] and [S. Islam, and A. Binayak.].

Under the chance constrained programming framework, a new mathematical model is developed to handle some uncertainties such as the stochastic output power of a PEV, that of a renewable DG, volatile fuel prices and future uncertain load growth in the optimal sitting and sizing of DGs in [Zhipeng Liu et al, 2010]. Then, a Monte Carlo simulation embedded genetic algorithm approach is presented to solve the developed CCP model. Finally, the test results of the IEEE 37-node test feeder demonstrate the feasibility and effectiveness of the developed model and method. A computer program is developed in the Matlab 7.0 and Visual C++ 6.0 environment. The IEEE 37-node test feeder, as shown in Fig. 2.

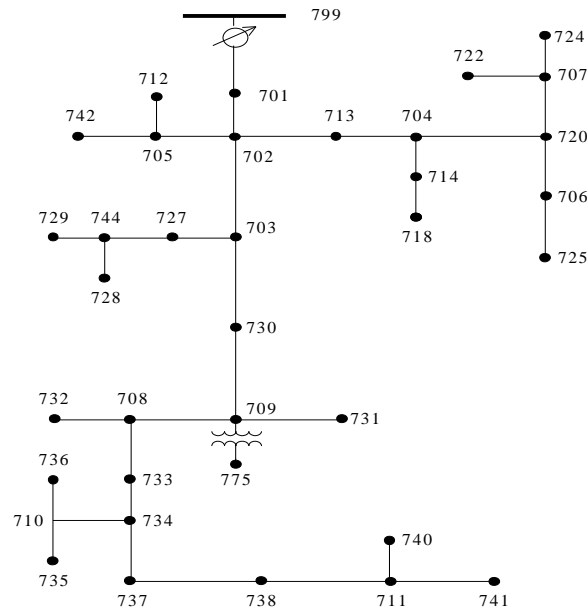


Fig. 2 The IEEE 37-node test feeder

The optimal sitting and sizing of DGs in the planning period under the confidence levels of $\alpha=0.95$ and $\beta=0.95$ are shown in Table I.

TABLE I
OPTIMAL SITTING AND SIZING OF DGS IN THE PLANNING PERIOD

Types	Node	$P_{DG_i}^N(t)/(\text{kW})$		
		$t = 1$	$t = 2$	$t = 3$
Renewable	Wind generation	718	10.00	20.00
		722	10.00	20.00
DGs	Photovoltaic generation	729		10.00
Fueled DGs		732	10.00	10.00
		736	10.00	20.00
		741	30.00	40.00
		742	40.00	50.00
PEVs		718	10.00	15.00
		722	10.00	15.00
Network loss ratio/(%)		2.71	1.96	1.56

From Fig.3, it could be observed that in each year of the planning period with newly added DGs, the voltage profile at each node of the test feeder has been greatly improved.

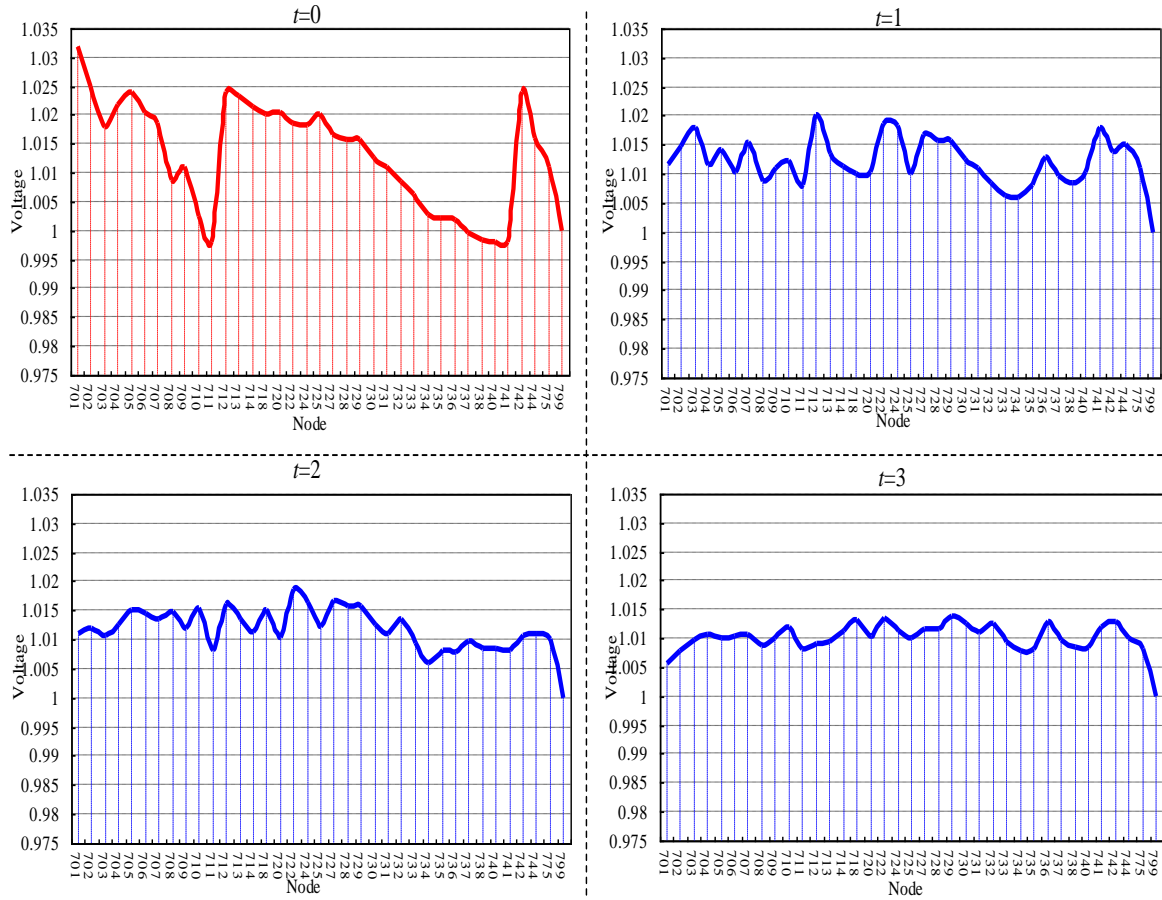


Fig. 3 The voltage variations at each node of the test feeder with added DGs in the planning period

In [Zhipeng Liu, POWERCON 2010], a new approach combining the loss sensitivity on every bus voltage with the MPDIPA is presented for optimizing the sitting and sizing of DGs. The former is used for the optimal sitting of DGs so as to reduce the calculation time and optimization scale. The latter is used for the optimal sizing of DGs. Test results of the IEEE 123-node test feeder demonstrate that the developed method can determine the sitting and sizing of DGs optimally, and as the result, the voltage profile could be significantly improved and the network loss obviously reduced.

In [I. Ziari et al, PES General Meeting 2010], a problem formulation and solution for the placement and sizing of DGs optimally, with consideration of time varying loads is present. After optimization, the sum of distribution line loss, the peak power (which applies an additional investment for using high rating equipment) and the reliability along with the costs for installation, operation and maintenance of DGs has been reduced.

Therefore, after optimization of sitting and sizing of DGs in designing the network, the benefits of DGs could be better explored.

PSO/GA planning over range of load levels and time horizon

This QUT tool optimizes over the daily load cycle and the load growth over 20 years . It includes the voltage constraints loss, capital and operating cost components as well as reliability benefit. Here a range of scenarios are planned over 3 load duration sections and over 20 years divided into 4 steps.

Scenario 1 (Conventional Planning)

Scenario 2 (Conventional Planning improved by Capacitors)

Scenario 3 (Planning by DGs)

Scenario 4 (Planning by DGs and Capacitors)

Scenario 5 (Planning by All Technologies)

There are several steps to ensure that the search routine does not stop prematurely because of local discrete effects so a combination of GA and PSO has been used to provide a high probability of finding the global optimal.

Comparison of Total Cost during 20 years (M\$)

Cost Elements	Scenario Number				
	1	2	3	4	5
Line	1.536	1.337	0	0	1.272
Transformer	3.542	2.686	0	0	1.237
Capacitor	0	0.357	0	0.404	0.306
DG	0	0	25.067	19.757	5.913
Loss	2.510	2.277	2.470	2.468	2.275
Reliability	17.624	17.624	10.043	10.497	13.593
Energy Selling	0	0	-11.259	-8.543	-2.517
Total Cost	25.212	24.281	26.321	24.583	22.079

As observed in the table above, by using the proposed comprehensive planning, the total cost is reduced by M\$ 3.133 compared with the conventional planning. This 12.5% reduction is enough to highlight the priority of the proposed technique over other available techniques.

The most costly planning belongs to the planning using DGs alone. The next most costly planning is then the conventional planning. These demonstrate that these two alone are not good techniques. These techniques can be improved by using DGs with other devices. Furthermore, these are considerably advanced by inclusion of all technologies. Note that the investment in line and transformer upgrades in scenario 5 is small as the DG's permit deferral of these infrastructure investments.

Conclusions

The relative importance of different components of network benefits from DG is summarized in the results in the two examples in this chapter. For incorporation of line investment deferral against the operation cost of DG a long time horizon optimization is required which accounts for the daily load cycle. The results in Table 1 show that non schedulable resources such as wind can be included in the long term planning as a DG benefit. Several researchers have focused on DG as a voltage support tool but these results show that much of those general benefits could be captured by capacitors if it only a steady state issue. The voltage control scheme introduced in Chapter 2 shows that transient voltage control may be a component to be considered also in the optimization.

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Chapter 6 Overall comments and summary of contributions

This report illustrates that the main network benefit applicable to distributed generation is in the area of reliability for cases where cross connection between feeders is not justifiable. Another strong benefit can be where the DG serves to defer investment in line upgrades. Here the DG would run during the short duration load peaks. The fuel cost per kilowatt may be high but the run time can be quite low thus there can be a strong benefit in deferring line investments until the peak increase of direction is such that the fuel cost now exceeds the deferral benefit. Other benefits such as voltage support and line loss reduction are primarily supplementary benefits to assist the business case rather than being a strong incentive in their own right.

There is no uniform benefit factor for generic use of DG as it is highly dependant on the peakiness of the load cycle and the opportunities to defer investment.

When there is a pattern where load growth is expected to exceed supply transformer capacity in the next few years there can be an opportunity for gain through the use of schedulable generation. In some cases this can be misleading since some load transfer to adjacent substations can be achieved through the use of switching. Quantifying the benefit to peak load is dependant on whether the line capacity, the distribution transformers or the substation transformers are showing as the limiting item. A DG unit connected at medium voltage will not be able to relieve overloading of Low voltage lines or transformers. Because the relative cost of the supply network per kW of customer load increases towards the fringe of network the opportunity for distribution network benefit from the use of DG is higher.

The appropriate level of investment in DG as a solution to load growth and reliability is highly dependant on the network and loading thus the optimization tool presented in Chapter 5 provides a tool to determine the best level of DG and other network options. This tool combines the peak load deferral aspects as well as the reliability benefits.

Technical barriers to continuing increase in DG such as photovoltaic inverters are starting to arise in terms of voltage control. The algorithms presented in Ch 2 show that voltage control is feasible. There will be some cost as the DC bus capacitors need to be larger to inject reactive power. The other dimension of the reactive injection control is that the power factor at the supply transformer can be made close to unity and the main benefit is that the peak load capacity of a feeder can be increased over 12% even with no sun available.

The other key technical barrier to simple connection of DG's is their impact on conventional protection schemes. At low penetration levels the ability of mask high impedance faults is limited but as the DG levels rise there is a growing concern about the reliable detection of high impedance faults. The algorithms presented enable greater precision of the detection of line faults even in the presence of DGs.

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- Yang, H., Wen, F. S., and Ledwich, G. (2010). "Optimal coordination of overcurrent relays in distribution systems with distributed generators based on differential evolution algorithm." submitted to *European Transactions on Electrical Power*.

Appendix: Publications and Developments Directly Associated with this Project

- [1] Wenxin Guo, Fushuan Wen, Gerard Ledwich, Zhiwei Liao, Xiangzhen He, and Junhui Liang. An analytic model for fault diagnosis in power systems considering malfunctions of protective relays and circuit breakers. *IEEE Transactions on Power Delivery*, Vol.25, No.3, 2010, pp.1393-1401.
- [2] Liuhong Wei, Wenxin Guo, Fushuan Wen, Gerard Ledwich, Zhiwei Liao, Jianbo Xin. Waveform matching approach for fault diagnosis of high voltage transmission lines employing harmony search algorithm. *IET Generation, Transmission and Distribution*, Vol.4, No.7, 2010, pp.801-809.
- [3] Liuhong Wei, Wenxin Guo, Fushuan Wen, Gerard Ledwich, Zhiwei Liao, Jianbo Xin. An on-line intelligent alarm processing system for digital substations, submitted to *IEEE Transactions on Power Delivery* (in revised form).
- [4] M. Dewadasa, A. Ghosh, G. Ledwich. Fold back current control and admittance protection scheme for a distribution network containing DGs, submitted to *IET Proceedings: Generation, Transmission and Distribution*
- [5] Hui Yang, Fushuan Wen, Gerard Ledwich. Optimal coordination of overcurrent relays in distribution systems with distributed generators based on differential evolution algorithm, submitted to *European Transactions on Electrical Power*.
- [6] Zhipeng Liu, Fushuan Wen, Ledwich Gerard. A chance constrained programming based approach for optimal sitting and sizing of distributed generators, to be submitted to *IET (IEE) Proceedings: Generation, Transmission and Distribution*.
- [7] Zhipeng Liu, Fushuan Wen, Ledwich Gerard. An optimal under-frequency load shedding strategy considering distributed generators and load static characteristics, to be submitted to *IEEE Transactions on Power Delivery*.
- [8] Zhipeng Liu, Fushuan Wen, Gerard Ledwich, Xingquan Ji. Optimal sitting and sizing of distributed generators based on a modified primal-dual interior point algorithm, accepted for publication in *Proceedings of 2010 International Conference on Power System technology (POWERCON2010)*, Oct. 24-28, 2010, Hangzhou, China.
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- [11] I. Ziari, G. Ledwich, M. Wishart, A. Ghosh, "Optimal Allocation of a Cross-Connection and Sectionalizers in Distribution Systems", TENCON 2009 Singapore
- [12] I. Ziari, G. Ledwich, M. Wishart, A. Ghosh, "Initial Steps in Optimal Planning of a Distribution System", AUPEC 2009 Australia
- [13] I. Ziari, G. Ledwich, A. Ghosh, D. Cornforth, M. Wishart, "Optimal Allocation and Sizing of DGs in Distribution Networks", PES General Meeting 2010
- [14] I. Ziari, G. Ledwich, A. Ghosh, G. Platt, "A New Method for Improving Reliability and Line Loss in Distribution Networks", accepted for AUPEC 2010
- [15] G. Ledwich, A. Ghosh, F. Zare, "Tuning Harmonic Absorption of Voltage Source Converters" Int Conf on Harmonics and Power Quality Bergamo 26-29 Sept 2010.
- [16] L. Perera, G. Ledwich, A. Ghosh, "Multiple DSTATCOMs for Distribution Feeder Voltage Support" under revision for IEEE Trans on Power Systems
- [17] G. Ledwich, L. Perera, "Balancing power factor and voltage control on distribution lines" under development
- [18] S. Islam, and A. Binayak. Value based optimum location of distributed generation, technical report.
- [19] Remy Tiako, Dilan Jayaweera, and Syed Islam. A class of intelligent algorithms for online dynamic security assessment of power systems, accepted for the publication at AUPEC 2010.
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- [23] Wenxin Guo, Fushuan Wen, Gerard Ledwich, Zhiwei Liao, Xiangzhen He, and Jiansheng Huang. A new analytic approach for power system fault diagnosis employing the temporal information of alarm messages, submitted to *Journal of Engineering Applications of Artificial Intelligence*.