Authors :
QUT:
Prof. Gerard Ledwich
Dr. Fushuan Wen
Dr. Iman Ziari

CUT:
Dr. Dilan Jayaweera
Professor Syed Islam
Sandeep Neduvelil Sukumar

INTELLIGENT GRID RESEARCH CLUSTER- PROJECT 3

Optimal Siting and Dispatch of Distributed Generations

Queensland University of Technology and

Curtin University of Technology

iGrid
intelligent grid
an Australian research collaboration

CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ABBREVIATIONS

ACO	ant colony optimisation
AENS	average energy not supplied
ARMA	autoregressive moving average
CAIDI	customer interruption duration index
CBD	Central Business District
CCP	chance-constrained programming
CCP	chance constraint programming
CPLEX	optimization software
DE	differential evolution
DG	Distributed generation
DPSO	Discrete Particle Swarm Optimisation
DSTATCOM	Distribution Static Var Compensator
GA	Genetic Algorithm
GHG	greenhouse gas
IEEE	Leading Professional Body
IPLAN	software
LCC	life-cycle costing
LP	linear programming
LQR	Linear Quadratic Regulator
MATLAB/SIMULINK	Analysis Software
MILP	mixed-integer linear programming
PABL	The probability of not violating all the branch power flow limits
PBL	The probability of not violating each branch power flow limit

PEV	plug-in electric vehicles
PSM	margin of system power flow
PSO	particle swarm optimisation
PV	photovoltaic
RBTS	Roy Billinton Test System
ROCOF	rate of change of frequency
SAIDI	system average interruption duration index
SEF	sensitive earth fault
TSP	transmission system planning
UFLS	under-frequency load shedding
UVLS	under-voltage load shedding
VSC	Voltage Source Converter
WPG	wind power generation

1. EXECUTIVE SUMMARY

Distributed generation (DG) refers to small-scale generation units, typically less than 30 megawatts (MW), sited within the distribution network. The applications of DG include combined heat and power, standby power, peak shaving, grid support and stand-alone power. DG technologies include photovoltaic (PV), wind turbines, fuel cells, small and micro-sized turbine packages, internal combustion engine generators and reciprocating engine generators.

While the direct costs of generation are often lower in larger scale central generation units, there are benefits gained by having the generation distributed close to the load, as is usually the case with DG technologies. One such benefit that has been found useful in Europe is that waste heat from DG can be used for domestic heating, or in Australia where cooling water derived from waste heat using absorption cycle chillers can be produced close to the demand for cooling. In these cases, there is a benefit due to the reduced cost of distribution infrastructure to supply electric chillers. This report focuses on the benefits available to electricity networks when generation is close to the load.

This report also addresses technical barriers to the expansion of DG, and pathways to overcoming these barriers. It aims to quantify benefits in terms of voltage support and reliability for particular networks, and to determine an appropriate level of investment in DG to achieve these benefits compared with other network investment options. In addition, the following topics are discussed in this report: protection issues caused by DGs in distribution systems; under-frequency load shedding considering DGs; optimal siting and sizing of DGs; generation scheduling with DGs; risk control in transmission-system planning with wind generators; sizing the distributed generation with life-cycle costing (LCC); and greenhouse gas (GHG) abatement effects.

1.1. Technical barriers and solutions: voltage

In analysing the operation of electricity distribution networks with multiple small sources of generation, there have been two significant barriers identified. The first issue is that distributed generation sources, such as PV panels, can cause substantial voltage-rise problems that in turn, under the operating rules that are in place at present, can cause the PV inverters connecting to the grid to trip off.

Voltage rises associated with PVs are recognised as a challenge for distribution utilities, as customers who have had PV panels are not able to contribute power to the grid, or to utilise their own energy source during a blackout, as well as not receiving the expected supply when the systems trip off. Traditionally, the voltage drops as it travels down the feeder from the main supply transformer; the utility builds-in compensation for this by having a higher step-up in voltage for the distribution transformers at the far end of the feeders. At light load in the middle of the day the voltage would normally be at the high end of the acceptable voltage range, so that at peak times when the voltage drops the lower voltage remains in the acceptable range. If PV systems send reversed power back up the line when the load is low, it takes only a small reverse flow to exceed the voltage permitted for the PV connection inverter, and thus trip the unit. This project contributes a solution to this issue. The present Australian Standard for the connection of PV inverters dictates that they must operate at unity power factor. This means that in an alternating current (AC) system the voltage and current must be in phase, and the inverter must appear like a resistor operating in reverse. This design is adequate for very small reverse flows, and avoids any issues on inverter voltage control oscillations.

The solutions contributed in this project lie in using the ability of inverters to operate at a leading or lagging power factor; to operate with some capacitive or inductive characteristic. For most power systems, operation in a partly inductive region will tend to cause voltage drops and operation in partly capacitive mode will tend to cause voltage rises. To overcome the voltage-rise issue, it is beneficial to operate the inverters in a partly inductive mode. This mode of operation needs to respond to the actual system conditions, or the inverters will worsen the voltage-drop problem at peak load. The inverters therefore need to have feedback control of voltage; however, this brings with it the problems of multiple independent units, each trying to control the line voltage. The solution examined in this project is to use the "voltage droop" concept that is useful for voltage-sharing in large power stations, where the reactive power injection is proportional to the voltage drop. The droop gains, which are high enough to give useful voltage control, can give rise to oscillations between adjacent inverters. The solution has been to use a low transient gain and a higher steady-state gain. The remaining issues are to modify the design of the PV inverters which need larger capacitors to provide the reactive power capability.

1.2. Technical barriers and solutions: protection

The second issue identified is that the presence of generation units can reduce the ability of protection systems to identify faults on the network. Protection systems are necessary to avoid power-line damage resulting from faults such as lightning strikes; they are also designed to switch off circuits when power lines fall to the ground, and hence reduce risks to public safety. However, network protection systems are based on the assumption that the power flows in one direction, from the generation station to customers.

The most basic element of protection is a fuse. When the current is too high the fuse melts and opens the circuit. However, there needs to be a grading of protection such that the smallest portion of the network is removed from operation: it would be undesirable for a fault in an appliance in one house to take out the protection of an entire suburb. Hence, there is a protection element for each of several circuits in the home: protection on the poletop supplying the home, protection on the distribution transformer supplying a cluster of homes, and then overall protection as the feeder leaves the substation.

When a power line falls to ground there may be only a small fault current flowing, so it is difficult to detect. Due to the danger presented by live power lines on the ground, sensitive earth fault (SEF) protection is used at the substation to improve the detection when there is a high impedance earth fault. When DGs are present some of the current supplying the fault can come from distributed generation, and thus less from the substation. In general, the presence of DG can reduce the ability of the protection system to clearly identify some faults.

Protection systems have traditionally been in the form of graded overcurrent protection, where there can be several protection items that respond to higher-than-normal current and their trip times depend on the current level, with slower response times closer to the substation. With inverter-supported grids it is easy to current-limit their fault contribution. Hence, an inverter whose rated current is 100A can be easily configured to limit peak currents to 200A. Current limiting is achieved by dropping the voltage until the current limit is reached; the problem now is that the current may be too close to normal operating currents such that the fuse cannot blow. The solution, which improves protection performance in a number of circumstances, has been to develop the admittance relay. This has a similar characteristic to conventional overcurrent relays and can be used in conjunction with them, but no response to the apparent impedance is seen. This makes the relays sensitive to faults even when the voltage drops. Further investigation is proceeding on the connection of earths for three-phase generation, but a clear picture on this

aspect has not yet come out. If we are to gain the reliability benefits for distributed generation, we need to be able to operate in microgrid or in grid-connected mode, and this requires changes in the earth referencing of generation. This aspect is not fully resolved.

1.3. Optimised use of DG for reliability improvement

There is a developing body literature on the use of DG's to provide network functions such as voltage support and line-loss reduction. For many of these benefits the DG units would need to be owned by, or arrangements made for them to be controlled by the distribution service provider. This project contributes to development of tools for optimal investment planning of distribution networks. In the first instance, this optimisation considered schedulable DG, devices that can be turned on as required, in contrast with wind power which may not be available.

The optimisation tools considered the power lost in the transmission lines; the capital and running costs of DG; and meeting load-growth issues by augmentation of the network (conductors and transformers), or alternatively by DG. The results were examined for several sample distribution networks. In general, the rewards from loss reduction or from voltage support alone were insufficient to justify investment of DG units dedicated to that purpose; however, if DG units are justified because of other considerations, there can be a network contribution from those aspects that would otherwise fail to constitute an economic case. This does not mean that there might be energy efficiency or peak demand management options that are lower cost than network augmentation, as demonstrated in the outcomes of Project 4.

In urban areas reliability of supply is obtained by having cross-connects. This is where a fault occurs on one line and needs to be isolated, but customers continue to be supplied by a connection to a nearby feeder. When there is a widespread limitation of supply to a CBD, backup generation in multiple buildings can contribute to reliability. For rural areas there are no nearby feeders, and reliability can be poor with outages exceeding 700 minutes per year. If local generation is able to continue supply when the main line is faulted, this could yield substantial benefit in reliability. Instead of every customer needing to maintain a generator, a local pool of generation can substantially change reliability. Rural business losses from lack of supply can be significant, as high as $70,000/MW/hr, and consideration of loss values at the level of $8,000/MW/hr could be sufficient to drive investment in backup supply.

This reliability of supply can often be supplemented by peak-lopping generation opportunities. As the peak demand for energy goes up over the years the supply lines and transformers may need upgrading. For the initial few years this equipment may be needed less than 1% of the time. If DG was used to supplement the supply for these peak times or energy efficiency in reducing the peak demand growth then this would defer the need for investment in network upgrades for several years, as described in Project 4 findings. The same generation that provides peak lopping can also provide increased reliability for customers. The sample system studied as part of this project shows that overall network savings by use of DG can reduce network investment costs by as much as 23%. The program developed during this project can be used to determine the optimal size and location of the network investments over the planning horizon for the distribution system.

For the system in Figure 1 there are five scenarios optimised over four planning periods for optimal investment. These are: 1) line and transformer planning; 2) adding capacitors; 3) using only DG; 4) capacitors with DGs; 5) all options. Table 1 shows there can be a substantial saving from integrated planning with all options. The original cost data employed to produce the results

contained in Table 1 are listed in Table 2. The reliability costing is based on the outages valued at $10000/MWhr.

Figure 1: Test system configuration after planning in the last time interval
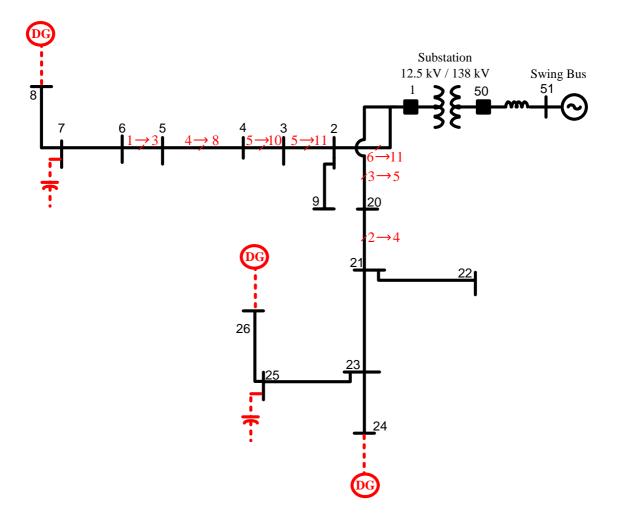
Table 1: Comparisons of total cost over 20 years

Cost elements ($M)	Scenario				
	1	2	3	4	5
Line	1.66	1.524	0	0	0.535
Transformer	3.59	2.734	0	0	1.237
Capacitor	0	0.358	0	0.509	0.098
DG	0	0	13.588	11.731	5.072
Loss cost	0.813	0.761	1.202	1.094	0.954
Reliability cost	15.766	15.766	6.477	6.700	9.530
Energy purchase reduction	0	0	-1.483	-1.359	-0.685
Total cost	21.829	21.143	19.784	18.675	16.741

Table 2: Characteristics of the test system

Parameter	Value
DG Installation Cost	$50000+$550/kVA
DG O&M Cost	¢11.4/kWh
DG Base Unit	300 kVA
Capacitor Installation cost	$3000+$35/kVar
Capacitor O&M Cost	$1/kVar
Capacitor Base Unit	300 kVar
Line Upgrading Cost	$(120000+30000 \times \Delta LT)$/km
Line O&M Cost	$2000/km
Failure Rate	0.01 (fault/km.yr)

| Switching Time | 30 minutes |
| Repair Time | 180 minutes |

1.4.   The under-frequency load shedding strategy and distributed generators

Normal power-system operation keeps the system frequency very close to 50Hz. Controls are required to add generation capacity if the frequency is falling, or to reduce generation when the frequency is above 50Hz. One motivation for a tight control on frequency is that turbine blades can incur severe damage from extended operation in the range 46–48Hz. Conventionally, if there is a rapid drop in frequency the system frequency cannot be saved by opening steam valves in thermal power stations; to prevent damage to generators the only solution is to shed load, causing the system frequency to increase until the load is less than the remaining generation.

In general, the well-established technique of under-frequency load shedding (UFLS) is the last of several effective remedial measures against a severe frequency decline in a power system. When a power system is suffering a severe disturbance, or when there is a severe power imbalance between generation and demand, the ability to maintain the power balance and further frequency stability is directly related to the UFLS strategy.

With the ever-increasing size of the power system and the extensive penetration of DGs in power systems, the development of an optimal UFLS strategy has new challenges. These include avoiding the isolated operation of DGs when the UFLS strategy is executed and loads are shed; and exploring the use of DGs to reduce the load amount to be shed or even avoid the load shedding. To our knowledge only a few research publications are devoted to investigating the impacts of increasing penetration of DGs on the UFLS strategy. Given this background, the research objective here is to develop an optimal UFLS strategy in a distribution system containing DGs and considering load static characteristics.

One contribution from controllable DG is to contribute more generation as the frequency falls. A concern is that the reliability benefits from DG are largely dependent on having isolated microgrids operational. In a small rural town there may be a reasonable amount of generation locally, but when the line from the main supply is lost, load shedding may be required so that local generation is sufficient. This report shows that the generation in small islands is typically of lower inertia, and the load shed must be faster when operating as a microgrid.

This project has developed an optimal UFLS strategy considering DGs and load static characteristics. Based on the frequency and rate of change of frequency (ROCOF), the strategy consists of the basic round and the special round. In the basic round, the frequency emergency can be alleviated by quickly shedding some loads. In the special round, the frequency security can be maintained and the operating parameters of the distribution system can be optimized by adjusting the output powers of DGs and some loads. The detailed settings, procedures, mathematical models and methods of the basic round and the special round are systematically investigated. In particular, some basic issues, such as the determinations of the amount of load to be shed and the load shedding priority, are well resolved. Finally, a modified IEEE 37-node test feeder with four DGs is employed to demonstrate the essential features of the developed optimal UFLS strategy in the MATLAB/SIMULINK environment.

1.5. Optimal siting and sizing of non-scheduled distributed generators in distribution systems

The increasing penetration of DGs in distribution systems means that the siting and sizing of DGs in distribution system planning are becoming increasingly important. Inappropriate siting and sizing of DGs could lead to negative effects on a distribution system concerned, with regard to relay system configurations, voltage profiles and network losses. On the other hand, increasing attention is being paid to the applications of plug-in electric vehicles (PHEV). However, there are potentially uncertainties in the stochastic output power of PHEVs due to uncertainties in their charging and discharging schedule. In the case of renewables there is also stochastic variability, in the case of a wind power unit due to the frequently variable wind speed, and that of a solar generating source due to the stochastic illumination intensity. Volatile fuel prices and future uncertain load growth also present uncertainty and have to be considered in determining the optimal siting and sizing of DGs in distribution system planning. Hence, optimal siting and sizing of DGs need to be carefully considered in distribution system planning.

Under the chance-constrained programming (CCP) framework a new mathematical model has been developed as part of this project to handle some uncertainties, including: the stochastic output power of PHEVs, renewable DGs and solar generating sources; volatile fuel prices used by a fuelled DG; and future uncertain load growth in the optimal siting and sizing of DGs. An algorithm is then applied to solve the developed CCP model. A computer program is developed in the Matlab 7 and Visual C++ 6.0 environment. The IEEE 37-node test feeder is used for demonstrating the developed model and method. It is shown by simulation results that the developed model and method provide a new way to control the decision-making risks associated with the siting and sizing of DGs. The decision-makers can specify the confidence levels associated with constraints so as to control the risks.

1.6. Generation scheduling with non-dispatchable distributed generators

Current generation scheduling cannot fully integrate the essential features of 'non-dispatchable' generation technologies – those that use an intermittent source, such as wind power, and cannot be relied upon to dispatch power on demand. This limitation is becoming an issue for grid operators, as there is mounting public and political pressure to increase the penetration of renewable generation technologies that depend on varying weather conditions. Existing generation scheduling is, however, generally based on deterministic models, and usually ignores the likelihood and the potential consequences of variable contingencies. Addressing this limitation, chapter 6 proposes a generation scheduling suitable for fluctuating wind power, and which is also applicable to other renewable power generation.

There are two methods to incorporate wind power into unit commitment. The first method is to take into account the wind power as a constant; in other words, the wind power can be forecasted without errors. The second method is the stochastic approach, and it is natural to apply a stochastic approach to a deterministic problem in the solution process.

A stochastic optimisation approach is proposed for the unit commitment problem considering the variability of wind power generation, based on the mixed-integer linear programming (MILP). The problem is formulated as minimising the total cost of thermal units. To consider wind-power generation, scenarios are generated using scenario-generation techniques. The stochastic problem is hence transformed to a deterministic one. A 10-unit system and a 100-unit system are employed for demonstrating the model and method. It has been shown in this project by simulation results that the expected scheduling cost by using stochastic programming is generally more than

by using the deterministic model. This is because the stochastic model accounts for the situation that the thermal units cannot meet the prediction error in time caused by the variation of wind power. Hence, the ramping capabilities of units and prediction accuracy of wind power are crucial when wind power varies.

The existence of intermitted and uncertain DGs can lead to the increase of the scheduling cost since the system must provide more reserves for a power system if the electricity prices from DGs are comparable with those from conventional generation units. However, if the electricity prices from DGs are much cheaper than those from conventional generation units, the scheduling cost may reduce for a power system with DGs.

1.7. Risk control in transmission system planning with wind generators

Although wind power is clean and renewable, the uncertain characteristics of wind farms can bring about significant unfavourable impacts on power systems. With the expansion of wind-power generation, and thus the increasing proportion of wind energy in power systems, these adverse influences could become the technical barriers to wind power integration, resulting in new challenges to transmission system planning (TSP) and operation. New approaches should be applied in TSP to facilitate the integration of wind energy, through increasing the power system's ability to defend against the influence.

This research has developed a probabilistic model for the power output of wind generators. The DC probabilistic power flow is calculated with the combined use of cumulants and Gram-Charlier series. Three risk-controlling strategies are then introduced to enhance the system defence against security risks, in allusion to the uncertain factors in TSP; they are: probability of not violating each branch power flow limit (PBL); probability of not violating system power flow limit (PSL); and probability for the security margin of system power flow (PSM).

Based on the above work, a TSP model with risk-controlling strategies is developed for power system containing wind generators. A cost-benefit method is utilised to evaluate the planning schemes in order to maximise the overall benefit.

Two case studies demonstrate that it is possible to achieve a good trade-off among the security, reliability and economics of TSP schemes by employing risk-controlling strategies. Consequently, the security risks of a system associated with the uncertainties due to wind generators can be controlled using the developed TSP model.

The existence of intermitted and uncertain DGs can lead to some risks to the security and economics associated with the transmission system planning. The system planner could define the tolerable risks in advance so to obtain an acceptable transmission system planning scheme which can withstand the possible risks in the future caused by DGs.

1.8. Sizing the distributed generation with life-cycle costing and greenhouse-gas abatement effects

Wind power and PV can be primary operating DGs in a modern distribution network, sharing a considerable amount of load compared with other supply sources in the network. Optimal planning algorithms are required for determining the type of generating technology to use for determining the machine ratings that will satisfy the demand, and to operate the system at minimum cost under constrained operating conditions.

Responding to those requirements, a software program has been developed and scripted as part of this project using IPLAN programming language to work in conjunction with PSS/E software. The algorithms corresponding to the software development are presented in chapter 8.

A set of scenarios were developed that investigate the most economical combinations of hybrid generating units, their performance and their individual merits with regard to objectives of this part of the project. The results suggest that the best possible combinations of various DGs, such as wind and PV systems, can be operated with critical supports of diesel units supplement to the grid power supply.

The case studies presented refer to constant cost factors of generating technologies and assets; however, the software program was developed to incorporate varying costs of generating technologies and assets that may arise through the inflation and life-cycle effects. Such facilities in the software enables us to incorporate varying cost components of PV and wind, for example, as well as the futuristic cost elements that may arise through government subsidies for the use of particular generating technologies.

The investigations further suggest that the wind–diesel generating unit combination gives the most economical power generation for the particular network that is considered for the assessment. The next most economical combinations are wind–PV–diesel, followed by PV–diesel.

The proposed algorithm gives not only the size of DG system and geographical location, but also the operating condition of the week that determines the optimal condition. Such information is useful in reducing computation time of extended applications that include the security of energy supply to consumers by DG and the reliability improvement with DG unit combinations.

The priority ranking of life cycle cost and greenhouse gas (GHG) emissions can be used by network regulators and policy-makers to set incentives, or to penalise those who adversely affect the environment. It also facilitates benchmarking distribution networks for the incentives as appropriate. The results of the program can also be used as a potential platform for the carbon trade and extended applications. On the other hand, distribution network operators can use the proposed methodology to balance the benefits between different types of DG combinations and overall benefits of reducing LCC and GHG emission. Such an approach is necessary in meeting renewable energy targets and balancing the economy verses carbon trade.

Key findings

1.8.1. Benefits

The main network benefit applicable to DG is in the area of reliability for cases where a 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.

DG could benefit the network loss reduction by avoiding long-distance transmission.

DG could benefit voltage control in the remote terminal of feeders.

1.8.2. Challenges and solutions

DG has challenges in integrating into existing distribution networks due to the capacity limitations, these can be minimised by strategically integrating DG resources.

A software program is developed that provides the most beneficial installed capacity for a particular distribution network in increased integration of DG through cost-based technical analysis.

The program also facilitates to differentiate the benefits of different DG technologies through dynamic network capacities.

1.8.3. Barriers and solutions

Technical barriers from an increased penetration of DGs are starting to arise in terms of voltage control. An algorithm is developed and simulations have demonstrated that it is effective.

The other key technical barrier to the connections of DGs is the impacts on conventional protection schemes.

An efficient protection coordination scheme is developed.

As the DG levels rise there is a growing concern about the reliable detection of high impedance faults. A method is presented with good detection precision of line high-impedance faults in the presence of DGs.

Distributed generation has the potential to make a substantial contribution to the energy supply; however, there needs to be a mix of factors working to make investment in DG viable. In edge-of-grid areas the costs of the network can be very significant; since DG acts to reduce the network requirements, then the edge -of-grid is likely to be one of the most viable places for DG. The strongest case for DG can be made with respect to improving reliability and deferring investment in lines and transformers.

To achieve this potential for reliability enhancement the issue of voltage control in microgrids needs to be solved and this project has made substantial contributions to the solution. Another impediment is that conventional power system protection can be compromised in the presence of distributed generation. This project has developed a modified protection strategy such that the risk of undetected system faults is reduced, and also a coordinated strategy for protective relays.

In addition, some important problems are investigated in depth in this project, such as: UFLS considering DGs, optimal siting and sizing of DGs, generation scheduling with DGs, risk-control in transmission system planning with wind generators, sizing the distributed generation with life-cycle costing, and GHG-abatement effects.

2. TECHNICAL BARRIERS AND SOLUTIONS: VOLTAGE

2.1. Background and barriers

Distributed generation sources such as photovoltaic (PV) panels can cause substantial voltage rise problems, which in turn can cause the PV inverters connecting to the grid to trip off. The voltage rise problem with PVs is being recognised as a particular problem by distribution utilities, as customers who paid to have PV panels connected are not getting the expected return when the systems trip off. Traditionally, the voltage drops the further down the feeder from the main supply transformer. The utility builds in compensation for this by having a higher step-up in voltage for the distribution transformers at the far end of the feeders. At light load in the middle of the day the voltage would normally be on the high end of the acceptable voltage range, so that at peak times when the voltage drops, the lower voltage remains in the acceptable range. Now, if PV starts to send reversed power back up the line when the load is low, it takes only a small reverse flow to exceed the permitted voltage for the PV connection inverter, and thus trip the unit. In this project there has been a contribution to a solution to this issue.

The present Australian standard for the connection of PV inverters is that they must operate at unity power factor. This means that in an AC system the voltage and current must be in phase and the inverter must appear like a resistor operating in reverse. This design is perfectly adequate for very small reverse flows and avoids any issues on inverter voltage control oscillations. The solutions contributed by this project lie in using the ability of inverters to operate at a leading or lagging power factor; to operate with some capacitive or inductive characteristic. For most power systems, operation in a partly inductive region will tend to cause voltage drops, while operation in partly capacitive mode will tend to cause voltage rises. Thus to overcome the voltage rise problems of PV inverters it is beneficial to operate the inverters in a partly inductive mode. This mode of operation needs to respond to the actual system conditions, or the inverters will worsen the voltage drop problem at peak load. Thus the inverters need to have feedback control of voltage. This brings with it the problems of multiple independent units each trying to control the line voltage. The solution examined here is to use the droop concept useful for voltage sharing in large power stations, where the reactive power injection is proportional to the voltage drop. The droop gains that are high enough to give useful voltage control can give rise to oscillations between adjacent inverters. The solution has been to use a low transient gain and a higher steady state gain. The remaining issues are to change the standard and to modify the design of the PV inverters that need larger capacitors to provide the reactive power capability.

2.2. The proposed solution

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

Inverter-based DG systems such as PV, fuel cells and microturbines all theoretically are capable of affecting the system voltage. The difficulty that is facing many utilities at present 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 as follows:

- export of the required real power
- export or import of reactive power to control voltage and/or power factor
- suppression of system harmonics.

The present regulation for inverters for PV connection focuses 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:

- The first is the development of a voltage-control process such that sets of inverters can contribute to feeder voltage control without risk of adverse interactions between the controllers.
- The next step reviews the power factor implications of voltage control. 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 maximised 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.
- The final aspect is the control of harmonics. Inverters are capable of current tracking, which means 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.

2.2.1. *Voltage control with multiple inverters*

Ledwich et al. (2010) have presented an analysis on impacts of multiple site reactive power compensation for distribution feeder voltage support. Initially, a radial distribution feeder with multiple DSTATCOMs was 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.
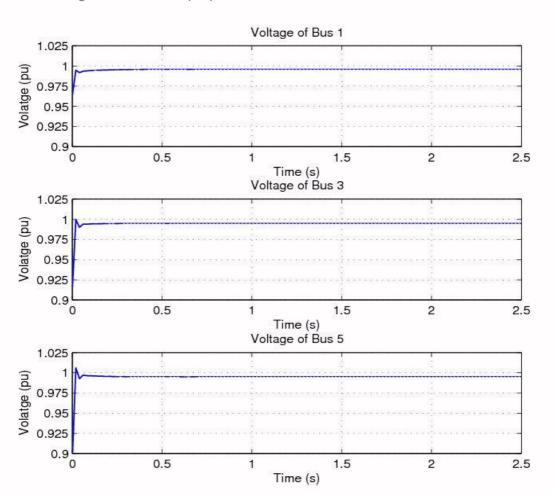
Table 3: Parameters used in simulation study with proportional controller

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 are listed in Table 3.

Figure 2 shows the variation of voltages at buses 1, 3 and 5 with time; and Figure 2 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 kp = 1, the system response becomes oscillatory and the control system becomes unstable, as illustrated in Figure 3. It is also observed that these voltage oscillations are getting larger with the bus number; that is, 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 a poor voltage profile along the feeder even when the DSTATCOMs have spare reactive power capacity.

Figure 2: Bus voltage variation with proportional controller

Figure 3: Steady state voltage profile of the feeder
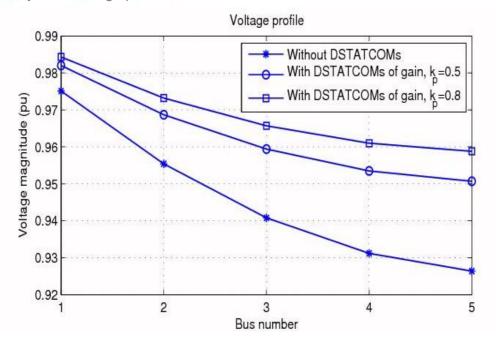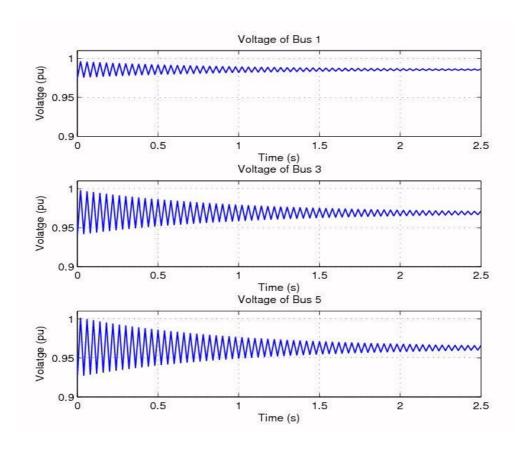
Figure 4: Bus voltage variation with high proportional gains (kp = 1)
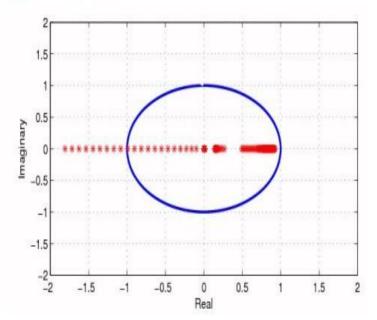
As a result, the DSTATCOMs are proposed to operate on their respective steady state droop lines in order to obtain the highest gain for voltage correction; and an integral controller is used to force the operating point on to the steady state droop line. The control strategy has shown enhanced sharing of reactive power among DSTATCOMs.

A mathematical model is developed, of a radial distribution feeder connected with multiple DSTATCOMs that are controlled by the proposed control strategy. Eigenvalue analysis 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; that is, 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 utilisation of DSTATCOMs at all operating conditions. The daily load profile must be considered when determining the number of DSTATCOMs and their positions and ratings. An Eigen analysis 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 eigenvalues for this system. These eigenvalues are plotted on Figure 1.4 for an integral gain range from 1 to 3 with 0.1 increments. A similar eigenvalue 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). Figure 1.4 shows there is a maximum or boundary integral gain before the system becomes unstable. This boundary integral gain is plotted for both 5- and 10-bus systems against the total load admittance, in Figure 1.5. These plots demonstrate that both systems become more sensitive to integral gain under light loading conditions, and that the 10-bus system becomes unstable at smaller integral gains than the 5-bus system; that is, the system is vulnerable to an increase of integral gains when the DSTATCOMs are situated much closer to each other.

Figure 5: Eigenvalue locus with varying integral gain for the 5-bus system
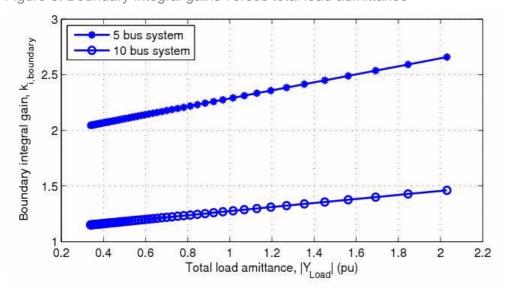
Alternatively, the boundary integral gain can be found by repetitive time domain simulations with gradual increments of integral gain. In this process, the boundary integral gain is identified with voltage oscillations. Boundary integral gains obtained in this manner for few randomly selected loads matched well with the values of Figure 5.

Only the test results for uniformly distributed DSTATCOM cases are presented and discussed, 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.

Figure 6: Boundary integral gains versus total load admittance

2.2.2. 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. Perera et al. (2010) made an effort 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 four 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 0.95pu.

The rating of lines and the line losses can be minimised if the power factor is kept close to unity through all line segments and transformers. For purely reactive lines, this corresponds to a flat voltage profile. However, the resistance in distribution lines can be quite significant; 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 minimising 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, there is no need for remote measurements, only for the voltage at the terminals of the inverter system.

The aim 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 +/- 5% error. The seven cases in this report 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.
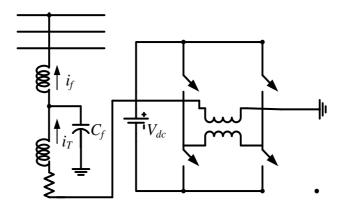
Therefore, the power factor or voltage control can be implemented without stability concerns, using the integral to droop line. If the line is purely reactive there is no conflict between voltage and power factor control. The unity power factor design is achieved by a voltage control to 1pu down the feeder with a shallow droop line for tight voltage control. When the line impedance is 30° from pure reactive, then this tight voltage control to 1p.u. will yield a current that is lagging by approximately 30°. In the seven examples of this report, 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 0.95pu, 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.

2.2.3. Tuning harmonic absorption of voltage source converters

In Ledwich, Ghosh and Zare (2010) 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 emphasising current tracking or a high level of absorption by emphasising voltage tracking. The robustness of the LQR-based hysteretic design can be clearly shown using the eigen-analysis tool developed in this project. The analysis process can be easily extended to include multiple converters that are connected to multiple buses of a power system.
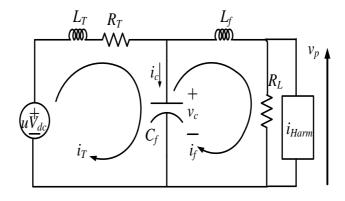
In this project the converters are assumed to consist of ideal DC voltage source supplying a voltage of VDC to a VSC. The structure of the VSC is shown in Fig 7. The VSC is set as an H-bridge supplied from a DC bus. The resistance RT represents the switching and transformer losses, while the inductance LT represents the leakage reactance of the transformers. The filter capacitor Cf is connected to the output of the transformers to bypass switching harmonics, while Lf represents an added output inductance of the DG system. Together LT, Cf and Lf form an LCL or T-filter.

Figure 7: Converter structure
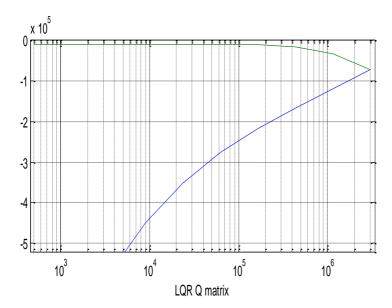
The equivalent circuit of the converter is shown in Figure 8; here, u·Vdc represents the converter output voltage, where u is the switching function and is given by u = ± 1. The main aim of the converter control is to generate u. The following state vector is chosen: $z^T = \begin{bmatrix} i_T & v_c & i_f \end{bmatrix}$.

Figure 8: Single-phase equivalent circuit of VSC

The results in Figure 9 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.

Figure 9: 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 be 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 project adjusts the relative harmonic impedance and will be operative even for sudden changes in the system distortion, as in arc furnaces. Multiple converters can have a form of droop line sharing of harmonic absorption, provided that the harmonic impedance is finite.

2.3. 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, the reactive capacity can be made to work cooperatively as a dispersed voltage controller using a new tool "integral to droop line control". This same tool can be set such that the peak-load ability 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.

3. TECHNICAL BARRIERS AND SOLUTIONS: PROTECTION

3.1. Background and barriers

A distributed generator is usually defined as a small-scale generator with a capacity less than 30 MW and normally connected to a distribution network. DG is helpful for improving the distribution system operation and power supply, especially in rural and remote areas (Enslin 2004). Specifically, the advantages of DG can be summarised as follows: enhancing reliability; reducing network losses; improving power quality; postponing network expansion; improving the environment by reducing CO_2 and NO_x emissions; and providing peak load service (Ei-Khattam & Salama 2004; Odagiri 2002; Erlich & Shewarega 2006; Chaitusaney & Yokoyama 2005). DG has been developing rapidly in recent years, as the result of the restructuring of the power industry and climate change concerns (Driesen & Belmans 2006).

However, the rapid increase in the number and capacity of distributed generators has also brought some problems to power system operation and control (Driesen & Belmans 2006; Zhang et al. 2007; Wen & Wang 2008; Wang & Guindo 2006; Chi et al. 2006; Chen et al. 2006). Whether the above-mentioned advantages of DGs can be achieved depends heavily on whether these problems can be properly resolved; and one important issue from these problems is the coordination of protective devices (Mcdermott & Dugen 2002; Girgis & Brahma 2001). Traditionally, the distribution system operates 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. If the conventional overcurrent protections/overcurrent relays are still employed, mis-operation of protections could occur because of the change of the current direction. The conventional protective relay scheme does not meet the requirement in this emerging situation. As the number and capacity of DGs increase in the distribution system, the issues concerned, namely the protective relay system design and coordination, will become increasingly challenging (Kauhaniemi & Kumpulainen 2004). It is expected that replacing protective devices will incur large amounts of investment and may not be cost-effective. Instead, the problem may be resolved 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.

The protective relay coordination refers to the ability to select appropriate relay setting values so they can meet the basic requirements for protective relays; namely selectivity, speed, sensitivity and reliability (Zeineldin et al. 2006), under different kinds of faults. An appropriately coordinated protection system can isolate faults quickly and maintain the operation of the remaining healthy part of the system (Britto et al. 2004). Directional overcurrent relays are widely employed in distribution systems, and hence it is very important to investigate the coordination problem when using these protective relays (Abyaneh et al. 2003). Some research has been done in this area, but in most of the existing methods linear or nonlinear programming approaches are employed for this purpose (Zeineldin et al. 2006). Only continuous variables can 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.

3.2. The proposed solution: optimal coordination of overcurrent relays in distribution systems with distributed generators

Given the above background, the optimal coordination problem of overcurrent relays is revisited and formulated as a mixed integer nonlinear programming problem (MINLP) in this work. 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 work, the well-established differential evolution (DE) algorithm (Yang & Luo 2006) is employed to solve this problem. The abovementioned problem of rounding the optimal solution of continuous variables in existing methods can 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 minimising the operating time of protective relays. Then, the DE algorithm is briefly introduced. Finally, a numerical example is presented to demonstrate the proposed approach.

In the developed mathematical model, both discrete and continuous variables are included, and the objective function is nonlinear. Hence this is a Mixed Integer Nonlinear Programming (MINLP) problem. In this work, the well-established differential evolution (DE) algorithm is employed to solve this MINLP problem.

3.3. Case studies

Figure 10: A sample distribution system
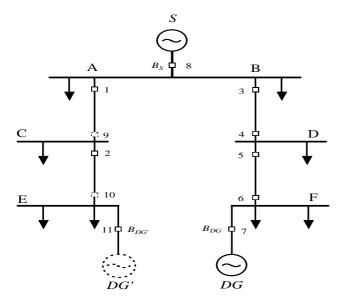
Figure 11:The objective value of the best individual and that of a given individual
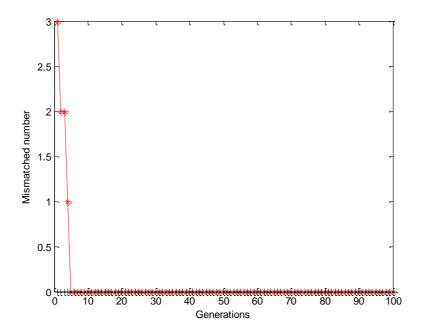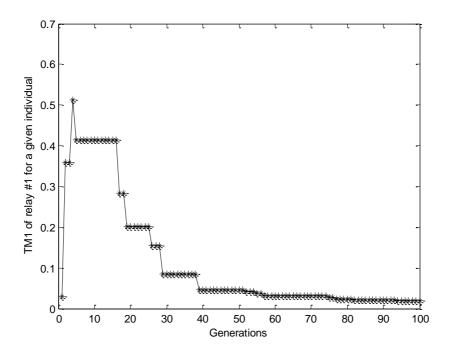
Figure 12: The mismatched number of protective relays in the best individual and a given individual

In this work, the sample system shown in Figure 11 is used to demonstrate the developed approach. It is obvious that when DGs are removed, the original system is a radial network, while when DGs are added, the distribution system will become a looped one, and the power flow as well as short-circuited current will no longer flow in just one direction. Directional overcurrent relays could be employed to protect the system. In this work, bus faults are employed in case studies, but the mathematical model and algorithm could be applied to a variety of fault locations as well as different types of faults, as long as the constraint conditions are included and respected. In order to keep the radial characteristic in the original distribution system and solve the new problems mentioned, the case study is chosen with a DG installed at the end of feeder B. If another DG is installed at the end of feeder A, as shown with the broken line in Figure 12, three protective relays should be installed. In this case, the current direction through each protective relay does not change when a fault takes place on a bus; the only change is the fault current amount. The mathematical model presented in this work can solve this situation.

The system shown in Figure 10 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; 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.

The original data of the sample system are shown in Tables 2.1–2.3. These tables respectively show the power supply parameters; the feeder parameters; and the placements of primary/backup protective relays.

Table 4: Power supply parameters

S_s	100 MVA	V_s	10.5 kV	X_s	1.46 Ω
S_{DG}	10 MVA	V_{DG}	10.5 kV	X_{DG}	0.42 Ω
f_s	50 Hz				

Table 5: Feeder parameters

Line	R （Ω）	L （H）
A-C	1.155	0.005
C-E	1.155	0.005
B-D	1.155	0.005
D-F	1.155	0.005

Table 6: The placements of primary/backup protective relays

No.	No. of primary relays	No. of backup relays
1	2	1
2	1	4
3	1	8
4	3	8
5	4	6
6	5	3
7	6	7

Table 7: Simulation results

T_{Mi}	Result	I_{Pi}	Result (A)
T_{M1}	0.0196	I_{P1}	1100
T_{M2}	0.0195	I_{P2}	400
T_{M3}	0.0192	I_{P3}	1100
T_{M4}	0.0565	I_{P4}	100
T_{M5}	0.0120	I_{P5}	600
T_{M6}	0.0136	I_{P6}	1000
T_{M7}	0.0689	I_{P7}	800
T_{M8}	0.0782	I_{P8}	1000
Objective value（sec）	4.8576		
Fitness value	0.2059		

Many simulation tests have been carried out. Test results with the following specified parameters are listed in Table 7: the initial population size N=300; and the maximum permitted number of generations is 100. To better understand the computational procedure of the DE algorithm, some simulation results are shown in Figures 11 -13. The optimal objective value and the objective value of a given individual in each generation are shown in Figure 2.2; the mismatched number of protective relays in the best individual and a given individual are shown in Figure 12; the TM1 of relay #1 of a given individual is shown in Figure 13.

It is illustrated by the simulation results in Table 7 that the protective relays can remove all the three-phase short-circuited faults quickly, given that the coordination constraint of primary/backup protective relays is respected. The coordination results between primary and backup protective relays are shown in Table 2.5. The line with crosses in Figure 11 represents the objective value of the best individual, while the line with stars represents the objective value of a given individual. The optimal objective value and the objective value of a given individual have clearly improved from generations 1 to 30. In Figure 12, the mismatch of protective relays between the best individual and a given individual is shown; the black line with crosses 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 Figure 2.3 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 Figure 13, 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.

Table 8: The coordination of the primary/backup protective relays

No.	Coordination pairs	Coordination time (s)
1	2-1	0.4101
2	1-4	0.4049
3	1-8	0.4446
4	3-8	0.4070
5	4-6	0.4246
6	5-3	0.4170
7	6-7	0.4122

Furthermore, when the outputs of DGs change in the distribution system, an ideal solution is to find a set of relay setting values that meet system operating requirements. However, in actual large-scale distribution systems, the situations are usually very complicated, and it is very difficult, if not impossible, to find a single optimal solution suitable for all system operating conditions.

Assuming that there are NDG distributed generators in the distribution system and NP situations for the output of each distributed generator, there will be $N_P{}^{N_{DG}}$ optimal solutions for all the

operating conditions, and the optimal solution for each situation can be calculated beforehand. In general, the larger NP is, the more accurate the result will be.

3.4. Conclusions

Distributed Generation can deliver many economic, technological and environmental benefits; however at the same time, DG presents a number of challenges. One the most important challenges is the coordination of protective relays. When DGs are connected in a distribution system, both the direction and distribution of the power flow and fault current in the distribution system could change significantly, such that the traditional protection scheme will no longer work correctly. Hence, there is a demand for new protection schemes.

In this work, the optimal coordination problem of protective relays in distribution systems with distributed generators is formulated as a mixed-integer nonlinear programming problem, and solved by the well-established DE algorithm. The feasibility and efficiency of the proposed method has been demonstrated by a sample system.

4. OPTIMISED USE OF DISTRIBUTION GENERATORS FOR RELIABILITY IMPROVEMENT

4.1. Background

The objective 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, as 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 a number of companies instead of a single utility.

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 with certain standards and in the amount needed. Power system reliability and power quality are closely related; 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.

4.1.1. Power supply reliability

An actual distribution network is studied in Jahangiri and Fotuhi-Firuzabad (2008) and 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 three 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.

4.1.2. Distribution network optimisation with reliability constraints

In Mitra et al. (2006), the cost of the network is optimised by the PSO (particle swarm optimisation) algorithm, while the stability index is added to the objective function as the penalty function. The optimisation method is tested by a 22-node distribution network. PSO is proven to be better than dynamic programming. In Haghifam et al. (2008), the optimisation 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 DG and without DG. 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 that can be selected by planners taking into account their experiences or the conditions of the distribution network.

4.1.3. 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 error. Having distributed generation (DG) as backup power sources can improve the system reliability (Waseem, Pipattanasomporn & Rahman 2009). Therefore, distributed generation is expected to play a key role in the residential, commercial and industrial sectors of the power system.

4.2.   The developed method

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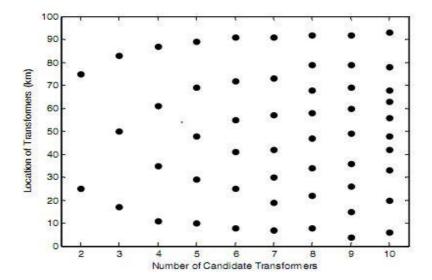
If properly installed and operated, DG can improve both end-user satisfaction and grid reliability. By analysing the influences of distribution generation we can propose an assumption that the energy production from renewable energy sources will be the major uncertainty for the energy industry.

This research team has done a significant body of work in this area. For example, Ziari et al. (2009) report the initial steps of research on planning of rural networks for MV and LV. In this paper by Ziari, two different cases are studied. These two models to some extent represent the distribution system in urban and rural areas, respectively. In the first case, 100 loads are distributed uniformly on a 100 km transmission line in a distribution network. In the second case, the load structure becomes closer to the rural situation: 21 loads are located in a distribution system so that their distance is increasing; that is, the distance between the first and second loads is 3 km; the distance between the second and third loads is 6 km, and so on. The objective function for the design of the optimal system consists of three main parts: cost of transformers and of 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 work, a heuristic and random-based method called Particle Swarm Optimisation (PSO) algorithm is used for planning of a simple distribution system. This tool is used in case 1 for a simple uniform load case; an analytical method, nonlinear programming (NLP) is utilised for case 2, 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, is considered. Based on the number of candidate transformers, up to 19 different cases for optimisation are assessed. Figure 13 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 five transformers for the uniform load case can be seen in Figure 13 as being 10%, 29%, 48%, 69% and 89%.

Figure 13: Location of transformers versus the number of candidate transformers

For the case 2 (21 nonlinear spaced loads), a simple linear form of a rural area is modelled. Twenty-one transformers are selected as candidates with variable size and location in the tested distribution system. Figure 14 shows the structure of loads in the system and the calculated transformers location. The first point is that the optimal design corresponds to only nine transformers being employed even though 21 possible sites were examined.

Figure 14: Locations of loads and transformers
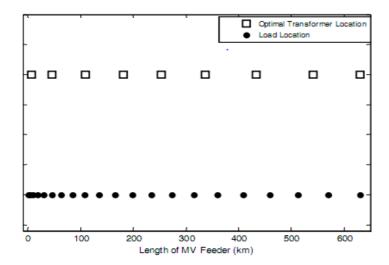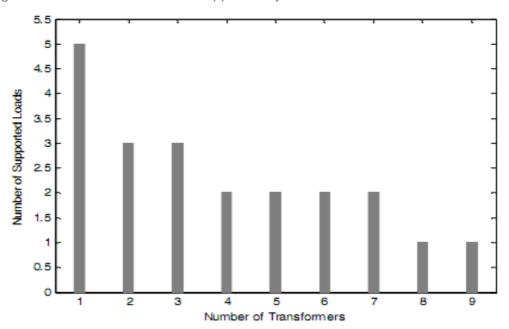
Figure 15: The number of loads supported by transformers

As shown in Figure 15, the optimal solution for the first transformers provides support for five loads.

Increasing the demand for electrical energy, tight restriction on expanding distribution lines to supply remote areas and system reliability are three main issues that 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 minimising the power loss and improving the reliability simultaneously will yield a better solution than optimising individually, only a few papers have investigated the combination of these elements. From the

reliability point of view, consideration of load shedding leads the optimisation 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 optimisation. 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 optimised using a combination of Discrete Particle Swarm Optimisation (DPSO) and Genetic Algorithm (GA). This increases the diversity of the optimising 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 Billiton Test System (RBTS), as shown in Figure 16, 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 9.

Figure 16: Distribution System for RBTS bus 2
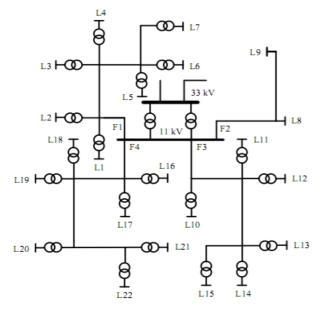
Table 9: Characteristics of the test system

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 Figure 16, 22 loads located in the first test system are composed of nine residential loads and six government loads located at feeders F1, F3 and F4; five commercial loads located at feeders F1 and F4, and two 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.

Figure 17: Load duration curve used in the testing distribution system
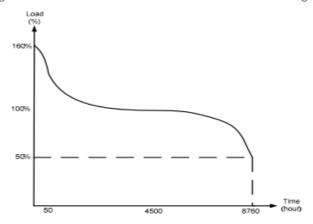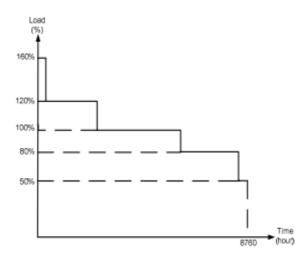
Figure 18: Approximation of load duration curve

The load duration curve of this test system is shown in Figure 17. 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 that might be inaccurate. In this project, to implement a compromise between accuracy and computation time, this curve is approximated with five load levels, as shown in Figure 18; however, using sensitivity analysis to find the optimal load level number can be included in the future. As shown in Figure 18, 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 10: Parameters and value used in the test

Parameters	Value
k_{PL}	168000 $/MW
C_{INSTAL}	400000 $/MVA
$C_{O\&M}$	45 $/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 10, the SAIDI weight factor is 5×106. As previously mentioned, 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 12,000 in the test system and the cost per 1-minute interruption is assumed $7, the SAIDI weight factor is calculated 5.04×10^6 (12000×60×7), in which 60 converts hours to minutes. As seen in Table 10, the SAIDI weight factor in this report is presumed 5×10^5. It is clear that by decreasing/increasing this factor, (the importance of reliability in the objective function), the optimal number/size of DGs will decrease/increase. Therefore, this factor can also be scaled by a coefficient to adjust the importance of reliability.

Table 11: DGs location and rating (MW) for average all load levers

		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

Table 11 shows that 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. To minimise the loss, to maximise the reliability and to meet the constraints, the following should also be installed: 13 DGs with a 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 a total rating of 13.5 MW for 80%, 100%, 120% and 160% of the average

load respectively. The highest level of DG is related to the peak load and the lowest level is related to the 50% loading. Table 12 illustrates a comparison between the outputs before and after the installation of DGs for all load levels.

Table 12: Comparison 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	2.956×10^7	1.907×10^5	3.794×10^7	4.102×10^5	3.961×10^7
Total		9.766×10^5	8.499×10^8	10.92×10^5	8.883×10^8	2.41×10^6	1.32×10^9

As observed in Table 12, 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.

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.

4.3.   Conclusions

Power system reliability is a key issue that can be addressed with DG. The optimisation of distribution design considered in this chapter shows that reliability is a strong benefit of deploying DG for areas that are not highly meshed. It is largely this reliability benefit that may indicate that the best case of DG, apart from the significant contribution to reducing greenhouse gas emissions.

5. THE UNDER-FREQUENCY LOAD SHEDDING STRATEGY AND DISTRIBUTED GENERATORS

5.1. Background

Under-frequency operation could be a huge threat to the secure and stable operation of a power system. For example, when the frequency is lower than its rated value, the vibration of blades in a turbine generator will increase in strength and the blades may even rupture due to resonance. In the end, the turbine generator may be forced to trip off and an accident/outage hence occurs.

Generally speaking, the well-established Under-Frequency Load Shedding (UFLS) is deemed to be the last of several effective remedial measures against a severe frequency decline in a power system. Therefore, when a power system is suffering a severe disturbance or when there is a severe power imbalance between generation and demand, the ability to maintain power balance and further frequency stability is directly related to the UFLS strategy.

A good UFLS strategy should meet the following requirements:

- The frequency decline can be restrained and the normal frequency value can be recovered
- As little time should be spent in the frequency recovery as possible. Meanwhile, frequency overshooting or hovering should be avoided
- The load amount to be shed should be minimized
- The cost of the UFLS strategy should be minimised.

Up until now, the available approaches for establishing the UFLS strategy can be divided into the conventional, half-adaptive and adaptive ones. In the conventional approach, when the frequency is lower than the given first threshold the load shedding will be executed. After that, if the frequency continues to decline and when it becomes lower than the given second threshold, the load shedding will proceed. The above steps will be repeated until the frequency has been restored to an acceptable range. In this approach, the shed load amount is determined based on some specified severe accidents. Thus, the load amount shed by the conventional approach is often more than what is actually needed. In the half-adaptive approach, when the frequency is lower than the specified threshold, ROCOF will be measured. The specific amount of load to be shed is determined by the measured value of ROCOF. The adaptive approach (Anderson & Mirheydar 1992) represents an algorithm improved from the conventional one. The frequency response model is built on the basis of the frequency differential equation and the rotor motion equation in this approach (Terzija 2006). Based on the frequency variations, the amount of load to be shed by this so-called adaptive approach can be determined more accurately, and the result is usually less than that determined by the other two approaches.

Up until now, many research papers have been published on the development of UFLS strategies. The traditional method for UFLS and under-voltage load shedding (UVLS) is based on a single-machine and a single-load model, and cannot meet the requirements of modern multi-machine power systems. Given this background, a new approach is proposed based on the risk management and the quantitative analysis method for the time response curve in Xue et al. (2009).

The ratio between the security margin and control cost is used to guide the risk minimisation process. In addition, the coordination between UFLS and UVLS among transient load shedding, middle-term load shedding and long-term load shedding is also studied. In Xue et al. (2009), the compromise between two control strategies, namely the fault-driven emergency control and the trajectory-driven corrective control, with consideration of the physical and economical characteristics of these two strategies, is examined in a risk management framework, and a global coordination approach is presented to find the solution of minimum risk. The optimisation and coordination between UFLS and UVLS are studied in Ren et al. (2009) using a decoupled optimisation and iterative coordination technique.

A new under-frequency load-shedding scheme is presented in Prasetijo et al. (1994) by utilising the frequency and voltage changes as well as ROCOF. In Xiong and Li (2006) a UFLS strategy with the load frequency characteristics considered is presented: the load with a smaller frequency sensitivity factor is shed earlier than other loads. This means that the remaining loads will be reducing more with frequency and thus aiding recovering the system frequency, and hence the system stability, quickly, but with numerical simulations limited to a single-machine power system. In Terzija and Koglin (2002), an adaptive approach for protecting a power system from dynamic instability and frequency collapse is presented, and the frequency and ROCOF are estimated by a non-recursive Newton-type algorithm with a simplified generator swing equation. In Chuvychin et al. (1996) an adaptive scheme employing the frequency and ROCOF measurements to dynamically set UFLS relays is developed; and a technique for coordinating UFLS and the dispatching of spinning reserves through a localised governor control is also presented.

In Girgis and Mathure (2010), the impact of the active power sensitivity to frequency and voltage variations on the load shedding is examined, and the magnitude of the power imbalance is determined by ROCOF; while the sensitive bus for the load shedding is identified by the rate of change of voltage with respect to active power. In addition, in some available publications the UFLS strategy is formulated as a nonlinear programming problem (Novosel & King 1994; El-Sadek et al. 1999; Wang & Billinton 2000; Sanaye-Pasand & Davarpanah 2005; Abou et al. 2006; Nakawiro & Erlich 2009). In the optimisation models developed, the objective functions could be specified to minimise: the load amount to be shed; the network loss after the load shedding; and the cost of load shedding. Many modern heuristic algorithms, such as the genetic algorithm (GA), particle swarm optimisation (PSO) and ant colony optimisation (ACO), are used to solve the optimisation models. Although there is a higher probability of obtaining the globally optimal solution with these algorithms, the procedure could be time-consuming and may be unable to meet the requirement in the emergent situation.

In summary, although much research has been done on developing optimal UFLS strategies, some issues, such as the determinations of the load amount to be shed and the load shedding priority, are still not well resolved.

With the ever-increasing size of the power system and the extensive penetration of DGs in power systems, the development of an optimal UFLS strategy is facing some new challenges, such as avoiding the isolated operation of DGs when the UFLS strategy is executed and the loads are shed; exploring the benefits of DGs to reduce the load amount to be shed; or even avoiding the load shedding. However, to the best of our knowledge, only a few research publications are devoted to investigating the impacts of the increasingly penetrated DGs on the UFLS strategy. Given this background, the problem of developing an optimal UFLS strategy in a distribution system with DGs, considering load static characteristics, is investigated in this work.

5.2. The methodological framework of the developed optimal UFLS strategy
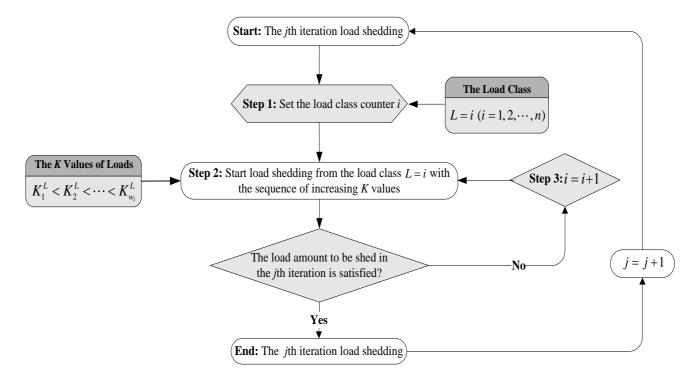
The developed optimal UFLS strategy in this work consists mainly of two procedures: the 'basic round' and the 'special round'. Specifically, the basic round is implemented with the starting signal making up the frequency and ROCOF. In terms of the swing equations of an equivalent generator and the spinning reserve of the power system concerned, the load amount to be shed in each round can be calculated quickly. Then, the load shedding is executed as specified in advance. Finally, the frequency emergency can be alleviated. However, the security/stability of the power system usually cannot be maintained by only implementing the basic round, because the state of the power system is always dynamic. Moreover, the load amount to be shed in each round is determined by the measured value of ROCOF. As a result, some error is inevitable due to the difference between the measured value and the real-time value of ROCOF. Therefore, the frequency and power imbalance can only be approximately adjusted and retrieved.

Although the frequency emergency can be alleviated in the basic round, the phenomena of fluctuation in the low frequency domain or floating around a low frequency value may still appear. To restore the frequency to a secure state as quickly as possible, and the loads at all nodes to a normal state as far as possible, a special round could be executed after the basic round is over. In the special round, the loads at all nodes can be adjusted by optimizing the output powers of DGs while respecting the security constraints.

5.2.1. The basic round

The main goal of the basic round is to stop the frequency decline as quickly as possible to eliminate the possibility of the frequency collapse, and to limit the shed load. The flowchart of the load shedding in each iteration of the basic round is shown in Figure 19.

Figure 19: The flowchart of the load shedding in each iteration of the basic round

5.2.2. The special round

As previously mentioned, DGs have some impacts on the development of the optimal UFLS strategy. With this in mind, the fluctuation in the low frequency range or floating around a low frequency value can be prevented, and the loads at all nodes can be adjusted by optimising the output powers of DGs in a special round.

5.2.3. The procedures and applications of the optimal UFLS strategy

In the developed optimal UFLS strategy, the basic round is executed first. The special round is then implemented after a specified delay. The procedures and applications of the developed UFLS strategy in this work are shown in Figures 20 and 21 respectively.

Figure 20: The implementation procedures of the developed optimal UFLS strategy
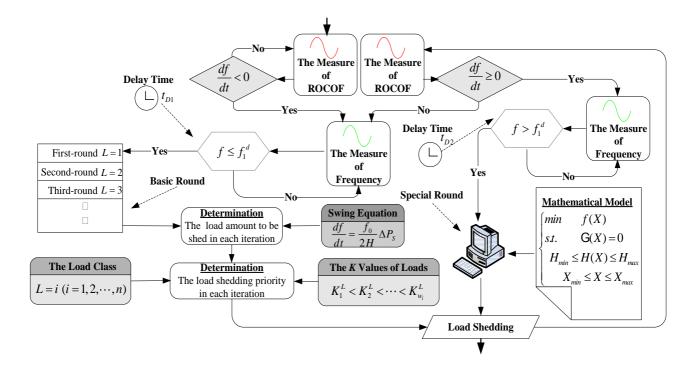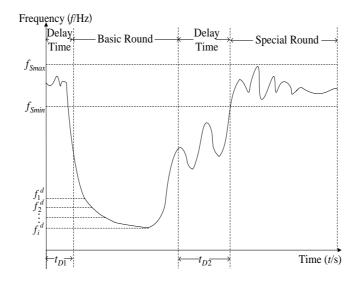
Figure 21: The application of the developed optimal UFLS strategy

5.3. Case studies

The modified IEEE 37-node test feeder, as shown in Figure 22, is used to demonstrate the effectiveness of the developed optimal UFLS strategy. Four DGs are installed at nodes 703, 704, 705 and 734. This test feeder is connected to other systems through node 799. Thus, suppose that the inertia time constant of the equivalent generator is 80.00s; the data of installed DGs and original loads are shown in Tables 13 and 14, respectively. The output power curve of each DG is shown in Figure 4.5, based on the output power fluctuation. The essential features of the developed optimal UFLS strategy are simulated in the MATLAB/SIMULINK environment. Its design diagram is shown in Figure 24.

Table 13: Data of the installed DGs

Location	Type	H_{DGi} , s	$P_{DGi}^{\min}$, kW	$P_{DGi}^{\max}$, kW	$Q_{DGi}^{\min}$, kVar	$Q_{DGi}^{\max}$, kVar	P_{DGi}^{avg} , kW	σ_{DGi} , kW
703	Micro Turbine	5.00	10.00	30.00	5.00	15.00	29.51	0.49
704	CHP	5.50	25.00	40.00	10.00	25.00	38.62	1.38
705	Gas Turbine	4.50	5.00	15.00	2.00	10.00	14.58	0.42
734	Micro Turbine	5.00	20.00	30.00	10.00	19.00	28.77	1.23

Note: P_{DGi}^{avg} and σ_{DGi} are respectively the mean value and the standard deviation of the output power of each DG

Table 14: Data of the original loads

Type	Node	Load Model*	P_{Li}^0 , kW	Q_{Li}^0 , kVar	K_{pf}	K_{qf}
First-class load	714	D-I	17.00	8.00	1.30	-0.10
	742	D-Z	8.00	4.00	1.20	-0.09
Second-class load	728	D-PQ	42.00	21.00	1.30	-0.05
	729	D-I	42.00	21.00	1.40	-0.06
	744	D-PQ	42.00	21.00	1.50	-0.03
Third-class load	718	D-Z	85.00	40.00	1.50	-0.10
	733	D-I	85.00	40.00	1.30	-0.04
Fourth-class load	701	D-PQ	140.00	70.00	1.40	-0.03
	737	D-I	140.00	70.00	1.20	-0.07
	738	D-PQ	126.00	62.00	1.70	-0.02

*Note:

1) D-PQ: The load is assigned with the delta connection code and constant kW and kVar model. According to Eqn. (1) and Eqn. (2), the parameters of its load model are $c_p = c_q = 1$,

$a_p = b_p = a_q = b_q = 0$;

2) D-I: The load is assigned with the delta connection code and constant current. The parameters of its load model are $b_p = b_q = 1$, $a_p = c_p = a_q = c_q = 0$;

3) D-Z: The load is assigned with the delta connection code and constant impedance. The parameters of its load model are $a_p = a_q = 1$, $b_p = c_p = b_q = c_q = 0$.

Figure 22: The IEEE-37 node test feeder
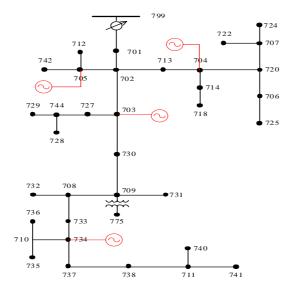
Figure 23: The output power curve of each DG
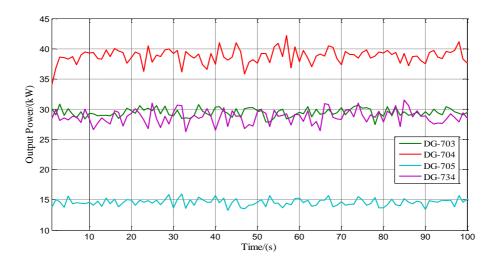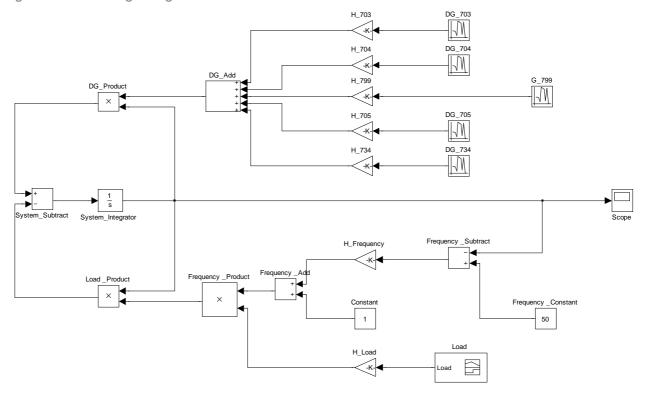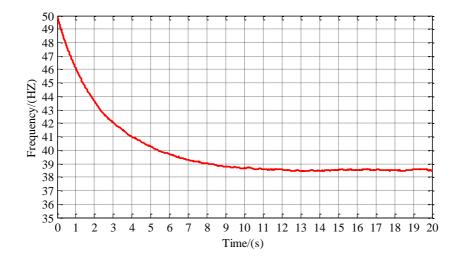
Figure 24:The design diagram in the MATLAB/SIMULINK environment
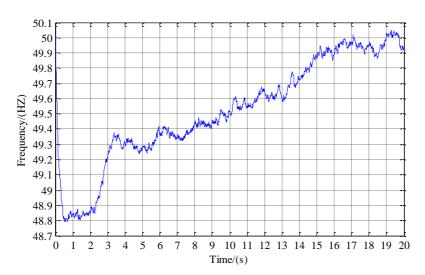
Suppose that one of the adjustable transformers at node 799 is forced to trip off due to a fault; thus, the other transformers operate with a limited overload. The active power from other systems through node 799 is reduced by 200 kW, which represents 22.33% of the total active power demand in this test feeder. The system frequency variations without the execution of any UFLS strategy are shown in Figure 25.

Figure 25: The system frequency variations without the execution of any UFLS strategy

When ROCOF<0 and the delay time t_{D1} has passed, the optimal UFLS strategy developed in this work will be activated. The system frequency variations during the whole execution procedure are shown in Figure 26.

Figure 26: The system frequency variations in the execution procedure of the developed optimal UFLS strategy

As shown in Figure 26, the frequency decline is stopped by quickly shedding some loads in the basic round. Moreover, the fluctuation in the low-frequency range or the floating around a low-frequency value has been avoided by optimising the output power of DGs and adjusting some loads in the special round. The shedding schemes in each iteration of the basic round are shown in Table 15. After the execution of the special round, the loads are shown in Table 16. It can be seen from Tables 14 -16 that the load amount shed in the basic round is more than that in the special

round. Finally, the output power variations of DGs and the values of all terms in the objective function expressed by Eqn. (13) before and after the execution of the special round are shown in Table 4.5 and Table 4.6 respectively. From Table 4.4 and Table 4.5, it can be observed that the shed load amount has been reduced to some extent with the support of DGs. In addition, as shown in Table 4.6, Figure 4.9 and Figure 4.10, the voltage profile at each node of the test feeder and the system frequency has been improved by the special round.

Table 15: The load shedding schemes in each iteration of the basic round

Iteration, times	Frequency setting, Hz	ROCOF, Hz/s	Load amount shed in each iteration, kw	Load amount shed at each node, kw	Percentage between load shed and total load, %
First	49.00	-48.74	127.70	$P_{S742} = 7.55$ $P_{S714} = 16.96$ $P_{S728} = 41.13$ $P_{S729} = 41.70$ $P_{S744} = 20.36$	17.57
Second	48.80	-16.31	65.21	$P_{S744} = 21.28$ $P_{S733} = 43.93$	8.97

Table 16: The loads after the execution of the special round

Type	Node	P_{Li}, kW	Q_{Li}, kVar
First-class load	714	2.63	1.24
	742	1.28	0.64
Second-class load	728	4.43	2.22
	729	6.38	3.19
	744	7.36	3.68
Third-class load	718	82.92	39.02
	733	40.01	18.82
Fourth-class load	701	138.72	69.36

| | 737 | 136.90 | 68.45 |
| | 738 | 123.87 | 60.95 |

Table 17:The output power variations of DGs before and after the execution of the special round

Node	Before Execution		After Execution	
	P_{DGi} , kW	Q_{DGi} , kVar	P_{DGi} , kW	Q_{DGi} , kVar
703	23.82	13.71	29.31	14.62
704	35.17	16.31	38.53	17.74
705	14.35	8.77	14.98	9.23
734	27.93	16.34	29.54	16.74

Table 18: Values of all terms in the objective function before and after the execution of the special round

Index Name	Weighting coefficients	Before execution	After execution
Cost of UFLS	0.42	1.6218	1.1605
The Sum of Squared Voltage Deviations	0.29	0.1140	0.0230
The Sum of Squared Frequency Deviations	0.29	0.2667	0.1826

Figure 27: The voltage variations at each bus of the test feeder after the execution of the special round
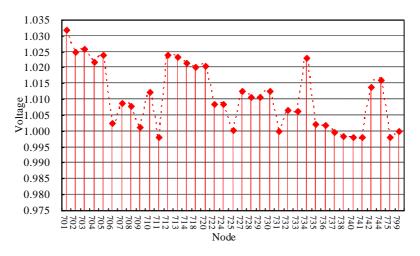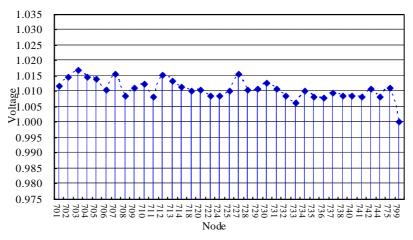
Figure 28: The voltage variations at each bus of the test feeder before the execution of the special round

5.4. Conclusions

With the fast development of distributed generators (DGs), the impact of DGs on the UFLS strategy is becoming an issue of concern. Given this background, an optimal UFLS strategy considering DGs and load static characteristics is developed in this work. Based on the frequency and ROCOF, the presented strategy consists of the basic round and the special round. The detailed settings, procedures, mathematical models and methods of the basic round and the special round are systematically investigated. Finally, a modified IEEE 37-node test feeder with four DGs is employed to demonstrate the essential features of the developed optimal UFLS strategy in the MATLAB/SIMULINK environment.

6.   OPTIMAL SITING AND SIZING OF DISTRIBUTED GENERATORS IN DISTRIBUTION SYSTEMS

6.1.   Background

With the progressing exhaustion of fossil energy, the limitation of available transmission corridors and the gradual increase in the global temperature, rapid development of DG has been observed around the world. Although the employment of DGs is helpful for postponing transmission investment, reducing primary energy consumption, decreasing the emission of greenhouse gases (and hence alleviating global warming), the extensive penetration of DGs could lead to some risks to the secure and economic operation of power systems.

Due to the increasing penetration of DGs in distribution systems, the siting and sizing of DGs in distribution-system planning is becoming increasingly important. Inappropriate siting and sizing of DGs could lead to many negative effects on the distribution systems concerned, such as the relay system configurations, voltage profiles and network losses. Another issue is the increasing attention to the applications of plug-in electric vehicles (PEV) (Rahman et al. 1993; Clement et al. 2010; Mitra et al. 2010). However, there are uncertainties that could lead to some risks in determining the optimal siting and sizing of DGs in distribution system planning (Haghifam et al. 2008; Zhu et al. 2006). These include the stochastic output power of a PEV, due to its random charging and discharging schedule (Stasts et al. 1997; Vlachogiannis et al. 2009; Etezadi et al. 2010), that of a wind power unit, due to the frequently variable wind speed, and that of a solar-generation source, due to the stochastic illumination intensity; volatile fuel prices; and future uncertain load-growth. Hence, the optimal siting and sizing of DGs need to be carefully considered in distribution system planning. In this work, for the simplicity of presentation, the load power of a PEV in the charging condition is regarded as the negative output power of the PEV and negative input power to the system concerned. Therefore, the load power of a PEV in both charging and discharging conditions is called the "output power" of the PEV. Moreover, the PEV is regarded as a kind of DG with stochastic output power.

At present, a large number of research papers are available on the subject of the optimal siting and sizing of DGs (Khattam et al. 2005; Wang et al. 2004; Carpinelli et al. 2005; Keane et al. 2005; Kim et al. 2008; Singh et al. 2009; Gautam et al. 2007; Ghosh et al. 2010; Gozel et al. 2009). However, most of these are based on deterministic methods. For example, in 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 minimisation of the network loss as the objective; in Kim et al. (2008), fuzzy goal programming is employed to determine the optimal placement of DGs for loss reduction and voltage improvement in distribution systems. In Ghosh et al. (2010) 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; the modified IEEE 6-bus, IEEE 14-bus and IEEE 30-bus test systems are employed to demonstrate the developed method. In Gozel et al. (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 minimisation of the total power losses as the objective. A new approach is proposed in Elnashar et al. (2010) to optimally determine the locations and sizes of DGs in a large mesh-connected system. Three indexes comprising the losses, voltage profile and short circuit level, are used to determine the optimal locations and sizes of DGs. In these papers, some deterministic mathematical models are employed to formulate the optimal siting and sizing of DGs; generally, the mathematical models obtained are of the m5.9ed-integer nonlinear programming variety, with multiple variables and constraints included.

6.2. The developed method

As previously mentioned, there are some uncertainties associated with the optimal siting and sizing of DGs in distribution system planning. Given this background, under the chance constraint programming (CCP) framework, a new method is presented to handle the risks brought about by these uncertainties in the optimal siting and sizing of DGs. First, a mathematical model of CCP is developed with the minimisation of DGs' investment cost, operating cost and maintenance cost; as well as the network-loss cost as the objective, security limitations as constraints, and the siting and sizing of DGs as optimisation variables. Then, a Monte Carlo simulation-embedded genetic algorithm approach is developed to solve the developed CCP model. Finally, the IEEE 37-node test feeder is employed to verify the feasibility and effectiveness of the developed model and method. Test results have demonstrated that the voltage profile can be significantly improved and the network loss substantially reduced.

The major components of the CCP-based optimal siting and sizing of DGs in distribution system planning are outlined in Figure 29, and the flowchart of the GA-embedded Monte Carlo simulation procedure in Figure 30.

Figure 29: The flowchart of the developed CCP-based method for optimal siting and sizing of DGs in distribution system planning
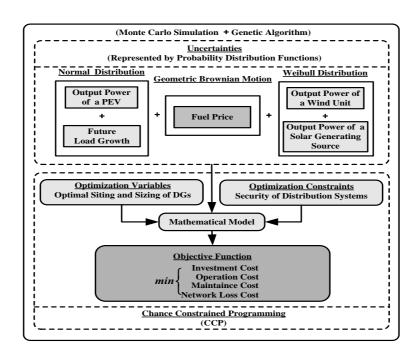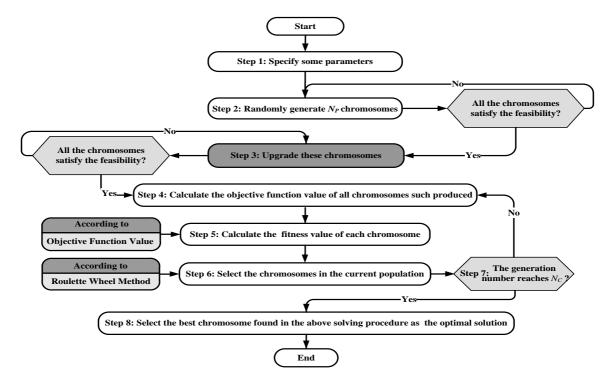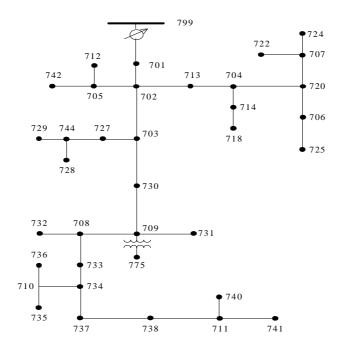
Figure 30: Flowchart of the GA-embedded Monte Carlo simulation procedure

6.3. Case studies

The IEEE 37-node test feeder, as shown in Figure 31, is used for demonstrating the developed model and method. A computer program is developed in the MATLAB 7.0 and Visual C++ 6.0 environment.

Figure 31: The IEEE 37-node test feeder

The parameters associated with the original loads and the probability distributions of the load growth are shown in Table 19 and Table 20 respectively.

The candidate schemes for the types, siting and sizing of DGs are shown in Table 21. In each year of the planning period, the retail electricity price for consumers and on-grid prices for DGs are shown in Table 22. The investment and maintenance costs of PEVs as well as the electricity price adjustment coefficients in the planning period are shown in Table 23. The investment and maintenance costs of renewable DGs and fueled DGs in the planning period are shown in Table 24 and Table 25 respectively.

Table 19: The original loads

Node	$P_{Li}(0)$/(kW)	$Q_{Li}(0)$/(kVar)	Node	$P_{Li}(0)$/(kW)	$Q_{Li}(0)$/(kVar)
701	140.00	70.00	731	0.00	0.00
712	0.00	0.00	732	0.00	0.00
713	0.00	0.00	733	85.00	40.00
714	17.00	8.00	734	0.00	0.00
718	85.00	40.00	735	0.00	0.00
720	0.00	0.00	736	0.00	0.00

722	0.00	0.00	737	140.00	70.00
724	0.00	0.00	738	126.00	62.00
725	0.00	0.00	740	0.00	0.00
727	0.00	0.00	741	0.00	0.00
728	42.00	21.00	742	8.00	4.00
729	42.00	21.00	744	42.00	21.00
730	0.00	0.00			

Table 20: Probability distribution parameters of the load growth

Node	$t = 1$		$t = 2$		$t = 3$	
	$\mu_i(t)$ /(kW)	$\sigma_i(t)$ /(kW)	$\mu_i(t)$ /(kW)	$\sigma_i(t)$ /(kW)	$\mu_i(t)$ /(kW)	$\sigma_i(t)$ /(kW)
701	30.84	6.20	40.14	10.38	47.04	12.08
712	8.38	2.03	10.93	4.60	15.40	6.94
713	6.89	2.62	9.30	3.63	12.37	5.48
714	9.81	4.47	11.56	4.04	14.00	4.51
718	2.93	1.13	3.37	2.57	4.34	2.73
720	6.90	3.32	6.90	3.32	8.739	4.29
722	13.74	4.65	15.82	5.21	17.93	6.00
724	4.63	1.03	4.83	1.90	5.38	2.12
725	5.01	2.00	5.93	2.67	6.02	2.90
727	8.74	3.20	9.14	4.56	10.00	4.80
728	14.87	3.73	15.45	4.74	16.24	4.86
729	3.23	2.42	4.53	3.59	5.75	4.14
730	5.23	1.25	5.60	1.35	6.23	2.33

731	6.32	2.73	7.25	3.07	7.98	3.69
732	5.92	3.21	6.45	4.32	7.93	5.56
733	27.98	14.64	30.10	15.63	32.87	15.71
734	4.34	1.86	4.47	1.98	5.23	2.06
735	4.34	1.86	4.47	1.98	5.23	2.06
736	23.21	10.10	24.27	11.34	25.35	13.21
737	43.73	24.83	44.35	24.96	47.97	27.62
738	30.39	15.83	32.43	16.36	33.64	17.75
740	13.30	5.02	14.07	5.53	15.34	6.48
741	17.62	4.24	17.96	5.01	18.03	5.83
742	25.24	12.23	28.02	14.45	36.38	15.39
744	13.84	2.33	14.57	2.374	18.08	3.72

Note: $\mu_i(t)$ and $\sigma_i(t)$ are the mean value and standard deviation of the load growth at node i, respectively.

Table 21: The candidate schemes for the types, siting and sizing of DGs

Siting of DGs	Sizing of DGs/(kW)	Types*
704	5.00, 10.00, 15.00	1, 2
705	5.00, 10.00, 15.00	1, 2
718	10.00, 15.00, 20.00	1, 2, 3
722	10.00, 15.00, 20.00	1, 2, 3
729	10.00, 15.00, 20.00	1, 2, 3
732	10.00, 20.00, 30.00	1, 2, 3, 4
736	10.00, 20.00, 30.00	1, 2, 3, 4
741	20.00, 30.00, 40.00	1, 2, 4

742	40.00, 50.00, 60.00	1, 2, 4

*Note: 1 = wind generation; 2 = photovoltaic generation; 3= PEV, 4 = fueled DGs

Table 22: The retail prices and on-grid prices in the planning period

Year	Retail prices $C^L(t)\,/(\,\$\cdot\text{kWh}^{-1}\,)$	On-grid prices $C^G(t)\,/(\,\$\cdot\text{kWh}^{-1}\,)$
$t = 1$	0.08	0.06
$t = 2$	0.09	0.07
$t = 3$	0.10	0.08

Table 23: Investment and maintenance costs of a PEV as well as electricity price adjustment coefficients in the planning period

Year	$C^I_{DG_i}(t)\,/$ $(\,\$\cdot\text{kW}^{-1}\,)$	$C^M_{DG_i}(t)\,/$ $(\,\$\cdot\text{kWh}^{-1}\,)$	Electricity price adjustment coefficients for charging		Electricity price adjustment coefficients for discharging	
			$r^C_{DG_i}(t)$ Off-peak periods (23:00-7:00)	$r^{C*}_{DG_i}(t)$ Other periods (7:00-23:00)	$r^D_{DG_i}(t)$ On-peak periods (9:00-11:00, 19:00-23:00)	$r^{D*}_{DG_i}(t)$ Other periods (23:00-9:00, 11:00-19:00)
$t = 1$	1,500.00	0.03	0.75	1.25	1.25	0.75
$t = 2$	1,250.00	0.02	0.80	1.20	1.20	0.80
$t = 3$	1,000.00	0.01	0.85	1.15	1.15	0.85

Table 24: Investment, maintenance and operating costs of renewable DGs in the planning period

Year	Wind generation			Photovoltaic generation		
	$C_{DG_i}^{I}(t)/($ $\$ \cdot \mathrm{kW}^{-1})$	$C_{DG_i}^{M}(t)/(\$ \cdot \mathrm{kWh}^{-1})$	$C_{DG_i}^{O}(t)/(\$ \cdot \mathrm{kWh}^{-1})$	$C_{DG_i}^{I}(t)/(\$ \cdot \mathrm{kW}^{-1})$	$C_{DG_i}^{M}(t)/(\$ \cdot \mathrm{kWh}^{-1})$	$C_{DG_i}^{O}(t)/(\$ \cdot \mathrm{kWh}^{-1})$
$t=1$	1.800.00	0.05	0.00	2.000.00	0.03	0.00
$t=2$	1.650.00	0.04	0.00	1.750.00	0.02	0.00
$t=3$	1.400.00	0.03	0.00	1.650.00	0.01	0.00

Table 25: Investment and maintenance costs of fuelled DGs in the planning period

Year	Fueled DGs	
	$C_{DG_i}^{I}(t)/(\$ \cdot \mathrm{kW}^{-1})$	$C_{DG_i}^{M}(t)/(\$ \cdot \mathrm{kWh}^{-1})$
$t=1$	850.00	0.04
$t=2$	800.00	0.03
$t=3$	760.00	0.02

The optimal siting and sizing of DGs and the cost items in the planning period under the confidence levels of $\alpha = 0.95$ and $\beta = 0.95$ are shown in Table 26 and Table 27 respectively. With the load growth in the planning period, several new DGs are built in this test feeder each year. Moreover, the sizing of each kind of DGs follows an increasing trend as shown in Figure 32.

On the other hand, the network loss ratio has been decreased from 2.71% to 1.56% in the planning period, as shown in Table 5.8, representing a 42.44% reduction, which almost approaches half of the network loss.

Table 26: Optimal siting and sizing of DGs in the planning period
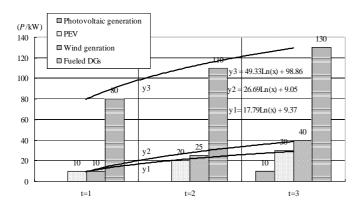
($\alpha = 0.95, \beta = 0.95$)

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

Table 27: Cost items in the planning period
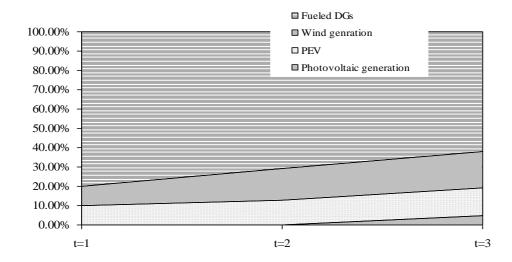
Year	C^I /($)	C^O /($)	C^M /($)	C^L /($)
$t = 1$	101,000.00	55,819.51	19,612.40	8,744.00
$t = 2$	61,250.00	85,479.16	18,804.50	7,870.50
$t = 3$	46,200.00	98,734.57	16,610.15	7,615.00

Figure 32: Optimal sizing of each kind of DGs in each year during the planning period

As shown in Figure 33, the numbers of PEVs and new renewable DGs are increasing more quickly in the planning period compared to fueled DGs. The total costs of PEVs and renewable DGs are gradually declining due to technological development, as shown in Table 23 and Table 24. It can be seen from Table 28 that although the investment and maintenance costs of fueled DGs are also decreasing, the growth of their operating costs caused by the increasing fueled price is much more than those of PEVs and renewable DGs. Therefore, in the long run, the fueled DGs will become less competitive.

Figure 33: The proportion of the annually added capacity of each kind of DGs during the planning period
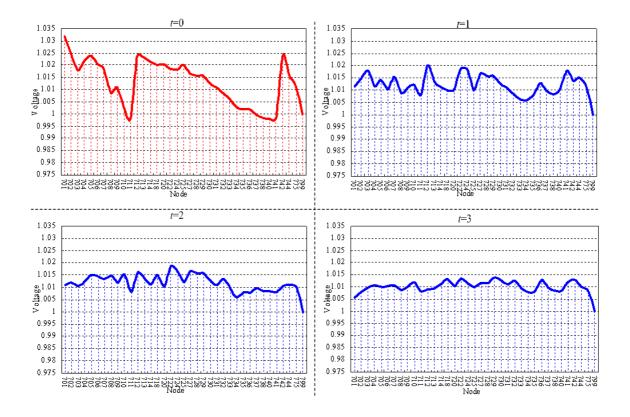
From Figure 34 it can be seen that in each year of the planning period with newly added DGs, the voltage profile at each node of the test feeder has been greatly improved.

The objective of the distribution system planning with DGs considered in this paper is to optimise the siting and sizing of DGs so as to minimize a given objective function, with the load growth constraints, some security constraints and uncertainties well respected. The test results demonstrate that more penetrations of renewable DGs could bring about significant environmental benefits. Moreover, the appropriate siting and sizing of DGs could lead to many advantageous effects on the distribution systems concerned, such as the total costs associated with DGs, network losses, and voltage profiles. Thus, with the ever-increasing deployment of DGs in modern power systems, the siting and sizing of DGs are becoming increasingly important in distribution system planning.

Figure 34 : The voltage variations at each node of the test feeder with added DGs in the planning period

6.4. Conclusions

Under the chance-constrained programming framework, a new mathematical model is developed to handle some uncertainties such as the stochastic output power of a PHEV, of a renewable DG, and of a solar generating source; volatile fuel prices used by a fueled DG; and future uncertain load growth in the optimal siting and sizing of DGs. 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.

7. GENERATION SCHEDULING WITH DISTRIBUTION GENERATORS

7.1. Background

Mitigating emissions of greenhouse gases contributing to global climate change is currently one of the most pressing issues facing the electricity generation sector in industrialised countries. To that end, several continental European countries, most notably Denmark, Germany, and Spain, are increasing the level of penetration of renewable and low carbon electricity generation resources; wind power generation (WPG) is the primary resource of this kind. The United Kingdom, although lagging its continental counterparts, has committed to cover 10% of its electricity demand from renewable resources by 2010 and reach 20% by 2020 (Department of Trade and Industry of UK 2003). In North America, although federal authorities in both the United States and Canada have been less proactive in the reduction of greenhouse gas emissions (Congress of the United States of America 2005; Government of Canada), several state and provincial jurisdictions have taken steps to increase the penetration of WPG and other renewable generation technologies (Bouffard & Galiana 2008).

Wind-power forecasting and associated forecasting accuracy issues are important in analysing the impact of wind power on power-system operations. Several investigations have looked at the prediction of wind speed for use in determining the available wind power. These investigations have been based on foundations such as fuzzy logic, neural networks, and time series (Hetzer et al. 2008). Although many prediction techniques are used to promote prediction accuracy, it cannot be forecasted without any error. Hence, the variation of wind power cannot be neglected.

Current generation scheduling cannot fully integrate the most essential features of non-dispatchable generation technologies like wind power. This limitation is becoming an issue for grid operators, as there is more and more public and political pressure to increase the penetration of renewable generation technologies, which depend on randomly-varying weather conditions. Existing generation scheduling is, however, generally based on deterministic models and usually ignores the likelihood and the potential consequences of the random contingencies. Because of this limitation, this chapter proposes a generation scheduling suitable for fluctuating wind power, which is also applicable to other renewable power generation.

The probabilistic approach is suitable for the modeling and prediction of varying wind power generation. In Carpentier et al. 1996; Samer et al. (1996), scenario trees are developed to solve unit commitment problems when demand is not certain. In (Ummels et al. 2007), a simulation method that was based on wind-speed time series for dealing with volatile wind generation employed the security-constrained economic dispatch algorithm, which was further developed to investigate the impact of wind power on thermal generation unit commitment and dispatch. A stochastic model was introduced in Barth et al. (2006) to evaluate the impact of integrating large amounts of intermittent wind power. However, the approach assumed that the generation unit status was already known. A security-constrained unit commitment algorithm that took the intermittency and volatility of wind power generation into account was presented in Wang et al. (2008). However, the algorithm requires a very high level of computing time and it seems that there is no practical application value for this algorithm.

The stochastic unit commitment problem is usually solved using the deterministic unit commitment algorithms. Due to developments in the past several decades, some solution techniques have

been proposed, such as heuristics, dynamic programming, mixed-integer linear programming (MILP), Lagrangian relaxation (LR), simulated annealing, and evolution-inspired approaches (Carrión & Arroyo 2006). A recent extensive literature survey on unit commitment can be found in Padhy (2004). MILP and LR are the most widely used. However, the benefits of the MIP formulation compared to the LR include: 1) Global optimality; 2) a more accurate measure of optimality; 3) improved modeling of security constraints; and 4) enhanced modeling capabilities and adaptability. Use of the MIP formulation to solve the Unit Commitment problem opens up many opportunities to deal directly with a number of constraints and models that tend to be very difficult to implement with the LR formulation. These include modeling of combined cycle plants, hydro unit commitment, forbidden zones, multi-area and zonal constraints, ancillary service markets, and many more (Streiffert et al. 2005). Hence, the MIP is utilised to solve the proposed optimisation problem.

7.2. Scenario generation and reduction

7.2.1. The wind-power prediction

Wind power depends on weather condition and always fluctuates. Therefore, for the integration of large amounts of wind power into the electricity supply system, it is necessary to predict the electricity generated and demanded for a period from between the next hours ahead to the next days ahead accurately and reliably. For power plant scheduling and electricity trading, the "day-ahead" prediction of demand is used; for grid operation, short-term forecasts are crucial (Pappala et al. 2009). In Yan et al. 2009) the impact of the prediction error of wind power on unit-commitment has been researched. Similar results are illustrated in this chapter.

In Giebel (2003) the use of wind-speed forecast with subsequent conversion to power offers no advantage over direct wind power prediction. It is found that two-stage modeling (conversion of wind-speed predictions to wind power in which correlation structure in power measurements is disregarded) is inferior to models that take the power correlation into account (Giebel 2003). Thus, using direct wind-power prediction might be more advantageous as it leads to higher forecast accuracy. Moreover, the level of error would be notably lower if we were considering an aggregation of wind farms, or a complete region, thanks to smoothing effects (Focken et al. 2001).
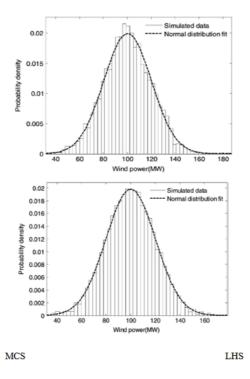
The autoregressive moving average ARMA approach is selected here because it is a powerful, well-known time-series technique and has been used by the California Independent System Operator in some of its forecasting work (Milligan et al. 2003). Interested readers can consult Box and Jenkins (1976) for details.

7.2.2. The sampling technology

The well-established Monte Carlo method usually generates a large number of scenarios subject to a normal distribution as well as other distributions. Due to the large number of samples typically required, Monte Carlo simulation and optimisation is often time-consuming. There have been several efforts to reduce the number of samples required. One popular method is Latin Hypercube sampling, which was initially proposed by (Mckay et al., 1979). The improvement offered by LHS over Monte Carlo can be easily demonstrated. Figure 35 compares the results obtained by sampling from a normal distribution $N \sim (100,100)$ with LHS and Monte Carlo sampling (Wang et al. 2008). Both simulations are conducted for 3000 samples. As shown in Figure 35, LHS can approximate the required normal distribution much better than the simple Monte Carlo method (Wang et al. 2008). It should be noted that LHS yields a stratified sample of the data, so the variance of a sample from this technique is considered smaller than that from MC (Jirutitijaroen

and Singh, 2008).

Figure 35: The normal distribution fit by simple MCS and LHS

MCS   LHS
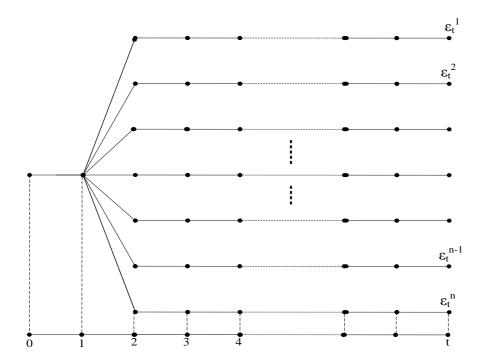
7.2.3. The scenario generation

Each scenario is assigned a probability, that is, one divided by the number of generated scenarios. In each scenario an hourly random wind-power generation based on the forecasted wind-power generation is considered. Kaut and Wallace (2007) listed different scenario generation and reduction algorithms. In Domenica et al. (2007) the general steps to generate scenarios can be found. The definition, goals, methods of scenario generation and measuring quality of scenario trees are introduced in Kaut (2006).

As the focus of this chapter is not on the wind-power forecasting, a wind-power forecast is assumed available and ARMA(1,1) model for wind-power forecast error developed, which is used to predict wind speed in Söder (2004).

The white noise is generated by LHS, and the set of wind power forecast error scenarios can be generated by the ARMA(1,1) model. A scenario fan is generated based on this model, and the process is shown in Figure 36.

Figure 36: The schematic depiction of the generation of a scenario fan

7.2.4. The scenario reduction

The total number of scenarios has a double exponential dependency in the sense that a model with m stages, and n scenarios at each stage, leads to a model with a total of n^m scenarios. Due to the computational complexity, it is necessary to reduce the scenarios such that its stochastic properties are not changed significantly. There are two main methods to reduce scenarios, namely moment-matching (Hoyland & Wallace 2001; Hoyland et al. 2003) and scenario reduction (Gröwe-kuska et al. 2003; Römisch & Heitsch, 2003; Dupačová 2003). If the model demands small scenario tree sizes, moment matching leads to better results; while for larger tree sizes, scenario reduction is more promising (Hasche, 2008).

In view of the computing expense of large-scale UC formulation, the scenario size must be very small. Hence, moment-matching is used to reduce scenarios. Moment-matching is based on the following parameters: mean values, standard deviations, skewness and kurtosis.

These four moments are examined for each scenario. If the four moments of a scenario match the corresponding four moments for the historical data, the scenario is accepted as a valid scenario; otherwise, it is deleted. In this way the collection of all generated scenarios can be reduced to a practical manageable size (Zhou et al. 2009).

7.3. Generation scheduling with wind power

Assume that the wind power is dispatched, no matter how much and when the wind power is generated; in this chapter the variance of demand prediction is not taken into account.

There are two methods to incorporate the wind power into unit commitment. One method is to take into account the wind power as a constant; that is, the wind power can be forecasted without errors. The second method one is the stochastic approach. The two strategies are presented as follows. Uncertainties are observed in wind-power generation and a stochastic approach is most suitable for the modelling of generation. It is natural to apply a stochastic approach to a deterministic problem in the solution process.
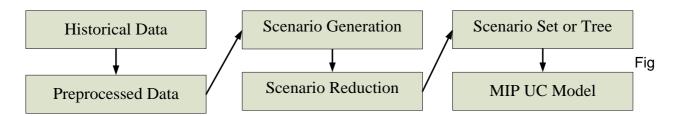
7.3.1. The deterministic model

The wind power is taken as a constant in this strategy. In this case, the only difference from the traditional UC model is the power balance constraints.

7.3.2. The stochastic model

Figure 37 shows the framework of the stochastic unit commitment. Historical data is used to estimate the parameters in the ARMA model and it is the so called pre-processed process. Scenarios generated by the ARMA approach and LHS introduced in section III and scenario reduction technology are also used to reduce the scenario number with the consideration of the computing complexity. Integrating the scenario data to MIP UC model is a key step in optimizing the solution, because the solution must satisfy all the constraints involving any scenario data.

Figure 37: The framework of the stochastic unit commitment

Fig

7.4. Case studies

A 10-unit system and a 100-unit system are used for testing the proposed algorithm considering the uncertainty of wind power generation. The impact of large-scale integration of wind power to power system is analysed based on economic indices such as operation costs and system security.

Table 28: System data 1

Units	Pmax (MW)	Pmin (MW)	Ton (h)	Toff (h)	IniState (h)
1	455	150	8	8	8
2	455	150	8	8	8
3	130	20	5	5	-5
4	130	20	5	5	-5
5	162	25	6	6	-6
6	80	20	3	3	-3
7	85	25	3	3	-3
8	55	10	1	1	-1
9	55	10	1	1	-1
10	55	10	1	1	-1

7.4.1. 6.4.1 The 10-unit system

In this study, a 10-generator system was used for test purposes. The data of the 10-unit system of Barth et al. (2006) is provided in Tables 27–29. Without the consideration of transmission constraints, a single wind unit can represent all the wind generators, and the forecasted wind power is shown in Table 6.3. A spinning reserve requirement of 10% of the load demand has to be met in each of the 24 hourly periods in which the time span is divided. The ramping of all non-wind units is assumed the same at180 MW/hour.

Table 29 :System data 2

Units	a($/h)	b($/MWh)	c($/MW^{2}h)	hc($/h)	cc($/h)	t_{cold}(h)
1	1000	16.19	0.00048	4500	9000	5
2	970	17.26	0.00031	5000	10000	5
3	700	16.6	0.00200	550	1100	4
4	680	16.5	0.00211	560	1120	4
5	450	19.7	0.00398	900	1800	4
6	370	22.26	0.00712	170	340	2
7	480	27.74	0.00079	260	520	2
8	660	25.92	0.00413	30	60	0
9	665	27.27	0.00222	30	60	0
10	670	27.79	0.00173	30	60	0

Table 30: System data 3

Hr	Load (MW)	$P^{w,f}$ (MW)	Hr	Load (MW)	$P^{w,f}$ (MW)
1	700	190	13	1400	390
2	750	300	14	1300	340
3	850	330	15	1200	320
4	950	360	16	1050	120
5	1000	350	17	1000	10
6	1100	370	18	1100	40
7	1150	440	19	1200	50
8	1200	460	20	1400	20

9	1300	350	21	1300	5
10	1400	250	22	1100	250
11	1450	420	23	900	350
12	1500	380	24	800	240

The model has been implemented on a PC with the AMD sempron 2800+ and 512 MB of RAM memory using CPLEX 10.1 to solve the proposed formulation.

Table 31: Generation scheduling with forecasted wind power

Hour	Units									
	1	2	3	4	5	6	7	8	9	10
1	180	150	69	86	25	0	0	0	0	0
2	235	150	20	20	25	0	0	0	0	0
3	305	150	20	20	25	0	0	0	0	0
4	375	150	20	20	25	0	0	0	0	0
5	432	153	20	20	25	0	0	0	0	0
6	449.67	208	20	27.333	25	0	0	0	0	0
7	382	263	20	20	25	0	0	0	0	0
8	455	208	20	32	25	0	0	0	0	0
9	455	263	71.333	90.667	25	20	25	0	0	0
10	455	355	130	130	25	20	25	10	0	0
11	455	263	100.67	121.33	25	20	25	10	10	0
12	455	305	130	130	25	20	25	10	10	10
13	455	258	89	108	25	20	25	10	10	10
14	455	243	81.333	100.67	25	20	25	10	0	0
15	455	150	107.33	122.67	25	20	0	0	0	0

16	455	190	130	130	25	0	0	0	0	0
17	455	250	130	130	25	0	0	0	0	0
18	455	320	130	130	25	0	0	0	0	0
19	455	410	130	130	25	0	0	0	0	0
20	455	455	130	130	155	20	25	10	0	0
21	455	455	130	130	70	20	25	10	0	0
22	455	285	20	20	25	20	25	0	0	0
23	340	165	0	0	25	20	0	0	0	0
24	390	150	0	0	0	20	0	0	0	0

7.4.2. The deterministic model

In this case, wind power is assumed to be forecasted without error. Hence, this is equivalent to the situation where the actual load demand subtracts a certain amount of wind power. The results are given in Table 32. The cheapest, unit 1 and unit 2 are committed during this decision period without any doubt. Unit 5 is also very cheap and not committed in the last hour. Unit 3 and Unit 4 are both committed between hour 1 and hour 23. Units 8–10 are the most expensive units, so they are committed only for a few hours. The total operation cost is $470,586.04. The model contains 9845 constraints, 5041 variables, 240 binary variables and the solving time is 2.09 seconds.

7.4.3. The stochastic model

In this case it is supposed that the white noise process of ARMA(1,1) model proposed obeys a normal distribution with the standard deviation of 10%. According to scenario reduction technology, 1000 scenarios are generated for each hourly wind power by LHS introduced before. Only 10 scenarios remain after moment matching, as shown in Table 33.

The results are given in Table 34. According to Table 35 and Table 36, the generation scheduling results of most non-wind units remain steady. The outputs of non-wind units, which are different from those of the deterministic model, are marked in shadow.

Table 32: Scenarios generated

Hr	Wind power scenarios									
	1	2	3	4	5	6	7	8	9	10
1	182.07	167.39	206.13	197.64	175.03	203.44	160.13	215.57	188.35	190.91
2	315.78	286.13	341.13	329.1	281.87	313.69	269.84	303.03	252.85	294.19
3	329.79	361.58	332.04	288.57	343.73	286.63	318.39	379.77	350.21	311.83
4	369.61	322.15	274.8	366.26	333.11	385.62	408.29	359.38	348.39	395.44
5	402.17	371.06	341.74	288.12	382.87	324.87	357.33	316.98	360.58	337.42
6	354.13	315.78	323.39	394.07	418.13	344.88	371.26	387.04	367.74	402.5
7	466.84	403.36	395.15	454.12	443.66	382.86	488.53	439.09	550.32	419.91
8	464.3	382.94	421.46	480.2	514.5	441.41	537.2	414.4	498.27	456.06
9	305.61	405.11	370.71	324.98	334.28	392.02	355.15	367.66	342.18	275.63
10	248.02	192.02	238.63	255.35	258.19	264.26	230.83	217.99	275	294.95
11	494.84	384.84	457.07	439.81	380.84	417.4	407.46	450.56	426.27	345.28
12	361.18	337.57	388.34	318.47	400.28	375.24	446.66	389.74	415.25	348.25
13	334.15	350.13	422.33	426.64	359.23	453.53	398.44	402.15	385.62	378.44
14	346.37	351.02	330.85	294.13	387.44	317.48	369.74	358.85	308.79	332.49
15	300.9	350.7	337.1	332.9	310.4	316.8	367.9	324.1	270.7	285.95

	9	3	5	7	4	1	3	4	1	
16	121.54	116.48	106.76	96.936	119.99	130.49	138.06	129.89	112.09	125.73
17	9.6226	10.044	7.8299	11.302	10.579	11.143	9.9483	10.271	9.3587	9.1359
18	36.571	52.929	39.175	37.999	36.989	34.369	44.632	42.215	41.235	40.825
19	55.17	52.535	61.054	43.528	43.947	53.195	49.574	50.394	47.06	48.431
20	18.687	19.318	21.5	20.123	19.791	20.532	15.728	21.759	18.127	23.249
21	4.8292	5.3131	4.6791	6.1619	5.0676	4.93	5.2196	5.4909	4.4765	4.2588
22	259.88	249.17	200.52	280.2	233.68	250.88	291.94	268.58	228.37	239.3
23	353.25	382.96	332.1	412.56	367.66	322.17	298.49	312.91	343.09	378.59
24	229.88	227.13	270.43	275.03	240.69	210.08	234.39	247.61	257.13	188.88

The total operation cost increases 0.01% to $470,633.3167. The simulation results show that the expected schedule cost under stochastic programming is generally more than that under the deterministic model. The difference in operating costs between the stochastic model and the deterministic model ($470,633.3167–$470,586.0391 = $47.2776) is the cost of maintaining the system security when considering the variation of wind power. Compared with the security of the system, the extra cost is insignificant, since the cost can be easily compensated for by the benefit brought by the security of system and policy inclination. The stochastic model contains 19,685 constraints, 7441 variables, 240 binary variables and the solving time is 5.8 seconds.

Table 33: Generation Scheduling with Varying Wind Power

Hour	Units									
	1	2	3	4	5	6	7	8	9	10
1	180	150	69	86	25	0	0	0	0	0
2	223.87	150	20	31.13	25	0	0	0	0	0
3	285.23	150	20	39.77	25	0	0	0	0	0
4	356.71	150	20	38.29	25	0	0	0	0	0
5	412.83	153	20	39.17	25	0	0	0	0	0
6	449.67	208	20	27.333	25	0	0	0	0	0
7	331.68	263	40.32	50	25	0	0	0	0	0
8	449.8	208	20	37.2	25	0	0	0	0	0
9	455	263	71.333	90.667	25	20	25	0	0	0
10	455	355	130	130	25	20	25	10	0	0
11	455	263	100.67	121.33	25	20	25	10	10	0
12	455	305	130	130	25	20	25	10	10	10
13	455	258	89	108	25	20	25	10	10	10
14	455	243	81.333	100.67	25	20	25	10	0	0
15	455	150	107.33	122.67	25	20	0	0	0	0
16	455	190	130	130	25	0	0	0	0	0
17	455	250	130	130	25	0	0	0	0	0
18	455	320	130	130	25	0	0	0	0	0
19	455	410	130	130	25	0	0	0	0	0
20	455	455	130	130	155	20	25	10	0	0
21	455	455	130	130	70	20	25	10	0	0

22	455	285	20	20	25	20	25	0	0	0
23	322.44	180	0	0	25	22.56	0	0	0	0
24	384.97	155.03	0	0	0	20	0	0	0	0

7.4.4. *Ramping Capabilities of Non-Wind Units and the Prediction Error of Wind Power*

To show the impact of precision of wind power prediction, the standard deviation is increased from 5% to 35% of the forecasted value with the ten-minutes ramping rate of non-wind units of 30MW/10-minute, with the results are shown in Table 34. The security cost is defined as the difference between the operation cost with predicted wind power and that with variable wind power. The security cost in the fourth column reflects the cost of maintaining the security of the system when the wind power is uncertain. As shown in the table, the more accurate the prediction level is, the more security cost needs to be paid.

The ramping requirements of non-wind units are strongly associated with the prediction errors of wind power. The results of increasing the ten-minutes ramping rate of non-wind units from 30 MW/10-minute to 50 MW/10-minute are shown in Table 35. The tolerance range of the volatility of wind power expands as the ramping capabilities increase, vice versa. Owing to the faster ramping, the standard deviation of forecasted wind power is allowable to be 30%. Another benefit of faster ramping is that the cost to maintain the system in a secure and reliable state decreases.

Table 34: The Impact of Prediction Errors

Standard Deviation	Feasible/ Infeasible	Operation Cost ($)	Security Cost ($)
0	feasible	470586.0391	0
5%	feasible	470589.3508	3.3117
10%	feasible	470633.3167	47.2776
15%	feasible	471859.8933	1273.854
20%	feasible	482084.2494	11498.21
25%	feasible	486160.5988	15574.56
30%	Infeasible	/	/
35%	Infeasible	/	/

Table 35: The impact of ramping on prediction errors

Standard Deviation	Feasible/ Infeasible	Operation Cost ($)	Security Cost ($)
0	feasible	470586.0391	0
5%	feasible	470586.1657	0.1266
10%	feasible	470633.3167	47.2776
15%	feasible	470643.4630	57.4239
20%	feasible	474885.6065	4299.567
25%	feasible	475380.9308	4794.892
30%	Infeasible		
35%	Infeasible	/	/

7.4.5. *Wind power as spinning reserve resource*

Usually, wind power is not considered as a resource to supply spinning reserve, so spinning reserve in a power system is given by traditional coal or water power. With the development of wind-power prediction technology and the increase of wind power installed capacity, it is necessary to consider wind power for offering certain spinning reserve share. Given this condition, wind power is looked upon as reliable power, which can give electrical assistance to satisfy the demand in order to keep power system stable.

Table 36: Total operating costs under different spinning reserve constrains

	Non-Wind spinning reserve ($)	Wind spinning reserve ($)
The deterministic model	470,586.0391	427,893.6444
The stochastic model	470633.3167	431076.5314

Table 36 shows the total operation cost under different spinning reserve constraints. It is obvious that the total operation cost decreases when wind power is considered a spinning reserve source. Similar to case 1, case 2 and case 3, security cost also need to be paid due to the volatility of wind power.

7.4.6. The 100-unit system

The 100-unit system is generated by replicating the above 10-unit system 10 times. A spinning reserve requirement of 10% of the load demand has to be met in each of the 24 hourly periods. The total installed wind power capacity is 10 times as large as that in the former system. In CPLEX, an optimality parameter can be specified to decide whether to find the optimal solution or to quickly obtain a suboptimal solution. In this case study, the execution of CPLEX was stopped when the value of the objective function was within 0.5% of the optimal solution (Carrión & Arroyo, 2006).

7.5. Conclusions

A stochastic optimisation approach is proposed for the unit commitment problem considering the uncertainty of wind-power generation, based on the mixed-integer linear programming (MILP). The problem is formulated as minimising the total cost of thermal units. To consider wind power generation, scenarios are generated using scenario-generation techniques. The stochastic problem is hence transformed to a deterministic one.

Since LHS produces a stratified sample of the data, the variance of samples from LHS is smaller than that from simple Monte Carlo sampling. Time series model ARMA generates a fan with the white noise process that is implemented by LHS. In order to tackle the problem of huge number of scenarios, scenario-reduction technology is introduced. The MILP-UC algorithm developed is efficient, and a scenario-reduction technology allows for the exploration of a practical algorithm for considering varying wind power generation.

A 10-unit system and 100-unit system are employed for demonstrating the proposed model and method. It is shown by simulation results that the expected scheduling cost by using stochastic programming is generally more than that by using the deterministic model. This is because the stochastic model takes into account the situation that the thermal units cannot meet the prediction error in time caused by the variation of wind power. Hence, the ramping capabilities of units and prediction accuracy of wind power are crucial when wind power varies.

8. RISK CONTROL IN TRANSMISSION-SYSTEM PLANNING WITH WIND GENERATORS

8.1. Background

Wind-power generation is drawing more attention than ever due to the urgent need for environmental protection and the continuous development of new technologies. For example, China, a country with abundant wind power resources, has experienced rapid development in recent years in terms of exploiting wind energy for power generation. A large number of wind-power bases with capacities of 10,000MW have been planned and constructed, and it is expected that increasing numbers of large-scale wind farms will be connected to China's power grids.

Although wind power is clean and renewable, wind farms can bring about significant unfavourable impacts on power systems due to their stochastic, intermittent and uncontrollable characteristics. With the expansion of wind-power generation, and thus the increasing quota of wind energy in power systems, these adverse influences could become technical barriers to wind-power integration, resulting in new challenges to transmission system planning (TSP) and operation (Salehi-Dobakhshari & Fotuhi-Firuzabad 1996; Sayas & Allan 1996). To address these challenges, new approaches should be applied in TSP to facilitate the integration of wind energy, through increasing the power system's ability to defend against the influence.

Until now, research on TSP that includes large-scale wind farms is still at its early stage. When taking into account the uncertainties associated with wind-power generation, existing methods only evaluate the system reliability and various investment schemes (Billinton and Wangdee, 2007). A chance-constrained method was proposed to resolve the uncertainties of transmission system expansion planning with wind generators. Nevertheless, the cost of computation using the convolution integral to calculate the probabilistic power flow was heavy. Accuracy of the model was also not assured, due to the assumption of the normal distribution of wind power generation. Furthermore, the "N-1" reliability constraint was not considered in the planning model (Yu et al. 2009). A flexible planning method based on multi-scenario probability was proposed in (Yuan et al. 2009) to match the transmission system which contains large-scale wind farms. With this method, however, the simulation for the operation of a wind farm was performed only using the rating power or the zero power of wind generators, and is hence unable to accurately describe the actual wind power generation.

8.2. The developed method

To overcome the shortcomings discussed above, this chapter presents a probabilistic model for the power output of wind generators. The DC probabilistic power flow is calculated with the combined use of cumulants and Gram-Charlier series. Three risk-controlling strategies are then introduced to enhance the system defence against security risks in allusion to the uncertain factors in TSP; they are: probability of not violating each branch power flow limit (PBL), probability of not violating system power flow limit (PSL), and probability for the security margin of system power flow (PSM).

Based on the above work, a TSP model with risk-controlling strategies is developed for power system containing wind generators. A cost-benefit method is utilised to evaluate the planning schemes in order to maximise the overall benefit.

8.3. Case study

The feasibility and effectiveness of the proposed TSP model is illustrated in the case study using two typical test systems: an 18-bus system and a 46-bus system, shown in Figures A1 and B1, and in Appendices A and B. The parameters of the two test systems are listed in Tables A1 and A2 and in Tables B1 and B2, and are also included in the appendix. The load and the power generation of the two study systems are assumed to follow the normal distribution. The mean values of the power generation and the load are assumed to be equal to the expected values and the standard deviation equal to 4% of the mean values. These assumptions describe the uncertainties of the power generation and load demands.

Suppose that the investment cost of each line is 1.0 million RMB Yuan/km, the outage rate per unit length per year is 0.05 times/km for each line, and that the fixing rate of the line is 9.13×10^{-4} year per line for each repair. The lower limit $\underline{r_l}$ of the probability for not violating the branch power flow limit is set as 0.7. Both the base mode and the "N-1" operation status are investigated in the case study.

8.3.1. The 18-bus system

Currently the power system contains 10 nodes and nine lines as shown in Figure 7.1 In future, the system is planned to expand to 18 nodes, composing seven generator nodes and 17 load nodes. With the added generator nodes 11,14,16 and 18, the total load capacity will reach 35,870 MW. The capacity of generators and loads are listed in Table A1, and the data for all branches are listed in Table A2. Suppose that the wind generators are connected to node 2 and their capacity is about 10% of that of the system.

a) Analysis of planning results

The computation time of the planning is 2 minutes and 25 seconds on a PC with Intel Core i3 CPU. Three optimal schemes are obtained as listed in Table 37, where the numbers enclosed by parentheses in the second column denote the numbers of the candidate lines. For example, 1-2(2) means two extra lines are to be added to the right-of-way of Line 1-2

Table 37: Comparisons of the three planning schemes for the 18-bus system

Scheme	Added candidate lines	Investment cost (10^6 RMB Yuan)	R	R/C ($\times 10^{-6}$)
A	1-2 (2), 1-11 (2), 4-16 (1), 5-11 (1), 5-12 (1), 6-13 (1), 6-14 (3),7-8 (2), 7-9 (1), 7-13 (2), 8-9 (3), 9-10 (3), 9-16 (2), 10-18 (2), 11-12 (1), 11-13 (1), 12-13 (1), 14-15 (3), 16-17 (1), 17-18 (4)	389600.00	1.1510	2.9543
B	1-2 (2), 1-11 (2), 2-3 (1), 3-4 (1), 4-16 (2), 5-12 (2), 6-13 (1), 6-14 (3), 7-8 (2), 7-9 (1), 7-13 (1), 8-9 (2), 9-10 (4), 9-16 (1), 10-18 (1), 11-12 (1), 11-13 (1), 14-15 (3), 16-17 (2), 17-18 (3)	412400.00	1.1678	2.8317
C	1-2 (2), 1-11 (2), 4-16 (1), 5-12 (1), 6-13 (2), 6-14 (3), 7-8 (2), 7-9 (1), 7-13 (2), 8-9 (3), 9-10 (3), 9-16 (2), 10-18 (2), 11-12 (1), 11-13 (1), 12-13 (1), 14-15 (3), 16-17 (1), 17-18 (3)	383100.00	1.0755	2.8074

Table 37 shows that the investment cost of scheme A is 1.70% more than that of scheme C, while the security risk index R of the former is 7.02% more than that of the latter. Therefore, the cost-benefit index R/C of scheme A is higher than that of scheme C. The investment cost of scheme B is the highest among the three. Compared with scheme A, the investment of scheme B is 5.85% higher, whereas its security risk index is only improved by 1.46%. The higher investment cost of scheme B does not lead to the expected level of security and reliability. In light of the above comparisons, scheme A appears to be the optimal one due to its highest cost-benefit index and the best composite beneficial results.

To further verify the validity of the security risk index, the mean power values of generators and loads are increased by 7%. The performance of the above three schemes are assessed and compared again. The PABL of the three schemes are 78.75%, 77.87 % and 68.92% respectively. Obviously, the lower limit of PABL in scheme C is violated due to its weak security risk index. As a consequence, even a small load fluctuation can cause the system employing scheme C to violate the security/reliability requirements. On the contrary, the higher security risk indexes of schemes A and B can protect the system against the security risk.

b) Performance comparison with conventional optimal planning schemes

To verify the feasibility of the proposed TSP model, scheme A is compared with scheme D, based on the investment minimisation model. The comparison is shown in Table 38, where the minimum PBL represents the highest risk of violating the branch power flow limit.

Table 38: Comparisons of the optimal planning schemes using the developed model and the investment minimisation model for the 18-bus system

Scheme	Added candidate lines	Investment cost (10^6 RMB Yuan)	Minimum PBL
A	1-2 (2), 1-11 (2), 4-16 (1), 5-11 (1), 5-12 (1), 6-13 (1), 6-14 (3),7-8 (2), 7-9 (1), 7-13 (2), 8-9 (3), 9-10 (3), 9-16 (2), 10-18 (2), 11-12 (1), 11-13 (1), 12-13 (1), 14-15 (3), 16-17 (1), 17-18 (4)	389600.00	0.8797
D	1-2 (2), 1-11 (2), 4-16 (1), 5-12 (1), 6-14 (2), 7-8 (2), 7-13 (2), 7-15 (1), 8-9 (2), 9-10 (3), 10-18 (1), 11-12 (1), 14-15 (2), 16-17 (2), 17-18 (1)	257300.00	0.2616

As shown in Table 38, the minimum PBL of scheme D is only 0.2616, far less than the required lower limit (0.70). Compared with scheme A, scheme D is much less capable of defending against the security risk due to neglect of the uncertainties, in spite of its lower investment cost.

c) Power flow analysis with different wind farm characteristics

To analyse the influence of characteristics of wind farms on the system power flow, five parameters reflecting the characteristics of wind farms are adjusted respectively, with each parameter varying in the range of $\pm 20\%$. The parameter adjustment and the influence to scheme A are shown in Table 39.

Table 39: The probability of not violating branch power flow limits

Characteristics of wind farm		Minimum PBL	
Parameter	Adjust range	Variation	Change range
v_{ci}	-20%～20%	0.9071～0.8507	3.12%～-3.29%

It is observed that the influence of parameter v_{ci}, c and k on power flow is significantly greater than that of the other two parameters. According to Table 3, the PBL only fluctuates slightly, and still meets the specified requirement when the characteristics of wind farms change significantly, demonstrating the robust performance of the developed model.

8.3.2. The 46-bus system

To further verify the feasibility and effectiveness of the proposed model, a 46-bus system is adopted in the simulation of the developed model and the investment minimisation model. The test system represents the southern part of the Brazilian interconnected network, which has 35 nodes and 62 rights-of-ways, as shown in Figure B1. The system is planned to expand to 46 nodes, including 12 generator nodes and 19 load nodes. With the added generator nodes 16, 28 and 31, the total load capacity will reach 6880.00MW. The capacity of generators and loads are listed in Table B1, and the data for all branches are listed in Table B2. More detailed data and further explanations for the original system are available in [ROMERO, R., MONTICELLI, A., GARCIA, A., et al. (2002)]. Assume that only wind generators are connected to node 17 and node 34, and that the capacity of wind-power generation is about 17.7% of the total capacity of the system. Other characteristics of the wind farm are all similar to that of the 18-bus system. The genetic algorithm is adopted and the computing time is 23 minutes and 43 seconds with the same PC. The planning results are shown in Table 7.4.

Table 40: Comparisons of the optimal planning schemes using the developed model and the investment minimisation model for the 46-bus system

Scheme	Added candidate lines	Investment cost (10^3 dollar)	Minimum PBL
E	12-14 (2), 19-21 (1), 17-19 (1), 14-22 (1), 22-26 (1), 24-33 (1), 37-39 (1), 32-43 (1), 42-44 (1), 44-45 (1), 20-21 (3), 42-43 (3), 14-15 (3), 46-10 (1), 05-11 (3), 46-06 (1), 46-03 (1), 21-25 (1), 25-32 (1), 31-32 (2), 28-31 (1), 28-30 (1), 26-29 (1), 28-41 (1), 46-11 (1), 24-25 (3), 29-30 (1), 40-41 (1), 02-03 (1), 05-06 (1), 09-10 (1)	462920.00	0.9659
F	12-14 (1), 19-21 (1), 17-19 (1), 14-22 (1), 20-21 (2), 42-43 (3), 14-15 (2), 46-10 (1), 05-11 (2), 46-06 (1), 46-03 (1), 21-25 (1), 25-32 (1), 31-32 (1), 28-31 (1), 28-30 (1), 26-29 (1), 28-43 (1), 31-41 (1), 40-45 (1), 46-11 (1), 24-25 (3), 29-30 (1), 40-41 (1), 02-03 (1), 05-06 (1), 09-10 (1)	414625.00	0.2526

Scheme E and scheme F are the optimal planning schemes obtained using the developed model and the investment minimisation model. It is observed from the table that the investment cost of scheme E is 11.6% higher than that of scheme F, whereas the minimum PBL of the former is 280% higher than that of the latter. Again, the proposed method is much more cost-effective compared with its conventional counterparts. As aforementioned, the low cost of the conventional methods is due to their negligence of the uncertainties and lack of risk-controlling strategies.

8.4. Conclusions

This chapter presents a probability model to simulate the uncertainties associated with the power output of wind generators integrated into a power system. The probability distribution of the branching power flow is obtained by the combined use of cumulants and Gram-Charlier series. This analytical approach has the advantages of low computation cost, efficiency and flexibility.

The two case studies demonstrate that it is possible to achieve a good trade-off among the security, reliability and economics of TSP schemes by employing risk-controlling strategies. Consequently, the security risks of a system associated with the uncertainties due to wind generators can be controlled using the developed TSP model.

9. SIZING THE DISTRIBUTED GENERATION WITH LIFE-CYCLE COSTING AND GREENHOUSE-GAS ABATEMENT EFFECTS

9.1. Background

The assessment techniques and DG technologies are significantly advancing with the increase in large-scale and dispersed integration of DG. This evokes the need of a generic network that can be used as a common platform to assess the performance of techniques and DG technologies. It also provides researchers with the platform for comparing alternative methods, and further advances the solutions.

There are distribution networks that are well designed to absorb additional capacity of DG. These networks do not exhibit how the hidden facts that operate can reverse the positive arguments of DG. One must see research problems within a problem in order to understand and investigate solutions. In that context, use of robust distribution network models may not be always the correct platform to assess the merits of DG. On the other hand, there are networks that inherit serious operating issues. They are either not suitable for the assessment of DG technologies or assessment techniques; this is because they may give pessimistic conclusions due to the unusual weakness of the network. Therefore, it is obvious that the correct balance is necessary in order to test any technique or technologies; the reason being that if the assessment platform is significantly off from majority of distribution networks, the research conclusion of the investigation may not be a fair conclusion for DG techniques and their benefits to distribution networks.

The above facts demonstrate the need for a network that can fairly assess the characteristics of DG technologies and performance of techniques that are aimed at assessing the benefits of DG. Therefore, this report proposes a test network that is designed based on the concepts of realistic distribution networks. The network is stable under normal operating conditions and without the presence of DG.

Modern distribution networks operate with DG of which the wind and PV (Alderfer et al., 2000) can be primary technologies. With the recent developments, they share a considerable amount of loads compared with other DG technologies that may exist in a typical distribution network. The output of some of the renewable power generation technologies, including wind and PV, varies throughout the year; however, their output can be dispatched with the support of energy-storage technologies. The optimum, efficient and economical operation of renewable and new-generation technologies requires the use of smart devices that enable the smart coordination of DGs. Such an arrangement would reduce the use of fossil-fuelled DGs, such as diesel units; that is, they may able to operate only when they are economical in the operating cycle.

There are algorithms in the published literature for investigating optimal generating unit combinations; however, they are mostly confined to single bus systems where the hybrid generation technologies are connected. The optimal planning algorithm requires determining the type of generating technology to use and the machine ratings that will satisfy the demand, and how to operate the system at minimum cost under constrained operating conditions (Inglis et al. 2010; Pan et al. 2009). The literature suggests there are three main types of algorithms that can be used to solve a planning problem: constructive heuristic algorithms, conventional optimisation algorithms and combinatorial algorithms (Romero et al. 1996; Gallego et al. 1998; Lavorato et al. 2009). They further highlight that the utilisation of robust and efficient linear programming algorithms are vital parts in realising the tasks within the problem. Heuristic and conventional optimisation algorithms,
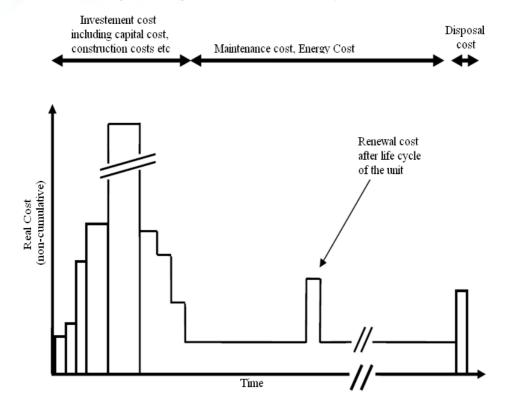
as presented in Garver (1970), are used to solve the linear programming (LP) problems associated with the optimisation. The LP algorithm provides a less-complex method to formulate the problem, and ensures fast and efficient solutions to the problem with large systems.

The LP algorithms consider all the specific characteristics of the problem, and they incorporate various constraints associated with the optimal planning of the electrical system and its auxiliaries.

The determination of costs is an integral part of the feasibility study and design of any power system. In the past, comparisons of different generation technology alternatives, whether at the conceptual or detailed design stage, was based mainly on initial capital costs. In order to achieve better outcomes from assets, ongoing operation and maintenance costs must be considered, as they consume more resources over the asset's service life cycle. Life-cycle costing (LCC) is a process to determine the sum of all the costs associated with an asset or part thereof, including acquisition, installation, operation and maintenance, refurbishment, and disposal costs.

LCC adds together all the costs of alternatives over their life period and enables an evaluation on a common basis for the period of interest, usually using discounted costs considering inflation. This enables decisions on acquisition, maintenance, refurbishment and disposal to be made in light of full cost implications. LCC can be calculated during any or all phases of an asset's life cycle. It can provide input to decisions regarding asset design, manufacture states, installation, operation, support and disposal. Early identification of acquisition and ownership costs enables the decision-maker to balance performance, reliability, maintainability, maintenance support and other goals against life-cycle cost. Figure 38 shows an example of LCC of a generating unit.

Figure 38: LCC phases of a generating unit (modified from Taylor 2003)

One of the environmentally hazardous outputs of conventional power generating units is the greenhouse gases (GHGs). GHGs are those gaseous constituents of the atmosphere, both natural and anthropogenic, that absorb and emit radiation at specific wavelengths within the spectrum of thermal infrared radiation emitted by the Earth's surface, BY the atmosphere itself and by clouds. This property causes "the greenhouse effect". Water vapour (H_2O), carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4) and ozone (O_3) are the primary greenhouse gases in the Earth's atmosphere (Wikipedia 2000b).

According to the data provided on GHG emissions by sector (Wikipedia 2000a), the largest contributor towards the GHG emission is the power industry and is responsible for highest percentage of CO_2 emissions. Such effects can be minimised with the integration of large-scale renewable distributed generation into power systems. Renewable power integration requires an adequate evaluation in order to assess the environmental impacts and economics of the overall production and utilisation life cycle, including the construction and operation stages of renewable plants (Mikhail Granovskii et al. 2006). For every kWh of electricity produced, a proportion of CO_2 is emitted to the atmosphere; this is known as the greenhouse coefficient. For example, one kWh of electricity produced by burning brown coal will emit approximately one kilogram of CO_2 into the atmosphere. The Australian Greenhouse Office annually determines the greenhouse coefficient of each state and territory, based on their respective sources of electricity generation. The highest greenhouse coefficient in Australia was found in Victoria with a value of 1.39, and this value is used as the basis to predict the worst case scenario (Emission Statement, 2010).
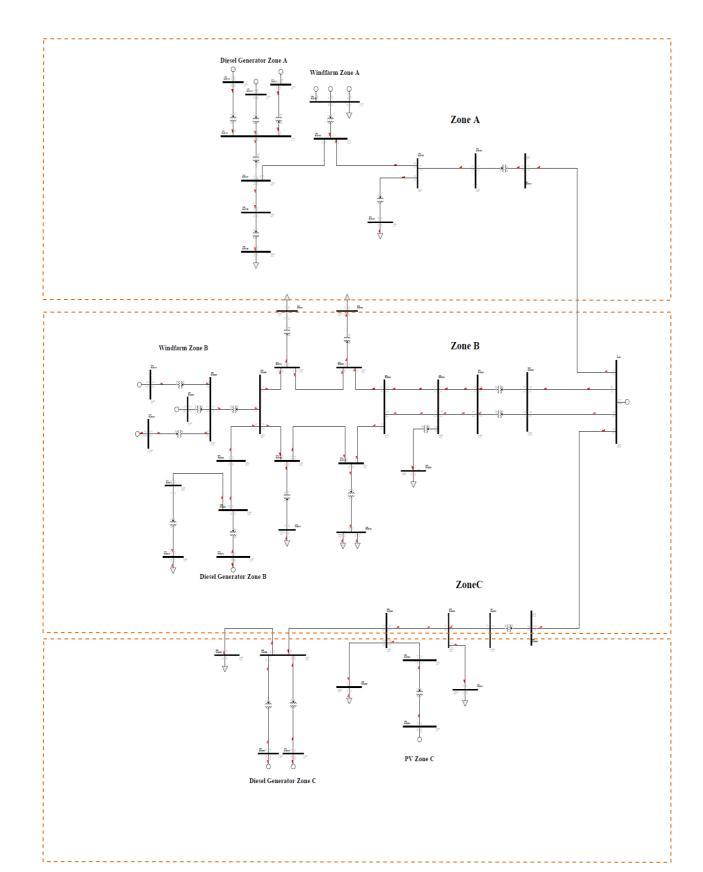
9.2.   The test network

The proposed test network consists of 49 buses, 52 feeders, 25 transformers, 13 load points, three diesel units, two wind farms and one PV farm; with a total active and reactive peak load of 42MW and 6MVAr respectively. The network is developed in such way that it would operate healthy under normal operating conditions.

Figure 39 shows the schematic diagram of the network. It is divided into three zones, zone A, zone B and zone C. One of the aims of zoning is to facilitate islanding and grid-connected modes of studies. Users need to provide the control mechanism that will prevent unintentional islanding. The added benefit of zoning is that the user can test the feasibility of mini/micro-grid associated research, as well as issues of inter-connection of mini/micro-grids. User can also test the feasibility of the operation of a distribution network with the operation of distribution network autonomous controllers.

The detailed technical data associated with each of the zones A, B and C are given in detail in (Jayaweera et al. 2010). It also provides various test case scenarios and details of the voltage and thermal loading distribution for the network. Under the normal operating conditions the network is steady state stable and there is no voltage limit (± 6) or thermal limit violations exist.
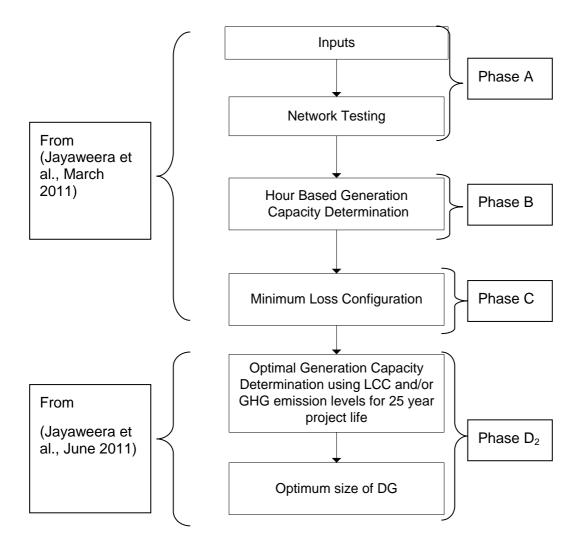
Figure 39: Schematic diagram of the proposed test network

9.3.   The developed methodology

Figure 40 shows the methodology used to determine the optimal DG sizes, including diesels with LCC and GHG emissions over 25 years. The algorithm is divided into four sections, namely phase A, phase B, phase C and phase D_2. Phases A, B and C are as explained in (Jayaweera et al. March 2011); the details for phase D2 are given in (Jayaweera et al. June 2011).

Figure 40: Overview of the generation size optimisation algorithm with LCC and GHG

Phase A of the algorithm involves data inputs and the verification of the network base case (Jayaweera et al. 2010) for network constraint violations. Upon entering the data, the network feasibility is checked by applying the Newton-Raphson algorithm. If the network converges for the operating condition without violating any constraints, the operating state is deemed feasible. On successful convergence of the network, the program proceeds to phase B of the algorithm.

In phase B, the most economical combination of DG units in the system is determined, including diesel units that best match the load and DG generation profile for each hour of the year. If it satisfies all the constraints, then the combination is saved and the operating costs associated with it is calculated and stored against the combination. On completion of the phase B, the DG unit combination with the least operating costs is inputted to the next phase.

Phase C of the algorithm is used to determine how best to allocate the generation in such a way that the DG unit combination produces least amount of power losses. This is obtained by calculating the sensitivity of alteration of each DG unit capacity combination to reduce power losses of the network.

In phase D_2, the total LCC and GHG emission are calculated and the final results for the investigation is given as output. The diesel generators are operated only if they operate within the economical (efficient) region. The algorithm treats 40% to 100% of the rated output power of a diesel unit as the economic region of the efficiency curve.

The number of years of the project is flexible and in this investigation is set to 25 years. The investment cost includes the capital cost per MW for each unit, procurement and design costs, and installation costs respectively. The maximum ratings of the units are used for investment cost calculation. Depending on the life of the individual units in the system, replacement or renewal costs for the units are to be considered for the LCC calculation. The replacement can occur more than once within the 25-year period of the assessment. The disposal cost is included within the replacement cost.

Using the total generated power associated with each unit, the yearly costs associated with the operation and maintenance, energy/fuel costs and cost of power losses can be calculated. This calculation assumes that the load profiles and magnitudes remain the same for the entire 25-year period. This facilitates simplified calculations, neglecting the costs for network restructuring, and reduces the computation time that is necessary for each year. Even though these elements are not incorporated, they can be embedded as an extension to the algorithm.

The cost of energy losses for the system is calculated assuming that all the energy lost in the network is supplied by the diesel generators; that is, diesel generators are assumed to generate the extra power required to meet the power loses of the network.

In this study, three options are offered to determine the optimal DG unit combination:

- Option 1 selects the optimal combination of DGs that include diesels, according to the total LCC for the whole period considered for the assessment (25 years).
- Option 2 considers the DG unit combination with the least GHG emission, and therefore provides the best environmentally friendly generation of power.
- Option 3 is used to arrive at an output that is both economical and environmentally friendly. This is done by ranking the full array of combinations. The first ranking set is determined based on the total LCC of combinations; the second ranking set is determined based on GHG emitting level of the combinations. Then, the priority ranking sets are combined together with weighting factors, and the DG unit combination with the lowest value out of the combined rank is considered the most beneficial and economical combination for the power network. In this investigation, equal weighting factors are assumed with the objective of giving equal importance to reduce LCC and GHG emissions.

9.4. The software development

The algorithm proposed before is scripted using the PSS/E version 32 based IPLAN programming. IPLAN modules can be created through any text editing software and have the ability to interact with PSS/E software to produce the desired outcome. IPLAN programs interrogate the PSS/E via various routines and control the execution of inbuilt commands in the PSS/E via a series of PUSH commands. The values entered for the PUSH commands appear to the host application if they were entered from the terminal. It can access the whole information and data from the PSS/E software, and can use the same to perform complex analytical and logical calculations to produce output values, which can be fed back to the software.
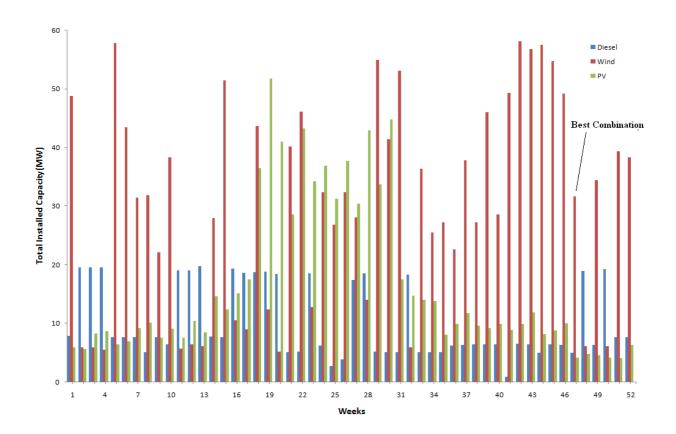
PSS/E has a large collection of application program interface commands that can be used to input various types of data to execute different types of power flow calculation, create output reports etc. These commands can be either given at the program input terminal or can be given as inline commands using the IPLAN software, enabling the seamless integration of the user defined subroutines with the actual inbuilt functions present in the PSS/E software package. More details on IPLAN programming is given in Jayaweera et al. June 2011) and Siemens Energy (2009).

9.5. Case studies

9.5.1. Impacts of load variation effects

The network loading is varied in percentage steps to determine the optimal size of generators; taking into account network constraints, total life cycle costs and power losses. Figure 41 shows the total installed capacities of operating conditions corresponding to weekly-based scenarios in a sample year. The vertical axis gives the total installed capacities (MW) of the wind, PV and diesel generators that will provide the minimum total life cycle costs; while the horizontal axis provides the combinations corresponding to each week calculated during the phase B.

Figure 41: Total installed capacities of generating technologies needed to meet weekly operating conditions with base case loading

Each of the generating unit size corresponding to each week is fed into phase C and thereafter phase D of the algorithm in achieving the goals.
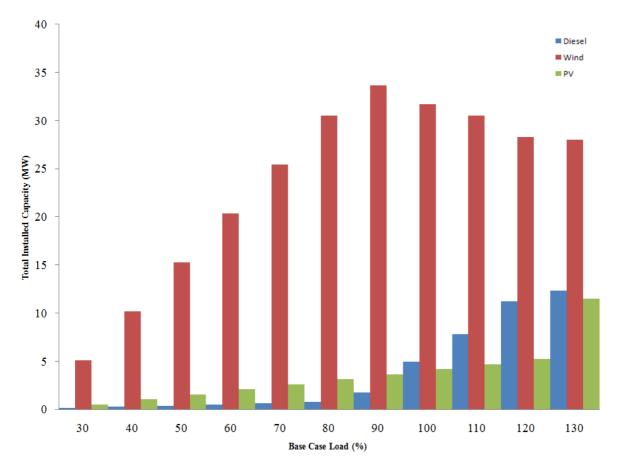
Installed capacity of the generating unit given at week 47 gives the most economical combination that can fulfil all the operating conditions of the year. This is highlighted in Figure 8.4. Thus, week 47 is representative for selecting the least cost of operation scenario, and provides the added benefit of optimal combination of distributed generating units. Identification of such an operating condition is infeasible without the application of exhaustive algorithms, due to simultaneous variation of several factors through the simulation period. Applications of random selective algorithms do not guarantee the most economical combination, and may skip the critical operating condition leading to erroneous conclusions.

Figure 42 shows the total installed capacity of most economic generating unit combination of all studies. Load at 90% of the base case load gives the largest required installed capacity to meet the operating conditions of the selected year. This is because the wind units of this scenario provide more power than other generating units. At 90% of full load, the penetration of wind and PV is more than that was for the full load condition. This can be attributed to greater relaxation available in the network voltage limit and thermal limit constraints, and indicates that the network mostly absorbs wind energy.

However, loading from 30% to 80% of the base load follows a linear variation of total installed capacity, which contributes to most economical configuration.

Once the base case loading is increased above 100%, the most economic combination demands more power from diesel units, resulting in a reduced penetration level of wind power. This situation arises because the extra capital cost of wind units is not economical with larger installed capacities demanded by increased loading levels to meet a safe operating condition of the network. The network operation is infeasible beyond 130% of base load due to presence of load flow divergence.
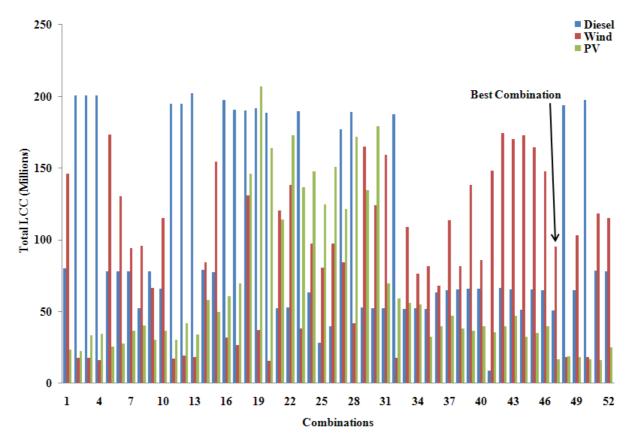
Figure 42: Sum of the generating unit sizes vs. variation in system load

9.5.2. Life cycle costs

Figure 43 shows the LCC incurred for the wind, PV and diesel generators for different DG unit combinations of the project for 25 years. The total load demand for the 25 years is assumed as constant throughout. A depreciation rate of 7 % is used to calculate the net present value of the costs for each year in dollars. Results suggest that the week corresponding to the critical operating condition that determines the optimal DG size is not affected throughout, and it remains at the 47th week.

Figure 43: LCC for different DG unit combinations in 25 years

9.5.3. The GHG abatement

The GHG abatement algorithm proposed in Jayaweera et al. (June 2011) was incorporated into the LCC subroutine as an addition to investigate the environmental impacts for different DG unit combinations. Upon successful testing of the software, a series of studies was performed to verify the effectiveness of the three options given in the algorithm under Phase D_2 in section 8.3.

Figure 4 4 provides the GHG emission in equivalent of CO_2 weight in tonnes for the 25-year study period. Results show that the DG unit combination corresponding to week 29 has the least GHG emission. Therefore, based on GHG, the operating condition at week 29 is the one that determines the most beneficial DG unit combination and size.

Figure 44: GHG emission for a 25-year project life
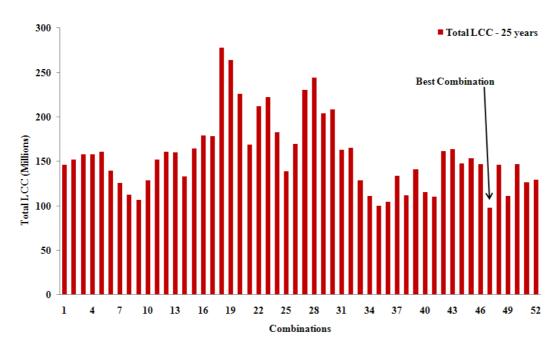
Figure 44 shows LCC totals of DG (wind, PV and diesel) unit combinations respective to a 52-week time-frame. Figure 45 shows the ascending order of ranking of various DG unit combinations taking into account GHG emission. The best rank (or the lowest position in the ascending order of ranks) results due to the operating condition at the 29th week. Figure 45 shows the ranking based on the LCC values. The results given in Figures 44 and 45 are used to derive the combined priority list to determine the most favourable DG unit combination taking into account both GHG emission and LCC costs.

Figure 45: GHG-based ranking
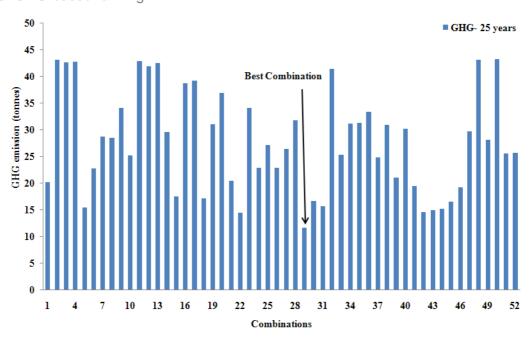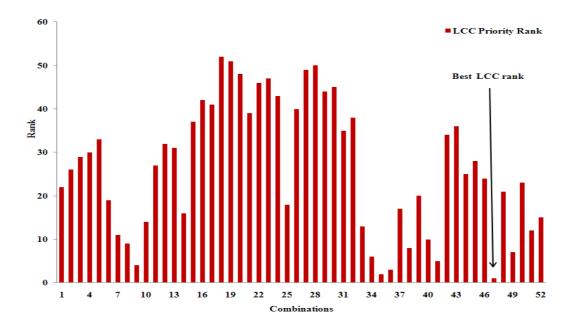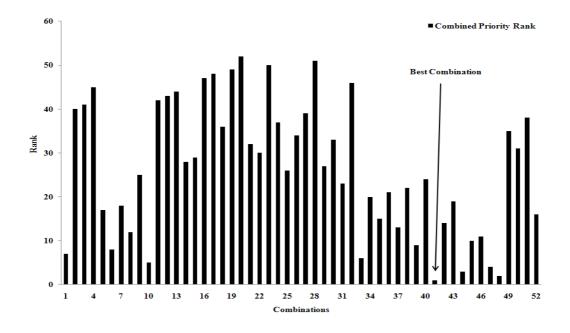
Figure 46 : LCC-based ranking

The ranks based on both GHG and LCC shown in Figure 47 are used to determine the best combination. Figure 46 also shows that the optimal DG unit combination corresponds to week 41; however it is not the best combination if either of the LCC and GHG was decupled and treated individually. Of the two best combinations, week 47 has a better ranking with LCC consideration than week 29 with GHG priority. This results in a better GHG ranking (lowest in the order) even though the LCC ranking is lower than week 47 resulting DG unit combination.

Figure 47: Equally weighted ranking based on both GHG and LCC
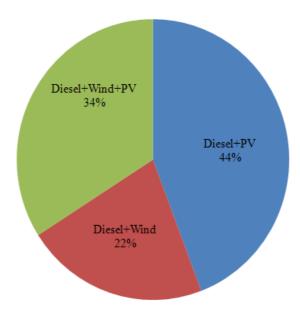
9.5.4. The GHG variation with combinations

The pie chart presented in Figure 48 shows the summary of the variation in total LCC associated with the system when combinations of generation technologies were varied to supply the same load demand. The most economical combination was found to be that of a hybrid system with diesel and wind units. This combination offers 12% less cost than the diesel–wind–PV unit combination. The results further suggest that the wind–diesel operation is 22% more economical than that of PV–diesel operation for the test network considered for the assessment.

Figure 48: LCC Cost–benefit analysis with different DG technologies
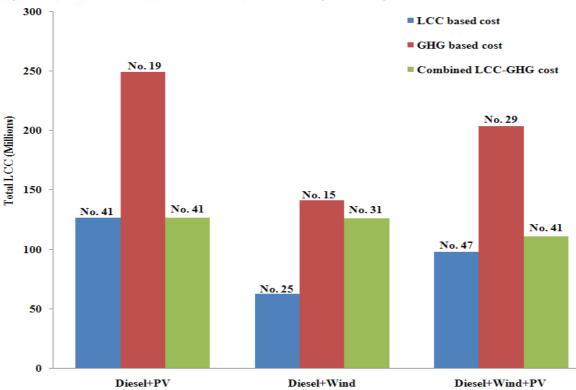
Figure 49: LCC and GHG emission variation with generating unit combinations

Figure 49 shows the summarised LCC and GHG emission cost variations in the context of diesel–PV, diesel–wind and diesel–wind–PV operations. The bar charts in blue, red and green give the total LCC corresponding to the optimal DG combination based only on LCC, based only on GHG, and considering LCC and GHG with equal weighting factors, respectively. The results in Figure 26 suggest that the operating condition at week 41 is the most critical operating condition, in terms of determining the distributed generating unit combination that provides most benefits in terms of reducing LCC and GHG emissions for the test network considered for the assessment.

The case studies presented in this report refer to constant cost factors of generating technologies and assets. However, the software program facilitates incorporation of cost of different makes and ages of DG technologies in the formulation. Such facilities in the software enable to incorporate varying cost components of PV, wind and other DG technologies; in addition to the futuristic cost elements that may arise through governmental subsidies and taxes set by governments for the sustainable energy future.

9.6. Conclusions

A test network is presented for the assessment of DG technologies and assessment techniques (Jayaweera et al. November 2010). The report presents technical data of the entire network component that are required for steady state analysis, time series characteristics of load, and the time series characteristics of wind and PV generation. The test network is designed in such a way that it is healthy under normal operating conditions. The proposed network can be used to compare different techniques and to generalise techniques. Time series characteristics of wind and PV can be used to quantify average effects of intermittent technology performance and to identify

hidden effects that can trigger significant impacts to the network operation. The technical data given in the report is for the steady state analysis; however, the users have the option to include transient and dynamic data of the equipment as necessary for their studies.

An algorithm is proposed for the calculation of the LCC and GHG abatement through the optimisation subroutines proposed in Jayaweera et al. (March 2011) and Jayaweera et al. (June 2011). The algorithm determines the most economical and environmentally friendly hybrid DG unit combination that can be accommodated to an active distribution network. The algorithm offers the most beneficial distributed generation unit mix and their capacities, respective to the geographical location of the system. The software program was developed, and the algorithm scripted using IPLAN subroutines to work in conjunction with PSS®E software (Siemens, June 2009). The program facilitates to differentiate the LCC benefits, GHG emission levels and combined effects. Such options are vital in trading off the business objectives of distributed energy business.

A set of case studies are performed to investigate the specific features of the test system (Jayaweera et al. November 2010). The results conclude that the optimal DG size can be affected not only by the constraints of the power system, but also by the GHG effects if a designer considers overall benefits. The particular network considered for the study shows that the best DG system and sizes are achieved through the operating condition of week 47 if the network constraints and LCC is considered; whereas the combined effects of GHG emissions, the ageing life of equipment and network constraints moves the critical operating condition to week 29. In other words, the operating condition in week 29 determines the most beneficial DG system and the size for the network if those constraints are considered.

The application of the proposed weighting approach suggests that with equal weightings, the best DG system and the unit sizes results are from the operating condition of week 41. The case studies also show the vulnerability for sizes of DG and the type in balancing the LCC and GHG emissions in an active distribution network. Thus, network planners need to make an extra effort to apply the balanced approach for global system benefits. Such approaches not only improve the network performance, but also reduce adverse impacts on the environment.

The most economical DG system of the network used for the assessment is the wind–diesel system. This system offers 12% less cost than the system with diesel, wind and PV units. The results further suggest that the wind–diesel operation is 22% more economical than that of PV–diesel operation for the network.

The results conclude that the operating condition at week 41 is the most critical operating condition in terms of determining the generating unit combination that provides most benefits in LCC and GHG emissions for the test network.

The proposed algorithm gives not only the size of DG system and geographical location, but also the operating condition of the week that determines the optimal condition. Such information is useful in reducing computation time of extended applications that include the security of energy supply to consumers by DG and the reliability improvement with DG unit combinations.

The priority ranking of LCC and GHG emissions can be used by network regulators and policy-makers for setting incentives, or to penalise those who adversely affect the environment. It also facilitates benchmarking distribution networks for the incentives as appropriate. The results of the program can also be used as a potential platform for the carbon trade and extended applications. On the other hand, distribution network operators can use the proposed methodology to balance the benefits between different types of DG combinations and overall benefits of reducing LCC and GHG emissions. Such an approach is necessary in meeting renewable energy targets and

balancing the economy verses the carbon trade.

10. CONCLUSIONS

Distributed Generation can deliver many economic, technological and environmental benefits; at the same time, DG has technical challenges to overcome before it can make a substantial contribution to the energy supply, and investment in DG is viable.

A key benefit of DG is its capability to address power system reliability issues. The optimisation of distribution design considered in this project shows that reliability is a strong component of the benefit of DG for areas that are not highly meshed. It is largely this reliability benefit that 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. In fringe-of-grid areas the costs of the network can be very significant; since DG acts to reduce the network requirements, then the fringe-of-grid is likely to be one of the early places for viable DG. Thus, the strongest case for DG can be made with respect to improving reliability, and also with respect to the benefits of possible deferment of investment in lines and transformers.

One the most important challenges for DG is the coordination of protective relays. When DGs are connected in a distribution system, both the direction and distribution of the power flow and fault current in the distribution system could change significantly, such that the traditional protection scheme will no longer work correctly. Hence, there is a demand for new protection schemes. This project has developed a modified protection strategy such that the risk of undetected system faults is reduced, and also a coordinated strategy for protective relays. The issue of voltage control in microgrids needs to be solved, and this project has made substantial contributions to the solution.

Additional important problems are investigated in depth in this project, such as: UFLS considering DGs, optimal siting and sizing of DGs, generation scheduling with DGs, risk-control in transmission system planning with wind generators, sizing the distributed generation with life-cycle costing, and GHG-abatement effects.

This project presents a probability model to simulate the uncertainties associated with the power output of wind generators integrated into a power system. 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, of a renewable DG, and of a solar generating source; volatile fuel prices used by a fuelled DG; and future uncertain load growth in the optimal siting and sizing of DGs. The test results of the IEEE 37-node test feeder demonstrate the feasibility and effectiveness of the developed model and method.

Two case studies demonstrate that it is possible to achieve a good trade-off among the security, reliability and economics of TSP schemes by employing risk-controlling strategies. Consequently, the security risks of a system associated with the uncertainties due to wind generators can be controlled using the developed TSP model.

A stochastic optimisation approach is proposed for the unit commitment problem considering the uncertainty of wind-power generation, based on the mixed-integer linear programming (MILP). The problem is formulated as minimising the total cost of thermal units. To consider wind power generation, scenarios are generated using scenario-generation techniques. The stochastic problem is hence transformed to a deterministic one.

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, the reactive capacity can be made to work cooperatively as a dispersed voltage controller using a new tool "integral to droop line control". This same tool can be set such that the peak-load ability 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.

With the fast development of distributed generators (DGs), the impact of DGs on the UFLS strategy is becoming an issue of extensive concern. An optimal UFLS strategy considering DGs and load static characteristics is developed in this project, and a modified IEEE 37-node test feeder with four DGs is employed to demonstrate the essential features of the developed optimal UFLS strategy in the MATLAB/SIMULINK environment.

A test network is presented for the assessment of DG technologies and assessment techniques (Jayaweera et al. November 2010). The report presents technical data of the entire network component that are required for steady state analysis, time series characteristics of load, and the time series characteristics of wind and PV generation. The proposed network can be used to compare different techniques and to generalise techniques. Time series characteristics of wind and PV can be used to quantify average effects of intermittent technology performance and to identify hidden effects that can trigger significant impacts to the network operation. The technical data given in the report is for the steady state analysis; however, the users have the option to include transient and dynamic data of the equipment as necessary for their studies.

An algorithm is proposed for the calculation of the LCC and GHG abatement through the optimisation subroutines proposed in Jayaweera et al. (March 2011) and Jayaweera et al. (June 2011). The algorithm determines the most economical and environmentally friendly hybrid DG unit combination that can be accommodated to an active distribution network. The algorithm offers the most beneficial distributed generation unit mix and their capacities, respective to the geographical location of the system. The software program was developed, and the algorithm scripted using IPLAN subroutines to work in conjunction with PSS®E software (Siemens, June 2009). The program facilitates to differentiate the LCC benefits, GHG emission levels and combined effects. Such options are vital in trading off the business objectives of distributed energy business.

Case studies presented show the vulnerability for sizes of DG and the type in balancing the LCC and GHG emissions in an active distribution network. Network planners need to make an extra effort to apply the balanced approach for global system benefits. Such approaches not only improve the network performance, but also reduce adverse impacts on the environment. The most economical DG system of the network used for the assessment is the wind–diesel system. This system offers 12% less cost than the system with diesel, wind and PV units. The priority ranking of LCC and GHG emissions can be used by network regulators and policy-makers for setting incentives, or to penalise those who adversely affect the environment. It also facilitates benchmarking distribution networks for the incentives as appropriate. The results of the program can also be used as a potential platform for the carbon trade and extended applications. On the other hand, distribution network operators can use the proposed methodology to balance the benefits between different types of DG combinations and overall benefits of reducing LCC and GHG emissions. Such an approach is necessary in meeting renewable energy targets and balancing the economy verses the carbon trade.

11. REFERENCE LIST

ABOU, AA, ZEIN EI-DIN, A & SPEA, SR: 'Optimal load shedding in power systems'. Proc. 11th International Middle East Power Systems Conference (MEPCON), EI-Minia, Egypt, December 2006, pp. 568-575

ABYANEH, H. A., AL-DABBAGH, M., KAREGAR, H. K., et al. (2003) 'A new optimal approach for coordination of overcurrent relays in interconnected power systems.' *IEEE Trans on Power Delivery*, 18(2), 430-435.

ACKERMANHN, T., & KNYAZKIN, V. (2002). 'Interaction between distributed generation and the distribution network.' *Asia Pacific. IEEE/PES Transmission and Distribution Conference and Exhibition*, 1357-1362.

AGALGAONKAR, A. P. & KULKARNI, S. V. (2003). "Impact of wind generation on losses and voltage profiles in a distribution system." *IEEE TENCON*, 775-779.

AGALGAONKAR, A. P., KULKARNI, S. V., & KHAPARDE, S. A. (2006). "Evaluation of configuration plans for dgs in developing countries using advanced planning techniques." *IEEE Trans. on Power systems*, 21(2), 973–981.

ALDERFER, B. R., STARRS, T. J. & ELDRIDGE, M. M. (2000) Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects. Golden CO, National Renewable Energy Laboratory.

AL-NASSERI, H., REDFERN, M. A, et al. (2006). "A voltage based protection for micro-grids containing power electronic converters." *Power Engineering Society General Meeting, IEEE*, 1-7.

ANDERSON, P.M., MIRHEYDAR, M.: 'An adaptive method for setting underfrequency load shedding relays'. *IEEE Trans. Power Syst.*, 1992, **7**, (2), pp. 647-655

ATWA, Y. M., & EL-SAADANY, E. F. (2009). "Reliability evaluation for distribution system with renewable distributed generation during islanded mode of operation." *IEEE Transactions on Power Systems*, 24(2), 572–581.

AZMY, A. M., & ERLICH, I. (2005). "Impact of distributed generation on the stability of electrical power systems." *Power Engineering Society General Meeting, IEEE*, 1056-1063.

BARTH, R., BRAND, H., MEIBOM, P., & WEBER, C. (June 2006) A stochastic unit-commitment model for the evaluation of the impacts of integration of large amounts of intermittent wind power. Proc. Int. Conf. Probabilistic Methods Applied to Power Systems, 11–15.

BILLINTON, R., WANGDEE, W.: 'Reliability-based transmission reinforcement planning associated with large-scale wind farms', *IEEE Trans. on Power Syst.*, 2007, **22**, (1), pp. 34-41

BOUFFARD, F. & GALIANA F. D. (2008) Stochastic security for operations planning with significant wind power generation. IEEE Trans. Power System, 23, (2), 306-316.

BOX, G.E.P., & JENKINS, G.M. (1976) Time Series Analysis: Forecasting and Control. 2nded. Holden-Day Press.

BRAHMA, S. M., & GIRGIS, A. A. (2002). "Microprocessor-based reclosing to coordinate fuse and recloser in a system with high penetration of distributed generation." *Proceedings of IEEE Power Eng. Soc. Winter Meeting*, 453-458.

BRITTO, T. M., MORAIS, D. R., MARIN, M. A., et al. (2004) Distributed generation impacts on the

coordination of protection systems in distribution networks. *Proceedings of IEEE/PES Transmission and Distribution Conference & Exposition*, 623-628.

BROWN, R. E., PAN, J. P., FENG, X. M., et al. (2001). "Siting distributed generation to defer T&D expansion." *Transmission and Distribution Conference and Exposition*, 622 – 627.

CARASTRO, F., SUMNER, M. & ZANCHETTA, P. (2006). "Mitigation of voltage dips and voltage harmonics within a micro-grid, using a single shunt active filter with energy storage." *32nd Annual Conference on IEEE Industrial Electronics*, 2546-2551.

CARPENTIER, P., COHEN, G., CULIOLI J.-C. & AUD, RENAUD A. (1996) Stochastic Optimisation of Unit; Commitment: a New Decomposition Framework. IEEE Trans. on Power System, 11, (2), 1067-1073.

CARPINELLI, G., CELLI, G., MOCCI, S., et al. (2005). "Optimisation of embedded generation sizing and siting by using a double trade-off method." *IEEE Proceedings of Generation, Transmission and Distribution*, 152(4), 503-513.

CARPINELLI, G., CELLI, G., PILO, F., et al. (2001). "Distributed generation siting and sizing under uncertainty." *IEEE Porto Power Tech Proceedings*, 7-14.

CARRIÓN, M., & ARROYO, J.M. (2006) A Computationally efficient mixed-integer linear formulation for the thermal unit commitment problem. IEEE Trans. Power Systems, 21, (3), 1371-1378.

CELLI, G., GHIANI, E., MOCCI, S., et al. (2003). "A multi-objective formulation for the optimal sizing and siting of embedded generation in distribution networks." *IEEE Power Tech Conference Proceedings*, 67-74.

CELLI, G., MOCCI, S., PILO, F., et al. (2008). "A multi-objective approach for the optimal distributed generation allocation with environmental constraints." *Proceedings of the 10th International Conference on Probabilistic Methods Applied to Power Systems*, 1-8.

CHAITUSANEY, S., YOKOYAMA, A. (2005) An appropriate distributed generation sizing considering recloser-fuse coordination. *Proceedings of IEEE/PES Transmission and Distribution Conference and Exhibition*, 1- 6.

CHAITUSANEY, S., YOKOYAMA, A. (2005) Impact of protection coordination on sizes of several distributed generation sources. *Proceedings of the 7th International Power Engineering Conference*, 2, 669-674.

CHAITUSANEY, S., YOKOYANA, A. (2005). "An appropriate distributed generation sizing considering recloser-fuse coordination." *Proceedings of IEEE/PES Transmission and Distribution Conference and Exhibition*, 1- 6.

CHAITUSANEY, S., YOKOYANA, A. (2005). "Impact of protection coordination on sizes of several distributed generation sources." *Proceedings of the 7th International Power Engineering Conference*, 669-674.

CHEN, H. Y., DUAN, X. Z., CHEN, J. F. (2006). "Distributed generation planning model and algorithm considering static voltage stability constrain in distribution network." *Power System Technology*, 30(21), 11-14, 110.

CHEN, J. F., FAN, R. Q., DUAN, X. Z., et al. (2009). "Penetration level optimisation for DG considering reliable action of relay protection device constrains." *Sustainable Power Generation and Supply*, 1-5.

CHEN, L., ZHONG, J., NI, Y., et al. (2006) Optimal reactive power planning of radial distribution

systems with distributed generation. *Automation of Electric Power Systems*, 30(14), 20-24.

CHEN, X., GAO, W. Z. (2008). "Effects of distributed generation on power loss, loadability and stability." *IEEE Southeastcon*, 468 – 473.

CHI, Y., WANG, W., LIU, Y., et al. (2006) Impact of large scale wind farm integration on power system transient stability. *Automation of Electric Power Systems*, 30(15), 10-14.

CHOI, B. K. (2006). "Development of composite load models of power systems using on-line measurement data." *KIEE J. Elect. Eng. &Technol.*, 1(2), 153–160.

CHOWDHURY, A. A., AGARWAL, S. K., KOVAL, D. O. (2003). "Reliability modelling of distributed generation in conventional distribution systems planning and analysis." *IEEE Trans. Ind. Appl.*, 39(5), pp. 1493–1498.

CHUVYCHIN, V.N., GUROV, N.S., VENKATA, S.S., BROWN, R.E.: 'An adaptive approach to load shedding and spinning reserve control during underfrequency conditions'. *IEEE Trans. Power Syst.*, 1996, **11**, (4), pp. 1805-1810

CLEMENT-NYNS, K., HAESEN, E. & DRIESEN, J. (Feb. 2010) The impact of charging plug-in hybrid electric vehicles on a residential distribution grid. *IEEE Transactions on Power Systems.*, 25, (1), 371-380.

Congress of the United States of America. (2005) Energy policy act of 2005. http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&=f:h6enr.txt.pdf

COSTA, P. M., AND MATOS, M. A. (2006). "Economic analysis of microgrids including reliability aspects." *9th International Conference on Probabilistic Methods Applied to Power Systems*, 1-8.

Department of Trade and Industry of UK. Energy white paper. (2003) Our energy future—creating a low carbon economy. http://www.dti.gov.uk/files/file10719.pdf

DIGEST OF UNITED KINGDOM ENERGY STATISTICS .<http://www.dti.gov.uk/energy/inform/dukes/>.

DOMENICA, N.D., BIRBILIS, G., MITRA, G., & VALENTE, P. (2007) Stochastic Programming and Scenario Generation within a Simulation Framework: An Information Systems perspective. Decision Support Systems, 42 , (4), 2197-2218.

DRIESEN, J., BELMANS, R. (2006) Distributed generation: challenges and possible solutions. *Proceedings of IEEE Power Engineering Society General Meeting*, 1-8.

DUGAN, R.C., MCDERMOTT, T. E., AND BALL, G.J. (2000). "Distribution planning for distributed generation," *Rural Electric Power Conference*, C4.1-C4.7.

DUPAČOVÁ, J., GRÖWE-KUSKA, G., & RÖMISCH, W. (2003) Scenario reduction in stochastic programming. Mathematical Programming. 95, (3), 493–511.

EA TECHNOLOGY. (2006). "Network Losses and Distributed Generation." <http://www.berr.gov.uk/files/file30523.pdf>.

EI-KHATTAM, W., SALAMA, M. M. A. (2004) Distributed generation technologies, definitions and benefits. *Electric Power Systems Research*, 71(2): 119-128.

EL-KHATTAM, W., HEGAZY, Y. G. & SALAMA, M. M. A. (May 2005) An integrated distributed generation optimisation model for distribution system planning. *IEEE Transactions on Power Systems.*, 20, (2), 1158-1165.

EL-SADEK, M.Z., MAHMOUD, G.A., DESSOUKY, M.M., RASHED, W.I.: 'Optimum load shedding for avoiding steady-state voltage instability'. *Electr. Power Syst. Res.*, 1999, 50, (2), pp. 119-123

EMISSION STATEMENT, P. L. (2010) http://www.emissionstatement.com.au/Climate_Change_Glossary_of_Terms.html

ENSLIN, J. H. R. (2004) Interconnection of distributed power to the distribution network. *Proceedings of IEEE PES Power Systems Conference and Exposition*, 2, 726-731.

ERLICH, I., SHEWAREGA, F. (2006) Interaction of large wind power generation plants with the power system. *Proceedings of First International Power and Energy Conference*, 12-18.

ETEZADI-AMOLI, M., CHOMA, K. & STEFANI, J. (July 2010) Rapid-charge electric-vehicle stations. *IEEE Transactions on Power Delivery.*, 25, (3), 1883-1887.

FOCKEN, U., LANGE, M., & WALDL, H.P. (June 2001) Previento: a wind power prediction system with an innovation upsacling algothrithm. Proc. Int. Conf. the 2001 European Wind Energy Association Conference, EWEC'01, 82-829.

FUJISAWA, C. H., & CASTRO, C. A. (2008). "Computation of voltage stability margins of distribution systems." *Transmission and Distribution Conference and Exposition*, 1-5.

GALLEGO, R. A., MONTICELLI, A. & ROMERO, R. (1998) Comparative studies of non-convex optimisation methods for transmission network expansion planning. IEEE Trans. Power Syst., 13, (3), 822–828.

GARVER, L. L. (1970) Transmission network estimation using linear programming. IEEE Trans. Power Appar. Syst., 89, (7), 1688– 1697.

GAUTAM, D., MITHULANANTHAN, N. (Oct. 2007) Optimal DG placement in deregulated electricity market. *Electric Power Systems Research.*, 77,(12), 1627-1636.

GHOSH, S., Ghoshal, S. P. & GHOSH, S. Optimal sizing and placement of distributed generation in a network system, *Electrical Power and Energy Systems*, 32, (8), 849-856.

GIEBEL, G. (2003) The state-of-the-art in short-term prediction of wind power A lit- erature overview. Position paper for the ANEMOS project. http://anemos.cma.fr.

GIL, H. A., EL CHEHALY, M., JOOS, G., & CANIZARES, C. (2009). "Bus-based indices for assessing the contribution of dg to the voltage security margin of the transmission grid." *Proc. IEEE-PES General Meeting*, 1-7.

GIRGIS, A., BRAHMA, S. (2001) Effect of distributed generation on protective device coordination in distribution system. *Proceedings of Large Engineering Systems Conference on Power Engineering*, 115-119.

GIRGIS, A.A., MATHURE, S.: 'Application of active power sensitivity to frequency and voltage variations on load shedding'. *Electr. Power Syst. Res.*, 2010, **80**, (3), pp. 306-310

Government of Canada. Moving forward on climate change: A plan for honouring our Kyoto commitment. http://www.climatechange.gc.ca/kyoto_commitments/report_e.pdf

GRIDWORKS. (2009). "Overview of the Electric Grid." U.S. Department of Energy-Office of Electricity Delivery & Energy Reliability.< http://sites.energetics.com/gridworks/grid.html>.

GRÖWE-KUSKA, N., HEITSCH, H., & RÖMISCH, W. (June 2003) Scenario reduction and scenario tree construction for power management problems. Proc. Int. Conf. IEEE Bologna Power Tech, 1-7.

HADIAN, A., HAGHIFAM, M. R., ZOHREVAND, J., & AKHAVAN-REZAI, E. (2009). "Probabilistic approach for renewable dg placement in distribution systems with uncertain and time varying loads." *Power & Energy Society General Meeting, Calgary*, 1-7.

HAGHIFAM, M.-R, TARBIAT M., FALAGHI, H., AND MALIK, O. P. (2008). "Risk-based distributed generation placement." *IET Generation, Transmission and Distribution*, 2(2), 252-260.

HASCHE B. (2008) Scenario Tree Generation for an Electricity Market Model. Research Report.

HEDAYATI, H., NABAVINIAKI, S.A., AKBARIMAJD, A. (2008). "A method for placement of dg units in distribution networks." *IEEE Trans on Power Delivery*, 23(3), 1621-1629.

HEGAZY, Y. G. & HASHEM, G. M. (2003). "Probabilistic power loss analysis of electrical distributed generation systems." *IEEE Canadian Conference on Electrical and Computer Engineering*, 623- 626.

HEMDAN, N. G. A., & KURRAT, M. (2008). "Distributed generation location and capacity effect on voltage stability of distribution networks." *IEEE Student Paper Conference*, 1-5.

HEMDAN. N. G. A., & KURRAT, M. (2008). "Distributed generation location and capacity effect on voltage stability of distribution networks." *2008 Annual IEEE Conference*, 1 – 5.

HETZER, J., YU D.C. & BHATTARAI, K. (2008) An economic dispatch model incorporating wind power, IEEE Trans. Energy Conversion, 23, (2), 603-611.

HOYLAND, K. & WALLACE, S.W. (2001) Generating Scenario Trees for Multistage Decision Problems. Management Science, 47, (2), 295–307.

HOYLAND, K., KAUT, M. & WALLACE, S.W. (2003) A Heuristic for Moment-Matching Scenario Generation. Computational Applications and Optimisation, 24, (2-3), 169-185. http://www.vosesoftware.com/modelriskhelp/index.htm#monte_carlo_simulation/latin_hypercube_sampling.htm.

INGLIS, S., AULT, G. W., ALARCON-RODRIGUEZ, A. & GALLOWAY, S. J. (2010) Multi-objective network planning tool for networks containing high penetrations of DER. Universities Power Engineering Conference (UPEC), 2010 45th International.

JAHANGIRI, P., & FOTUHI-FIRUZABAD, M. (2008). "Reliability assessment of distribution system with distributed generation." *IEEE 2nd International Power and Energy Conference*, 1551 – 1556.

JAVADIAN, S. A. M. & HAGHIFAM, M.-R. (2008). "Implementation of a new protection scheme on a real distribution system in presence of DG." *IEEE Power India Conference*, 1-7.

JAYAWEERA, D., BURT, G. & MCDONALD, D. (2007). "Customer security assessment in distribution networks with high penetration of wind power." *IEEE Transactions on Power Systems*, 22(3), 1360-1368.

JAYAWEERA, D., SYED, I. & SANDEEP, S. (June 2011) Sizing the Distributed Generation with Life Cycle Costing and Greenhouse Gas Abatement.

JAYAWEERA, D., SYED, I. & SANDEEP, S. (March 2011) A software development and simulation of generation and cost optimised controller.

JAYAWEERA, D., SYED, I. & SANDEEP, S. (November 2010) Test Network for the optimal sitting and dispatch assessment of distributed generation.

JIRUTITIJAROEN, P. & SINGH, C. (2008) Reliability constrained multi-Area adequacy planning using stochastic programming with sample-average approximations. IEEE Trans. Power

Systems, 23, (2), 504–513.

KAI, Z., AGALGAONKAR, A. P, MUTTAQI, K. M, et al. (2008). "Optimisation of distributed generation units and shunt capacitors for economic operation of distribution systems." *Universities Power Engineering Conference*, 1–7.

KARLSSON, P., BJORNSTEDT, J., & STROM, M. (2005). "Stability of voltage and frequency control in distributed generation based on parallel-connected converters feeding constant power loads." *European Conference on Power Electronics and Applications*, 1-10.

KASHEM, M. A., LE, D. T., NEGNEVITSKY, M. & LEDWICH, G. (2006). "Distributed generation for minimization of power losses in distribution systems." *IEEE Power Engineering Society General Meeting, Quebec, Canada*, 1-8.

KAUHANIEMI, K., KUMPULAINEN, L. (2004) Impact of distributed generation on the protection of distribution network. *Proceedings of the Eighth IEE International Conference on Developments in Power System Protection*, 1, 315-318.

KAUT, M. & WALLACE, S.W. (2007) Evaluation of scenario generation methods for stochastic programming. Pac. J. Optimiz., 3, (2), 257–271.

KAUT, M. (2006) Scenario Generation for Stochastic Programming A Practical Introduction. Tutorial on Scenario Reduction, http://work.michalkaut.net/papers_etc/scen-gen_intro.pdf.

KEANE, A., O'MALLEY, M. (Aug. 2005) Optimal allocation of embedded generation on distribution networks. *IEEE Transactions on Power Systems.*, 20, (3), 1640-1646.

Kim, K. H., Song, K. B. & Joo, S. K. (Apr. 2008) Multiobjective distributed generation placement using fuzzy goal programming with genetic algorithm. *European Transactions on Electrical Power.*, 18, (3), 217-230.

KUBOTA, Y., GENJI, T., & MIYAZATO, K. (2002). "Verification of cooperative control method for voltage control equipment on distribution network simulator considering interconnection of wind power generators." *Proc of IEEE Power Engineering Society Transmission and Distribution Conference*, 1151-1156.

KUMAR, K. V. & SELVAN, M. P. (2009). "Planning and operation of Distributed Generations in distribution systems for improved voltage profile." *Power Systems Conference and Exposition*, 1–7.

LAVORATO, M., RIDER, M. J., GARCIA, A. V. & ROMERO, R. (2009) Distribution network planning using a constructive heuristic algorithm. Power & Energy Society General Meeting, 2009. PES '09. IEEE.

LE AN, D. T., KASHEM, M. A., NEGNEVITSKY M., AND LEDWICH, G. (2006). "Distributed generation diversity level for optimal investment planning", A*ustralian Universities Power Engineering Conference (AUPEC)*, Melbourne, Australia.

LEDWICH, G., GHOSH, A., ZARE, F. (2010). "Tuning harmonic absorption of voltage source converters." *International Conference on Harmonics and Quality of Power (ICHQP), 2010 Bergamo, Sept 2010*, pp.1-6.

LEDWICH, G., PERERA, L. "Balancing power factor and voltage control on distribution lines" under development.

LONDERO, R. R., AFFONSO, C. M., & NUNES, M. V. (2009). "Impact of Distributed generation in steady state, voltage and transient stability-real case." *IEEE Bucharest Power Tech Conference, Bucharest, Romania*, 1-6.

MCDERMOTT, T. E., DUGEN, R. C. (2002) Distributed generation impact on reliability and power quality indices. *Proceedings of IEEE Rural Electric Power Conference*, D3-D3_7.

MCKAY, M.D., BECKMAN, R.J. & CONOVER, W.J. (1979) A comparison of three methods for selecting values of input variables in the analysis of output from a computer code. Technometrics, 21, (1), 239–245.

MIKHAIL GRANOVSKII, IBRAHIM DINCER & ROSEN, M. A. (May 2006) Economic Aspects Of Greenhouse Gas Emissions Reduction By Utilisation Of Wind And Solar Energies To Produce Electricity And Hydrogen

MILLIGAN, M., SCHWARTZ, M. & WAN, Y. (2003) Statistical Wind Power Forecasting Models: Results forU.S. Wind Farms, Reserach Report.

MITRA, J., PATRA, S. B., & RANADE, S. J. (2006). "Reliability stipulated microgrid architecture using particle swarm optimisation." *International Conference on Probabilistic Methods Applied to Power Systems*, 1–7.

MITRA, P., VENAYAGAMOORTHY, G. K. (Oct. 2010) Wide area control for improving stability of a power system with plug-in electric vehicles. *IET Generation, Transmission & Distribution.*, 4, (10), 1151-1163.

MOISES, P., & MATOS, M. A. (2004). "Loss allocation in distribution networks with embedded generation." *IEEE Transaction on Power Systems*, 19(1), 384-389.

MUTALE, J., STRBAC, G., CURICC, S. & JENKINS, N. (2000). "Allocation of losses in distribution systems with embedded generation." *IEE Proceedings on Generation, Transmission, and Distribution*, 147(1), 7-14.

NAKAWIRO, W., ERLICH, I.: 'Optimal load shedding for voltage stability enhancement by ant colony optimisation'. Proc. 15th International Conference on Intelligent System Applications to Power Systems, Curitiba, November 2009, pp. 1-6

NOVOSEL, D., KING, R.L.: 'Using artificial new neiworks for load shedding to alleviate overloaded lines'. *IEEE Transactions on Power Delivery*, 1994, **9**, (1), pp. 425-433

OCHOA, L. F., PADILHA-FELTRIN, A., HARRISON, P. (2006). "Evaluating distributed generation impacts with a multi objective index." *IEEE Transactions on Power delivery*, 21(3), 1452-1458.

ODAGIRI, S. (2002) Connection between dispersed power sources and utility distribution systems: TEPCO's technical challenges. *Proceedings of IEEE/PES Transmission and Distribution Conference and Exhibition*, 2, 1364-1366.

PADHY, N.P. (2004) Unit commitment—A bibliographical survey. IEEE Trans. Power Syst., 19, (2), 1196-1205.

PAN, F., ZONG, M. & ZHOU, M. (2009) Planning of distributed generation considering marginal capacity cost. Transmission & Distribution Conference & Exposition: Asia and Pacific, 2009.

PAPPALA, V.S., ERLICH, I., ROHRIG, K. & DOBSCHINSKI J. (2009) A Stochastic Model for the Optimal Operation of a Wind-Thermal Power System. IEEE Trans. Power Syst., 24, (2), 940-950.

PERERA, L., LEDWICH, G., GHOSH, A. (2010). "Multiple DSTATCOMs for Distribution Feeder Voltage Support." *under revision for IEEE Trans. on Power Systems*.

PRASETIJO, D., LACHS, W.R., SUTANTO, D.: 'A new load shedding scheme for limiting underfrequency'. *IEEE Trans. Power Systs.*, 1994, **9**, (3), pp. 1371–1378

PREGELJ, A., BEGOVIC, M., & OHATGI, A. (2006). "Recloser allocation for improved reliability of DG-enhanced distribution networks." *IEEE Trans. on Power Systems*, 21(3), 1442-1449.

QUEZADA, V. H. M., ABBAD, J. R., & ROMAN, T. G. (2006). "Assessment of energy distribution losses for increasing penetration of distributed generation." *IEEE Transaction on Power Systems*, 21(2), 533-540.

RAHMAN, S., SHRESTHA, G. B. (1993) An investigation into the impact of electric vehicle load on the electric utility distribution system. *IEEE Transactions on Power Delivery.*, 8, (2), 591-597.

REN, X.C., XUE, Y.S., WU, Q.H., WEI, H.: 'Optimisation and coordination of UF/UVLS placement and multi-step load shedding'. *Autom. of Electr. Power Syst.*, 2009, **33**, (11), pp. 1-7

ROMERO, R., MONTICELLI, A., GARCIA, A., et al. (2002) Test systems and mathematical models for transmission network expansion planning. IEE Proc. Gener. Transm. Distrib., 149, (1), pp. 27-36

ROMERO, R., GALLEGO, R. A. & MONTICELLI, A. (1996) Transmission system expansion planning by simulated annealing. IEEE Trans. Power Syst., 11, (1), 364-369.

RÖMISCH, W., & HEITSCH, H. (2003) Scenario reduction algorithms in stochastic program. Computational Optimisation and Applications, 24, (2-3), 187–206.

SALEHI-DOBAKHSHARI, A., FOTUHI-FIRUZABAD, M.: 'Integration of large-scale wind farm projects including system reliability analysis', *IET Renew. Power Gener.*, 2011, **5**, (1), pp. 89-98

SAMER T., JOHN R.B., & ERIK L. (1996) A Stochastic Model for the Unit Commitment Problem. IEEE Trans. on Power Systems, 11, (3), 1497-1508.

SANAYE-PASAND, M., DAVARPANAH, M.: 'A new adaptive multidimensioanal load shedding scheme using genetic algorithm'. Proc. Canadian Conference on Electrical and Computer Engineering, Saskatoon, Sask., Canada, May 2005, pp. 1974-1977

SAYAS, F.C., ALLAN, R.N.: 'Generation availability assessment of wind farms', *IEE Proc. Gener. Transm. Distrib.*, 1996, 143, (5), pp. 507–518

SIEMENS ENERGY, I. (March 2009) Release 18.2 IPLAN Program Manual PSS®E 32.0.

SIEMENS, P. S. S. (June 2009) PSSE 32.0 Online Documentation.

SINGH, R. K., GOSWAMI S. K. (Feb. 2009) Optimum siting and sizing of distributed generations in radial and networked systems, *Electric Power Components and Systems*, 37, (2), 127-145.

SO, C. W., LI, K. K. (2002). "Protection relay coordination on ring-fed distribution network with distributed generations." *Proceedings of 2002 IEEE Region 10 Conference on Computers, Communications, Control and Power Engineering*, 1885-1888.

SÖDER, L. (September 2004) Simulation of wind speed forecast errors for operation planning of multi-area power system. Proc. Int. Conf. PMAPS, Ames, 723-728.

STAATS, P. T., GRADY, W. M. & ARAPOSTATHIS, A. (Oct. 1997) A procedure for derating a substation transformer in the presence of wide spread electric vehicle battery charging. *IEEE Transactions on Power Delivery*, 12, (4), 1562-1568.

STREIFFERT, DAN., PHILBRICK, R., & OTT A. (June 2005) A Mixed Integer Programming Solution for Market Clearing and Reliability Analysis. Proc. Int. Conf. IEEE Power Engineering Society General Meeting, San Francisco, 2724-2731.

SUN, Q. Y., LI, Z. X., & ZHANG, H. G. (2009). "Impact of distributed generation on voltage profile in distribution system." *2009 International Joint Conference on Computational Sciences and Optimisation*, 1-4.

TAYLOR, A. (June 2003) An Introduction to Life Cycle Costing Involving Structural Stormwater Quality Management Measures

TAYLOR, T. M., WILLIS, H. L., ENGEL, M. V. (1997). "New considerations for distributed network planning and design." *CIRED*, 611-615.

TENG, J. H., LUOR, T. S, LIU, Y. H. (2002). "Strategic distributed generator placements for service reliability improvements." *Power Engineering Society Summer Meeting, IEEE*, 719 – 724.

TERZIJA, V.V., KOGLIN, H.J.: 'Adaptive underfrequency load shedding integrated with a frequency estimation numerical algorithm'. *IEE Proc. Gener. Transm. Distrib.*, 2002, 149, (6), pp. 713-718

TERZIJA, V.V.: 'Adaptive underfrequency load shedding based on the magnitude of the disturbance estimation'. *IEEE Trans. Power Syst.*, 2006, **21**, (3), pp. 1260-1266

UMMELS, B.C., GIBESCU, M. PELGRUM, E., KLING, W.L., & BRAND, A.J. (2007) Impacts of wind power on thermal generation unit commitment and dispatch. *IEEE Transactions on Energy Conversion*, 22, (1), 44–51.

VALLEM, M. R., MITRA, J., & PATRA, S. B. (2006). "Distributed generation placement for optimal microgrid architecture." *Transmission and Distribution Conference and Exhibition*, 1191-1195.

VLACHOGIANNIS, J. G. (Nov. 2009) Probabilistic constrained load flow considering integration of wind power generation and electric vehicles. *IEEE Transactions on Power Systems.*, 24, (4), 1808-1817.

WAN, H., WONG, K. P., CHUNG, C. Y. (2008). "Multi-agent application in protection coordination of power system with distributed generations." *Proceedings of IEEE Power and Energy Society General Meeting-Conversion and Delivery of Electrical Energy in the 21st Century*, 1-6.

WANG, C. & NEHRIR, M. H. (2004). "Analytical approaches for optimal placement of distributed generation sources in power systems." *IEEE Transaction on Power Systems, 19(1)*, 2068-2076.

WANG, C., GUINDO, M. (2006) Three-phase unbalanced radial distribution power flow analysis with wind farms considered. *Automation of Electric Power Systems*, 30(16), 21-26.

WANG, J.H., SHAHIDEHPOUR, M., & LI Z.Y. (2008) Security-constrained unit commitment with volatile wind power generation. *IEEE Transactions on Power Systems*, 23, (3), 1319-1327.

WANG, L. F., & SINGH, C. (2008). "Reliability-constrained optimum placement of reclosers and distributed generators in distribution networks using an ant colony system algorithm." *IEEE Transactions on Systems, Man and Cybernetics Part C: Applications and Reviews, 38(6)*, 757-764.

WANG, L., CHEUNG, H., HAMLYU, A., & YANG, C. G. (2006). "Network-facilitated voltage stability control strategy for power distribution systems." *Pulp and Paper Industry Technical Conference, Canada*, 2006, 1849-1854.

WANG, P., BILLINTON, R.: 'Optimum load-shedding technique to reduce the total customer interruption cost in a distribution system'. *IEE Proc. Gener. Transm. Distrib.*, 2000, **147**, (1), pp. 51-56

WANG, S. X., HUANG, L. J., WANG, C. S., et al. (2007). "Unbalanced power flow for distributed generation in distribution system." *Electric Power Automation Equipment*, 27(8), 11-15, 129.

WANG, X. Z. (2006). "The study of protection coordinate of distributed generation." *M.S. dissertation, Dept. Electrical Engineering, Zhejiang University.*

WASEEM, I., PIPATTANASOMPORN, M., & RAHMAN, S. (2009). "Reliability benefits of distributed generation as a backup source." *IEEE Power & Energy Society General Meeting,* 1 – 8.

WEN, Y., WANG, X. (2008) Effect of distributed generation on protection in distribution system. *Relay*, 36(1), 12-14, 26.

WIKIPEDIA (2000a) http://en.wikipedia.org/wiki/Carbon_emissions_reporting.

WIKIPEDIA (2000b) http://en.wikipedia.org/wiki/Greenhouse_gas

WILLIS, H. L., AND RACKLIFFE, G. B. (1994). "Introduction to integrated resource T&D planning." *ABB Power T&D Company, Inc.*

WILLIS, H. L., SCOTT, W. G. (2000). "Distributed power generation: planning and evaluation." *Marcel Dekker, Inc.*

XIONG, X.F., LI, W.Y.: 'A new under-frequency load shedding scheme considering load frequency characteristics'. *Proc. International Conference on Power System Technology*, Chongqin, China, October 2006, pp. 1-4

XUE, Y.S., REN, X.C., WU, Q.H., WEI, H.: 'A review on optimisation and coordination of under frequency/voltage load shedding'. *Autom. of Electr. Power Syst.*, 2009, **33**, (9), pp. 100-107

XUE, Y.S., WANG, D., WU, Q.H., WEN, F.S.: 'A review on optimisation and coordination of emergency control and correction control'. *Autom. of Electr. Power Syst.*, 2009, **33**, (12), pp. 1-7

YAN, Y., YANG, S.H. WEN, F.S., & MACGILL I. (April 2009) Generation Scheduling with Volatile Wind Power Generation. *Proceedings of SUPERGEN 2009.*

YANG, M., LUO, C. (2006) Optimisation theory, method and solution software. Beijing: Science Press.

YU, H., CHUNG, C. Y., WONG, K. P., et al.: 'A chance constrained transmission network expansion planning method with consideration of load and wind farm uncertainties', *IEEE Trans. on Power Syst.*, 2009, **24**, (3), pp. 1568-1576

YUAN, Y., WU, B. W., LI, Z. J., et al.: 'Flexible planning of transmission system with large wind farm based on multi-scenario probability'. *Electric Power Automation Equipment*, 2009, **29**, (10), pp. 8-12

ZEINELDIN, H. H, EL-SAADANY, E. F., & SALAMA. M. M. A. (2006). "Protective relay coordination for micro-grid operation using particle swarm optimisation." *Large Engineering Systems Conference*, 152-157.

ZEINELDIN, H. H., EL-SAADANY, E. F., SALAMA, M. M. A. (2006) Optimal coordination of overcurrent relays using a modified particle swarm optimisation. *Electric Power Systems Research*, 76(11), 988-995.

ZENG X. J, LI, K. K., CHANG, W. L., et al. (2004). "Multi-agents based protection for distributed generation systems." *Proceedings of the 2004 IEEE International Conference on Electric Utility Deregulation, Restructuring and Power Technologies*, 393-397.

ZHANG, D., XU, X., YANG, L., et al (2007) The Impact of Distributed Generators on Distribution Network Over-voltage. *Automation of Electric Power Systems*, 31(12), 50-54, 85.

ZHOU, Q., TESFATSION, L., & LIU, C.C. (March 2009) Scenario Generation for Price Forecasting in Restructured Wholesale Power Markets. Proc. Int. Conf. IEEE Power Systems & Exposition Conference, 1-8.

ZHU, D., BROADWATER, R. P. & TAM, K. S. (Feb. 2006) Impact of DG placement on reliability and efficiency with time-varying loads. *IEEE Transactions on Power Systems,* 21, (1), 419-427.

ZIARI, I., LEDWICH, G., GHOSH, A., CORNFORTH, D. AND WISHART, M. (2010). "Optimal allocation and sizing of dgs in distribution networks." *IEEE Power & Energy Society General Meeting*, IEEE, USA.

ZIARI, I., LEDWICH, G., GHOSH, WISHART, M., GHOSH, A. (2009). "Initial steps i*n* optimal planning of a distribution system", *Australasian Universities Power Engineering Conference (AUPEC)*, Australia.

12. PUBLICATION LIST FOR PROJECT 3

Research publications on DGs from the joint research teams in Queensland University of Technology and Curtin University of Technology during the Project 3 research period are listed below.

12.1. Part 1: Published and accepted journal papers

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.

Liuhong Wei, Wenxin Guo, Fushuan Wen, Gerard Ledwich, Zhiwei Liao, Jianbo Xin. An on-line intelligent alarm processing system for digital substations. *IEEE Transactions on Power Delivery*, Vol.26, No.3, 2011, pp.1615-1624.

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 *(IEE) Generation, Transmission & Distribution,* Vol.4, No.7, 2010, pp.801-809.

Zhipeng Liu, Fushuan Wen, Ledwich Gerard. Optimal sitting and sizing of distributed generators in distribution systems with uncertainties, accepted for publication in IEEE Transactions on Power Delivery (in press).

Shunqi Zeng, Zhenzhi Lin, Fushuan Wen, Gerard Ledwich. A new approach for power system black-start decision-making with vague set theory, accepted for publication in International Journal of Electrical Power and Energy Systems (in press).

Hui Yang, Fushuan Wen, Gerard Ledwich. Optimal coordination of overcurrent relays in distribution systems with distributed generators based on differential evolution algorithm, accepted for publication by European Transactions on Electrical Power (in press).

M Dewadasa, A Ghosh and G Ledwich. Fold back current control and admittance protection scheme for a distribution network containing DGs. IET Generation, Transmission & Distribution. Vol. 4, No. 8, 2010, pp. 952–962

Ziari, G. Ledwich, A. Ghosh. Optimal voltage support mechanism in distribution networks. *IET Generation, Transmission & Distribution*, Vol. 5, No.1, 2011, PP. 127-135.

Ziari, G. Ledwich, A. Ghosh, D. Cornforth, M. Wishart. Optimal allocation and sizing of capacitors to minimize the transmission line loss and to improve the voltage profile. *Computers & Mathematics with Applications*, Vol. 60, No.4, PP. 1003-1013.

Ziari, G. Ledwich, A. Ghosh. Optimal integrated planning of MV-LV distribution systems using DPSO. *Electric Power Systems Research*, Paper Number EPSR-D-10-00983, Accepted for Publication.

12.2. Part 2: Submitted journal papers

Zhipeng Liu, Fushuan Wen, Gerard Ledwich. Optimal planning of electric vehicle charging Stations in Distribution Systems, submitted to *IEEE Transactions on Power Delivery*.

Jing Zheng, Fushuan Wen, Gerard Ledwich, Jiansheng Huang. Risk control in transmission system planning with wind generators, submitted to IET (IEE) Generation, Transmission and Distribution.

Zhipeng Liu, Fushuan Wen, Ledwich Gerard. An optimal under-frequency load shedding strategy considering distributed generators and load static characteristics, submitted to IET (IEE) Generation, Transmission and Distribution*.*

Weijia Liu, Zhenzhi Lin, Fushuan Wen, Gerard Ledwich. An intuitionistic fuzzy Choquet integral operator based approach for black-start decision-making, submitted to IET Generation, Transmission and Distribution.

Wenxin Guo, Fushuan Wen, Gerard Ledwich, Zhiwei Liao, Xiangzhen He, Jiansheng Huang. A new analytic approach for power system fault diagnosis employing the temporal information of alarm messages, submitted to International Journal of Electrical Power and Energy Systems.

Ming Dong, Liuhong Wei, Fushuan Wen, Gerard Ledwich, Jiansheng Huang. A chance-constrained programming based method for power system fault diagnosis, submitted to International Journal of Electrical Power and Energy Systems.

Lingrong Lu, Fushuan Wen, Gerard Ledwich, Jiansheng Huang. Unit commitment in power systems with plug-in electric vehicles, submitted to European Transactions on Electrical Power.

Ziari, G. Ledwich, A. Ghosh, G. Platt. Integrated distribution systems planning to improve reliability under load growth, Submitted to IEEE Transactions on Power Delivery, March 2011.

Ziari, G. Ledwich, A. Ghosh, G. Platt. Optimal distribution network reinforcement considering load growth, line loss and reliability, Submitted to IEEE Transactions on Power Systems on February 2011.

Ziari, G. Ledwich, A. Ghosh, Optimal Allocation and Sizing of Capacitors and Setting of LTC, Submitted to International Journal of Electrical Power & Energy Systems on November 2010.

Remy Tiako, Dilan Jayaweera, Syed Islam. A Hybrid Algorithm for On-Line Dynamic Security Assessment of Wind Farm Connected Power Systems, submitted to IEEE Transactions on Power Systems.

Dilan Jayaweera, Syed Islam, Sandeep Neduvelil Sukumar. Optimum Sizing of Distributed Generation in Active Distribution Networks, draft is almost ready to submit for *IEEE Transactions on Smart Grids*.

12.3. Part 3: Published/accepted conference papers

Zhipeng Liu, Fushuan Wen, Gerard Ledwich, Xingquan Ji. Optimal sitting and sizing of distributed generators based on a modified primal-dual interior point algorithm, *Proceedings of Fourth*

International Conference on Electric Utility Deregulation and Restructuring and Power Technologies (DRPT 2011), July 6-9, 2011, pp. 1360-1365.

Zhipeng Liu, Fushuan Wen, Gerard Ledwich. Potential benefits of distributed generators to power systems, *Proceedings of Fourth International Conference on Electric Utility Deregulation and Restructuring and Power Technologies* (DRPT 2011), July 6-9, 2011, pp. 1417-1424.

J. M. Dewadasa, A. Ghosh and G. Ledwich. Distance protection solution for a converter controlled microgrid, *Proc. National Power Systems Conference* (NPSC'08), IIT Bombay, 2008.

J. M. Dewadasa, A. Ghosh and G. Ledwich. Line protection in inverter supplied networks, *Proc. Australasian Universities Power Engineering Conference*, AUPEC, Sydney, 2008.

M. Dewadasa, R. Majumder, A. Ghosh and G. Ledwich. Control and protection of a microgrid with converter interfaced micro sources, *International Conference on Power Systems* (ICPS-2009), IIT Kharagpur, December, 2009.

Manjula Dewadasa, Ritwik Majumder, Arindam Ghosh and Gerard Ledwich. Control and protection of a microgrid with converter interfaced micro sources. *International conference in power system* 2009

M. Dewadasa, A. Ghosh and G. Ledwich. An inverse time admittance relay for fault detection in distribution networks containing DGs. *IEEE Asia-Pacific Region-10 Conference TENCON'09*, Singapore, Nov., 2009.

M. Wishart, I. Ziari, M. Dewadasa, G. Ledwich, A. Ghosh. Intelligent distribution planning and control incorporating micro-grids. *IEEE PES General Meeting 2011*, USA.

Ziari, G. Ledwich, A. Ghosh, G. Platt. A new method for improving reliability and line loss in distribution networks. *AUPEC 2010*, December 2010, New Zealand.

Ziari, G. Ledwich, A. Ghosh, D. Cornforth, M. Wishart. Optimal allocation and sizing of DGs in distribution networks. IEEE PES General Meeting 2010, USA.

Ziari, G. Ledwich, M. Wishart, A. Ghosh, D. Cornforth. Optimal allocation and sizing of capacitors to minimize the transmission line loss and to improve the voltage profile. *PCO 2010*, February 2010, Australia.

Ziari, G. Ledwich, M. Wishart, A. Ghosh, M. Dewadasa. Optimal allocation of a cross-connection and sectionalizers in distribution systems. *TENCON 2009*, November 2009, Singapore.

Ziari, G. Ledwich, M. Wishart, A. Ghosh. Optimal allocation and sizing of DGs in a distribution system using PSO. *QUT Smart Systems Postgraduate Student Conference 2009*, October 2009, Australia.

Ziari, G. Ledwich, M. Wishart, A. Ghosh. Initial steps in optimal planning of a distribution system. *AUPEC 2009*, September 2009, Australia.

Dilan Jayaweera, Syed Islam. Value based integration of distributed generation. *20th Australasian Universities Power Engineering Conference: Power Quality for the 21st Century*, Christchurch, New Zealand 5-8 December 2010

Remy Tiako, Dilan Jayaweera, Syed Islam. A class of intelligent techniques for the dynamic security assessment of power systems. *20th Australasian Universities Power Engineering Conference: Power Quality for the 21st Century*, Christchurch, New Zealand 5-8 December 2010

Dilan Jayaweera, Syed Islam, and P. Tinney. Analytical approaches to assess embedded wind

generation effects on distribution networks. *Probabilistic methods Applied to Power Systems Conference*, Singapore, 14-17 June 2010

Dilan Jayaweera, Syed Islam. Probabilistic assessment of distribution network capacity for wind power generation integration. 1*9th Australasian Universities Power Engineering Conference: Sustainable Energy Technologies and Systems*, Adelaide, Australia 27-30 September 2009

12.4. Part 4: Submitted conference papers

Ziari, G. Ledwich, A. Ghosh, G. Platt. Optimal control of distributed generators and capacitors by hybrid discrete particle swarm optimisation, *AUPEC 2011*, September 2011, Australia.

Dilan Jayaweera, Raymond C. Wee, and Syed Islam. Security of supply with dispersed integration of wind power in distribution networks, submitted for *AUPEC 2011*for review

Remy Tiako, Dilan Jayaweera, Syed Islam. Case based reasoning approach for dynamic security assessment of power systems with large penetration of wind power, submitted for *AUPEC 2011* for review

13. APPENDICES

13.1. Appendix A

13.1.1. Table A1 Bus data of the 18-bus system

Bus no	Power of generator（MW）	power of load（MW）	Bus no	Power of generator（MW）	power of load（MW）
1	0	550	10	7500	940
2	3600	840	11	5400	7000
3	0	1540	12	0	1900
4	0	380	13	0	1100
5	7600	6390	14	5400	320
6	0	1990	15	0	2000
7	0	2130	16	4950	1320
8	0	880	17	0	4000
9	0	2590	18	1420	0
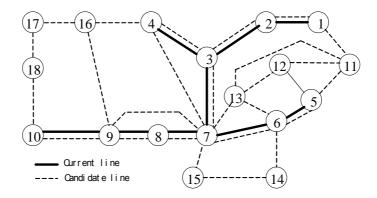
13.2. Table A2 Branch data of the 18-bus system

Branch no	Start bus no	End bus no	Reactance (p.u.）	Rating power (MW）	Original line number	Length (km)
1	1	2	0.0176	2300	1	70
2	1	11	0.0102	2300	0	40
3	2	3	0.0348	2300	1	138
4	3	4	0.0404	2300	1	155
5	3	7	0.0325	2300	1	129
6	4	7	0.0501	2300	0	200
7	4	16	0.0501	2300	0	200
8	5	6	0.0267	2300	1	106
9	5	11	0.0153	2300	0	60
10	5	12	0.0102	2300	0	40
11	6	7	0.0126	2300	1	50
12	6	13	0.0126	2300	0	50
13	6	14	0.0554	2300	0	220
14	7	8	0.0151	2300	1	60
15	7	9	0.0318	2300	0	126
16	7	13	0.0126	2300	0	50
17	7	15	0.0448	2300	0	178
18	8	9	0.0102	2300	1	40
19	9	10	0.0501	2300	1	200
20	9	16	0.0501	2300	0	200
21	10	18	0.0255	2300	0	100
22	11	12	0.0126	2300	0	50

23	11	13	0.0255	2300	0	100
24	12	13	0.0153	2300	0	60
25	14	15	0.0428	2300	0	170
26	16	17	0.0153	2300	0	60
27	17	18	0.014	2300	0	55

13.3. Figure A1 18-bus system

14. APPENDIX B

14.1. Table B1 Bus data of the 46-bus system

Bus no.	Power of generator （MW）	Power of load （MW）	Bus no.	Power of generator （MW）	Power of load （MW）
1	0	0	24	0	478.2
2	0	443.1	25	0	0
3	0	0	26	0	231.9
4	0	300.7	27	54	0
5	0	238	28	730	0
6	0	0	29	0	0
7	0	0	30	0	0
8	0	72.2	31	310	0
9	0	0	32	450	0
10	0	0	33	0	229.1
11	0	0	34	221	0
12	0	511.9	35	0	216
13	0	185.8	36	0	90.1
14	944	0	37	212	0
15	0	0	38	0	216
16	1366	0	39	221	0
17	1000	0	40	0	262.1
18	0	0	41	0	0
19	773	0	42	0	1607.9
20	0	1091.2	43	0	0

| 21 | 0 | 0 | 44 | 0 | 79.1 |
| 22 | 0 | 81.9 | 45 | 0 | 86.7 |
| 23 | 0 | 458.1 | 46 | 599 | 0 |

14.2. Table B2 Branch data of the 46-bus system

Branch no	Start bus no	End bus no	Reactance (p.u.)	Rating power (MW)	Original line number	Cost (10³ dollar)
1	1	7	0.0616	270	1	4349
2	1	2	0.1065	270	2	7076
3	4	9	0.0924	270	1	6217
4	5	9	0.1173	270	1	7732
5	5	8	0.1132	270	1	7480
6	7	8	0.1023	270	1	6823
7	4	5	0.0566	270	2	4046
8	2	5	0.0324	270	2	2581
9	8	13	0.1348	240	1	8793
10	9	14	0.1756	220	2	11267
11	12	14	0.074	270	2	5106
12	14	18	0.1514	240	2	9803
13	13	18	0.1805	220	1	11570
14	13	20	0.1073	270	1	7126
15	18	20	0.1997	200	1	12732
16	19	21	0.0278	1500	1	32632
17	16	17	0.0078	2000	1	10505

18	17	19	0.0061	2000	1	8715
19	14	26	0.1614	220	1	10409
20	14	22	0.084	270	1	5712
21	22	26	0.079	270	1	5409
22	20	23	0.0932	270	2	6268
23	23	24	0.0774	270	2	5308
24	26	27	0.0832	270	2	5662
25	24	34	0.1647	220	1	10611
26	24	33	0.1448	240	1	9399
27	33	34	0.1265	270	1	8288
28	27	36	0.0915	270	1	6167
29	27	38	0.208	200	2	13237
30	36	37	0.1057	270	1	7025
31	34	35	0.0491	270	2	3591
32	35	38	0.198	200	1	12631
33	37	39	0.0283	270	1	2329
34	37	40	0.1281	270	1	8389
35	37	42	0.2105	200	1	13388
36	39	42	0.203	200	3	12934
37	40	42	0.0932	270	1	6268
38	38	42	0.0907	270	3	6116
39	32	43	0.0309	1400	1	35957
40	42	44	0.1206	270	1	7934
41	44	45	0.1864	200	1	11924
42	19	32	0.0195	1800	1	23423

43	46	19	0.0222	1800	1	26365
44	46	16	0.0203	1800	1	24319
45	18	19	0.0125	600	1	8178
46	20	21	0.0125	600	1	8178
47	42	43	0.0125	600	1	8178
48	2	4	0.0882	270	0	5965
49	14	15	0.0374	270	0	2884
50	46	10	0.0081	2000	0	10889
51	4	11	0.2246	240	0	14247
52	5	11	0.0915	270	0	6167
53	46	6	0.0128	2000	0	16005
54	46	3	0.0203	1800	0	24319
55	16	28	0.0222	1800	0	26365
56	16	32	0.0311	1400	0	36213
57	17	32	0.0232	1700	0	27516
58	19	25	0.0325	1400	0	37748
59	21	25	0.0174	2000	0	21121
60	25	32	0.0319	1400	0	37109
61	31	32	0.0046	2000	0	7052
62	28	31	0.0053	2000	0	7819
63	28	30	0.0058	2000	0	8331
64	27	29	0.0998	270	0	6672
65	26	29	0.0541	270	0	3894
66	28	41	0.0339	1300	0	39283
67	28	43	0.0406	1200	0	46701

68	31	41	0.0278	1500	0	32632
69	32	41	0.0309	1400	0	35957
70	41	43	0.0139	2000	0	17284
71	40	45	0.2205	180	0	13994
72	15	16	0.0125	600	0	8178
73	46	11	0.0125	600	0	8178
74	24	25	0.0125	600	0	8178
75	29	30	0.0125	600	0	8178
76	40	41	0.0125	600	0	8178
77	2	3	0.0125	600	0	8178
78	5	6	0.0125	600	0	8178
79	9	10	0.0125	600	0	8178

14.3. Figure B1 46-bus system