Strategic Distribution Network Planning with Smart Grid Technologies

A thesis submitted to

Imperial College London

For the degree of Doctor of Philosophy

By

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September 2014

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Declaration of Originality

The material contained within this thesis is my own work, except where other work is appropriately referenced. Any use of the first person plural is for reasons of clarity.

Sara Mohtashami

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Abstract

Increased penetration of distributed generations in distribution networks are altering the technical characteristics of the grid, pushing them to operate closer to their limits of safe and reliable operation. New renewable generators connecting to the distribution network will be constrained due to the presence of thermal and voltage constraints during times of low demand and high generation output. The traditional reinforcement planning by means of increasing the capacity of network assets can be very costly and usually ends up in overinvested network with low utilization rates of the assets. In recent years, some smart technologies have been introduced to be used to increase the utilization of network assets and provide the adequate capacity for Distributed Generations (DGs). These smart solutions can help the Distributed Network Operators (DNOs) to provide cheaper and faster network connections for DGs.

This thesis presents a multi epoch Optimal Power Flow (OPF) model for capacity and voltage management of a distribution network for integrating new DGs. The model uses the smart solutions including Dynamic Line Rating (DLR), Quad-Booster (QB), Static VAR Compensator (SVC) and Automatic Network Management (ANM) for DGs as well as the traditional reinforcement options. Also the model finds the optimal connection points for new DGs to reduce the cost of network investment and DG curtailment.

The multi epoch model is solved with both incremental approach where the investment is carried out incrementally and with integrated approach where the planning is done strategically anticipating the future needs of the network. It compares the application of smart solutions in short and long term planning. The proposed model is applied to a generic UK distribution network and the results are discussed.

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List of Symbols

IC_{ep}	investment cost of the system in ep^{th} epoch
OC_{ep}	operation cost of the system in ep^{th} epoch
C_{ep}^{Tr}	transformer reinforcement cost in ep^{th} epoch
C_{ep}^{QB}	quad booster investment cost in ep^{th} epoch
C_{ep}^{DLR}	DLR investment cost in ep^{th} epoch
C_{ep}^{line}	line reinforcement cost in ep^{th} epoch
C_{ep}^{svc}	SVC investment cost in ep^{th} epoch
N_{final}	final year in the planning horizon
$StrYr_{ep}$	the start year of ep^{th} epoch
$EndYr_{ep}$	the end year of ep^{th} epoch
K_y	present value factor
$T_{candidate}$	the set of transformers which are candidate for reinforcement
$Tr_{i,ep}$	additional capacity for transformer i as reinforcement in ep^{th} epoch
$\pi_{i,ep}^{Tr}$	the annuitized cost of reinforcing the transformer i in ep^{th} epoch, (£/MVA.yr)
$QB_{candidate}$	the set of lines which are candidates for installing quad booster
$QB_{i,ep}$	decision variable to install a QB in series with line i in ep^{th} epoch (binary)
π_{ep}^{QB}	the annuitized cost of installing a QB in ep^{th} epoch (£/MVA.yr)
Cap_{QB_i}	the capacity of QB installed in series with line i
$L_{i,ep}$	additional capacity for line i as reinforcement in ep^{th} epoch
$\pi_{i,ep}^{VL}$	the annuitized variable cost of reinforcing line i in ep^{th} epoch ,(£/MVA.yr)

$F_{i,ep}^L$	decision variable to reinforce line i (binary)
$\pi_{i,ep}^{fixL}$	fixed cost of reinforcing line i in ep^{th} epoch (£)
$B_{i,ep}^{DLR}$	decision variable to install DLR in line i in ep^{th} epoch (binary)
π_{ep}^{DLR}	the annuitized cost of installing DLR in a line in ep^{th} epoch (£/yr)
DLRcandidate	the set of overhead lines which are candidates to install DLR
Lcandidate	the set of lines which are candidates for reinforcement
π_{ep}^{SVC}	the annuitized cost of installing SVC in ep^{th} epoch, (£/MVAR.yr)
$Q_{i,ep}^{SVC}$	Capacity of installed SVC on bus i in ep^{th} epoch
SVCcandidate	the set of buses which are candidates to install SVC
C_{ep}^{dgcur}	total DG curtailment cost in ep^{th} epoch
C_{ep}^{Lshed}	load shedding cost in ep^{th} epoch
C_{ep}^{os}	over slack cost in ep^{th} epoch
Th	set of operating snapshots per year
NF-DG:	set of DGs connected to network with a non-firm connection policy
π_y^{ec}	cost of energy curtailment in y^{th} year (£/MWh)
$\tau(t)$	the duration of t^{th} snapshots in a year, (hrs)
$\overline{Pdg}_{i,t,ep}$	generation capacity of DG_i at t^{th} snapshot in ep^{th} epoch
$Pdg_{i,t,y}$	power generation of DG_i at t^{th} snapshot of year y
π_y^{shed}	cost of load shedding in y^{th} year (£/MWh)
$Pshed_{i,t,y}$	involuntary loss of active power at bus i at t^{th} snapshot of year y
$Qshed_{i,t,y}$	involuntary loss of reactive power at bus i in t^{th} snapshot of year y
π_{slack}	penalty cost of overslack variables
$P_{i,t,y}^{os}$	positive decision variables representing an artificial active load
$Q_{i,t,y}^{os}$	positive decision variables representing an artificial reactive load
Nbus	set of network buses
Nload	set of network loads
G	the conductance matrix of the network
B:	the susceptance matrix of the network
δ	the delta matrix of the network
QBtap	QB shift angle
Gbr_i	conductances of i^{th} branch
Bbr_i	susceptances of i^{th} branch
deltacap	the difference between dynamic and static capacity of an overhead line

P_{export}	the amount of active power exported to the upstream grid in connection buses
Q_{export}	the amount of reactive power exported to the upstream grid in connection buses

Abbreviations

DNO	Distribution Network Operator
LCTP	Low Carbon Transition Plan
DG	Distributed Generator
DLR	Dynamic Line Rating
QB	Quad-Booster
ANM	Active Network Management
AVC	Automatic Voltage Controller
OLTC	On Load Tap Changer
SVC	Static Var compensator
SCL	Short Circuit Level
SCR	Short Circuit Ratio
SAIFI	System Average Interruption Frequency Index
SAIDI	System Average Interruption Duration Index
ROCOF	rate of change of frequency
DER	Distributed Energy Resources
QBCS	Quad-booster Controller System

Publication

S. Mohtashami, D. Pudjianto and G. Strbac, “Strategic Distribution Network Planning with Smart Grid Technologies,” submitted to *IEEE Trans. Smart grids*.

Acknowledgements

I would like to express my sincere gratitude to my supervisor Prof. Goran Strbac for his continuous support and guidance through all stages of my research and his exceptional insights into the subject which has resulted in this thesis. Without his help this work was simply impossible.

I extend my thanks to Dr. Danny Pudjianto. A considerable large volume of this work was for his inspiring discussions and valuable suggestions during this research.

I have to thank Dr. Jianzhong Wu from Cardiff University and Dr. Balarko Chaudhuri who had kindly accepted to the examiners of my thesis and improved this thesis with their useful suggestions.

Thanks also to past and present colleagues in the Control and Power Group at Imperial College for providing an enjoyable working environment: Jelena, Sara, Jose, George, Ankur, Yousef, Claudia(s), Yashodhan, Hossein, James, Hadi, Pedro and Suzan. Also I have to thank Dr. Vladimir Stanojevic and Ankur Majumdar for their influence on this work through the sharing of knowledge.

And most importantly, my thanks and love to my father Aboutaleb and my sister Samira who inspired me to continue my study through all the difficulties in last two years.

Introduction

1-1- Motivation

UK has committed itself to dramatic cuts in greenhouse gas emissions. The UK's Climate Change Bill [1] provides a legally binding commitment to an 80% cut by 2050 from the 1990 baseline. Renewable energy is at the heart of the UK Low Carbon Transition Plan (LCTP) [2]. In the Renewable Energy Strategy [3], the Department of Energy and Climate Change (DECC) sets an ambitious target for 30% of the UK's electricity to be generated from renewable energy sources by 2020 and up to 40% by 2030. Wind farms, the UK's largest renewable energy growth sector, are suitable for connection to the distribution system when rated at 30MW or below. The increasing penetration of distributed generators (DGs) is changing

the role of distribution systems. This may be costly if not accompanied by commensurate changes to the operation/planning strategy.

Over recent years distribution network owners (DNOs) in UK have experienced increased activity in renewable generation development in their networks. There is a rapid rise in connection applications in most area of the distribution networks. This increase distribution connected DG capacity is expected to require significant network reinforcement to mitigate network thermal and voltage constraints and reverse power flow issues. Long-term development statements, which are produced by all distribution network operators in GB, provide generation developers with some visibility of available network capacity. However, where multiple developments are under consideration, these long-term statements cannot provide a reliable indication of the many potential permutations of generation which may eventually be connected, or in what order, or therefore at what point in time substantial reinforcement would be required. This leaves generation developers in the unsatisfactory position of being unable to reliably predict network connection costs or, therefore, the commercial viability of their projects [4].

The fit and forget approach to network investment, arising from generation connection, leads to suboptimal solutions, causing overinvested network with high connection costs. In addition, these higher costs and/or the uncertainty of future connection costs can make the financial risk of generation investment unattractive to developers. This poses a significant risk to the success of the Renewable Energy Strategy [4].

This thesis aims to demonstrate how, through the innovative integration of smart technological and commercial solutions, the cost effective connection of renewable generation to a distribution network can be achieved.

1-2 Problem statement

The main research questions of this thesis are:

1. What are the technical solutions that allow faster and cheaper integration of DG within the distribution network?

The thesis will use an innovative approach to integrate new technology in order to address the technical problems of the distribution networks caused by integrating DGs. The technical problem considered here are:

Thermal constraints -Increased penetration of distributed generations in distribution networks are altering the technical characteristics of the grid, pushing them to operate closer to their limits of safe and reliable operation. New renewable generators connecting to the network will be constrained due to the presence of thermal constraints during times of low demand and high generation output.

Voltage constraints- it is uncommon for a considerable level of renewable generation to be connected to a limited area of distribution network without increasing the voltage profile of the network.

Technical solutions

The traditional reinforcement planning by means of increasing the capacity of network asset can be very costly and usually ends up in overinvested network with low utilization rates of the assets. In recent years, some smart technologies have been introduced to be used to increase the utilization of network assets and provide the adequate capacity for DGs. The most distinctive and recent ones are:

- **Dynamic Line Rating (DLR)** - DLR involves monitoring local weather station data and calculating the ampacity ratings of overhead lines based on the real weather conditions. Dynamic line rating has the potential to allow relaxations of existing constraints and prevent the need for prescribed seasonal limits to export to the distribution network.
- **Quad-Booster (QB)** - QB is installed in series with lines in order to manage power flows in parallel circuits. QB forces a phase angle shift between the two ends of a line and creates a real power flow. A phase shift of degrees is all that is needed to move massive amount of power around the system. QB has been used widely at the transmission level over the years to control power flow on parallel three phase network. Its application at distribution level has been introduced for the first time by UK Power Networks which designed a quad booster for 33kV distribution network.
- **Active Network Management (ANM)** - connects separate components of a smart grid such as smaller energy generators, renewable generation, storage devices, etc... by implementing software to monitor and control the operation of these devices. Connection of these technologies to the main network ensures they are fully integrated into the energy system and thus can be used in an efficient way, thereby reducing the need to invest in expensive energy network reinforcement. Under this scheme, new energy

generators can be instructed, via automated controls, to limit their power output thus avoiding too much energy being put onto the network that could otherwise cause outages and system faults. Calculations of the allowed amount of power that can be put onto the network are derived from real-time network measurements. Active Network Management takes continuous measurements necessary to control demand and generation and network control devices, whilst minimizing network losses, stabilizing the system and detecting faults. Active network management monitors and controls the grid so that power companies and utilities can use this reserve capacity for new connections. This approach can create up to two or three times more capacity to host new generation and demand. Making this capacity available for new generators and loads, means that the existing grid can accommodate a larger amount of DGs [6].

In this thesis a novel mixed integer AC OPF model is formulated to plan for network reinforcement considering both the traditional and the smart solutions at the same time and find the optimal plan.

2. What are the commercial solutions that allow DNOs to integrate more DGs with lower connection costs in network?

In fit and forget approach the DNOs provide a firm network access for the DGs so the DGs can operate with full capacity in all operating conditions. This firm access of DGs use the capacity of the grid in suboptimal way and can sterilize the network to integrate more DGs. The non-firm access for DGs can lower the reinforcement costs of network and increase the capacity of networks to integrate more DGs.

Recently, in UK distribution networks, a limited form of active control over generators provides control signals to constrain generator output during unplanned outages. Most of these systems are relay driven meaning that they are only on/off operation conditions or they have a number of preset seasonal power export levels. These systems cannot provide a real time control of generators power export in regards to available capacity on the network. ANM can provide real time control of both active and reactive power of generator export and enable a closer match to available network capacity. If generators are to be connected to the distribution network and be actively managed (i.e. have their output regulated to meet distribution network constraints) then new commercial arrangements and connection agreements are required.

The mixed integer AC OPF model formulated in this thesis makes a balance between the cost of investment and the reduction in the operating cost, and anticipates the volumes of energy curtailment to arrange a commercial agreement between the DNOs and DGs owners.

3. Where the optimal connection point is for a new DG regards to network investment and operation costs?

The size and the location of the DGs in the grid can affect the cost and the amount of network reinforcement. Although in most cases the locations of DGs are not decided by the DNOs, still the network connection points can be decided by them. The shortest feasible path to connect a DG to a grid is not always the best connection although the connection cost is at its minimum. Sometimes, it is more beneficial to invest a bit more on the network connection and choose a longer path

if in return there would be a cut in the reinforcement cost of the grid or the amount of DGs curtailment. The connection point of a DG can also affect the capacity of the grid to integrate more DGs in future. When a DG is connected to a particular constrained area of a grid it can disable the grid for further DG integration as a result of voltage rise or overloaded circuits. Therefore, along with the connection cost, it is important to consider network capacity for further DG integration when connecting a new DG. In this thesis a multi-epoch optimization model is formulated to find the optimum connection point for projected DGs to minimize network reinforcement and DG curtailment costs.

1-3 Thesis structure

This thesis is organized into six technical chapters, each of which addresses one or more of the tasks identified in section 1.2.

Chapter 2 discusses about the technical impacts of DGs integration on distribution networks. It reviews the different DG connection policies and different approaches towards the future distribution systems.

Chapter 3 introduces the Quad Booster and the Dynamic Line Rating as two of the smart technologies used in distribution network reinforcement planning. Both of these two technologies are used combined with ANM. The operation and application of these two technologies are discussed.

Chapter 4 develops a multi epoch model for the voltage and thermal management of distribution networks with integration of new DGs. The traditional reinforcement as well as smart technologies and ANM of DGs are considered as planning options to find the

minimum cost solution to integrate DGs in distribution networks. The multi epoch OPF models are solved with two different approaches: incremental and integrated. In incremental planning the planning horizon is divided into short-terms periods and the investment is carried out incrementally started from the first period. The integrated planning is a long-term planning that finds the optimal solution for the planning horizon. In this approach the investment is carried out strategically, anticipating the future needs of the network.

Chapter 5 applies the proposed OPF model to a 33kV distribution network similar to that of the UK Power Network in Peterborough area. The model is solved via an incremental approach. To investigate the impact of smart and commercial solutions on the network planning cost, the planning is done with different planning options as follows and the results are compared:

- 1) DG curtailment
- 2) Traditional reinforcement + DG curtailment
- 3) Smart + traditional reinforcement
- 4) Smart + traditional reinforcement + DG curtailment

Chapter 6 applies the OPF model to the same network, this time with the integrated approach. The results are then compared to the results in Chapter 5 to see if the smart technologies have the same competences in both short and long term planning.

Chapter 7 modifies the OPF model in Chapter 4 to include the DG connection costs. There would be some alternative connection points besides the conventional points for the new DGs. The model makes a trade-off between the connection costs, network reinforcement and DG curtailment costs and finds the optimum connection points for the

new DGs. The model is applied to the test network and the results are compared to the results of Chapters 5 and 6 to see how different connection points can affect the network planning costs.

Chapter 8 summarizes the achievements of this thesis and considers some further work that would improve the planning tool.

1-4- Original contributions

The current passive “fit and forget” distribution network planning approach is not fit for systems with high DG penetration. The network based solutions will lead in high integration costs and discourage deployment of new DGs. Alternative approaches such as use of ANM and the application of smart grid technologies (DLR, QB, SVC) require new distribution network planning tools. The spectrum of investment possibilities increases significantly with these new technologies and the planner will require timing, location, type and the optimal amount of investment as well as the setting of control devices. The use of traditional load flow analysis based on manual trial and error practices will not be efficient and lead to sub-optimal results. Also application of smart solutions requires that all feasible operating conditions be modeled and optimized for planning purposes. To balance the cost of investment with the operation cost contributed by the lost revenue of DG due to network constraints, accurate modeling of the impact and duration of the constraints is also needed.

This work has made significant and novel contributions in the area of optimal distribution reinforcement planning. A mixed integer AC OPF model formulated in this thesis makes a balance between the cost of investment and the reduction in the network operating cost. Both traditional and smart reinforcement options are considered at the

same time as planning options. The smart reinforcement options include using DLR, QB, SVC and DG curtailment under the concept of ANM. This is the first planning study to incorporate quad boosters as a means of controlling power flow in order to increase utilization of network assets in the distribution network.

The planning is done based on a wide range of operating conditions not like most of the planning which only consider the two extreme operating conditions: minimum generation – maximum load and maximum generation – minimum load. Each operating snapshot is a unique combination of load and generation level. Also different seasonal conditions are considered to be able to model the impact of DLR.

Current planning approach focuses on minimizing the short-term cost. The price control period is much shorter than the lifetime of the assets. Thus the investment decisions may not be optimal in the long-term and the investment is carried out incrementally rather than strategically anticipating the future needs of the network. In this thesis the multi epoch distribution network planning is solved both with incremental and integrated approaches to compare the results of short-term and long-term planning.

The case study presented in Chapter 5 provides a new analysis of the value of smart solutions and non-firm network access in managing the voltage and capacity of networks, compared to the traditional solutions and firm access. Also the relative value of smart and commercial solutions in network reinforcement planning is compared in different planning horizons in Chapters 5 & 6.

The extension of the OPF model in Chapter 7 is new in considering the tradeoff between the connection costs of DGs with network reinforcement and DGs curtailment costs. The OPF model in this chapter uses a novel method to model the switching of new

DGs to their candidate connection points without adding to the complexity of the OPF model.

Review of traditional and alternative DG connection policies

Existing electrical energy systems were designed and built to accommodate large-scale generating plants, with demand traditionally viewed as uncontrollable and inflexible and with centrally controlled operation and management. At a regional level, electricity is delivered from transmission to the distribution networks and then to the end consumers in a unidirectional fashion via a number of voltage transformations.

Radical changes are now underway within the existing electricity network caused by re-regulation of the energy supply, economical and environmental constraints, more sensitive equipments, power quality requirements and the increasing penetration of distributed generation. Increased concern over climate change and associated interest in

renewable energy and energy efficiency has resulted in a continuous increase in the amount of renewable generation. Figure 2-1 shows the amount of UK renewable installed capacity during 2006 – 2012.

Figure 2.1: UK renewable installed capacity during 2006- 2012 [6]

Wind farms with a rating less than 30MW are suitable for connection to the distribution system, given the lower cost of connection for the generator and their relatively small capacity [7].

The increasing penetration of distributed generation is changing the role of distribution systems. What were originally passive networks purely for the delivery of electricity to the consumer are now networks that are being utilised for the harvesting of energy from a myriad of distributed energy resources. The increased proliferation of these distributed generators has lead to changes in the characteristics of the network, with more variable and bidirectional active and reactive power flows. These generators

are altering the technical characteristics of the networks, and pushing them to operate closer to their limits of safe and reliable operation.

The appearance of distributed power generation technology has made an enormous impact on the run of distribution network, brought a substantial challenge to the traditional distribution network planning as well, making power planners take into account the impact of the distributed power generation in the selection of the best programs. The general power of distributed generation is always directly connected to the power distribution system, so that when there is a large number of a connection, it will seriously affect the design, control and operation of the distribution system and affect the reliability and security of the system. This requires making appropriate changes to the methods of traditional distribution network planning.

In Section 1 the impacts of DGs integration on the network are reviewed. Different connection policies are discussed as long as different approaches towards future distribution systems in Sections 2 and 3. Section 4 discusses about active network management and smart technologies and their application in new distribution networks. Section 5 reviews the commercial arrangement for allocating constrained capacity with some national and international practices of integrating DGs and Section 6 gives a summary of the chapter.

2-1- Technical impacts of DGs

The impact of DG on the distribution network planning includes the following areas:

- Load Forecast
- Equipment Ratings
- Short Circuit Level

- Short Circuit Ratio
- Voltage Rise
- Losses
- Power Quality
- Reliability
- Security of supply
- Protection

Load Forecast

The existence of DGs in the distribution networks causes more uncertainty to the load forecasting than before. As large number of consumers will install DG, it would be more difficult for the network planners to perform an accurate load growth forecast.

Equipment Ratings

The increased proliferation of these distributed generators has lead to changes in the characteristics of the network, with more variable and bidirectional active and reactive power flows. These generators are altering the technical characteristics of the networks, and pushing them to operate closer to their limits of safe and reliable operation. As a result, the need for distribution networks to operate at their maximum capacity is being felt particularly with DG.

Short Circuit Level (SCL)

The magnitude of the transient voltage drop experienced at the buses in a network is an indication of the strength of the system. In this manner the SCL is a measure of the strength or robustness of a system [52]. The SCL of a system refers to the current that

results when there is a fault on the system. Generators, depending on the type of electrical machine employed, may contribute to the SCL. An increase in the SCL is generally favourable as it will increase the strength of the system. Although it must be ensured that the short circuit level does not exceed the rating of breakers and other equipment and this poses a hazard to the safe operation of the network. A maximum short circuit rating for all equipment is laid down in distribution codes [7].

Short Circuit Ratio (SCR)

The short circuit ratio is the ratio of generator power to the short circuit level [8]. It gives an indication of the voltage dip experienced near the generation in the event of a feeder outage. The connection of induction generators to high impedance circuits may lead to voltage instability problems if the SCR is not kept within acceptable limits. The dip in wind farm terminal voltage that results from a fault leads to an acceleration of the induction generator, leading to over speed [9]. If the speed is increased to a level above the critical value, the generator will accelerate out of control. This may lead to voltage collapse as the induction generator absorbs more reactive power [10]. If the short circuit level is large enough, the transient voltage dip will be limited and the system will remain stable.

Voltage Rise

When DG is connected to a part of network, it changes the active and reactive flows as a result the voltage profile through the lines. It has been shown that DG leads to a significant voltage rise at the end of the long, high impedance lines [11]. Voltage rise happens in low demand and high generation profiles, which leads to a large amount of power flow along lightly loaded lines with high impedance. This often happens in rural

areas, where demand tends to be low. In addition, the resistive element of the lines on distribution systems is higher than other lines. This leads to an X/R ratio of ≤ 5 rather than a more typical value of between 10 and 20 on transmission systems. This only serves to exacerbate the voltage rise problem. In the circuit shown in Figure 2-2, the voltage at the generator is given by equation (2-1).

Figure 2.2: Voltage rise in a line

$$V_G = V_L + \frac{PR_L + XQ_L}{V_L} + j \frac{XP_L - RQ_L}{V_L} \quad (2-1)$$

$Z=R+jX$: is the impedance of the line, P_L and Q_L are active and reactive power at the bus and V_G and V_L are the voltages at the generator and bus respectively. Thus it can be seen that the generator voltage will be the load/bus voltage plus some value related to the impedance of the line and the power flows along that line. It is evident that the larger the impedance and power flow the larger the voltage rise. The increased active power flows on the distribution network have a large impact on the voltage level because the resistive elements of the lines on distribution networks are higher than other lines. The voltage must be kept within standard limits at each bus as given by Equation (2-2).

$$\forall i \in N \quad V_{\min i} < V_i < V_{\max i} \quad (2-2)$$

where $V_{\min i}$ and $V_{\max i}$ refer to the minimum and maximum voltage limits at the i^{th} bus.

Losses

Losses are an important consideration when designing and planning the distribution system. Losses are inevitable on any network; however, the amount can vary considerably depending on the design of the network. With the introduction of distributed generation, the network is being utilised in a different way with more variable and bidirectional power flows. The level of losses is closely linked to the power flows. Losses are a function of the square of the current, i.e. a doubling in current results in losses being quadrupled. Therefore, the allocation of DG and the altered power flows that result may have a significant impact on losses and may provide an opportunity to ameliorate them. By accessing DG nearby loads in distribution network, the power flow direction of the whole distribution network will change. There are 3 conditions according to the relationship between nodal load and DG's contribute value:

(1) The load of every node in the system is bigger than or equal to the output value of DG of this node;

(2) At least one node's DG output value is bigger than the load of this node, but the whole system's DG output value is smaller than the system's total loads;

(3) At least one node's DG output value is bigger than the load of this node, and but the whole system's DG output value is bigger than the system's total loads.

As for condition (1), DG will have effected on reducing loss of the distribution network. As for condition (2), DG will probably increase the loss of some lines in the distribution network, but generally speaking, the whole system's loss will reduce. As for condition (3), if DG's total output value is twice smaller than the total load, the result is similar to condition (2), otherwise, the whole distribution network system's loss will more than that without DG. Therefore, the application of DG may increase or reduce the system's loss.

Power Quality

DG can have a considerable impact on power quality within the distribution system. Voltage flicker refers to dynamic variations in the system voltage. It can be an issue with wind power, given the variable nature of its energy source. However, the development of more sophisticated turbines has reduced the severity of flicker, due to the increased filtering effect of the generators. Some forms of DG may employ power electronic converters to interface with the system. This can alter the harmonic impedance of the system and care must be taken at the design and planning stage. In particular, there is the potential for resonances between capacitors or cables, which may have a detrimental effect on the operation of the generator. There are standards which dictate the acceptable levels of each of these quantities, which must be adhered to [12]. DG also has the potential to improve the power quality, through its contribution to the short circuit level.

Reliability

Reliability has always been an important issue for system planners and operators [13]. Reliability can be measured by the indices of SAIFI (System Average Interruption

Frequency Index) and SAIDI (System Average Interruption Duration Index), which measure the average frequency and duration of supply interruptions respectively. With the advent of DG, new reliability models and methods of assessing distribution reliability have been proposed.

If the distributed generation is only used as the standby power supply, it can improve power supply system reliability; but if there is parallel operation between DG and power network, the reliability of power supply system is possible to be weakened. For instance: there are a great deal of DG in the system, if DG is failed to coordinate with each other DG will decrease system reliability. In addition to that, when there are disturbances appearing, due to the high uncertainty of DG (such as the photovoltaic cells influenced by the intensity of solar radiation), the system reliability is also probably decreased. At present, once there disturbances arise in actual system; it's used to cut off all the DG to renew the system to the original structure, however, which is not the best way.

Protection

The majority of protection systems for distribution network operate based on unidirectional power flows from the transmission network down through the lower voltage networks [13]. As mentioned previously DG is changing the flows on the network. This can lead to problems with the operation of the protection system such as false tripping [8] another issue encountered with DG is loss of mains detection or islanding. Two techniques for loss of mains are normally used. These are vector shift and rate of change of frequency (ROCOF). Vector shift relays detect a change in load impedance to the generator by detecting the change in the voltage vectors and can be used to trip the generator breaker, enforcing the controlled re-synchronisation

procedure. ROCOF is the most common form of loss of mains protection used as it may be used with induction generators. Induction generators are the most common type of machine used with wind generation. ROCOF operates based on the resulting change in frequency from the loss of grid supply. There is, however, a number of performance issues associated with ROCOF relays as detailed in [9]. New methods of islanding detection have also been proposed which are designed to work effectively with DG [10].

2-2- Connection policies

Distribution network operators face the challenge of accommodating high concentrations of distributed generation connections on the electricity network. Where there is high demand of connection requests, the connection can be costly and time consuming.

The DG connection policy employed by the DNO will affect the penetration of DG and also the costs and benefits from installing DG.

There are two different types of network connection policies for DGs: firm and non-firm access. The amount of firm access granted under the connection agreement to distributed generator is the level of output at which they can always operate without violating any of the networks constraints [7]. Non-firm access refers to output greater than this amount, at which generators may be allowed to operate depending on the system conditions throughout the year. This means that in the presence of network constraints (e.g. voltage and thermal constraints), the DNO reserves the right to reduce the generation output based on the terms and conditions set in the interruptible contract agreement.

In non-firm connection there would be an amount of risk for DG owner as the DGs are only allowed to export their generation to the grid in certain operating conditions. Non-firm connection is assumed recently as a cost effective way to integrate DGs in distribution networks.

The firm connection is the traditional connection which allows the export of full generation capacity to the network to guaranty the capacity, in this kind of connection, the reinforcement of the distribution network is usually needed. The firm connection is more reasonable for non-variable energy sources but in the case of variable energy sources such as wind non-firm connection is more applicable due to the unpredictability of the sources [7].

These two different connections both have advantages and disadvantages. A non-firm connection provides a cheaper connection costs, avoidance of network reinforcement, faster connection and larger capacity connections. A firm connection guarantees the maximum export capacity and offers market compensation in the case of network constraints. However, a non-firm connection may affect the financial viability of the generator as a result of interruptible capacity and no payment for energy curtailed. A firm connection on the other side needs high connection and reinforcement costs and longer connection time.

It is cleare that both schemes has pros and cons and represent two different alternatives for DG connections. The preference of either option depends on the DG business model and regulatory framework. The combination of both schemes can also be an option.

2-3- Distribution network management

When the amount of DGs in distribution system reaches a certain level, it will become too expensive and inefficient to reinforce the network to supply all DGs within the existing service quality. In this case, in many places the network constraints would be active for few hours per year. Overcoming the network limitation for these few hours can be very costly.

Integrating a huge amount of DG and other Distributed Energy Resources (DERs) including distributed generation, energy storage and demand side management, requires new regulatory structure and solutions for both the network users and operators. Distribution network planning and operation need to be reviewed and revised to take the new solutions into account.

There is not a one sole solution for all distribution networks as there is variety of different networks regards to the grid equipments and DG density. Each system should be considered individually in terms of its structure (consumers and connected DGs) and infrastructures (load and population density).

However, the different approaches towards future distribution systems can be classified in three different classes:

- 1) Fit and forget
- 2) Connect and manage
- 3) Active network management

Fit and forget

The traditional ‘fit and forget’ approach refers to increasing the capacity of grid infrastructures (lines and transformers) to provide firm access for DGs. While this

might be considered a secure, reliable and proven approach it can be very costly and time consuming and usually ends up in an oversized network where the utilization of the assets is low most of the time [15]. It neglects the fact that renewable sources, such as wind power, are inherently variable and hence there will be many periods where assets are not fully utilized. Indeed, these fit-and-forget connections have significantly curtailed the ability of certain networks to integrate more generation capacity as the extra costs are not viable for most DG developers.

This is used in passive distribution networks. This approach has both advantages and disadvantages. It has the advantage of requiring low flexibility and control but it can only be applied to the networks which have low DER penetration level. When DER penetration level reaches a certain level, significant network investment is needed to provide the network access in all contingencies. In overall this approach is less economical.

Connect and manage

This is often known as the ‘only operation’ approach. This is used in some countries with huge penetration of DG where the regulation requires connecting as much as DG as possible and then the grid problems are solved at operation level by limiting both load and DG. In this approach the DG output could be restricted during many hours per year and can result in negative business case for DG [16].

Active network management

The active approach allows for interaction between planning, access & connection and operational timeframes. Different levels of connection firmness and real-time flexibility can reduce investment needs [5]. Active network management monitors and

controls the grid so that power companies and utilities can use this reserve capacity for new connections. This approach can create up to two or three times more capacity to host new generation and demand. ANM involves a range of software, automation and controls that monitor the grid in real time to ensure it remains within its operating constraints. It can also increase the capacity of the grid in certain operating conditions and allow more power to be transferred. Making this capacity available for new generators and loads, it means that the existing grid can accommodate a larger amount of DGs [6]. For new DGs, an additional benefit is cheaper grid connections and shorter lead times on low carbon projects. The network reinforcement could be deferred until the moment when it becomes more cost-effective than the on-going cost of procuring services from DER.

Using the active system management approach would allow maximal integration of DER, making the most of the existing grid while enabling DNOs to fulfil the security standards and enabling DER to find the right conditions for their business plan in the most cost-effective way.

2-4- Active network management and smart technologies

In recent years, some smart technologies and solutions have been introduced to be used by ANM to increase the utilization of network assets and provide the adequate capacity for DGs. The most distinctive and recent ones are discussed here.

- A Quad-booster and Quad-booster Controller System (QBCS)

The QBCS automatically controls the tap position of the Quad-booster in order to manage power flows in a parallel circuit. The ANM system is required to monitor and

control the generator output in order to optimise the flow of power in the circuits, without conflict with the QBCS.

- Dynamic Line Rating (DLR)

The function of the dynamic line rating will be to monitor local weather station data and calculate ampacity ratings based on the real weather conditions. The ampacity ratings will be provided to the ANM system, which will dynamically manage thermal constraints, according to the generators and constraint locations.

A study performed by San Diego Gas and Electric shows that the capacity increased between 40% and 80% when transmission lines were monitored using DLR [50]. DLR allows the reduction of curtailment to the minimum strict levels and the increase of the available connection capacity for new power plants [50]. A study performed by the Belgian Transmission System Operator, shows that on average the available connection capacity increases more than 30%, but up to 100% when wind perpendicular to the line is more than 4 m/s [50].

Currently, the implementation of these solutions can be observed in a different number of initiatives including trials such as the Twenties Project (EU), Orkney Project (Scottish and Southern Energy Power Distribution, UK), Skegness Project (Western Power Distribution, UK), Transmission System Operators from Ireland (EirGrid) and Belgium (ELIA). However, the implementation of these solutions is still in the initial stage.

- Automatic Voltage Controller (AVC)

The primary function of the AVC will be to monitor the voltage level (11kV or 33kV) by controlling the transformer On Load Tap Changer (OLTC) to maintain voltages on the electrical network which it supplies within appropriate/statutory limits.

- Smart DG Curtailment

The implementation on smart solutions implies optimising network use and controlling output from generators [50]. This involves a smart way to manage the amount and frequency of curtailment in order to provide system reliability, minimise social costs (i.e. negative prices that are incurred by end customers) and attract DG investment. The challenge is to identify arrangements that are (1) cost-effective for DNOs and generators, (2) economically efficient and (3) socially efficient (maximising social welfare including carbon price and the social value of more connected renewables).

2-5- Commercial arrangement for allocating constrained capacity

The commercial rule for allocating constrained capacity supported by smart solutions such as ANM scheme has been characterised in [50] as a “Principle of Access”. Some of these allocation rules are described in this section.

(1) Last In First Out (LIFO): Specific ranking is made based on selected parameters such as the connection date, for curtailing the generators. The last on the list is the first generator to be curtailed in network constraint conditions. This strategy does not support the connection of new more efficient generators as they will be removed first under the constraint conditions in the network.

(2) Pro Rata, equal percentage basis or shared percentage: Curtailment is equally allocated between all generators that contribute to the constraint. The amount of curtailment can be computed as a percentage of available capacity, installed capacity, or any other ratio. In contrast with LIFO, the Federal Energy Regulatory Commission (FERC), a United States federal agency [53], supports this kind of curtailment allocation for both firm and non-firm services. A recent consultation for managing curtailment in tie break situations conducted by the Single Electricity Market from Ireland and Northern Ireland [51]; has demonstrated that electricity firms and organisations such as wind associations find this a much more suitable kind of allocation as compared to LIFO [50].

(3) Market-Based: Generators compete to be curtailed by offering a price based on market mechanisms. This approach is seen as the most optimal allocation rule. This is because it exploits the private information available to individual generators on their financial contracts and or the performance of their turbines [50].

National experiences on DG integration

In this section two of the recent national practices for accelerating the integration of DGs to the electricity networks are briefly introduced.

- Orkney ANM Project Case Study

The Project has been implemented in the Orkney Isles, in the North of Scotland and is the first smart grid in Britain. It is concentrated on the use of smart solutions and innovative commercial arrangements for the connection of generation facilities to the DNO (Scottish and Southern Energy Power Distribution - SSEPD). Before the smart solutions, the network had two groups of generation: 26MW firm generation and

20MW non-firm generation. ANM was selected as the solution for connecting new DGs for total capacity of 13MW. It has been shown that smart solutions provide a cost-effective way for increasing the capacity under a non-firm access with adequate levels of curtailment under NNFG (ANM solution: £500k versus conventional reinforcement: £30million) [50].

- **Ireland and Northern Ireland Case Study**

This case study introduces an interesting initiative regarding the curtailment mechanisms for wind generation in tie-break situations. It is very instructive due to the introduction of different approaches to deal with curtailment and constraints, which are defined differently. Under the proposed new approach, generators will be curtailed Pro Rata and compensation will only be given to firms with a FAQ different from zero [50]. It suggests innovations in the way of compensating wind generators in curtailment situations. In addition, Single Electricity Market (SEM) is trying to promote the connection of more efficient wind generation plants in which the level of compensation due to wind curtailment would not be decisive for the business case. The challenge is to reduce curtailment because this affects both the wind generators and customers.

2-6- Summary

It is evident from the selection of publications mentioned above that the integration of DGs into distribution network has considerable impacts on network planning and operation. Considerable amount of network reinforcement is unavoidable when DGs are connected to the grid. One of the main challenges of network owners is to reduce the amount of reinforcement when connecting new DGs. The deployment of smart

solutions on the electricity networks will help to accommodate, facilitate and increase the connection of low carbon technologies. This is the topic discussed in chapter 3.

Application of Quad Booster and Dynamic Line Rating to Maximize the Utilization of Network Assets

Increased penetration of DGs in distribution networks are altering the technical characteristics of the networks, and pushing them to operate closer to their limits of safe and reliable operation. To integrate existing and future DGs into their network the DNOs need to reinforce their networks to provide adequate capacity for DG connections. In recent years there have been introduced some smart technologies to be used in network capacity management that can be used to increase the utilization of

network assets and provide the adequate capacity for DGs connection in particular operating conditions. The application of these smart technologies requires active network management but can be more economical than traditional reinforcement options.

Dynamic Line Rating and Quad Booster are two of these smart technologies that are used in network capacity management. In this chapter these two technologies are introduced and their application in increasing the utilization of a distribution network is discussed. They will be further used in the network planning model in the next chapters.

Section 3-1 discusses about Quad Booster and its application in distribution networks. Section 3-2 presents the concept of dynamic line rating, its calculation and modelling.

3-1- Quad Booster

If two areas of power system are connected with a number of lines and paths, it is sometimes necessary to control the flow of real power through the network lines. Quad Booster is installed to force a phase angle shift between the ends of line and create a real power flow. A phase shift of degrees is all that is needed to move massive amount of power around the system. The power flow between two buses can be approximated by the following equation [17].

$$P = \frac{V_s \times V_r \times \sin \phi}{X} \quad (3-1)$$

where:

P: real power flow in per unit

V_s : per unit voltage of the sending bus

V_r : per unit voltage of the receiving bus

ϕ : phase angle difference between V_r and V_s

X : per unit reactance between the sending and receiving bus

A quad booster typically consists of two separate transformers: a shunt unit and a series unit. The shunt unit has its windings connected across the phases, so it produces output voltages shifted by 90° with respect to the supply. Its output is then applied as input to the series unit, which, because its secondary winding is in series with the main circuit, adds the phase-shifted component. The overall output voltage is hence the vector sum of the supply voltage and the 90° quadrature component.

Tap connections on the shunt unit allow the magnitude of the quadrature component to be controlled, and thus the magnitude of the phase shift across the quadrature booster. The flow on the circuit containing the quad booster may be increased (boost tapping) or reduced (buck tapping). Subject to system conditions, the flow may even be bucked enough to completely reverse from its neutral-tap direction.

Figure 3.1: Simplified circuit diagram of a three-phase quad booster

Quad booster has been used widely in transmission level over years to control power flow on parallel three phase network. But its application in distribution level has been introduced recently in UK Power Network which designed a quad booster for 33kV distribution network [18]. For this purpose a 30 MVA rated quad booster was installed at UK Power Network, Wissington 33kV substation to overcome an existing constraint due to sub-optimal load sharing on two 33kV parallel circuits emanating from the substation.

Figure 3-2 shows the single diagram of the distribution grid near the Wissington 33kV bus substation which is the connection point of the Wissington BSC CHP plant with the installed capacity of 70MW. The CHP plant exports its generation to the UKPN distribution network via three 33 kV circuits running interconnected with four 132/33 kV grids.

The export capacity of the Wissington CHP has been limited due to the uneven load sharing on the outgoing 33kV circuits.

Network assessment of the circuit out of the Wissington has identified the need to trial a QB to achieve optimal load sharing of the 33kV circuits 1 and 2 to increase export capacity from Wissington CHP. The QB will be series-connected in circuit 2 to boost the circuit impedance and force more power to flow through circuit 1. A summary of the exciting circuit data (without the proposed QB) is shown in Table 3-1.

Figure 3.2: The general Wissington 33kV network interconnection [18]

Table 3-1 shows that in winter maximum export operation circuit 2 is loaded twice the amount of circuit 3. The modelling results in DIgSilent show that with the quad booster at tap 7, it will be a balance load sharing between circuit 1 and 2. (Figure 3-3 right)

Table 3.1: Circuit impedance data of Wissington CHP circuits

Circuit data					
		Circuit No.	Circuit Length (km)	Impedance (ohms)	Average loading (%) (on winter loading)
Wissindton - Northwold	A	1	11.07	3.915	46
Northwold - Downham Market Tee	B		8.154	3.703	34
Wissington - Northwold-Downham Market Tee	A+B		19.224	7.618	
Wissington- Downham Market Tee		2	5.364	1.187	88
Wissington- Southery		3	6.31	2.265	41

Figure 3.3: The Wissington circuits loading before (left) and after (right) connecting the QB (in winter max. export)

In this case the export limit of Wissington can be increased by 10 MW to 64.5 MW with no need to reinforce the circuits. In this thesis the Quad Booster is modelled as an ideal transformer that does not have any losses.

In next chapter QB is used as a reinforcement option in reinforcement planning of distribution networks. The QB is modelled as an ideal transformer than only shifts the angle between the two ends of a line. The active and reactive flow through line i in Figure 3-4 in presence of a QB are as follows:

$$P_{sr} = V_s^2 \times G_i - V_s V_r \times [G_i \cos(\delta_s - \delta_r + \delta_{QB}) + B_i \sin(\delta_s - \delta_r + \delta_{QB})] \quad (3-2)$$

$$Q_{sr} = -V_s^2 \times B_i - V_s V_r \times [G_i \sin(\delta_s - \delta_r + \delta_{QB}) - B_i \cos(\delta_s - \delta_r + \delta_{QB})] \quad (3-3)$$

Figure 3.4: Effect of tapping a quad booster

3-2-Dynamic Line Rating

The line thermal rating is based on the highest current that a power line can carry without compromising the strength of the conductor material or without the conductor sagging too low. The conventional way to evaluate a line rating is to use a fixed, general conservative methodological value in standard, internationally used formula to calculate the summer and winter ratings. But in reality, the real capacity of an overhead line is not static value. It varies with weather conditions, the wind speed and direction, ambient temperature and solar radiation, which all contribute to cooling or heating of the overhead line, which in turn affects how much power it can carry. Dynamic Line Rating (DLR) uses real-time measurements from weather sensors to calculate the real time rating automatically, which is then compared to the line current. When the line current is close to the line rating, control commands can be sent to hold or lower the power output of distributed generation such as wind farms. This allows optimization of the line capacity and power output of the DG.

Using DLR can be very cost effective in combination with wind generation. DLR and wind generation are in natural synergy. In windy situation the wind turbine will generate more power and on the other hand, high speed wind means more cooling effect for overhead lines, so they can transfer more power.

The function of the dynamic line rating will be to monitor the local weather station data and calculate ampacity rating based on the real weather conditions. The new ampacity rating will be provided to the ANM system, which will dynamically manage thermal constraints.

3-2-1- Calculating the ampacity of a conductor

The current carrying capacity of overhead lines can be calculated through different methods [20, 21]. Based on the IEEE Std 738-2006 [20] for an overhead line considering the maximum permissible temperature of the conductor thermal ampacity will be obtained as follows:

$$I^2 R(T_c) + q_s + q_m + q_i = q_c + q_r + q_w \quad (3-4)$$

where:

T_c : conductor temperature (°C)

q_s : solar heating (W/m)

q_m : magnetic heating (W/m)

q_i : corona heating (W/m)

q_c : convective cooling (W/m)

q_r : radiative cooling (W/m)

q_w : evaporative cooling (W/m)

q_m , q_i and q_w are usually neglected so we will have [20]:

$$I^2 R(T_c) + q_s = q_c + q_r \quad (3-5)$$

The ampacity of the conductor is thus given by:

$$I = \sqrt{\frac{q_c + q_r - q_s}{R(T_c)}} \quad (3-6)$$

Convective cooling q_c

It is made of two forces: natural and forced natural convection q_{cn} depends on the conductor temperature, ambient temperature, overall diameter of the conductor and the air density [20].

$$q_{cn} = 0.0205 \rho_f^{0.5} D^{0.75} (T_c - T_a)^{1.25} \quad (3-7)$$

Forced convection is the cooling provided by wind. There are two types of forced convection, one for low wind speeds and another for high wind speeds and having as reference the IEEE standard, the biggest value of the natural and the two forced convection components is used.

$$q_{clow} = [1.01 + 0.0372 \left(\frac{D \rho_f V_w}{\mu_f} \right)^{0.52}] k_f K_{angle} (T_c - T_a) \quad (3-8)$$

$$q_{chigh} = [0.0119 \left(\frac{D \rho_f V_w}{\mu_f} \right)^{0.6}] k_f K_{angle} (T_c - T_a) \quad (3-9)$$

where:

ρ_f : Air density (kg/m³)

V_w : wind speed (m/s)

μ_f : dynamic viscosity of air (Pa-s)

k_f : thermal conductivity of air (W/(m. °C))

K_{angle} : wind direction factor

D : conductor diameter (mm)

T_a : ambient temperature (°C)

Radiative loss q_r

Radiated heat loss is calculated as follows [20].

$$q_r = 0.0178D\varepsilon \left[\left(\frac{T_c+273}{100} \right)^4 - \left(\frac{T_a+273}{100} \right)^4 \right] \quad (3-10)$$

where:

ε : emissivity

Solar heat gain q_s

solar heating gain is given by:

$$q_s = \alpha Q_s \sin(\theta) A' \quad (3-11)$$

where:

α : solar absorptivity (Pa·s)

Q_s : total heat flux received by a surface at sea level (W/m²)

θ : effective angle of incident of the sun's rays (°)

A' : projected area of conductor per unit length (m²/m)

3-2-2 UK seasonal weather assumptions

In the UK, Engineering Recommendation (ER) P27 provides the standard for calculating seasonal thermal ratings using assumed temperatures of 2°C, 9°C and 20°C in winter, spring/autumn, and summer, respectively, for a constant wind speed of 0.5m/s and zero solar radiation [19]. In particular, the assumption of such a low wind speed neglects the potential cooling effect of the wind, thus giving a conservative rating value in many circumstances.

Table 3-2 shows the maximum current-carrying capacity based on ER P27 of an ASCR 100mm² and ASCR 200mm² conductors, with a diameter of 14.5mm, and 19.3mm and 0.22 and 0.1362 Ω/km of AC resistance at 20°C and 0.329Ω/km and 0.164 at 75°C, respectively. The adopted T_c + is 50°C.

Table 3.2: Seasonal capacity of ASCR 100mm² and ASCR 200mm² based on ER P27

seasonal ampacity (A)			
	summer	spring/autumn	winter
DOG 100 ASCR	282	327	351
JAGUAR 200 ASCR	462	534	575

If all the parameters used in ampacity calculation remain the same and only the wind speed changes from 1m/s to 13 m/s the dynamic thermal rating for these two conductors will change as they are shown in Figures 3-5 and 3-6.

Figure 3.5: ASCR 100mm2 seasonal and dynamic rating

Figure 3.6: ASCR 200mm2 seasonal and dynamic rating

In short the weather parameters that are needed for calculating the ampacity of the overhead lines are: air density, ambient temperature, air thermal conductivity, air viscosity, wind direction angle, emissivity, heat flux, effective angle of incident of the sun's rays and the wind speed. Here in this thesis, apart from the wind speed which is

changing in different operating snap shots, all other parameters are set to their seasonal values as they are recommended in UK ER P27 (Table 3-3) [19].

Also to have a conservative assumption, the wind direction factor (K_{angle}) is assumed to be 0.38 and the effective angle of incident of the sun's rays is set to 90° .

Table 3.3: Seasonal weather condition parameters in UK based on ER P27

	Ambient Tem. (C)	Air density (kg/m ³)	Air thermal conductivity (W/(m K))	Air viscosity (Pa·s)	Heat Flux (w/m ²)
summer	20	1.440	2.69E-02	1.88E-05	812
spring/autumn	9	1.165	2.64E-02	1.86E-05	584
winter	2	1.179	2.62E-02	1.84E-05	287

2-3- Summary

In this chapter Quad Booster and Dynamic Line Rating were introduced as two of smart technologies using in distribution network reinforcement planning. Both of these network assets defer the need for upgrading the network. These two technologies are used in Chapter 4 as reinforcement options in network planning.

Network Capacity and Voltage Management Formulation with Smart Technologies

In this chapter, a multi-epoch AC optimal power flow is formulated for managing the voltage and capacity of a given network for integrating new DGs. The model evaluates the impact of smart technologies in network reinforcement plans. The smart technologies such as DLR, QB and SVC as well as the traditional network reinforcement are considered as investment options. In addition to the investment options, DG curtailment is also an option for DGs with non-firm network access. The formulation of the AC OPF is presented in this chapter and its application for different

case studies will be presented in following chapters. Section 1 is the nomenclature; section 2 includes the OPF formulation, section 3 illustrates how to model the smart technologies in load flow equations and in section 4 the problem constraints are listed. Section 5 describes how the operating snapshots are created to include all the operating conditions of the network. Section 6 describes the solution method of the multi integer AC OPF model and section 7 is a summary of the chapter.

4-1- Nomenclature

IC_{ep}	investment cost of the system in ep^{th} epoch
OC_{ep}	operation cost of the system in ep^{th} epoch
C_{ep}^{Tr}	transformer reinforcement cost in ep^{th} epoch
C_{ep}^{QB}	quad booster investment cost in ep^{th} epoch
C_{ep}^{DLR}	DLR investment cost in ep^{th} epoch
C_{ep}^{line}	line reinforcement cost in ep^{th} epoch
C_{ep}^{svc}	SVC investment cost in ep^{th} epoch
N_{final}	final year in the planning horizon
$StrYr_{ep}$	the start year of ep^{th} epoch
$EndYr_{ep}$	the end year of ep^{th} epoch
K_y	present value factor
$T_{candidate}$	the set of transformers which are candidate for reinforcement
$Tr_{i,ep}$	additional capacity for transformer i as reinforcement in ep^{th} epoch
$F_{i,ep}^{Tr}$	decision variable to reinforce Trans i (binary)
$\pi_{i,ep}^{VTr}$	the annuitized variable cost of reinforcing the transformer i in ep^{th} epoch, (£/MVA.yr)
$\pi_{i,ep}^{fixT}$	fixed cost of reinforcing line i in ep^{th} epoch (£)
$QB_{candidate}$	the set of lines which are candidates for installing quad booster
$QB_{i,ep}$	decision variable to install a QB in series with line i in ep^{th} epoch

	(binary)
π_{ep}^{QB}	the annuitized cost of installing a QB in ep^{th} epoch (£/MVA.yr)
Cap_{QB_i}	the capacity of QB installed in series with line i
$L_{i,ep}$	additional capacity for line i as reinforcement in ep^{th} epoch
$\pi_{i,ep}^{VL}$	the annuitized variable cost of reinforcing line i in ep^{th} epoch, (£/MVA.yr)
$F_{i,ep}^L$	decision variable to reinforce line i (binary)
$\pi_{i,ep}^{fixL}$	fixed cost of reinforcing line i in ep^{th} epoch (£)
$B_{i,ep}^{DLR}$	decision variable to install DLR in line i in ep^{th} epoch (binary)
π_{ep}^{DLR}	the annuitized cost of installing DLR in a line in ep^{th} epoch (£/yr)
$DLRcandidate$	the set of overhead lines which are candidates to install DLR
$Lcandidate$	the set of lines which are candidates for reinforcement
π_{ep}^{SVC}	the annuitized cost of installing SVC in ep^{th} epoch, (£/MVAR.yr)
$Q_{i,ep}^{svc}$	Capacity of installed SVC on bus i in ep^{th} epoch
$SVCcandidate$	the set of buses which are candidates to install SVC
C_{ep}^{dgcur}	total DG curtailment cost in ep^{th} epoch
C_{ep}^{Lshed}	load shedding cost in ep^{th} epoch
C_{ep}^{os}	over slack cost in ep^{th} epoch
Th	set of operating snapshots per year
$NF-DG:$	set of DGs connected to network with a non-firm connection policy
π_y^{ec}	cost of energy curtailment in y^{th} year (£/MWh)
$\tau(t)$	the duration of t^{th} snapshots in a year, (hrs)
$\overline{Pdg}_{i,t,ep}$	Maximum output of DG_i at t^{th} snapshot in ep^{th} epoch
$Pdg_{i,t,y}$	power generation of DG_i at t^{th} snapshot of year y
π_y^{Pshed}	cost of load shedding in y^{th} year (£/MWh)
π_y^{Qshed}	cost of load shedding in y^{th} year (£/MVarh)
$Pshed_{i,t,y}$	involuntary loss of active power at bus i at t^{th} snapshot of year y
$Qshed_{i,t,y}$	involuntary loss of reactive power at bus i in t^{th} snapshot of year y
π_{slack}	penalty cost of overslack variables
$P_{i,t,y}^{os}$	positive decision variables representing an artificial active load

$Q_{i,t,y}^{os}$	positive decision variables representing an artificial reactive load
N_{bus}	set of network buses
N_{load}	set of network loads
G	the conductance matrix of the network
B :	the susceptance matrix of the network
δ	the delta matrix of the network
QB_{tap}	QB shift angle
Gbr_i	conductances of i^{th} branch
Bbr_i	susceptances of i^{th} branch
$deltacap$	the difference between dynamic and static capacity of an overhead line
P_{export}	the amount of active power exported to the upstream grid in connection buses
Q_{export}	the amount of reactive power exported to the upstream grid in connection buses

4-2- Problem Formulation

In this chapter the nonlinear programming (NLP) formulation of a multi-epoch AC OPF is adopted to manage capacity and voltage of a given distribution network when integrating DGs. The model reinforces the network to be able to integrate new DGs. Traditional reinforcement options by means of upgrading the capacity of lines and transformers, as well as new smart solutions are considered as reinforcement options. Because of the integer decision variables related to reinforcement plan, the model is a MINLP.

The planning is a multi-epoch planning. Each epoch consists of few years and each year has different operating snapshots with different combination of load and wind profiles and ambient temperature. It is considered that for each epoch all the investment happens in its first year. The cost function for each epoch is the sum of present value of

the costs of the network investment and the costs of DGs curtailment and load shedding.

The cost function of each epoch is the summation of the investment and the operation costs.

$$\text{Min } Cost_{ep} = IC_{ep} + OC_{ep} \quad (4-1)$$

The investment cost includes the cost of reinforcement of network assets and installation of smart technologies as it will be described in section 4-2-1. The operating cost includes the cost of DGs curtailment and load shedding and the penalty cost of slack variables. The objective function balances the cost of investment with the reduction in the operating costs.

4-2-1-Investment Cost

The cost function in (4-1) reflects the present value of operation and investment costs of the network during the time horizon of the epoch. Therefore, the investment cost should be annuitized. In order to annuitize the investment cost, the life time of the assets is considered to be 33 years [56] and the Weighted Average Cost of Capital (WACC) factor of 5.3% is used. The equivalent annual cost (EAC) will be [54]:

$$EAC = \frac{PV}{A_{33,5.3}} \quad (4-2)$$

$$A_{33,5.3} = \frac{1-(1/1.053)^{33}}{0.053} \quad (4-3)$$

The present value of money will be obtained as follows [54]:

$$PV = K_y \times C \quad (4-4)$$

$$K_y = \frac{1}{(1+interest\ rate)^y} \quad (4-5)$$

Where C is the future amount of money that must be discounted, y is the number of compounding periods between the present date and the date where the sum is worth C .

The investment cost per epoch can be obtained as the summation of the different terms described as follows:

$$IC_{ep} = C_{ep}^{Tr} + C_{ep}^{QB} + C_{ep}^{DLR} + C_{ep}^{line} + C_{ep}^{svc} \quad (4-6)$$

The transformer reinforcement cost can be expressed as:

$$C_{ep}^{Tr} = \sum_{i \in Tcandicate} K_y F_{i,ep}^{Tr} \times \pi_{i,ep}^{fixT} + \sum_{y=StrYr_{ep}}^{EndYr_{ep}} \sum_{i \in Tcandicate} K_y \times Tr_{i,ep} \times \pi_{i,ep}^{VTr} \quad (4-7)$$

$$0.01(Tr_{i,ep}) \leq F_{i,ep}^{Tr} \quad F_{i,ep}^{Tr} \text{ is binary} \quad (4-8)$$

Transformer reinforcement cost is made of two terms: fixed cost and variable cost. The variable cost depends on the amount of added capacity where the fixed cost is a fixed amount. $F_{i,ep}^{Tr}$ is a binary decision variable which is equal to 1 when Trans i is reinforced in epoch ep , otherwise it is 0 (Eq. 4-8).

The quad booster installation cost can be expressed as:

$$C_{ep}^{QB} = \sum_{y=StrYr_{ep}}^{EndYr_{ep}} \sum_{i \in QBcandicate} K_y \times QB_{i,ep} \times Cap_{QB_i} \times \pi_{ep}^{QB} \quad (4-9)$$

The $QB_{i,ep}$ is the decision variable of installing QB in series with line i in epoch ep which can be 0 or 1. The capacity of the QB should be the same as the capacity of the related line as the QB is installed in series with lines.

The DLR installation cost can be expressed as:

$$C_{ep}^{DLR} = \sum_{y=StrYr_{ep}}^{EndYr_{ep}} \sum_{i \in DLRcandidate} K_y \times B_{i,ep}^{DLR} \times \pi_{ep}^{DLR} \quad (4-10)$$

The DLR decision variable $B_{i,ep}^{DLR}$ is also a binary variable.

The Line reinforcement cost can be expressed as:

$$C_{ep}^{line} = \sum_{i \in Lcandidate} K_y F_{i,ep}^L \times \pi_{i,ep}^{fixL} + \sum_{y=StrYr_{ep}}^{EndYr_{ep}} \sum_{i \in Lcandidate} K_y \times L_{i,ep} \times \pi_{i,ep}^{VL} \quad (4-11)$$

$$0.01(L_{i,ep}) \leq F_{i,ep}^L \quad F_{i,ep}^L \text{ is binary} \quad (4-12)$$

Line reinforcement cost is made of two terms: fixed cost and variable cost. The variable cost depends on the amount of added capacity but the fixed cost only depends on the length of the lines. $F_{i,ep}^L$ is a binary decision variable which is equal to 1 when line i is reinforced in epoch ep , otherwise it is 0.

The SVC installation cost can be expressed as:

$$C_{ep}^{svc} = \sum_{y=StrYr_{ep}}^{EndYr_{ep}} \sum_{i \in SVCcandidate} K_y \times Q_{i,ep}^{svc} \times \pi_{ep}^{svc} \quad (4-13)$$

4-2-2- Operation Cost

The operation cost includes three different terms:

$$OC_{ep} = C_{ep}^{dgcur} + C_{ep}^{Lshed} + C_{ep}^{os} \quad (4-14)$$

The DG curtailment can be expressed as:

$$C_{ep}^{dgcur} = \sum_{y=StrYr_{ep}}^{EndYr_{ep}} k_y \times \sum_{i \in NFDG} \sum_{t \in Th} [\pi_y^{ec} \times \tau(t) \times (\overline{Pdg}_{i,t,ep} - Pdg_{i,t,y})] \quad (4-15)$$

The DG curtailment is only allowed for those DGs which have non-firm network access.

The load shedding cost can be expressed as:

$$\sum_{y=Str_yrep}^{EndYrep} K_y \times \sum_{i \in Nload} \sum_{t \in Th} [\pi_y^{Pshed} \times Pshed_{i,t,y} + \pi_y^{Qshed} \times Qshed_{i,t,y}] \quad (4-16)$$

The over slack penalty cost can be expressed as:

$$C_{ep}^{Os} = \sum_{y=Str_yrep}^{EndYrep} K_y \times \sum_{i \in Nbus} \sum_{t \in Th} [\pi_{slack} \times (P_{i,t,y}^{os} + Q_{i,t,y}^{os})] \quad (4-17)$$

These slack variables will only take positive values in case when the generators reach their lower production limits being still higher than load. Cost of using over-slack load has a very high value, so normally they take zero values.

4-3-Modeling Smart technologies

QB Modeling

The following equations are used here to model the QB in the power flow formulation. The equations show the real and apparent flow through line i which is between bus a and b .

$$P_{a,b} = V_a^2 \times Gbr_i - V_a V_b \times [Gbr_i \cos(\delta_a - \delta_b + I_i^{QB} \times QBtap_{a,b}) + Bbr_i \sin(\delta_a - \delta_b + I_i^{QB} \times QBtap_{a,b})] \quad (4-18)$$

$$Q_{a,b} = -V_a^2 \times Bbr_i - V_a V_b \times [Gbr_i \sin(\delta_a - \delta_b + I_i^{QB} \times QBtap_{a,b}) - Bbr_i \cos(\delta_a - \delta_b + I_i^{QB} \times QBtap_{a,b})] \quad (4-19)$$

I_i^{QB} is a binary variable which shows if there is a QB in series with line i or not.

DLR Modeling

To include the impact of DLR on the ampacity of overhead lines in this study, the ambient temperature and wind speed are varying at different snapshots in regards to the available recorded data of UK weather conditions. With different convective cooling value in every snapshot $\text{deltacap}_{i,t}$ is calculated for the overhead line i at snapshot (t). $\text{deltacap}_{i,t}$ indicates the difference of the static seasonal capacity of line i with its dynamic line capacity at snapshot t .

The thermal constraint for overhead lines in presence of DLR will then become:

$$P_{i,t,y}^2 + Q_{i,t,y}^2 \leq (\text{Capacity}L_i + \text{DLR}_{i,ep} \times \text{deltacap}_i)^2 \quad (4-20)$$

$$0 \leq \text{DLR}_{i,ep} \leq \sum_{s=1}^{ep} B_{s,ep}^{DLR} \quad (4-21)$$

$\text{DLR}_{i,ep}$ is a continuous variable which is introduced to avoid the complexity of using a binary variable ($B_{i,ep}^{DLR}$) in nonlinear constraints.

4-4- Problem constraints

The problem has the following constraints. They are the load flow equations constraints, thermal and voltage constraints and the constraints related to the operating limits of DGs.

- Injected power at each bus:

$$i \in N_{bus} \quad t \in Th \quad y \in \text{StrYr}_{ep} \dots \text{EndYr}_{ep}$$

$$P_{inject_{i,t,y}} = \sum_{j \in Nbus} V_{i,t,y} \times V_{j,t,y} \times (G_{i,j} \cos(\delta_{i,t,y} - \delta_{j,t,y} + QB_i \times QB_{tap_{i,j,t,y}}) + B_{i,j} \sin(\delta_{i,t,y} - \delta_{j,t,y} + QB_i \times QB_{tap_{i,j,t,y}})) \quad (4-22)$$

$$Q_{inject_{i,t,y}} = \sum_{j \in Nbus} V_{i,t,y} \times V_{j,t,y} \times (G_{i,j} \sin(\delta_{i,t,y} - \delta_{j,t,y} + QB_i \times QB_{tap_{i,j,t,y}}) - B_{i,j} \cos(\delta_{i,t,y} - \delta_{j,t,y} + QB_i \times QB_{tap_{i,j,t,y}})) \quad (4-23)$$

- Power balance in each bus:

$$P_{load_{i,t,y}} - P_{shed_{i,t,y}} + P_{inject_{i,t,y}} + P_{export_{i,t,y}} + P_{overslack_{i,t,y}} - P_{gen_{i,t,y}} = 0 \quad (4-24)$$

$$Q_{load_{i,t,y}} - Q_{shed_{i,t,y}} + Q_{inject_{i,t,y}} + Q_{export_{i,t,y}} + Q_{overslack_{i,t,y}} - Q_{gen_{i,t,y}} = 0 \quad (4-25)$$

- Generators limits

$$i \in firmDG \quad Pdg_{i,t,y} = \overline{Pdg}_{i,t,ep} \quad (4-26)$$

$$i \in non\ firmDG \quad \underline{Pdg}_{i,t,ep} \leq Pdg_{i,t,y} \leq \overline{Pdg}_{i,t,ep} \quad (4-27)$$

- Thermal capacity of lines

$$\forall i \in NLines$$

(Line i is between bus a and b)

$$\begin{aligned}
Pij_{i,t,y} = & \\
V_{a,t,y}^2 \times Gbr_i - V_{i,t,y}V_{b,t,y} \times [Gbr_i \cos(\delta_{a,t,y} - \delta_{b,t,y} + I_{i,ep}^{QB} \times QBtap_{a,b,t,y}) + & \\
Bbr_i \sin(\delta_{a,t,y} - \delta_{b,t,y} + I_{i,ep}^{QB} \times QBtap_{a,b,t,y})] & \quad (4-28)
\end{aligned}$$

$$\begin{aligned}
Qij_{i,t,y} = -V_{a,t,y}^2 \times Bbr_i - V_{i,t,y}V_{b,t,y} \times [Gbr_i \sin(\delta_{a,t,y} - \delta_{b,t,y} + I_{i,ep}^{QB} * & \\
QBtap_{a,b,t,y}) - Bbr_i \cos(\delta_{a,t,y} - \delta_{b,t,y} + I_{i,ep}^{QB} * QBtap_{a,b,t,y})] & \quad (4-29)
\end{aligned}$$

$$Pij_{i,t,y}^2 + Qij_{i,t,y}^2 \leq (\text{Capacity}L_i + DLR_{i,ep} \times deltacap_i + \sum_{s=1}^{ep} L_{i,s})^2 \quad (4-30)$$

$$Pji_{i,t,y}^2 + Qji_{i,t,y}^2 \leq (\text{Capacity}L_i + DLR_{i,ep} \times deltacap_i + \sum_{s=1}^{ep} L_{i,s})^2 \quad (4-31)$$

$$0 \leq DLR_{i,ep} \leq \sum_{s=1}^{ep} B_{i,ep}^{DLR} \quad (4-32)$$

Thermal capacity of transformers

$\forall i \in NTrans$

(Trans i is between bus a and b)

$$\begin{aligned}
Pij_{i,t,y} = \left(\frac{1}{tap_{i,t,y}}\right)^2 (V_{a,t,y})^2 \times Gbr_i - \frac{1}{tap_{i,t,y}} V_{a,t,y}V_{b,t,y} \times [Gbr_i \times \cos(\delta_{a,t,y} - \delta_{b,t,y}) + & \\
Bbr_i \times \sin(\delta_{a,t,y} - \delta_{b,t,y})] & \quad (4-33)
\end{aligned}$$

$$\begin{aligned}
Qij_{i,t,y} = -\left(\frac{1}{tap_{i,t,y}}\right)^2 (V_{a,t,y})^2 \times Bbr_i - \frac{1}{tap_{i,t,y}} V_{a,t,y}V_{b,t,y} \times [Gbr_i \times \sin(\delta_{a,t,y} - & \\
\delta_{b,t,y}) - Bbr_i \times \cos(\delta_{a,t,y} - \delta_{b,t,y})] & \quad (4-34)
\end{aligned}$$

$$Pij_{i,t,y}^2 + Qij_{i,t,y}^2 \leq (\text{Capacity}Tr_i + \sum_{s=1}^{ep} Tr_{i,ep})^2 \quad (4-35)$$

- Stability constraints

The angles between two connected buses should be between $\frac{-\pi}{2}$ and $\frac{\pi}{2}$.

$$\delta_{i,t,y} - \delta_{j,t,y} + QB_{i,ep} * QBtap_{i,j,t,y} \leq \pi/2 \quad (4-36)$$

$$\delta_{i,t} - \delta_{j,t} + QB_{i,ep} * QBtap_{i,j,t,y} \geq \pi/2 \quad (4-37)$$

- Voltage constraints: voltage of buses should remain in security limits in all time

$$\forall i \in Nbus$$

$$\underline{V} \leq V_{i,t,y} \leq \bar{V} \quad (4-38)$$

4-5- Operating conditions profiles

The optimization model formulated here is a multi epoch, multi snap shots OPF. Each year is consisting of different snapshots to include wide range of possible operating profiles in the network planning. Most of the studies about network reinforcement only consider two extreme operating conditions: minimum generation with maximum load and maximum generation with minimum load. Considering only these extreme operating conditions can result in very expensive plans with low level of assets utilization in most times of a year.

In this model as the objective function makes a balance between the investment cost and the operating cost of the network and the investment cost is compared to the operating cost, it is very important to profile a wide range of possible operating conditions of the network and have the duration of each of the profiles. Here, each year is divided into 300 different operating snap shots with a unique combination of load and wind profiles and seasonal ambient temperature (spring/autumn, summer and winter)

(Figure 4-1). The duration of the snapshots are not the same as each other but the sum of all the snapshots in a year is equal to 8760 hrs.

Each snap shot is characterized with demand level (d), wind output profile (w) and seasonal temperature and it has a share of $\tau(t)$ hours in a year (Figures 4-2, 4-3). The characteristic load profiles and wind profiles have be derived from year round hourly profiles. 10 different demand levels and 10 different wind outputs have been considered. In each season ten different demand levels have been defined and then a probability density function (pdf) of wind output has been defined for each demand level. This procedure is done for three different seasons (3x10x10). 92 snapshots out of these 300 snapshots have zero duration; therefore the number of snapshots which are considered in the OPF model is 208.

Figure 4.1: Capturing Demand and DG variations

Figure 4.2: Normalized load and wind profiles

Figure 4.3: The duration of operating snapshots for each season

Figure 4.4: Load, wind and temperature profiles for one year

4-6- Solution method

The optimization problem described here is a mixed-integer non-linear problem whose dimension depends on the size of the network. In order to solve this problem, commercial optimization software, FICO Xpress, has been used. Non-linear problem is loaded and solved by invoking SLP module, which stands for Successive Linear Programming. In summary, the numerical method that has been employed in SLP module makes a linear approximation of the original nonlinear problem. Linearization is made in vicinity of initial point. It is a common practice in AC power flow to choose the initial point by setting bus voltage magnitudes to 1.0 p.u and voltage angles to 0 rad. If the linear optimal solution is close enough to the initial point, then the SLP is considered successfully converged and the procedure stops. If not, the next iteration starts. A new initial point is calculated from the previous result and a new linear approximation is made. This procedure is repeated until the solution converges. However, the actual algorithm that is in the core of the optimization engine is not disclosed [55].

4-7- Summary

In this chapter a multi epoch formulation for voltage and thermal management of distribution networks was formulated. The traditional reinforcement as well as smart technologies and ANM are considered as planning options to find the minimum cost solution to integrate DGs in distribution networks. Also the profiling of the operating conditions, considered in the model, was described. In next chapters the multi epoch OPF will be solved with two different approaches: incremental and integrated.

Voltage and Capacity Management of Distribution Networks to Integrate DGs with an Incremental Approach

In this chapter the proposed OPF model is applied to a given 33kV distribution network for voltage and capacity management when couple of new DGs are connected to the grid. The OPF model evaluates the impact of smart technologies in network reinforcement plans. The smart technologies including DLR, QB and SVC are considered as investment options as well as the traditional network reinforcement. DG curtailment is also an option for DGs with non-firm network access. To compare the value of traditional and smart technologies in both short and long term planning, the multi-epoch model OPF is solved with two approaches: the incremental approach in

which the planning is done for one epoch at each run and the integrated approach in which the planning is done for the whole study period in one run. The results are then compared to see if the smart technologies have the same competence in both short and long term planning.

Section 1 describes the test network. Section 2 describes the case study scenarios. The multi-epoch solution method is discussed in Section 3. The initial network operating condition and its constraints are discussed in Section 4. The incremental planning results are presented in Section 5 and Section 6 gives a summary of the chapter.

5-1- Test study description

The proposed methodology in Chapter 4 is applied on a 33kV distribution network with 29 buses and 36 branches shown in Figures 5-1 and 5-2. It is a part of UK Power Networks connected to Peterborough Central and March grid. This area of the network is connected to the upstream 132kV network in two connection points: Bus 2 and bus 27 with two 132/33 kV transformers at each of the two buses. Power can be exported or imported to the upstream network from both connections points. The network is also connected to downstream 11 kV network in five 33/11kV substations. Each of these substations has two 33/11kV transformers.

The network is supplying 7 loads which are connected to both 33kV and the 11kV levels. The peak demand is 101 MW and the power factor ($\cos\phi$) is assumed to be 0.98.

There are 36 branches in the network, 14 of them are transformers. 6 branches are underground cables and 16 branches are overhead lines (Table 5.2). There are four different types of underground cables and three different kinds of overhead lines. The type of each line can be found in Table 5.3.

Table 5.1: Network data

NetWork Data	
Installed Generation Capacity	160 MW
Max. Load	101 MW
Load Factor	0.98
Voltage Level	33 kV
Number of buses	29
Number of Branches	36

Table 5.2: Network branches type

No.	from Bus	to Bus	Trans or Line	UC/OH	No.	from Bus	to Bus	Trans or Line	UC/OH
1	2	3	L	UC	19	11	18	L	OH
2	2	4	L	OH	20	14	26	L	UC
3	3	5	L	OH	21	18	19	L	OH
4	5	6	L	OH	22	19	20	L	OH
5	2	7	L	UC	23	20	21	L	UC
6	2	8	L	UC	24	22	23	L	OH
7	7	10	L	OH	25	23	24	L	OH
8	8	12	L	UC	26	22	26	L	OH
9	10	9	L	OH	27	26	27	L	OH
10	10	11	L	OH	28	20	27	L	OH
11	12	13	L	OH	29	21	25	T	-
12	13	14	L	OH	30	24	25	T	-
13	3	15	T	-	31	1	2	T	-
14	4	15	T	-	32	1	2	T	-
15	7	16	T	-	33	27	28	T	-
16	8	16	T	-	34	27	28	T	-
17	9	17	T	-	35	27	29	T	-
18	12	17	T	-	36	27	29	T	-

Figure 5.1: Case study network single line diagram

Table 5.3: Types of conductor in the network

conductor ID	OH/UG	Type	Seasonal Capacity		
			summer	spring/autumn	winter
			(A)		
1	OH	DOG 100 ASCR	282	327	351
2	OH	DINGO 150 ASC	382	443	475
3	OH	JAGUAR 200 AS	462	534	575
4	UG	45 OF AL	461	485	504
5	UG	300 AL	470	495	515
6	UG	630 ALSL	782	803	824
7	UG	185 AL	365	375	385

The system has 15 DGs with total generation capacity of 160 MW. All the DGs are assumed to be wind turbines. The DGs are connected to both 11kV and 33kV grid.

Table 5.4 shows the capacity of DGs at each bus.

Table5.4: Network DGs data

Network DGs Data				
No.	at Bus	Type	Capacity (MW)	Min Output (MW)
1	2	WT	14.5	0
2	5	WT	17.5	0
3	6	WT	12.5	0
4	11	WT	10	0
5	13	WT	8	0
6	14	WT	18.5	0
7	16	WT	12	0
8	17	WT	3.7	0
9	18	WT	4.67	0
10	19	WT	6	0
11	22	WT	10	0
12	23	WT	10	0
13	25	WT	2	0
14	27	WT	25.5	0
15	29	WT	6	0

5-2- Case study description

Six new DGs are going to be connected to the grid in 16 years. The planning horizon is 16 years. Regarding to new DGs connection plans the planning horizon is divided into 4 epochs. All the epochs have the same duration of 4 years. The projected plan for DGs connection is as follows:

DG 1 at Bus 6: 7.5 MW at 1st epoch

DG 2 at Bus 11: 6 MW at 1st epoch, 4MW at 2nd epoch

DG 3 at Bus 21: 17.5MW at 1st epoch

DG 4 at Bus 13: 10MW at 2nd epoch, 2MW at 3rd epoch

DG 5 at Bus 14: 6 MW at 2nd, 4MW at 3rd epoch

DG 6 at Bus 15: 5 MW at 4th epoch

Table 5.5: Projected DGs Plan

DGs Instalation Plan					
No.	Bus	epoch			
		1	2	3	4
DG 1	6	7.5 MW			
DG 2	11	6 MW	4MW		
DG 3	21	17.5 MW			
DG 4	13		10 MW	2MW	
DG 5	14		6 MW	4 MW	
DG 6	15				5 MW

All the future DGs are considered to be wind turbines. The load profile is assumed to remain the same for all the loads in all four epochs except for the load at bus 25 which will increase by 20% from the second epoch as a result of a new connection.

To compare the effectiveness of smart solutions and the advantages of having non-firm connections for DGs, the planning is done in four different cases with different planning options:

- Case 1: the planning includes the smart and traditional reinforcement options and newly added DGs have non-firm access
- Case 2: the planning includes only traditional reinforcement options and newly added DGs have non-firm access
- Case 3: the planning includes the smart and traditional reinforcement options and all the DGs including the newly added DGs have firm access
- Case 4: newly added DGs have non-firm access but there is no reinforcement.

5-3- Solution method

The cost function in chapter 4 equation (4-1) is the cost of the ep^{th} epoch. To solve the OPF for a multi-epoch problem there are two different approaches: incremental planning and the integrated planning.

In incremental approach the planning is started from the initial network (epoch 0) and the OPF is run to find the minimum cost feasible solution for the 1st epoch. Then to plan for the 2nd epoch it takes the solution of the 1st epoch as the initial network and finds the optimum feasible solution for the 2nd epoch. The procedure continues till the last epoch.

The incremental approach can be expressed as:

$$\forall ep \in 1..N_{ep} \quad \text{Minimize } Cost_{ep} \quad (5-1)$$

Figure 5.2: Incremental approach procedure

This surely will find the cheapest possible network planning per epoch. But this can come at the expense of possible suboptimalities over the full studying time and therefore, can increase total costs.

In integrated approach the planning is done for the whole epochs at once. This planning approach guarantees an optimal network planning over the whole studying period. The integrated approach can be expressed as:

$$\text{Minimize } \sum_{i \in 1}^{N_{ep}} \text{Cost}_{ep} \quad (5-2)$$

The integrated planning yields to cost-optimized networks. But in reality some factors in the network planning process strongly influence the cost balance of the planning procedures.

The future demand and generation capacity of the network are an estimate and therefore always affected by uncertainty. If the real demand or real generation capacity differ from the forecast levels, the integrated planning has to diverge from the calculated plan. Therefore, the integrated planning can no longer guarantee a cost-optimal network plan. The incremental planning is not impaired since it does not rely on forecast. Thus, the costs for network planning in the integrated planning may exceed the costs of the incremental procedure, if the real demand and generation capacity differ from the forecast. It is important to analyze the risk of planning due to the uncertainty in the future system when using the integrated approach.

5-4- Initial network condition

Before connecting the new DGs, the system is sufficient enough to integrate all DGs with no curtailment. Connecting the new DGs to the grid will activate some voltage and thermal constraints which could result in DG curtailment if no reinforcement is planned to overcome the problems. Figure 5.3 shows the constraint areas of the network when the new DGs are connected.

Figure 5.3: Network constraint area with new DGs connected

The first constraint area is between buses 2 to 6. When DG1 is connected to Bus 6, the voltage at buses 5 and 6 will reach its highest limit and L3-5 and L2-3 will reach their highest thermal limits in some of the snapshots. Figure 5.4 shows how DG1

would be curtailed in some high wind snapshots due to the voltage rise at bus 6 when DG1 is connected. The solid line shows the percentage of DG1 generation curtailed in each snapshot. The square dot shows the voltage at bus 6. The diagram demonstrates that the curtailment happens whenever the voltage is at its maximum limit.

Figure 5.4: Active voltage constraint in Bus 6

The second constraint area is the lines connected to buses 10 and 11. Connecting DG2 to bus 11 will overload lines L7-10 and L10-11. To prevent the overloading of these two lines, the output of DG2 should be curtailed in some of the snapshots. It is shown in Figure 5.5 that whenever DG2 is curtailed at least one of these two lines has reached its maximum capacity.

Figure 5.5: DG2 curtailment and active thermal constraints

The third constraint area is Bus 25. DG 3 will cause the voltage rise at bus 25 and in numbers of snapshots it results in curtailment for DG 3 (Figure 5.6).

Figure 5.6: DG3 curtailment and active voltage constraint in bus 25

The last constraint area is the lines connected to buses 13 and 14. Figure 5.7 shows how DG 4 will increase the flow through lines L8-12 and L12-13 when it is connected to bus 13. To prevent the overloading of these two lines the output of DG 4 and DG 5 are curtailed in some high wind snapshots.

Figure 5.7: DG4 curtailment and active thermal constraints

Table 5.6 shows the annual energy curtailment in these new DGs as the result of active voltage or thermal constraints. Also Figure 5.8 shows the maximum curtailment of these non-firm DGs in the snapshots.

Table 5.6: New DGs annual curtailment in the initial network

DG No.	annual energy curtailment (%)
1	47
2	20
3	3
4	7
5	30
6	0

Figure 5.8: Newly added DGs curtailment in the initial network

Figure 5.9: Branch utilization in the initial network

5-5- Planning results

To overcome the network capacity and voltage problems the network planning was done using the incremental approach in four different cases listed in section 5-2.

Case 1: Smart and traditional solutions with non-firm access for new DGs

Reinforcements required for the network in four epochs with the incremental approach are shown in Table 5.7. The term 'Line Rei' refers to increasing the capacity of existing lines. 'QB' refers to installing a quad booster in series with a line. The DG

curtailment was only allowed for newly added generators. All the investments are done in the first year of each epoch. The cost of network assets used here, are given in Appendix A [57-58].

Table 5.7: Incremental approach planning results

Epoch	Item	ID	Capacity	Cost (£)
epoch 1	SVC	Bus 6	3.6 Mvar	544196
	SVC	Bus 25	1 Mvar	151165.56
	DLR	Line 3-5		134513
	DG	1	887 MWh	45553
	DG	2	2189 MWh	112391
	DG	3	966 MWh	49603
epoch 2	Line	Line 8-12	6.6 MVA	239242
	DLR	Line 12-13		99270
	QB	Line 11-18	18.69 MVA	367931
	DG	1	809 MWh	37153
	DG	4	852 MWh	39153
epoch 3	Line	Line 8-12	5.1 MVA	180132
	Line	Line 12-13	5.7 MVA	115630
	DG	1	758 MWh	31138
	DG	4	859 MWh	35311
epoch 4	Line	Line 2-3	2.5 MVA	146947
	DG	1	781 MWh	28706
	DG	4	858 MWh	31538
	DG	6	432 MWh	15878
Total cost in 16 years				2,405,451

Table 5.8: Incremental approach planning costs

epoch	smart assets cost (£)	traditional assets cost (£)	total capital cost of assets (£)	energy curtailed (MWh)	curtailment cost (£)	curtailment cost + assets cost
1	829,874	-	829,874	4,042	207,547	1,037,421
2	467,201	239,242	706,443	1,661	76,306	782,749
3	-	295,762	295,762	1,617	66,449	362,211
4	-	146,947	146,947	2,071	76,122	223,069
Total	1,297,075	681,951	1,979,026	9,391	426,424	2,405,450

In the first epoch DG1 is connecting to Bus 6 with 7.5MW capacity. A SVC shall be installed at B6 as there is voltage rise in this bus which will cause DG curtailment. The connection of DG1 will result in 7.5 MW extra flows through L3-5 and L2-3. Line 3-5 has almost reached its nominal capacity in the initial network so it needs to be reinforced to be able to integrate DG1. As it is an overhead line DLR is available as a cheap reinforcement option. The dynamic rating of L3-5 is sufficient for delivering the flow from B6 to B5, so a DLR shall be installed on the L3-5. Still 887 MWh (0.4%) of DG1 output will be curtailed. Figure 5.10 shows the voltage profile at Bus 6 and DG1 curtailment in the operating snapshots. As none of the lines connected to Bus 6 are overloaded the only reason for the curtailment of DG 1 is the voltage rise in bus 6. Also it can be seen in figure 5-13 that when DG1 is curtailed, the SVC at bus 6 is running at its maximum capacity. Comparing to Figures 5.11 and 5.13 to Figure 5.4 there is considerable decrease in the curtailment of DG1 as a result of the reinforcements.

Figure 5.10: Active voltage constraint in Bus 6 in the 1st epoch

Figure 5.11: SVC utilization at Bus 6 in the 1st epoch

Figure 5.12: SVC utilization and DG curtailment at Bus 6

Figure 5.13: Branch utilization in the 1st epoch based on the static rating

Figure 5.14: Branch utilization in the 1st epoch based on the dynamic rating

Figure 5.13 shows the utilization of network branches in regards to their static rating. The utilization of L3-5 has exceeded its static rate as a result of DLR implication on this overhead line. Figure 5.14 shows the utilization of branch, this time the dynamic rating of Line 3-5 has been considered.

Also in the first epoch, DG2 is planned to be connected to B11. DG2 will be connected to the network via two circuits L10-11 and L11-18. L10-11 reaches its maximum loading limit by connecting DG2 and as the flow direction is from bus 11 towards bus 10, DG2 output will be curtailed in some of the snapshots. But the amount of curtailment is not high enough to require any reinforcement.

In the second epoch the capacity of DG2 increased to 10MW. As L10-11 is already overloaded, a Quad Booster in series with L11-18 is installed to achieve optimal load sharing between L10-11 and L11-18 to be able to export extra generation from DG2 at B11. If the QB was not an option in the reinforcement planning, connecting DG2 to Bus 11 would result in reinforcing L7-10 and L10-11. The direction of flow in this part of the network is from Bus 18 to Bus 11 through L11-18, from Bus 11 towards Bus 10 and from Bus 10 towards Bus 7. Before connection of DG2, L10-11 has

reached its maximum capacity in some of the snapshots. Adding DG2 to Bus 11 will worsen the situation. But installing a QB in series with L11-18 can control the flow through this line and it decreases the flow toward Bus11 in high wind profiles to stop L10-11 being overloaded. Therefore when a QB is in series with L11-18, the network can integrate DG2 at Bus11 without any additional capacity required.

Figure5.15: The impact of QB on L11-18 power flow

Figure 5.15 shows the utilization of Line 11-18, Line 10-11 and DG2 generation rate in 6 snapshots. It is shown that when DG2 generation increases and L10-11 reaches its maximum capacity the flow through L11-18 decreases with QB to avoid L10-11 of being overload or DG2 of being curtailed. This indicates the effect of Quad-Booster in these lines which limits the flow from Bus18 to Bus11 when the generation of DG2 at Bus11 is high and therefore, prevents L10-11 and L7-11 from being overloaded.

Also in the second epoch 10MW, DG4 and 6MW, DG5 are connected to Bus 13 and Bus 14. The connection of these two DGs increases flows through constraint lines L12-13 and L8-12. L12-13 is an overhead line and using a DLR can gain up to 60% above its static capacity. Line 8-12 is underground cable and it would be reinforced for

6.6 MW. Still the DG4 will be curtailed in some snapshots regards to the thermal limits of these two lines.

As shown in Figure 5.16, at a point of time, 100% capacity of the reinforced circuits has been utilized and no unnecessary reinforcement is proposed even though all additional capacity gained by DLR in Line 12-13 has been utilized.

There is still 852MWh/yr curtailment in DG4. This is due to overloading of L8-12 (Figure5.18). The curtailment happens only in three snapshots therefore, further reinforcement of L8-12 is not economically required.

Figure5.16: Branch utilization (% of static rating) in the second epoch

Figure 5.17: Branch normalized power flow (% of dynamic rating) in the second epoch

Figure 5.18: DG 4 curtailment in the second epoch

In the third epoch, the capacity of DG5 increases for 4 MW and as a result more capacity is needed in line 8-12 and 12-13. Although line 12-13 is equipped with DLR but more capacity is needed than its dynamic rating and therefore, it would be reinforced for 5.7 MW in the third epoch.

Figure 5.19: Branch utilization (% of dynamic rating) in the third epoch

Figure 5.20: Active thermal constraints and DG 4 curtailment

In the last epoch, L2-3 is reinforced. By connecting DG6 to B15, a part of the load at bus 15 will be supplied locally so more share of generation of DGs in B5 and B6 will flow through L2-3 towards B2 and as it has already reached its maximum capacity it shall be reinforced to avoid more DGs curtailment.

Note that all the DGs curtailment in these four epochs is less than 1% of the DGs generation capacity.

Figure 5.21: Branch loading range in the fourth epochs

Figure 5.22: Active thermal constraint and DG 6 curtailment

Case two: traditional solution with non-firm access for new DGs

To illustrate the value of smart solutions in network voltage and capacity management, the incremental planning is repeated in this case only with traditional reinforcement options (cables, lines and transformers) and DG curtailment for new DGs.

Table 5.9 shows the planning results. Five of the network cables and lines have been reinforced in different epochs. The 132/33 kV transformer in Peterborough Central bus (T 1-2) has been reinforced in three epochs.

As SVC is not an available option in this case, due to voltage rise in the grid, new DGs cannot be connected to the grid unless the surplus generation will be exported to the upstream network. Therefore 132/33kV transformer has been reinforced to increase the export capacity from 33kV network to 132 kV network.

As it was expected the investment cost has been increased almost 3.5 times than the first case which smart solutions were also included in the planning options.

Table5.9: Incremental approach planning results
(traditional solutions + DG curtailment)

Epoch	Item	ID	Amount	Cost (£)
epoch 1	Line Rei	Line 3-5	4.3 MVA	603533
	Line Rei	Line 7-10	8 MVA	357014
	Line Rei	Line 8-12	8 MVA	313529
	Line Rei	Line 10-11	11 MVA	673919
	Line Rei	Line 12-13	10 MVA	179589
	Trans Rei	T1-2	10 MVA	2135127
	DG	1	4695 MWh	241088.3
	DG	3	8586 MWh	440891.1
epoch 2	Line Rei	Line 7-10	2.7 MVA	174094
	Line Rei	Line 8-12	5.9 MVA	229923
	Line Rei	Line 10-11	3.5 MVA	291152
	Line Rei	Line 12-13	6.1 MVA	136799
	Trans Rei	T1-2	8 MVA	1260571
	DG	1	3521 MWh	161684.3
	DG	3	14764 MWh	677962.9
epoch 3	DG	1	4302 MWh	176683.1
	DG	3	20 MWh	821.4
	DG	5	18137 MWh	744886.6
epoch 4	Line Rei	Line 12-13	1 MVA	91430
	Trans Rei	T1-2	3.3 MVA	176148
	DG	1	5781 MWh	212451.8
	DG	3	18067 MWh	663962.3
	DG	5	23 MWh	845.25
total cost in 16 years				9,944,105

Table 5.10: Incremental approach planning costs
(traditional solutions + DG curtailment)

epoch	traditional assets cost (£)	energy curtailed	curtailment cost (£)	curtailment cost + assets cost
1	4,262,711	13,281	681,979	4,944,690
2	2,092,539	18,285	839,647	2,932,186
3	0	22,459	922,391	922,391
4	267,578	23,871	877,259	1,144,837
Total	6,622,828	77,896	3,321,276	9,944,104

The QB installation in L11-18 has been replaced by reinforcing L10-11, L7-10, L8-10. L12-13 which had been equipped with DLR in the previous case has been reinforced here. The energy curtailment cost has increased about 7.8 times than before.

Case 3: Smart and traditional solution with firm access for new DGs

In this case the incremental planning is done again. Both the smart and traditional reinforcement options are included in planning options but the newly added DGs have firm access to the grid. Tables 5.11 and 5.12 show the planning results in this case study. The total cost of planning in study horizon has increased by 23% and the investment cost has increased to 220% compared to case 1.

Table 5.11: Incremental approach planning results
(smart and traditional solutions)

Epoch	Item	ID	Capacity	Cost (£)
epoch 1	Line Rei	Line 2-3	2.5 MVA	266792
	DLR	Line12-13		134489
	QB	Line 11-18	18.69 MVA	498552
	SVC	Bus 6	4 Mvar	604662.2
	SVC	Bus 1	1 Mvar	151165.6
epoch 2	Line Rei	Line 8-12	12.3 MVA	315130
	Line Rei	Line 12-13	13.7 MVA	166913
epoch 3	Line Rei	Line 2-3	5.9 MVA	245674
	Line Rei	Line 8-12	10 MVA	223093
	DLR	Line 12-13		136505
epoch 4	Line Rei	Line 2-3	3 MVA	151418
	SVC	Bus 5	1 Mvar	36648
	SVC	Bus 29	1 Mvar	36648
total cost in 16 years				2,967,690

Table 5.12: Incremental approach planning costs
(smart and traditional solutions)

epoch	smart assets Cost (£)	traditional assets cost (£)	total capital cost of assets (£)
1	1,388,868	266,792	1,655,660
2	-	482,043	482,043
3	136,505	468,767	605,272
4	73,296	151,418	224,714
Total	1,598,669	1,369,020	2,967,689

Case 4: No reinforcement only DG curtailment for new DGs

If no reinforcement is done to the grid, 18% of generation capacity of new DGs would be curtailed as a result of active voltage and thermal constraints in the network.

Table 5-13 shows the summary of the planning results in these four cases. The costs of reinforcements and DG curtailments are compared to case 1.

Table 5.13: Planning results in 4 cases with incremental approach

case study		smart assets				traditional assets			total	DG curtailment		total
		1	2	3	4	5	6	7	8	9	10	11
		No. O f DLR	No. O f QB	No. O f SVC	total capital cost of smart assets	No. of reinforced OH/Cable	No. of reinforced Trans	total capital cost of traditional assets	Total investment cost	DG curtailment (% of total generation capacity)	DG curtailment cost	total cost 4+7+10
1	Smart and traditional Reinforcement + DG curtailment	2	1	2	1	3	0	1	1	0.49%	1	1
2	Traditional Reinforcement + DG curtailment	0	0	0	0	5	1	9.71	3.35	4%	7.79	4.13
3	Smart and traditional Reinforcement	2	1	4	1.13	3	0	2.20	1.50	0	0.00	1.23
4	No reinforcement	0	0	0	0	0	0	0.00	0.00	18.00	25.06	4.44

The minimum cost planning is case 1 where both smart and traditional options are available and the new DGs have non-firm access. Although the new DGs have non-firm access the annual curtailment is only 0.49% of the total generation capacity of new DGs. Five smart assets have been used in the network and three of the lines have been reinforced.

In case 2 when the smart assets are not available in the planning, the investment cost of the network increases to 3.35 times of the investment cost in case 1. Despite the increase in network investment the DG curtailment is almost 10 times of its amount in case 1. These figures show how smart technologies like DLR, QB and SVC can increase the utilization of network assets and increase the capacity of networks to integrate more DGs. In total the planning cost in case 2 is 4.13 times of the planning cost in case 1 over 16 years.

In case 3 both smart and traditional options are available but the new DGs have firm access to the grid. In order to reduce 0.49% DG curtailment which was in case 1, the investment cost increases for 50% in case 3. The results in case 3 shows that

delivering the last few MWh generation of the new DGs (9391 MWh or 0.49% of total generation capacity) are much more expensive than the first 99.51% of the total generation capacity. Considering non-firm access for the new DGs will result in only 0.49% of energy curtailment but can cut the investment by 50%.

The last case shows the ability of the network to integrate the new DGs without any reinforcement. 18% of the generation capacity of the new DGs would be curtailed due to voltage and thermal constraints of the grid as discussed earlier. The total cost of the planning in case 4 is highest among all 4 cases.

5-6- Summary

The proposed OPF model in chapter 4 was applied to a 33kV distribution network similar to the UK Power Network in Peterborough area. The model was solved with incremental approach. To illustrate the impact of smart solutions and non-firm network access on the planning cost the planning was done with different planning options:

- 1) Smart + traditional reinforcement + DG curtailment
- 2) Traditional reinforcement + DG curtailment
- 3) Smart + traditional reinforcement
- 4) DG curtailment

The results show how smart technologies can increase the utilization of the network assets and increase the capacity of network to integrate more DGs. Also the results indicate that non-firm access can bring a considerable saving to the network investment by cutting the DG output only for few hours per year.

Voltage and Capacity Management of Distribution Networks with an Integrated Approach

In this chapter the proposed OPF model is again applied to the test network described in Chapter 5. This time the integrated approach is used to solve the multi-epoch planning. The results are then compared to the results in chapter 5 to see if the smart technologies have the same competence in both short and long term planning.

The test network data is the same as data in Chapter 5, as well as the case study scenario and the DGs connections plans. The planning options are the same as case 1 which includes the traditional reinforcement, ANM for DGs and smart technologies.

This chapter is structured as follows: section 6-1 is nomenclature, section 6-2 presents the problem formulation. The application of proposed model and the results are

presented in section 6-3. Section 6-4 summarizes the differences between the results in the incremental and the integrated planning in all aspects and section 6-5 is the summary of findings.

6-1- Nomenclature

C_{ep}^{Tr}	Transformers reinforcement cost in ep^{th} epoch
C_{ep}^{QB}	Quad Boosters installation cost in ep^{th} epoch
C_{ep}^{DLR}	DLRs installation cost in ep^{th} epoch
C_{ep}^{line}	Lines reinforcement cost in ep^{th} epoch
C_{ep}^{svc}	SVCs installation cost in ep^{th} epoch
N_{final}	final year in the planning horizon
$StrYr_{ep}$	the start year of ep^{th} epoch
$EndYr_{ep}$	the end year of ep^{th} epoch
K_y	present value factor
$T_{candidate}$	the set of transformers which are candidates for reinforcement
$Tr_{i,ep}$	additional capacity for transformer i as reinforcement in ep^{th} epoch
$\pi_{i,ep}^{Tr}$	the annuitized cost of reinforcing the transformer i in ep^{th} epoch, (£/MVA.yr)
$QB_{candidate}$	the set of lines which are candidates for installing a Quad Booster
$QB_{i,ep}$	decision variable to install a QB in series with line i in ep^{th} epoch (binary)
π_{ep}^{QB}	the annuitized cost of installing a QB in ep^{th} epoch (£/MVA.yr)
Cap_{QB_i}	the capacity of QB installed in series with line i
$L_{i,ep}$	additional capacity for line i as reinforcement in ep^{th} epoch
$\pi_{i,ep}^{VL}$	the annuitized variable cost of reinforcement of line i in ep^{th} epoch, (£/MVA.yr)
$F_{i,ep}^L$	decision variable to reinforce line i (binary)
$\pi_{i,ep}^{fixL}$	Fixed cost of reinforcing line i in ep^{th} epoch
$B_{i,ep}^{DLR}$	decision variable to install DLR on line i in ep^{th} epoch (binary)

π_{ep}^{DLR}	the annuitized cost of installing DLR on a line in ep^{th} epoch (£/yr)
$DLRcandidate$	the set of overhead lines which are candidates to install DLR
$\pi_{i,ep}^{SVC}$	the annuitized cost of installing SVC on bus i in ep^{th} epoch, (£/MVAR.yr)
$Q_{svc_{i,ep}}$	Capacity of installed SVC on bus i in ep^{th} epoch
$SVCcandidate$	the set of buses which are candidates to install SVC
$Cost_{ep}^{DGcur}$	total DG curtailment cost in ep^{th} epoch
$Cost_{ep}^{Lshed}$	total load shedding cost in ep^{th} epoch
C_{ep}^{os}	total over slack cost in ep^{th} epoch
Th	set of operating snapshots per year
π_y^{ec}	cost of generation curtailment in y^{th} year (£/MWh)
$\tau(t)$	the duration of t^{th} snapshots, (in hours)
$\overline{Pdg}_{i,t,ep}$	generation capacity of DG_i at t^{th} snapshot in ep^{th} epoch
$Pdg_{i,t,y}$	power generation of DG_i at t^{th} snapshot of year y in ep^{th} epoch
π_y^{shed}	cost of load shedding in y^{th} year (£/MWh)
$Pshed_{i,t,y}$	involuntary loss of active power on bus i at t^{th} snapshot of year y in ep^{th} epoch
$Qshed_{i,t,y}$	involuntary loss of reactive power on bus i at t^{th} snapshot of year y in ep^{th} epoch
π_{slack}	penalty cost of overslack variables
$P_{i,t,y}^{OS}$	positive decision variables representing an artificial load
$Q_{i,t,y}^{OS}$	positive decision variables representing an artificial load

6-2- Problem formulation

The OPF model described in Chapter 4 is used here. As the integrated planning approach is used to solve the multi-epoch problem, it is worth to bring some of the equations again here to clarify the planning procedure.

The model is formulated as follows:

$$\min \sum_{ep=1}^{N_{ep}} Cost_{ep}^{Re} + Cost_{ep}^{DGcur} + Cost_{ep}^{Lshed} + Cost_{ep}^{svc} + Cost_{ep}^{OS} \quad (6-1)$$

$$N_{ep} = 4$$

The cost function reflects the present value of operation and investment costs of the network during the time horizon of the optimization which is 4 epochs (16 years).

The reinforcement cost per epoch can be obtained as the summation of the different terms described as follows:

$$Cost_{ep}^{Re} = C_{ep}^{Tr} + C_{ep}^{QB} + C_{ep}^{DLR} + C_{ep}^{line} + C_{ep}^{svc} \quad (6-2)$$

$Cost_{ep}^{Re}$ includes the annuitized cost of any investment in epoch ep till the end of 16 years of studying period. For instant if a QB is installed in the second epoch, $Cost_2^{Re}$ includes the present value of the QB annuitized cost for 12 years starting from the fifth year (epoch 2 start year).

The transformer reinforcement cost per epoch can be expressed as:

$$C_{ep}^{Tr} = \sum_{i \in T_{candidate}} K_y F_{i,ep}^{Tr} \times \pi_{i,ep}^{fixT} + \sum_{y=StrYr_{ep}}^{N_{final}} \sum_{i \in T_{candidate}} K_y \times Tr_{i,ep} \times \pi_{i,ep}^{Tr} \quad (6-3)$$

$$K_y = 1/(1 + intrestate)^y \quad (6-4)$$

K_y is present value factor which calculates the present value of future investment.

$N_{final} = 16$, is the final year of planning horizon

$StrYr_1 = 1$, is the beginning year of the first epoch

$StrYr_2 = 5$, is the beginning year of the second epoch

$StrYr_3 = 9$, is the beginning year of the third epoch

$StrYr_4 = 13$, is the beginning year of the last epoch

The quad booster installation cost in each epoch can be expressed as:

$$C_{ep}^{QB} = \sum_{y=StrYr_{ep}}^{Nfinal} \sum_{i \in QBcandidate} K_y \times QB_{i,ep} \times Cap_{QB_i} \times \pi_{ep}^{QB} \quad (6-5)$$

The $QB_{i,ep}$ is the decision variable of installing QB in series with line i in epoch ep which can be 0 or 1. Cap_{QB_i} is the capacity of the QB in series with line i that should be the same as the capacity of the line i .

The DLR installation cost in each epoch can be expressed as:

$$C_{ep}^{DLR} = \sum_{y=StrYr_{ep}}^{Nfinal} \sum_{i \in DLRcandidate} K_y \times B_{i,ep}^{DLR} \times \pi_{ep}^{DLR} \quad (6-6)$$

The DLR decision variable $B_{i,ep}^{DLR}$ is also a binary variable.

The Line reinforcement cost per epoch can be expressed as:

$$C_{ep}^{line} = \sum_{y=StrYr_{ep}}^{Nfinal} \left(\sum_{i \in Lcandidate} K_y \times L_{i,ep} \times \pi_{i,ep}^{VL} \right) + \sum_{i \in Lcandidate} F_{i,ep}^L \times \pi_{i,ep}^{fixL} \quad (6-7)$$

Line reinforcement cost is made of two terms: fixed cost and variable cost. The variable cost depends on the amount of added capacity but the fixed cost only depends on the length of the line. $F_{i,ep}^L$ is a binary decision variable which is equal to 1 when line i is reinforced in epoch ep , otherwise it is 0. The first term in equation 6-7 represents the variable cost of line reinforcement and the second term represents the fixed cost of line reinforcement.

The SVC installation cost in each epoch can be expressed as:

$$C_{ep}^{svc} = \sum_{y=StrYr_{ep}}^{Nfinal} \sum_{i \in SVCcandidate} K_y \times Q_{i,ep}^{svc} \times \pi_{ep}^{svc} \quad (6-8)$$

The DGs curtailment cost per epoch can be expressed as:

$$Cost_{ep}^{DGcur} = Curt_{ep}^{Non-firm DG} \quad (6-9)$$

$$C_{Curt_{ep}}^{Non-firm DG} =$$

$$\sum_{y=Stryrep}^{EndYrep} k_y \times \sum_{i \in NDG} \sum_{t \in Th} [\pi_y^{ec} \times \tau(t) \times (\overline{Pdg}_{i,t,ep} - Pdg_{i,t,y})] \quad (6-10)$$

The load shedding cost can be expressed as:

$$Cost_{ep}^{Lshed} = \sum_{y=Stryrep}^{endYrep} K_y \times \sum_{i \in Nload} \sum_{t \in Th} [\pi_y^{shed} \times (Pshed_{i,t,y} + Qshed_{i,t,y})] \quad (6-11)$$

The over slack penalty cost can be expressed as:

$$C_{ep}^{Os} = \sum_{y=Stryrep}^{EndYrep} K_y \times \sum_{i \in Nbus} \sum_{t \in Th} [\pi_{slack} \times (P_{i,t,y}^{os} + Q_{i,t,y}^{os})] \quad (6-12)$$

The constraints are the same as those described in chapter 4.

6-3- Integrated planning results

The optimal planning results for these four epochs with the integrated approach are shown in Tables 6.1 and 6.2.

Table 6.1: Integrated approach planning results

Epoch	Item	ID	Capacity	Cost (£)
epoch 1	SVC	Bus6	3.6 Mvar	544196
	DLR	Line 3-5		134513
	QB	Line11-18	18.69 MVA	498552
	DG	1	1437 MWh	73790
	DG	3	391 MWh	20278
epoch 2	Line	Line 12-13	14.6 MVA	170479
	Line	Line 8-12	11 MVA	297822
	DG	1	755 MWh	34697
	DG	4	61 MWh	2842
epoch 3	DG	1	784 MWh	32218
	DG	4	1231 Mwh	50593
epoch 4	Line	Line2-3	2.5 MVA	146947
	DG	1	945 MWh	34744
	DG	4	1229 MWh	45188
	DG	6	163 MWh	6008
Total cost in 16 years				2092867

Table 6.2: Integrated approach planning results costs

epoch	smart assets cost (£)	traditional assets cost (£)	total cost of assets (£)	energy curtailed (MWh)	curtailment cost (£)	curtailment cost + assets cost
1	1,177,261	-	1,177,261	1,828	94,068	1,271,329
2	0	468,301	468,301	816	37,539	505,840
3	0	0	0	2,015	82,811	82,811
4	0	146,947	146,947	2,337	85,940	232,887
Total	1,177,261	615,248	1,792,509	6,996	300,358	2,092,867

Table 6.3: comparison of the integrated and the incremental approaches results

case study		multi epoch approach	smart assets				traditional assets			total	DG curtailment		total
			1	2	3	4	5	6	7	8	9	10	11
			No. O f DLR	No. O f QB	No. O f SVC	total cost of smart assets	No. of reinforced OH/Cable	No. of reinforced Trans	total cost of traditional assets	Total investment cost	DG curtailment (% of total generation capacity)	DG curtailment cost	total cost 4+7+10
1	Smart and traditional Reinforcement + DG curtailment	incremental	2	1	2	1	3	0	1	1	0.49%	1	1
5	Smart and traditional Reinforcement + DG curtailment	integrated	1	1	1	0.91	3	0	0.90	0.91	0.36%	0.70	0.87

Table 6.3 compares the integrated and the incremental approach plans. The total cost in the integrated approach is 13% less than the incremental approach. This reduction in the cost was expected as the integrated approach finds the optimal solution for the whole study horizon while the incremental approach finds the optimal solution for each epoch which does not necessarily result in the optimum solution for the whole study horizon.

Table 6.4: comparison of the integrated and the incremental approaches results in first epoch

Incremental				Integrated			
epoch 1	SVC	Bus 6	3.6 Mvar	epoch 1	SVC	6	3.6 Mvar
	SVC	Bus 25	1 Mvar		DLR	Line 3-5	
	DLR	Line 3-5			QB	Line 11-18	18.69 MVA
	DG	1	887 MWh		DG	1	1437MWh
	DG	2	2189 MWh		DG	3	391MWh
	DG	3	966 MWh	cost		1,271,129	
cost		1,037,421					

Table 6.4 compares the two approaches in the first epoch. The costs are the annuitized cost in the study time horizon (16 years). The integrated approach cost is higher in the first epoch than the incremental approach. This is because the QB has been installed in the first epoch in the integrated approach which was installed in the second epoch in the incremental approach. As the result of QB there is no curtailment for DG2 and the curtailment of DG3 has decreased. When the planning is done only for epoch 1 in incremental approach, the curtailment of DG2 and DG3 are not high enough to require any reinforcement. Reinforcing this part of the network with a QB has been postponed to the second epoch when the curtailment of these two DGs increased enough to require an investment. But with integrated planning, installing the QB will be brought forward from epoch 2 to epoch 1 so it can prevent the curtailment of DG 2 & 3 in the first epoch as well and therefore reduces the total planning costs in 16 years.

A SVC is installed in bus 6 in the integrated planning the same as the incremental approach to overcome the voltage rise problem and allow DG1 to export its generation to the grid. Still there is some curtailment in some of the snapshots caused by voltage rise.

The 1 MVar SVC at Bus 25 in the incremental planning is not in the results with the integrated approach. As the load in bus 25 increases in the second epoch there would be no need for a SVC except for the first epoch, therefore in the integrated planning it was not worth to install a SVC only for one epoch.

L3-5 is equipped with DLR. Figure 6.2 shows both dynamic and static thermal rate of L3-5 at each snapshot. The DLR has increased the capacity of the line by 33% in average. Figure 6.3 shows the power flow through L3-5 and its dynamic rating.

Figure 6.1: Branch normalized power flow (% of branch dynamic rating) in the first epoch

Figure 6.2: Line 3-5 static and dynamic line rating (MVA) in different snapshots

Figure 6.3: Line 3-5 flow and dynamic capacity (MVA in different snapshots)

In the second epoch L8-12 and L12-13 are reinforced. Although DLR is an available option for L12-13 and its dynamic rating is sufficient for the second epoch, but when considering the whole planning horizon the DLR effect is not enough and traditional reinforcement is needed as well. Therefore it is more beneficial to reinforce the line in the first place and avoid reinvesting on the line later in epoch 3.

Line 8-12 shall be reinforced only once and for 11 MW in the second epoch. This is to avoid paying the fixed cost twice as it was the case in the incremental approach.

In the second epoch the curtailment of DG4 has reduced considerably than the results in the incremental approach. This is due to the thermal capacity of Line 8-12 and Line 12-13 which are higher than their capacity in the incremental approach.

Figure 6.5 compares the dynamic rating of L12-13 and its reinforced capacity. As it is shown in the diagram the reinforced capacity is higher than the dynamic capacity.

Figure 6.4: Branch normalized power flow (% of dynamic rating) in the second epoch

Figure 6.5: L12-13 dynamic and reinforced capacity

There is no investment in the third epoch as the required investment has been already done in the last epoch and the increased capacity of DG4 and DG5 will not impose extra investment. Still both of these DGs are forced to cut their output in some of the snapshots to avoid L8-12 and L12-13 of being overloaded (Figures 6.7 and 6.8).

Figure 6.6: Branch normalized power flow (% of dynamic rating) in the third epoch

Figure6.7: DG 4 curtailment and active thermal constraints in the third epoch

Figure 6.8: DG 5 curtailment and active thermal constraints in the third epoch

In the last epoch Line 3-2 is reinforced the same as the results in the incremental approach to integrate the generation of DG6.

Figure 6.9: Branch normalized power flow (% of dynamic rating) in the fourth epoch

6-4- Comparison between the integrated and the incremental solutions

In this section the comparisons of the results of the incremental approach and the integrated approach are summarized in different aspects.

- Schedule of planning

As it was mentioned in the previous section in the integrated planning, installing the QB has been brought forward from epoch 2 in the incremental planning to epoch 1. As a result, the cost of the first epoch is higher in the integrated approach than its cost in the incremental approach but the DG curtailment in epoch 1 is less in the integrated approach than in the incremental approach. Also L12-13 and L8-12 are only reinforced in the second epoch with integrated approach where they are reinforced in both second and third epoch with incremental approach.

- Type of investment

The types of the investments are similar to each others in both approach expect the case with L12-13. In the incremental approach L12-13 was equipped with DLR in the second epoch as the dynamic rating of this line was enough in epoch 2 to integrate DG 4 and 5. In the third epoch when the capacity of these two DGs increased the dynamic rating of L12-13 was not sufficient to integrate new capacities so it was reinforced for 5.7 MVA. In the integrated approach the line was reinforced only once for 11 MVA in the second epoch and DLR was not considered for it as it could not defer the reinforcement for the whole study period. The total cost of investment for L12-13 in the incremental approach is higher than its cost in integrated approach and also curtailment of DG 4 and 5 are less in the integrated approach than the incremental approach.

Also the SVC at bus 25 which was planned in the incremental approach is not included in the results of the integrated approach. This is due to the increase in the load at bus 25 in epoch 2 which automatically solves the voltage rise problem in bus 21 and 25.

- Economy of scale

To avoid paying twice for the fixed cost, L8-12 is reinforced once in the integrated approach in epoch 2 for 11 MVA where it is reinforced twice in the incremental approach in epoch 2 and 3.

- Cost of planning

The total cost of planning in integrated planning is 13% less than the cost in the incremental planning. The cost of investment is 9% and the DG curtailment cost is 30% less in the integrated approach than the incremental approach.

6-5- Summary

In this chapter the network planning is solved by the integrated approach. The total cost of DGs curtailment and the investment is 87% of the total cost in the incremental approach. This result was expected as the integrated approach finds the optimum solution for the whole studying period.

In the incremental approach, where planning is done for a short period of time, smart technologies were the first selected options as they are much cheaper than reinforcing the network and they could defer the needs of network reinforcement.

In the integrated approach, when the planning is done for a longer period of time, in some cases the traditional reinforcement are still better options than smart ones as it is sometimes better to reinforce a part of the network in first place rather than to defer it with smart solutions and reinvest again in near future.

The proposed model was applied to a 33kV distribution network similar to the UK Power Network in Peterborough area. In both approaches, a Quad Booster was used to avoid network reinforcement when integrating a new DG. But in the integrated approach installing the QB was brought forward from epoch 2 to epoch 1. Bringing forward the QB installation has increased the cost of the first epoch in the integrated

approach but has reduced the total cost in the planning horizon as it reduces the DG curtailments in the first epoch.

In the incremental approach, Dynamic Line Rating was the first option for overhead lines when extra capacity was needed. In the integrated approach, in one case where more capacity than the dynamic capacity would be needed in next epochs, it was cheaper to reinforce the overhead line in the first place than to delay it with DLR for the next epochs.

The DG curtailment was also reduced in the integrated approach (0.36%) compared to its amount in the incremental approach (0.49%).

Optimal DGs Connection Points in Network Considering Network Reinforcement Cost

The increasing number of DGs in distribution networks, which were traditionally viewed as a passive part of the power system, has posed many challenges to distribution network owners. One of the challenges is that integration of DGs can be very costly to the distribution networks. They can impose a large amount of reinforcement to the grid to provide adequate capacity. The cost and the amount of network reinforcement depend on the size and the location of the DGs in the grid.

Most of the available literatures consider a fixed location for DG in the network and plan for the network reinforcement to integrate the projected DGs. But although in most cases the location of DG is not decided by the DNO. But still the connection point of a DG to the grid can be decided to lower the cost of required reinforcement. The shortest feasible path to connect a DG to a grid is not always the best connection although the connection cost can be at its minimum. Sometimes, it is worth to invest more on the connection circuit and choose a longer path if in return there would be a cut in the network reinforcement costs.

The connection point of a DG can also affect the capacity of the grid to be able to integrate more DGs in future. Connecting a DG to a particular part of a grid can sterilize the grid for further DG integration due to voltage rise or overloaded circuits. Considering all these issues it is important for the planners to consider the network capacity and network reinforcement plans along with the connection cost, when deciding about connecting a new DG to their grid.

In this chapter the multi-epoch OPF model presented in chapter 4, has been modified to decide about the connection points for projected DGs as well planning the network reinforcement. When a new DG is going to be connected to the network, numbers of possible connection points are candidates for connection. The best point is chosen in regards to the total cost of connection, reinforcement and DG curtailment over the studying period. The model is an integrated multi-epoch planning which makes it possible to consider the future DG integration plans.

Section 1 describes the details of problem formulation and the solution method. Section 2 presents the case study and the results. Section 3 is the summary of results in all case studies in this thesis and section 4 is the summary of this chapter.

7-1- Problem formulation

An integrated multi epochs AC OPF model is adopted here to find the least cost plan for integrating new DGs in a given distribution network. The cost function of the model is the summation of network reinforcement costs, DGs connection costs, DGs curtailment costs, load shedding costs and the over slack penalty cost .

The integrated approach is taken to solve the planning in a multi-epoch scenario. The model is formulated as follows:

$$\min \sum_{ep=1}^{N_{ep}} Cost_{ep}^{Re} + Cost_{ep}^{DGcon} + Cost_{ep}^{DGcur} + Cost_{ep}^{Lshed} + Cost_{ep}^{OS} \quad (7-1)$$

The cost function reflects the present value of operation and investment costs of the network during the time horizon of the optimization; therefore the annuitized costs are used for the investment cost.

The reinforcement cost per epoch can be obtained as the summation of the different terms, described as follows:

$$Cost_{ep}^{Re} = C_{ep}^{Tr} + C_{ep}^{QB} + C_{ep}^{DLR} + C_{ep}^{line} + C_{ep}^{svc} \quad (7-2)$$

It is the same as the reinforcement cost in chapter 6 so the details are not discussed here again.

The connection cost of new DGs in epoch ep is expressed as:

$$Cost_{ep}^{DGcon} = \sum_{i \in DG_{ep}^{new}} [\sum_{j \in ConSet_i} K_y \times D_{i,j} \times \pi_{ep,j}^{fix} + \sum_{y=StrYr_{ep}}^{Nfinal} (\sum_{j \in ConSet_i} K_y \times D_{i,j} \times \pi_{i,ep,j}^{var})] \quad (7-3)$$

The connection cost has two terms: variable and fixed costs.

Figure 7.1: Five bus example network diagram

The DG_{ep}^{new} is the set of new DGs which are going to be connected to the grid in the ep^{th} epoch. For each new DG ($Newdg_i$), there is a set of candidate points to connect the DG to the grid ($ConSet_i$).

To illustrate the model a simple example is used here. The example network is shown in Figure 7.1. There are two new DGs to be connected to the network in epoch ep . DG1 has 3 candidate connection points and DG2 has two candidate connection points:

$$DG_{ep}^{new} = \{1, 2\}$$

$$ConSet_1 = \{1, 2, 4\}$$

$$ConSet_2 = \{5, 3\}$$

$D_{i,j}$ is a binary decision variable which shows whether $Newdg_i$ will be connected to the candidate point j in $ConSet_i$ or not. For each $Newdg_i$, one and only one of the $D_{i,j}$ should get a non-zero value. This constraint is put in the model in Equations (7-22) and (7-23) that will be described later.

DG1 connection decision variable set is:

$$D1 = \{D_{1,1}, D_{1,2}, D_{1,4}\}$$

($D_{1,1}$ shows whether DG1 is connected to bus 1 or not and so on)

DG2 connection decision variable set is:

$$D2 = \{D_{2,3}, D_{2,5}\}$$

($D_{2,3}$ shows whether DG2 is connected to bus 3 or not and so on)

The DGs curtailment cost per epoch can be expressed as:

$$Cost_{ep}^{DGcur} = C_Curt_{ep}^{Non-firm DG} + C_Curt_{ep}^{new DG} \quad (7-4)$$

$C_Curt_{ep}^{Non-firm DG}$ and $C_Curt_{ep}^{new DG}$ are the total energy curtailment cost of non-firm DGs and newly added DGs in the ep^{th} epoch.

$$C_{Curt_{ep}}^{Non-firm DG} = \sum_{y=Start_{ep}}^{EndY_{rep}} k_y \times \sum_{i \in NDG} \sum_{t \in Th} [\pi_y^{ec} \times \tau(t) \times (\overline{Pdg}_{i,t,ep} - Pdg_{i,t,y})] \quad (7-5)$$

Figure7.2: The equivalent DGs for the example network

The amounts of energy curtailment of the new DGs in epoch ep depend on their connection points that are yet to be decided by the model. Therefore to formulate the DG curtailment of new DGs, it is assumed that for each new DG, $Newdg_i$, an equivalent DG is connected to every connection points in $ConSet_i$. (Figure 7.2)

For the example network in figure 7-2 it would be:

DG 1 equivalent DGs:

$$dg_{1,1}, dg_{1,2}, dg_{1,4}$$

DG 2 equivalent DGs:

$$dg_{2,3}, dg_{2,5}$$

The total capacity of these equivalent DGs are equal to the capacity of $Newdg_i$. But the capacity of each of them should be decided by the model. Of course only one of

them can have the same capacity as $Newdg_i$ and the rest of them have zero capacity.

For the example network it models as follows:

For DG1:

$$dg_{1,1} + dg_{1,2} + dg_{1,4} = DG_1 \quad (7-6)$$

$$0 \leq dg_{1,1} = S_{1,1} * DG_1 \quad (7-7)$$

$$0 \leq dg_{1,2} = S_{1,2} * DG_1 \quad (7-8)$$

$$0 \leq dg_{1,4} = S_{1,4} * DG_1 \quad (7-9)$$

$$S_{1,1} + S_{1,2} + S_{1,4} = 1 \quad (7-10)$$

For DG2:

$$dg_{2,3} + dg_{2,5} = DG_2 \quad (7-11)$$

$$0 \leq dg_{2,3} = S_{2,3} * DG_2 \quad (7-12)$$

$$0 \leq dg_{2,5} = S_{2,5} * DG_2 \quad (7-13)$$

$$S_{2,3} + S_{2,5} = 1 \quad (7-14)$$

To model the new DG, only one of these equivalent DGs can have the same capacity as the main DG and the rest of them should have zero capacity. This means that mathematically $S_{i,j}$ should be defined as a binary variable equal to $D_{i,j}$. But this will bring more complexity to the model by bringing more integer variables in non-linear AC power flow equations.

To avoid more binary variables in non-linear AC power flow equations, $S_{i,j}$ is not defined as a binary variable but it is related to the binary variable $D_{i,j}$ as follows:

$$S_{1,1} \leq D_{1,1} \quad (7-15)$$

$$S_{1,2} \leq D_{1,2} \quad (7-16)$$

$$S_{1,4} \leq D_{1,4} \quad (7-17)$$

$$S_{2,3} \leq D_{2,3} \quad (7-18)$$

$$S_{2,5} \leq D_{2,5} \quad (7-19)$$

Although $S_{1,1}, S_{1,2}, S_{1,4}$ are not defined to be binary but regards to equation 7-10 and equation 7-15 to 7-17 one of them will get 1 value and the rest two will get zero values. This is the same for $S_{2,3}, S_{2,5}$.

The equations from 7-6 to 7-19 can be written in the model as:

$$\forall j \in \text{ConSet}_i \quad 0 \leq Pdg_{i,t,y} \leq S_{i,j} \times \overline{PDG}_{i,t,ep} \quad (7-20)$$

$$\forall j \in \text{ConSet}_i \quad 0 \leq S_{i,j} \leq 1 \quad (7-21)$$

$$\sum_{j \in \text{ConSet}_i} S_{i,j} = 1 \quad (7-22)$$

$$S_{i,j} \leq D_{i,j} \quad (7-23)$$

Equation 7-22 and 7-23 together guarantee that all except one of the $S_{i,j}$ have zero quantity and one and only one of the $S_{i,j}$ is equal to 1 which indicates the connection point of DG_i .

Therefore the energy curtailment for newly added DGs will be expressed as:

$$C_Curt_{ep}^{new\ DG} = \sum_{y=Str_{yr_{ep}}^{endYr_{ep}}} k_y \times \sum_{i \in DG_{ep}^{new}} \sum_{t \in Th} [\pi_y^{ec} \times \tau(t) \times (\overline{PDG}_{i,t,ep} - \sum_{j \in ConSet_i} Pdg_{i,t,y})] \quad (7-24)$$

The load shedding cost and the slack penalty cost are the same as described in Chapter 6.

7-2- Case study

The proposed planning model is applied to the test network in Chapter 5. The case study scenario is the same as case 1 in chapter 5. The planning is an integrated multi-epoch OPF planning and the planning options include both traditional and smart solutions and also DG curtailment for newly added DGs.

For DG 1 the initial convention connection offer is at Bus 6 with 7 km distance circuit from the DG. There are two existing wind turbine generators connected to this part of the grid with total capacity of 28 MW. Line 3-5 is already potentially overloaded and the voltage at Bus 6 reaches its maximum limit in high wind profiles.

There is an alternative connection point for this DG on Bus 3 with 10 km circuit length. The connection point for DG 1 will be chosen among these two points through the optimization model to minimize the total cost of the network.

Figure 7.3: Test network diagram

For DG 5, the initial convention connection offer is at Bus 14 with 3 km distance circuit from the DG. There is also an alternative connection point for this DG on Bus 26 with 5 km circuit length.

In the past chapters the initial connection points (Bus 6 for DG1 and Bus 14 for DG5) were considered for these two DGs. Here the connection points for these two DGs will be decided through the optimization model. The connection cost for the rest 4 DGs are not included in the model as there is only one connection point for each of them.

The optimal planning results are shown in the Tables 7.1 and 7.2.

Table 7.1: The planning results

Connection point				annuitized cost
DG	1	Bus 3		528,481
DG	5	Bus 26		198,216
Reinforcement Planning				
	Type	ID	Capacity	
epoch 1	SVC	Bus 6	2.9 Mvar	442,404
	QB	Line 11-18	18.69 MVA	498,552
	DG	1	848 MWh	43,547
	DG	3	542 MWh	27,861
epoch 2	DLR	Line 12-13		99,270
	DLR	Line 26-27		99,270
	DG	1	881 MWh	39,697
	DG	4	21 MWh	946
epoch 3	DG	1	881 MWh	36,193
	DG	3	482 MWh	19,807
	DG	4	873 MWh	35,868
epoch 4	Line Rei	Line 2-3	2.5 MVA	146,947
	DG	1	803 MWh	29,835
	DG	2	317 MWh	11,680
	DG	3	108 MWh	3,985
	DG	4	927 MWh	34,100
Total cost in 16 yrs				2,296,659

Table 7.2: The planning investment and operation costs in 4 epochs

epoch	smart assets cost (£)	traditional assets cost (£)	total investmnet cost (£)	energy curtailed (MWh)	energy curtailment cost (£)	connection cost (£)	Total cost
1	940,956	0	940,956	1,390	71,408	528,481	1,540,845
2	198,540	0	198,540	902	40,643	198,216	437,399
3	0	0	0	2,236	91,868	0	91,868
4	0	146,947	146,947	2,155	79,600	0	226,547
Total	1,139,496	146,947	1,286,443	6,683	283,519	726,697	2,296,659

The alternative connection points have been chosen for both the DGs. Although the alternative points have longer circuit distance to the DGs but they will lead to cheaper plan when the curtailment and the reinforcement costs of the network are considered. Table 7.3 shows the cost of function of the model when the DG1 & 5 are connected to the initial points.

Table 7.3: Network planning cost in 16 years when DG1& 5 are connected to their initial connection points

Connection point				annuitized cost
DG	1	Bus 6		369937
DG	5	Bus 14		118930
Reinforcement Planning				
	Type	ID	Capacity	
epoch 1	SVC	Bus 6	3.6 Mvar	544196
	DLR	Line 3-5		134513
	QB	Line 11-18	18.69 MV	498552
	DG	1	1437 MW	73790
	DG	3	391 MWh	20278
epoch 2	Line Rei	Line 12-13	14.6 MVA	170479
	Line Rei	Line 8-12	11 MVA	297822
	DG	1	755 MWh	34697
	DG	4	61 MWh	2842
epoch 3	DG	1	784 MWh	32218
	DG	4	1231 MWh	50593
epoch 4	Line	Line 2-3	2.5 MVA	146947
	DG	1	945 MWh	34744
	DG	4	1229 MW	45188
	DG	6	163 MWh	6008
Total cost in 16 yrs				2,581,733

The total cost function in Table 7.1 is 89% of the cost function in Table 7.3 although the connection cost in Table 7.1 is 150% of the connection cost in Table 7.3. The cost function is the summation of the DG curtailment costs, annuitized reinforcement costs and annuitized connection costs of DG 1 and 5 in 16 years of planning.

The voltage at bus 6 has already reached its maximum limit in high wind profiles before connecting DG1. In chapter 6 when DG 1 was connected to Bus 6, a 3.6 MVar SVC was installed in this bus to control the voltage and to prevent the DG curtailment. When DG 1 is connected to bus 3, still a SVC will be installed at bus 6 to control the voltage but the capacity of the SVC is 2.9 MVar and also the curtailment of DG1 will decrease compared to the previous case. The curtailment of DG1 at bus 3 is 87% of its curtailment when it was connected to bus 6. The other difference between two cases is that there is no need to reinforce Line 3-5 by DLR as DG 1 is connected to bus 3 and its generation will not flow through Line 3-5 in this case.

When DG 5 is connected to bus 26 instead of bus 14, there would be no need to upgrade the capacity of Line 8-12 and Line 12-13. Dynamic rating of Line 12-13 will be enough to integrate the generation of DG 4 at bus 13, and Line 8-12 does not need extra capacity. In this case Line 26-27 will be equipped with DLR as it has already reached its maximum capacity before connecting DG 5 at bus 26. The curtailment of DG 4 is 72% than its curtailment in the previous case.

Figure 7.4 compares the results of the optimal connection points to the results of chapter 6 when the two DGs were connected to their initial connection points. Table 7.5 compares the two cases in different terms.

Figure 7.4: Comparing the results of optimal connection points with initial connection points

Table 7.4: Comparing the results of optimal connection points with initial connection points

case study	1	2
	smart and traditional solution & DG curtailment	smart and traditional solution & DG curtailment
approach	Integrated	Integrated
reinforcement investment cost	1	0.72
smart solutions capital cost	1	0.97
traditonal solutions capital cost	1	0.24
DG curtailment	0.36	0.34
connection cost	1	1.49
total cost	1	0.89

7-3- Conclusion of the case studies

In this section a summary of all the network planning in all the case studies in this thesis is presented. Table 7-5 shows the planning results in each case and table 7-6 compares the costs with the costs of case study 1.

The case studies are as follows:

- 1) Incremental approach: Smart + traditional reinforcement + DG curtailment
- 2) Incremental approach: Traditional reinforcement + DG curtailment
- 3) Incremental approach: Smart + traditional reinforcement
- 4) DG curtailment
- 5) Integrated approach: Smart + traditional reinforcement + DG curtailment
- 6) Integrated approach: Optimal connection point + Smart + traditional reinforcement + DG curtailment

Table 7.5: Summary of results in 6 case studies

case study	multi epoch approach	smart assets				traditional assets			total	DG curtailment		total	connection cost	total
		1	2	3	4	5	6	7	8	9	10	11	12	13
		No. O f DLR	No. O f QB	No. O f SVC	present value of annuitized cost of smart assets (£)	No. of reinforcement dOH/Cable	No. of reinforcement d Trans	present value of annuitized cost of traditional assets (£)	Total investment cost	DG curtailment (% of total generation capacity)	DG curtailment cost (£)	total cost 4+7+10	present value annuitized cost of connection circuits	4+7+10+12
1	Smart and traditional Reinforcement + DG curtailment	2	1	2	1,297,076	3	0	681,951	1,979,027	0.49%	426424	2,405,451	488,866	2,894,317
2	Traditional Reinforcement + DG curtailment	0	0	0	0	5	1	6,622,828	6,622,828	4%	3321276.93	9,944,105	-	-
3	smart and traditional Reinforcement	2	1	4	1,598,669	3	0	1,369,020	2,967,689	0	0	2,967,689	-	-
4	No reinforcement	0	0	0	0	0	0	0	0	18%	10684834	10,684,834	-	-
5	Smart and traditional Reinforcement + DG curtailment	1	1	1	1,177,261	3	0	615,248	1,792,509	0.36%	300358	2,092,867	488,866	2,581,733
6	Smart and traditional Reinforcement + DG curtailment + optimal connection point	2	1	1	1,139,496	1	0	146,947	1,286,443	0.34%	283519	1,569,962	726,697	2,296,659

Table 7.6: Summary of results in 6 case studies

case study	multi epoch approach	smart assets				traditional assets			total	DG curtailment		total	connection cost	total
		1	2	3	4	5	6	7	8	9	10	11	12	total
		No. O f DLR	No. O f QB	No. O f SVC	present value of annuitized cost of smart assets	No. of reinforcement dOH/Cable	No. of reinforcement d Trans	present value of annuitized cost of traditional assets	Total investment cost	DG curtailment (% of total generation capacity)	DG curtailment cost	total cost 4+7+10	present value annuitized cost of connection circuits	4+7+10+12
1	Smart and traditional Reinforcement + DG curtailment	2	1	2	1	3	0	1	1	0.49%	1	1	1	1
2	Traditional Reinforcement + DG curtailment	0	0	0	0	5	1	9.71	3.35	4%	7.79	4.13	-	-
3	Smart and traditional Reinforcement	2	1	4	1.13	3	0	2.20	1.50	0%	0.00	1.23	-	-
4	No reinforcement	0	0	0	0	0	0	0.00	0.00	18%	0.00	4.44	-	-
5	Smart and traditional Reinforcement + DG curtailment	1	1	1	0.91	3	0	0.90	0.91	0.36%	0.70	0.87	1	0.89
6	Smart and traditional Reinforcement + DG curtailment + optimal connection point	2	1	1	0.88	1	0	0.22	0.65	0.34%	0.66	0.65	1.49	0.79

7-4- Summary

In this chapter the multi-epoch OPF model was modified to decide about the DG connection points as well. The model finds the best DG connection points to reduce the cost of network reinforcement, energy curtailment and DG connections. The smart solutions including Dynamic Line Rating (DLR), Quad-Booster, SVC and Automatic Network Management (ANM) were included in the reinforcement options as well as traditional reinforcement options.

The multi-epoch model is formulated as an integrated multi-period optimization problem. This helps to take into account the future network expansion plans and projected DG connections when deciding about the connection points of new DGs and network reinforcement and find the minimum plan for the studying period.

The proposed model was applied to the test network and with the optimal connection points the total costs of the network decreased for 11% compared to the results in chapter 6 where the initial connection points were used. This is despite the increase in the connection costs as the saving in network reinforcement and DG curtailment costs was higher than the extra connection costs.

Concluding remarks and further works

The main objective of this thesis is to investigate the potential of smart technologies and commercial solutions for enabling the distribution networks owners to integrate new DGs more quickly and cheaply within their network. For this purpose a novel capacity and voltage management model is developed using the AC OPF algorithm to plan the required reinforcement of network when new DGs are connected to the grid. Both the traditional reinforcement options, such as upgrading the capacity of transformers, cables and overhead lines, and the smart solutions including dynamic line rating, SVC and quad booster, are considered as the planning options. Besides the investment options, ANM of

DGs, transformers taps and SVCs are available in the model to manage the thermal and voltage constraints of the network.

The developed models are tested with actual distribution network data and it was demonstrated that the proposed models can be successfully applied to real distribution networks to plan the integration of new DGs with minimum investment costs. 300 different operating snapshots are included for each year. Each of the snapshots is a unique combination of load, wind speed and seasonal temperature to cover a wide range of possible operational conditions in a real network.

The models can help the DNOs to implement commercial agreements with DG owners returning the benefits of cheaper network access to the DG operators; reducing network reinforcement costs and increasing overall DG carrying capacity for the DNO.

8-1- Summary of achievements

The main achievements and conclusions of the thesis can be summarized as follows.

- **Developing a mixed integer AC OPF model for distribution reinforcement planning considering both the traditional and smart solutions**

The proposed model facilitates the active network management to optimise the existing network capacity utilization with smart solutions, and if it is needed, reinforces the network by means of traditional reinforcement. All the decisions are made based on the cost of the planning.

The model makes a balance between the cost of investment on one hand and the costs of DG curtailment and load shedding on the other hand. As the model makes a trade-off

between the investment and the operating costs it is very important to study the network in a wide range of possible operating conditions and to consider a real duration for each operating snapshots so that the operating cost can correctly represent the real costs of the network and can be compared with the investment cost. Despite most of the reinforcement models that only use two extreme operating conditions: minimum generation – maximum load, maximum generation – minimum load, here the model uses 300 operating snapshots each of them with a unique combination of load/wind/ambient temperature that cover a wide range of the operation conditions of the network during a year.

When generators are connected to the distribution network and they can be actively managed (i.e. have their output regulated to meet distribution network constraints) then new commercial arrangements and connection agreements are required. To arrange the commercial agreement, an estimate of anticipated energy volumes exported will be required. In this thesis the optimal annual energy curtailment for new DGs are calculated through the OPF model to minimize the total investment and operating costs of the network. DNOs can use these results to arrange an agreement to benefit both sides. A commercial framework which is based on the optimal planning and operating framework of the networks would be a significant advancement on connection charge assessment procedures.

- **Finding the optimal DG connection points to minimize the investment and the operating costs of the network**

The OPF model in Chapter 7 proposed a novel model which decides about the connection points of new DGs in regards to their impact on their connection costs,

network reinforcement costs and DG curtailment. The model makes a trade-off between these three factors and finds the most suitable points among the available candidates. Although the DG location is not decided by the DNOs but the results in Chapter 7 show in some cases the amount of required network reinforcement and the energy curtailment can change considerably by just shifting the connection point from one bus to another. Therefore, in some cases it is worth to spend more on the connection circuit and choose a longer path to the grid for an alternative connection if it can make a saving in the network reinforcement and energy curtailment.

- **Comparing the application of smart assets in short and long term planning**

Two different approaches are taken here to solve the multi-epoch planning model: incremental planning and integrated planning. In the incremental approach when the planning is done for a short period of time in a run (one epoch, four years) the smart solutions, facilitated by active network management, are used to defer the network reinforcement wherever they are available. But in the integrated approach when the planning is done for the whole study horizon in one run in some cases the smart solutions are replaced by traditional solutions. When the smart solutions cannot defer the reinforcement of an asset, for the whole planning horizon sometimes it is better to reinforce the network in first place instead of deferring it.

- **Application of Quad booster in distribution level for increasing the utilization of network assets**

The results in chapters 5 and 6 show that Quad Booster has a significant role in increasing the utilization of network assets by balancing flows through different circuits. In the case study in chapter 5, installing a QB called off the reinforcement of two lines

when a new DG was connected to the grid. The tap of the QB was controlled regards to the thermal capacity of the related lines and the output of the DG and it increased the export of the DG output by optimizing the loading of the parallel lines.

- **Application of DLR in increasing the capacity of network for integrating wind generations**

The proposed OPF model quantifies the benefits of using Dynamic Line Rating for overhead lines if the static seasonal capacity was not enough to export DGs output to the grid. The results based on the real network data from UK Power Networks in Peterborough area, show that the Dynamic Line Rating is in a natural synergy with wind generation. In this example the new wind generators were curtailed during high wind profiles due to the thermal restrictions of lines connected to the DGs. On the other hand, in those high wind profiles, the dynamic ratings of the OH lines were sufficient to deliver the DGs generation to the grid. This synergy between wind turbines and DLR deferred the reinforcement of the lines and allowed the connection of the new DGs without any further reinforcement. In Peterborough area the average rates of OH lines increased by 30% with considering the DLR. This level of increase was obtained by conservative assumptions of weather condition and wind speed in this part of the UK.

- **Comparing the effect of firm and non-firm connection policies on network investment costs**

Making an obligation for DNOs to provide a firm access for new DGs imposes large amount of extra investment to the networks only for few more MWh energy to be delivered. The results in Chapter 5 show that when firm network access is considered for the DGs, the investment in the network will increase for 23% compared to the case where

the new DGs have non-firm access. This 23% increase in the investment cost is only for delivering the 0.49% of annual generation capacity of the network which was curtailed with non-firm access policy.

8-2- Further Work

Some possible directions regarding future work are as follows:

- **Contingency analysis**

As the proposed model plans the network reinforcement for the study horizon it should include the N-1 contingency analysis in the study. Considering the contingency analysis, the contribution of DG to system security can also play an important factor which may affect the planning results.

- **Flexible network configurations**

The standard switches currently deployed in the most of the distribution networks are not designed for frequent operation and have to be reset manually; replacing these with new 'frequent use' that would be controlled remotely, will enable more flexible network configurations to reduce or remove network constraints [4]. With considering the automatic network management for the network flexible network configuration should also be considered in network planning as part of smart solutions.

- **Commercial arrangements**

In the proposed models the DG curtailment is done in an optimized approach to reduce the total cost of the network. It is worth to consider different approaches for curtailing the DG such as pro-rata, priority or cost based approaches and to define different commercial arrangements for the new DGs and analyse the effect of different

arrangements and approaches on the network costs and on potential benefits for DG investors.

- **Risk analysis**

The future demand and generation capacity of the network are an estimate and are always affected by uncertainty as long as future development of the network. Therefore, it is necessary to analyze the risk of planning due to the uncertainty in the future system specially when using the integrated approach.

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Appendix A

Network Cost

Cost of QB: 2.5k/MVA/year

Cost of SVC: 15/kVAr/year

Reinforcement cost for 33 kV Over Head (OH) Line and Underground Cables (UC)

Cross section (mm ²)	OH			
	R (Ohm/km)	X (Ohm/km)	Capacity (MVA)	Reinforcement Price (£/MW/km)
95	0.398	0.400	13.430	3,946
185	0.205	0.360	19.140	2,769
300	0.126	0.340	24.860	2,132
630	0.060	0.280	43.440	1,220
1000	0.038	0.210	49.156	1,078

Cross section (mm ²)	UG			
	R (Ohm/km)	X (Ohm/km)	Capacity (MVA)	Reinforcement Price (£/MW/km)
95	0.398	0.127	13.430	25,838
185	0.205	0.114	19.140	18,130
300	0.126	0.105	24.860	13,958
630	0.060	0.094	43.440	7,988
1000	0.038	0.087	49.156	7,059

Reinforcement Cost for transformers:

Index	Name	Seconda	Rating (MVA)	Load los	No-load	Impeda	Cost (€/MW)
1	Tx 0.4kV 0.04MVA	0.4	0.04	0.00086	0.00020	4.0	262,500
2	Tx 0.4kV 0.05MVA	0.4	0.05	0.00105	0.00019	4.0	220,000
3	Tx 0.4kV 0.063MVA	0.4	0.063	0.00142	0.00027	4.0	182,540
4	Tx 0.4kV 0.1MVA	0.4	0.1	0.00188	0.00030	4.0	120,000
5	Tx 0.4kV 0.16MVA	0.4	0.16	0.00253	0.00044	4.0	78,125
6	Tx 0.4kV 0.25MVA	0.4	0.25	0.00369	0.00064	4.0	52,000
7	Tx 0.4kV 0.315MVA	0.4	0.315	0.00390	0.00079	4.3	42,857
8	Tx 0.4kV 0.4MVA	0.4	0.4	0.00460	0.00077	4.0	37,500
9	Tx 0.4kV 0.63MVA	0.4	0.63	0.00711	0.00123	4.0	27,778
10	Tx 0.4kV 1MVA	0.4	1	0.01350	0.00175	4.0	21,500
11	Tx 10kV 4MVA	10	4	0.03300	0.00550	6.0	87,500
12	Tx 10kV 8MVA	10	8	0.05400	0.00940	7.0	50,000
13	Tx 10kV 12MVA	10	12	0.05400	0.00940	7.0	37,500
14	Tx 10kV 17.5MVA	10	17.5	0.20000	0.00860	20.0	29,429
15	Tx 10kV 31.5MVA	10	31.5	0.17800	0.03050	11.0	19,048
16	Tx 11kV 4MVA	11	4	0.03300	0.00550	6.0	87,500
17	Tx 11kV 7.5MVA	11	7.5	0.05180	0.01000	20.0	53,333
18	Tx 11kV 12MVA	11	12	0.05400	0.00940	7.0	37,500
19	Tx 11kV 17.5MVA	11	17.5	0.20000	0.00860	20.0	29,429
20	Tx 11kV 31.5MVA	11	31.5	0.30000	0.01000	20.0	29,206
21	Tx 15kV 8MVA	15	8	0.05400	0.00940	7.0	50,000
22	Tx 15kV 16MVA	15	16	0.08380	0.01064	17.3	32,500
23	Tx 15kV 25MVA	15	25	0.16500	0.01900	16.6	34,000
24	Tx 20kV 16MVA	20	16	0.08380	0.01064	17.3	32,500
25	Tx 20kV 25MVA	20	25	0.16500	0.01900	16.6	34,000
26	Tx 20kV 31.5MVA	20	31.5	0.18500	0.04600	13.0	29,206
27	Tx 20kV 40MVA	20	40	0.14000	0.01950	16.0	27,000
28	Tx 33kV 30MVA	33	30	0.18500	0.04600	13.0	30,667
29	Tx 33kV 40MVA	33	40	0.21100	0.03600	11.0	27,000
30	Tx 33kV 66MVA	33	66	0.20000	0.02000	20.0	21,212
31	Tx 33kV 80MVA	33	80	0.28700	0.03000	22.0	20,000
32	Tx 35kV 30MVA	35	30	0.18500	0.04600	13.0	30,667
33	Tx 35kV 40MVA	35	40	0.21100	0.03600	11.0	27,000
34	Tx 35kV 66MVA	35	66	0.20000	0.02000	20.0	21,212
35	Tx 35kV 80MVA	35	80	0.28700	0.03000	22.0	20,000
36	Tx 110kV 160MVA	110	160	0.39800	0.07800	5.4	14,375
37	Tx 110kV 240MVA	110	240	0.10000	0.20000	20.0	12,083
38	Tx 110kV 300MVA	110	300	0.75000	0.12500	15.3	11,667
39	Tx 132kV 160MVA	132	160	0.39800	0.07800	5.4	14,375
40	Tx 132kV 240MVA	132	240	0.10000	0.20000	20.0	12,083
41	Tx 132kV 300MVA	132	300	0.20000	0.30000	22.0	11,667