Maximising Renewable Hosting Capacity in Electricity Networks

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Abstract

The electricity network is undergoing significant changes in the transition to a low carbon system. The growth of renewable distributed generation (DG) creates a number of technical and economic challenges in the electricity network. While the development of the smart grid promises alternative ways to manage network constraints, their impact on the ability of the network to accommodate DG – the 'hosting capacity'- is not fully understood. It is of significance for both DNOs and DGs developers to quantify the hosting capacity according to given technical or commercial objectives while subject to a set of predefined limits. The combinational nature of the hosting capacity problem, together with the intermittent nature of renewable generation and the complex actions of smart control systems, means evaluation of hosting capacity requires appropriate optimisation techniques.

This thesis extends the knowledge of hosting capacity. Three specific but related areas are examined to fill the gaps identified in existing knowledge. New evaluation methods are developed that allow the study of hosting capacity (1) under different curtailment priority rules, (2) with harmonic distortion limits, and (3) alongside energy storage systems. These works together improve DG planning in two directions: demonstrating the benefit provided by a range of smart grid solutions; and evaluating extensive impacts to ensure compliance with all relevant planning standards and grid codes. As an outcome, the methods developed can help both DNOs and DG developers make sound and practical decisions, facilitating the integration of renewable DG in a more cost-effective way.

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Firstly I must thank my supervisor, Professor Gareth Harrison, for his support given to me while pursuing this PhD, including knowledge, guidance, inspirations and humours, which are invaluable experiences in my life.

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A special acknowledgement to my dearest parents, for giving me all of the encouragement and support I could need, without them, my PhD and this thesis would not exist.

Declaration

I, Wei Sun, declare that this thesis was composed by myself, that the work contained herein is my own except where explicitly stated otherwise in the text, and that this work has not been submitted for any other degree or professional qualification except as specified.

Signed:

Date:

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Abbreviations

AC	Alternating Current
ANM	Active Network Management
APFM	Active Power Flow Management
AVC	Automatic Voltage Control
AVR	Automatic Voltage Regulator
AVRS	Automatic Voltage Reference Setting
BESS	Battery Energy Storage Systems
CG	Centralised Generation
CHP	Combined Heat And Power
CVC	Coordinated Voltage Control
DC	Direct Current
DECC	Department of Energy And Climate Change
DER	Distributed Energy Resources
DFIG	Doubly-Fed Induction Generator
DG	Distributed Generation
DNO	Distribution Network Operators
DOPF	Dynamic Optimal Power Flow
EHV	Extra High Voltage
ENA	Energy Networks Association
ER	Engineering Recommendation
ESS	Energy Storage System
FIT	Feed-in Tariffs
GA	Genetic Algorithms
GB	Great Britain
GSP	Grid Supply Point
GW	Gigawatt
GWh	Gigawatt-hour
HOPF	Harmonic Optimal Power Flow
HV	High Voltage
Hz	Hertz
IFI	Innovation Funding Incentive
IHD	Individual Harmonic Distortion
LP	Linear Programming
kW	Kilowatt
kWh	Kilowatt-hour
LCIF	Low Carbon Innovation Fund

LIFO	Last In First Out
LV	Low Voltage
MOPF	Multi-Period Optimal Power Flow
MV	Meduim Voltage
Na/S	Sodium–Sulfur
NETS	National Electricity Transmission System
NFG	Non-Firm Generation
NGET	National Grid Electricity Transmission
NPV	Net Present Value
Ofgem	Office of the Gas and Electricity Markets
O&M	Operations And Maintenance
OHL	Overhead Line
OLTC	On Load Tap Changer
OPF	Optimal Power Flow
PFc	Power Factor Control
PLC	Power Line Conditioner
PoA	Principles Of Access
PV	Photovoltaic
RNFG	Regulated Non-Firm Generation
RO	Renewable Obligation
ROC	Renewable Obligation Certificates
RPZ	Registered Power Zones
RTUs	Remote Terminal Unit
SOC	State Of Charge
SP	Scottish Power
THD	Total Harmonic Distortion
TS	Time Series
UKGDS	United Kingdom Generic Distribution System
Zn/Br	Zinc Bromide

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Chapter 1

Introduction

1.1 Thesis Background

Greater capacities of renewable generation are now being deployed to meet ambitious national targets for more diversified energy sources as well as for the reduction of carbon emissions. Figure 1.1 shows the growth of electricity generated from renewable resources in the main EU countries from 2000 to 2010. Its percentage in gross electricity consumption increased from around 13% to 20% within a decade. However, the UK in particular lags behind in the utilisation of renewable electricity generation in Europe, as shown in Figure 1.2. The UK Government is working towards a target of renewable energy providing 15% of energy demand by 2020, increasing the amount of electricity coming from renewables from 11% in 2012 to around 30% by 2020 [1]. This will require the installation of around 29 GW of generation capacity in electrical networks. The renewable resources in this projected energy mix include hydro, wind, solar, geothermal, wave, tidal and biomass/wastes.

These renewable resources tend to be located in remote or non-urban regions and their integration into power grids typically occurs in the distribution network, as distributed generation (DG) [2]. This runs contrary to the conventional design philosophy of power system infrastructure, which favours large, centralised generation facilities with unidirectional power flow from source to load through reducing voltage levels.

Incorporating high volumes of distributed generation from renewables into distribution networks introduces both technical and economic challenges that must be addressed [3], such as reversed power flow, local voltage rise, power quality and increasing fault levels, among others. A common practice among network operators to connect distributed generation on a first-come first-served basis may also compound the issues by possibly ‘sterilising’ portions of the network.

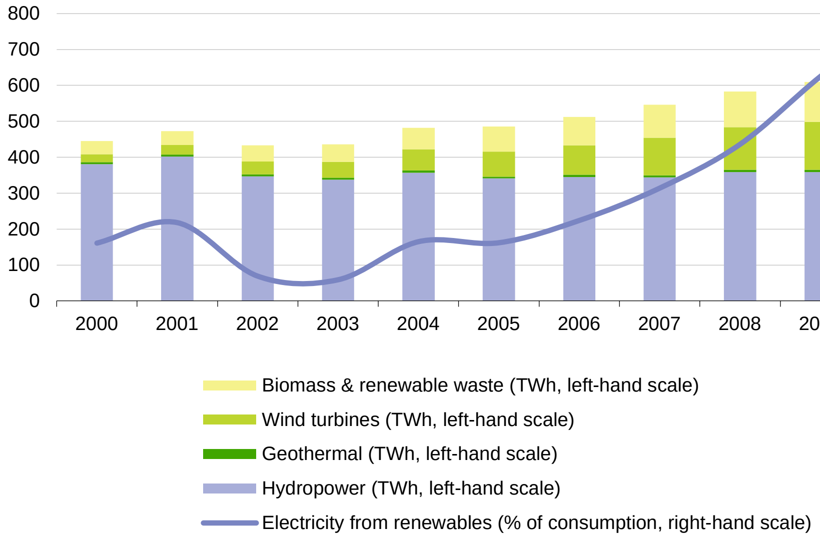


Figure 1.1: Electricity generated from renewables , EU-27, 2000-2010 [4]

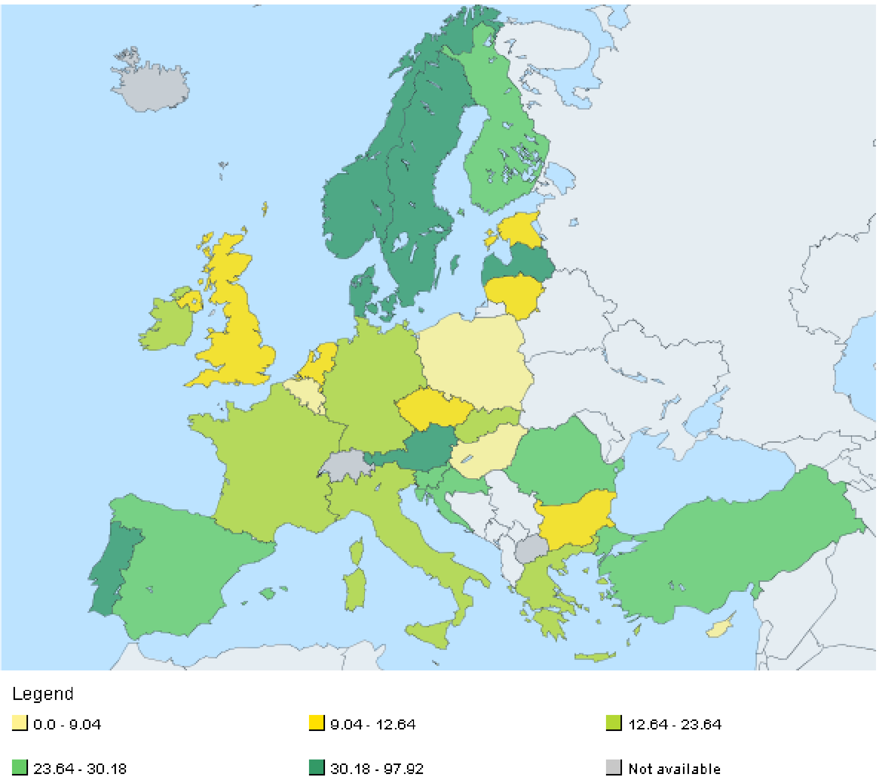


Figure 1.2: Electricity generated from renewables in EU for 2010 (% of gross electricity consumption) [5]

Whilst these issues may be overcome by network reinforcement, such asset upgrades is not desirable due to the cost of financing investment in new infrastructure and sometimes impossible or slow to realisation due to planning restrictions, environmental concerns, and public objections. Given these potential obstacles, it is desirable that any new DG development is carried out in a manner that maximises the utilisation of existing assets.

In seeking for alternative network options for DG connection, it is meaningful to leverage the recently technical development in the power industry. “Smart Grids” have been put forward as a new dimension for future electricity networks. Smart grid may simply be defined as “smarter” electricity network, however, explicit meaning of the term can be expressed in many different ways depending on application. As the driver for advancing the electricity systems mainly involve significant changes to the generation and demand patterns, the development of smart grid to manage such changes are focused on five main purposes [6]:1) to enable the production and supply of electricity more cost-effectively; 2) to allow consumers to be informed with necessary information such as electricity price and their energy-use behaviour in order to obtain the most efficient and economic energy consumption; 3) to encourage renewable DG integration; 4) to enhance the electricity systems’ security and reliability; 5) to support the growing use of electric vehicles in the coming decades to reduce dependency on oil.

In the UK, smart grid technologies appear largely as under the term “Active Network Management”. The transition from historical practice to active management increases the “smartness” of the electricity network. In this context, ANM can therefore be regarded as one branch within a smart grid. Similarly to smart grid, ANM has no generally accepted definition. One definition [7] is: “Devices, systems and practices that operate pre-emptively to maintain networks within accepted operating parameters. ANM may be compatible with automation of the network to speed supply restoration following an abnormal event, and increased visibility and control of the network to facilitate management practices.” Currie et al. [8] refers to ANM to a solution that addresses the communications and control requirements for managing the technical constraints in real time. Both definitions recognize the active and adaptive operation of network to achieve the improved constraint management as the key purpose of ANM development. In addition, active management of distribution networks also provides an alternative method that optimises existing network operation in order to accommodate more DG [9].

While smart grids have extensive implications and provide the general background of the direction of development in the power industry, ANM is the specific area this thesis investigates. In particular, the characteristic of ANM that can make the most use of network headroom for DG integration and avoid costly reinforcement by better managing network constraints is the key topic studied within this thesis. A literature review of most relevant ANM schemes is presented in Chapter 3 in detail.

Whilst ANM is intended to provide additional scope to connect DG without traditional reinforcements, the extent of its ability to relieve the network constraints is not fully understood. The limitations of the existing distribution network in a regime of high DG penetration are becoming increasingly obvious, such as a lack of adaptive measures to tackle occurrences of violation of voltage, thermal and power quality limits due to the variability of renewables. Therefore, it is desirable for customers, developers of renewable, DNOs and regulators that the body of knowledge in the field of planning DG in the context of ANM continues to grow to prevent the network from turning into a significant limiting factor for the increased deployment of DGs.

In order to leverage the benefits arising from ANM in planning and operating the network for connecting more DG, a large amount of work is going on the detailed control methodologies, but an emerging research area is ‘hosting capacity’. Hosting capacity is an effective and flexible framework for investigating the maximum available network headroom to accommodate generation and provide insights for DNOs and developers. Instead of a reactive approach to connecting and integrate renewables, hosting capacity offers a means of providing a more structured and planned integration. Some literature refers to it as ‘optimal’ planning or “allocation”, but its use is potentially much wider as part of new planning approaches. While existing literature has outlined many useful advances there remain significant areas that require development to enable hosting capacity and the tools on which it relies to be truly useful to DNOs, regulators and developers.

One major application of hosting capacity is in understanding the impact of successive waves of renewable generation on the need for grid upgrades or whether a more structured form of DNO-driven planning will deliver the ‘more for less’ solution that smart grid pursues. Hosting capacity can provide a one-step analysis that indicates what capacity is feasible at a location or locations. This differs significantly from the existing utility practice which looks at each development in isolation and analyses the impact of a given generation scheme with given capacity to identify if a breach of any of the technical constraints occurs. Integrating high volumes of renewable DG means a great number of development schemes seek connection approval, which increases the complexity of analysis as many of their impact are interrelated. Meanwhile, the variability of renewable DG output means that analysis cannot be constrained to just maximum or minimum demand patterns. Considering whole time series or ranges of conditions is much more time consuming. It is desirable to be carried out by automated but repeatable approaches so that analyse and engineering time can be released to more productive tasks.

With the complicated impacts from intermittent DG, it needs to be extendable to various aspects of concern. The methodologies developed in this work grow the knowledge of hosting capacity, especially in tackling DG curtailment rules, harmonic assessment and energy storage supporting network management. Its extensions will allow for hosting capacity studies to better capture and cope with the complexity of network constraints and exploring technologies to enable the greatest potential in energy export.

1.2 Research objectives

The objectives of this research are:

1. To examine the behaviour and severity of network constraints imposed by increasing connections of DG and its variability in rural distribution networks;

2. To investigate the influence of DG curtailment priority on network hosting capacity, and develop methodologies for rapidly identifying the network hosting capacity under different access rules;

3. To extend previous work on hosting capacity analysis to develop a constraints management scheme that is capable of embedding harmonic emission from DG as an additional constraint into the optimisation framework;

4. To develop a planning approach for energy storage systems in order to offer a cost-effective sizing tool for reducing curtailment requirements and improve the hosting capacity;

5. To compare the performance of the developed active planning and management schemes on the basis of economic viability, technical feasibility, risks and benefits and enhancement in renewable penetrations.

1.3 Research hypothesis and Contribution

The hypothesis of this research is:

> *Hosting capacity provides new insight into the grid integration of renewable energy.*

The contribution from this thesis concentrates on developing new algorithms and models to extend the knowledge of DG planning and optimisation, especially in the area of hosting capacity analysis. The work in this thesis is essential to establish an accurate, extendable, cost-effective planning system to assist in increasing DG penetration effectively. The following summarises the work in three sub-areas around hosting capacity that are delivered in thesis.

The improvement in hosting capacity study is first achieved by analysis of the impact of curtailment management schemes on economic hosting capacity. A new multi-period OPF-based evaluation approach is proposed in this thesis to determine the optimal economic capacity subject to technical constraints as well as the economic viability of schemes participating in the connection arrangements. Using this method, different ANM curtailment priority schemes can be quantified and compared, which helps DG developers to justify their investment from both technical and economic aspects. The knowledge of benefit of different priority settings could also form a basis for DNOs to provide economic incentives to facilitate the DG planning process.

Another major contribution of the research reported in this thesis is to provide the first study of the impact of DG harmonic emission on hosting capacity. An innovative harmonic-constrained multi-period OPF method is developed to evaluate the network hosting capacity, without violating harmonic distortion limits alongside other constraints. Using the method, harmonic evaluation could be considered at the initial stage of network planning instead of being performed as an after-thought following 'blind' DG development, which is more effective to ensure optimality. Based on the proposed harmonic-constrained multi-period OPF techniques, the benefits of active mitigation and other advanced harmonic control schemes can also be evaluated. The assessment of network capacity that complies with harmonic distortion requirements would provide additional information and enable a fuller picture to guide DG developers and DNOs in maximising DG capacity.

The enhancement of DG hosting capacity analysis is further supported by exploring the potential of ESS in reducing curtailment and increasing hosting capacity. A new co-optimisation concept is proposed to determine the DG and ESS capacity together in order to obtain the maximum financial return.. Given that ESS techniques are still challenging to reach economic viability at the current development state, the developed method provides an approach to help justify investments on a case by case basis. By clearly demonstrating the benefits of adopting a particular ESS technology in a curtailment reduction scheme, the method will facilitate the development of ESS-supported DG, increase the renewable generation and enables the better use of the existing network assets.

Aside from the progress in each topic that present their own and unique contribution, the following benefits are generally achieved from this thesis:

- For DNOs, the increase in utilisation of network assets will promote DG connections, defer the network reinforcement, and also avoid the unnecessary replacement of assets;

- For DG developers, the growth in the installed capacity and annual generation without costly and time-consuming infrastructure upgrades will raise the financial return of their investments;

- For customers, benefit from insuring appropriate levels of network capacity, adequate to meet security and quality standards of power supply..

Overall, the development of new optimisation algorithms and models for improved DG planning is believed to facilitate the connection of increasing DG capacity in a cost-effective way, thus allowing the associated environmental and social benefits to be captured. The work presented in this thesis will be useful for the whole power system and help it to meet the changing needs of the transition of the UK electricity industry to the more sustainable and smart one

1.4 Publications arising from this thesis

A number of publications have arisen from the work in this thesis:

Journal papers:

W. Sun and G. P. Harrison, "Influence of Generator Curtailment Priority on Economic Hosting Capacity," *IEEE Transactions on Power Systems*, In review.

Conference Proceedings

1. W. Sun, G. P. Harrison, and S. Z. Djokic, "Distribution network capacity assessment: Incorporating harmonic distortion limits," in *Power and Energy Society General Meeting, 2012 IEEE*, 2012, pp. 1-7.

2. W. Sun, G. P. Harrison, and S. Z. Djokic, "Incorporating harmonic limits into assessment of the hosting capacity of active networks," in *Integration of Renewables into the Distribution Grid, CIRED 2012 Workshop*, 2012, pp. 1-4.
3. W. Sun and G. P. Harrison, "Influence of generator curtailment priority on network hosting capacity," in *Electricity Distribution (CIRED 2013), 22nd International Conference and Exhibition on*, 2013, pp. 1-4.

Technical Report

1. W. Sun, L. Cradden, and G. P. Harrison, "Integration of Wind and Wave Platforms: A Distribution System Analysis," *MARINA Platform Work Package 8 Deliverable 8.5 (EU 7th Framework Programme),* 2014

1.5 Structure of the Thesis

The main content of this thesis consists of 7 chapters and is structured as shown in Figure 1.3:

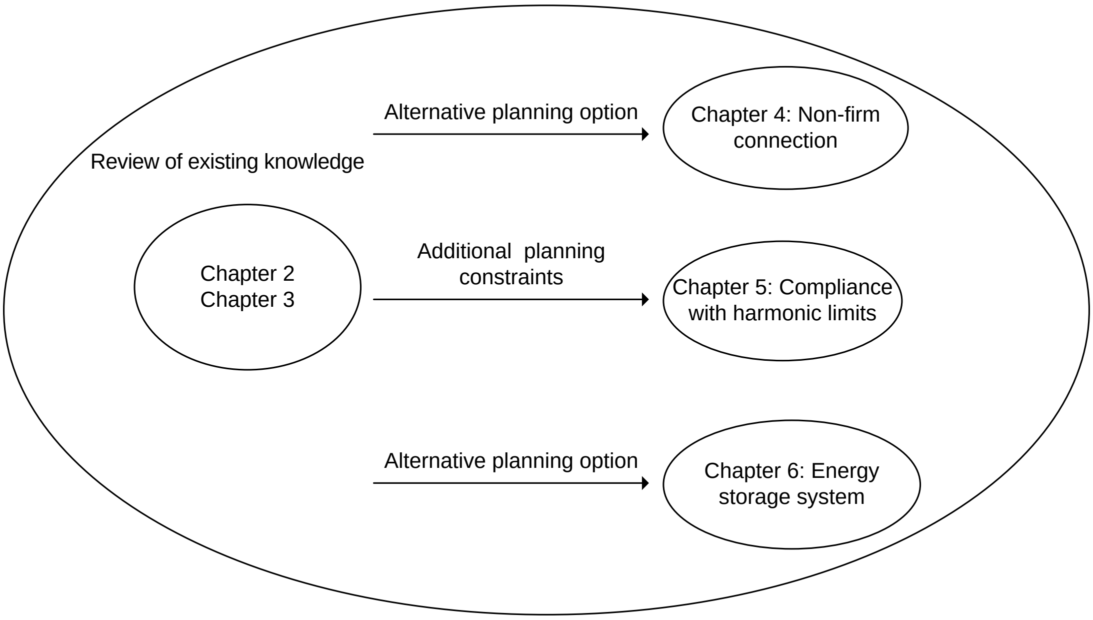


Figure 1.3: Content flow of the thesis classified by different purposes

Chapter 2 describes the major challenges of increasing DG integration. It first overviews the conventional power system, and the different renewable DG technologies. Since the traditional distribution network was passively planned and operated, the impact of the ongoing rise of DG capacity is studied.

Chapter 3 explores the techniques that are available to facilitate the integration of renewable DG, with focus on the development of optimal planning methods for active integration. The planning philosophy under the transition to the smart grid is studied. Then, smart-grid based constraint management approaches are reviewed in order to explore alternative cost-effective planning options. The concept of hosting capacity and associated optimisation techniques that enable better understanding of the benefits from these smart-grid techniques are studied in detail. The gaps in existing knowledge are identified and three specific but related areas are outlined for further outlined in Chapters 4, 5 and 6.

Chapter 4 studies the issue of adopting non-firm connection schemes as an alternative planning solution. Built on earlier work on planning studies of hosting capacity, it explicitly links hosting capacity to the financial consequences of different priority schemes. It extends the use of a multi-period OPF planning tool to compare the influences of alternative curtailment schemes on the hosting capacity and maximise the life time return from delivered energy.

Chapter 5 develops a new network constraint for the hosting capacity study. Harmonic emissions from DG and their propagation though the distribution network is studied. The fundamental methods for analysing harmonics are described, and then harmonic models of network and DG are built. Eventually, these models are used to develop a functional prototype of a harmonic constrained MOPF method. The generalised procedure of using the developed HOPF framework to evaluate harmonic constrained hosting capacity is also summarised.

Chapter 6 explores the potential of energy storage systems (ESS) to provide an alternative solution for facilitating non-firm connected DGs without curtailing energy. In this chapter, ESS is modelled and embedded as a constraint management option to reduce the curtailment and improve energy production of planned DGs. The hosting capacity is analysed by a two-step OPF based optimisation method and measured by total economic benefit of ESS and DG together. To demonstrate the proposed co-optimisation method, the case study was presented with the mix of different DG and ESS technologies.

Overall conclusions of the thesis are drawn in Chapter 7. This chapter also discusses the advantages and limitations of using the approaches developed. The potential directions of the future work are also addressed.

Chapter 2

Distribution Network and Distributed Generation

2.1 Introduction

This chapter describes major aspects of electricity distribution networks and distributed generation, with a focus on the challenges for integration of renewable distributed generation. It begins with an overview of the conventional power system where the design concept is specifically to connect centralised power sources. Since the traditional distribution network is not designed to accommodate a large volume of intermittent renewable DG, the ongoing rise of DG capacity imposes a number of technical constraints, which has become a critical concern for all participants. This chapter then discusses the challenges posed for the traditional distribution network. Finally, overviews of current practices and policy frameworks for connection of DG are also presented.

2.2 Conventional power systems and distribution networks

The conventional power system architecture has been primarily based upon the concept of large power plants constructed at strategic locations so that cost-effective generation of electricity can be close to the sources of primary energy or other resources required to support the process, such as cooling water. The power delivery network was developed to transport bulk power unidirectionally over great distances from the source to the loads, via a hierarchical series of reducing voltage levels [10]. This resulted in systems which were designed and optimised specifically to connect a relatively small number of high-capacity, centralised power sources to a large number of distributed users, with factors such as loss minimisation, network redundancy, protection and power quality playing important roles in defining the layout of the network [11].

In the conventional power system architecture, the distribution network has been primarily viewed as a "passive" transport provider. Large power plants were not expected in this section of the network. The historic configuration of the distribution system is that virtually all the electricity is supplied from the transmission networks at several points in each distribution area and is then distributed to consumers at lower voltages [12]. A typical abstraction of the distribution network configuration is shown in Figure 2.1.

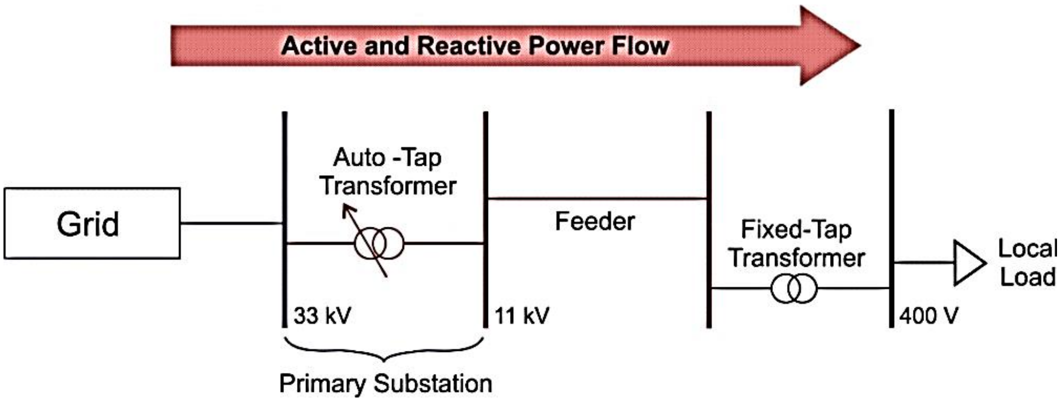


Figure 2.1: Traditional passive distribution network architecture [13]

2.3 Electricity network in Great Britain

The transmission system in Great Britain (GB) is owned and maintained by regional transmission companies. Currently they are National Grid Electricity Transmission PLC (NGET) for England and Wales, Scottish Power Transmission Limited for southern Scotland and Scottish Hydro Electric Transmission Limited for northern Scotland and the Scottish islands. However, the transmission network across the UK as a whole is operated by a single System Operator, which is currently National Grid Electricity Transmission PLC. National Grid balance supply with demand on a second by second basis, ensuring the stability and security of the system [14].

Distribution of electricity in the UK is now a licensed activity according to the Utilities Act 2000. There are 14 licensed distribution network operators (DNOs) and each is responsible for a regional service area, with duty to connect customers and maintain the supply within their area [15].

This unique arrangement of electricity business in the UK implies that it is DNOs to whom DG developers need to apply connection for-, but DNOs have no direct control of where these DGs go. This type of arrangement may increase the complexity of hosting capacity analysis as the drivers for connection between DNOs and DG is not the completely same and can be in conflict. This issue will be investigated in the thesis, especially when it comes to economic aspects of the application of hosting capacity.

2.3.1 Voltage Level

The transmission network in GB is operated at 400kV and 275kV. The voltage level below 275kV is normally regarded as the distribution network. In Scotland, the 132kV levels are also considered to be part of the transmission network while there are many long 132kV and 33kV radials in Scotland [16]. The distribution network is normally operated at 33kV, 11kV and 400V three phase.

2.3.2 Network configurations

Apart from the voltage level, the structure of the transmission network and the distribution network are also different. Normally, the former can be interconnected but the latter is almost entirely radial. Figure 2.2 illustrates the types of network configurations that are observed from both transmission and distribution level in electricity network.

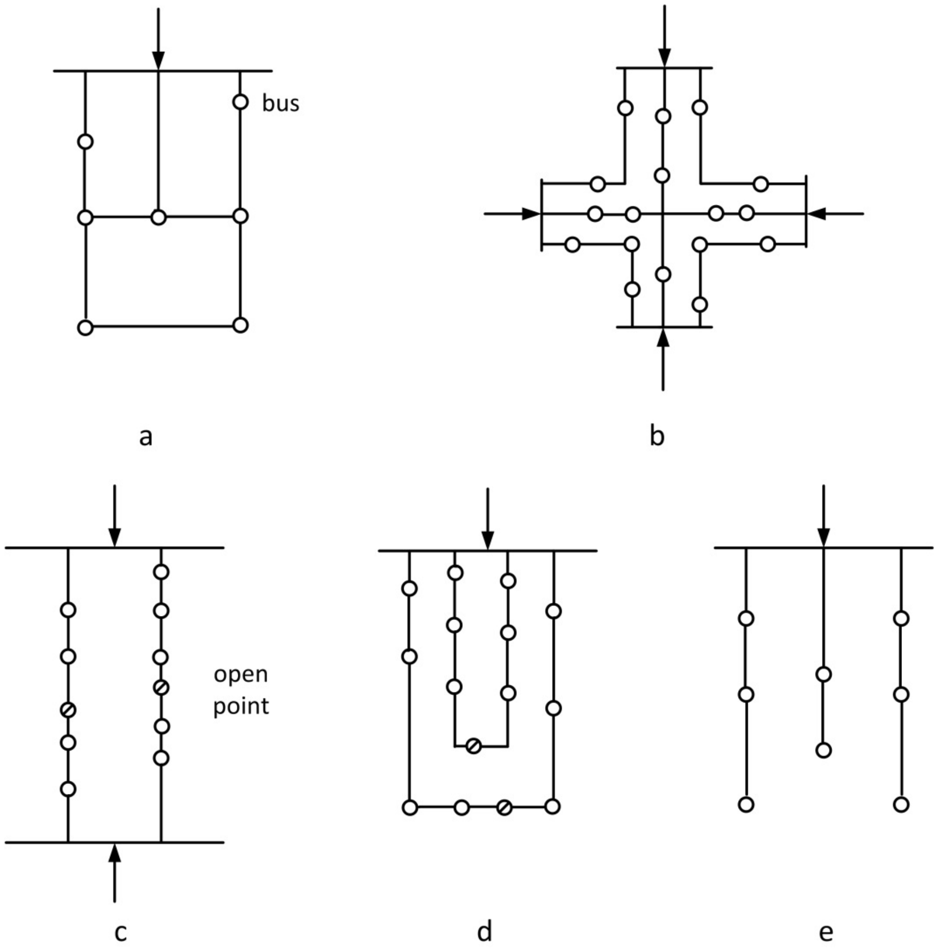


Figure 2.2: Types of network configurations in electrical network (a - mesh; b - interconnected network; c - link arrangement; d - open loop; e - radial system) **[17]**

The transmission network is a typical meshed or interconnected network (as Figure 2.2a and Figure 2.2b). This type of network can provide multiple electrical links among all the system participants (generators and loads), the benefits of which are realised for maintenance during a fault, a small area of the network can be isolated and the remainder can keep supplying power to the grid supply points; for economic dispatch, it is possible to select the cheapest available generation.

Most distribution networks in the UK are operated as radial networks (Figure 2.2e). In this type of network each component has a unique path towards the source of supply, which means there is only one path for power to flow from the distribution substation to the user. If interconnected networks are constructed, they normally operate in the same way as radial networks by using open connection points (Figure

2.2c and Figure 2.2d). A radial network starts at a step down transformer from the grid supply point, and then goes through the network area without any normal connections to other supplies. A series of transformers, which step the voltage level further down, are located along the route. It is a typical configuration in rural lines for supplying isolated load areas.

The network configuration differences between transmission and distribution level lay the basis for the later discussion in this thesis and provide background knowledge to understanding technical challenges raised when DG connecting to the radial and weak mashed distribution network.

2.4 Renewable distributed generation

Prior to the detailed discussion of issues around DG, it is of importance to clarify the term "distributed generation" (or "embedded generation" or "decentralised generation") used in thesis, since it can have a wide range of definitions, from those that are generic and descriptive in nature to more specific ones that may include the type of technology used, size of facility, power or voltage levels and other parameters [18]. These can differ significantly between countries and technical bodies, as well as the context in which the term is utilised, with no single standard being prevalent [11]. For the purpose of this thesis, a generic definition shall be used where distributed generation (DG) is considered to be the production of electricity from renewable sources located within the distribution network.

While DGs are synonymous with renewable generation, the term itself does not automatically imply that the source is renewable. Conventional generation, such as diesel generators and small scale combined heat and power (CHP) plants can be broadly classified as DGs as well [19]. However, environmental and energy security concerns have become key energy policy drivers in many countries, leading to targets for the deployment of renewable sources for distributed power generation. The advances in technologies have enabled the use of various renewable sources such as wind, solar photovoltaic (PV), biomass, wave and tidal to generate electricity at the distribution level. In order to integrate efficiently, the impacts of renewable DG on the distribution network are analysed in the following section.

2.5 Impacts of DG on distribution network

In this section, the impact of connecting DG into electricity distribution networks is presented. Each of these technical issues ultimately can impose constraints on the network for planning and operating a large volume of DG, therefore they need to be considered for the study of hosting capacity. Some of them have been already tackled in existing studies, for example, the voltage variation in [20] and loss consideration in [21]. However, there still remain areas that need to be studied to enable a more generalised application of hosting capacity to be truly useful to DNOs, regulators and developers, such the impact of maintaining required level of power quality, protection and stability on hosting capacity, of which harmonics is examined by this thesis. In addition, the relationships between the impacts of DG are complex and will vary between different technologies, so it is challenging in term of exactly working out what constraint is active. This will be emphasised when discussing specific application of hosting capacity in the following chapters.

Sites suitable for renewable generation are typically distributed over wide geographical regions based on natural resource availability and connections to the network are usually made at distribution level where these resources are more prevalent. This does not conform to the philosophy governing the design of conventional networks and must be accounted for as larger capacities of renewable generation come online in parts of the network that used to contain only loads. Therefore, the penetration of DG creates a greater impetus to explore their impact upon the current electricity network. It demands changes in the distribution network design to meet the needs of higher generation capacity.

The impacts of connecting DG to distribution networks have been the subject of a large number of studies, with work by Barker *et al.* [22], Ackerman *et al.* [18], Dondi *et al.* [11] and Pecas Lopes *et al.* [23] being just some of the many examples. Key issues commonly highlighted include reverse power flows, increased fault levels, voltage rise, harmonics, and power quality and system stability. These are generally not of significant concern when DG penetration is small as their impact can be absorbed by the conventional network architecture. However, the risk rapidly increases with growing DG capacities [19].

2.5.1 Voltage variation

One significant concern about connecting DG to the distribution network is that the voltage profile of feeders will be affected [24]. The specific impact depends on the total capacity, type and position of DG to be connected. When DG operates at unity power factor, the relative voltage change ΔV is approximately equal to

$$\Delta V \approx R \cdot P_G \qquad (2.1)$$

where R is the line resistance, P_G is the injected active power from DG. As illustrated in Figure 2.3, if the DG output is much larger than the local load ($P_G > P_L$), the connection of new generators can cause significant voltage rise.

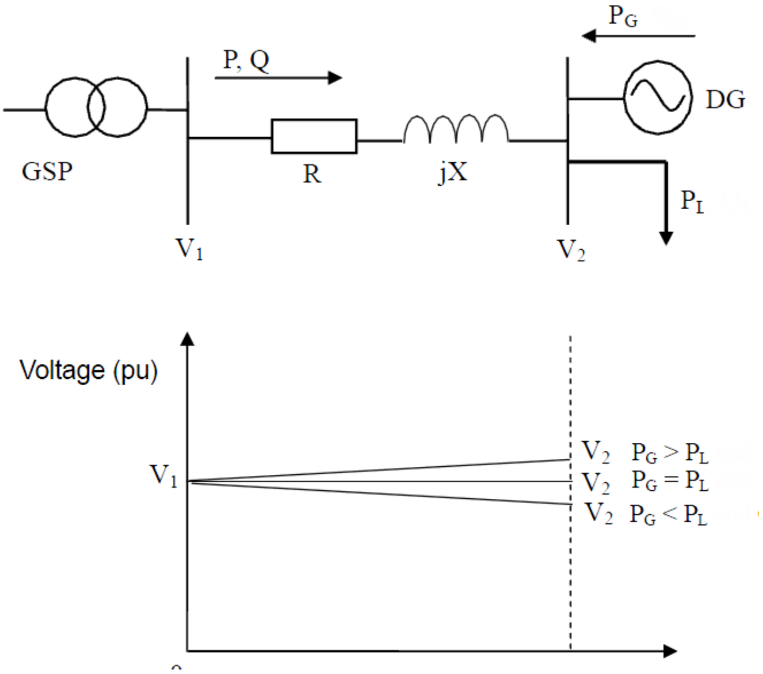


Figure 2.3: Voltage variations relative to DG outputs

DNOs are obligated to maintain the network voltage within statutory limits. To tackle the voltage rise issue caused by increasing DG integration, it is desirable for DNOs to make full use of existing assets distributed within the network before rebuilding new lines. For example, by properly adjusting the position of transformer taps [25], the expected goal of voltage regulation could be reached using voltage regulators on the feeders. Considering the intermittent nature of most renewable sources, more active measures have be taken to minimize the harm of voltage variation to the system [26, 27].

2.5.2 Thermal capacity and loss

Small penetration levels of DG can improve the thermal properties of feeders and transformers, since the load near to the DG can often be partly supplied by the DG. As a result, the requirement for power delivered from upper voltage levels would be less, the loss along the feeder is reduced, and extra capacity on the conductors is released.

Depending on the connection arrangement and local demand, when DG capacity surpasses a particular level, it may start to export energy to the higher level of network after meeting all the local demand. Reverse power flow of any significance observed by the higher network will lead to a rise in usage of the conductors. If the DG export keeps rising, thermal overload may occur and the losses can also rise above the original level. Figure 2.4 shows a common ‘u-shape’ loss curve for three cases: maximum demand, variable demand, variable demand and DG output, where DG capacity initially lowers losses before higher capacities see losses increase.

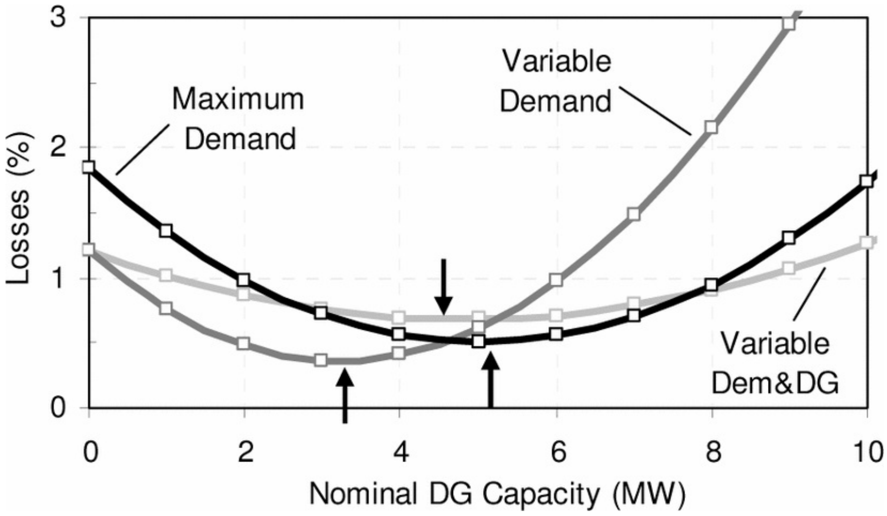


Figure 2.4: Percentage power losses relative to DG capacity [21]

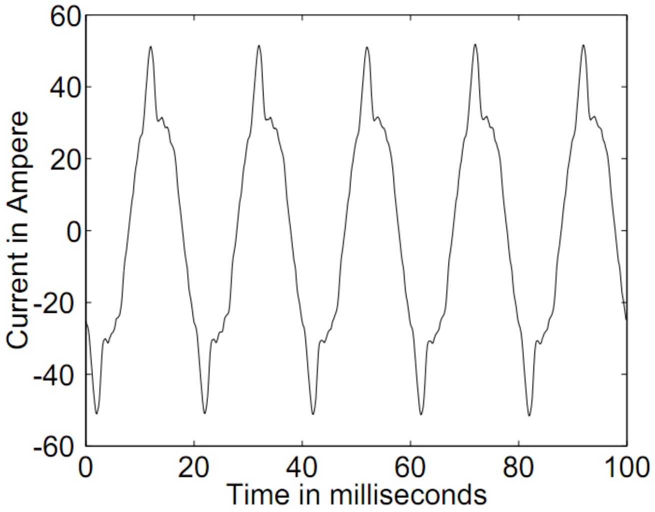
The changes of network losses according to different locations and capacities of DG as well as different DG technologies, have been analysed thoroughly in [28]. Since the loss reduction after connecting DG does not always occur, optimisation methods is generally applied [29] to find the optimum allocation of DG for minimising the loss.

2.5.3 Power quality

In general, power quality covers all deviations from ideal voltage and current [30]. Power quality issues arising from DG connection is regarded as one of the main issues in research [31] . DG can impact power quality in a number of ways [32], with voltage interruptions and dips, harmonics [33] and flicker [34] being dominant. It may lead to significant local impacts and even across the network. Voltage flicker is fast changes in voltage magnitude that result in a phenomenon called “light flicker”. The frequency range of change is between 1 and 10 Hz. There is concern with DG whose generated power could vary quickly with time, notably wind and solar power.

The term “harmonic” refers to the non-sinusoidal current or voltage in a power system [35]. An example of it is presented in Figure 2.5 with a distorted current waveform in the time domain and the corresponding spectra in frequency domain. The superposition of different frequencies alter the shape of otherwise sinusoidal wave . Harmonic distortion can harm the network by overheating of induction motors, transformers and capacitors and overloading of neutrals [36]. Harmonics arise mainly because non-linear loads are connected to the network, wherein such loads draw a non-sinusoidal current from a sinusoidal voltage source. Typical non-linear loads include electric arc furnaces, static VAR compensators, inverters, DC converters, switch-mode power supplies, and AC or DC motor drives. In the case of a motor drive, the AC current at the input to the rectifier looks more like a square wave than a sine wave. Through the impedance of the network, the total harmonic current from non-linear loads can lead to the voltage waveform being distorted across the network.

Engineering Recommendation (ER) G5/4-1 [37] is the standard that specifies limits on the amount of harmonics allowed in the grid. The connection of DGs can cause alteration of voltage level at the connection point above these limits, particularly variable generation like wind driven by doubly-fed induction generators (DFIG) and solar PV in rural networks. DFIG contain either full or partial rated converters while PV uses inverters to convert the DC output of solar panels into AC that can be fed into the grid. The presence of power electronic components means that a distorted current is expected. Harmonic distortion has become a concern for electric utilities in determining whether new DG could be connected, since distortion levels in the network may increase above the G5/4 limit with increased penetration of DGs. The examination of the constraints that harmonics place on DG capacity will be focus of this thesis.



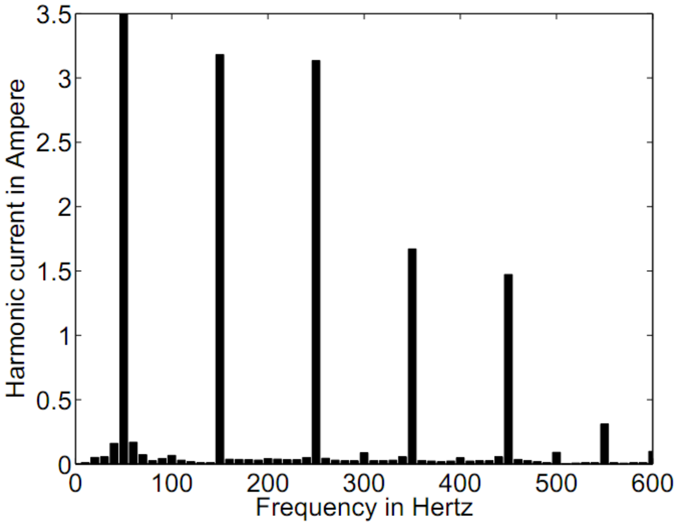


Figure 2.5: Example of a distorted current waveform (top) and spectrum (bottom) [30]

2.5.4 Protection

In power systems, a fault could be any abnormal type of electric current. The network employs protective devices to detect fault conditions and operate devices, such as circuit breakers and switchgear, to isolate the affected part of network, limit the loss of service and ensure the normal operation of the unaffected part [38]. Typical design fault levels for UK distribution voltages are shown in Table 2.1. From this, fault currents are calculated for various fault locations and switchgear is selected accordingly at energy sources, switching points or loads.

Before the introduction of DGs, protection schemes were based on the traditional operation of the network, where the provision and co-ordination of protection devices were designed and co-ordinated largely for unidirectional flows [17]. However, the installation of DG can contribute to the fault-current and also change its direction. The use of existing protection configurations with bi-directional power flows may lead to unstable, malicious actions or other errors in operation of protection devices such as voltage/current relays [39], and automatic reclosing breakers [40, 41].

Table 2.1: Typical design fault levels for UK distribution voltages [42]

Voltage (kV)	Fault current (kA)	Fault level (MVA)
132	21.9	5000
33	17.5	1000
11	13.1	250

The adjustment of protection device settings must maintain effective protection during DG operation. It must also consider intermittent DG, especially when the DG is shut down. The achievement of such a balance requires careful evaluation and may leave the network less protected. Furthermore, DG may be required to remain connected during a fault (ride-through). In the UK, the Grid Code and Distribution Code specify that large DG units should be capable of withstanding faults for several milliseconds without tripping [43, 44]. As a result, network islanding could occur after the fault, where the part of the network which is supposed to be disconnected from the main grid still remains energized due to the connection of the DG. If the DNO is not aware of this complex phenomenon, danger would arise to public safety

Adaptive protection schemes have been developed to improve the co-ordination of protection devices in the presence of DG. One solution by Brahma and Girgis [45] divides distribution networks into multiple smaller sections. The fault location can be detected separately in each section by measuring the fault current contributed by each DG. The co-ordination of protection devices has proven to be one of the most challenging tasks for UK DNOs [46].

2.5.5 Stability

The stability of a generator refers to its ability to maintain synchronism after being subjected to an external disturbance [47]. Stability analysis can be broadly categorised as either steady-state stability or transient stability. Steady-state stability is the response of a generator to small or slow disturbances such as gradual changes to load and generation, while transient stability involves larger or more abrupt disturbances such as those caused by system faults, loss of generation or sudden load changes [48]. The effects of transient stability are examined within this section.

The ability of DG to remain connected to the network during transient conditions caused by load changes or network reconfiguration depends on network topography, the nature of the perturbation and the DG characteristics. The work of Boemer *et al.* [49] indicates that DG can have both positive and negative influences on the transient stability property of networks. From a positive aspect, they note that high penetration of DG can reduce the overall loading of large conventional generators (CG) and transmission lines as the power generated is spread over a wider geographical area and located closer to the loads. As a result, the imbalance between CGs and loads during any network disturbance is less, causing smaller rotor swings. Furthermore, as DGs typically have lower power ratings than CGs, their individual tripping would have less impact on the overall network. On the other hand, they stress that as DGs are smaller machines with less inertia, they have lower inherent stability and respond to changes much quicker than larger conventional machines. They observed that networks with high penetrations of DG exhibit increased frequency oscillation after a disturbance with longer settling times. They also caution that increased replacement of CG with DG would require current methods of network modelling to be re-evaluated to account for the impact that this change may have.

2.6 Connection rules

Compounding the inherent technical issues are the general practices commonly adopted by network operators for the connection of new DG installations. This is usually done based on a ‘first-come-first-served’ basis and may possibly sterilise portions of the network [50]. This occurs if a poorly-sited DG pushes the network close to its operating limits, thereby excluding future installations in the area and resulting in the waste of generating potential from renewables.

While network reinforcement may help to mitigate the problem, availability of finance to invest in new equipment and obtaining the required planning permissions are often uncertain factors and may delay or prevent such projects. It is therefore a more desirable option for network operators to leverage existing infrastructure in order to achieve the maximum possible capacity from renewables. In order to do so, tools and methods are needed for network operators to optimally allocate generating capacity by carrying out holistic, long-term planning. A large number of studies have been carried out with this aim using various techniques such as optimal power flow [20, 21, 50-55], multi-objective impact indices [56] and genetic algorithms [57-59]. As optimisation techniques are direct relevant for the development of the hosting capacity method in this thesis, a thorough review of these papers is presented in section 3.5.

2.7 Technical requirements and guidelines

Considering the substantial impact of DG on the distribution network, technical requirements and guidelines for the connection processes and configurations are generally issued by network regulators. An overview of the regulations and legislations with the integration of renewable DG plants in the UK is presented in this section.

For connection processes, the guidelines for renewable DG connection are provided by the Energy Networks Association (ENA) [60]. Depending on the range of the connected voltages and DG rating, the guidelines are categorised into three sections. Their scopes are briefly outlined below. These guides provide a ‘route map’ of the processes for getting a generation scheme connected to the distribution network [61].

- ER G83/2 – applies to generators of up to 16A/phase, connected to low voltage systems.

- ER G59/3 – applies to generators of up to 5 MW output connected below 20kV.

- ER G75/1 – applies to generators of greater than 5 MW output or connected at a voltage above 20kV.

As a user of the distribution network, DGs are obliged to meet the connection requirements as outlined in the Distribution Code [43]. Distribution Codes specify a series of requirements on various aspects of planning and operation of the network.

Through a range of network studies, the compliance assessment of those requirements would be carried out by the DNO. Corresponding to the impacts described in previous section, relevant Engineering Recommendations are listed in Table 2.2.

Table 2.2: Relevant Grid Codes and Engineering Recommendations for DG

G5/4-1	Planning levels for harmonic voltage distortion and connection of non-linear equipment to transmission and distribution networks
P28	Planning limits for voltage fluctuations caused by Industrial, Commercial and Domestic equipment
P29	Planning limits for voltage unbalance in the United Kingdom for 132 kV and below
P2/6	Security of Supply
G12/3	Requirements for the application of protective multiple earthings to low voltage networks
P25/1	The short circuit characteristics of PES low voltage distribution networks and the co-ordination of over-current protective devices on 230v single phase supplies up to 100A
P26	The estimation of maximum prospective short-circuit current for three phase 415V supplies
G74	Procedure to meet the requirements of IEC 909 for the calculation of short- circuit currents in three-phase AC power systems

2.8 Support mechanisms and incentives

In the UK, there are mainly two support mechanisms designed to incentivise the deployment of renewable generation. Smaller scale DG (< 5 MW) is supported through the Feed-In Tariff (FIT) [62]. For large-scale DG, the scheme is the Renewable Obligation (RO) [63]. Under RO, electricity suppliers are obliged to source a specified share of their delivered electricity from renewable. Tradable Renewable Obligation Certificates (ROCs) are issued to qualified DGs. The values of ROCs vary with generation technology and are related to the volume of eligible renewable electricity they generate. In order to meet the obligation, electricity suppliers purchase ROCs from DG. If electricity suppliers fail to meet the compliance, they pay a penalty, known as the ‘buy-out payment’.

In general, these supporting mechanisms have been promoting the development of DG with capacities of wind and solar growing to over 10GW since 2001 [1]. Such high penetration levels of DG have imposed challenges on DNOs. Correspondingly, incentives have been introduced to encourage DNOs to apply innovation in the development of their networks to provide more cost effective ways of connecting and operating renewable generation. The support includes the now defunct Innovation Funding Incentive (IFI) [64] and Registered Power Zones (RPZ) [65] and the recent Network Innovation Allowance (NIA) [66]. Benefitting from these schemes, a wide range of network management techniques have been developed, for example, the Orkney ANM project supported by IFI [67]. Further details and description of some techniques of most relevance are given in the next chapter in the context of advanced constraint management technologies for DG integration.

2.9 Chapter summary

In this chapter, conventional power systems are reviewed and the current transition in distribution networks driven by renewable generation is discussed. Renewable generation has attracted great interest worldwide due to environmental considerations and is supported by the UK government. With the rapid development of generation technologies, various renewable sources have been explored to generate electricity. Many of these generators will be connected to distribution networks as DG due to the location of renewable resources and the size of projects. As the conventional power system is not designed to accept DG in distribution levels, their connections create a wide range of technical problems. With increased DG connections, their influence on power system performance cannot be neglected. To avoid impeding the development of renewables, the philosophy of how distribution networks should be planned and operated must change. The understanding of renewable DGs and its impacts provided in this chapter will help develop appropriate solutions for facilitating DG integration and will be drawn upon in the remainder of the thesis.

Chapter 3

Active Integration and Effective Planning of Distributed Generation

3.1 Introduction

This chapter addresses the DG integration techniques that have been recently developed and discusses key surrounding subjects including different integration methodologies, constraint management solutions, effective planning tools and optimisation techniques. The chapter begins with an overview of integration philosophies that require various levels of smartness and therefore present different capabilities of accommodating DGs. It then outlines the transition towards a smarter distribution network, which would provide alternative and cost-efficient reinforcement options and also improve operational performance. Active network management (ANM) is emphasised for solving voltage and power flow issues. Examples of ANM in the UK to date are presented. The potential of energy storage systems in supporting intermittent DG penetration is also discussed. The remainder of this chapter focuses on effective planning tools which could adopt the active integration methodology and leverage the full benefit from smart grid techniques. To meet the requirements of active planning tools on flexibility and extensibility, a literature survey of optimisation techniques is described in detail to consider how the overall performance of a distribution system with a significant penetration of DG may be optimised from the initial planning stage. By providing these discussions, this chapter provide a thorough review of the existing development and relavant research interest in the area of hosting capacity, which move forwards the general introduction of DG in previous chapter and lays a solid foundation for developing applications of hosting capacity for specific areas in following chapters.

3.2 DG integration: from passive to active

The distribution network is historically designed on a top-down basis to distribute energy. The DNO’s primary role is to deliver energy flowing in one direction, from remote large power plants down to end users [17]. Under the paradigm “networks follow demand”, the load mainly determines power flows and voltages. Unlike intermittent renewable DGs, load is more predictable and less variable. With predictable flows, the passive topological design has the advantage of requiring low levels of monitoring, control and supervision.

To connect DGs, different integration methodologies exist with various levels of requirements for advanced design, monitoring and management techniques, or “smartness levels”. It can be seen in Figure 3.1 that the evolution of future distribution networks will progress from (1) “passive integration” via (2) “reactive integration” to (3) “active integration”. With the diversity in “smartness” levels, the capability for accommodating DGs in each integration approach will increase and is elaborated in the following chapters.

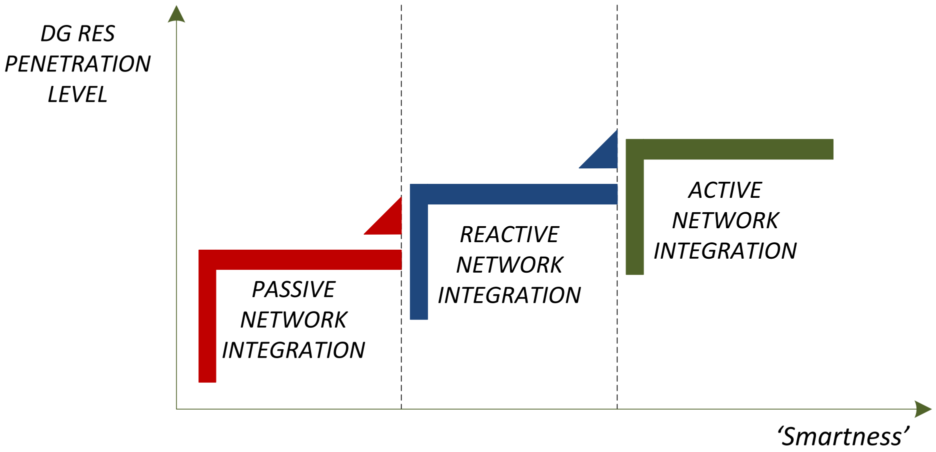


Figure 3.1: Three-Step Evolution of Distribution System [68]

3.2.1 Passive integration

Adopting the traditional development philosophy, most DNOs use the policy of ‘fit-and-forget’ for DG connections [7]. In general, this approach still considers the generators as “negative load”. Under such connections, which are termed as ‘firm’, DG are able to output full capacity regardless of the network configuration, load condition or even security condition. This approach aims to resolve most DG integration challenges at the planning stage [68]. Assessment of firm connection agreements are based on snapshot analysis of critical or worst-case situations, such as maximum generation and minimum demand, which restrict renewable capacities despite infrequent occurrence of the extreme conditions.

The advantage of ‘fit-and-forget’ is its low monitoring, control and supervision requirement during network operation. For grid operation, such as voltage control, independent and standalone regulating devices are able to achieve the operational requirements and maintain voltage within limits. The tap changer ratio of the MV/LV transformer can be pre-adjusted so that all customers, especially the most remote customer, receive acceptable voltage even in worst-case situations. Advanced network management systems using co-ordinated monitoring, simulation and control units are not necessary for this approach.

However, the ‘fit-and-forget’ approach is regarded as a significant constraint on increasing renewable DG capacity [50] and tends to result in a ‘sterilised’ network. The variable characteristics of renewable energy mean that full nameplate outputs of generators are produced more or less infrequently. In many cases, the network would be constrained for just a few hours per year by intermittent DG [69, 70]. The headroom of networks for connecting DG is not sufficiently well used during most of the year. In addition, the constraint problems may not be limited to specific locations. Therefore, this passive approach is only possible where the network penetration level was low, like the early stage of renewable DG development. To date, with the rising DG connections, the passive development cannot accommodate all installations without significant investments in basic infrastructure, such as primary transformers and new lines, making it expensive and inefficient [68].

3.2.2 Reactive integration

The reactive integration approach mainly focuses on the operation stage. During the planning stage, the regulations encourage as much DG connection as possible with few restrictions. Network constraints are to be managed by restricting both load and generation during the operation. This approach is currently used in some countries where high penetrations of DG have already been developed.

The control of DG under the reactive integration approach is more flexible than passive network. Co-ordination between load and generation exists to solve the operational constraints. Although increased hosting capacity could be connected than passive integration, “blind” development, i.e. lack of optimisation at the planning stage could also sterilise portions of the network. A prior poorly-sited DG can push the network to its accommodation limit, thereby subsequent DG installations in the area have to restrict output for many hours per year affecting their business cases [50].

3.2.3 Active integration

Both passive and reactive integration imply an attempt to solve the immediate technical issues of integrating DG by largely neglecting either the planning or operational stage. The existing headroom of distribution networks can be better used if an approach would allow for optimal interaction between planning and operation. This approach of DG development is termed as “active integration” in this work.

The active integration approach would allow overall optimisation of the network and DGs, to maximise integration of DGs while avoiding or deferring network upgrades [71]. Compared with others, this active approach enables DG developers and DNOs to find the most cost-effective way for their business plans.

The electricity network is still under transition to the smart grid. Most of the relevant technologies and methods are not completely developed or deployed. This means that DNOs and DG developers have considerable need for better support to effectively design networks that deliver the full benefits of active integration. In particular, the characteristics of active integration that make most use of alternative methods to avoid expensive investments in primary plant and increase the connecting capacity of DG will be emphasised.

The full realisation of the active integration approach is challenging. For example, difficulties could arise from the detailed level of a planning study which involves considerably increased input data, and also from delivery of planned solutions through the operational practices of control rooms. The focus of this work is mainly on the planning stage. The aim is to solve some of the remaining issues in achieving effective planning tools for active DG integration. The adoption of the active integration approach at the planning stage is referred to as ‘active planning’ in this work.

To provide an understanding of issues around active planning, and to provide a basis for studies in the following chapters, the remaining sections of this chapter will review the constraint management strategies that can be used as planning options; the requirements of effective planning tools for active integration; and also techniques that seek optimal planning results.

3.3 Constraint management for DG integration

The technical requirements of active integration of DGs do not only need proper evaluation of network constraints for connecting DGs, but also require suitable monitoring, control and supervision techniques that are able to release these constraints. The latest development of smart grid technology enriches planning options yet also creates challenges on how to effectively embed them into planning procedures. In order to understand available techniques, the conventional and innovative approaches for managing the constraints arising from DG integration are discussed in this section.

3.3.1 Conventional network upgrade

Where thermal limit is the binding constraint for connecting new DG, the most obvious measure to increase the volume of DG that can connect is to build new distribution lines. However, this is an expensive and time-consuming solution. Moreover, as a result of environmental concerns it has become difficult to obtain permission to build.

The traditional approach to control voltage is done by transformers using on and off load tap changers [17]. In practice, DNOs prepare several critical scenarios within which voltages must be maintained within agreed ranges. This will define a fixed set-point for the worst case in each season. If feasibility studies found that voltage variation is the constraining factor for increasing DG capacity, then under traditional upgrades, additional equipment such as shunt or series capacitors, shunt reactors and FACTS elements, need to be installed at critical locations. The applicability of such reinforcement measures depends on each individual distribution network. But those equipment are expensive like distribution lines.

In addition, conventional network upgrading to accommodate new DG is not only expensive but also frequently inefficient. In many cases, the network would only be constrained for few hours per year [12]. Also, constraint problems will no longer be limited to specific locations. This requires more flexible and cost-effective solutions.

3.3.2 Active network management

When traditional network upgrades cannot rapidly relieve the constraints on increased DG penetration without high capital expenditure, alternative methods have been explored to provide more commercially viable solutions. Active network management (ANM) is widely recognised as being an effective and low cost solution to manage the technical impacts of DG connection [72]. At the time of writing this thesis, a wide range of ANM technology has been developed. This section will summarise and discuss existing ANM activities that are most relevant.

3.3.2.1 Real time thermal rating

Thermal overloading, as one of the main cause of limitation for DG connection at distribution level, has driven the development of real time rating technologies [73, 74]. The aim of this technique is to obtain the real-time transmission capacity of network components, such as overhead lines, cables and power transformers at critical locations, in order to relieve the limitation. Its concept is based on the fact that the power carrying capacity of components is strongly influenced by variable environmental parameters such as air temperature or wind speed [75]. However, the current operating practice fails to reflect this variable characteristic, where static component ratings based on conservative assumptions are used. It is a very useful option for facilitating wind energy connections, because of the positive correlation between thermal rating and wind farm output. With high wind speeds, network components experience better cooling and hence have higher rating than under low wind speed conditions. Accordingly, the thermal rating tend to automatically increase with increasing wind speeds and increasing wind farm outputs,

The implementation of real time rating schemes involves the installation of meteorological units to monitor critical equipment in the network. Yip *et al.* [73] developed a monitoring device called the ‘Power Donut™’ that is able to be fitted to the line. Its measurement of conductor temperature is processed together with a thermal model of lines. Accordingly, it is possible to predict the actual real-time thermal ratings at any moment. The adoption of this device to monitor the 132kV overhead line between Skegness and Boston (East of England) revealed that constraints imposed on the wind farm output by thermal overloads could be largely avoided. It successfully unlocked extra capacity and more wind generation can be connected compared to using the static line ratings.

3.3.2.2 Active voltage control

As the renewable DG connections increase, variation of DG output lead to more frequent modifications of voltage profiles. Traditional passive control by fixing operational points is no longer possible to constantly maintain voltage without active approaches and dynamic resources. Continuous adaption of voltage control at local points and also network level are required. Several active voltage control techniques have been developed in distribution networks:

Adaptive OLTC transformer control: the voltage regulation function provided by the OLTC transformers could be exploited in a more active way with DG connections. Alternative OLTC setting practices that go beyond the present pre-set has been studied by researchers. Actively modifying the setting of the tap instead of pre-setting according to historic or seasonal data is generally proposed [26, 27].

White *et al.* [76] developed an OLTC transformer control technique called GenAVC^{TM}. As shown in Figure 3.2, its controller is installed in the 33/11kV substation to provide real-time control of OLTC transformers to maintain the secondary side voltage within the limits. The voltage reference setting is estimated and calculated using Remote Terminal Units (RTUs) deployed at remote feeders and also DG buses. The performance of the GenAVC^{TM} has been verified by different trials as being effective in managing the voltages in the network with renewable DGs [77].

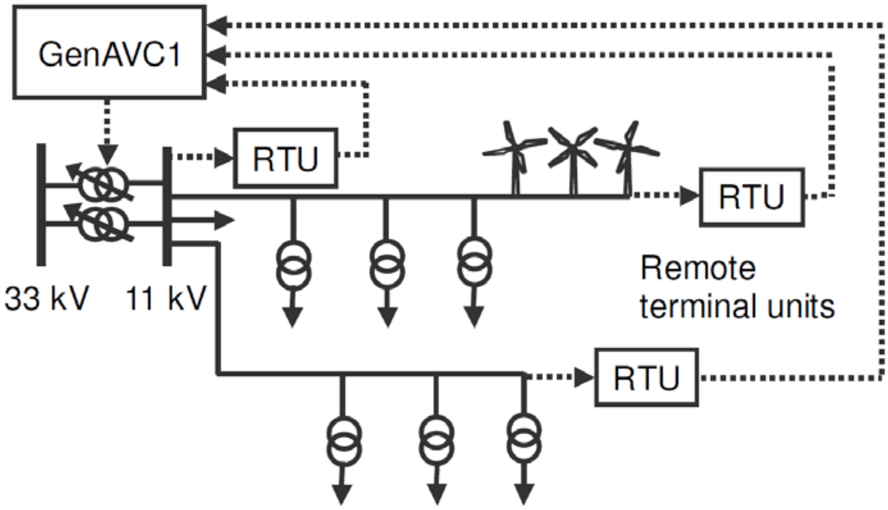


Figure 3.2: Structure of the GenAVC^{TM} system [76]

Li and Leite [78] proposed a similar real-time approach for OLTC transformers control but using a unique technique called Automatic Voltage Reference Setting (AVRS) to decide the tap action of the transformers. The structure of the AVRS is shown in Figure 3.3. The system is based on the comparison between specified limits and measured voltages at the sending-end, receiving-end and also DG buses. A voltage reference is accordingly estimated for the AVC relay to drive the tap change.

Case studies in [78] reveals that the approach can accommodate more DG by correctly managing the voltages.

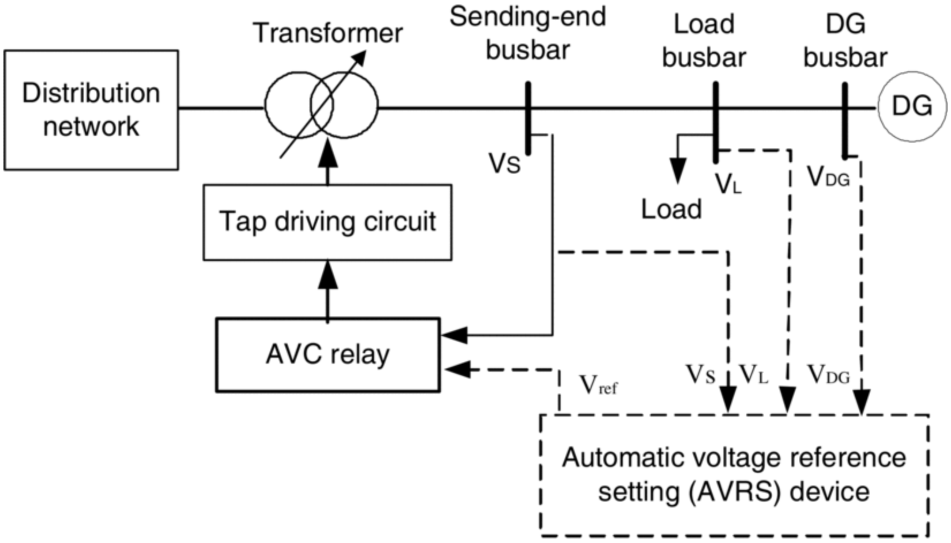


Figure 3.3: Structure of the AVRS system [78]

Adaptive power factor control: DG could contribute to voltage control by absorbing and delivering reactive power. This has been already proposed in [20, 79, 80], where DG above a certain capacity may be required to have reactive power capabilities. The capable generation technologies include modern wind turbines, small hydro and DGs with power electronics components. Inverters originally supported either active or reactive power control. Based on pre-defined and dynamically configurable set-points, DG would react to voltage changes or disturbances by altering reactive power, in a similar way to how frequency control operates.

Coordinated combination of adaptive controls: A combination of the above solutions could be used and is likely to be the more cost-effective in keeping voltage stable in distribution networks. Where this combination is suitable, the coordination between control actions needs to be carefully arranged and optimisation could also be applied. Several studies have tackled this issue, for example:

Viehweider *et al.* [81] used a priority list to schedule voltage control solutions, including actions of the OLTC tap, DG reactive power management and DG active and reactive power settings. The order of intervention, by which the control actions will take place, is defined by state machine methods and based on interval arithmetic. The authors demonstrated that the control algorithm could effectively lessen the impact of DG on the voltage variation.

Tao *et al.* [82] proposed a case-based reasoning approach to select voltage control solutions from OLTC control, power output and power factor control, energy storage and network reconfiguration. By building up an extensive case library, each specific voltage problem is matched with an available control solution. Where a single method may not be sufficient or effectively reduce the voltage variation, the combination of solutions is adopted. The effective management of voltage variation problems and the improvement in DG output was shown by the authors.

3.3.2.3 Variable connection rules

It is of significant importance for DG developers to search for the most commercially viable connection method. At present, most DG connection proposals in the UK are provided with a ‘firm’ connection [83]. The firm connection tends to limit the network capacity for the connection of DG due to the infrequent occurrence of the worst-case scenarios.

To tackle the restriction imposed by firm connection due to the variability of renewables, ‘non-firm’ connection is an alternative option. Curtailment of renewable DG is one option considered by [84, 85], wherein the DNO reserves the right to reduce the output of the renewable generators by active network management system. Through trimming or tripping units during low demand periods, larger generators can be connected, while ensuring that network parameters still remain within limits.

Amongst the non-firm connection research, the most well-known is Active Power Flow Management (APFM) scheme developed by Ault *et al.* [72] and Currie *et al.* [85, 86]. It has been deployed on the Orkney Islands distribution network with several renewable generating units. It actively manages the output of multiple DG units to release thermal congestion on a real-time basis. According to its controlling philosophy, DGs are categorised into three groups: firm generation (FG), non-firm generation (NFG) and regulated-non-firm generation (RNFG). RNFGs are the units that are subject to trim and trip against a thermal limit threshold in critical network components. In the Orkney network, this is the cable connecting the island to the mainland which has limited exporting capability [87]. The priority order among RNFG units in the APFM scheme follow a principle called ‘Last-In-First-Out’ (LIFO) by which the last unit connected to the network will be the first one to be trimmed or tripped. The operation of APFM in the Orkney network confirms its performance in enabling the further connection capacity from renewables while maintaining secure and reliable network operation [88]. More details is provided in section 4.3.

The occurrence of curtailment under non-firm connection means the loss of production and potentially an adverse effect on the financial viability of the project [84]. The probability of the coincidence of some scenarios, such as minimum load demand and maximum generation, will largely determine the total annual energy curtailed. The assessment of non-firm connection arrangements is more complex than with the traditional ‘snapshot’ assessment at critical conditions. Ault et al use a logic based Optimisation methods are useful to establish the appropriate arrangement of curtailment rules among DGs from different owners. Otherwise, under certain conditions, inappropriate management schemes may still reduce or ‘sterilise’ available network capacity for non-firm connections by over-curtailing production to an uneconomic level [89].

The impact of variable connection rules is identified as an emerging area for hosting capacity in this thesis and chapter 4 provides a specific study with a novel method developed for calculating the hosting capacity under different connection rules.

3.3.3 Energy storage systems

Unlike the dispatchable sources used for centralised electricity generation, the main challenge of renewable generation (most of them are DG) for network operators is the variability of production, which alternates over time and may not be fully predictable. The rapid development of energy storage systems (ESS) provides one promising solution for managing the network constraints arising from the variability of renewable DG [90].

ESS offers the potential for matching electricity generated from DG and consumption as required and therefore managing the constraints on increasing DG connections. Electricity is taken from the DG with a certain efficiency factor, allowing it to be stored for some period. When needed, the stored energy is then converted to electricity with certain losses. With the introduction of ESS into a network of high DG density, two significant factors of network operation could be improved: efficiency and flexibility [91]. It allows renewable generation to be captured and stored for later use, thus not wasting the curtailed energy which cannot otherwise be used. It is also a valuable instrument to provide the needed flexibility. Different timeframes of dispatching operations could be “firmed up” according to requirements from seconds to hourly, days and even seasonally.

Many different types of energy storage technologies have been tested in distribution networks [92]. Some technologies are more appropriate for providing improvements for certain power quality requirements in a short range of time, such as smoothing the variety of output of wind farm from seconds to minutes. Others are useful for storing and releasing large amounts of energy over longer time periods. Together, a wide spectrum of performance characteristics and capacities can be provided for different application requirements.

Large-scale storage, like hydro reservoirs and pumped storage plants are able to store and discharge energy in the timeframe of hours up to days. While they are suitable to help integrate renewable DG, their current applications mainly feed into the high voltage level as spinning reserve to stabilise frequency and support electricity markets [93]. Existing and emerging technologies draw more attention at the distribution level, including batteries (lead acid, lithium, nickel, lead, sodium and ZnBr based), flywheel electric energy storage systems and superconducting magnetic energy storage (SMES) system. They are suitable for both small and medium scale applications [94]. Their installation can be close to renewable generation sources or demand. Accordingly, the decentralised deployments provide a promising match to distributed generation. The development of many new storage technologies still focus on feasibility studies, and only a few technologies may be able to make a relevant contribution in the near future. The concerns are not only about technology problems but also cost and whether it is economic compared to other alternatives.

Considering the current low economic efficiency of ESS, the combination of them with other smart grid solutions is more appealing to managing network constraints in a cost-effective manner. Their application on non-firm connections has been investigated [95, 96] and considered for adoption by some DNOs [97]. Whilst controlling DG output under low demand periods is beneficial in term of increasing DG capacity, curtailment cannot avoid the loss of revenue to DG developers. ESS provides one promising solution to save energy that otherwise would be curtailed. The co-operation of ESS with ANM techniques can offer benefits to both DG developers and DNOs [98, 99].

Indeed, ESS not only can facilitate renewable DG integration, but also useful to ensure continuity of supply, improve reliability and increase energy autonomy. Until now, the deployment of ESS alongside renewable DG has been rather small with handful of schemes and trails [94]. The growth of knowledge on optimising the planning and operation of ESS would be useful to improve the economic efficiency. The quantified benefit brought by ESS to increasing DG capacity and output would reduce the uncertainty of the decision making process, when comparing to other alternatives.

The capability of ESS on improving hosting capacity is another area this thesis explicitly studies and a novel method developed for calculating the economic hosting capacity under different ESS technologies is provided in Chapter 6.

3.3.4 Integrated active distribution management systems

While the constraint releasing techniques identified can be utilised to increase capacities of new DG to be connected in distribution networks, concerns about conflicts between new techniques and existing network regulations arise [7]. The competition among owners of renewable DGs in the same network may further worsen this problem. The development of ANM would be expected to put the emphasis on coordination among control approaches in the system.

It is important for DNOs and DG developers to understand the technical and economic consequences of the control approaches. For example, under the non-firm connection scheme, the economic consequences of the curtailment need to be carefully evaluated to verify the financial viability of the project. Such impacts due to the presence of non-firm DG are discussed in detail in the next section.

Davidson *et al.* [100, 101] introduce an ‘Autonomous Regional Active Network Management System’ (AuRA-NMS) based on multi-agent systems technology to co-ordinate different control functions. Multiple network issues are considered, including voltage control and line power flow management, automatic restoration and loss minimisation. Each control task is treated as an agent to act within its vicinity to solve constraints. The communication and coordination between each agent are provided by an agent management system. The system requires integration of advanced techniques in distributed control, decision making, network analysis and communications. It has been partially tested in medium voltage networks and further deployment is promised.

3.4 Effective planning tools for DG integration

The active integration approach and smart-grid based constraint management techniques together promise substantial potential to increase DG penetration. However, there is no ‘one-size-fits-all’ solution since distribution networks are rather diverse in topology structure, infrastructures, load and DG density. To some extent every distribution network should be assessed individually. Effective planning tools that can be widely applied to active integration of DGs are therefore of interest. This section investigates the requirements for developing effective planning tools in this context.

A number of difficulties to achieve effective planning tools can be easily identified. For example, the variable nature of renewable DG output means an increased computational burden from detailed input data. Also, a range of the latest smart grid techniques need to be modelled and compared. Moreover, the different objectives of DG developers and network operators may complicate the active integration of DG.

To solve these challenges, the capability to conduct detailed analysis of impact of DG on network is crucial to the success of planning tools. The variability of renewable implies that the level of detail not only requires the worst-case but also the series of normal operating conditions must be effectively considered for exploring the unused network headroom. The tools should also be flexible to embed selective network constraints and be tailored for different development objectives. This flexibility means providing solutions under different deployment options to help both DNOs and DG developers make sound and practical decisions. To better interact with the deployment and operational stage, a clear road map illustrating how the planned benefits will be delivered for the operational needs of the control room is essential.

In summary, the features that should be included in the active planning tools are as follows [102]:

- Support detailed input data, including time-series profiles and probability distributions of generator, demand and weather profiles;
- Ensure that solutions comply with all relevant planning standards and grid codes;
- Provide various Principles of Access options to obtain more viable commercial arrangements;
- Make use of the latest developments of smart grid technology solutions to facilitate DG integration;
- Demonstrate clear, quantifiable benefits for grid performance of adopting a particular smart grid technology;
- Build in flexibility and extensibility so that the solutions can evolve to meet the changing needs of the electricity grid and the transition to the smart grid over time.

A wide range of planning tools will be sought by DNOs and DG developers which will require extensive research in this area. A number of strategies and methods have been developed in recent years. This work asserts that optimisation techniques will be important to address DG integration and planning issues. These are reviewed in the following section.

3.5 Optimisation techniques for DG Planning

The introduction of DG will affect the performance of the distribution network. In fact, every change in the placement of DG, e.g. their size and location, may affect the performance of network. Conversely, it could improve the network in one case but deteriorate it in another. With high densities of DG penetration, the adverse impact becomes the main concern. Under certain conditions, even a small change of the DG placement could affect security [24]. Effectively, this type of impact could be used to define the location and/or size of DG that does not breach limits. This is termed as the ‘hosting capacity’ and is now a substantial area of research.

Hosting capacity by large can be thought as, calculating the space available in the network. Optimisation techniques are an obvious approach for this. Optimisation techniques for DG planning have been well studied and can be broadly categorised as linear analysis-based or OPF-based. This section provided a detailed literature review on these techniques beginning with the explicit explanation of the “hosting capacity”.

3.5.1 Hosting capacity analysis

It is of significance for both DNOs and DGs developers to quantify the maximum available headroom in the network to accommodate new DG according to given technical or commercial objectives while subject to a set of predefined limits. Although this DG planning problem can be complex in many respects and be approached from various angles, “hosting capacity” is generally used as a common indicator. Bollen and Hassan [24] proposed and defined ‘hosting capacity’ as the amount of DG connected to network beyond which the security and reliability of supply, becomes unacceptable. Other terms predate this description but mean the same : capacity evaluation [86], optimal allocation [103]..

The particular driver for DNO and DG developers to determine the hosting capacity of a network could be different. The hosting capacity has been directly assessed by searching for the maximum power rating of DG while all technical impacts are within the limits [20]. It is also investigated by focusing on other concerns, such as minimisation of loss in [21] and minimisation of reactive power support in [104]. The work in [105, 106] even evaluates the hosting capacity by improve the performance of multiple objectives, such as maximising the power rating of DG while minimising the loss of the network. These studies make significant steps in term of improving a more generalised application of hosting capacity. Ultimately, hosting capacity only becomes useful when it incorporates relevant aspect of the impact and provides a structured solution through one step analysis.

The hosting capacity is also affected by the particular aspects of DG impacts on the network that are considered. Voltage and thermal limits of line and transformer are commonly included for hosting capacity analysis. Aside from them, voltage step constraints [54], fault level constraints [52, 53] and security constraints [107] have been considered in the context of hosting capacity. The extension of the scope of DG impacts that could be embedded into hosting capacity analysis has become a focus in several works as will be elaborated on later. An assessment taking account of more impacts would enable a fuller picture for decision making.

With the development of smart grid techniques, the headroom for accommodating DG in the distribution network is expected to be improved. The quantification of the released hosting capacity would help verify those new solutions from both technical and economic aspects, and lay the basis for comparison with traditional network upgrades. However, the hosting capacity analysis has not been applied extensively in providing smart grid based planning solutions, an obvious gap is in examining the impact of alternative access rules realised by ANM on hosting capacity . To understanding the challenges ahead in this research area and investigate the relevant analysis method, a literature review on the optimisation techniques that have been used to tackle hosting capacity problems is provided in the following subsections.

3.5.2 Analytical method

For situations where only a typical or critical scenario and a specific aspect of DG impacts are taken into account, the hosting capacity can be calculated analytically through a simplified set of equations and procedures. A notable example of this approach has been given in [84] where the voltage rise effect of DG is illustrated using a two bus system in Figure 3.4.

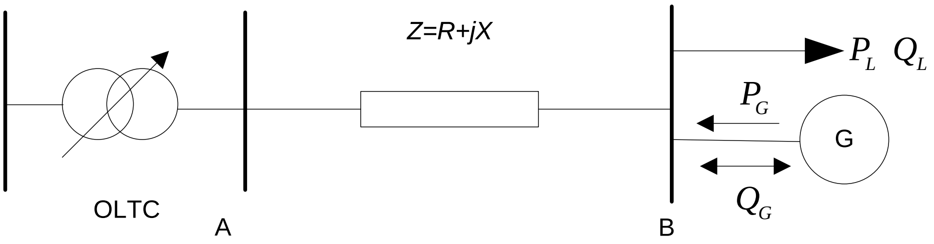


Figure 3.4: A 2 bus system for modelling voltage rise [84]

The DG is connected to busbar B with active power P_g and reactive power Q_g. Neglecting losses, the voltage at busbar B is simplified using

$$V_B \approx V_A + R(P_G - P_L) + X(\pm Q_G - Q_L) \tag{3.1}$$

Based on this simple equation, the relationship between the amount of generation that can be connected and the voltage at busbar B can be analysed, and also the impact of control actions. For example:

1) Determine the optimal capacity ($P_G^{\max}$) of DG under unity power factor using (3.2) below, while maintaining the voltage rise at busbar B within the statutory limit ($V_B^{\max}$).

$$P_G^{\max} = \frac{(\mathrm{V}_B^{\max} - V_A)}{R} - \frac{QX}{R} \tag{3.2}$$

2) Evaluate the effect of curtailing generation (P_{curt}^G) on optimal capacity ($P_G^{\max}$) as shown in (3.3), while the voltage at busbar 2 rises to that of the statutory limit ($V_B^{\max}$). If the probability of the given scenario occurring, such as the worst situation

(minimum load/maximum generation), is low, it may be beneficial to accommodate a larger DG at busbar *B* with the curtailment of DG output at the critical period.

$$P_G^{\max} = P_G^{curt} + \frac{(\mathrm{V}_B^{\max} - V_A)}{R} - \frac{QX}{R} \tag{3.3}$$

3) Management of reactive flows may also make a considerable impact on the hosting capacity. If reactive power is absorbed from the network at busbar *B*, it could reduce the voltage rise impact. The effect of reactive flows on increasing the amount of DG capacity is

$$P_G^{\max} = \frac{(\mathrm{V}_B^{\max} - V_A)}{R} + \frac{Q_{import} X}{R} \tag{3.4}$$

For the considered snapshot scenario, the analytical analysis is able to provide a quick overview of hosting capacity for the given DG location. The effect of some non-coordinated operation could be incorporated and studied. This type of analysis was also used in [108, 109] focusing on power losses.

However, the analytical approach has several limitations that make its results only indicative and scenario-limited. In considering a snapshot scenario, technical issues may arise beyond the given scenario due to the inherently variable nature of demand and renewable generation. While the analytical formulation caters for a specific technical aspect, other technical constraints might also impose on DG [110]. Another limitation is that the analytical method can only evaluate a single DG at a time [12]. In addition, the attempt to evaluate multiple separate DG cannot guarantee the appropriately arrangement of them as a whole and may lead to the ‘sterilization’ of capacity. The active network solutions, such as coordinated voltage control or generation curtailment cannot be embedded either.

3.5.3 Linear programming

Linear programming is a method to achieve the optimal results in a mathematical model whose requirements are represented by linear relationships [111]. Linear programming is used in a variety of power system issues and applications, from operational analysis such as generation scheduling, to network planning and capital investment [112]. It has also been adopted to address the hosting capacity problem for DGs [107].

In order to apply linear programming methods, a linearised network model must be used. This requires some approximation and simplification in network modelling [113]. Consequently, error will be unavoidably introduced but it was demonstrated that in certain circumstances it may not be a significant one, for example, in the context of discrete turbine sizes [107, 114].

Linear programming has been used as an optimisation tool to tackle many of the same problems described in the section above. It was used in [115] to maximise the capacity of DG. In [116] it was applied to minimize the annual active generation curtailment cost under non-firm DG connection. In [114], a linear programming formulation of optimal power flow is employed to manage the voltage constraints from DG. The application of linear programming commonly uses linearised sensitivity factors to simplify the non-linear AC power flow [89, 114]. These factors can reflect the sensitivities of changes applied in one technical aspect of DG to another. A range of constraints, such as voltage, thermal and short- circuit limits could be approximated using the sensitivities. For example, the voltage sensitivities to the active and reactive injections from DG, $\partial V / \partial P$ and $\partial V / \partial Q$ can be calculated from the Newton–Raphson load flow equation. This is represented as

$$\begin{bmatrix} \Delta\theta \\ \Delta V \end{bmatrix} = J^{-1} \begin{bmatrix} \Delta P \\ \Delta Q \end{bmatrix} \tag{3.5}$$

where V is the magnitude of nodal voltages vector, θ is the voltage angle, P and Q are the DG power output and J is the Jacobian matrix given below:

$$J = \begin{bmatrix} \dfrac{\partial P}{\partial \theta} & \dfrac{\partial P}{\partial V} \\ \dfrac{\partial Q}{\partial \theta} & \dfrac{\partial Q}{\partial V} \end{bmatrix} \tag{3.6}$$

The resultant value of sensitivity factors is dependent on the operating condition. Due to the variable nature of load and DG, it means that the operating point of the network will vary frequently and sensitivities will change accordingly. It may result in a number of repetitive sub-calculations. Another limitation is when the network constraints are interacting the constraints cannot be linearly superposed [117]. The advantage of linear programming is that it offers fast solutions by simplifying the complex nonlinear AC power flow, therefore provides significant potential for the development of real-time operational methods. However, at a planning stage, AC OPF approaches would be a more rigorous and robust.

3.5.4 AC optimal power flow (OPF)

Optimal Power Flow is a powerful analysis tool used to solve complex power flow problems [117]. Initially, OPF was developed to find an optimal solution for economic dispatch [118]. After that, OPF has been extensively used by the electricity industry to solve problems, such as minimisation of losses, reactive power dispatch and load shedding [38].

For example, an economic dispatch analysis is formulated with the objective to minimise the overall fuel costs, taking into account line flow and voltage variation limit. The objective function and constraint statements for a typical economic dispatch analysis are provided:

$$\min C = \sum_{g=1}^{n} c_g \bullet P_g \tag{3.7}$$

subject to:

$$P_{g,\min} \le P_g \le P_{g,\max} \tag{3.8}$$

$$S_{\min} \le S \le S_{\max} \tag{3.9}$$

$$V_{min} \le V \le V_{max} \tag{3.10}$$

where C is the overall fuel costs, c is the cost per unit output; P is the active power output from generation unit g (within the maximum and minimum output limits: $P_{g,min}$ and $P_{g,max}$); S is the line current capacity and V is the DG bus voltage (within their range min – max respectively). The OPF formulation enables a search for an optimal amount of active power output from the participating generators to meet demand and losses and to satisfy network limits at minimum fuel costs.

In terms of its application to DG, OPF has been adopted to evaluate the available hosting capacity across multiple sites with and without security constraints in [50, 52]. These OPF based approaches are efficient in searching for maximum DG capacity. However, only worst cases and passive operation of the network were considered. Boehme *et al.* [70] developed a time-sequential OPF to evaluate the maximum energy extracted from multiple given DG. If attempts are made to define hosting capacity (MW) instead of optimising generated energy (MWh), directly applying this time-sequential approach however requires long processing times, and may result in problems that are intractable. To scale down the size of the problem, a multi-period based OPF was developed by Ochoa *et al.* [20]. It reduces the exhaustive time-sequential periods into multiple periods by matching the similar coincidence of demand and DG outputs. In fact, the flexibility provided by multi-period OPF can be also used to investigate different objective functions that represent various technical, economic and environmental aspects of DG. For example, the same multi-period OPF framework was used in [21] to evaluate hosting capacity from the prospect of minimising energy losses. In the application of this method, care must be taken to maintain the balance in terms of size reduction and accuracy. Other than coincidence matching [54], typical periods [56] have also been investigated to reduce dimensionality.

Mathematically, AC OPF is a nonlinear programming problem (NLP) [119]. Many solution methods to solve the AC OPF problem exist such as special linear programming formulations and branch and bound techniques [120, 121]. Commercial solvers which are highly specialised for NLP problems are also available, such as CONOPT [122], a generalised reduced gradient solver, and KNITRO [123], an interior point solver. In addition, the objective functions of AC

OPF are not necessarily convex, and so multiple local optima may occur, requiring multiple starting values to check for appropriate convergence [124].[20]

3.5.5 Multi-Objective programming

It is clear that DG simultaneously imposes differing impacts on the network to which it is connected. The impacts could be either beneficial for some aspects of the network but adverse for others, depending on the DG characteristics and the load conditions. In addtion, some objectives of the hosting capacity planning problem are naturally conflicting. In some cases there is no single planning solution that will satisfy all stakeholders. It requires methodologies to evaluate the DG performance in a multi-objective manner.

One of the common solutions for multi-objective programs is to use preference information to aggregate multi-objectives into a single one, and solve as a single-objective optimisation problem [111]. The example of a multi-objective index was introduced by Ochoa *et al.* [103] and further developed later in [105, 106]. It considered extensive impacts of DG on system, and aggregated all the sub-indices used for measuring impacts into a weighted-sum referred to as '*IMO*'. Formally this is given as (3.11)

$$\begin{aligned} & IMO^k = w_1 IL_p^k + w_2 IVD^k + w_3 ISC3^k + w_4 ISC1^k \\ & where: \sum_{i=1}^{4} w_i = 1 \qquad \forall \; w_i \in [0,1] \end{aligned} \tag{3.11}$$

k indicates the k-th distribution network configuration considering DG. The first and second indices (*ILp* and *IVD*) indicate the benefits of properly located DG: decrease of real power losses (*ILp*) and improvement of voltage profile (*IVD)*; the third and fourth indices (*ISC3* and *ISC1*) express the impacts of DG on the protection devices which are compared with the case without such generation units. Using a proposed single objective GA, the best locations to connect DG impacts was determined. This paper recognizes that DNOs might not have control over DG investments, but that information about optimal DG locations could shape the nature of the contract between the DNO and the DER developer. In the study, a higher total value of the multi-objective index implies that DG would have more positive impacts on the distribution network. Based on similar concept of weighting factors, the multi-objective index was approach was later extend to the snapshot analysis [106] and time-series analysis [105]. The use of an aggregated multi-objective index in the mentioned studies effectively reduced the computational burden. However, the yielding of a single final objective will require strong knowledge to provide priorities for each sub-index, which could be a risk for the decision makers.

In some cases, there is no single planning solution that will satisfy all stakeholders. Instead, a set of solutions can provide more information for the decision makers to trade-off, known as the Pareto set. An example of this method is the study in [125] to explore the trade-off between DG Developers and DNO. The resultant Pareto set is shown in Figure 3.5. It illustrated that the two sets of final compromise solutions are found by different decision making techniques: max-min and knee-set approach.

Generic Algorithms (GA) are also employed in solving multi-objective optimization problems. In this context, it is known as multi-objective genetic algorithms (MOGA) The main advantage is that MOGA are able to find many solutions of the Pareto set at once and also provide the opportunity of using complex objective evaluations in the formulation to provide more realistic models of the problem. In [126], a non-dominated sorting genetic algorithm (NSGA) is applied to find the configurations that maximize the integration of DG while using time-series-based approach to model the variability of load and generation. The compromise between the maximization of energy export and the minimization of DG impact was represented by a set of Pareto optimal solutions

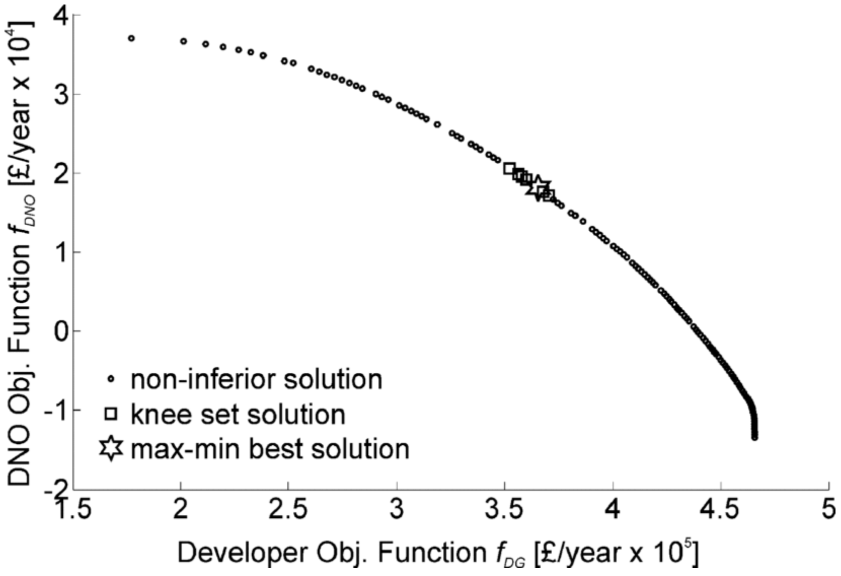


Figure 3.5: Pareto solutions for DNO and developer objectives with no deferral benefit. [125]

The recent development of multi-objective genetic algorithms (MOGA) technique aims to improve the efficiency of searching for Pareto sets, and to deal with the formulation of complex problems. Studies in [56, 126-128] have applied this approach to solve DG issues, such stochastic and probabilistic simulations. In fact, [56, 126, 129-131] employed MOGA to approach DG planning by a combination of technical, economic and environmental objectives simultaneously.

In the context of hosting capacity that this thesis mainly targets, multi-objective programming provides a method to solve the realistic problems in some cases where conflicting aspects exist between different shareholders on the DG development. Therefore, it is worthwhile to provide some reviews on this area. The insight of non-dominated solutions provided by this method however leaves the final decision to system planners and operators and open to interpretation by different parties.

3.6 Extension of OPF based planning tools

The challenges of effectively planning DG integration arise from various aspects, such as the variability of generation, its coincidence with demand and also the adoption of emerging ANM techniques. In general, it can be inferred that more effective and accurate modelling techniques are required to represent the interaction between DG, network and ANM techniques, and therefore to determine the correct balance in terms of capacity and siting that will maximize the total hosting capacity but minimise the negative effects. It has drawn attention in several works but still needs to be further developed. The development of appropriate application of OPF techniques would enhance the study of DG planning and provide potential to evaluate a range of new ANM techniques.

One driver of advancing the OPF techniques is to make it possible to analyse extensive aspects of DG. OPF could be tailored to cater not only for compliance with thermal and voltage limits but also other relevant planning standards and codes [132]. The work in [107] embedded security of supply constraints (N-1 security) to determine the maximum DG capacity able to connect to a given network. Under similar objective functions, voltage step change and fault level was incorporated in [54] and [53]. By embedding these network constraints, improved optimal solutions can help DNOs and DG developers make sound decisions. However, in the body of work the harmonic current emissions from power electronic converter-interfaced wind turbines are largely neglected in planning studies. The increased renewable DG unlocked by ANM means harmonics might become a critical limit on the hosting capacity. The extension of hosting capacity studies to embed harmonics is essential for DNOs and DG developers. The work on this issue is presented in Chapter 5 of this thesis, where a harmonic constrained OPF is developed for DG planning.

Another demand of extending OPF based hosting capacity studies is to evaluate a wide range of alternative integration solutions, such as ANM, energy storage and demand response. These ANM techniques have been rapidly developed recent years. Their impact on the hosting capacity is worthwhile being addressed so that the deployment of these advanced techniques can be optimised to facilitate DG integration. At the time of commencing this research, not all existing smart grid techniques are thoroughly considered in the hosting capacity studies, of which this thesis will pick out two missing aspects, active generation curtailment and energy storage to fill the gaps in the knowledge of hosting capacity.Several studies ,such as

[20] by Ochoa *et al.*, [86] by Currie *et al.* and [27] by Vovos *et al.* indicate that the DG planning capacity can be increased by incorporating ANM techniques. It also provides a firm foundation for further multi-period OPF research.

Although generation curtailment is a widely mentioned ANM approaches to deal with the constraints arising from increased DG connected, its impact on planning connections is not yet fully analysed. Whilst several operational methods of minimising curtailment with a known set of DG generators have been proposed [69, 114], the evaluation of hosting capacity with different curtailment priority rules is generally neglected and highly complex. Any generator intending to connect with a non-firm connection will need to undertake very detailed estimation of their actual generation and therefore test the investment viabilities. Understanding this issue requires approaches for rapidly identifying the hosting capacity under different ANM access rules. Chapter 4 of this thesis presents an extension of multi-period OPF method to compare the differing influence of ANM priority schemes.

ESS is also a standing issue for hosting capacity studies. While the rapid development of ESS might increase the hosting capacity without wasting otherwise curtailed energy [95]. The challenge of maximising the benefits from ESS supported DGs is not yet solved. ESS characteristics (such as charging state, battery size, charging/discharging power, charging efficiency) can considerably increase the complexity of OPF formulations [99]. The modelling of inter-temporal links between different time periods over the control horizon is generally required [133]. The proposed method of embedding ESS into planning tools is presented in Chapter 6, where DG and ESS can be simultaneously optimised at the planning stage.

3.7 Chapter summary

This chapter discusses a number of key issues that arise from facilitating the integration of DG into the distribution network. First, the transition towards an active integration philosophy is illustrated. Then, as enablers for more cost-effective planning solutions, smart grid technologies are outlined. The characteristics of effective planning approaches are also conducted. For a fair assessment, the term “hosting capacity” is introduced as an indicator of optimal integration solutions. A literature survey of optimisation technologies that can be utilised for hosting capacity analysis are presented with a focus on OPF-based methods, since they are flexible and extendable to meet the requirements of effective planning tools.

Finally, three separate but related areas of work are identified in which research in this thesis can provide contributions: (1) assessing the influence of curtailment priority rules on hosting capacity; (2) considering grid codes on harmonic distortion limits in hosting capacity analysis; (3) evaluating the value of energy storage systems on improving hosting capacity. The thorough studies on these topics are presented in following chapters of this thesis.

Chapter 4

Influence of DG Curtailment Priority Rules on Assessment of Hosting Capacity

4.1 Introduction

The integration of DG imposes significant challenges on the distribution network. In most cases, the challenges arise from the lack of coincidence between output and demand [19]. The increased DG capacity especially worsens the concern of reverse power flow, causing voltage rise and thermal overload issues [24]. To tackle these issues, most DNOs in the UK limit the installed capacity of DG according to the ‘worst-case’ conditions, typically the coincidence of maximum generation and minimum demand. The DG under this connection arrangement is referred to as ‘firm’ DG and is able to generate at its full capacity largely regardless of load conditions.

The firm connection guarantees the network can operate without additional active control requirements but it restricts the network hosting capacity due to the infrequent occurrence of the worst case conditions. The issue for firm DG connections was highlighted by the work of the UK’s Embedded Generation Working Group in the early 2000s [134]. DG expansion under the firm connection arrangement may easily provoke costly network reinforcements that are fully or partly paid by the developers. The costs can make potential schemes substantially less attractive or even impede the development of DG.

In order to facilitate DG connections at distribution level, alternative arrangements and constraint management methods are required. A ‘Non-firm’ connection approach has been used to tackle the restrictions arising from firm connections [86, 89]. Under non-firm connections, the DNO reserves the right to reduce the output of generators. Through trimming or tripping units during low demand periods enabled by ANM systems, larger generators can be connected while network parameters remain within limits.

Operating ANM schemes for non-firm connection requires that DGs are curtailed on the basis of priority schemes [89, 114]. Several settings of the priority rules have been proposed.[85, 89]. Techniques were also developed to implement selected schemes [87]. While these implementations have been proved by successfully maintaining network limits under high level of DG penetrations, they only tackle the issues at the operational stage with given DG capacities. How curtailment strategy impacts DG planning and network expansion, i.e. most available and viable hosting capacity to be connected under various priority rules, is largely neglected. Without a clear method to evaluate the long-term impact of different curtailment schemes, the operation of ANM has significant risks of reactively using curtailment to manage the unnecessary constraints, which are introduced by inappropriately sited DG. How to determine the optimal capacity of DG considering different curtailment priority rules remains an unsolved problem prior to this work.

This chapter presents a methodology for evaluating the impact of non-firm connections considering different priority rules. The process is simplified using the optimal planning of ‘network hosting capacity’ as a guide. The impact of priority schemes on hosting capacity is studied from both technical and economic aspects. Besides the overall optimisation of the network, the ownership differences between DGs in deregulated electricity markets are also taken into account. The compensation between DGs and the impacts of priority schemes on the enhanced network capacity are considered.

The chapter begins with a discussion of priority rules for non-firm connections. Then a literature survey of techniques and methodologies for implementing these priority settings with ANM operation is presented. Earlier work on determining DG capacity allocation using multi-period OPF techniques is reviewed in detail, which provides the foundation to extend the hosting capacity study. Then, various priority rules of curtailment are modelled under the framework of the multi-period OPF. The approach of explicitly linking hosting capacity to the financial consequences of different priority schemes is proposed. Case study and performance assessments on example networks are also presented. Finally, the chapter summarises the methodology and application of the proposed techniques.

4.2 Curtailment priority rules for multiple non-firm connections

Under non-firm connections, the outputs of multiple DG are governed by a set of priority rules that dictate the order and sharing of the curtailment between each DG. The priority rules are also known as ‘Principles of Access’ (PoA) in other studies [98, 135-137]. Priority rules can be regarded as the core part of the curtailment strategy. In managing voltage and thermal constraints, priority rules largely determine the actual curtailment from DG units and therefore influence the viability of connection plans [138]. Several priority rules have been mooted including ‘last in first out’ (LIFO), ‘proportional reduction’ and the ‘most technically appropriate’ rule. The principle of these priority rules is outlined in this section and followed by detailed review of their implementation techniques in the next section.

4.2.1 Last In First Out

Based on the practice in UK, the most well-known curtailment strategy for non-firm connections is LIFO, where the last unit connected to the network is the first to trim or trip. This approach is adopted by Active Power Flow Management (APFM) developed by Ault *et al.* [72] and Currie *et al.* [85-88, 139]. Boehme *et al.* [69] used a pseudo-price-based approach to realise a similar LIFO-based OPF method. An ANM system using LIFO scheme is currently used in the Orkney Islands.

The LIFO rule is straight forward to implemented and simple to administrate. Using this approach, the operation of early DGs will not be affected by the network constraints introduced by later connections. Since earlier DG connections will enjoy preferable treatment, LIFO obviously encourages DG developers to complete to propose connection requirements, in order to avoid curtailment and maximise their output. However, the connection result is not necessarily the most technically or economically efficient way of managing the network as a whole.

The risk with LIFO is that the last connection may be located at a network position where reducing the output of the DG has less impact on managing network constraints [89]. In other words, the same voltage or thermal control could be made by other DG with less curtailment. Under certain conditions, inappropriate LIFO schemes may reduce or ‘sterilise’ available hosting capacity for latter connections by over curtailing their production to an uneconomic level.

4.2.2 Proportional Reduction

As LIFO favours early connections, it may be considered unfair to later connections with reduced available hosting capacity and economic viability. The approach of proportional reduction is designed as that, where all DG are treated equally as network users and contribute the same impact to network constraints [89]. Once the network experiences constraints, the proportional reduction rule requires all non-firm DG to reduce the same percentage of its output to solve the issue. The sharing could be also be set with respect to its full rating [136], which generates the same reduction in capacity factor for all DGs.

The proportional reduction rule is effective to reserve a fair share of hosting capacity for later DG by reducing the output of early connections. However, it can be expected that more curtailment will occur when DG connections increase. Early installed DG is exposed to the risk of curtailing an increased proportion of its output through DG expansion. This uncertainty for economic viability could discourage the development of DG.

4.2.3 Most technically appropriate scheme

Both LIFO and proportional reduction ignore the technical differences of DGs and therefore fail to consider the management of constraints in the overall most electrically efficient way. Contributions to network constraints are generally different among DGs, which implies that the last connected DG may be sited at the location where managing the output of DG has less impact on relieving network constraints. Curtailing a small amount on an existing DG elsewhere which is beyond the allowance under LIFO or proportional schemes might be more efficient to relieve the constraint, therefore benefitting the later connections without heavy loss of generation and minimising the total curtailment. It has been shown separately in [89, 114], that the DGs with the best technical ability to manage network constraints are selected to be constrained first.

4.3 Literature survey on non-firm connection studies

The way to implement the access rules outlined in previous section is various. A range of evaluation techniques and optimisation methods were adopted to assessment of curtailment under various access and avoid the unnecessary loss of output. The operation of non-firm connections using operating margins, sensitivity factors and OPF techniques is reviewed in this section. The lack of effective planning tools to evaluate non-firm connection options considering the long term impact of priority rules is concluded.

4.3.1 Operation margin method

Currie *et al.* [86] proposed a LIFO-based curtailment scheme using pre-set operating margins to trim non-firm DG units. The operating margin takes account of the worst case scenario of load and generation. When the early installed DGs all raise their outputs at the maximum ramp rates while at the same time load ramping down at the largest possible rate, the network experiences the overall biggest export ramping. Substituting the curtailment rate of the non-firm DGs from this total ramping up value, the MVA size of the trim operating margin can be determined.

To prevent the export breaching the thermal limit or causing the protection systems to act, the real-time power flow is continuously measured against the threshold of trimming. Once the power export at critical points reaches operational margins, the last connected DG units will be curtailed at the rate according to the connection arrangement. If the power flow still exceeds the operation margin after a given response time, the second last connected DG will be curtailed sequentially.

The adoption of operating margins in LIFO presents a practical ANM system. It has been proven by the application on the Orkney network [85]. However, the margin of trim and the amount of curtailment are calculated on the worst case that occurs very infrequently, rather than the network actual condition, and therefore could lead to unnecessary curtailment.

4.3.2 Sensitivity method

Zhou and Balek [114] and Jupe *et al.* [89] both used the sensitivity method to determine the curtailment that would be required to mitigate constraints. The work in [114] applied the method to solve voltage rise issues while the thermal overloading is the main concern in [89]. Given the required changes on the network binding constraints, the method employs sensitivity factors which relate the changes to the curtailment of DG output. The values of sensitivity factors are derived from the inverse Jacobin matrix using a full AC load flow solution. The factors are calculated for each non-firm DG with respect to the thermal overloading of lines ($\partial P_l / \partial P_g$) or the voltage variation at buses ($\partial V_b / \partial P_g$). Various priority schemes can be implemented using the sensitivity method:

- For the adoption of sensitivity method to calculate curtailment under LIFO rule: in the case of managing thermal overload at line *l*, the curtailment ΔP_g on DG g^{last} (the last connected DG, itemed as g^{last}) is:

$$\Delta P_g = \frac{\Delta P_l}{\partial P_l / \partial P_g} \qquad g = g^{last} \tag{4.1}$$

where ΔP_l is the required change in real power flowing through the constrained branch l .

- For proportional reduction, the shared curtailment percentage on all non-firm DG could be calculated based on the sensitivity factors. Weighting by sensitivity factor as in (4.3), those generators making more impact on the constraints would be equated with more curtailment. In the case of managing thermal overload at line *l*, the required curtailment on each DG *g* that is participated in the output control scheme (itemed as $\forall g \in G$) is:

$$\Delta P_g = P_g \times \phi \qquad \forall g \in G \tag{4.2}$$

$$\phi = \frac{\Delta P_l}{\sum_{g \in G} ((\partial P_l / \partial P_g) \times P_g)} \tag{4.3}$$

where P_g is the pre-curtailment output of DG *g*, φ is the same reduction percentage that will apply to all non-firm connected DG.

- For more technically appropriate curtailment, it is logical to minimise the total curtailment based on the sensitivity factor ranking. The DG with the highest sensitivity factor indicates the best technical ability to manage network power flows, and therefore is selected to be curtailed first. In the case of managing thermal overload at line *l*, The required curtailment on DG g^{best} (the DG with highest sensitivity factor is item as g^{best}) is:

$$\Delta P_g = \frac{\Delta P_l}{\partial P_l / \partial P_g}, \quad g = g^{best} \tag{4.4}$$

While the sensitivity method can be applied to operate different curtailment schemes, there are two main concerns about its adoption. First, sensitivity factors depend on the network operational conditions, but the intermittent nature of renewable DG implies that the power flow and voltage profile in the network can vary frequently. The sensitivity factors therefore need to be recalculated every time network conditions change, which means a number of repetitive sub-calculations. Moreover, if more than one constraint is concerned, their interacting relations with DG output cannot be easily simplified in a linear way. As pointed out by Zhou *et al.* [114], curtailment based on the sensitivity factor rank is better than proportional reduction rules but it is still not the optimal solution. Managing multiple constraints through curtailment would require solving an optimisation problem.

4.3.3 OPF based method

OPF based approaches has also been proposed to evaluate DG curtailment under non-firm connections. When constraints are identified from installed DG and need to be solved through curtailment, the issue can be generalised as an optimisation problem aiming at minimizing the total curtailment as follows:

$$\min \sum_{g \in G} Curt_g \tag{4.5}$$

where $Curt_g$ is the curtailment on the g^{th} DG unit DG g. The realisation of the OPF depends on the priority settings and is formulated in a different manner among studies.

Boehme *et al*. [69] analysed the curtailment of extensive renewable generation subject to both thermal and voltage constraints. The proportional scheme is modelled using stepwise reductions using a load flow engine and the most technically appropriate reductions determined by OPF with the dispatch of each DG being based on equal (pseudo) costs for each renewable generator.

Dolan *et al.* [135] adopted OPF to develop an online technique to manage thermal constraints. The priority arrangement is based on LIFO and formulated by allocating different values to generator cost reflecting its connection order. It optimises the curtailment while maintaining LIFO rights by curtailing more from “expensive” DG which represents the later connected units. The control robustness of the OPF approach with regard to its application on a real time online operation is further discussed and demonstrated in [137].

OPF techniques also enable other ANM techniques to be evaluated alongside curtailment. By embedding additional ANM schemes to facilitate the constraint management, curtailment is expected to be further reduced [20]. Gill *et al.* [98]

developed a dynamic optimal power flow (DOPF) that integrates time dependent variables into the standard OPF formulation. Based on the DOPF a day-ahead schedule aiming to minimize the curtailment of non-firm connections using energy storage and flexible demand is presented.

Capitanescu *et al.* [140] comprehensively modelled a wide range of possible controls in the OPF to minimise the required curtailment. The benefits of comprehensive curtailment optimisation are demonstrated on a snapshot basis. This work show the total curtailment can be further reduced when alternative control techniques effectively solve network constraints and only adopting curtailment as the last resort.

Overall, all techniques reviewed in this section proved to be effective in determining curtailment and solving operational constraints. But how these various access rules can impact the hosting capacity has not been not clearly tacked. These studies are still within the spectrum of reactive integration: reactively using curtailment to manage network constraints, which might be introduced by inappropriately sited DG and can be avoided through better planning. To obtain the curtailment-wise hosting capacity, the objective function needs to be re-formulated from minimising the curtailment ($Curt_g$) for operating installed DGs to maximising the planned DG capacity (P_g) by properly considering curtailment priority setting from the technically or economically optimal points of view. The following sections present an optimisation approach developed to evaluate the long term impact of curtailment schemes on hosting capacity.

4.4 Framework for multi-period OPF based hosting capacity analysis

In this section, the multi-period OPF (MOPF) established in this thesis for hosting capacity assessment is reviewed in detail. The MOPF-based technique lays the basis for the extension of hosting capacity study in next section to consider the financial consequences of different priority schemes.

When a DG developer is looking to connect to a network that offers non-firm connection options, they will need to undertake very detailed assessments of the likely output of other generators and the resulting power flows in order to estimate their own likely generation and extent of curtailment. These values depend on the capacity of already connected generators, resource levels at each location, the technological and economic characteristics of the DG and any access rules governing operation of the ANM. Should it be present, the complexity of networks and competition for network access among developers makes this process challenging. It may be simplified using the network ‘hosting capacity’ as a guide. The work here uses hosting capacity as a proxy for the ease of integration of DG at one, multiple or all connection points whilst satisfying the considered constraints.

OPF techniques can be developed to allow the effective evaluation of hosting capacity. Ideally, the OPF should be able to directly embed the full time-series of generation and demand data to represent network operation conditions for each period. However, this introduces a significant number of time-varying variables and correspondingly additional constraints into the optimisation. The explicit time-series OPF could create a large computational burden by attempting to find a unique inter-temporal solution across the whole period. For example, a set of hourly data for 1 year will generate 8760 scenarios to be considered simultaneously in the optimisation. It means that a study on even a relatively small section of the distribution network is laborious. As such, evaluating the hosting capacity requires a means of effectively dealing with the problems of multi-dimensionality without unduly increasing the associated computational burden.

To efficiently adapt the OPF approach to hosting capacity analysis, a multi-period AC OPF using a nonlinear programming (NLP) formulation was developed by Ochoa *et al*. [20]. It is applied to determine the maximum DG capacity able to be connected to a given network. The multi-period OPF approach is adapted and further developed in this work catering for generation under various network control and priority schemes.

Multi-period OPF reduces the computational burden of a full time-series analysis by aggregating generation availability and demand into a manageable number of generation/demand scenarios based on their joint probability of occurrence. This is illustrated in Figure 4.1 where the original (top) hourly demand and wind power data for Scotland [21] is discretised by rounding to the mean value of its nearest bin range (bottom; arrows indicate hours where demand is 0.7pu and wind is zero).

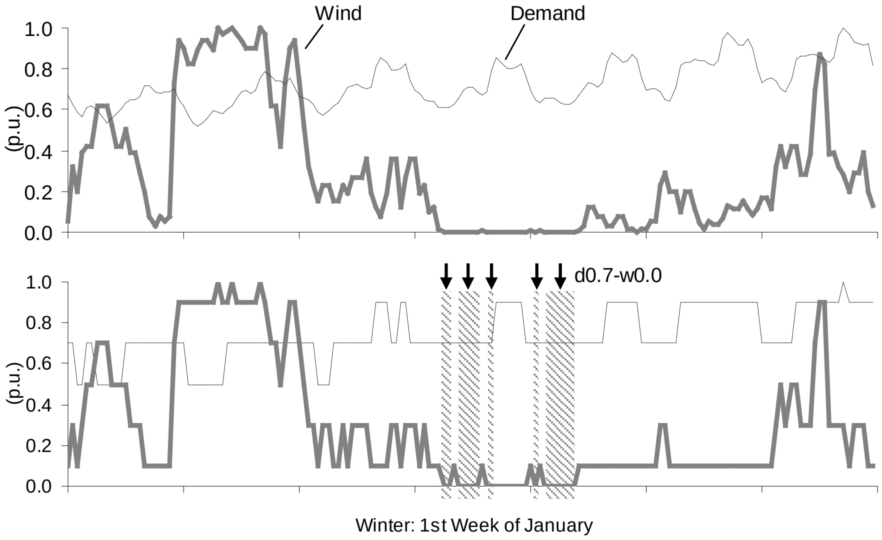


Figure 4.1 (top) Winter week hourly demand and wind power for central Scotland, 2003; (bottom) Discretised data processed before aggregating the coincident hours of each demand-generation scenario [21].

The "duration" of each scenario τ_m is the number of total coincident hours which it represents across the whole time period *M*. Figure 4.2 illustrated an example of these multiple scenarios for 1 year. By adopting the aggregation process, the original time-series data are broken into a series of bins: ten ranges for demand and eleven ranges for generation are used. After the aggregation, only 74 non-zero scenarios are effectively left (demand is never below 0.35 pu) and need to be considered in the analysis.

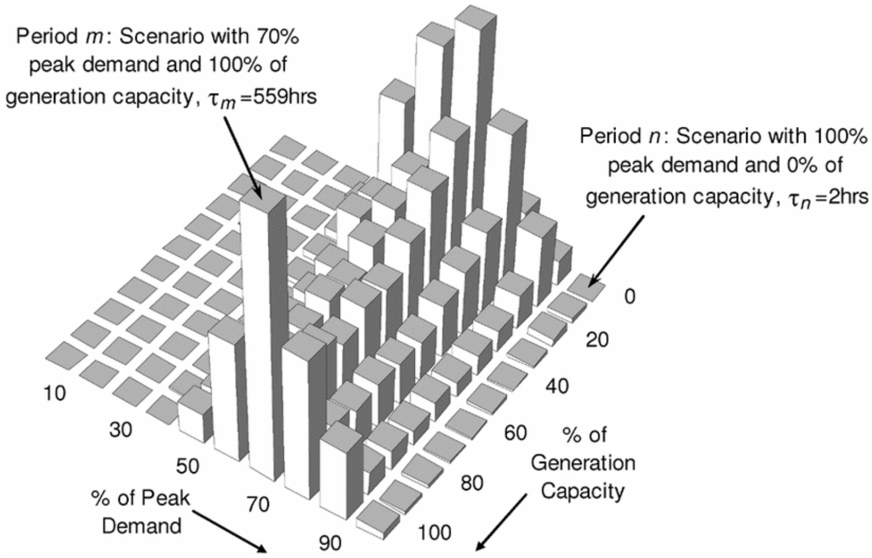


Figure 4.2: Illustrative example of multiple periods [20]

The application of multi-period OPF for maximizing hosting capacity can be formulated as follows

$$\max \sum_{g \in G} P_g \tag{4.6}$$

where P_g is the capacity of generator g. The multi-periodicity across the set of periods M is introduced and achieved by varying power flow variables with time (indexed by m). A unique, inter-period set of generation capacity variables is used throughout the analysis. This is shown schematically in Figure 4.3.

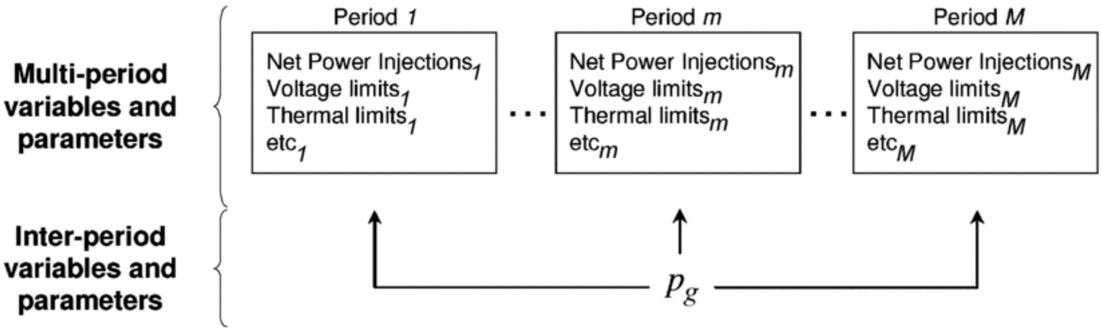


Figure 4.3: Multi-period interdependency in multi-period AC OPF [20]

The multi-period AC OPF is subject to a set of constraints representing the network characteristics such as voltage limit, thermal limits and power balance:

1) Voltage level limits:

Voltages at bus b ($b \in B$, set of buses) are constrained by max/min levels $V_b^{(+,-)}$:

$$V_b^- \leq V_{b,m} \leq V_b^+, \quad \forall b \in B \tag{4.7}$$

2) Thermal limits:

Constraints on the flow at each end of lines and transformers, l ($l \in L$, set of lines L):

$$\left(f_{l,m}^{(1,2),P} \right)^2 + \left(f_{l,m}^{(1,2),Q} \right)^2 \leq \left(f_l^+ \right)^2, \quad \forall l \in L \tag{4.8}$$

where $f_{l,m}^{(1,2),P}$ and $f_{l,m}^{(1,2),Q}$ are the active and reactive power injections at each end of the branch (denoted 1 and 2) and f_l^+ is the apparent power flow limit on the branch.

3) Real and reactive nodal power balance:

Kirchhoff's current law [38] describes the active and reactive nodal power balance, β indicate the connection bus of line or generator.

$$\sum_{l \in L | \beta_l^{1,2} = b} P_{b,m}^{\mathrm{L}} + D_b^P \eta_m = \sum_{g \in G_b | \beta_g = b} P_g \omega_m + \sum_{x \in X | \beta_x = b} P_{x,m} \tag{4.9}$$

$$\sum_{l\in L|\beta_l^{1,2}=b} Q_{b,m}^{\mathrm{L}} + D_b^{Q}\eta_m = \sum_{g\in G_b|\beta_g=b} P_g\omega_m \tan(\phi_{g,m}) + \sum_{x\in X|\beta_x=b} Q_{x,m} \tag{4.10}$$

where $P^{L}_{b,m}$ and $\mathrm{Q}^{L}_{b,m}$ are the total power injections onto lines at bus b, (i.e., $f_{l,m}^{(1,2),P}$ + $f_{l,m}^{(1,2),Q}$); and D^{P}_{b} and D^{Q}_{b} are the peak active or reactive demands at same bus. In period m, η_m is the demand level relative to peak and ω_m is the generation level relative to nominal capacity as dictated by the variable (renewable) resource in that period. The set X represent the external connections in the network, including the grid supply point (GSP) substation as well as interconnectors. The import/export constraints at the GSP or interconnector x are:

$$\begin{aligned} P_x^{-} \le P_{x,m} \le P_x^{+} \\ Q_x^{-} \le Q_{x,m} \le Q_x^{+} \end{aligned} \qquad \forall x \in X \tag{4.11}$$

To evaluate various curtailment schemes under the multi-period OPF framework, new variables and the corresponding constraints are required. The value of the power curtailment is formulated by adding an extra time-dependent variable $P_{g,m}^{curt}$, to act as negative generation at the same location of non-firm connected DG unit. The actual delivered power generation $P_g\omega_m$ from DG unit g in constraint equations (4.9) and (4.10) will be replaced by $(P_g - P_{g,m}^{curt})\omega_m$ to give

$$\sum_{l\in L|\beta_l^{1,2}=b} P_{b,m}^{\mathrm{L}} + D_b^{P}\eta_m = \sum_{g\in G_b|\beta_g=b} (P_g - P_{g,m}^{curt})\omega_m + \sum_{x\in X|\beta_x=b} P_{x,m} \tag{4.12}$$

and

$$\sum_{l\in L|\beta_l^{1,2}=b} Q_{b,m}^{\mathrm{L}} + D_b^{Q}\eta_m = \sum_{g\in G_b|\beta_g=b} (P_g - P_{g,m}^{curt})\omega_m \tan(\phi_{g,m}) + \sum_{x\in X|\beta_x=b} Q_{x,m} \tag{4.13}$$

Physical meaning, the curtailment $P_{g,m}^{curt}$ should not exceed the output of $P_g\omega_m$ at the corresponding period, hence

$$P_{g,m}^{curt} \le P_g\omega_m \tag{4.14}$$

In terms of embedding curtailment priority rules, it has not been comprehensively studied. The analysis in [20] assumed controls would accommodate DG in the technically most effective manner and the extent of curtailment was limited to a pre-specified proportion of energy generation in order to avoid excessive curtailment and unreasonable volumes of capacity added. However there was no explicit consideration of whether curtailment was economically viable nor did it cover other priority schemes.

4.5 Extension of hosting capacity study for non-firm connections

In this section, the methodology for determining hosting capacity under various priority rules is developed. Key factors including ownership differences and the compensation mechanisms are also explained. The generalised procedure to apply the proposed evaluation methodology is summarised.

The new development on the earlier MOPF based work is the re-framing of the hosting capacity problem such that it is driven by the financial viability of DG as determined by its capacity, the curtailment priority rules and the extent of curtailment. The optimal hosting capacity P_n is measured by maximising its economic return (RE) across the lifespan ($\max RE$).

4.5.1 Objective function of maximising the economic return

In evaluating non-firm connection arrangements on hosting capacity, especially estimating their impact of economic viability for DG development projects, it is important to clarify the DG’s ownership first. The ownership substantially affects the optimisation objectives by determining to whom the costs of curtailment would be charged and who would benefit from the increased output.

4.5.1.1 Network view

If DGs are owned by the DNOs, or DGs are owned by developers but the overall improvement of the network is preferred, the evaluation of curtailment schemes can be made by only examining the total returns *RE* from all DGs ($g \in G$). The fairness issues rising from LIFO and the most technically appropriate scheme largely disappear since there is no competition among DGs. The objective function becomes:

$$\max \sum_{g \in G} RE(P_g) \tag{4.16}$$

Where $RE(P_g)$ is the economic return of the g^{th} DG unit in term of it power rating.

4.5.1.2 Individual DG view

In the UK and most European countries, however distribution is an unbundled business. DGs are not owned by DNOs. The different ownership of DG associated with individual developers implies competition for access to hosting capacity. Given rational economic behaviour, each DG developer will aim to maximise its own financial return from electricity sales. This objective can be met with increased installed capacity but it is influenced by the curtailment priority rule, especially when the network hosting capacity has been largely utilized by earlier connections.

The ownership differences make the issue of fairness important. The adoption of curtailment rules would need to include a compensation mechanism, especially where DG has been connected on a firm connection basis and its reversion to non-firm operation would deliver substantial increases in output overall. The objective function becomes:

$$\max\{RE(P_g)\} - E_{com} \tag{4.17}$$

where E_{com} is compensation payment.

4.5.1.3 Generalised objective function

To represent both ownership scenarios, the objective function in (4.15) is generalised as:

$$\max \sum_{g} \{(RE(P_g) - E_{com})\}\kappa \tag{4.18}$$

where annuity factor κ is used to convert lifetime return into net present value (NPV). The embedded compensation E_{com} would be modified based on the ownership conditions and the curtailment priority schemes. By choosing different sets of g in the formulation, both the network overall optimisation and optimisation for each separately owned DG can adopt the generalised objective function. These are:

$$\begin{array}{ll} \textit{the set of all DG}: & g \in G \\ \textit{the set of new DG to connect}: & g \in N \\ \textit{the set of installed DG}: & g \in G \mid g \notin N \end{array} \tag{4.19}$$

The economic return of DG, denoted as $RE(P_g)$ is obtained by subtracting the cost of installations, operations and maintenance from the revenues of selling the generated electricity. In the multi-period OPF, the annual energy produced is formulated as

$$\sum_{m \in M} (P_g \omega_m - P_{g,m}^{curt})\tau_m \tag{4.20}$$

where across the whole year period M (indexed by m), P_g is the optimal capacity of DG g. In period m, ω_m is the generation level determined by renewable resources, $P_{g,m}^{curt}$ is the extent of energy curtailment of DG g and τ_m is the duration of period m. Accordingly, the annual economic return before any compensation can be formulated as:

$$E_{ret,g} = \sum_{m \in M} \{(P_g \omega_m - P_{g,m}^{curt})\, \tau_m \cdot (R_{wholesale} + R_{sub})\} - C_{inv} - C_{om} \tag{4.21}$$

where the electricity price R includes the subsidy mechanism R_{sub} as well as the wholesale price $R_{wholesale}$. The DG costs are a function of DG capacity: capital cost

C_{inv} and operations and maintenance cost C_{om}. The formulation can be extended to include the implementation cost of ANM techniques as well, although that is omitted here for clarity. Therefore, the complete form of the objective function aiming to maximise the net present value of economic return from considered DGs across the lifespan is given as:

$$\max \sum_{g} \{ \sum_{m \in M} (P_g \omega_m - P_{g,m}^{curt})\, \tau_m \cdot (R_{wholesale} + R_{sub}) - E_{com} \} \kappa - C_{om} - C_{inv} \qquad (4.22)$$

The optimisation is subject to a range of network constraints: real and reactive nodal power balance, voltage level constraints and thermal limits. While the constraint formulations (4.7) - (4.14) in the previous section can be directly adopted in here, extra constraints to represent the priority rules are needed if there are to be accounted for. Different from the hosting capacity formulation in [20] which limited the total amount of curtailed energy for each DG, here the economic performance and curtailment priority strategies act as the constraints.

4.5.2 Constraints for curtailment priority strategies

The development of the constraint modes to represent curtailment priority rules is presented in this section. Three strategies are considered and embedded into the OPF formulation:

4.5.2.1 LIFO

The aim of the LIFO arrangement is to avoid or reduce the risk of extra curtailment being imposed on an earlier installed DG by the later ones. In the operational context, by curtailing the last connection first, earlier connections are able to continue to output in the same way as before connecting the new DGs. To achieve the same principle in the planning stage, an extra constraint is added in the optimisation to ensure the preferable treatment of earlier DG connections over later connections by maintaining the capacity factor of installed DG:

$$\frac{\sum_{m\in M}(P_g\omega_m - P_{g,m}^{curt})\tau_m}{\sum_{m\in M}P_g\tau_m} \geq \alpha_g^{prev}, \qquad \forall g \in G \,|\, g \neq N \tag{4.23}$$

Here, the output factor of existing DG (indexed by $\forall \mathrm{g} \in \mathrm{G} \,|\, \mathrm{g} \notin N$) after the connection of new planned DG is limited by a low value α_g^{prev}, which can be equal to the same level before the new connection or adjusted based on the resource forecast and other incentives. The output factor is defined as the ratio of actual production after curtailment to the potential. This is similar in principle to capacity factor but not identical as its denominator already accounts for the resource variability.

Since the LIFO rules aim to maintain the generation of early installed DG and isolate it from the impacts introduced by new DG, the preferential treatment means it is not necessary to compensate the curtailment that already occurred before the new DG connecting to the network. As such E_{com} in objective function (4.18) is assumed as zero and neglected.

4.5.2.2 Proportional reduction

Proportional reduction rules treat all DGs equally as network users contributing the same impact to network constraints. Output factor is also used as the guide to define the long term impact. The proportional reduction scheme is modelled as a constraint that all non-firm DGs reduce by the same percentage of their output factors as a result of curtailment. Thus

$$\frac{\sum_{m\in M}(P_g\omega_m - P_{g,m}^{curt})\tau_m}{\sum_{m\in M}P_g\tau_m} = \alpha^{shared}, \qquad \forall g \in G \tag{4.24}$$

All DG including the already connected and new planned DG share the same reduction percentage α^{shared} calculated across the whole time period *M*. Since the increasing penetration may require the previous connections to share the cumulative curtailment and reduce their output to an uneconomic level, a sound limit of the reduction is introduced to avoid uncertainty and encourage developers. The constraint of maximum reduction α^{upper} is given as

$$\alpha^{shared} \leq \alpha^{upper} \tag{4.25}$$

Similar to LIFO, there is no compensation between DG due to the philosophy of equally treating all DG as network users. It is also important to highlight that although both LIFO and proportional reduction scheme needs a constraint to represent certain priority rules among the DGs in the optimisation formulation, the curtailment setting for each DG and each period is still optimised under this restriction. The difference between the considered schemes here is just limited to this additional control requirement.

4.5.2.3 Most technically appropriate scheme

Different from both the previous schemes, the curtailment of each DG under the most technically appropriate rules is directly optimised by the OPF to maximise the hosting capacity of the last DG, which is represented in economic form. It is relatively simple in the constraints formulation since this control scheme excludes constraints (4.23) to (4.25). However, a concern that has been largely neglected elsewhere is that although the overall performance of network is optimised with minimum curtailment, the loss associated with the curtailment of the early installed DG needs to be recovered in a way [89]. Otherwise, this scheme will impose the risks of reduced output factors on the earlier connections in the long term and discourage development. It is reasonable for later connections to compensate the additional curtailment to a certain extent. Accordingly, the objective function needs to embed the cost of compensation for existing DG as their curtailment benefits the new planned DG. The compensation E_{com} can be formulated as

$$E_{com} = \sum_{m \in M} P_g \tau_m \alpha_g^{prev} - \sum_{m \in M} (P_g \omega_m - P_{g,m}^{curt}) \tau_m, \quad \forall g \in G \mid g \neq n \tag{4.26}$$

where α_g^{prev} is the level of curtailment for the g^{th} DG unit which reflects the network condition before the new connections. The compensation E_{com} actually acts as a constraint to limit the new capacity.

4.5.3 Coordination with other active network management techniques

Whilst controlling DG output under non-firm connection is beneficial in terms of managing network constraints and increasing hosting capacity, curtailment cannot avoid the loss of revenue to DG developers. It is arguably better to consider this as the last resort only when other ANM techniques, such as adaptive control of OLTC or DG power factors, has been exhausted.

The modelling of ANM control approaches within an OPF framework has been outlined in [20, 21]. The formulation here could be extended to include the variety of ANM techniques. While some control means may have discrete behaviour, ANM approaches and their operation ranges can be generally represented as additional control variables and constraints in the optimisation while retaining the main objective function. Coordinated voltage control (CVC) using OLTC is chosen in this chapter to give an example. The secondary side voltage of the substation is treated as variable V_{tr} (*TR* denote the set of OLTC transformers) and dynamically controlled by the OLTC. Its statutory range is correspondingly modelled as:

$$V_{tr}^{\min} \le V_{tr} \le V_{tr}^{\max} \qquad tr \in TR \tag{4.27}$$

4.5.4 Implementation

Due to the non-linear nature of an AC OPF, the modelling environment needs to be able to support non-linear constraints and objectives. The AIMMS modelling software used to develop the hosting capacity analysis model [20, 141] is also adopted in this work. The AIMMS configuration defines the multi-period OPF by the declaration of sets, parameters, variables, constraints and executables. The resultant NLP is solved by AIMMS using NLP solver CONOPT (a generalised reduced gradient solver) [142]. Building on the previous modelling work [20, 21], the new development in AIMMS from this thesis is in reframing the objective function and also adding new variable and constraints to present the different non-firm connection rules. This implementation approach is selected aiming to keep consistency and compatibility with other work in this thesis, and eventually to generate a flexible planning tool with a comprehensive set of functional modules.

4.5.5 Generalised procedure for hosting capacity analysis considering curtailment priority rules

By embedding different connection options, the proposed approach for assessing the impact of priority rules on hosting capacity forms a generalised method to search for optimal DG capacity and obtain the maximum returns. The procedure of selecting the best connection option and determining the installed output of this thesis is summarised in Figure 4.4. Besides the network itself, key factors are highlighted, including the allowed reduction on the capacity factors and the compensation mechanism, which determine the economic viability of non-firm connection options. The final decision as to the connection arrangement will rest with the DG developers and DNOs. The quantified financial return for each available connection options offers a means of exploring approaches to the connection contract.

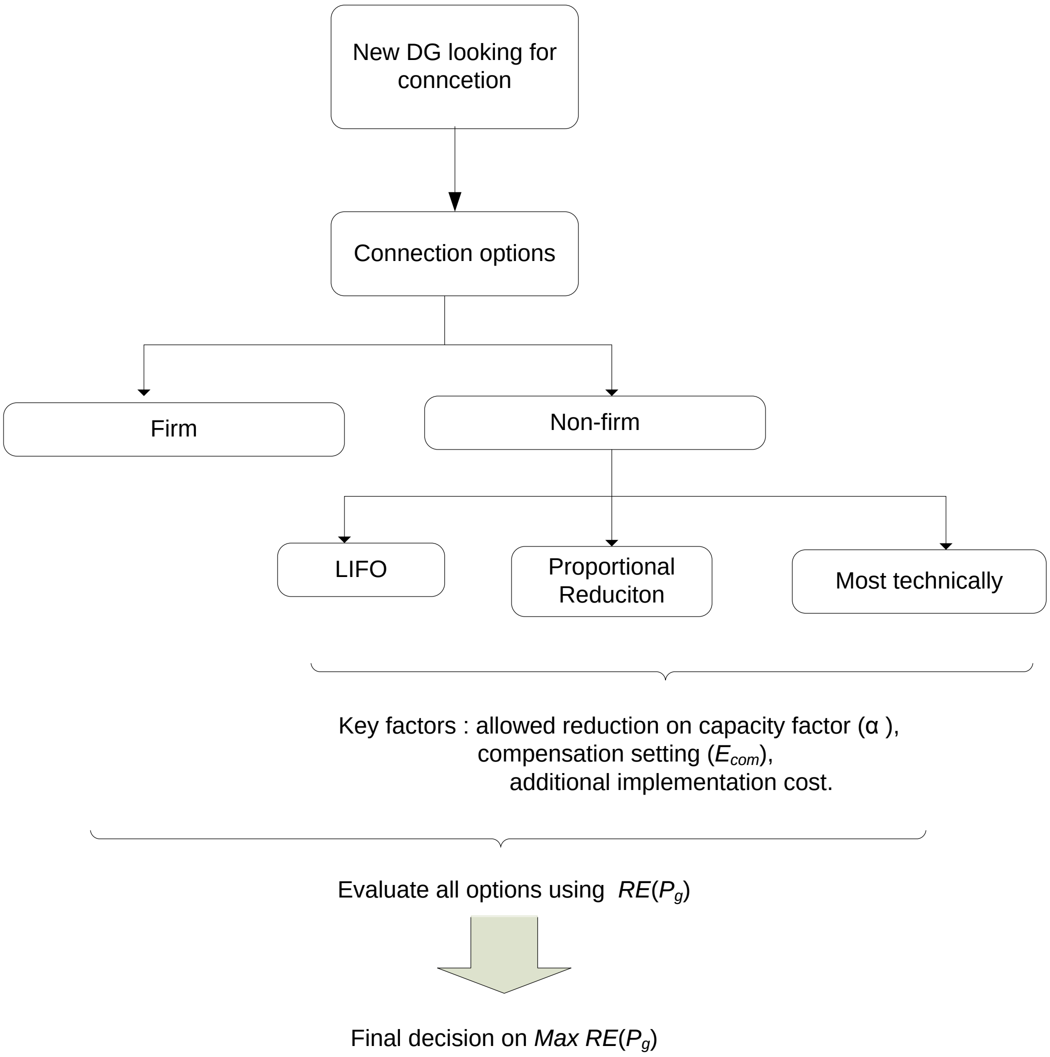


Figure 4.4: Schematic diagram of the procedures to compare connection options

4.6 Case study

4.6.1 Case description

A case study is presented in this section. A typical rural section of a medium voltage distribution network with a weakly meshed topology is used here as a case network. It is based on the Simplified EHV1 Network from the UK Generic Distribution System (GDS) [143]. Selected as it is simple to illustrate and offers the potential to compare with results in [20]. The one-line diagram is shown in Figure 4.5 and the line data is given in [143]. The feeders are supplied by two 30 MVA 132/33kV transformers. The GSP voltage is assumed to be nominal and voltage limits are taken to be ±6% of nominal to reflect UK practice. A voltage regulator (VR) is located between buses 8 and 9, with the latter having a target voltage of 1.03 pu. The maximum demand of the network is 38.16 MW.

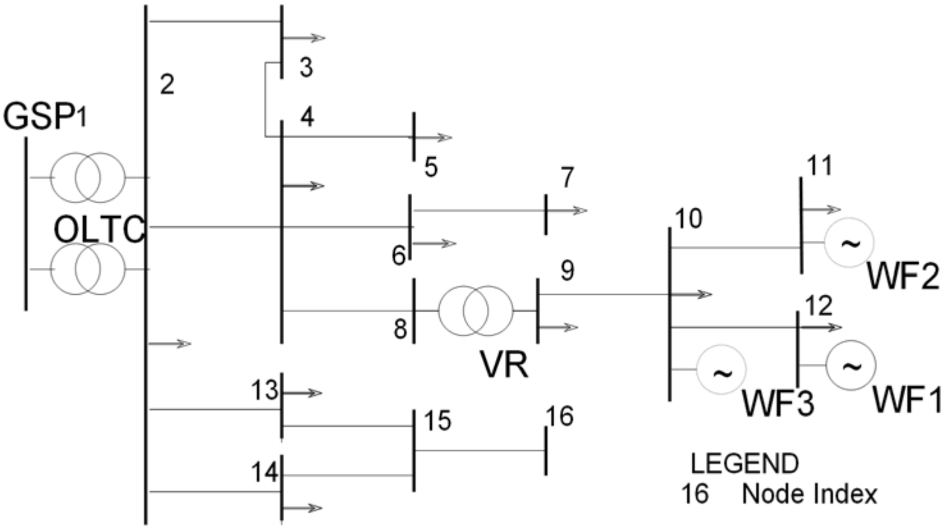


Figure 4.5: Simplified EHV1 Network with wind farm connected

Three potential locations are considered in the network at which DG can be connected: buses 10, 11 and 12. To keep the case study simple, all DG are modelled as wind farms and assumed to be operated at unity power factor. Also, wind Farm 1 (WF1) at bus 12 is assumed to be already installed with 2.8 MW capacity, which is the maximum capacity from a firm connection analysis. For this network, the binding constraint which limits the DG connection is voltage rise at the wind farm buses.

The optimisation of hosting capacity for new planned DG is determined across a year. The half-hour time series data of historical generation and demand level [21] is illustrated in Figure 4.6. These were processed to reduce the computational burden down to 74 representative combinations of generation and demand. The same wind pattern applies at all locations. Each wind farm is assumed owned by a different developer, and correspondingly their aim is to maximise their own economic benefits.

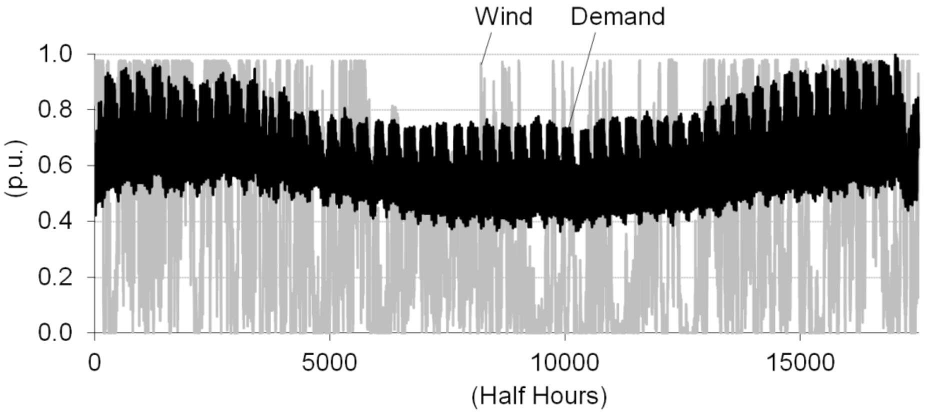


Figure 4.6: Half-hourly wind and demand data

The economic parameters for financial evaluation are given in Table 4.1. The sale of Renewable Obligation Certificates (ROCs) [144] under the current subsidy mechanism in the UK is included alongside the wholesale price of electricity. The estimate of NPV is based on a 20 year lifespan and 10% discount rate (annuity factor of 8.51). For clarity, it is assumed that the resource and demand level remains the same over the project lifetime; this could be extended to include more sophisticated assumptions about inter-annual variation.

Table 4.1: Economic parameters used in financial evaluation

Wholesale price of electrity [145]	£50/MWh
ROC sales price [146]	£51.34/MWh
DG capital cost [147]	£1524/kW
Operation and maintenance cost [147]	£57.2/kW year

To demonstrate the extendibility of proposed framework, an additional ANM scheme, the Coordinated Voltage Control (CVC) using OLTC at the substation (as explained at section 4.5.3) is considered, and correspondingly the voltage at bus 2 in this case is dynamically controlled along with curtailment to mitigate voltage constraints. The OLTC control would be fully utilised before any curtailment occurs, since only the cost of energy loss from curtailment is explicitly included in the objective function and minimized. The impact of alternative priority rules on hosting capacity is expected to be amplified with CVC in the network.

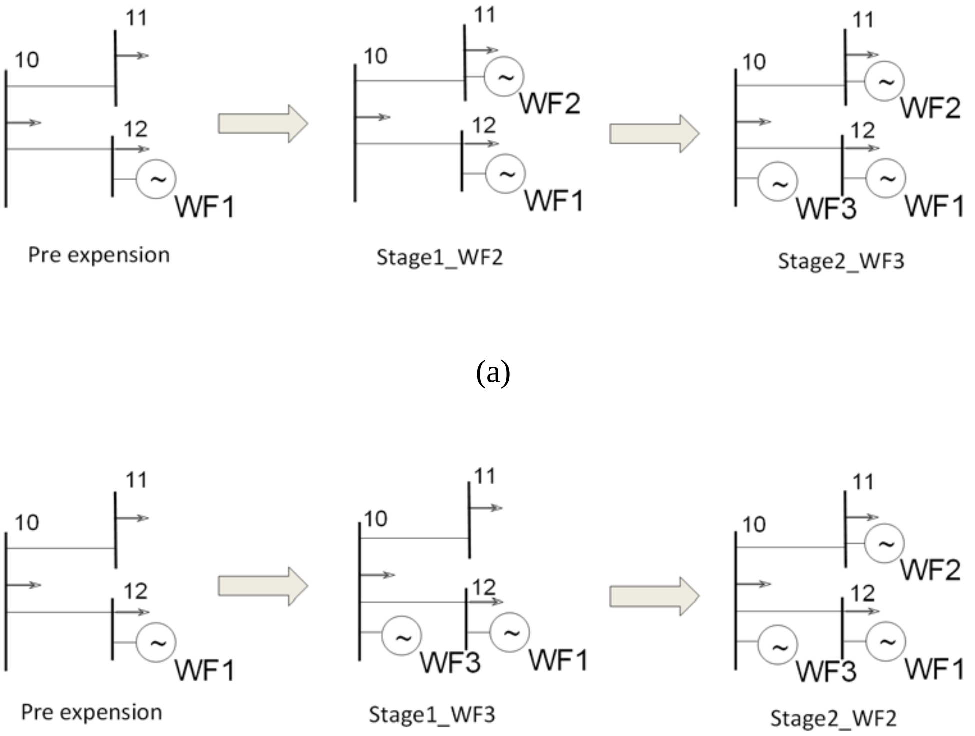
To draw out the importance of the DNO not having direct control over DG connections, two connection sequences are studied to reflect the possible scenarios from separate ownership of WF2 and WF3:

- **Connection sequence A**: WF2 is connected before WF3;
- **Connection sequence B**: WF3 is connected before WF2.

For each connection sequence, the hosting capacity is analysed in two ‘stages’ as outlined in Table 4.2 and also illustrated by Figure 4.7. It means the new DG optimised at the first stage would act as an existing connection which imposes limits on the optimisation of the DG at stage 2. The order of connection sequences means new DGs are competing for non-firm capacity to maximise financial return. The consideration of multi-stage expansion offers a manner to investigate the long-term impact of different curtailment schemes from the network point of view. Note that the ‘stages’ only indicate the connection sequence rather than explicitly defining the connection time.

Table 4.2: Sequences of DG connecting at each stage

Connection sequence	Stage 1		Stage 2	
	Existing	New	Existing	New
A	WF1	WF2	WF1 & 2	WF3
B	WF1	WF3	WF1 & 3	WF2



(a)

(b)

Figure 4.7: Illustration of connection sequence (a) and (b)

A ‘base’ case scenario analyses the optimal capacity of WF2 and WF3 that can be accommodated as firm connections together with the 2.8 MW WF1. This assumes a passive network without curtailment so the “worst-case” condition of minimum demand and maximum generation is the main constraint on capacity. As the ‘Base’ column in Table 4.3 shows the total hosting capacity is just 3.1 MW where only 0.3 MW is left for the connection of WF2 and no further headroom for WF3. It is clear that the already connected WF1 absorbs most of the available hosting capacity for firm connections and ‘sterilizes’ the network for DG connections. Since the limitation on DG capacity is imposed by the “worst-case” conditions, the curtailment of generation during these periods will alleviate the voltage rise constraints allowing installed capacity and overall energy production to increase. The three curtailment strategies together with two connection sequences give a set of six curtailment scenarios to be examined. In the proportional curtailment scheme the maximum reduction in output factor (α^{upper}) is arbitrarily limited to 10%.

4.6.2 Connection sequence A

The results from each scenario for connection sequence A at each stage are presented and compared in Table 4.3. It can be seen that after the two stage connections, all curtailment schemes have much greater overall hosting capacity than the passive network analysis: 3 to 5.5 times larger. With more capacity accommodated, curtailment schemes control production to guarantee that the network operates below the voltage and thermal limits during low demand scenarios. However, the differences of capacities and curtailment percentages between the schemes and among the wind farms in each individual scheme are significant. The technically most appropriate scheme delivers the largest overall capacity. In both LIFO and proportional schemes, WF2 is the largest generator connected resulting in near-zero capacity for the later-connected WF3. However, with the technically most appropriate scheme WF3 is some 60% larger than WF2.

The LIFO scheme protects earlier connections from the effects of later connections, as seen in the zero curtailment of WF1 after connection of WF2. Maximum NPV for WF2 is with a capacity of 4.4 MW and 17% curtailment. At the next stage WF3 cannot connect with any economically viable capacity. The non-firm connected WF2 is enough to double the total energy production from the base case with total curtailment of 10%.

With the proportional scheme, there is no compensation for extra curtailment of previous connections as long as it is within the contractual limits,(i.e.(4.25)). At stage 1, connection of WF2 raises the curtailment of WF1 from zero to almost the maximum (9.6%), by increasing hosting capacity at no cost to itself. It delivers the best performance for WF2 with high capacity and low curtailment. When WF3 comes to connect at stage 2, as a result of WF2 and WF1 already operating at the maximum allowed curtailment, a capacity of only 0.2 MW is available for WF3. With 10% curtailment, hosting capacity is tripled and production rises 168%.

The technically most appropriate scheme delivers almost double the capacity of the others, at the expense of curtailing 18% of total generation. This scheme dynamically changes the curtailment allocation and delivers cumulative effects through the connection process. The connection of WF2 reaches its optimal capacity when WF1 contributes to curtailment. The same trend of curtailing earlier connections to release more capacity is maintained when WF3 connects. It is notable that WF1 and WF2 would considerably reduce their generation to release substantial network headroom for WF3 which operates without being curtailed. With the compensation settings used here the cost of limiting output from WF1 and WF2 is relatively lower than the benefits from increased generation at WF3. In other words, the connection of WF1 and WF2 at their specific locations did not most effectively utilize overall network hosting capacity. Although bus 10 (WF3) is shown to be the better location to connect DG, only the technically most appropriate scheme will exploit its capacity through curtailment of the prior connections at WF1 and WF2.

In terms of total NPV for all the wind farms, it can be seen from Table 4.5 that all curtailment schemes deliver more overall economic benefits from increased connection capacity and production. The lifetime NPV from the proportional scheme lies between that of the LIFO and the technically most appropriate cases. Figure 4.8(a) shows the split for each farm by scheme. For the proportional scheme WF2 delivers 11% more NPV than the technically most appropriate case. However, it is notable that this is at the expense of a 23% reduction in WF1 NPV arising from non-compensated curtailment. In contrast, the technically most appropriate scheme handles the trade-off between WF1 and WF2 by ensuring no reduction in NPV at WF1 and a marginally lower NPV at WF2. Even with cost of compensation it still delivers a significant increase in NPV at WF3 driving the overall NPV of the three wind farms up by 37% and 81% over the proportional and LIFO schemes, respectively. It demonstrates that the technically most appropriate scheme is most economically efficient in maximising connections.

Table 4.3: Comparison of DG capacity and curtailment under different curtailment priority schemes for connection sequence A (OPT is the most technically appropriate scheme while PROP is the Proportional Curtailment scheme)

DG capacity

DG	Capacity (MW)			
	Base	LIFO	PROP	OPT
WF1	2.8	2.8	2.8	2.8
stage 1: WF2	0.3	4.4	6.3	5.5
stage 2: WF3	0	2.1	0.2	8.8
Total	3.1	9.3	9.3	17.1

Curtailment

DG (in connection order)	Curtailment (%)					
	LIFO		PROP		OPT	
	stage1_WF2	stage2_WF3	stage1_WF2	stage2_WF3	stage1_WF2	stage2_WF3
WF1	0%	0%	10%	10%	9%	48%
WF2	17%	17%	10%	10%	4%	31%
WF3	-	39%	-	10%	-	0%
Total	total:	17%	total:	10%	total:	18%

4.6.3 Connection sequence B

The analysis is repeated for a connection sequence where WF3 is connected first followed by WF2. The optimal capacity and curtailment level for each priority scheme is presented in Table 4.4. In terms of the total capacity of all three wind farms that can be accommodated, it follows a similar pattern to connection sequence A with all schemes boosting connections and the technically most appropriate scheme delivering most capacity. The obvious difference from sequence A is that the hosting capacity in the technically most appropriate scheme is reduced by 13% but the overall energy production falls by only 6% and curtailment is almost halved. The connection process presents different outcomes for specific wind farms. All curtailment schemes with sequence B see no hosting capacity left for the later connecting WF2, whereas with sequence A the later WF3 still can be connected although its capacity varies by scheme.

Table 4.4: Comparison of DG capacity and curtailment under different curtailment priority schemes for connection sequence B

DG capacity

DG (in connection order)	Capacity (MW)			
	Base	LIFO	PROP	OPT
WF1	2.8	2.8	2.8	2.8
stage 1: WF3	0.3	4.4	6.4	12.0
stage 2: WF2	0.0	0.0	0.0	0.0
Total	3.1	7.2	9.2	14.8

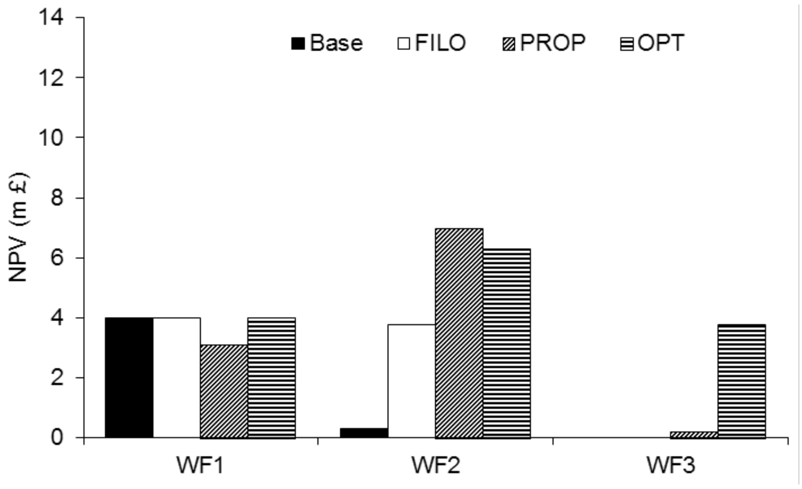
Curtailment

DG (in connection order)	Curtailment (%)					
	LIFO		PROP		OPT	
	stage1_WF3	stage2_WF2	stage1_WF3	stage2_WF2	stage1_WF3	stage2_WF2
WF1	0%	0%	10%	10%	46%	46%
WF3	16%	16%	10%	10%	2%	2%
WF2	-	-	-	-	-	-
Total	total:	10%	total:	10%	total:	10%

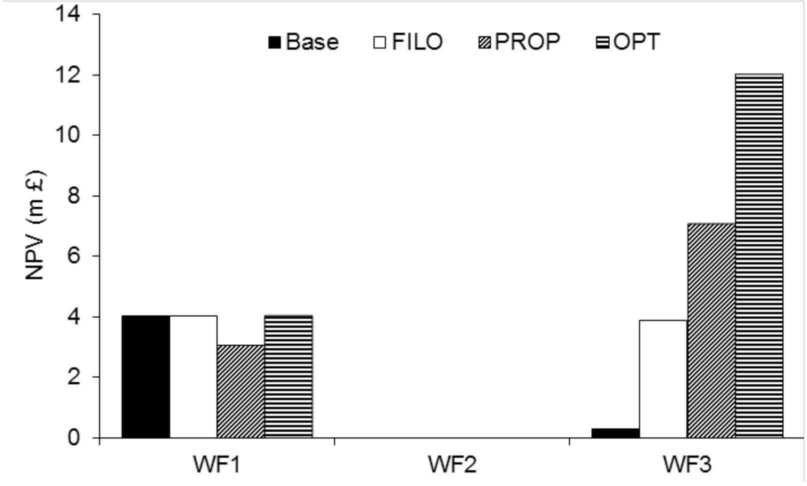
The technically most appropriate scheme delivers financial returns significantly better than the others (as Figure 4.8(b) shows) but also exceeds the total returns for sequence A by 14%. It further demonstrates that bus 10 (WF3) is where the hosting capacity can be maximised. When the connection sequence is closer to the optimal sequence (i.e. B in this case), less curtailment is required and greater returns can be obtained.

Table 4.5: Comparison of life time NPV under different curtailment schemes and connection sequences

Priority rules	Sequence A		Sequence B		Increase (A-B)
	E (GWh)	NPV (m£)	E (GWh)	NPV (m£)	NPV
Base	250	4.3	250	4.3	-
LIFO	515	7.8	517	7.9	1%
PROP	669	10.2	667	10.1	-1%
OPT	1124	14.1	1059	16.0	14%



a) Connection sequence A



b) Connection sequence B

Figure 4.8: Maximised NPV for each wind farm under different cases

4.7 Discussion

The evaluation approach provides a better understanding of planning non-firm connections, which is highly desirable for both DG developers and DNOs. Using the proposed optimisation technique, the maximum project returns under different curtailment schemes can be quantified and therefore offer a detailed “test bed” for designing connection contracts. As demonstrated in the case study, developments under non-firm connection schemes generally deliver more generation capacity in the network although financial returns for specific DG is determined by its connection order and principles of access. This means it is particularly important for developers to conduct ‘what if’ analyses of potential investments and for DNOs in monitoring efficient use of their network capacity. The implementation of curtailment schemes still needs appropriate commercial arrangements and policy frameworks, and the specifics of compensation could be different from the assumptions made here, e.g. in/exclusion of subsidies etc. The issue of fairness is particularly important where DG has been connected on a firm connection basis without curtailment and where reversion to non-firm operation would deliver substantial increases in output overall although that specific DG may see decreases. It has to be equitable in that DGs that contribute to curtailment to deliver more revenue overall see some benefit.

The analysis in the thesis is conducted from the developers’ point of view in that they effectively compete for hosting capacity and seek to improve their economic benefits. Competition-driven DG development does not guarantee the overall optimization of the network. In the UK, DNOs cannot directly control the placement of DGs. Therefore there is a risk that initial DG connections occur where they have a detrimental impact on network hosting capacity, significantly reducing opportunities for later developers. Competition for hosting capacity at poor locations only worsens network potential. The technically most appropriate curtailment scheme provides a means to partially mitigate such outcomes in networks where existing DGs connections are substantially different from the ‘optimal’. It has been shown in the case study, that by adopting the technically most appropriate curtailment scheme, the network potential can still be exploited through effectively limiting generation from the poorly located DG yet ensuring it remains economically viable through full compensation. While the technical and economic performance is still constrained by connection order, the technically most appropriate scheme outperforms the LIFO and proportional approaches in terms of greater hosting capacity.

This work raises an interesting point as to the extent of compensating curtailment at early connections given that overall hosting capacity may be disproportionally reduced by its connection. It suggests that DNOs need proper incentive arrangements to encourage developers’ connection plans to be more closely aligned with the overall optimisation of network hosting capacity. This is particularly important where regulatory and social pressures on minimising grid expansion are strong. One possible solution could be to adopt location-specific charging mechanisms for DG connections by exploiting shadow pricing.

While the proposed approach presented is a potential valuable step forward in analysis of smart grid planning, there are a number of enhancements that could be made which the framework adopted can effectively handle. First, the optimisation can be extended to include control of DG power factor [10] or alternatively reactive power pricing. Second, with energy loss an important focus for DNOs, the effect of non-firm DG connections on losses can be brought into the analysis, e.g. [21]. Third, the cost of building and operating ANM control systems is not considered in the case study but evidence suggests it is modest relative to the value of the generation capacity released and would have a marginal impact on the precise capacities suggested. Finally, although all wind farms use the same production profile here, the spatial characteristics of the resource can be incorporated and may result in greater hosting capacity with more modest levels of curtailment (as would a portfolio of different resources) [21].

4.8 Chapter summary

When DG developers are offered non-firm connection options, priority rules that govern the curtailment sharing of the DGs is a key concern of economic viability. In this chapter, a novel, flexible and multi-period OPF-based evaluation approach is proposed to determine the optimal capacity and curtailment level in order to obtain the maximum financial return for DG developers. Different ANM curtailment priority schemes can be quantified and compared using this method.

Results from the case study clearly show that most technically appropriate approach has technical and economic advantages on facilitating DG connection over other the two schemes. The economic benefits of later connection can be improved without harming the early connected DG under a properly designed compensation mechanism. The benefit brought by non-firm schemes would be varied on a case-by-case basis.

The proposed method allows rapid identification of financial returns under different access arrangements, providing better understanding of this issue. The knowledge of economic benefit of different priority settings could also form a basis for providing economic incentives to facilitate the DG planning process.

The work in this chapter represents the first part of the continuous effort in this thesis to adopt advanced OPF to extend the capability of hosting capacity study. Chapter 5 will continue the progress but from a different aspect, which enables hosting capacity solutions complying with the harmonic planning limits. The curtailment schemes presented will also be revisited in Chapter 6, where energy storage systems are introduced to reduce curtailment and add extra revenues.

Chapter 5

Incorporating Harmonic Distortion Limits into Assessment of Hosting Capacity

5.1 Introduction

In the previous chapter the extension of the DG planning tools was made by developing an evaluation method for non-firm connections considering different priority rules. Through implementing the curtailment based non-firm connections, voltage rise and thermal problems were managed and DG capacity increased. However, the inherent constraints that limit DG development also include other factors and it is important for active integration to take into account more constraints to provide a practical guide to DG development.

This chapter develops power quality (harmonics) as a new constraint for hosting capacity analysis. Firstly, the background and challenge for studying harmonic impact on DG integration are discussed. Then, the modelling approach for analysing harmonics is described. These models are used to produce a functional prototype of a harmonic-constrained multi-period OPF, which incorporates harmonic distortion limits into the optimisation of the hosting capacity. Case study and performance assessments are also presented. Finally, the chapter summarises the methodology, application and implementation of the proposed harmonic-constrained OPF for hosting capacity studies.

5.2 Research background and challenges

The problems of voltage rise and power flow (thermal) limits are now seen as being manageable by ANM schemes which promise to unlock new DG connections [27, 137]. However, the harmonic current emissions from power electronic converter-interfaced DG together with a general rise in background harmonic levels are rapidly moving up the agenda of DNOs and developers [148, 149]. The scale of new DG connections enabled by ANM means there is the potential for harmonics to inadvertently place limits on the ability of distribution networks to accommodate DG.

Traditionally, harmonic studies in the distribution network mainly focus on the measurement and management of harmonic voltage distortions from non-linear loads [150, 151]. Well-accepted component models, simulation methods and analysis procedures have been developed. These include harmonic frequency scan [152] and harmonic power flow [153] for propagation studies as well as the design and placement of harmonic filters for mitigation [154]. These harmonic analysis approaches are generally based on passive networks, where DG does not exist and the configurations of harmonic generating load are given and fixed during the period of interest.

Due to widespread application of power electronic inverter interfaces, renewable generation can inject considerable amount of harmonic current through the point of common connection into the upstream network. Harmonic emissions from renewable generation such as wind and solar is easily identified in a wide range of harmonic studies [24, 31, 148, 155]. It becomes a complex issue when increased renewable generation is connected into the distribution network. These harmonic-producing DGs are distributed across the network and are comparable in size. It leads to a quite different situation from the past, where dominant harmonic-producing loads were large and concentrated in a few locations.

The rapid development of DG makes the generation capacity in distribution networks a dynamic problem as DG volumes will substantially change over the planning horizon. It is therefore important to study harmonics from the perspective of DG planning and aim for overall optimisation within the network.. Harmonic studies need to be considered at the initial stage of network planning instead of being performed as an after-thought following 'blind' DG development. In this context, it demands a clear method to determine the hosting capacity that complies with harmonic distortion limits.

The previous work on hosting capacity studies as reviewed in Chapter 4 provides a firm foundation to incorporate harmonic distortion limits into the hosting capacity studies. The integration of harmonic distortion limits into the existing DG planning tools appears to be logical. However, there is a complete absence of methodologies that consider harmonic-constrained hosting capacity.

To fill the gap left by previous hosting capacity work on harmonic issue, in this chapter, an advanced OPF technique is adopted to maximize the DG capacity while meeting not only voltage and thermal constraints but also harmonic distortion limits. As an important part of the smart grid, advanced control schemes are also evaluated. In the following sections, the detailed explanation of the assessment method is presented.

5.3 Harmonic modelling of network component and DG

Similar to other power system studies at the fundamental frequency, typical harmonic studies start by choosing equivalent models to present the network and harmonic sources of interest, followed by simulations of the modelled system under various scenarios. Many approaches have been proposed to model linear and nonlinear components [153, 156, 157]. Those techniques vary in terms of complexity, data requirements and solution algorithm. It is appropriate to note that at the planning stage, relatively simplified models are acceptable given that data, like the generator design data and operating conditions may not be fully known. The discussion of component modelling and the considerations for the method adopted in this work is presented in the following subsection.

5.3.1 Overhead line and cables

For balanced systems, overhead line and cables can be accurately modelled as multiple nominal sections using positive sequence impedance data. According to [36], in a 50 Hz system, an error of less than 1.25% can be obtained when every single section modelled is below 10km for overhead line and 6km for cable. Given common practice in distribution networks, the long line effect is further neglected and a lumped model is used. The distribution line is represented by a single phase circuit with resistance *R* and reactance *X* as follows, where *R* is constant regardless of the frequency while *X* varies with frequency:

$$R_h = R_0 \tag{5.1}$$

$$X_h = X_0 \cdot h \tag{5.2}$$

where *h* is the harmonic frequency order, R_0 and X_0 are the resistance and reactance at the fundamental frequency.

The skin effect is another issue that should be considered to improve accuracy. As transmission and distribution grids are designed to carry the fundamental frequency, electric current may not fully penetrate the conductor at different frequencies (harmonics). When the current travels on the outer edge of conductors, the increase in resistance can be substantial at higher harmonics. Accordingly, the equivalent model of (5.1) can adopt skin effects to further improve modelling accuracy, this is given as

$$R_h = R_0[A_0 + A \cdot h^{0.5} + A_1 \cdot h + A_2 \cdot h^2 + A_3 \cdot h^3] \tag{5.3}$$

where A_n represents the skin effect factors added to the resistance. The value depends on the conductor materials and also operational conditions. In practice, the skin effect can be neglected for short distribution feeders.

5.3.2 Transformers

The main characteristics of a transformer that affect harmonic flows are the short-circuit impedance and winding connection type. It is generally acceptable to model transformers as series impedance considering the skin effect:

$$R_h = R_0[A_0 + A \cdot h^{0.5} + A_1 \cdot h + A_2 \cdot h^2 + A_3 \cdot h^3] \tag{5.4}$$

$$X_h = X_0 \cdot h \tag{5.5}$$

where R_0 and X_0 represent its short circuit impedance at the fundamental frequency.

5.3.3 Passive and nonlinear Load

Aggregated values (MW and Mvar) for system load are usually readily available. For passive load, a simplified parallel form representation is suggested in [156] and adopted in this work:

$$R_h = \frac{V^2}{P} \tag{5.6}$$

$$X_h = \frac{V^2}{Q} \cdot h \tag{5.7}$$

where R_h and X_h is the equivalent harmonic impedance of load at the harmonic order h; V is the voltage; and P and Q represent the active and reactive part of load at the fundamental frequency. The total reactive load is assigned to an inductor L and its X_h varies with harmonic frequencies.

When the load also has considerable nonlinear demand, it is reasonable in the context of DG planning to present this nonlinear component of loads as harmonic current sources which cause background distortions. The current source can be connected with the passive part in parallel as shown in Figure 5.1.

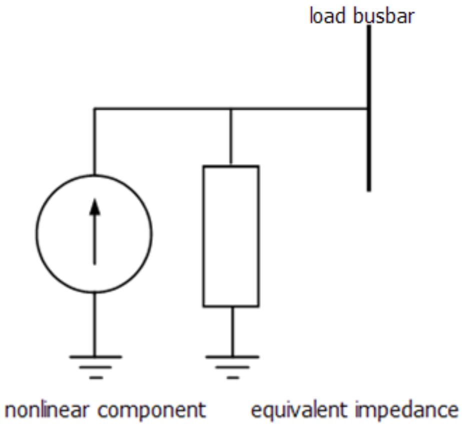


Figure 5.1: The parallel form model of load for harmonic studies

To characterize models properly, the detailed composition of load that determines the nonlinear composition and harmonic spectrum is necessary, but such data is usually not easily available and likely requires measurement.

5.3.4 DG harmonic model

While this work focuses on the DG harmonic studies, the modelling of DG harmonic emissions is more complex compared with the above network components. Given the various impact factors, such as variable DG output and aggregation rules, DG harmonic emissions present dynamic and uncertain characteristics. In this subsection, the approach of modelling DG harmonic is discussed in detail. A simplified but practical DG emission model is also obtained.

5.3.4.1 Impact of varying DG outputs

It is important to note that the harmonic emission data provided by turbine manufacturers is normally measured at its full capacity to present the worst-case scenario. Given the intermittent nature of renewable resources, the output of turbines will vary throughout the day [158]. The variable resource level alongside other factors suggests that the harmonic emissions at the turbine terminal will not always be at maximum values. If short term violation of harmonic distortion limits is allowed to some extent, it is worthwhile evaluating the impact of the DG output on harmonic emission in detail. When the high level of harmonic current only lasts for a short period for the study case, estimating distortions using the maximum emission value can lead to an unnecessary overestimate of the issue. However, there is no comprehensively defined model to predict the harmonic emission in particular operation conditions. Harmonic emissions from specific DG units depends on its technology and there is substantial diversity [155]; therefore a generally accepted model to present the impact of varying DG output on harmonic emission may not exist.

5.3.4.2 Impact of phase difference

Normally at voltages of 11kV and above, wind farms and solar farms connect several generator units together at the same bus. In hosting capacity study, the units at the same bus are usually modelled as a single DG with aggregated values [50]. However, the estimation of harmonic currents from the aggregated DG is complex. The phase angle difference between each DG will largely determine the summated current. The phase angle of different harmonic source is rarely the same, so the summed current tends to be lower than the arithmetic sum of their magnitudes. The angle of the DG harmonic current can vary frequently and the impact of weather condition is hard to model [155].

5.3.4.3 Impact of DG internal layout

The internal layout of renewable farms also affects the final aggregated harmonic current emitted at the connection point. It is particularly the case for large offshore wind farms, where the long subsea cables connecting generator units have considerably high capacitance. Their interaction with inductive network components may lead to parallel or series resonances [149], and fundamentally change the harmonic current propagated from the connection point into the onshore network. For small scale DG, explicit modelling of the internal network is also helpful but time consuming and its impact is relatively small. Accordingly, simplified methods are suggested in this work.

5.3.4.4 Aggregation method of IEC standard 61000-3-6

IEC standard 61000-3-6 [159] has recommended an aggregation method for summating load harmonic current, which is based on the fact that the aggregation of harmonic vectors that vary statistically with time results in a lower value than their arithmetic sum. This is given formally as

$$I_{h,\mathrm{sum}}^{\beta} = \sqrt[\beta]{\sum_i I_{h,i}^{\beta}} \tag{5.7}$$

where β is the summation exponent, $I_{h,sum}^{\beta}$ is the sum of the harmonic current, and $I_{h,i}$ are the individual harmonic components. The value of summation coefficients β for different harmonic orders is shown in Table 5.1. Larger β at the high harmonic order (which leads to small sum value) is due to individual harmonics tending to become more uncorrelated. The method provides a reasonable and simplified approach. However, studies [155, 160] suggest that it does not accurately represent the aggregation of harmonic currents for DG. Summation coefficients could be validated for any specific type of DG using extensive field measurements given the variety of converter techniques and operating conditions.

Table 5.1: Summation exponents according to IEC 61000-3-6

Harmonic Order	β
$h<5$	1.0
$5\leq h\leq 10$	1.4
$h>10$	2.0

5.3.4.5 Adopted DG emission models

It is clear that to accurately model DG harmonic emissions, detailed knowledge of specific turbines on these aspects is required. At the planning stage, such knowledge might be unknown or require a great effort to determine. To facilitate the planning procedure, a simplified model that represents each DG unit as a harmonic current source is presented below:

$$I_{h,i} = I_{h}^{spectrum} \frac{S_{i}^{turbine}}{V_{i}} \tag{5.8}$$

where $I_{h,i}^{spectrum}$ indicates the h^{th} order current element of the harmonic spectrum for DG according to the turbine technology; $S_{i}^{turbine}$ is the total rated DG capacity installed at bus i; V_{i} is nodal voltage; and $I_{h,i}$ represents the h order harmonic current distortion injected at the DG connection point i.

To estimate the total harmonic current of aggregated DG, the method of IEC 61000-3-6 can be adapted here as:

$$I_{h,i} = \sqrt[\beta]{\sum_{n=1}^{N} ((S_i^{turbine} / V_i) I_h^{spectrum})^{\beta}} \tag{5.9}$$

where total DG capacity in (5.8) is replaced by the rated capacity of a single turbine $S_i^{turbine}$, and $I_h^{spectrum}$ indicates the h th element of a typical harmonic spectrum for DG. Applying this model for DG, say for a wind farm, will need an explicit number of wind turbines (N in the model) and accordingly results in discrete values in total DG capacity. This model is applicable for cases where the planner has a strong idea of the specific turbine type for the whole network.

It is notable that more sophisticated models can be used for DG and other components when corresponding data is available. The level of detail in models will increase the complexity of the analysis, and in practice will largely decrease the feasibility of reliable data being obtained. Although the models and assumptions adopted in here may lead to conservative results, this is often desirable for network planning.

5.3.5 Harmonic voltage distortion limits in the UK

To quantify the impact of DG harmonics, the indicator of the distortion level and the corresponding limits need to be clarified. The required limits for harmonic indicators, as total harmonic distortion (THD) and individual harmonic distortion for each order (IHD) are outlined in this section. The current regulation specifying the limits of harmonic voltage distortions in the UK is Engineering Recommendation (ER) G5/4-1 [37]. ER G5/4-1 sets the planning levels of harmonic voltage distortion for the connection of non-linear equipment. The predicted harmonic voltage distortions are required to be less than or equal to the specified limits. It is applicable to both non-linear load and generation. For the 33 kV systems values for each harmonic order (IHD) as described in Table 5.2 would be applied for planning studies.

Table 5.2: Planning level for 20 to 145kV [37]

Odd harmonics (non-multiple of 3)		Odd harmonics (Multiple of 3)		Even harmonics	
h	Harmonic voltage(%)	*h*	Harmonic voltage(%)	*h*	Harmonic voltage(%)
5	2	3	2	2	1
7	2	9	1	4	0.8
11	1.5	15	0.3	6	0.5
13	1.5	21	0.2	8	0.4
17	1	>21	0.2	10	0.4
19	1			12	0.2
23	0.7			>12	0.2
25	0.7				
>25	0.2+0.5(25/*h*)				

Besides IHD, indicators of harmonic distortion also include the THD. THD is calculated as the root mean square value of individual harmonic voltages:

$$THD = \sqrt{\sum_{h=2}^{h=50} V_h^2} \tag{5.10}$$

The planning levels of THD for various voltage levels are given in Table 5.3. For DG connections, the applicable value is determined by the voltage level of its connection point to the main network.

Table 5.3: Summary of THD planning levels [37]

System Voltage	THD Limit
400V	5%
6.6, 11 and 20kV	4%
22kV to 400kV	3%

Since harmonic voltages generally exist in the network prior to the connection of new DGs, the value of existing distortion needs to be considered. These pre-connection harmonic distortions are referred to as background harmonics. It could be calculated using simulation by proper modelling of the network and existing harmonic generating resources. In practice, it is more often determined through field measurements with the procedure outlined in the ER G5/4-1. The assessments are carried out though a selected continuous period, normally a minimum of 7 days. The background harmonic distortion for any particular order is the maximum value of the distortion for 95% of the time of the selected period.

For harmonic compliance studies, it is also important to note that ER G5/4-1 is not a statutory regulation. The compliance with its recommended harmonic distortion limits is through agreement reached between the DNO and DG developers. There may be situations where the planning levels are exceeded. However, the ER G5/4-1 is generally adopted in DNOs' Distribution Codes. Where connection of new DG would impose harmonic voltage distortion greater than the planning levels as ER G5/4-1, the DNO can refuse such connection. In other countries, different standards and regulations on harmonic distortion limits may be adopted. The limits specified in ER G5/4-1 are used in this work to reflect UK practice.

5.4 Harmonic-constrained hosting capacity

In the previous section, the network modelling approaches for harmonic study are presented. In this section, these models are used to develop a method to evaluate harmonic-constrained hosting capacity. Firstly, the traditional harmonic assessment method, the harmonic power flow [36], is outlined and the discussion of its direct application to hosting capacity study is presented. Then, the proposed technique of harmonic-constrained OPF is explained in detail. A range of aspects are considered and embedded into the harmonic-constrained OPF framework, including the multi-period optimisation method, active network control schemes and harmonic mitigation equipment. The generalised procedure of using the developed HOPF framework to evaluate harmonic-constrained hosting capacity is also summarised.

5.4.1 Harmonic power flow

Harmonic power flow has been extensively used to study harmonic propagation in the network [36, 151]. Harmonic power flow is a simulation method to quantify the harmonic voltage at different orders in the network. The results are useful to verify compliance with distortion limits and identify any potential resonance. Mathematically, harmonic power flow can be presented as:

$$[V_h] = [Z_h][I_h] \tag{5.11}$$

where at harmonic order h, $[Z_h]$ is the harmonic impedance matrix of the network; $[I_h]$ is the vector of nodal harmonic current injections; and $[V_h]$ is the corresponding harmonic voltage. The general form of Z_h is given as

$$Z_h = \begin{bmatrix} Z_{1,1,h} & \cdots & Z_{1,\mathrm{j},h} \\ \vdots & \ddots & \vdots \\ Z_{\mathrm{i},1,h} & \cdots & Z_{\mathrm{i},\mathrm{j},h} \end{bmatrix} \quad \forall h \in H \tag{5.12}$$

where $Z_{i,j,h}$ is the harmonic transfer impedance between buses i and j at order h. Note that both impedance matrices of the network and harmonic current injections are based on the network component models and harmonic sources presented in the previous section.

In the basic formulation (5.11), the evaluation of harmonic voltage at any bus of the network is derived by the superposition principle of linear circuit theory [36]. After the modelling of network and harmonic sources, the harmonic voltages $[V_h]$ can be easily calculated if the matrix Z_h is linear. Compared with AC power flow, the complexity and time are much reduced.

Directly using harmonic power flow seems a plausible way to evaluate harmonic-constrained DG capacities. When DG developers wish to connect their generation into the network, harmonic assessment could be separately conducted for every single connection using harmonic power flow. Modifying the DG capacity or installing expensive harmonic filters is necessary when the proposal violates harmonic distortion limits [148, 161]. However, solutions deemed reasonable for each individual connection could deliver poor results for the network as a whole. For example, an early and minor connection may prevent development of other larger sites due to adverse harmonic propagation impacts, effectively reducing the total hosting capacity of the network or increasing the cost of additional filters. Given this network sterilisation effect, a method of evaluating the impact of DG harmonics with considering the overall optimisation of hosting capacity is a logical step and the focus of this chapter.

One possible way of conducting the harmonic evaluation in capacity allocation studies is to neglect harmonic impacts at the initial step. After obtaining the DG capacity from other established optimal planning techniques, e.g., [50], or a direct proposal from DG developers, THD and individual harmonic distortion are evaluated using harmonic power flow. If the results do not comply with distortion limits, then the DG capacity needs to be reduced by a certain volume or a bank of filters installed for the next assessment. A similar procedure repeats until specific objectives are achieved, such as: maximum DG capacity, minimum network investment or a trade-off between filter cost and DG capacity. This method guarantees the final result has harmonic compliance and is relatively simple in every step. However, the obligation of managing harmonics during initial DG capacity assessment creates a time-consuming repetitive procedure to check harmonic compliance. It is also not straightforward to decide how much to reduce DG capacity or where to install filters at every step, especially for multiple DG cases

5.4.2 Harmonic-constrained multi-period optimal power flow

Considering these shortcomings outlined in previous section about existing methods, an alternative method based on advanced OPF techniques is proposed in this section, to provide a better solution to access the harmonic constrained hosting capacity. An overview of the method is present first, followed by detailed discussions about modelling techniques.

5.4.2.1 Overview of harmonic-constrained multi-period optimal power flow

Similar to other physical constraints, harmonic distortion limits can be incorporated into the OPF framework using results from harmonic power flow by constraining THD and IHD. In this work, the harmonic constraints are incorporated within the multi-period AC OPF formulation with ANM controls [20]. The objective function for harmonic-constrained hosting capacity analysis is given as:

$$\max \sum_{g \in G} P_g \qquad (5.13)$$

where P_g is the active capacity (MW) of DG connection g determined across a reduced time series analysis that groups wind generation and demand by a series of coincident ranges (see section 3.5.5).

This objective function is subject to a range of constraints which can be categorized into three sets: basic network limits, ANM constraints and the new harmonic distortion limits considered here. Figure 5.2 shows the constraints structure for the HOPF.

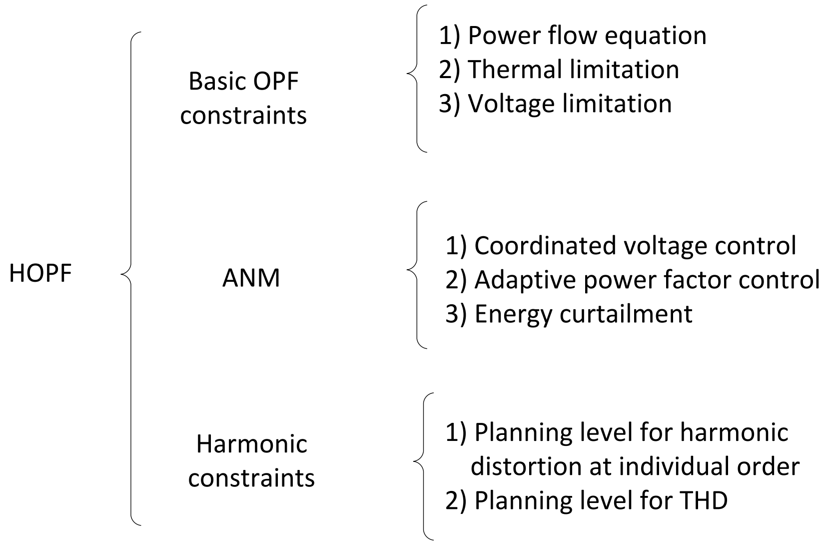


Figure 5.2: Constraints within the HOPF formulation

It is clear that the both basic OPF constraints and ANM in Figure 5.2 are related to the network variables at the fundamental frequency, but harmonic constraints are based on the network variables above the fundamental order. Through the ratio between the harmonic emission currents (in Ampere) and the capacity of DG (in MVA), a unique and inter-frequency set of generation capacity variables (P_g) is used in the objective function (5.13) throughout the analysis.

Given the intermittent nature of DG output and its impact on harmonic emissions, time-series analysis is required. The multi-period approach that reduces time-series data into to a series of representative bins can be adopted there. The extension of the original approach [20], from only considering the fundamental frequency into a range of selected harmonic orders, is achieved by providing each scenario (*m*) with an additional set of harmonic variables and constraints indexed by *h*. An example of how these multi-period and multi-frequency scenarios can be visualized is given in Figure 5.3.

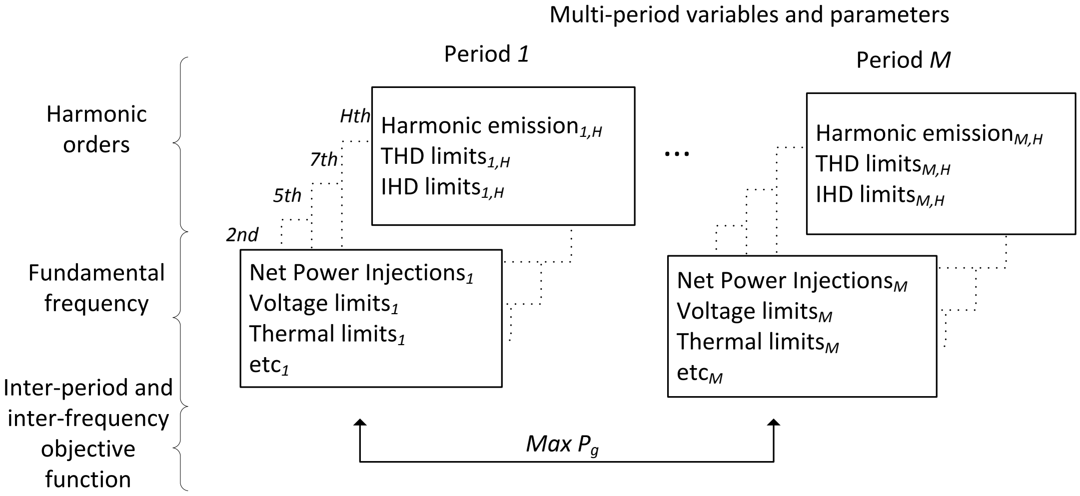


Figure 5.3: Structure within harmonic constrained MOPF formulation

The introduction of harmonic variables and constraints into the multi-period OPF framework will not change the formulations at the fundamental frequency. From this perspective, harmonic evaluation can be added into the multi-period analysis techniques and retain consistency with other enhancement attempts. The variables and constraints in the basic OPF and ANM as illustrated in Figure 5.2 is largely the same as these used in Chapter 4. For them, the previous formulation work can be directly used here. Given the predominantly linear feature of the harmonic equations as modelled, the complexity of the optimisation would not see significant increase after embedding the harmonic models.

5.4.2.2 Harmonic variables

In the multi-period HOPF, harmonic current emission from DG g is formulated as variable $I_{g,m,h}$, determined for each period m at each harmonic order h. A simplified output-dependent model is used where DG harmonic current emission $I_{g,m,h}$ is assumed to change linearly with DG power output. Adopting the model in (5.8), the harmonic current is linked to the DG capacity P_g as follows

$$I_{g,m,h} = I_h^{spectrum} \frac{P_g \omega_m}{V_g} \tag{5.14}$$

where ω_m is the generation level relative to nominal capacity. It is important to note that the actual harmonic current from DG exhibits random variations and distributional features. To improve the output dependency of the DG harmonic model, which present random and statistic features, further development on the knowledge of DG harmonic modelling (as outlined in section 5.3.4) is required.

The harmonic network impedances are also changed during the different periods. The varying demand level determines the equivalent harmonic impedance of load according to (5.6).

$$[V_{b,m,h}] = [Z_{m,h}][I_{g,m,h}] \tag{5.15}$$

where the harmonic network impedance shown in (5.12) is reformulated here in a multi-period manner as $Z_{m,h}$. Harmonic voltage $V_{b,m,h}$ at bus b during the period m for the harmonic order h is then calculated using the harmonic power flow equation (5.15), where the DG emission $I_{g,m,h}$ forms the set of harmonic current sources.

5.4.2.3 Harmonic distortion constraints

To provide the capability to ensure that DG capacity is compliant with harmonic regulations, both IHD and THD are formulated as constraints for harmonic constrained hosting capacity. For multi-period HOPF, the following expressions of harmonic constraints apply:

$$\frac{V_{b,m,h}}{V_{b.m}} \le IHD_h \tag{5.16}$$

and

$$\frac{\sqrt{\sum_{h=2}^{50}(V_{b,m,h})^2}}{V_{b,m}} \leq THD \tag{5.17}$$

where within each period m, $V_{b,m,h}$ is the harmonic voltage at bus b for harmonic order h; $V_{b,m}$ is the voltage at the bus at the fundamental frequency; and IHD_h and THD are the planning levels as given in harmonic standards and regulations. $V_{b,m,h}$ is obtained from the multi-period harmonic power flow equation (5.15) and it is ultimately determined by the DG capacity P_g. By adding IHD and THD constraints, the HOPF-defined DG volumes would comply with the harmonic regulation at all frequencies across all the considered time periods.

For a simplified snapshot analysis of the worst case scenario, the period m is limited to the coincidence of the maximum output and selected demand level. The harmonically critical scenario can be different from the condition at fundamental frequency, where the scenarios of low demand level constrain the hosting capacity. Depending on the load type and its comparison with the generation, load at the peak level may inject considerable harmonic current into the background distortion and actively constrain the harmonic hosting capacity. It is therefore necessary to conduct worst case scenario analysis for both low demand and high demand cases.

5.4.2.4 Active harmonic filter

Should harmonics be above limited levels, harmonic filters can be used to mitigate DG harmonic distortion and as thus to release hosting capacity [161]. In this subsection, the consideration of filters under the proposed method is presented. The filters deployed in power systems are classified into three categories: passive, active and hybrid. Conventional passive L-C filters are lower cost [162] while active filters provide dynamic and adjustable compensation [154]. Due to the high rating required for the active filter, a combined filter is presented [163] using series connected passive and active filter to reduce the cost. When it comes to the DG planning problem, there is a potential shortcoming with passive filters. While voltage rise problem can be (partly) mitigated by operating DG at lagging power factor [141] through absorbing reactive power, the capacitor installed within the passive filter will provide a local reactive source which will tend to worsen voltage rise. Given this, active filters are suggested as being more appropriate here.

The most extensively applied active filter is the active power line conditioner (APLC). It can be modelled in filter planning studies as a current source injecting harmonics to its connection bus [164]:

$$I_{b,h}^{F} = I_{b,h}^{F,r} + jI_{b,h}^{F,i} \tag{5.18}$$

where $I_{b,h}^{F,r}$ and $I_{b,h}^{F,i}$ represent the real and imaginary part of the APLC current $I_{b,h}^{F}$ at bus b. After installing active filters at the DG connection bus g, the harmonic current emission is adjusted as:

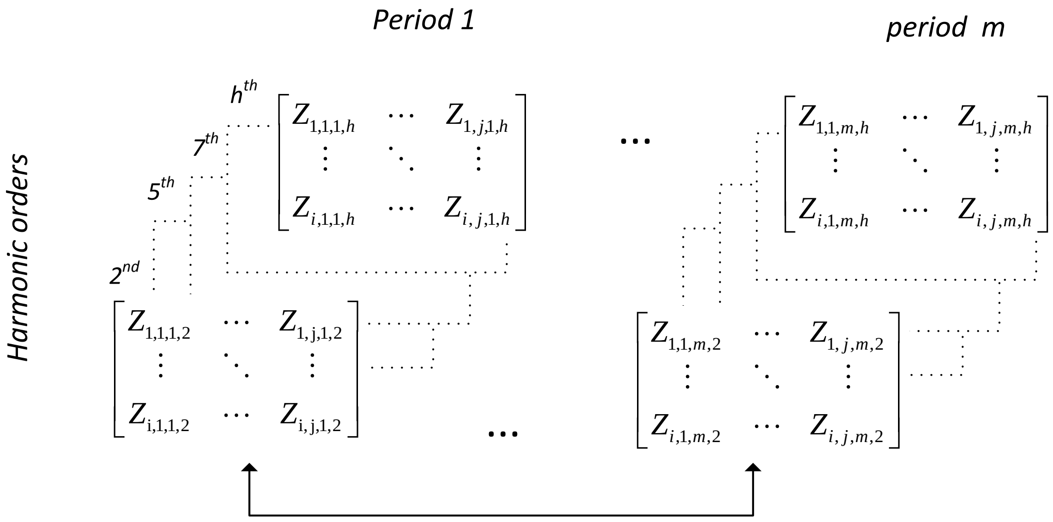
$$I_{g,h}^{miti} = I_{g,h} - I_{g,h}^{F} \tag{5.19}$$

The impact of filters can be examined by replacing the original emission current $I_{g,h,m}$ with the mitigated harmonic current $I_{g,h}^{miti}$ in the harmonic constrained OPF formulation, and recalculating the harmonic voltage.

5.4.3 Implementation

The implementation of proposed harmonic constrained OPF method is briefly explained in this subsection. To retain compatibility with other hosting capacity studies, such as Chapter 4, AIMMS is also used here to develop the main method. The harmonic analysis function is coded as an additional module into the multi-period OPF planning tool. Parameters, variables and constraints are added to represent the developed models and formulations. The optimisation is solved using the CONOPT NLP solver.

MATLAB is used to prepare data and generate the harmonic network impedance matrix $Z_{m,h}$ for AIMMS inputs. Given the considerable dimensions of this $Z_{m,h}$, which vary with the demand level at period m and the harmonic order h (as illustrated in Figure 5.4), MATLAB is more efficient in this part of implementation.



$$\left[Z_{i,j,m,h}\right] \quad \forall j,i \in B \quad \forall m \in M \quad \forall\, h \in H$$

Figure 5.4: Schematic structure of the multi-period harmonic network impedance $Z_{m,h}$

5.4.4 Generalised procedure for hosting capacity analysis considering harmonic distortion limits

Using the proposed harmonic analysis method, a generic assessment procedure is summarized and explained in this subsection. The following steps begin with harmonic data preparation while the whole assessment normally starts with the calculations at the fundamental frequency. In order to emphasise the new aspects, only steps associated with harmonic analysis are present here.

1. Obtain the values of the existing background distortion in the network, particularly at the DG connection points;

2. Obtain the frequency dependency of the network components. Based on selected models, the equivalent harmonic impedance of the network can be established;

3. Obtain the harmonic current from DG. From the aggregation, the hosting capacity in MW can be represented in harmonic current;

4. Determine the analysis scenarios. Depending on the data availability from previous steps and the requirements from DNOs, either snapshot analysis for the worst cases or multi-period analysis across the full period will be chosen;

5. Apply the harmonic-constrained OPF analysis approach, determine the optimal capacity and find the binding constraint;

6. When harmonic constraints are the active limit for the hosting capacity results, mitigation methods like adding filters can be considered. Where other constraints limit the hosting capacity, corresponding management techniques are evaluated;

7. Re-run the harmonic constrained OPF tool with mitigation methods to examine mitigation effect of management techniques.

The final decision as to the hosting capacity and whether to install mitigation equipment will rest with the DG developers and DNOs on a cost benefit basis.

5.5 Case study

To demonstrate the proposed method of incorporating harmonic impacts into the hosting capacity study, studies on two case networks are provided. Beginning with constant DG output and a simplified harmonic spectrum, the comparison between the non-harmonically-constrained and harmonic-constrained hosting capacity is illustrated. Then in a more realistic case of the UK generic distribution network, further issues around the harmonic-constrained hosting capacity are studied, including varying DG and demand levels, the coordination with ANM schemes and mitigation with active filters.

5.5.1 38kV Irish network: snapshot analysis with multiple DGs

5.5.1.1 Case description

A section of the typical rural distribution network is used here as the first case [141]. Since it is originally based on the Irish network, the voltage level is 38kV and therefore different to UK 33kV practice. It has been selected as it is simple to illustrate and can be compared with the influence of harmonic constraints, The harmonic voltage planning levels for 33kV systems in the UK are adopted here.

The one-line diagram of the medium voltage distribution network is shown in Figure 5.5. The corresponding line data is included in Table 5.4. All values are in per unit (100MVA base). The feeders are supplied by one 31.5MVA 110/38kV transformer. The Grid Supply Point (GSP) voltage is assumed to be nominal. Voltage limits are taken to be ±10% of nominal. The maximum demand of the network is 15.12MW.

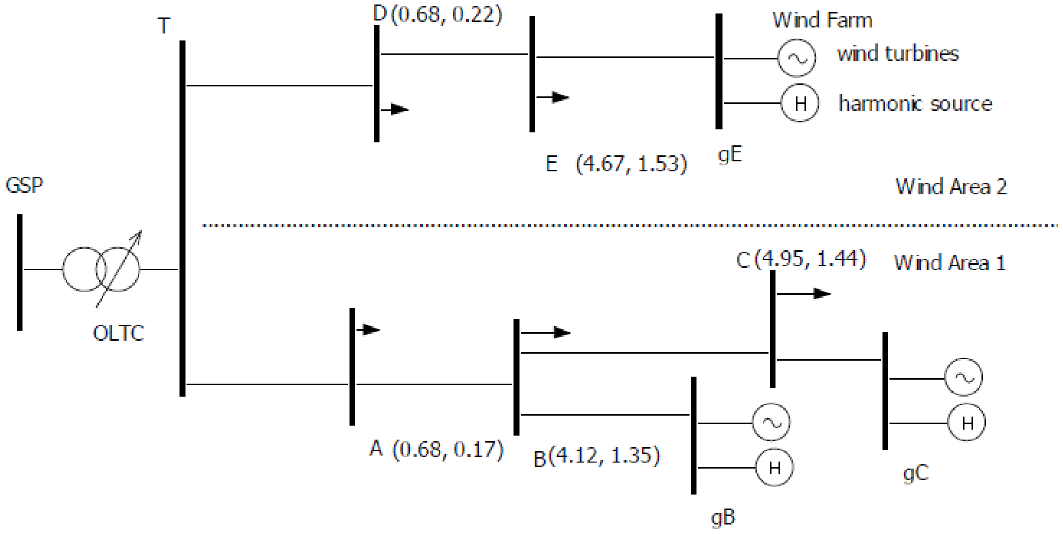


Figure 5.5: 38kV 5-bus network one-line diagram during maximum load conditions.

Table 5.4: Line and transformer parameters for the 38kV 5-bus network (per unit, 100MVA base).

Line	R	X	Smax	Line	R	X	Smax
GSP - T	-	0.25	0.315	D - E	0.155	0.1629	0.1975
T - A	0.0296	0.0863	0.3817	B - gB	0.1292	0.1357	0.1975
A - B	0.5941	0.6244	0.1975	C - gC	0.1292	0.1357	0.1975
B - C	0.3875	0.4072	0.1975	E - gE	0.1292	0.1357	0.1975
T - D	1.126	1.193	0.3817				

The network has three potential locations at which new DGs can be connected: buses gB, gC and gE in Figure 5.6. Generally, harmonics below the 50th are considered. The first two harmonics, the 5th and 7th (the 3rd harmonic can be eliminated by the transformer at the DG grid connection), are the most severe in the system. In this case, for illustrative purpose, a value of 1% is chosen for the harmonic emission at both the 5^{th} and 7^{th} orders as given in Table 5.5. Also all three DGs are assumed to have identical harmonic emissions spectra. To illustrate the base problem, DG capacity at each bus is defined as a continuous value instead of a discrete one.

Table 5.5: Simplified harmonic currents of DG for illustration

Harmonic Order	Harmonic Current of DG (% in I_{rated})	Planning level at 33&132 kV (%)
5	1	2
7	1	2
THD		3

To illustrate how background harmonics may be incorporated, the existing voltage distortion at nearby buses around the DGs is given as firm values: 1.0% at the 5th order and 0.5% at the 7th order. The other orders of background voltage distortion are neglected accordingly for clarity. More detailed data will be used in the second case and can be updated when detailed measurement is available.

5.5.1.2 Non-harmonically-constrained hosting capacity results

At the fundamental frequency, the network capability to accommodate DG mainly depends on local load level. Under low demand levels, a given DG output means more exported power with network voltage and thermal constraints more likely to be active. Only the worst case of minimum demand and maximum generation are considered here for determining the network's ability to accommodate DG capacity. The minimum load level is 40% of the peak demand. Another factor is the transformer tap setting in substations: to minimize voltage rise limits on the DG, the tap changer is adjusted to 1.035 p.u. to lower the secondary side voltage of OLTC between the GSP and bus T.

Ignoring harmonic constraints, the initial OPF evaluation of the new generation capacity that can be accommodated considers only voltage and thermal constraints. The result of this is presented in column 2 of Table 5.6. It is evident that even under the worst-case scenario used here, the network exports power since the 42 MW total DG capacity surpasses local demand by some margin. Substantial amounts of capacity are available at buses gC and gE while a much smaller amount is possible at bus gB. This is largely due to gB sharing the same feeder as gC while gE alone is connected to a separate feeder. The constraints that actively limit the capacity at these locations are: the voltage at bus gE is at the upper voltage limit (1.1 p.u.) due to the relatively high line impedance, while there are thermal limits on both line C-gC (connecting directly to Bus C) and the GSP transformer. The overall limit to DG capacity created by the transformer export limit means that the split in capacity between gC and gB is governed by a fairly small difference in net exports along the feeder associated with the greater impedance to reach bus gC. In other words, the additional losses that this creates delivers a higher overall net capacity so the optimisation exploits this by loading bus gC to its limit before directing 'spare' capacity to bus gB. Were the feeder voltage-constrained, however, the optimisation would direct more capacity to bus gB as it has lower voltage sensitivity.

Table 5.6: Comparison of optimal DG capacity result between OPF (no harmonics) and HOPF (harmonic constrained)

DG bus	OPF (MW)	HOPF (MW)	Change in capacity (%)
gB	7.3	8.5	+16.3
gC	17.2	2.5	–85.7
gE	17.1	6.0	–64.8
Total	41.6	17.0	–59.2

5.5.1.3 Harmonic compliance

For the optimal 42 MW of DG capacity identified by the non-harmonically constrained OPF, the harmonic current injections from each DG are shown in Table 5.7. These are calculated by scaling the maximum harmonic current spectrum of a single turbine by the capacity at the bus.

Table 5.7: Harmonic current injections from the DGs

Harmonic Order	Harmonic Current (p.u.)		
	gB	gC	gE
5	0.007	0.017	0.017
7	0.007	0.017	0.017

Based on the models discussed in Section 5.3, the harmonic network impedance matrix $Z_{m,h}$ for the 5th and 7th harmonic orders under minimum demand is calculated and shown in Table 5.8. The network impedance increases with harmonic orders when there is no resonance.

Table 5.8: Network impedance matrix under minimum load level

a) at the 5th harmonic

	GSP	T	A	B	C	D	E	gB	gC	gE
GSP	1.2	1.2	1.2	1.2	1.1	1.2	1.2	1.2	1.1	1.2
T	1.2	2.4	2.4	2.3	2.3	2.3	2.3	2.3	2.3	2.3
A	1.2	2.4	2.8	2.7	2.7	2.3	2.3	2.7	2.7	2.3
B	1.2	2.3	2.7	5.7	5.6	2.2	2.2	5.7	5.6	2.2
C	1.1	2.3	2.7	5.6	7.6	2.2	2.2	5.6	7.6	2.2
D	1.2	2.3	2.3	2.2	2.2	8.0	8.0	2.2	2.2	8.0
E	1.2	2.3	2.3	2.2	2.2	8.0	8.8	2.2	2.2	8.8
gB	1.2	2.3	2.7	5.7	5.6	2.2	2.2	6.4	5.6	2.2
gC	1.1	2.3	2.7	5.6	7.6	2.2	2.2	5.6	8.3	2.2
gE	1.2	2.3	2.3	2.2	2.2	8.0	8.8	2.2	2.2	9.5

b) at the 7th harmonic

	GSP	T	A	B	C	D	E	gB	gC	gE
GSP	1.7	1.6	1.6	1.6	1.5	1.6	1.6	1.6	1.5	1.6
T	1.6	3.3	3.3	3.1	3.1	3.1	3.1	3.1	3.1	3.1
A	1.6	3.3	3.8	3.7	3.6	3.1	3.1	3.7	3.6	3.1
B	1.6	3.1	3.7	7.7	7.6	3.0	3.0	7.7	7.6	3.0
C	1.5	3.1	3.6	7.6	10.3	2.9	2.9	7.6	10.3	2.9
D	1.6	3.1	3.1	3.0	2.9	10.9	10.9	3.0	2.9	10.9
E	1.6	3.1	3.1	3.0	2.9	10.9	12.0	3.0	2.9	12.0
gB	1.6	3.1	3.7	7.7	7.6	3.0	3.0	8.6	7.6	3.0
gC	1.5	3.1	3.6	7.6	10.3	2.9	2.9	7.6	11.2	2.9
gE	1.6	3.1	3.1	3.0	2.9	10.9	12.0	3.0	2.9	12.9

Using these results as inputs, the harmonic compliance in the network is assessed by running a harmonic power flow. The results of THD at each bus are given in Figure 5.6. For the least constrained DG capacity at bus gC, it has the worst THD with its individual harmonics given in Figure 5.7 and 5.8. Comparing with the planning level in ER G5/4-1 (shown as red dotted line), both THD and IHD results show that the 42 MW of hosting capacity suggested by the non-harmonically constrained OPF heavily violates the harmonic distortion limits. Therefore, it would not be considered as a viable option by the DNOs without sufficient harmonic filtering being commissioned.

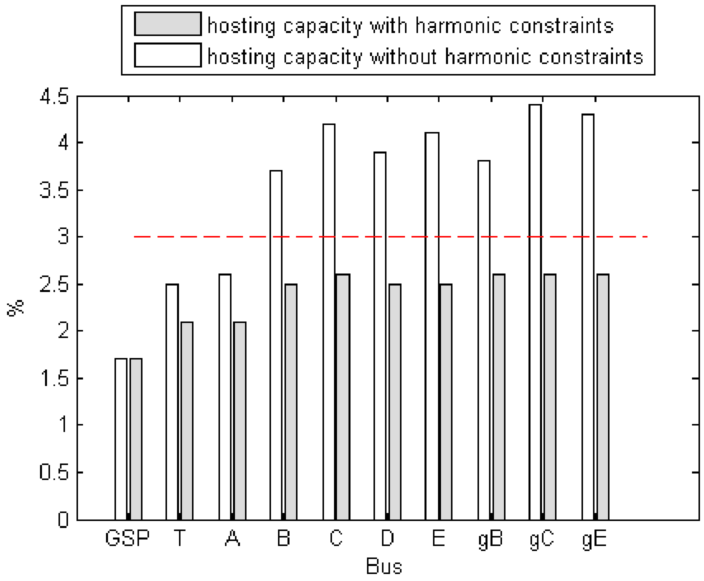


Figure 5.6: THD at each bus under different hosting capacity results

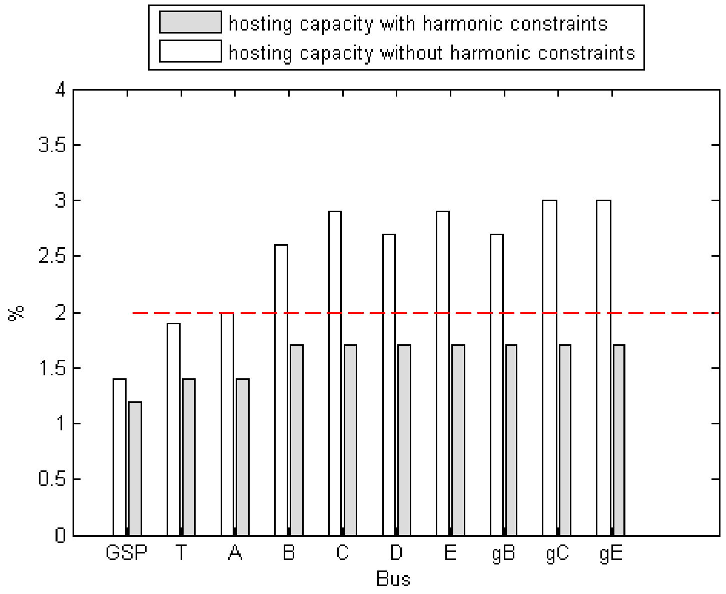


Figure 5.7: 5th harmonic distortion at each bus under different hosting capacity results

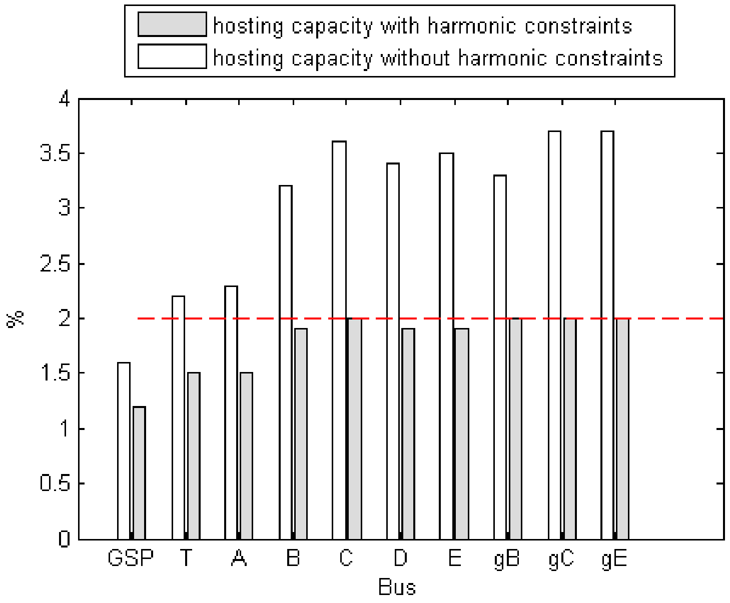


Figure 5.8: 7th harmonic distortion at each bus under different hosting capacity results

5.5.1.4 Harmonic constrained hosting capacity results

With the initial non-harmonically-constrained OPF failing to comply with the G5/4-1 harmonic distortion limits, obtaining a hosting capacity that complies with the harmonic requirements will be helpful in understanding the influence of harmonics on DG capacity and the requirement for mitigation.

Applying the harmonic-constrained OPF approach outlined in Section 5.4, for the same DG harmonic emission characteristics and the same planning level as ER G5/4-1, a revised estimate for maximum DG capacity can be gained. The results are shown in Table 5.6 and Figure 5.9. These show an overall 17MW of DG capacity, a two-thirds reduction from the non-harmonically constrained result.

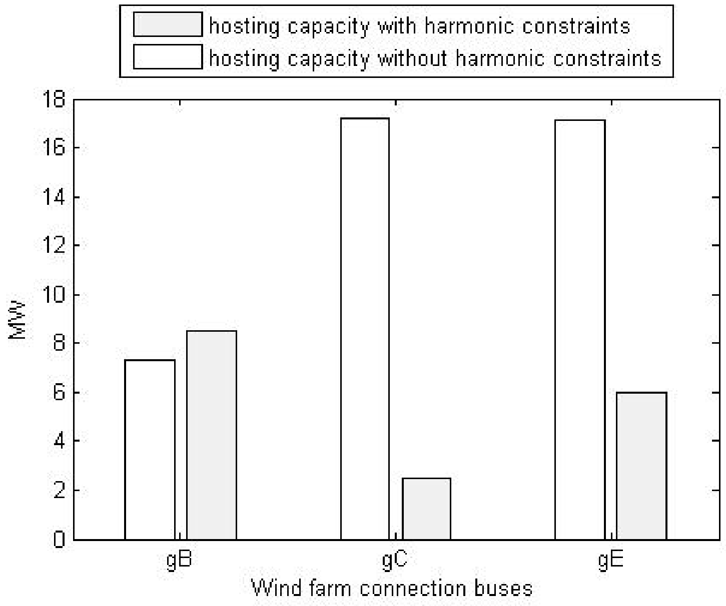


Figure 5.9: Hosting capacity under different constraint considerations

The changes are non-uniform with capacity at buses gC and gE reducing by 86% and 65%, respectively, while the capacity at gB actually goes up by 17%. The reason for the increase at gB is that the large reduction in capacity at gC lowers overall harmonic levels allowing an increase at the less harmonically 'sensitive' gB. The non-uniform changes between OPF and HOPF hosting capacity clearly demonstrate the advantage of the method. The alternative, using harmonic evaluation with non-harmonically constrained OPF results requires manual changes to the DG capacity through a series of harmonic evaluation steps. This will not only be time consuming, but also hard to find the adjustment direction and determine whether to reduce or increase the capacity of specific DGs.

THD and IHD under this capacity allocation are presented in Figures 5.7 – 5.9 alongside the original values. It is clear that the results identified by the HOPF comply with harmonic distortion limits. When inspecting the optimisation result, there are active constraints associated with the 7th harmonic at buses gB, gC and gE which all reach the 2% distortion limit with the latter being the binding constraint that prevents the network from accommodating more capacity. This reduction reflects the importance of introducing sufficient harmonic filter facilities, and with the 7th harmonic treated as a priority in this case.

5.5.2 UKGDS network: multi-period analysis with ANM and mitigation schemes

5.5.2.1 Case description

While the simple 5 bus case clearly illustrates the considerable impact of DG harmonic emissions on the hosting capacity, a more realistic UK distribution network is used in this section as the second case study to discuss other factors including ANM and mitigation methods. The multi-period analysis method is used to calculate harmonic constrained hosting capacity. Under various ANM schemes, the non-harmonically constrained result is presented first then the comparison with harmonic hosting capacity is made. The mitigation effect of active filters is also demonstrated.

The EHV1 Network from the UKGDS [143] previous used in Chapter 4 is also used here and re-drawn in Figure 5.10. The network has one potential location (bus 16) at which new wind farms can be connected. Since the previous Irish case has already demonstrated the redistributive effect of the HOPF, the intention here is to focus on discussing the influence of various load/generation levels, ANM and mitigation schemes. To show the impact of these clearly, a single DG is used, although the analysis could be applicable to multiple DGs as the previous case.

For harmonic analysis, the DG is modelled as current sources. The harmonic generation profile of a medium sized wind turbine in [165] is chosen as the basis for DG harmonic current here. Accordingly, the DG at bus 16 is specified as a wind farm. Figure 5.11 presents the full frequency spectrum of maximum harmonic current produced by this turbine. It extends up to the 50th order (2500 Hz) and shows high harmonic distortion at both lower (5th and 7th orders) and higher frequencies (20th - 30th orders).

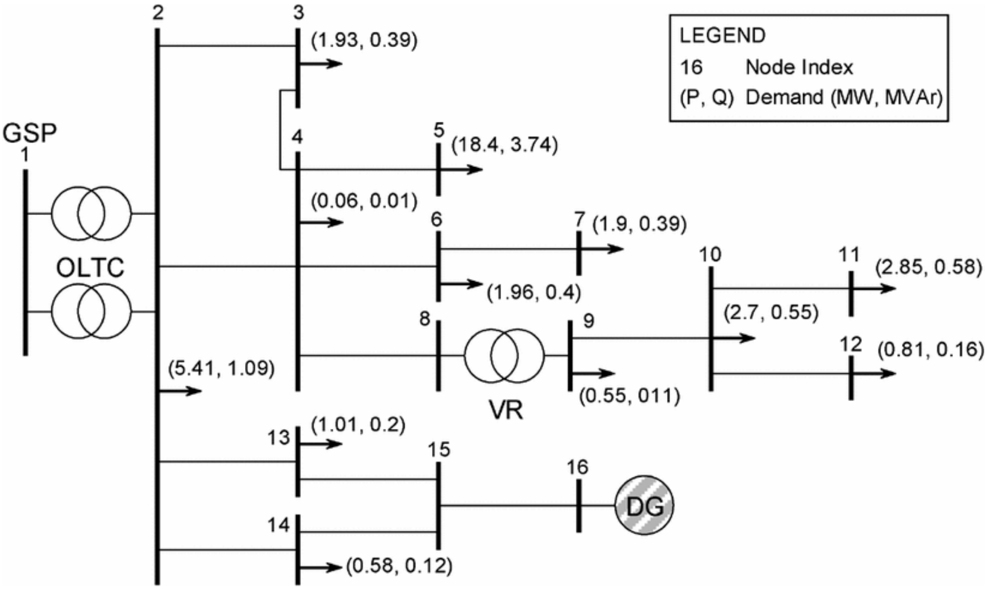


Figure 5.10: Simplified EHV1 network at maximum load [143]

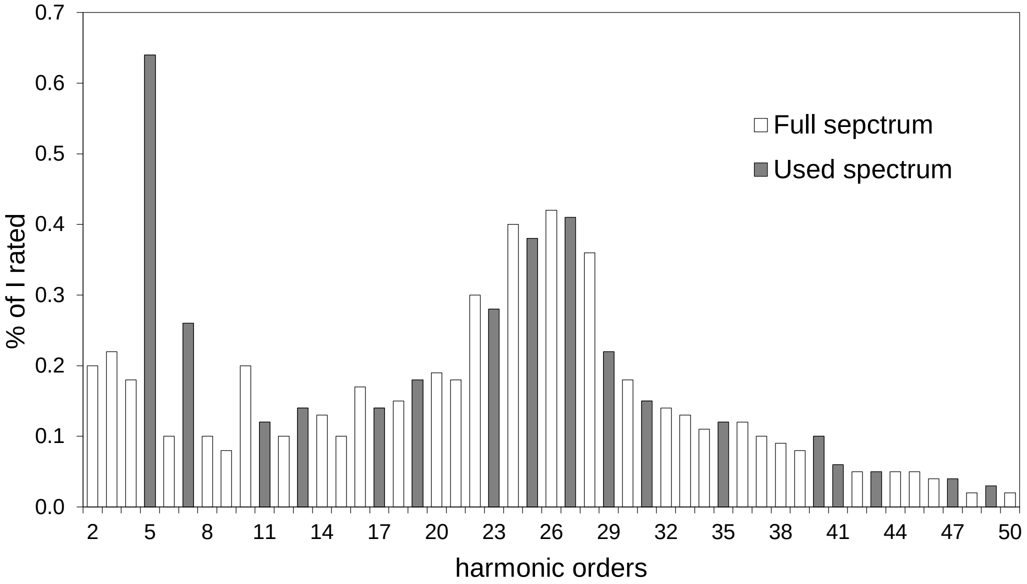


Figure 5.11: Harmonic current injections from the wind farm [165]

In order to facilitate the simulation, all triple harmonic orders (3rd, 6th, etc.) are assumed to be eliminated by the HV-MV transformer when either side is Delta-connected; and all even orders are cancelled since positive and negative parts of the current waveform are almost identical. The remaining harmonic orders are highlighted in Figure 5.11, which will be used in the following simulations. The reduced spectrum still contained most of its original characteristic, such as the maximum value and change patterns, but is more realistic and aids computation.

The DG harmonic model given in (5.14) is used to relate the above harmonic emission profile to DG capacity. Since a wide range of harmonic orders is considered here, it is impractical to assume the level of background distortion for each order like the previous case. All background that already exists in the network is neglected due to the lack of measured data but this can be included effectively where they are available. It would be expected that distortion levels tend to further rise after considering background harmonics.

5.5.2.2 Non-harmonically-constrained hosting capacity results

To provide a basis for comparison, a series of analyses determine the hosting capacity whilst ignoring potential harmonic constraints. The snapshot analyses at maximum and minimum load are first considered, followed by the more sophisticated multi-period analysis over the year. All three cases are based on passive network operation without ANM control methods. Following widely accepted practice, the wind farm at bus 16 is assumed operating at unity power factor. The results for the analyses are shown in the Figure 5.12. It is clear that the DG hosting capacity identified from the snapshot at maximum load is identical to the whole year study while both are much lower than the minimum load case. This is very different from the commonly assumed ‘worst case’ scenario of minimum DG output at minimum load. The reason for this is that the relatively large load at bus 5 forces a high voltage setting at bus 2 limiting the voltage headroom for DG capacity elsewhere. Therefore, it is notable this network is mainly constrained by the power flow transmitted to load at bus 5. The allowed DG capacity is defined at 3.6MW, as determined by the period of maximum load and verified from the multi-period analysis.

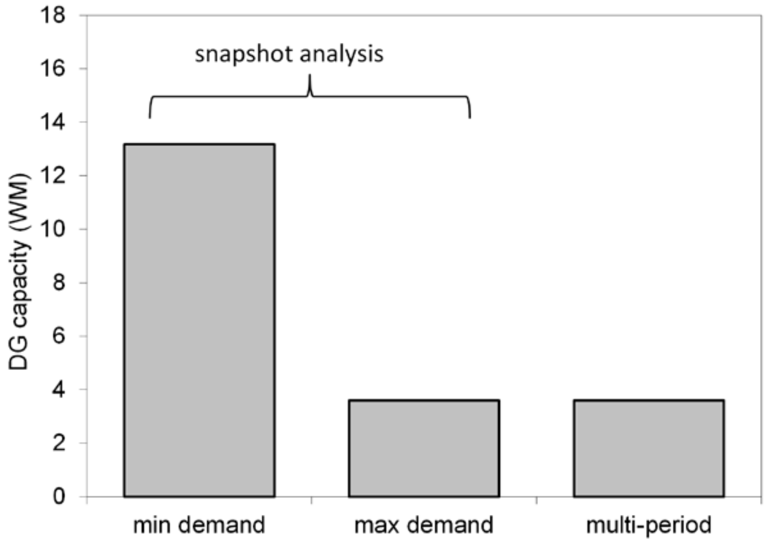


Figure 5.12: Hosting capacity from snapshot and multi-period analyses

The impact of ANM schemes on hosting capacity is now assessed using four different ANM combinations as shown in Figure 5.13. The least effective technique for the network is coordinated voltage control (CVC) which has the almost same hosting capacity as the basic passive case (3.9MW vs 3.6MW); this is unusual but demonstrates the conflicting requirements for the OLTC voltage control. Power factor control (PFC) improves capacity levels by 45% by importing reactive power at peak demand. Allowing wind to be curtailed by up to 5% over the year, sees selective reductions in DG production at peak demand that allow hosting capacity to increase by 148%. After applying all the ANM together, DG capacity slightly surpasses the result for the minimum load snapshot scenario (13.4 vs. 13.2 MW).

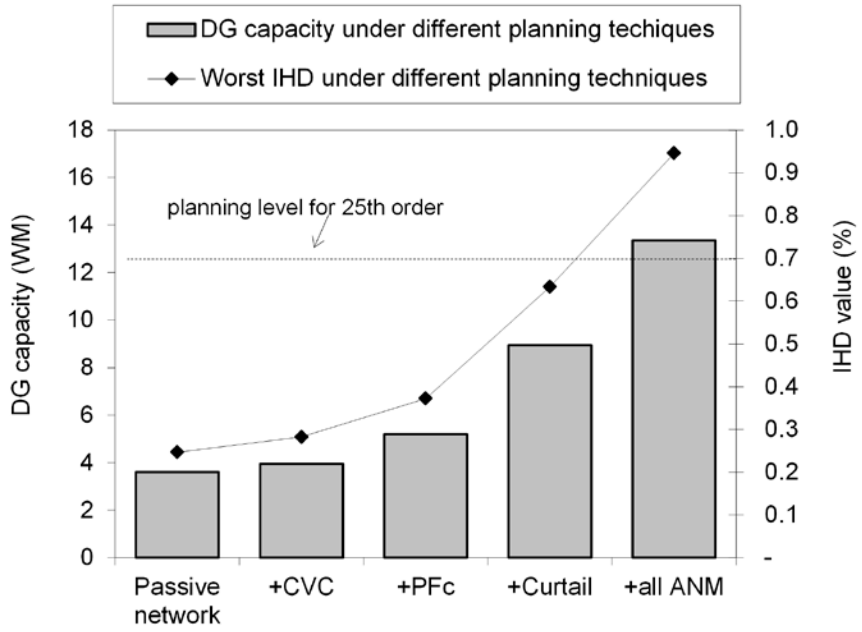


Figure 5.13: DG capacity and voltage distortion for the 25th harmonic order under different ANM cases

To consider whether the suggested hosting capacities are harmonically compliant, a series of harmonic power flow analyses were conducted. The THD in all cases shows compliance but the IHD of order 25 at DG bus 16 violates the requirement (0.7%) in the highest capacity case (full ANM). The IHD results are given as points along with the capacity column in Figure 5.13. Due to the specific topology and loading patterns in this network that restrict hosting capacity, harmonics are not active constraints until higher levels of capacity and/or extensive ANM techniques are applied. However, in general ignoring harmonics from assessments may result in harmonic non-compliance given the scale of new DG capacity enabled by ANM.

5.5.2.3 Harmonic-constrained hosting capacity results

As the initial OPF failed to comply with the G5/4-1 harmonic distortion limits at higher capacity levels, obtaining a planning capacity within the distortion requirements will be helpful in understanding the influence of harmonics on active networks. Applying the harmonic-constrained MOPF model using the same harmonic emissions characteristics, a revised estimate for maximum DG capacity can be gained. The harmonic constrained results are shown in Figure 5.14. The 11.2MW DG capacity is a 16% reduction from the non-harmonically constrained result. The change is entirely the result of the harmonic constraints becoming active and restricting the ANM-enhanced DG capacity to maintain harmonic compliance. The worst IHD for the 25th harmonic order at DG connection bus under each capacity allocation are also presented in Figure 5.14. It is clear that the results identified by the HOPF comply with harmonic distortion limits.

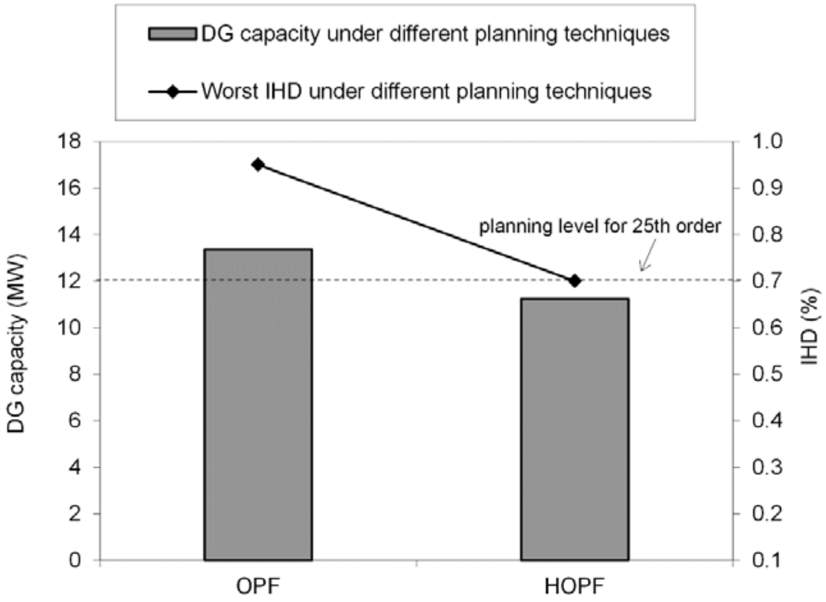


Figure 5.14: DG capacity for ANM case under different constraint considerations

5.5.2.4 Mitigation with active filters

This reduction of hosting capacity indicated by the HOPF suggests the potential value of introducing sufficient harmonic filter facilities to allow hosting capacity to rise, here specifically to treat the 25th harmonic order. To illustrate the influence of active filters a sequence of HOPF analyses were run for the full ANM case with the filter capacity increasing progressively from zero. Figure 5.15 shows the impact of these active filters on the hosting capacity. It demonstrates that the hosting capacity initially increases with filter size as larger filters offset more of the 25th harmonic.

The levelling off of hosting capacity despite larger filters indicates that the harmonic constraint has become non-binding and other constraints start to dominate.

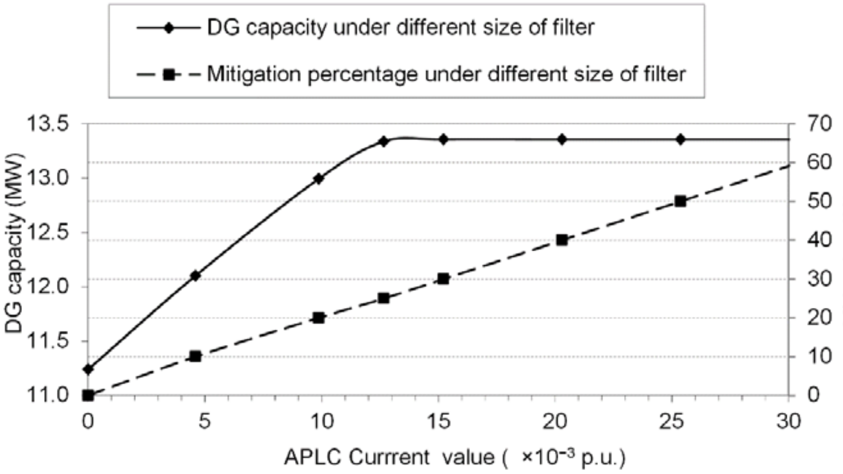


Figure 5.15: Impact of different sized filters for full ANM case

5.6 Discussion

As mentioned earlier, one option for defining DG capacities that comply with harmonic limits is to undertake an indirect iterative process of: (1) obtaining DG capacity from the only voltage and thermal constrained analysis; (2) running classic harmonic power flow to check harmonic compliance; and (3) if any violation occurs, reducing the capacity step by step until the final result complying with harmonic limits. On the face of it this is a straightforward process, but in practice it is more difficult to ensure optimality, especially when there are multiple DGs in the network. As demonstrated in Table 5.6 , the proportional changes at each DG bus between the initial OPF and final harmonic-constrained OPF capacities are not the same and in the case bus gB actually increases after considering harmonics. Hosting capacity is significantly changed by the re-distributive effect of harmonic constraints. Therefore, it is inappropriate to define the same reduction ratio among DGs for the repeating procedure. As such the proposed harmonic-constrained MOPF method, which directly and explicitly links DG capacity and harmonics, is more effective in handling the complex interaction between different DG in terms of harmonic emissions as well as voltage and thermal constraints.

While the harmonic constrained multi-period OPF method can effectively consider the DG variable output (demonstrated in the UKGDS case), predicting the harmonic emissions under specific outputs is complex. As discussed in Section 5.3.4, DG emission characteristics are affected by a number of factors, such as turbine technology and the internal grid, therefore it is difficult to make a fully generalised output-dependent harmonic model to use in the multi-period analysis. Snapshot analysis using the critical harmonic scenarios may be preferred in practice where the detailed knowledge of DG is not available. In these snapshot cases, the harmonic constrained multi-period OPF framework is still effective and applicable (as demonstrated in the Irish network case). Using the same formulation, analysis can be rapidly conducted by limiting the set of scenarios or just considering the worst case.

In the larger second case study network, the reduction of the hosting capacity considering harmonic limits is clearly demonstrated, especially when ANM ‘frees up’ sufficient new capacity. With the development of smart grid techniques, the distribution network will be able to accommodate increasing DG but consequently will introduce more harmonic generating sources. It is important to conduct harmonic study at the initial planning stage to avoid this violation risk. The proposed harmonic evaluation framework can be effectively extended to incorporate a wide range of ANM schemes.

Alongside DG harmonic emission, nonlinear load is another main source for harmonic distortion in distribution network. While the background level is assumed at a relatively low value in the case study, it could be significant in practice when increasing electronic-based active loads have been connected into the network. Extensive measurement efforts are required to determine the hosting space left by nonlinear load in terms of harmonic compliance.

When harmonic limits highly influence DG capacity, harmonic filters could be installed as a mitigation solution. The cost of filters requires appropriate placement and trade-off analysis, so that an optimization method is useful in this respect. As shown in the case study, the active constraint found by the harmonic constrained OPF can indicate the harmonic order(s) that constrains DG and also determines the level of mitigation required. The proposed method here would also lay the basis of future cost-benefit studies for harmonic filters.

5.7 Chapter summary

In this chapter, the method of evaluating the network hosting capacity to accommodate DG without violating harmonic distortion limits alongside other constraints is developed. Harmonic distortion limits are introduced as new constraints embedded into an established OPF framework. The proposed harmonic-constrained OPF provides additional information to guide DG developers and DNOs in maximising DG capacity. Based on the proposed HOPF techniques, potential harmonic mitigation solutions such as active filters are briefly explored in terms of their ability to free-up capacity.

As demonstrated in case studies, the harmonic propagation following a non-harmonically constrained optimisation suggest that violation of harmonic distortion limits and consequently impractical DG capacity levels can occur especially when ANM ‘frees up’ sufficient new capacity. By incorporating THD and IHD planning level limits into the optimisation, harmonic constrained DG capacity sees a substantial reduction in the connectable capacity. While the harmonics act as binding constraints in the case network, the evaluation still needs conducted on a case-by-case basis.

To obtain accurate harmonic constrained hosting capacity, considerations on random variation and distribution nature of DG harmonic emission are also discussed. Based on the current knowledge, it is concluded that it is difficult to make general statements on the selection of preferred DG harmonic models for planning studies. While simplified models are used in the formulations of this chapter and results might be overestimated, the proposed harmonic constrained OPF can easily adopt more complex harmonic models.

The work in this chapter provides the study of DG harmonic emission, which is the second topic of hosting capacity this thesis examined. The work in the third and last topic will be presented in Chapter 6, where the benefit of energy storage systems for DG curtailment reduction is studied and incorporated into the assessment of hosting capacity.

Chapter 6

Incorporating Energy Storage System into Assessment of Hosting Capacity

6.1 Introduction

Increasing penetration of distributed generation (DG) in distribution networks requires techniques to provide greater flexibility and better use of existing network assets. Whilst the output reduction by non-firm connection arrangements (discussed in the chapter 4) is beneficial in terms of managing network constraints, curtailment necessarily features the loss of revenue to DG developers.

The rapid development of energy storage systems (ESS) provides one promising solution for increasing DG capacity without wasting curtailed energy. The DG generation that exceeds the network hosting capacity are captured and stored in ESS for later use, thus reducing the otherwise-spilled energy. The co-operation of ESS with non-firm DG can add benefits for both DNO and DG developers but needs to be properly planned.

In the ESS-supported DG schemes, investment viability relies on the performance of both DG and ESS. In order to maximise the total return, the planning study that can incorporate ESS characteristics (such as charging strategy, maximum charging/discharging power, charging efficiency, etc.) and co-optimising DG and ESS capacity together is of interest. However, this combined hosting capacity problem is very challenging. The time sequence approach is generally necessary for the ESS study, which involves inter-temporal links between time periods over the optimisation horizon. The multi-period techniques used in previous chapters therefore are not directly suitable for this ESS-associated hosting capacity problem.

In this chapter, an evaluation method to determine the economic hosting capacity of combined DG and ESS scheme is developed. It begins with a summary of ESS roles in the power system, where the comparison of two main applications is presented. A detailed literature survey focusing on ESS optimisation problems is also provided to target the challenges for this research. Then, the ESS modelling approach and control strategy are described. These are used to develop a two-step approach to co-optimise both ESS and DG capacity so that the total economic return can be maximised. The case study and discussions are also presented. Finally, the chapter summarises the outcomes and highlights areas for future study.

6.2 Research background and challenges

To identify the research requirements for adapting ESS in the DG curtailment scheme, a brief review of ESS roles in the power system is first presented in this section. Among these technical potential roles, two of the economically most promising applications in the current UK electricity market are compared. While the simple comparison presents attractive results, its validation requires more detailed analysis. The research challenge is outlined in the following detailed literature survey focusing on ESS modelling and optimisation techniques.

6.2.1 The role of ESS in power systems

Discussions on the role of ESS in the power system have been made in [166-168]. They addressed a wide range of ESS technologies, namely hydroelectric storage systems, compressed air energy storage, flywheel energy storage, semiconducting magnetic energy storage, and battery energy storage systems (BESS). Comparisons of different storage technologies were also presented. In the reviews, BESS is generally found to be of particular interest for DNOs, given its commercial readiness. In this context, the research in this chapter is laid out on the BESS basis. The term ESS in the following sections could be interpreted as being limited to BESS.

Based on the literature review, the roles of ESS in power systems include:

- *Price trading (or arbitrage)*: purchasing electricity during the period of low spot prices and then selling at the period high price;
- *Asset deferral*: shaving peak load to defer the need for additional transmission facilities;
- *Fluctuation suppression*: flattening and stabilising the variations in generation output;
- *Frequency Support*: supporting the grid frequency during the sudden loss of generation over a short interval;
- *Forecast Hedge*: reducing the errors in generation forecast and mitigating risk of violating the bidding position in the market;
- *Curtailment reduction*: reducing or avoiding the loss of curtailing generation under insufficient transmission capacity;
- *Black-Start*: starting up on their own in order to energise other facilities to start-up and synchronise to the grid;
- *Power quality improvement*: reducing oscillations or disruptions (such as flicker) of sensitive loads;
- *Reliability improvement*: providing bulk or distributed reserves to ride through a power disruption.

While technically ESS is beneficial to the network in so many aspects, it may not always be an economically viable solution in each application. Firstly, the cost of ESS is still expensive [169]. Moreover, the market mechanism which can reflect the benefits of installing ESS is not clear, such as the rewarding for asset deferral and penalising for forecast error. The applications which have high potential to achieve economic feasibility by itself are limited. In the current UK electricity market, two of the most widely mentioned promising options for the ESS investment are price arbitrage and curtailment reduction.

6.2.2 Curtailment mitigation vs pricing arbitrage

To demonstrate the financial benefits of the selected ESS applications, a simple comparison of the benefits from curtailment mitigation and pricing arbitrage is presented. The electricity price is simplified into two blocks: peak demand (set as occurring at daytime) and low demand (night). The latter is given as £50/MWh, and four peak demand price cases are investigated with a rise of 25%, 50%, 100% and 200% respectively above the low demand price. The same ESS is used, capable to time-shifting 18-MWh of energy for both load arbitrage and curtailment reduction scenarios in the day. While the arbitrage explores the price differences through buying and selling with the grid, the ESS in the curtailment reduction scheme is considered to store otherwise spilled energy at no cost and its return is only related to selling price. Accordingly, its revenue ranges from the best case where all otherwise-spilled energy is sold at peak price, to the worst case where it is all at low price.

The results for these different application cases are given in Table 6.1. The benefit from the curtailment reduction scheme is considerably higher than all arbitrage cases until the on/off peak price differential reaches 200%. If including subsidies such as ROCs (currently £51.34/MWh) in the curtailment reduction scheme, the differences are even bigger. For the best case, the curtailment-mitigating ESS can obtain 800% more revenue compared to the arbitrage at 25% price differential, and 100% more than the arbitrage at 200% price differential.

Table 6.1: Revenue comparison (typical day) of ESS application scenarios between load arbitrage and curtailment mitigation

ESS application scenarios		On/off peak Price difference			
		25%	50%	100%	200%
Arbitrage		£225	£450	£900	£1800
Curtailment mitigation	*worst*	£1822	£1822	£1822	£1822
	best	£2047	£2272	£2722	£3622

It is notable that the economic returns of these selected ESS application are determined by the assumed spot prices. In the UK electricity market, the distribution function of price increase within one day across 2009 is shown in Figure 6.1 [170].

As suggested, the chance of the price rising above 200% in the next 24 hours is lower than 10%. On this basis, the simple comparison indicates that the arbitrage scheme would be less economically competitive than the curtailment-mitigation model for most of the time in the UK.

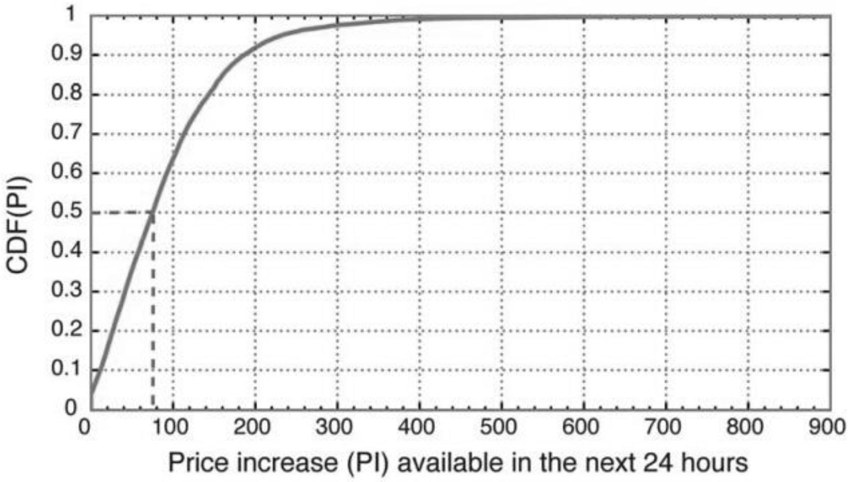


Figure 6.1: Cumulative distribution functions of electricity spot price increase (%) in 2009

While the results from this simple comparison prefer the curtailment reduction scheme, the finding is not conclusive. The final validation will be determined by the ESS real utilisation factor over a long period, instead of simply studying a single day. For price arbitrage, demand generally shows the variations between day and night, and therefore ESS is more likely to follow a fixed daily pattern. But for the curtailment reduction scheme, the intermittent output (especially for wind) means the curtailment will not be confined to a certain period of the day. Moreover, the curtailment in most cases is uncorrelated with beneficial spot prices [171]. Therefore, the economic advantage of the curtailment-driven ESS as indicated in the simple comparison could be largely reduced or even reversed in a specific case.

To investigate the true value of curtailment-reducing ESS, detailed study of the network over a long period is necessary. The complexity arises from the need of modelling the network, the DG and the ESS characteristics together. It is not a straight forward issue to determine the economic viability. Optimisation methods are required to obtain the maximum total return from the DG and ESS investment. This will be discussed in the following sections in more detail.

6.2.3 ESS optimisation with DG

To build up the understanding in the area of ESS modelling and optimisation, a literature survey focusing on ESS applications with renewable DG, especially related to the ESS ‘sizing’ problem, is presented below in this section.

The combined wind generation and ESS system was suggested as economic imperative in [172] by taking into account the ESS cost. The ESS is mainly used for two objectives: (a) maximise returns from the market considering the best forecast; and (b) minimise risks considering the forecast uncertainties. The ability of reducing curtailment under high penetrations of wind is not considered. The study focuses on the 24-h horizon, a day-ahead unit commitment process which provides a linear programming optimisation to schedule a given size of ESS, but the sizing problem is not studied.

The mixed wind farm, ESS and flexible load system was studied in [98] aiming to maxing the total energy exported. A novel dynamic optimal power flow (DOPF) is developed specifically to model the time dependent feature of ESS and flexible demand. Using the proposed DOPF framework, the optimal operation of ESS could raise export and also reduce curtailment of non-firm DG. Similar to [172], the application of the ESS is for one-day horizon scheduling. The case study showed that although the export energy increases with bigger ESS the marginal benefits are reduced. It implies that a properly sized ESS is needed for this application but was not clearly investigated.

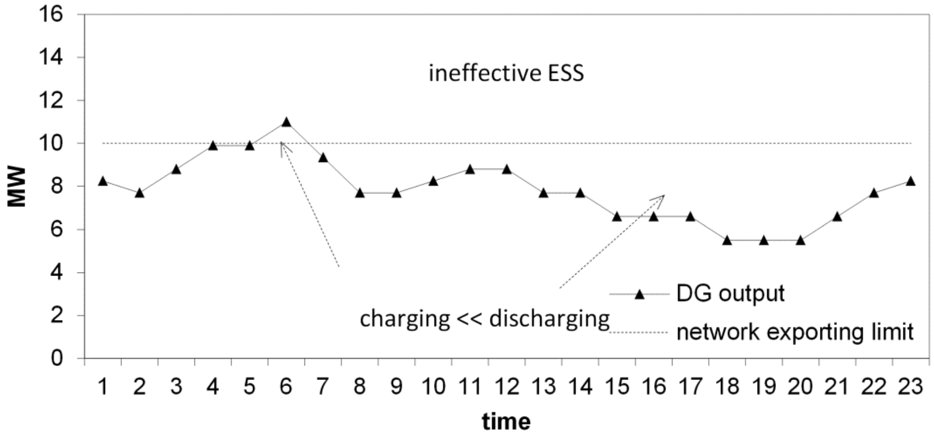
The optimal sizing of ESS is considered together with a smoothing control strategy in [173]. The developed methodology uses fast-acting ESS to cover the uncertainty of wind plant output and reduce reserve requirements. The work demonstrated that through the coordinated control, the combined output of ESS and the wind farm can be buffered within a tight range of deviations from the forecast. It is notable that the use of ESS in this application has few effects on the base revenue since it does not greatly change the total generation. The benefit of ESS in the work depends on the specific market setting, where the wind farm would be penalised if its actual output is under or over the forecast production.

An integrated cost analysis for renewable generation and ESS in autonomous electrical networks is presented in [174]. The analysis takes into consideration the initial cost of the energy storage equipment, the input electricity and fuel costs, as well as the fixed and variable O&M cost of the entire installation. Based on the case study, it concluded that by reducing import energy requirements, electricity production cost reduced. However, the work tends to overestimate the benefits from the combined ESS and renewable generator system, due to use of a simplified ESS model which largely neglected the inter-temporal constraints on the operation of the ESS battery.

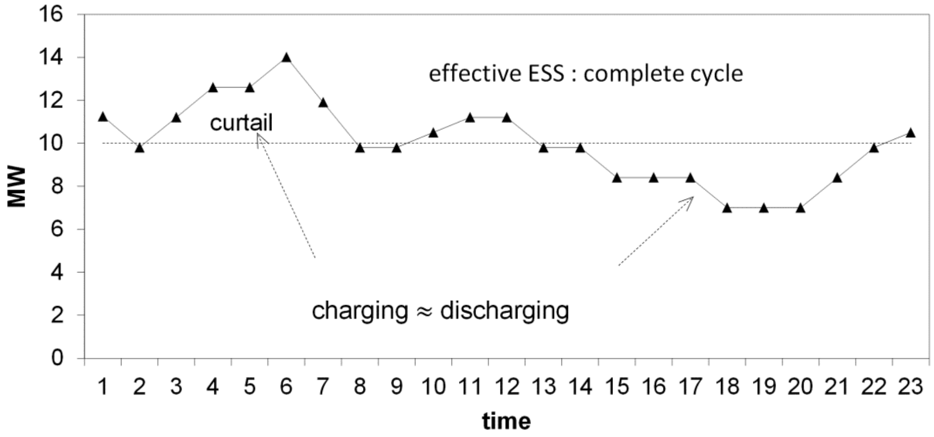
The work in [95] investigated the locating problem of ESS to fully accommodate the otherwise spilled energy in the network with high penetration of wind generation. A methodology based on OPF is proposed for optimally allocating ESSs in order to minimize the annual electricity cost. The cost/benefit analysis is also conducted and showed the proposed application is economically feasible only when the least expensive ESS is used. The work modelled the ESS operations based on a daily cycle assumption: where the curtailment always occurs at night when demand is low and exporting capacity for discharging is always available in the day; accordingly the ESS is able to complete one charge/ discharge cycle every day. This fixed daily cycle would easily become invalid in most cases of high DG penetration as the curtailment does not only occur during the night.

From the above literature survey, it is clear that a reasonable amount of work has been done in the area of optimising ESS to mitigate the problems arising from the lack of coincidence between renewable DG and demand. However, these works all focus on planning or operating ESS for a given network with installed DG. In fact, a poorly installed DG may largely reduce the viability of ESS or even make the any project infeasible. To maximise the value, the capacity of ESS needs to be co-optimised with the capacity of DG together. The need for co-optimisation can be illustrated using the case in Figure 6.2. In a network with the 10 MW exporting capacity limit, the operation of same sized ESS under three different DG capacity cases (a = 11MW, b=14MW, c=17MW) are compared. By inspection only the proper size of DG (b in the case) can help the ESS effectively complete a full charging/discharging cycle while the others two cases either (a) see too few or (c) too frequent curtailment, with the ESS not fully used and reduced benefits.

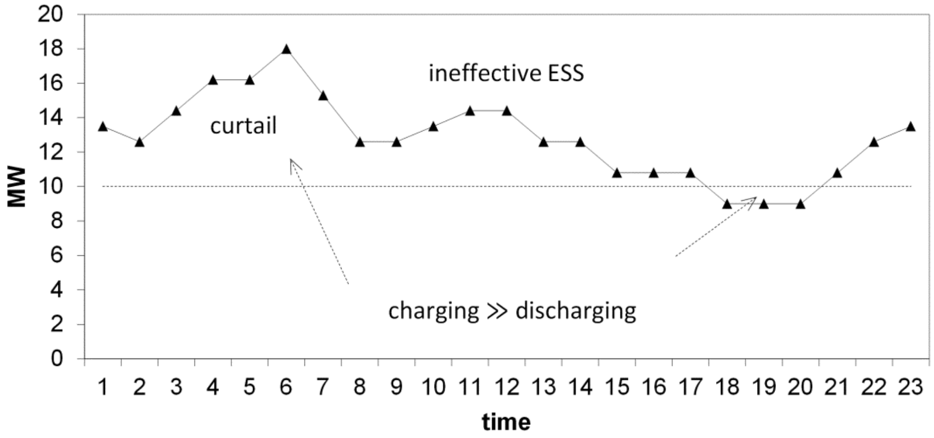
While it is clear that the DG capacity has a significant impact on the ESS performance, the concept of optimally integrating ESS into the DG planning solution has not been investigated yet in the literature. The objective of this work is to develop a hosting capacity analysis method to co-optimise the size of DG and ESS. The optimal combination of DG and ESS is determined so that the increased DG can be accommodated and the otherwise curtailed energy can be effectively utilised by ESS. The overall objective would be evaluated in the economic manner to maximise the total return of the entire installation.



a) DG size = 11MW



b) DG size = 14 MW



c) DG size = 17MW

Figure 6.2: Impact of DG sizing on ESS operation

6.3 Evaluation method

The suggested evaluation method for optimal sizing of ESS and DG together is developed in this section. The ESS modelling and its control strategy are explained first, and then a novel optimisation technique is proposed to tackle the complexity arising from the dynamic features of ESS and the requirement of a long study horizon.

6.3.1 ESS modelling

In general, ESS, especially battery ESS, consists of a power electronic interface to control the charging/discharging power flow. The power electronic interface is composed of high frequency switching devices which could be challenging to model. Several equivalent models for ESS have been developed: some studies use more accurate dynamic models [175, 176] for evaluating ESS behaviour in relatively short periods, while others employ more simple models to study the impact in the whole network [95, 98, 177]. The suitability of these modelling techniques depends on the application and the desired goal. In this work, a model which simplifies the convertor model but takes into account the battery dynamic state is adopted and explained as follows.

The ESS is modelled as illustrated in Figure 6.3, and consists of a power electronic converter and a battery. The ESS can be seen as a generator during discharging or a load during charging. Its output would be controlled within the power rating of its energy converter (P^{+}_{ESS}, P^{-}_{ESS}). Both the charging and discharging operation will incur losses. The model takes this into account through charging efficiency $EF_{charging}$, and discharge efficiency $EF_{discharging}$. The production of the two efficiencies defines the round trip efficiency EF_{round} per MWh electricity stored.

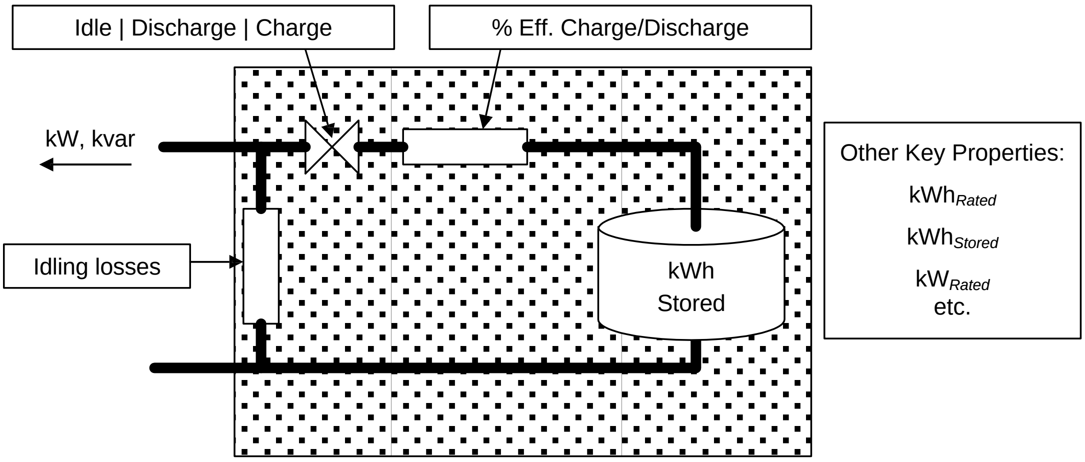


Figure 6.3: Generic model of energy storage system

The amount of electricity that has been stored after a given period t is termed as the state of charge (SOC_t). It needs to be updated at every time interval according to:

$$SOC_{t+1} = SOC_t + (P^{+}_{ESS,t} \cdot EF_{charging} - P^{-}_{ESS,t} / EF_{discharging}) \cdot \tau_t \tag{6.1}$$

where $P^{\pm}_{ESS,t}$ are the power of the charging (+) or discharging (-) during the time interval, and they will not occur at the same time, and τ_t is the time interval between t and $t+1$.

The ESS also has a maximum and minimum state of charging (SOC^{+}, SOC^{-}). Whilst it is able to charge up to the rated capacity of the battery, a minimum amount of space in the battery could be reserved at all times, in order to provide support in the network disturbances. Similarly, a small amount of stored energy could be always maintained in the battery during any discharge operation to preserve its lifespan. This battery model with limited available capacity can be illustrated in Figure 6.4.

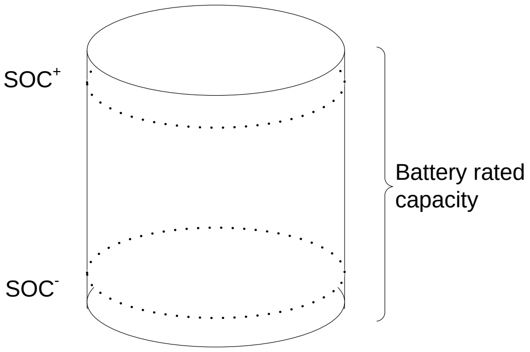


Figure 6.4: Battery model with limited available capacity

6.3.2 Charging and discharging strategy

There are two main strategies of charging and discharging operations: optimal dispatch and fast cycle. The optimal dispatch controls ESS to improve overall performance across the control horizon while the fast cycle strategy simply raises the output of ESS (charging/discharge) up to the limits in each time interval.

The dispatch strategy is generally related to spot price arbitrage. Under the given battery capacity, ESS is scheduled to exploit the biggest price difference to reach the maximum economic return over the whole period. Whilst the optimal dispatch promises better performance, it could be heavily affected by the accuracy of forecasts. An additional concern is that the computation burden of the dispatch is unduly increased with the expansion of schedule horizons. It is suggested in [99] that dispatch at a single bus over a 4 month horizon requires a high performance parallel computer running for 2 hours.

Compared with the optimal dispatch, the fast cycle strategy is more suitable to be applied in the DG curtailment scheme. The curtailment-driven ESS is constrained by the resource nature and in most cases lack of correlation with the spot price differences. While the optimal dispatch may control the ESS to discharge saved curtailment at higher price, the uncorrelated curtailment largely reduces the chance of realising this benefit. In fact, the evaluation of ESS in a curtailment reduction scheme depends on its utilisation factor. By quickly emptying the stored energy for the next charging period, the fast cycle strategy provides a practical way to increase the utilisation factor and avoid the uncertainty from forecasts.

6.3.2.1 Fast cycle strategy

The formulation of the fast cycle strategy is presented as follows with the validation on a simple case:

Charging

The schematic diagram of the ESS charging process in the fast cycle strategy is presented in Figure 6.5. The charging operation is used to reduce curtailment by storing all the otherwise spilled energy unless it reaches the limit.

At time interval *t*, if the DG output ($P_{g,t}$) exceeds the current network exporting limit for DG ($P_{n,t}$), the decision-making process is activated. At first, the remaining battery capacity for charging is checked by comparing the state of charge SOC_t with the upper limit SOC^+. Unless the battery has been already fully charged from the previous time, the ESS begins to charge the excess energy at the minimum required or maximum allowed charging rate. The charging power is calculated by three factors: the power rating of its energy converter P^+_{ESS}, the available battery capacity ($SOC_+ - SOC_t$) and the minimum required curtailment ($P_{g,t} - P_{n,t}$). The minimum of the three factors determines the final charging power. The curtailment only occurs when the ESS cannot store all the excess energy. After the time interval *t*, the ESS enters into the next period *t*+1 with updated SOC_{t+1} which is calculated by (6.1).

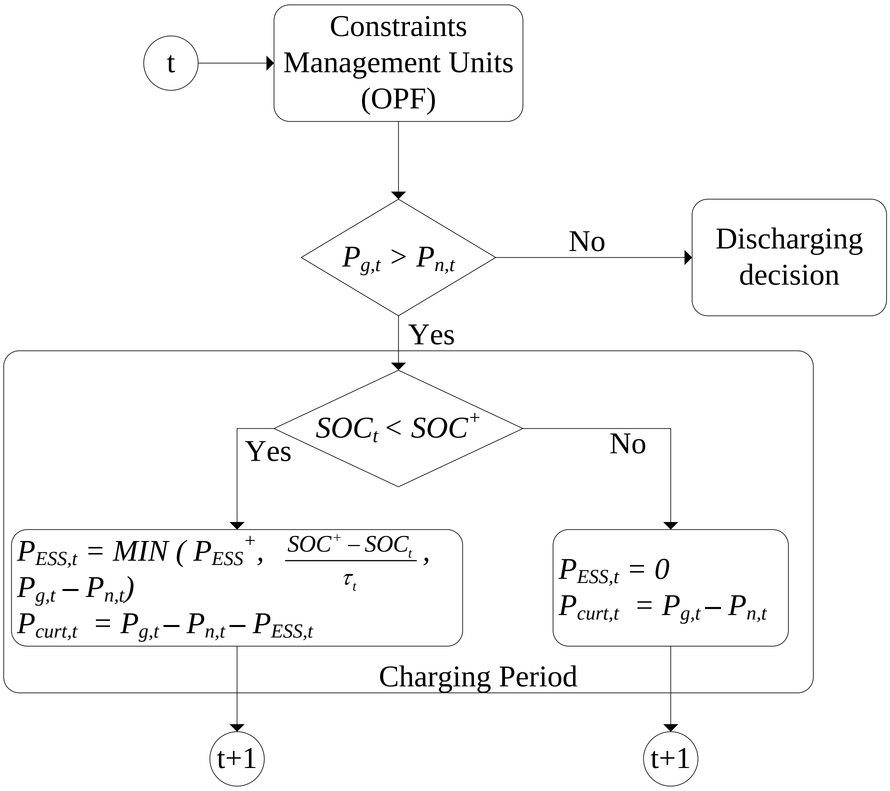


Figure 6.5: Control flow under charging procedures

Discharging

Following the charging period, ESS will discharge the stored energy once the network has unused exporting capacity (illustrated in Figure 6.6). Under the fast cycle strategy, ESS output power for discharging is set at the maximum allowed discharging rate (governed by its power rating and network exporting capability). As illustrated in Figure 6.6, the calculation of discharging rate ($P_{ESS,\,t}$) at time interval t takes into account the rating of the power electronic converter (P^{-}_{ESS}), the total stored energy after previous times (SOC_t – SOC^{-}), and the maximum network spare exporting capacity ($P_{n,t}$ - $P_{g,t}$). Similar to the charging state, the minimum of these three factors actively constrains the discharging power.

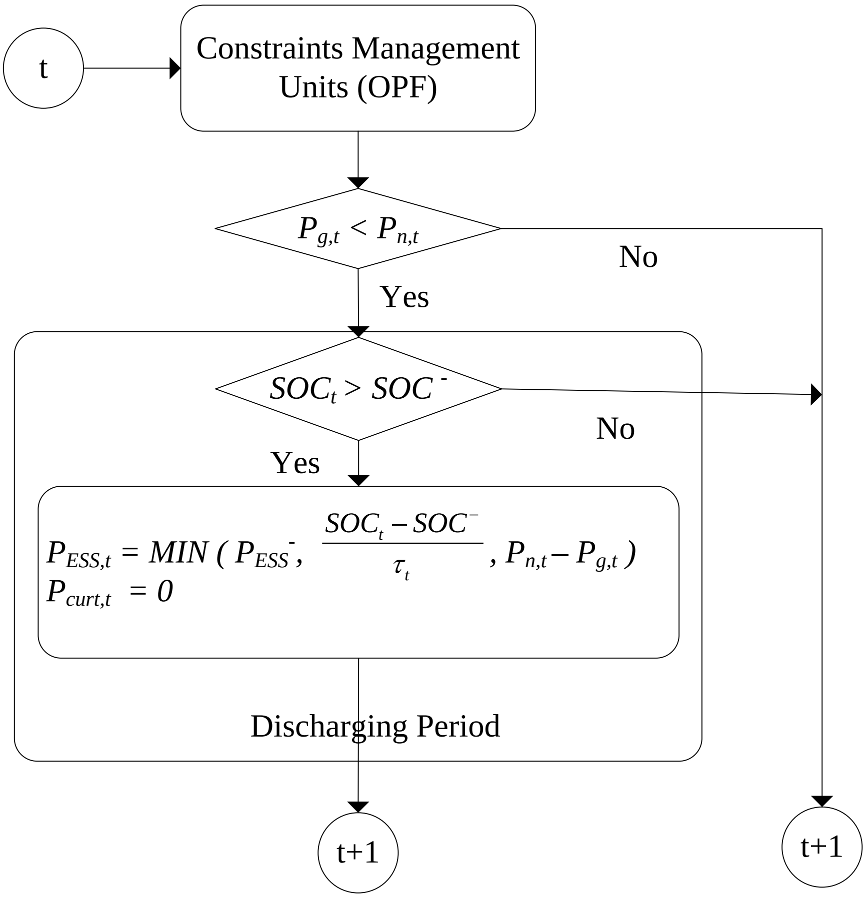


Figure 6.6: Control flow under discharging procedures

6.3.2.2 Model Evaluation

To validate the fast cycle strategy, a simple case is demonstrated in Figure 6.7. An ESS with 2MW output rating and 10MWh battery is applied in a network with fixed exporting limits and variable DG output. In the 24 hour simulation, the ESS enters into charging mode when the DG output exceeds the network exporting capacity, but its charging power is limited by its rating power (constrained at 04:00 – 06:00 as indicated in Figure 6.7(b)) and its battery size (constrained at 12:00 in Figure 6.7(b) since being fully charged at 11am in Figure 6.7(c)). Following the charging operation, the ESS discharges the saved energy once the network has unused exporting capacity (08:00 - 09:00 and 13:00 – 21:00). The discharging cycle fully exploits the network capacity until the battery is mostly discharged (at 20:00). It can be seen from the Figure 6.7(d) that the original curtailment is reduced by 69%. The ESS battery also returns to almost empty status at the end of the day (in Figure 6.7(c)) and therefore ready for the curtailment-mitigating operation for the next day.

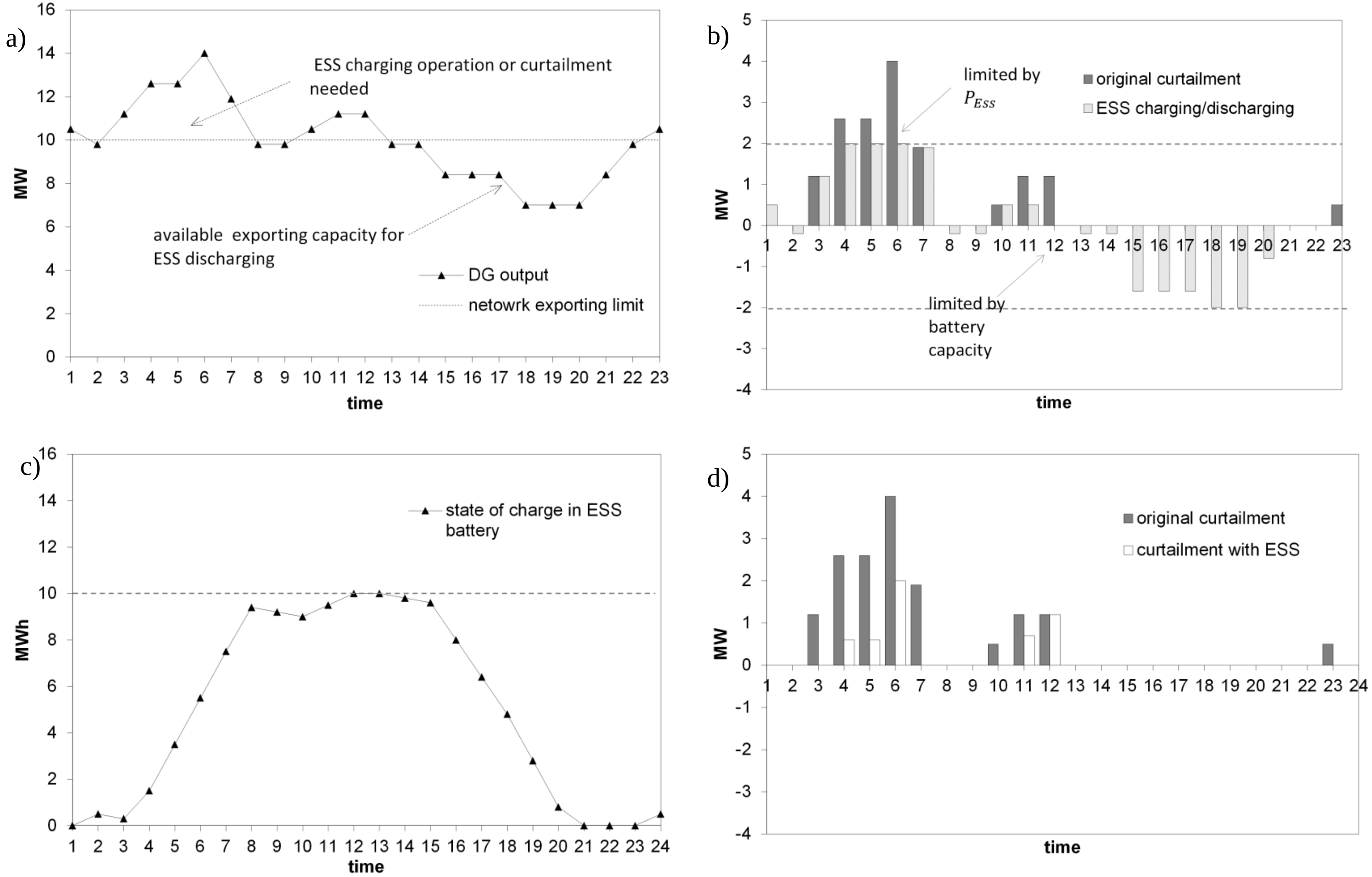


Figure 6.7: Validation of the charging strategy in a simple case

a) DG output; b) ESS charging/discharging power; c) ESS battery state of charge; d) curtailment with ESS.

6.3.3 Integrated system optimisation

6.3.3.1 Objective function

When the DG developers or DNOs consider installing an ESS to improve benefits obtained from the planned non-firm DG, they need to undertake detailed assessments of the likely coordinated operation in order to estimate the output and saved curtailment. These values are determined by the size of both ESS and DG, but also constrained by other factors, such as resource levels, network characteristics and the coordinated control strategy. The complex process could continue using the established knowledge of the (economic) ‘hosting capacity’ study as a guide. It is extended from the DG itself to the combination of DG and ESS. The aim of this hosting capacity analysis becomes to maximise the total return (*RE*) from the integrated system. The objective function can be formulated as follows:

$$\max \left\{ RE(P_g) + RE(ESS) \right\} \tag{6.2}$$

The evaluation of DG return $RE(P_g)$ has been discussed in Chapter 4. Its calculation is based on: the income obtained from selling the energy produced at the electricity price R_t (which could include a subsidy mechanism as well as the wholesale price); the capital cost C_{inv} and the operations and maintenance cost C_{om} (both are a function of DG capacity P_g); and any applied compensation charges E_{com} governed by ANM priority schemes:

$$RE(P_g) = \sum_{t \in T} (P_{g,t} - P_{g,t}^{curt}) \cdot R_t - E_{com} - C_{inv} - C_{om} \tag{6.3}$$

Across the whole time period T, P_g is the installed capacity of DG g and $P_{g,\mathrm{t}}^{curt}$ is the extent of energy curtailment in period t.

The ESS obtains its return $RE(ESS)$ from selling the stored energy though discharging at electricity price R_t. In the curtailment reduction scheme, ESS charges energy at no cost to reflect the fact that this energy would be otherwise spilled, and therefore it is not considered in this formulation. The capital cost of ESS contains the cost of electronic convertor units and batteries, which are calculated as a function of rating power of the convertor (P_{ESS}^{+} , assuming $P_{ESS}^{+} = P_{ESS}^{-}$) and the maximum allowed charging capacity of battery (SOC^{+}), respectively. The operations and maintenance cost $C_{om,ess}$ is also included and calculated on an annual basis. The formulation of ESS return is given as follows

$$RE(ESS) = \sum_{t \in T} P_{ESS,t}^{discharging} \cdot R_t - C_{converter} \cdot P_{ESS}^{+} - C_{battery} \cdot SOC^{+} - C_{om,ESS} \tag{6.4}$$

The complexity of evaluating the formulated objective functions can be easily identified as the inter-period behaviour of the ESS itself and its interrelationship with DG capacity which determines the curtailment.

In the following subsections, an attempt to use an integrated simulation to solve the optimisation is presented first, following by a two-step simulation which provides a more practical solution to the problem.

6.3.3.2 Integrated simulation: initial study

The OPF in the previous chapters provides a foundation to build up the solution for the co-optimised sizing issues here. The special consideration for adapting these OPF techniques to ESS study is that a sequential time-series approach is necessary, since the charging states of ESS requires the inter-temporal link between contiguous periods over the optimisation horizon. While the multi-period OPF approach is effective in reducing the computational burden by aggregating actual time-series data into a limited data set, this method is not directly applicable for ESS since its aggregation process eliminates the time sequence among the original data.

The initial study formulates an integrated simulation aiming to directly find the solution. Built upon the established multi-period OPF formulation [20], two significant modifications is made: 1) instead of applying the aggregation process, the original time-series data is used directly. Accordingly, the aggregated period *m* in the multi-period OPF formulation is replaced by actual time step *t* in the time sequence.

2) ESS-related variables and constraints are added. The formulation of these ESS-relevant elements at each time step is given below:

1) Coordinated DG and ESS output P_{net}:

$$P_{net} = P_g \omega_t + P_{ESS,t}^{discharge} - P_{ESS,t}^{charge} - P_{g,t}^{curt} \quad \forall t \in T \tag{6.5}$$

2) ESS rating power constraints:

$$0 < P_{ESS,t}^{charge} < P_{ESS}^{-} \quad \forall t \in T \tag{6.6}$$

$$0 < P_{ESS,t}^{discharge} < P_{ESS}^{+} \quad \forall t \in T \tag{6.7}$$

3) ESS state of charge constraints:

$$SOC_{t+1} = SOC_t + (P_{ESS,t}^{charging} \cdot EF_{charging} - P_{ESS,t}^{discharging} / EF_{discharging}) \cdot \tau_t \quad \forall t \in T \tag{6.7}$$

$$SOC^{-} < SOC_{t+1} < SOC^{+} \quad \forall t \in T \tag{6.9}$$

These formulations are implemented in the AIMMS optimisation suites. However, the CONOPT solver failed to generate solutions on an even small network. The obvious difference between the above time-series OPF and the proven multi-period approach is the size of the unknown. For the same data used in previous chapter, the multi-period method manages to reduce the whole year time-series of hourly demand and generation data into 78 scenarios (M =78), which is significantly less than the time steps (T = 8760) required by ESS here.

To identify the implementation limits, different sizes of optimisation horizon are tested in AIMMS, which range from one day, one week and one month up to the whole year. Only the case with reduced study horizon, namely one day up to one month are able to solve. Any case over 1000 periods gives the AIMMS solver too many variables to calculate. However, on the basis of hourly time scale, the study over two months already involves an optimising horizon with 1440 time intervals.

On the one side, the intermittent output of DG and the correspondingly curtailment-driven ESS operation requires long-term study, typically over a whole year. And the inter-temporal linkage within the ESS model does not allow the optimising horizon being aggregated. On the other side, the AIMMS solver can only process the optimisation with a large but finite number of unknowns. The initial approach which directly modelled this as a single integrated OPF results in too many scenarios to be solved. Therefore, an alternative method was required.

6.3.3.3 Two-step simulation

To reduce the complexity of thousands of unknown variables and constraints, a two-step procedure is developed. This is illustrated in Figure 6.8.

At the first step, the exporting capacity in the network is evaluated for the each time interval across a year, especially at the potential locations where DG and ESS is to connect. The hosting capacity analysis simply assuming firm generation (without considering the resource level in this first step) and solving at each time interval with the varying demand level. From this, it generates a non-aggregated time-series of network exporting capacity ($P_{n,1}, P_{n,2} \dots P_{n,8760}$) at location n. This solution is to be used as input to the second step.

With reference to figure 6.8, t;he second step uses an analytical approach. It begins with an initial size of DG and ESS. Then, the time-series simulations across the whole study horizon governed by the proposed fast cycle strategy are repeated with the gradually increased DG and ESS capacity. The resource level at each time interval which governs the varying DG output is considered at this step. The operation of DG and ESS are determined by the assumed capacities, resource level and the network exporting capacity obtained from the previous step. For each size of the DG and ESS, the economic evaluation, namely$RE(P_g) + RE(ESS)$, is calculated based on times-series simulation. Comparing all results within the search space, the maximum financial return is obtained and with it, the economically optimal size of the DG and ESS.

By splitting the integrated simulation outlined in previous subsection into two steps, each only considers a subset of the variables and constraints. The first step focuses on determining network exporting limits which vary with demand while the second investigates the ESS and DG under the identified network constraints. In terms of study horizon, the separated snapshot AC OPFs in first step follow the time sequence but without links between each other. The time series simulations at second step consider the inter-temporal relationship of ESS charging status but it does not involve dynamic optimisation. In terms of computation intensity, the OPF used at first step for the exporting limit evaluations only tackle variables within each time interval. A series of such separated snapshot OPFs is much faster than a single integrated OPF optimising across the whole horizon as the initial attempt (which is infeasible over 1000 intervals). While the second step involves an analytical approach that exhaustively explores the entire (or most of) search space, it is not necessarily computationally intensive. The evaluation of ESS performance with each capacity from the search space can be efficiently implemented using the fast cycle control strategy. Moreover, since that ESS in the curtailment reduction scheme is generally located alongside the non-firm DG, rather than distributed across the network, the size of the search space is limited.

In this way, the computational burden arising from the combination of a long optimisation horizon and the dynamic feature of unknowns which initially result in an implementation-infeasible OPF, is largely reduced.

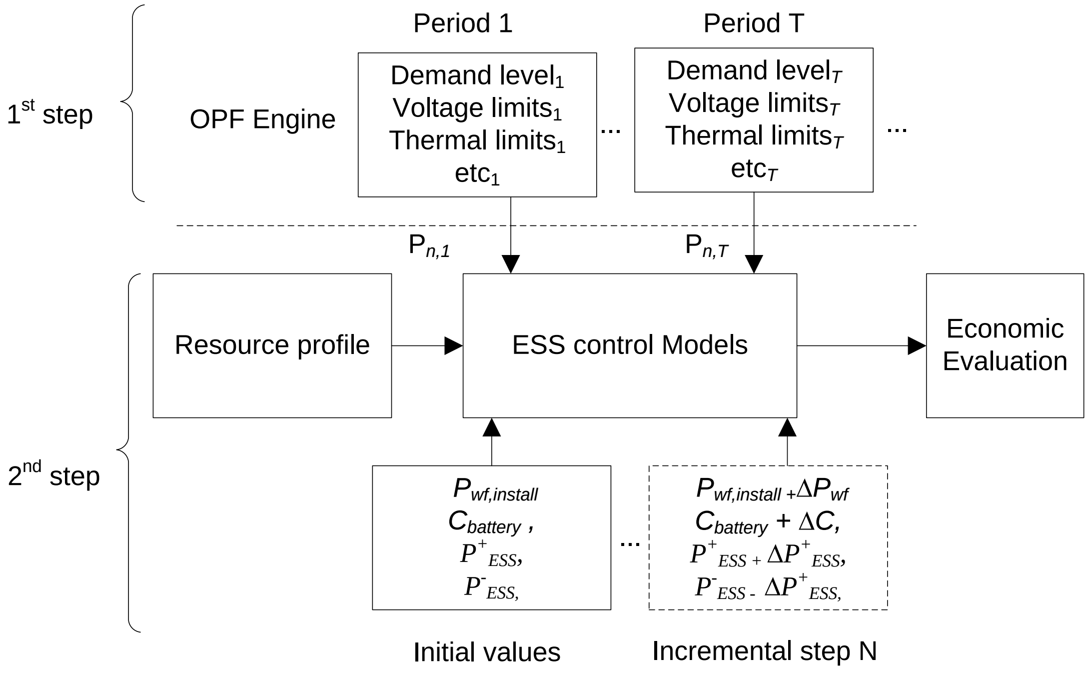


Figure 6.8: Schematic diagram of the two-step procedure for ESS performance evaluation

6.3.3.4 Implementation

The two-step evaluation is implemented using the AIMMS and MATLAB suites. The OPF at the first step is solved by the AIMMS non-linear solver CONOPT 3.14A. The ESS control model at the second step and the final economic evaluation through the search space is coded in MATLAB.

The mixed use of AIMMS and MATLAB follows the similar implementation strategy as previous chapter: AIMMS is efficient to handle non-linear programming in the first step, and established OPF formulations can be easily adapted to incorporate the development here; MATLAB performs better in manipulation of matrix and arrays, therefore it is used in the second step to simulate the ESS operation over a number of search steps. Although an integrated implementation is possible only using AIMMS, the required MI(N)LP technique would be more complicated. The combination of AIMMS and MATLAB used here has been proven computationally efficient. The evaluation in the case study over the whole year is completed within 7 minutes.

6.4 Case study

To demonstrate the proposed optimisation method, the case study is presented in this section. The hosting capacity analysis is extended in the previous used network to maximise return from the non-firm DG and ESS together. The study uses historical data [178] and considers the different mix of energy resources and ESS technologies to assess the economic viability. By demonstrating the use of the optimisation techniques developed, some important issues are highlighted and discussed.

6.4.1 Case description

6.4.1.1 Network descriptions

The simplified EHV1 Network from the UKGDS [143] (previously used in Chapter 4 and 5, and reproduced in Figure 6.9 with ESS) is used here. For this network, the binding constraint limiting DG connection is voltage rise. To facilitate connections, a Coordinated Voltage Control (CVC) [20] scheme is deployed to dynamically control the OLTC at the substation. This ANM setting is expected to amplify the differences of hosting capacity between planning options in the case network.

Since the focus here is to discuss the benefits of ESS on curtailment reduction, and demonstrate the use of the developed method to determine the economic hosting capacity for an ESS supported DG planning project, a single DG and ESS is used to make the results clear. It could be extended to consider the multiple DGs case as in chapter 4, where DG developers complete for connection and the curtailment rules have an important role. The implication for the network with multiple DGs the will be concluded on the discussion parts of this thesis.

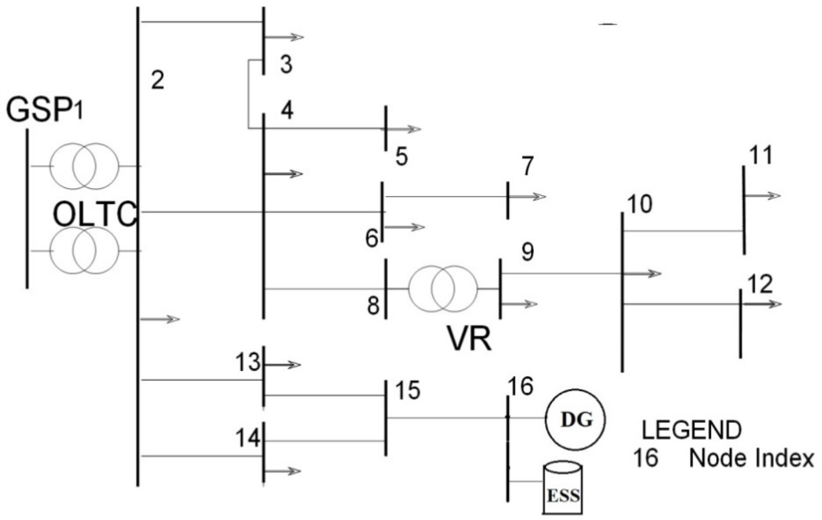


Figure 6.9: Simplified EHV1 Network with DG and ESS connected

6.4.1.2 Electricity demand

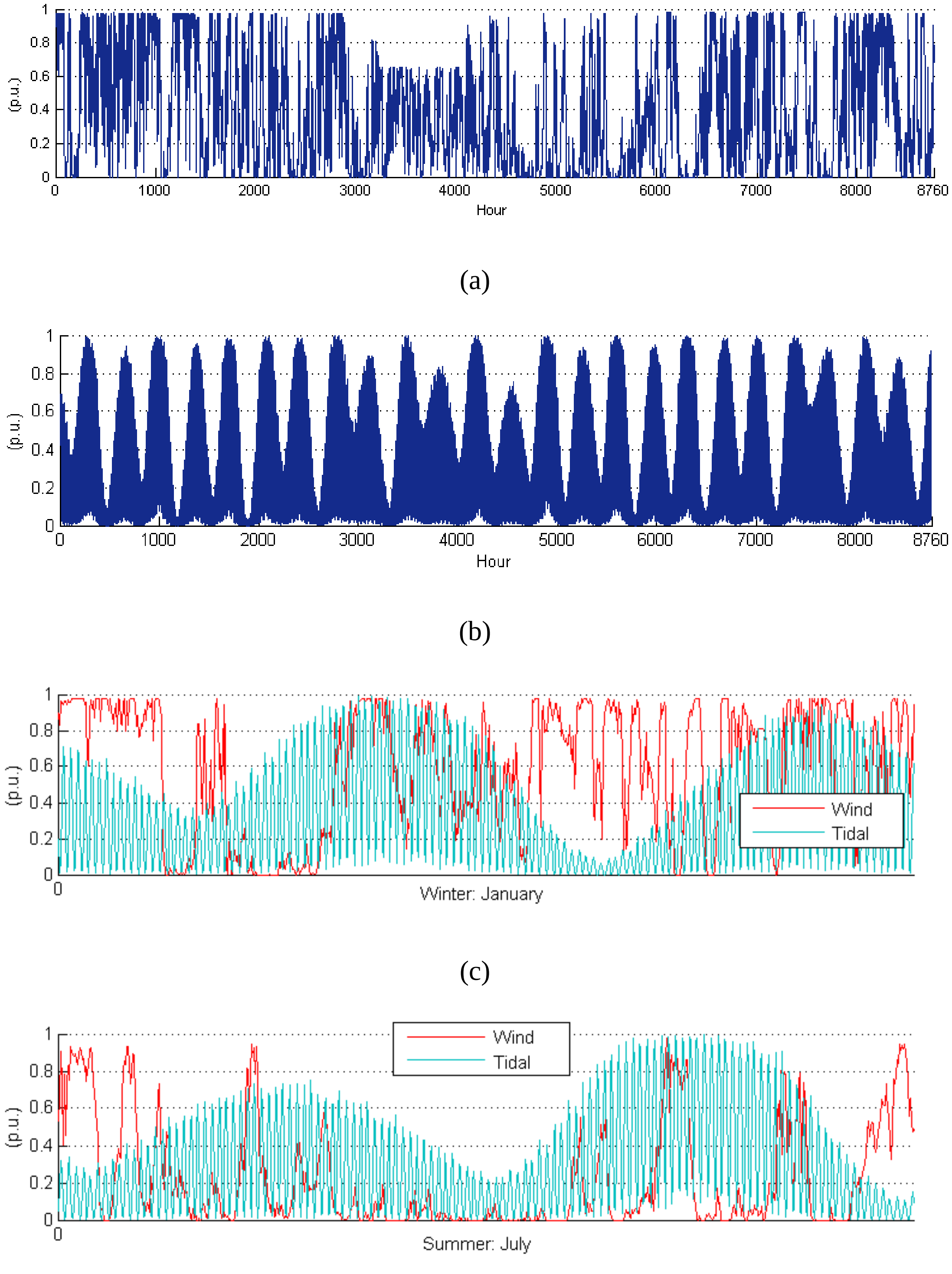
Hourly demand data for electricity from central Scotland in 2003 [178] is used. The load factor is 0.63. Demand values in the network are scaled correspondingly. This demand profile displays the regular daily, weekly and seasonal variations. The majority of the demand occurs within the moderate level (60-80% of peak demand) while the peak demand itself only happens for 83 hours for the whole year, similar to the lowest level of 110 hours.

6.4.1.3 Onshore wind and tidal resources

The DG connection point is located at bus 16 as shown in Figure 6.9. The output is driven by the corresponding resource profile. Hourly historical data from two energy resources are examined: onshore wind [20] and tidal current [179]. These data are illustrated in Figure 6.10. The aim is to show the impact of their different intermittent characteristics on the hosting capacity analysis. The wind data is from 2003 and has been used in the previous chapters (see chapter 4 &5). The tidal data is from 2009 but it is used as coincident with the demand data in 2003.

The capacity factor of the wind profile is 40%. Whilst it is higher than the UK average of 27%, the wind resource is not evenly distributed across the year. As shown in Figure 6.10, the wind in the summer is generally lower than the winter. The difference between the windiest month (66.6% in February) and the least (19.3% in August) is significant. Moreover, the variations between each day are also considerable. If the DG requires curtailment under this wind profile, the occurrence possibility and frequency would be quite different across days and months. Consequently, the operations of ESS aiming to reduce the curtailment may vary significantly across the period.

The capacity factor of the tidal profile is 31%. Compared with wind, the tidal pattern is shown to be regular with daily and weekly variations, and no strong seasonal impact exists. It is beneficial for the ESS to increase the cycles of charging/discharging. The long-term period study could help to quantify this impact.



(a)

(b)

(c)

(d)

Figure 6.10: Hourly output levels for the wind and tidal resources

(From top to bottom: the whole year output of wind (a) and tidal current (b); the comparisons in winter (c) and summer (d))

6.4.1.4 DG cost, electricity price and subsidies

The cost of DG based on the energy types is provided in Table 6.2. The DG using tidal energy is more expensive than onshore wind, since tidal current devices are at a relatively early stage of development before fully commercialisation. With this high cost, it is still of interest to investigate its economic viability. The UK has great potential for tidal current energy production [180, 181]. The development of tidal generation been boosted by the government though higher subsidies. In the recent Renewables Obligation Certificates (ROCs) setting [144], tidal generation receives 5 times more ROC payments than onshore wind. This could significantly impact the economic performance of the tidal DG and its associated ESS. The wholesale price of electricity is given as £50 per MWh and the price of ROC is £51.34 (the same as Chapter 4).

Table 6.2: Economic parameters used in DG cost estimation

	Onshore Wind	Tidal Stream
Capital cost (£/kW) [147]	1524	3500
Operation and Maintenance cost (£/kW per year) [147]	57.2	200
ROCs (per MWh) [144]	1	5

6.4.1.5 ESS cost

The ESS capital cost varies widely with techniques. Several promising battery technologies can be considered in the curtailment reduction applications: lead acid (LA), valve-regulated LA (VRLA), sodium sulphur (Na/S), zinc/bromine (Zn/Br) and vanadium redox (VB) [173]. The Na/S and Zn/Br ESS are used as examples here, which is cheaper than the others. Table 6.3 presents the cost estimate of these two ESS technologies. Due to the fact that they are both not fully commercialised, the cost estimate shows the large variability in the literature. While the cost parameters used are uncertain, it aims to demonstrate the optimisation techniques presented. In addition, the cost for ESS storing otherwise-curtailed energy is set as zero.

Table 6.3: Economic parameters used in ESS cost estimation [95, 182]

(Figures from the references are converted to Pounds Sterling at: £1 = US$1.71)

	Na/S	Zn/Br
Efficiency	0.77	0.77
Unit cost for power electronic (£/kW)	585	102
Unit cost for storage battery (£/kWh)	292	131
Fixed O&M cost (£/kW)	12	12
Number of charges/discharges in life	2500	10000

6.4.1.6 NPV

In the following evaluation, all economic returns are calculated using net present value (NPV), based on a 20 year lifespan and 10% discount rate (annuity factor of 8.51). For clarity, it is assumed that the resource and demand level remains the same over the project lifetime. This could be extended to include more sophisticated assumptions about inter-annual variation.

6.4.2 Optimisation Setting

The study is carried out on an hourly time step over one year using the two-step optimisation method. The key results from the optimisation are the combined capacities of the ESS and DG together, which gives the maximum total NPV. Aside from them, the analytical process within the optimisation, which involves the repeated simulations at incremental steps across the whole search space, also provides the information to investigate the impact of the key characteristics. A set of results are presented and studied in the following subsections, including:

- Network export limits;
- Hosting capacity of DG without considering ESS, and the maximum return;
- Hosting capacity of the combined DG and ESS, and the maximum total return;
- The impact of DG capacity on ESS performance;

- The impact of Battery size on ESS performance;
- The impact of the output rating of the power electronic units on ESS performance.

6.4.2.1 Step 1: the network exporting limit evaluations

The first step of the study is identifying the network exporting limit at the DG connection point for each time step. The results (presented in Figure 6.11) are obtained by re-running the snapshot OPF through the year time sequence. Since the resource level is not considered in this stage, the results only vary with the demand level. It is expected that the low demand period, as generally regarded as 'worst case scenarios', will have the less export capacity. However, in this specific case, the heavy load at bus 5 (counts for 48% of the total demand) actively constrains the available export capacity at DG connection bus 16. Given they are separately connected to the same GSP, the voltage drop effect from the load conflicts with the voltage rise required from the DG. This condition becomes worse at higher load level. This reverse relation is clear shown in Figure 6.11. The lowest exporting limit is identified at approximately 4MW which is the same as the Chapter 5 (the CVC case).

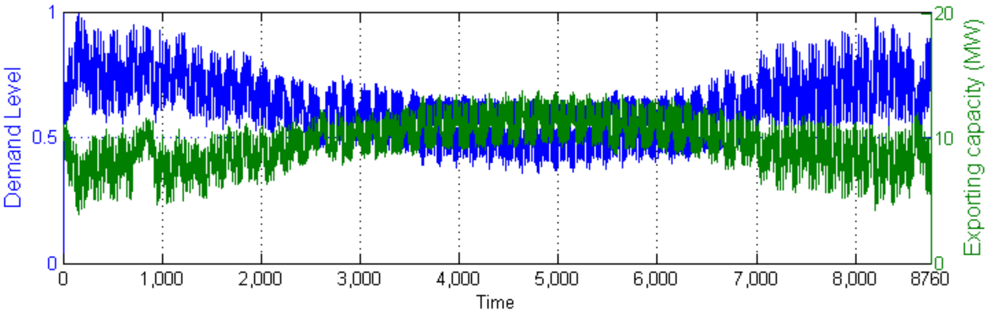


Figure 6.11: Hourly exporting limits at the bus 16

6.4.2.2 Step 2: DG and ESS evaluation

With the network export limits identified, the capacity evaluation of DG and ESS together is conducted across the search space. The initial capacity of DG is set as 3 MW and increased by 1MW for each simulation up to 40 MW. Within each DG capacity scale, the ESS capacity is searched by increasing: 1) its power output from 0 MW to the maximum required curtailment power; 2) and its battery size from 0 to 100 MWh, separately.

6.4.3 Wind case

6.4.3.1 Wind: without ESS

A base-case scenario that analyses the optimal wind DG capacity without considering ESS is given first. Since the network has the lowest 4 MW exporting capacity at the bus 16, DG with the capacity beyond that level will need to connect in a non-firm manner and curtail its output when it breaches the limits. While curtailment enables increased capacity, the capacity factor is reduced, this diminishes the marginal benefit. It is shown in Figure 6.12 that the wind DG reaches the maximum return with 9MW capacity but reduced capacity factor of 38%.

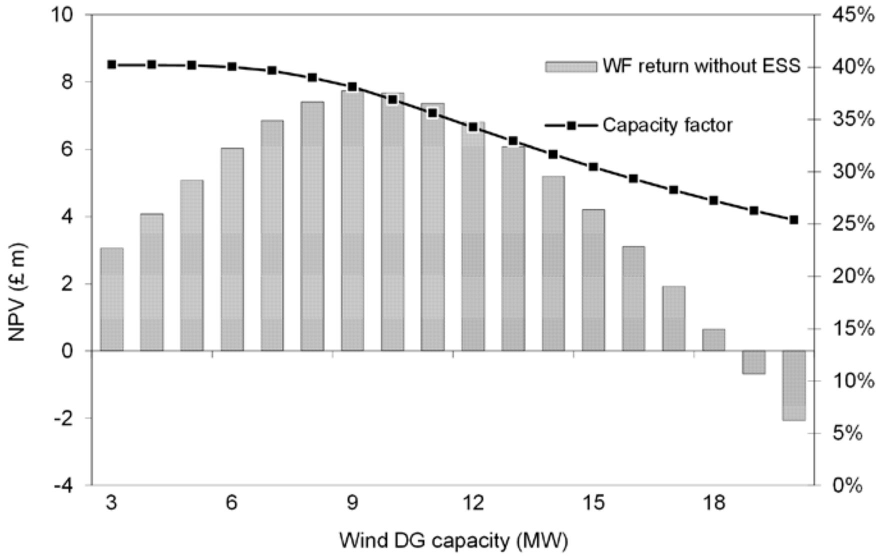


Figure 6.12: Optimal wind DG capacity without considering ESS

6.4.3.2 Wind: with ESS

The analysis is re-run adding ESS into the optimisation, firstly with Zn/Br and then Na/S ESS technology. Across the search space, the optimal combination of the DG and ESS is identified and given in Table 6.4. It shows that the optimisation actually attempts to avoid the ESS by limiting its capacity at the lower bound of the searching space (0 MW/0 MWh). It means in the scenario modelled, using ESS to reduce the curtailment would not be economically viable regardless of the capacity combinations. There always is a net cost brought by ESS rather than a net benefit to the project.

Table 6.4: Optimal capacity and return of wind DG with and without ESS

	Without ESS	With Zn/Br ESS	With Na/S ESS
DG capacity (MW)	9	9	9
ESS battery (MWh)	-	0	0
ESS power rating (MW)	-	0	0
DG NPV (£m)	7.7	0	0
ESS NPV (£m)	-	0	0
Total (£m)	7.7	7.7	7.7

6.4.4 Tidal case

6.4.4.1 Tidal: without ESS

The study is repeated with the tidal case. The results of the tidal base case are presented in Figure 6.13. The optimal tidal capacity without ESS is 11 MW with 5.7% curtailment, which generates maximum NPV of £17M. They are significantly higher than the wind case. Although the tidal DG has lower capacity factor and is more expensive to build, the significantly higher ROC subsidy has largely facilitated the tidal capacity here and boosts the return. With higher incentives, tidal returns change with its capacity in the same manner as wind. The law of diminishing returns applies to the capacity factor and marginal benefit. The maximum return sees the capacity factor at 29.5% in Figure 6.13, after which the marginal benefit become negative; further increasing capacity will only reduce the returns.

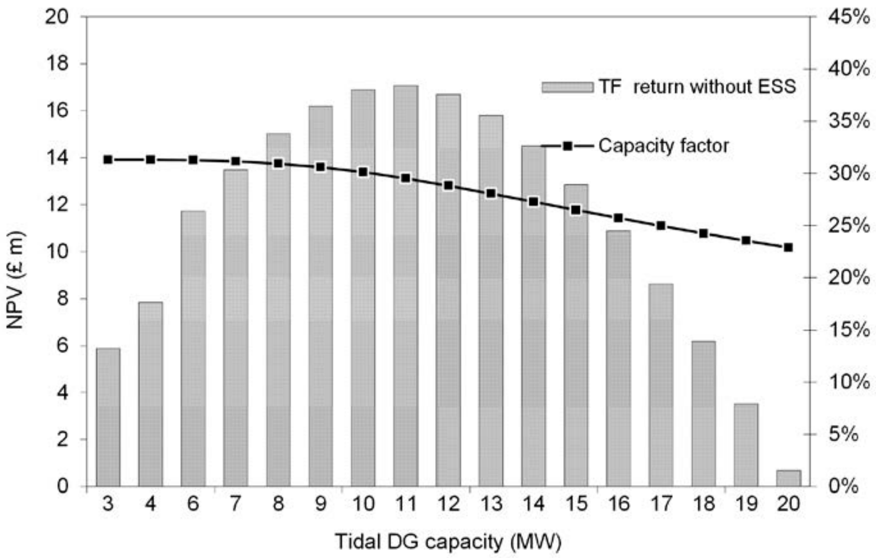


Figure 6.13: Optimal tidal DG capacity without considering ESS

6.4.4.2 Tidal: with ESS

The ESS supported tidal DG is then evaluated and presented in Table 6.5. Different from the wind case, the ESS generates economically viable results with the optimal combined capacity here. Compared to its base case, the total return is 2.3% higher with the Na/S ESS and 25.5% with Zn/Br ESS.

Table 6.5: Optimal capacity and return of tidal DG with and without ESS

	Without ESS	With Na/s ESS	With Zn/Br ESS
DG capacity (MW)	11	13	16
ESS battery (MWh)	-	6	15
ESS power rating (MW)	-	3	7
DG return (£m)	17.1	15.8	10.9
ESS return (£m)	-	1.7	10.6
Total (£m)	17.1	17.5	21.5

An interesting point from Table 6.5 is that the tidal DG capacity within the optimal combination is higher than in the base case. It shows the DG capacity impacts on both the DG and ESS return. While the increased capacity actually comes with the reduced return for the DG itself, the ESS return under this DG capacity surpasses the loss and generates higher overall return. The trade-off between the DG and ESS is clear in the Na/S and Zn/Br case and generates better total return.

6.4.5 Impact of increasing DG capacity

To better understand the impact of the DG capacity on the overall return, the result from the tidal and Zn/Br case is presented in Figure 6.14. Both DG and ESS NPV are compared with the different DG capacities (the return is obtained with the optimal ESS sizes). Basically, bigger DG requires more curtailment, and accordingly provides more chance for the ESS to store energy and improve the return. However, the DG return itself follows the diminishing marginal benefit with its capacity and may conflict with the ESS return at the some point. As shown, from the 11 MW capacity, the DG return passes its maximum value and begins to reduce but the ESS return still keeps increasing. The overall maximum return is obtained with 16 MW DG as the trade-off of the conflict between DG and ESS.

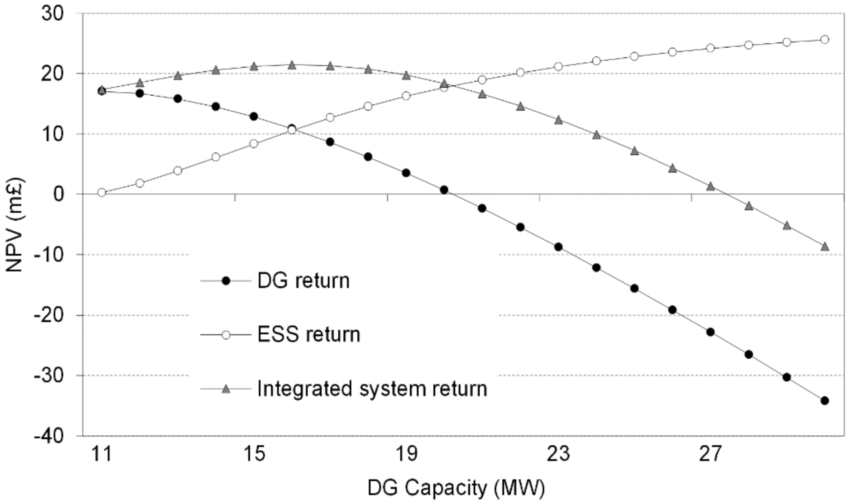


Figure 6.14: Impact of increasing DG capacity on the overall return in the tidal and Zn/Br case

6.4.6 Impact of increasing ESS battery sizes

The ESS performance is also impacted by its battery size. The Figure 6.15 shows the curtailment saved by the ESS and its return with the different size batteries. The results are obtained with the tidal and Zn/Br case. For clarity, the other impact factors are fixed: the DG capacity and ESS power rating are set at the optimal value (from Table 6.5, 16 MW and 7 MW respectively). Figure 6.15 shows that with bigger battery size, the ESS can save more curtailed energy. However, the marginal benefits are reduced. Taking the cost into account, the net return from the increasing battery size is limited. The optimal return is obtained with a 15MWh battery, which saves 68% of the original curtailment. After that, the saved curtailment still increases but the return will decrease.

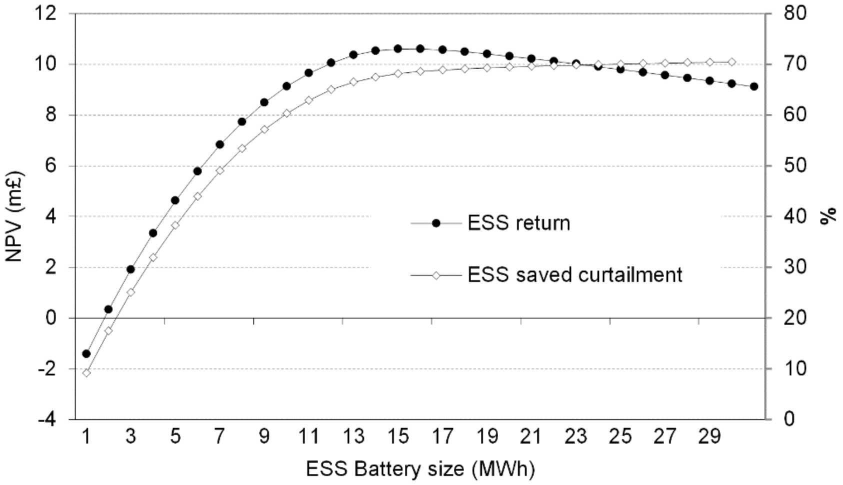


Figure 6.15: Impact of increasing battery size on the ESS performance in tidal case

6.4.7 Impact of increasing ESS power output rating

The third factor affecting the ESS performance is the power rating of its power electronic unit. From the tidal and Zn/Br case, the battery size is fixed to the optimal value of 15 MWh and the power rating varies. In Figure 6.16, the power rating clearly shows similar impact on the ESS performance as the battery size. The increasing power rating improves the curtailment saved but with reducing marginal benefits. The optimal rating is where the marginal benefits of increasing ESS power rating start to reduce, which is 7MW in Figure 6.16.

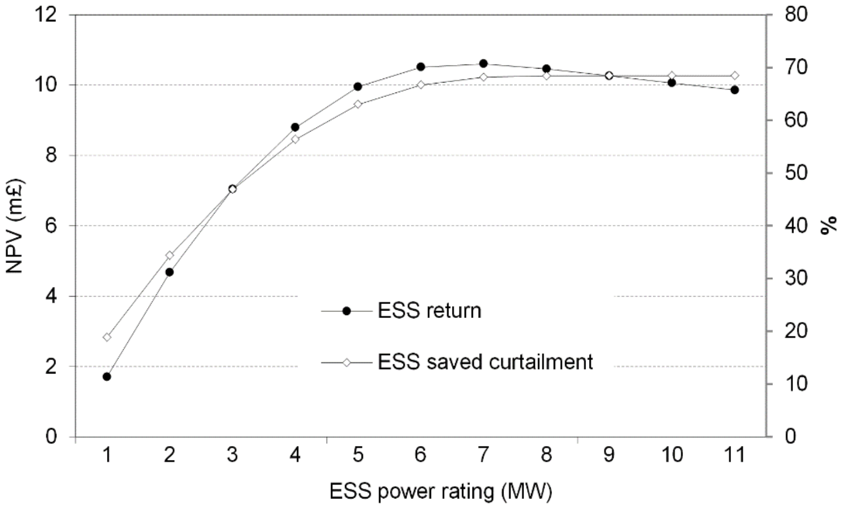


Figure 6.16: Impact of increasing power output rating on the ESS performance in tidal case

6.5 Discussion

In this section, the findings identified from the case study and the application of the method is discussed.

6.5.1 Co-optimised capacity

The key results from the case study are the balancing of the capacities of DG and ESS together. The optimal combination of DG capacity, ESS battery size and its power rating gives the overall maximum return.

For DG, the return is determined by its capacity. Increasing the capacity under the non-firm connection will improve the generation but reduce the capacity factor. Financially, it means diminishing marginal benefits. The optimal economic capacity is identified where the marginal benefit drops down to zero. For ESS, it is more complicated. The performance is improved by its battery size and power output, but also affected by the DG capacity. Increasing DG capacity requires more curtailment and accordingly provides more chance for ESS to store energy, which tends to increase the ESS return. However, it sometimes conflicts with the DG return itself (as shown in Figure 6.14). The overall optimisation of total return is the trade-off between DG and ESS. The more comparable the ESS is with the DG return, the more impact it has on determining the DG capacity. The capacity analysis need be conducted in a co-optimised manner.

Between the wind and tidal cases, the results are significantly different. Although wind has high capacity factor and costs less to build, the significantly higher ROCs for tidal does not only boost the capacity and revenue of its own but also the value of the associated ESS. According to the optimisation results, adding ESS brought net cost to the wind project while it could be economically viable in the tidal case. The overall return by adding ESS is considerably higher in the tidal and Zn/Br case.

6.5.2 Computational Performance

The case studies are processed on a PC with Intel Corei5 2.13 GHz of CPU and 4.00 GB of RAM. For computational speed, the first step which runs the snapshot OPF in time sequence to investigate the network exporting limits, takes 148 seconds to solve. The second step takes another 4 minutes to explore the search space. The whole evaluation is completed within 7 minutes for each resource and ESS type mix.

While the search space at the second step can be further expanded (beyond 40MW for DG and 100MWh for ESS) and refined (smaller incremental step than 1MW/1MWh), it would not see the considerable increase in the computing time due to its mainly linear nature. The settings used suit the case network well and has shown the change in hosting capacity after introducing ESS.

It is worth mentioning that fixed ratio of ESS power output rating (kW) to its battery size (kWh) was suggested in [98, 99], as a mean to reduce the computation burden. But it is not necessary for the proposed method here. On one hand, the adoption of fixed ratio does not help to reduce the optimisation horizon of the problem, therefore the initial attempt of using a single integrated optimisation will still be unfeasible. On the other hand, while the fixed ratio can largely reduce the size of search space in the two-step approach, the computational performance over the full space is already reasonable (4 minutes). And it is impractical to decide the fixed ratio which will generate the optimal results. As demonstrated in Table 6.5, the optimal ratio changes between different application scenarios.

6.5.3 Lifetime of ESS and Charging cycles

In the case study, the ESS lifetime is simplified by assuming a fixed value (20 year for all scenarios). The actual lifetime depends on the number of charging/discharging cycles. For most ESS technologies, devices can only operate for a limited number of cycles within a lifetime. A review in [183] estimated the maximum number of charge cycles for battery ESS ranges from 10000 (chemical batteries) down to 200 (lead acid). The number of cycles could be calculated in the simulation. As in the tidal and

Zn/Br case, with the optimal size of DG and ESS, the number of cycles is 722 per year. Accordingly, the life time expected for this operation scenario is 13.9 years.

However, this lifetime value is likely underestimated. The lifetime also depends on the depth of charge/discharge, with deeper cycles resulting in a smaller lifetime. The investigation of ESS lifetime generally assumes that the device operates on a fixed fully charging/discharging cycle each day. The curtailment-driven ESS operates in a different manner with the mixture of full and partial discharge cycles. Their lifetime estimate is more difficult and requires counting the cycles based on the various discharge depth. Gill et al. in [99] proposed a rain-flow method to calculate the distribution of discharge depth. This rain-flow method can be adopted in the modelling presented in this work to improve the accuracy (with the simulation results of ESS at the step two). Accordingly, the economic evaluation would take the updated life time into account adding replacement costs in the future.

6.5.4 ESS ownership

The work presented here represents the DG development scenario in which the DG developer aims to maximise the return by adopting non-firm connection arrangements and ESS together. The economic evaluation is based on the storage being owned and operated by the DG developer himself who obtain the revenue from the total generation. While a DG owned ESS could be a typical option in the UK where the distribution is an unbundled business, alternative ownership options also exist, such as the ESS being owned by DNOs or a separate third party. The different ownership scenario would result in different planning and operational objectives and also implies the differences for control strategies. For the example of the DNO-owned ESS, it is more likely to optimise for the wide range of technical issues, such as reducing loss, improving power quality and so on. In the third party-owned ESS, the economically rational objective would be exploring the pricing mechanism to maximise the profits, therefore the price arbitrage is an attractive option. While the ESS planning under these different ownership scenarios should be studied separately, the proposed optimisation technique provides an analysis framework, considering both network constraints and inter-temporal characteristics in a detailed and effective way.

6.5.5 Priority rules

In the case study, only a single DG is considered. This is different from the chapter 4 where multiple DG competed for the connection and priority rules had important impact on the economic evaluations. Adopting the ESS in a distribution network with already connected DG, its location needs to be decided first. Given that the ESS is used for the curtailment reduction, it is more likely that the DG with high level of curtailment provide the high benefits of installing ESS. Therefore, the location issue becomes to identify the curtailment level among the DGs with the applied priority rules.

For the LIFO rule, it is the latest connected DG that will be curtailed first and therefore the most appropriate location for ESS. For the proportional reduction rule, all DG share the same level of curtailment. While the ESS could be investigated for all connections the new DG rather than existing DG is more likely to obtain the optimal benefits, since both DG and ESS capacity are available to optimise. For the technically most appropriate rule, the high curtailment level may not occur with the last connected DG (as shown in the case study in Chapter 4). The location can be determined using the capacity analysis method developed in Chapter 4. For the developers of the new DG, installing ESS on this location can reduce the cost of compensation that they have to pay.

6.5.6 Benefits from the DNO perspective

While according to the ownership assumption used in this work the ESS provides direct return to the DG developers, it also has value for the DNO. By adding ESS, the increased generation is beneficial for DNOs under incentives that facilitate the renewable DG penetrations. The reduced curtailment could also defer the investment on infrastructures to increase the transmission capabilities. However, these benefits, unlike the sale of electricity and ROCs, are not clearly accessible under the existing market rules. They are not included in the economic evaluation here but could further increase the capacity of DG and ESS and add extra revenue streams.

6.6 Chapter summary

This chapter extended the research on hosting capacity analysis for non-firm DG in the chapter 4. The role of energy storage systems in reducing curtailment has been investigated. To maximise the total return of the ESS-supported DG, a novel method is developed to optimise the combined capacity of the DG and ESS together.

The ESS is controlled by a fast cycle strategy which aims to facilitate the charging and discharging cycle so that curtailment can be minimised. Considering the computational burden arising from the dynamic features and the long-term study horizon, a two-step approach is proposed to effectively solve the DG and ESS integrated planning problem.

The developed method is demonstrated on the UKGDS network with a mix of different energy resources and ESS types. The case study provides a number of useful general results. For both wind and tidal cases, the following conclusions are reached:

- While ESS is technically effective in increasing the generated energy, it is challenging to reach economic viability.
- Both DG and ESS return are impacted by the DG capacity. The optimal DG capacity is the result of the trade-off between DG and ESS.
- The return of ESS is also affected by its battery size and power rating , which can improve the stored curtailment but shows diminishing marginal benefit;
- To achieve the overall maximum return, the capacity of DG and ESS need be co-optimised.

- High ROC rewards play an important role in the better economic performance when adopting ESS in the tidal DG project.

While the differences in economic viability between the cases suggest a general conclusion on whether adding ESS into the DG development plan cannot be reached, the proposed evaluation method in this chapter provides a fast and effective approach to analyses this issue. It is of value for the DG developers during the decision making process. When ESS is proved to be economically viable in a specific case, the proposed method could maximise the return with increased renewable generation. It is also beneficial for the DNOs. By facilitating the ESS-supported DG, the developed planning technique enables the better use of the existing network assets and defers investment on infrastructure.

Chapter 7

Discussion and Conclusion

7.1 Introduction

This final chapter concludes the research presented. It summarises the key findings, discusses the main aspects and brings together the contributions to knowledge. The limitations of the methods that have arisen throughout this thesis are also presented, which lays the foundation for a number of further research directions. The potential future work is recommended and outlined.

7.2 Overview of chapters

The work presented in this thesis concentrated on DG planning, especially the study of hosting capacity, which is now a substantial area of research and is the key to facilitate DG penetration. Six chapters have been presented in this thesis, each of which provides a perspective on the main thesis topic; the principal messages are summarised as follows:

Chapter 1 began the thesis with its research background and motivations where the hypothesis, objectives and scopes of this research were reviewed. An overview of the research methodology together with the main contributions and deliverables were also given.

Chapter 2 detailed the integration challenges that are arise from increasing DG penetrations in the network. The main background subjects regarding conventional distribution networks, DG technologies and its potential development in the UK were reviewed. Several technical impacts on the network arising from DG integration were highlighted including voltage rise, thermal overload and power quality. The DG connection rules and guidelines in the UK which reflect on these technical concerns are outlined, with the associated support mechanisms and incentives being discussed. The chapter concluded that to avoid impeding the development of DG, the philosophy of how distribution networks should be planned must change.

Chapter 3 covered the different integration philosophies, its implication for DG planning tools and also reviewed the hosting capacity studies and the optimisation techniques that had been employed elsewhere and to be used as parts of this thesis. The active integration approach which focuses on the overall optimisation between the network and DGs enables DG developers and DNOs to find the most cost-effective way for their business plans, but it also highlighted the continuing need to understand smart grid technologies, and the need to develop the methods to analyse the benefits of them. As such, a range of smart grid technologies including ANM, variable access connection and energy storage system were reviewed. For a fair assessment, the term “hosting capacity” was introduced as an indicator of ‘optimal’ integration solutions. A literature survey of optimisation technologies that can be utilised for hosting capacity analysis were presented with a focus on OPF based methods. The conclusion of this chapter identified the research gaps in the current hosting capacity study. Three separate but related subareas are chosen and addressed by this thesis, which are the study of hosting capacity (1) under different curtailment priority rules, (2) with harmonic distortion limits, and (3) alongside energy storage systems. .

Chapter 4 focused on the influence of DG curtailment priority rules on the hosting capacity. The chapter begins with a discussion of priority rules for non-firm connections. Then a literature survey of techniques and methodologies for implementing these priority settings with ANM operation was presented. Earlier work on determining DG capacity allocation using multi-period OPF techniques was reviewed in detail, which provided the foundation to extend the hosting capacity study. A novel, flexible and multi-period OPF based evaluation approach was then proposed to determine the optimal capacity and curtailment level in order to obtain the maximum financial return for DG developers. A case study and performance assessments on example networks were also presented.

Chapter 5 concentrated on the harmonic emissions from renewable DG, and how to introduce them as a new constraint for the optimal allocation of DG capacity. Firstly, the background and challenge for studying harmonic impact on the DG integration were discussed. The modelling approach for analysing DG harmonic emissions was explained. These models were used to produce a functional prototype of a harmonic constrained multi-period OPF, which incorporates harmonic limits into the optimisation. The generalised procedure of using the developed harmonic constrained multi-period OPF framework to evaluate harmonic constrained hosting capacity was also summarised. A case study was presented, where the comparison between the non-harmonically constrained and harmonic constrained hosting capacity was clearly illustrated.

Chapter 6 further extended the research on the hosting capacity analysis for non-firm DG. The role of energy storage systems in adding benefits by reducing curtailment has been investigated. The chapter begins with a summary of ESS roles in the power system, where the two main applications of arbitrage and curtailment reduction were presented. An overview of relevant ESS optimisation studies was then provided to identify the research challenges for its roles in curtailment reduction schemes. To maximise the total revenue, an innovative method was developed to optimise the combined capacity of the DG and ESS together. A two-step modelling approach was also proposed to tackle the concern on computational burden. A case study was presented with the mix of different DG and ESS technologies.

7.3 Key results and the contribution to knowledge

7.3.1 Overall remarks

Relating to the overall objective of this thesis declared in Chapter 1, it was aimed to adopt advanced optimisation techniques to facilitate DG integration by developing hosting capacity analysing methods with enhanced capability. At the end of thesis, three new evaluation methods have been developed that allow the study of hosting capacity under different curtailment priority rules (Chapter 4), with harmonic distortion limits (Chapter 5), and with energy storage systems (Chapter 6). These separate but related works together enrich the body of knowledge for DG planning in two directions: evaluating extensive network constraints to ensure solutions complying with all relevant planning standards and grid codes; and demonstrating the benefit provided by a range of smart grid technology solutions to facilitate DG integration. These outcomes are important to improve the efficiency and flexibility of hosting capacity study so that it can: embed selective network constraints, chose various smart grid solutions and be tailored for different development objectives. These developed methods are applicable under different deployment contexts to help both DNOs and DG developers make sound and practical decisions, so that DG integration can be facilitated in a more cost-effective way.

The more detailed findings, discussion and the contribution for the main chapters are summarised below.

7.3.2 Influence of DG curtailment priority rules on hosting capacity

A multi-period OPF based method is developed in Chapter 4 to estimate hosting capacity subject to technical constraints as well as the economic viability of curtailment schemes participating in the connection arrangements. The evaluation approach provides a better understanding of planning non-firm connections, which is highly desirable for both DG developers and DNOs. Using the proposed optimisation technique, the maximum project returns under different curtailment schemes can be quantified and therefore offer a detailed “test bed” for designing connection contracts. As demonstrated in the case study, developments under non-firm connection schemes generally deliver more generation capacity in the network although financial returns for specific DG is determined by its connection order and principles of access. This means it is particularly important for developers to conduct ‘what if’ analyses of potential investments and for DNOs in monitoring efficient use of their network capacity.

The issue of fairness is particularly important where DG has been connected on a firm connection basis without curtailment and where reversion to non-firm operation would deliver substantial increases in output overall although that specific DG may see decreases. It has to be equitable in that DGs that contribute to curtailment to deliver more revenue overall see some benefit.

The technically most appropriate curtailment scheme provides a means to partially mitigate the negative outcomes in networks where existing DGs connections are substantially different from the ‘optimal’. It has been shown in the case study, that by adopting the technically most appropriate curtailment scheme, the network potential can still be exploited through effectively limiting generation from the poorly located DG yet ensuring it remains economically viable through full compensation. While the technical and economic performance is still constrained by connection orders, the technically most appropriate scheme outperforms the LIFO and proportional approaches in terms of greater hosting capacity.

The study raises an interesting point as to the extent of compensating curtailment at early connections given that overall hosting capacity may be disproportionally reduced by its connection. It suggests that DNOs need proper incentive arrangements to encourage developers’ connection plans to be more closely aligned with the overall optimisation of network hosting capacity. This is particularly important where regulatory and social pressures on minimising grid expansion are strong. One possible solution could be to adopt location-specific charging mechanisms for DG connections by exploiting shadow pricing.

7.3.3 Harmonic constrained hosting capacity

The multi-period OPF technique has been substantially extended to also take account of harmonic distortion limits. A new harmonic-constrained multi-period OPF method is developed in Chapter 5 to rapidly identify the harmonic constraints on the hosting capacity. The widespread use of power electronic interfaced DG connections means there is the rising potential for harmonics to inadvertently place limits on the ability of distribution networks to accommodate DG. It is important for hosting capacity analysis to take account of this constraint to provide practical guidance to DG development. While the harmonic modelling presents complicated features, the introduction of harmonic variables and constraints into the multi-period OPF framework incurs few changes for the formulations at the fundamental frequency. Using the proposed harmonic-constrained OPF method, Harmonic evaluation is added into the capacity study in a manner that ensures consistency with other attempts for enhancement of the hosting capacity study.

A re-distributive effect of harmonic distortion constraints on hosting capacity is demonstrated in the case study. It shows that the proportional changes between the initial OPF and final HOPF capacities at each DG may not be the same and one DG in the case network increases after enforcing the harmonic distortion limits. The re-distributive effect indicates that harmonic studies should be considered at the initial phase of planning, instead of being an afterthought following 'blind' DG development. Otherwise, it is difficult to ensure optimality. The developed harmonic-constrained MOPF method that explicitly links DG capacity and harmonics is more effective in handling the complex interaction between different DG in terms of harmonic emissions as well as impact on voltage and thermal constraints.

The strict compliance with the ER G5/4-1 standard contributes to the significant reduction of the hosting capacity shown after considering harmonic limits in the case study, especially the case when ANM ‘frees up’ sufficient new capacity. It is important to note that the ER G5/4-1 is not a statutory regulation. The compliance with its recommended harmonic planning level is through agreement reached between the DNO and DG developers. In practice, the harmonic requirement is not as strongly enforced as voltage variation and thermal rating limits, and the scenario with high level DG harmonic emission may infrequently happen. As a result there could be more 'space' for accommodating DG according based on the actual connection agreements between developers and DNOs.

When harmonic distortion actively constrains the hosting capacity, harmonic filters can provide a mitigation solution. The active constraint found by the harmonic-constrained MOPF method can indicate the order(s) at the buses that constrains DG. The developed method can also be used to check the required level of mitigation required, at which point the active constraint will switch to other network constraints instead of harmonics. Thus it is of value for the DNO and DG developer to determine the filter sizes and also lay the basis for a cost-benefit analysis.

7.3.4 Influence of energy storage systems on hosting capacity

The rapid development of energy storage technologies provides an alternative constraint management solution for distribution networks and is promising for application in DG schemes. While technically ESS is beneficial to the network in many aspects, it may not always be an economically viable solution in each application. Analysis suggests that ESS in curtailment reduction schemes has better economic performance than alternatives, but the intermittent output of DG means the curtailment will not be confined to specific periods of the day. The final validations need to be evaluated over a long period, which requires detailed modelling of ESS inter-temporal operation, proper control strategies and also optimisation methods to determine the economic capacity.

A fast cycle strategy is proven effective in controlling the ESS for curtailment reduction. While alternative control strategies exist, such as optimal dispatch which controls the ESS to discharge saved curtailment at higher prices, the lack of correlation between curtailment and spot price reduces the chance of realising this benefit. By quickly emptying the stored energy for the next charging period, the fast cycle strategy provides a practical way to increase the utilisation factor and avoid uncertainty from forecasts.

The literature review on the ESS optimisation highlights that the DG capacity has a significant impact on the value of ESS in a curtailment reduction scheme, but it was poorly understood. A new co-optimisation concept was proposed in Chapter 5 to optimise the DG and ESS capacity together in order to obtain the maximum financial return. In modelling, a two-step approach is proposed to effectively split the size of unknowns and study horizon in the optimisation so that the additional computational requirement can be managed.

The developed method is demonstrated in the UKDGS network with the mix of different energy resources and ESS types. Several conclusions were reached: First, while ESS is technically effective in increasing the generated energy, it is a challenge to reach economic viability and high ROC rewards play important roles in the better economic performance when adopting ESS in the tidal DG project; Secondly, both DG and ESS revenue are impacted by the DG capacity, and they may conflict with each other at some point. As shown in the case study, when DG return passes its maximum value and begins to reduce, the ESS return still keeps increasing and surpasses the loss from DG return to some extent. To achieve the overall maximum revenue, the optimal DG capacity is the result of the trade-off between DG and ESS.

The economic viability differences shown among the mix of different energy resources and different ESS types in the case study suggest that a general conclusion on the benefits of adding ESS into the DG planning cannot be reached. It is expected that with the rapid development of ESS technologies and associated incentives available, their cost could be reduced. As shown in the case study, the more economically comparable the ESS will be with the DG, the more impact it has on determining the DG capacity. To promote the application of ESS-supported DG, it is important for the planning study to be conducted in a co-optimised manner. The proposed method provides an effective approach for the DG developers and DNOs to rapidly analyse the optimal DG and ESS capacity, and to justify their investment with the maximum return and increased renewable generation.

7.4 Limitations and future work

While three research gaps in the area of hosting capacity have been tackled in the thesis and these works together formed a valuable step forward in improving DG planning techniques in the transition to smart grid, there are still a number of enhancements that the author would have liked to consider but nevertheless was not able to contribute due to time limitations.

7.4.1 The study on DG curtailment priority rules

Several limits can be identified in the presented study on priority rules. First, the cost of building and operating ANM control systems is not considered in the case study. While evidence suggest it is modest relative to the value of the generation capacity released and would have a marginal impact on the precise capacities suggested, it would be beneficial to validate this in detail. Second, while the proposed framework is versatile to include more control options, the coordination between the non-firm connection arrangement and other smart grid controls has not been extensively studied. For example, the optimisation can be extended to include the adaptive control of DG power factor or alternatively reactive power pricing. Finally, although all DG in the case study use the same production profile here, the spatial characteristics of the resource can be incorporated and may result in greater hosting capacity with more modest levels of curtailment (as would a portfolio of different resources).

7.4.2 The study on harmonic distortion constraints

For the presented study on harmonic constraints, the main limitation arises from the modelling of harmonic emissions itself, which acts as the key input for the harmonic constrained hosting capacity analysis and will affect the accuracy of the output. Given the current knowledge of DG harmonic modelling, it is concluded that there is great difficulty in making a general statement on the selection of preferable models. In Chapter 4, as simplified DG harmonic models are used and further work is required to evaluate the harmonic emissions from different DG technologies and their aggregation effect at the connection points. The coordination between locations can be challenging considering the impact of phase differences. The random variation of DG harmonics also raises an interesting point that their impact could be evaluated in a probabilistic manner.

When harmonic impacts highly influence DG capacity, harmonic filters could be installed as a mitigation solution. Only active filters are used in Chapter 4 to demonstrate the benefit. A range of different mitigation solutions can be considered in the future. Moreover, the cost of filter installation and maintenance should not be neglected. The proposed framework here can be the basis for further cost-benefit studies.

7.4.3 The study on energy storage system

The study on adding ESS in the curtailment scheme also has some limitations. First, the ESS lifetime is not explicitly included in proposed capacity analysis method. It is simplified by assuming a fixed value in the case study. The actual lifetime depends on the number and depth of charging/discharging cycles. Detailed study on the distribution of discharge depth is useful for the economic evaluation to update the replacement cost in the future.

Secondly, the work represents the ownership scenario in which the ESS is owned by the non-firm DG to increase the actual generation. Alternative ownership options also exist, which would result in various planning objectives and may also imply some differences on the control strategies. While the ESS value under these ownership scenarios should be studied separately, the proposed analysis framework in Chapter 4 can be generally applied.

Thirdly, the ESS in the study is located in a centralised way alongside DG, which is reasonable for the curtailment reduction scheme. For the other applications, where ESS may be installed on a small scale and distributed across the network, the proposed analysis techniques may not be able to directly apply. Further work could evaluate the value of distributed small scale ESS.

7.4.4 Further research on hosting capacity

As for the whole picture in the research area of hosting capacity, the following directions are recommended for future work.

7.4.4.1 Incorporate the impact of DG on the network dynamics

The impact of DG on the network dynamics has not been clearly considered on hosting capacity. DG has the potential to affect transient stability. Similar to the well-studied thermal and voltage impact, such dynamic impacts of DG are also able to limit the network hosting capability. Based on the proposed framework featuring advanced OPF techniques, the further work could be extended to embed the constraints of extensive network disturbances such as fault currents limits and equipment potential outages, and also analyse the benefits of the reinforcements required.

7.4.4.2 Integrate the functional modules into an combined planning tool

While a number of works on hosting capacity have already been established, most of them were formulated by focusing on specific aspects of DG impacts. Moreover, various objectives have been pursued in the optimisation. Those separate developments at research level would approach a point where integrated planning tools become feasible which can flexibly select network constraints and tailor them for different development objectives. It is a necessary step forward to reduce the implementation barriers of these advanced planning studies for DNOs and DG developers. This thesis generally follows this requirement by developing the separate works using similar modelling techniques, but further effort is required. Through an integrated planning tool, the complicated process of planning networks with DG can be tackled in a single framework and finally accelerate progress on deployment.

7.4.4.3 Reflect the hosting capacity study on driving the changes of charging mechanisms

The overall network point of view to achieve the global technical and economic benefits was adopted in most hosting capacity studies and also has been considered in this thesis. However, this might be distinct from the regulatory framework in place, particularly where there is private ownership of DG. For example, in the UK, a DNO can only specify if given DG capacities are permissible but are not in a position to specify a preferred overall allocation to maximize capacity. As such, how to translate a calculated global benefit for the network and DG into a delivered one could be very challenging. The method to integrate the hosting capacity study into new charging mechanisms for DG connection is important in the future research. Thus the price signals could reflect the global benefits and help DNOs to steer DG connections towards the specific areas and with the suggested capacity where the overall technical and economic performance are improved.

7.5 Thesis conclusion

The thesis draws together information and techniques from a number of subject areas and uses them to identify and address research gaps in the body of knowledge surrounding network ‘hosting capacity’.

The key outcomes are three new evaluation methods developed to allow the study of hosting capacity under different curtailment priority rules, with harmonic distortion limits, and alongside energy storage systems. A key conclusion is that these enhancements on the hosting capacity study improve the understanding of benefits of smart-grid based network management techniques and facilitate their application in increasing DG integration.

It is, therefore, possible to confirm the hypothesis that, the development of the smart grid does require and benefit from advanced optimisation methods to allow new ANM techniques to be evaluated in term of their impact on network hosting capacity.

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A.1 Appendix A : Technical report - *MARINA Platform* project

This appendix gives a summary of the technical report delivered as an outcome of the work on the *MARINA Platform Work Package 8 Deliverable 8.5* (*EU 7th Framework Programme, Grant agreement number:* 241402). It is arisen from the work in this thesis. Should the readers wish to obtain more details of this project, the full *MARINA Platform* report could be accessed at www.marina-platform.info. The contribution of this author is the section "GB case study (distribution system analysis)".

The main objective of the project on *Deliverable 8.5* is to carry out a UK case study on Marine Renewable Energy (MRE) integration in power systems. This case study examines the grid integration of wind and wave energy generation and specifically how their individual and combined characteristics affect this. It focuses on the distribution system and while it considers UK-specific resources and network design, it is broadly applicable elsewhere. The case study makes extensive use of the concept of network 'hosting capacity' in framing the analysis. Hosting capacity describes the level of generation that can be accommodated within a given network subject to technical and economic constraints. It is applied here as it is an indicator of the efficiency with which a given generator or group of generators make use of existing grid capacity and has been shown to be affected by the characteristics of renewable resources and its relationship with demand.

The approach for assessing the hosting capacity is based on multi-period Optimal Power Flow (OPF) techniques developed by the University of Edinburgh. It effectively models the variation of output from offshore renewable generation and also its coincidence with demands. Grid Code and statutory compliance on both voltage and thermal limits can be easily assessed by the method.

The case study is undertaken using representative information from Scotland: hourly resource data and co-temporal electricity demand data and a generic distribution network. In this way, a whole year of operating scenarios is produced with time series offshore generation and onshore demand data. Through this simulation, the methodology for evaluating network hosting capacity has been established and examined.

Available constraint mitigation methods increase the offshore energy integration; here the focus is on alternative ‘smart grid’ schemes rather than traditional infrastructure upgrades. Given the current move towards smart grids across Europe, innovative control techniques that enable the release of network headroom in a more cost-efficient and timely manner are widely favoured. Three network control schemes are modelled and simulated, including adaptive voltage control, active output control, and energy storage systems.

A.2 Appendix B : Publications

This section gives the author's publications in full. All works are progressive outcomes throughout the time of this PhD. The journal and conference publications are provided in a chronological order.

Conference Proceedings

1. W. Sun, G. P. Harrison, and S. Z. Djokic, "Distribution network capacity assessment: Incorporating harmonic distortion limits," in *Power and Energy Society General Meeting, 2012 IEEE*, 2012, pp. 1-7.

2. W. Sun, G. P. Harrison, and S. Z. Djokic, "Incorporating harmonic limits into assessment of the hosting capacity of active networks," in *Integration of Renewables into the Distribution Grid, CIRED 2012 Workshop*, 2012, pp. 1-4.

3. W. Sun and G. P. Harrison, "Influence of generator curtailment priority on network hosting capacity," in *Electricity Distribution (CIRED 2013), 22nd International Conference and Exhibition on*, 2013, pp. 1-4.

Journal papers:

1. W. Sun and G. P. Harrison, "Influence of Generator Curtailment Priority on Economic Hosting Capacity," *IEEE Transactions on Power Systems*, Draft, In review

Distribution Network Capacity Assessment: Incorporating Harmonic Distortion Limits

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***Abstract*—The capacity of distributed generation (DG) connected in distribution networks is increasing as part of the drive to connect renewable energy sources. Due to widespread application of power electronic inverter interfaces, DG can inject harmonic current through the point of common connection into the upstream network. Harmonic current emission may cause voltage distortion problems when harmonic resonance exists in the network. Harmonic distortion is one area of concern for electric utilities in determining whether DG could be connected, although there are differences in utility practices in applying limits. To explore the impact of harmonic regulations on the ability of distribution networks to host DG, this work incorporates harmonic voltage constraints into an established optimal power flow (OPF) planning method. The case study shows that harmonic distortion limits have substantial impacts on the allowable penetration of DG. Furthermore, the complex interconnectivity between DG locations means that voltage, thermal and harmonic constraints have a large influence on the location preference for DG capacity.**

***Index Terms*—Harmonic analysis, distributed generation, distribution networks, optimal power flow.**

I. INTRODUCTION

DRIVEN by concern over greenhouse gas emissions and energy security, governments worldwide are aiming to increase renewable-based power production. Due to the nature of renewable resources, many generation projects will be connected to distribution network as Distributed Generation (DG). However, there are several challenges for network planners to accept DG, the most readily cited being voltage rise and power flow limitations. However, issues arising from harmonic current emissions from power electronic converters in grid-connected DGs is starting to move up the agenda as being a potential limitation on the capacity of the distribution network to accommodate DG.

Traditionally, harmonic studies in distribution network mainly focus on identification and management of harmonic voltage distortions. Well-accepted component models, simulation methods and analysis procedure has been developed. These include harmonic frequency scan [1] and harmonic power flow [2] for propagation studies as well as the design and placement of harmonic filters for mitigation. Those harmonic analysis approaches generally are based on a well-developed network, in which the entire generation capacity and load configurations are given and fixed during the period of interest. However, the rapid development of DG makes the generation capacity in distribution networks a dynamic problem with DG volumes changing substantially over the planning horizon. The harmonic simulation and filter planning methods mentioned above are not sufficient to address problems in a changing network.

There are a range of DG planning problems and studies in the literature. One major research interest focusses on how to maximize the hosting capacity while avoiding costly network upgrades. There are many approaches demonstrated that apply a range of heuristic and classical optimization methods. One class of approach makes use of optimal power flow (OPF) and models the DG capacity allocation problem while meeting the steady state constraints [3]. This method has been further extended to consider voltage step constraints [4] and security constraints [5]. The influence of various advanced control schemes, which will be incorporated in the smart grid, are studied under an adapted OPF framework [6]. There is a complete absence of methodologies that perform capacity assessments of variable renewable generation with harmonic consideration. While an optimal harmonic power flow approach is presented in [7], the objective is to use optimization method to minimize Total Harmonic Distortion (THD) by controlling taps and capacitor positions in a given system, where generation level is fixed (and therefore is not a DG planning problem).

Harmonic studies should be considered at the initial stage of network planning instead of being performed as an afterthought following 'blind' DG development. In this context, harmonic studies could be incorporated into the DG capacity evaluation. Here, an AC optimal power flow technique is adopted to maximize the DG capacity while meeting not only voltage and thermal constraints but also harmonic distortion limits. Active mitigation and advanced control scheme can also be evaluated under this extended harmonic OPF framework. The assessment of network capacity that complies with mandatory harmonic requirements in the U.K. and elsewhere would enable a fuller picture for decision making.

This paper is structured as follows: Section II summarizes harmonic modeling methods and harmonic power flow. Section III introduces a harmonic-constrained optimal power flow method to formulate the DG capacity allocation problem. In section IV, the proposed method is applied on a section of medium voltage distribution network. The results demonstrate the considerable impact of harmonic emissions on DG development, and the advantage of directly integrating harmonic assessment into OPF formulation. Finally, section V concludes the work.

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II. FORMULATION

A. Network Component and DG Modeling

Similar to other power system studies at the fundamental frequency, typical harmonic studies start by choosing models to present network and harmonic sources of interest. Many models have been proposed to present those linear and nonlinear components [2], [8]-[9]. Those techniques vary in terms of complexity, data requirement and solution algorithm. Specific models adopted in this paper are as follows:

1) Overhead Line and Cables: For balanced systems, overhead line and cables can be modeled as multiple nominal sections using positive sequence impedance data. According to [10], in a 50 Hz system, an error of less than 1.25% can be obtained when every single section modeled is below 10km for overhead line and 6km for cable. An equivalent model can be adopted to further improve modeling accuracy.

2) Transformers: The main characteristics of a transformer that affect harmonic flows are the short-circuit impedance and winding connection type. It is generally acceptable to model short-circuit impedance as constant R and L.

3) Passive Load: Aggregated values (MW and Mvar) for system passive load is usually readily available. Detailed composition of load is useful to characterize models properly but such data is usually not easily available. A parallel form of load representation (1) is suggested in this paper. This model can be further extended to include more detail, such as (2). However, a generally accepted model for all loads may not exist, and field measurement is needed for specific cases.

$$R_h = V^2/P X_h = V^2(h)/Q \tag{1}$$

$$R_h = V^2/P(0.9+0.1h) X_h = V^2(h)/Q(0.9+0.1h) \tag{2}$$

4) Non Linear Load: It is reasonable to present non linear loads as harmonic current sources which cause background distortion in the context of DG planning. An aggregated model is adopted here to represent different load types given their nonlinear composition and harmonic spectrum.

5) DG: Harmonic emission from DG is dependent on the specific turbine technology and internal feeder layout. However, explicit modeling is time consuming. The specific data on DG is unknown at the planning stage, and presented as an optimization variable in this paper. A simplified DG model is presented below:

$$I_{h,i} = I_h^{spectrum}(S_i^{DG}/V_i) \tag{3}$$

where $I_{h,i}^{spectrum}$ indicates the hth order current element of harmonic spectrum for DG according to the turbine technology; S_i^{DG} represents total rated DG capacity installed in bus i; V_i is nodal voltage; and $I_{h,i}$ represents the hth order harmonic current distortion injected at the DG connection point i.

IEC 61000-3-6 [11] has recommended an aggregation method for summating load harmonic current. This method can be adapted here as:

$$I_{h,i} = I_h^{spectrum} \sqrt[\beta]{\sum_{n=1}^{N}(S_i^{turbine}/V_i)} \tag{4}$$

where total DG capacity in (3) is replaced by the rated capacity of single turbine $S_i^{turbine}$. $I_h^{spectrum}$ indicates the hth order current element of typical harmonic spectrum for DG. Exponent β provides the correlation at higher frequency and recommended values are given in Table I. Applying this model for DG, say for a wind farm, will need an explicit number of wind turbines (N in the model) and accordingly results in discrete values in total DG capacity. This model is applicable for cases where the planner has a strong idea of the specific turbine type for the whole network.

TABLE I
SUMMATION EXPONENTS ACCORDING TO IEC 61000-3-6

Harmonic Order	β
h<5	1.0
5≤h≤10	1.4
h>10	2.0

It is important to point out that more sophisticated models can be used for each component when corresponding data is available. The level of detail in models will increase the complexity of the analysis, and in practice will largely decrease the feasibility of reliable data being obtained. Although the models and assumptions adopted in this paper may lead to conservative results, this is often desirable to for network planning.

B. Harmonic Power Flow

Harmonic power flow has been extensively used to quantify the distortion of current and voltage wave forms in the power network. The results are useful to determine potential resonance conditions and verify compliance with harmonic limits. Mathematically, harmonic power flow at the frequencies of interest need to solve: (5).

$$[V_h] = [Z_h][I_{h,g}] \tag{5}$$

where $[Z_h]$ is the network impedance matrix at harmonic order h; $[I_{h,g}]$ is the vector of nodal harmonic current injection of each bus; $[V_h]$ is the resulting harmonic voltage at the corresponding order. The formulation of the impedance matrix of the network and vectors of harmonic current injections is based on the selection of network component models and harmonic sources presented in the previous section.

One way of conducting harmonic assessment in DG capacity allocation studies is to neglect harmonic limits for the initial simulation. For the DG connection capacity obtained by other established optimal planning techniques, e.g., [3], or a direct proposal from DG developers, THD and individual harmonic distortion are evaluated using harmonic power flow. If the results do not comply with harmonic requirements, then the DG capacity needs to be reduced by a certain volume or a bank of filters installed for the next assessment. A similar procedure repeats until specific objectives are achieved, such as: maximum DG capacity, minimum network investment or a tradeoff between filter cost and DG capacity. This method guarantees the final result has harmonic compliance and is relatively simple in every step. However, the obligation of managing harmonics during initial DG capacity assessment creates a time-consuming repetitive procedure to check harmonic compliance. It is also not straightforward to decide how much to reduce DG capacity or where to install filters at every step, especially for multiple DG cases. Considering those shortcomings, directly embedding harmonic power flow into initial DG planning techniques is proposed in this paper.

III. OPTIMAL POWER FLOW WITH HARMONIC CONSTRAINTS

OPF has been developed and extensively applied in formulating the DG capacity allocation problem [3]-[6]. Optimal potential DG penetration level can be found within the physical limitations of the network. Similar to other network characteristics such voltage and thermal limits, there are statutory requirements for harmonic distortion, indexed by total harmonic distortion (THD) and maximum distortion for each individual harmonic order (IHD). In the United Kingdom the applicable standard is Engineering Recommendation (ER) G5/4-1 [12]. When considering a connection application, DNOs in the U.K. are obliged to ensure THD and IHD compliance at connection points and all other surrounding buses, especially when high background harmonic exists in the network. As such, the integration of harmonic limits into the DG generation planning problem appears to a logical approach. The adapted AC OPF formulation is designed to maximize the total active DG capacity considering harmonic distortion limits. The objective function given as follows:

$$\max \sum_{g\in G} p_g \tag{6}$$

where P_g is active DG capacity of a set of generators G (indexed by g). It is subject to a range of constraints, which can be categorized in to two sets: one is basic network limits, the other considers harmonic distortion.

1) Basic Network Constraint:

$$\sum_{l\in L|\beta_l^{1,2}=b} p_b^L + d_b^P = \sum_{g\in G_b|\beta_g=b} p_g + \sum_{x\in G_b|\beta_x=b} p_x \tag{7}$$

$$\sum_{l\in L|\beta_l^{1,2}=b} q_b^L + d_b^P = \sum_{g\in G_b|\beta_g=b} q_g + \sum_{x\in G_b|\beta_x=b} q_x \tag{8}$$

$$V_b^- \le V_b \le V_b^+, \ \ \forall b \in B \tag{9}$$

$$S_l - S_l^+ \le 0 \tag{10}$$

Kirchhoff's current law as described in equation (7) and (8) ensures the active and reactive nodal power balance, where $(p,q)_b^L$ are the total power injections into lines at b and $d_b^{(P,Q)}$ are the active and reactive demands at the same bus. The allowable network voltage at each bus b and thermal constraints for each branch l are given in (9) and (10), respectively.

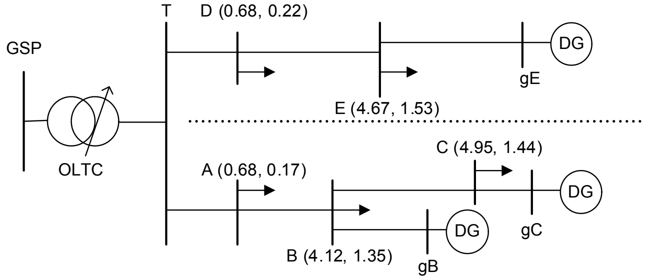

Fig. 1. 5-bus network one-line diagram during maximum load

2) Harmonic Distortion Constraints: To ensure compliance with harmonic level standards such as U.K. standard G5/4-1 following DG connection, the following harmonic constraints apply:

$$V_b^h \le IHD^{h,+} \tag{11}$$

$$\frac{\sqrt{\sum\limits_{h=2}^{H} (V_b^h)^2}}{V_b^1} \le THD^+ \tag{12}$$

where V_b^h is voltage distortion at bus b for harmonic order h. As introduced in section II, V_b^h can be obtained from the harmonic power flow equation (5). When DG is modeled as a current injection source the injections are defined by the DG capacity described in both equation (3) and (4). Constraints (11) and (12) ensure that the HOPF defines DG volumes that comply with the harmonic standard.

IV. CASE STUDY

A typical rural section of the Irish distribution network is used here as a case study [13]. While the voltage level of this network is 38kV and therefore different to U.K. 33kV practice, it has been selected as it is very simple. To illustrate the influence of harmonic constraints, the harmonic voltage planning levels for 33kV systems in the U.K. are adopted here as firm limits.

A. Distribution Network

The one-line diagram of the medium voltage distribution network is shown in Fig. 1. The corresponding line data is included in Table II. All values are in per unit (100MVA base). The feeders are supplied by one 31.5MVA 110/38kV transformer. The Grid Supply Point (GSP) voltage is assumed to be nominal. Voltage limits are taken to be ±10% of nominal. The maximum demand of the network is 15.12MW.

B. DG and Harmonic Sources

The network has three potential locations at which new wind farms can be connected: buses gB, gC and gE in Fig.1. A medium sized (0.6MW) wind turbine [14] is chosen to produce all the new power. As a widely accepted and historically encouraged operational practice, all wind farms operate at unity power factor. For harmonic analysis, wind farms are modeled as current sources. Fig. 2 presents the full frequency spectrum

TABLE II
LINE AND TRANSFORMER PARAMETERS

Line	R	X	Smax
GSP - T	-	0.25	0.315
T - A	0.0296	0.0863	0.3817
A - B	0.5941	0.6244	0.2975
B - C	0.3875	0.4072	0.1975
T - D	1.126	1.193	0.3817
D - E	0.155	0.1629	0.1975
B - gB	0.1292	0.1357	0.1975
C - gC	0.1292	0.1357	0.1975
E - gE	0.1292	0.1357	0.1975

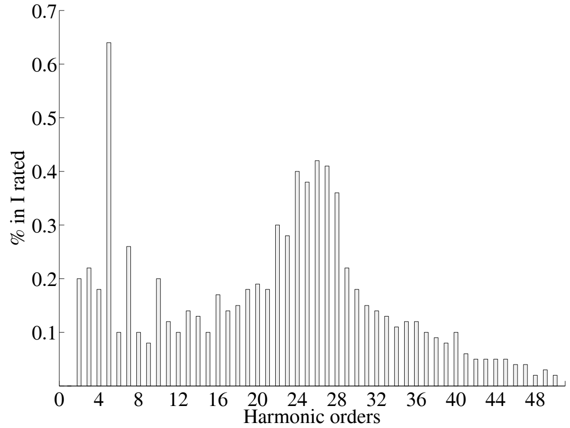

Fig. 2. Maximum harmonic current produced by wind turbine

of maximum harmonic current produced by this turbine. It extends up to 2500 kilohertz and has high harmonic distortion at lower (5th and 7th orders) and also higher frequencies (20th - 30th orders). In order to facilitate the simulation, harmonic current from all turbines is assumed to have the same phase angle to obtain the worst possible distortion, and all turbines produce balanced harmonic currents. Furthermore, all triple harmonic orders (3rd, 6th, etc.) will be eliminated by the HV-MV transformer if either side is Delta-connected and all even orders are canceled since positive and negative parts of the current waveform are almost identical. The harmonic current value of reduced order for wind farm aggregation is given in table III and will be used in the following section.

For background harmonic distortion, the 5th and 7th orders are generally most severe in the distribution system. In this paper, the voltage distortion from nonlinear load in nearby buses around the wind farms are given as firm values. Existing harmonics are set to 1.0% distortion at the 5th order and 0.5% at the 7th order. The other orders of background voltage distortion are very small and can be neglected. This data can be updated when detailed measurement is available.

C. Maximum DG Capacity

The network capability to accommodate DG depends on local load level. Under low demand levels, a given DG output means more exported power with network voltage and thermal constraints more likely to be active. The worst-case scenarios of minimum demand and maximum generation are assumed here for determining the network's ability to accommodate DG capacity. The minimum load level is 40% of the peak demand. Another factor is the transformer tap setting in substations: to minimize voltage rise limits on the DG, the tap changer is adjusted to 1.05 p.u. to lower the secondary side voltage of OLTC between GSP and bus T.

TABLE III
MAXIMUM HARMONIC CURRENT PRODUCED BY WIND TURBINE AND PLANNING LEVELS FOR HARMONIC VOLTAGE AT 33 & 132 KV SYSTEMS FOR REDUCED ORDERS

Harmonic Order	Harmonic Current (% in I_{rated})	Planning Level 33 &132kV (%)
5	0.64	2
7	0.26	2
11	0.12	1.5
13	0.14	1.5
17	0.14	1
19	0.18	1
23	0.28	0.7
25	0.38	0.7
27	0.41	0.66
29	0.22	0.63
31	0.15	0.6
35	0.12	0.56
37	0.1	0.54
41	0.06	0.5
43	0.05	0.49
47	0.04	0.47
49	0.03	0.46
THD		3

The initial OPF evaluation of the new generation capacity that can be accommodated considers only voltage and thermal constraints and ignores harmonic constraints. The result of this is presented in column 2 of Table IV. It is evident that even under the worst-case scenario used here, the network exports power since the 42 MW total DG capacity surpasses local demand by some margin. Substantial amounts of capacity are available at buses gC and gE while a much smaller amount is possible at bus gB. This is largely due to gB sharing the same feeder as gC while gE alone is connected to a separated feeder. The constraints that actively limit the capacity at these locations are: the voltage at bus gE is at the upper voltage limit (1.1 p.u.) due to the relatively high line impedance, while there are thermal limits on both line C-gC (connecting directly to wind farm C) and the GSP transformer. The overall limit to DG capacity created by the transformer export limit means that the split in capacity between gC and gB is governed by a fairly small difference in net exports along the feeder associated with the greater impedance to reach bus gC. In other words, the additional losses that this creates delivers a higher overall net capacity so the optimization exploits this by loading bus gC to its limit before directing 'spare' capacity to bus gB. Were the feeder voltage-constrained, however, the optimization would direct more capacity to bus gB as it has a

TABLE IV
COMPARISON OF OPTIMAL DG CAPACITY RESULT BETWEEN OPF (NO HARMONICS) AND HOPF (HARMONIC CONSTRAINED)

DG bus	OPF (WM)	HOPF (WM)	Reduction (%)
gB	3.43	6.52	-90%
gC	19.75	2.32	88%
gE	18.85	4.61	76%
Total	42.03	13.44	68%

TABLE V
HARMONIC CURRENT INJECTIONS FROM THE WIND FARMS

Harmonic Order	Harmonic Current (p.u.)		
	gB	gC	gE
5	0.022	0.126	0.121
7	0.009	0.051	0.049
11	0.004	0.024	0.023
13	0.005	0.028	0.026
17	0.005	0.028	0.026
19	0.006	0.036	0.034
23	0.010	0.055	0.053
25	0.013	0.075	0.072
27	0.014	0.081	0.077
29	0.008	0.043	0.041
31	0.005	0.030	0.028
35	0.004	0.024	0.023
37	0.003	0.020	0.019
41	0.002	0.012	0.011
43	0.002	0.010	0.009
47	0.001	0.008	0.008
49	0.001	0.006	0.006

lower voltage sensitivity.

D. Compliance With Harmonic Limits

For the optimal 42 MW DG capacity identified by the non-harmonically constrained OPF, the harmonic current injections from each wind farm is shown in Table V. These are calculated by scaling the maximum harmonic current spectrum of a single turbine by the capacity at the bus. The harmonic propagation in the network is assessed by running a harmonic power flow and the results of this for THD at each bus is given in Fig. 3. For the most highly constrained wind farm at bus gE, it has the worst THD with its individual harmonics given in Fig. 4. Comparing with the planning level for harmonic voltage distortion given by ER G5/4-1 in Table III, both Fig. 3 and Fig. 4 show that the 42 MW of DG capacity suggested by the non-harmonically constrained OPF heavily violates the harmonic limits. Therefore it would not be considered as a viable option by the DNOs without sufficient harmonic filtering being commissioned.

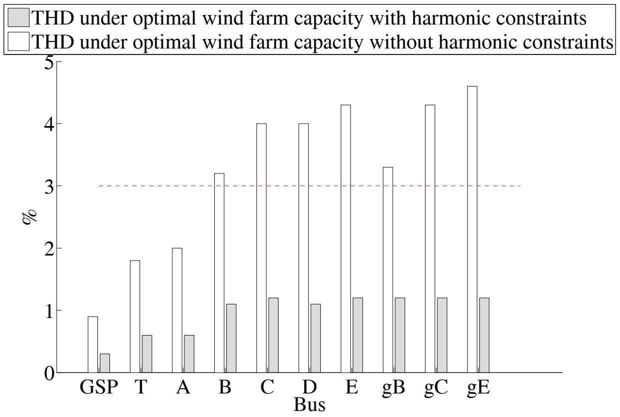

Fig. 3. Total harmonic voltage distortion at each bus under different optimal DG capacity results

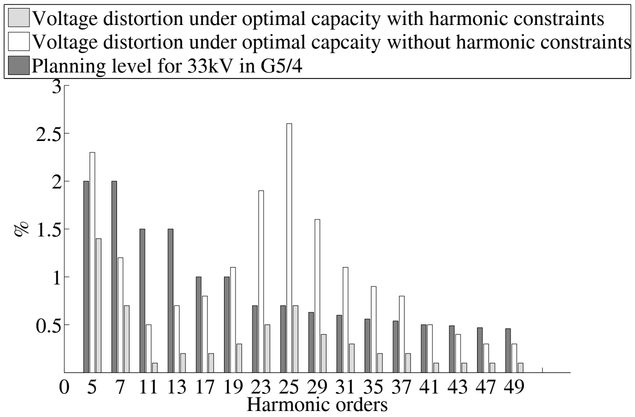

Fig. 4. Harmonic voltage distortion for individual orders at bus gE under different optimal DG capacity results

E. Analysis with Harmonic-Constrained Optimal Power Flow

With the initial OPF failing to comply with the G5/4 harmonic limits, obtaining a planning capacity that complies with the harmonic requirements will be vital in understanding the influence of harmonics on DG capacity and the requirement for mitigation. To simplify the simulation, the relationship between harmonic injections and DG capacity at each bus is defined as a continuous value instead of a discrete one. Applying the harmonic-constrained HOPF modeling outlined in Section III, for the same wind turbine harmonic emission characteristics and the same ER G5/4-1 constraints, a revised estimate for maximum DG capacity can be gained. The results are shown in Table IV and Fig. 5. These show an overall DG capacity of 13.44MW, a two-thirds reduction from the non-harmonically constrained result. The reduction is entirely the result of the harmonic constraints becoming active and which keep the DG capacity down to maintain harmonic compliance. This differs significantly from the non-harmonically constrained case where voltage and thermal limits alone constrain DG capacity. It is also notable that the changes are non-uniform with capacity at buses gC and gE reduced by around 80% while the capacity at gB actually goes up by 90% (as indicated by a 'negative' reduction). The reason for the increase is that the large reduction in capacity at gC lowers overall harmonic levels allowing an increase at the less harmonically 'sensitive' gB. THD and IHD under this capacity allocation are also presented in Fig. 3 and 4, respectively.

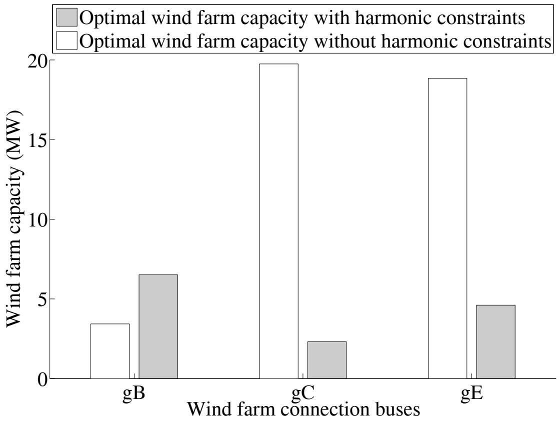

Fig. 5. Maximum DG capacity under different constraint considerations

It is clear that the results identified by the HOPF comply with harmonic limits. When inspecting the optimization result, there are active constraints associated with the 25th order harmonic at buses gB, gC and gE which all reach the 0.7% distortion limit with the latter being the binding constraint that prevents the network from accommodating more capacity. This reduction reflects the importance of introducing sufficient harmonic filter facilities, and with the 25th order harmonic treated as a priority.

F. Discussion

As mentioned earlier, one option for defining DG capacities that comply with harmonic limits is to undertake an indirect iterative process of: (1) obtaining DG capacity from the voltage and thermally constrained-OPF analysis (Section IV-C); (2) running harmonic power flow assessment; and (3) reducing DG capacity to comply with the harmonic limits. On the face of it this is a straightforward process, but in practice it is more difficult to ensure optimality. As Table IV shows the proportional changes between the initial OPF and final HOPF capacities at each bus are not the same and in the case of bus gB actually increase after considering harmonics. Therefore, it is inappropriate to define the same reduction ratio for the repeating procedure. As such a more direct method that explicitly links DG capacity and harmonics is more effective in handling the complex interaction between different DG in terms of harmonic emissions as well as impact on voltage and thermal constraints.

A significant reduction of the hosting capacity of the network is shown after considering harmonic limits. The simulation using worst-case scenarios and also strict compliance with the ER G5/4-1 standard contribute to this result. In practice, the harmonic requirement is not as strongly enforced as voltage variation and thermal rating limits, and the worst-case scenario may infrequently happen. As a result there could be more 'space' for accommodating DG according based on the actual connection agreements between developers and DNOs.

Harmonic filters can provide a mitigation solution to facilitate DG integration. The cost of filters requires appropriate placement and tradeoff analysis and an optimization method is useful in this respect. The active constraint found in the HOPF analysis can indicate the order(s) at the buses that constrains DG. It can also be used to check the required level of mitigation required, at which point the active constraint will switch to other network constraints instead of harmonics.

V. CONCLUSION

New DG development in distribution networks has inherent constraints such as energy resource availability, transmission capacity, and therefore it is of value for DNOs to access the extent to which their networks are capable of connecting new generation. In this context, the more constraints that the simulation modeling can take into account, the more applicable the results are.

In this paper, harmonic distortion limits are introduced as new constraints into the study of the ability of distribution networks to accommodate DG. The harmonic propagation results following a snapshot scenario optimization suggests severe violation of statutory harmonic requirements, and potentially impractical DG capacity planning results. Directly incorporating THD and individual harmonic planning level limits into the optimization of DG capacity sees a substantial reduction in connectable capacity.

Further work is required to improve and validate the harmonic emission model of DG presented here. Nonlinear load in the distribution network is another main source for voltage distortion which will also need to be measured and modeled in detail. When harmonics highly influence DG capacity limits, harmonic filter will need to be installed as a mitigation solution and the model here can be the basis for cost-benefit studies. It will also be necessary to carry out the analysis using larger, more realistic distribution networks.

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INCORPORATING HARMONIC LIMITS INTO ASSESSMENT OF THE HOSTING CAPACITY OF ACTIVE NETWORKS

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ABSTRACT

Harmonic emissions from converter-interfaced distributed generation connection can potentially lead to voltage distortion levels that are above applicable standards. The risk increases as greater connection volumes are facilitated by Active Network Management schemes. By incorporating harmonic limits into assessment of the hosting capacity of active networks, this paper demonstrates that by incorporating harmonic levels at the planning stage can prevent inadvertent restrictions on the integration of renewables. Other aspects considered include: the impact of active network controls on harmonic propagation and hosting capacity and the role of active harmonic mitigation methods.

INTRODUCTION

Development of renewable distributed generation (DG) creates ongoing challenges for distribution network operators (DNOs). The problems of voltage rise and power flow (thermal) limits are seen as being manageable by active network management (ANM) schemes which promise to unlock new DG connections [1]. However, harmonic current emissions from power electronic converter-interfaced wind turbines are rapidly moving up the agenda of DNOs and developers. The scale of new DG connections enabled by active network management (ANM) means there is potential for harmonics to inadvertently place limits on the ability of distribution networks to accommodate DG.

Traditionally, harmonic studies in distribution networks focus on comparing harmonics and total harmonic distortion (THD) against standards such as the UK's Engineering Recommendation (ER) G5/4. Harmonic analyses are generally based on a well-developed network, in which generation capacity and load configurations are given and fixed. However, the rapid developments of DG make generation capacity a dynamic factor wherein DG volumes change substantially over the planning horizon. Existing harmonic simulation and filter planning methods may not be sufficient to address harmonic constraints in DG planning studies. It is proposed here that harmonic studies should be considered at the initial phase of planning, instead of being an afterthought following 'blind' DG development.

A multi-period AC optimal power flow technique has been previously applied to measure the distribution network hosting capacity under voltage and thermal constraints and with active network controls [1]. Here, it has been substantially extended to also take account of harmonic distortion limits. Harmonic power flow is then embedded into a harmonic-constrained optimal power flow (HOPF) model to ensure that individual harmonics and THD comply with the ER G5/4 standard.

A section of a UK generic distribution network is used as a case study. Several cases are examined. The first considers the hosting capacity of the active network without the harmonic constraints applied; subsequent assessment of harmonic propagation shows violations of statutory limits and impractical planned DG capacities when ANM is implemented. A second case enforces the harmonic standards resulting in reductions in hosting capacity.

PROBLEM FORMULATION

Harmonic Power Flow

Harmonic power flow analysis has been extensively used to study harmonic propagation in the network. The results of distortion level and voltage wave forms are useful to verify compliance with harmonic limits. Harmonic power flow can be presented mathematically as [2, 3]:

$$[V_h] = [Z_h][I_h] \tag{1}$$

where $[Z_h]$ is the network impedance matrix; $[I_h]$ is the vector of nodal harmonic current injection of each bus; $[V_h]$ is the resulting harmonic voltage; and h is the harmonic order. Harmonic assessment using harmonic power flow can be separately conducted for every single DG applying for connection to the network. Modifying the DG capacity or installing expensive harmonic filters is necessary when the proposal violates harmonic limits. However, solutions deemed reasonable for each individual connection could deliver poor results for the network as a whole. For example, an early and minor connection may prevent development of other larger sites due to adverse harmonic propagation impacts, effectively reducing the total hosting capacity of the network or increasing the cost of additional filters. Given this network sterilisation effect, directly embedding harmonic power flow into initial DG planning techniques is a logical step and the focus of this work.

Harmonic Constrained Multi-Period Optimal Power Flow

AC OPF techniques have been proposed to find the hosting capacity of networks within given limitations and can guide DG planning to choose optimal connection location and capacity [4]. Similar to other physical constraints, harmonic limits can be incorporated into the OPF framework using results from harmonic power flow by constraining THD and individual maximum harmonic distortion (IHD). The harmonic constraints are incorporated within an existing sophisticated multi-period AC OPF formulation [1] designed to determine hosting capacity whilst accounting for variability and coincidence of demand and wind generation as well as a suite of ANM controls. The objective function is given as follows:

$$\max \sum_{g \in G} P_g \tag{2}$$

where P_g is the active capacity (MW) of DG connection g determined across a reduced time series (TS) analysis that groups wind generation and demand by a series of coincident ranges. This objective function is subject to a range of constraints which can be categorized into three sets: basic network limits; ANM constraints as well as the new harmonic distortion limits considered here. Fig. 1 shows the constraints structure for this proposed HOPF.

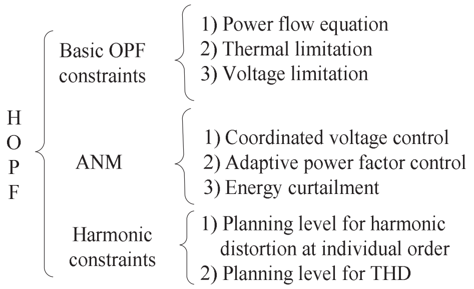

Fig. 1 Constraints within proposed HOPF formulation

1) Basic Network Constraint and ANM:

The allowable voltage at each bus and thermal rating for each branch in the network is ensured in every period by the thermal and voltage constraints. Active and reactive power balances are maintained by the power flow equation according to Kirchhoff's current law. A series of ANM controls are also embedded within the OPF formulation [1] to explore the capacity and harmonic implications of ANM. These are:

Coordinated Voltage Control (CVC): The transformer secondary voltage is dynamically set within upper or lower values to ensure more voltage headroom in the network.

Adaptive Power Factor Control (PFc): Many DG can operate at leading or lagging power factors and this control scheme dispatches the DG power angle for each period.

Energy Curtailment: The network characteristics and wind power pattern may necessitate curtailment of DG output in a given period to constrain voltage rise or power flows.

2) Harmonic Distortion Constraints

To provide the capability to constrain DG capacity and operation to ensure compliance with harmonic standards (ER G5/4-1), the following harmonic constraints apply:

$$V_{b,m}^{h} \le IHD^{h,+} \tag{3}$$

$$\frac{\sqrt{\sum_{h=2}^{H} (V_{b,m}^{h})^2}}{V_{b,m}^{1}} \le THD^{+} \tag{4}$$

where $V_{b,m}^{h}$ is voltage distortion at bus b for harmonic order h during the period m. $V_{b,m}^{h}$ can be obtained from the harmonic power flow equation (1). Constraints (3) and (4) guarantee that the HOPF defined DG volumes will comply with the harmonic standard.

Active Harmonic Filter

Should harmonics be above statutory levels filters can be used to mitigate them. The filters deployed in power systems can be classified into three categories: passive, active and hybrid. Conventional passive L-C filters are more economic [5] while active filters provide dynamic and adjustable compensation [6]. When it comes to the DG planning problem, there is a potential shortcoming with passive filters due to its power factor correction capability. The voltage rise problem can be (partly) mitigated by operating DG at lagging power factor [7] through absorbing reactive power. However, the capacitor installed within the passive filter will provide a local reactive source which will tend to worsen voltage rise. Given this, active filters are suggested here.

The most extensively applied active filter is the active power line conditioner (APLC). It is commonly modelled in filter planning areas as a current source injecting harmonics to its connection bus [8]:

$$I_{F,m}^{h} = I_{F,m}^{h,r} + jI_{F,m}^{h,i} \tag{5}$$

where $I_{F,m}^{h,r}$ and $I_{F,m}^{h,j}$ represent the real and imaginary part of APLC current $I_{F,m}^{h}$ at bus m.

CASE STUDY

A generic UK distribution network is used here as a case study. Fig. 2 shows the one line diagram of this simplified EHV1 Network from the UK Generic Distribution System. Full data for this 16-bus 33-kV rural network are available in [9]. The feeders are supplied by two 30 MVA 132/33kV transformers. The Grid Supply Point (GSP) voltage is assumed to be nominal. Voltage limits are taken to be ±6% of nominal. A voltage regulator (VR) is located between buses 8 and 9, with the latter having a target voltage of 1.03 pu. The maximum demand of the network is 38.16 MW.

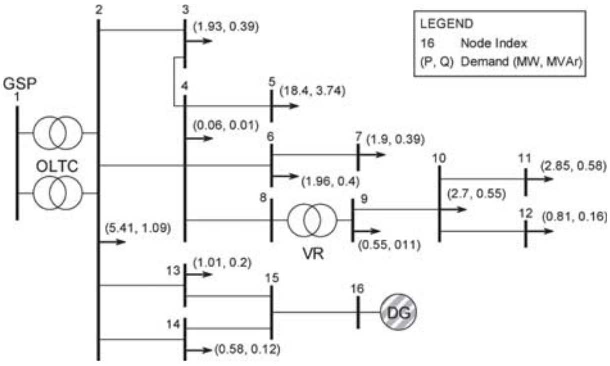

Fig. 2 Simplified EHV1 network [9] at maximum load

The network has one potential location (bus 16) at which new wind farms can be connected. For harmonic analysis, wind farms are modelled as current sources. The harmonic characteristics of a medium sized (0.6MW) wind turbine [10] are used for the analysis: Fig. 3 presents the frequency spectrum of maximum harmonic current where all triple harmonic orders (3rd, 6th, etc.) have been eliminated by the HV-MV transformer and all even orders cancelled since positive and negative parts of the current waveform are almost identical. In this paper, all harmonics from background nonlinear load is neglected due to the lack of data but this can be included effectively where detailed measurement or load models are available. It would be expected that distortion levels would tend to rise after considering background harmonics.

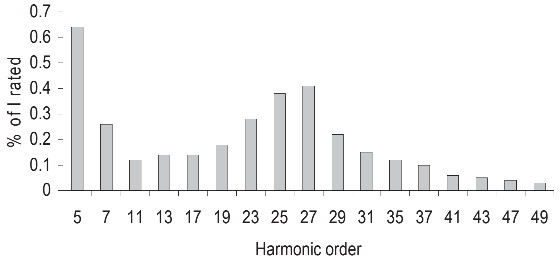

Fig. 3 Maximum harmonic current produced by wind turbine

Hosting Capacity and Harmonic Compliance

In this section, a series of analyses determine hosting capacity whilst ignoring potential harmonic constraints. Two snapshot analyses at maximum and minimum load are first considered, followed by the more sophisticated multi-period time-series (TS) analysis over the year. Following widely accepted practice, the wind farm at bus 16 is assumed operating at unity power factor. The results for these three analyses are shown in the first three columns of Fig. 4. It is clear that the DG hosting capacity from maximum load is identical to the whole year TS study while both are much lower than the minimum load case. This is very different from the commonly assumed 'worst case' scenario of maximum DG output at minimum load. The reason for this is that the relatively large load at bus 5 forces a high voltage setting at bus 2 limiting the voltage headroom for DG capacity elsewhere. This contrary requirement will be worse at maximum load levels. Therefore, it is notable that the hosting capacity of this network is mainly constrained by the power flow transmitted to load at bus 5.

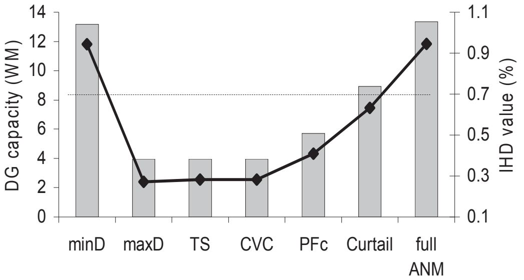

Fig. 4 DG capacity and IHD under different cases

The impact of ANM schemes on hosting capacity is now assessed using four different ANM combinations. The additional capacities after ANM implementation are shown in Fig. 4. The least effective technique for the network is CVC which has the same hosting capacity as the maximum load; this is unusual but demonstrates the conflicting requirements for the OLTC voltage control. PFc improves capacity levels by 45% by importing reactive power at low demand. Allowing wind to be curtailed by up to 5% over the year, sees selective reductions in DG production at low demand that allow hosting capacity to increase by 127%. After applying all the ANM, DG capacity slightly surpasses the result for the minimum load scenario (13.4 vs. 13.2 MW).

To consider whether the suggested hosting capacities are harmonically compliant, a series of harmonic power flow analyses were conducted. The THD in all cases shows compliance but the IHD of order 25 at DG bus 16 violates the requirement (0.7%) in the two high capacity cases (minimum load and full ANM). The IHD results are given as points along with the capacity column in Fig. 4. Due to the specific topology and loading patterns in this network that restrict hosting capacity, harmonics are not active constraints until higher levels of capacity and/or extensive ANM are applied. However, in general ignoring harmonics from assessments may result in harmonic non-compliance given the scale of new DG capacity enabled by ANM.

Analysis with Harmonic-Constrained OPF

With the initial OPF failing to comply with the G5/4 harmonic limits at higher capacity levels, obtaining a planning capacity within the distortion requirements will be vital in understanding the influence of harmonics on active networks. Applying the harmonic-constrained HOPF model using the same harmonic emission characteristics, a revised estimate for maximum DG capacity can be gained. The results are shown in Fig. 5. The 11.2MW DG capacity is a 16% reduction from the non-harmonically constrained result. The change is entirely the result of the harmonic constraints becoming active and restricting the ANM-enhanced DG capacity down to maintain harmonic compliance. The worst IHD of the 25th order harmonic at DG connection bus under each capacity allocation are also presented in Fig. 5. It is clear that the results identified by the HOPF comply with harmonic limits (Fig. 5).

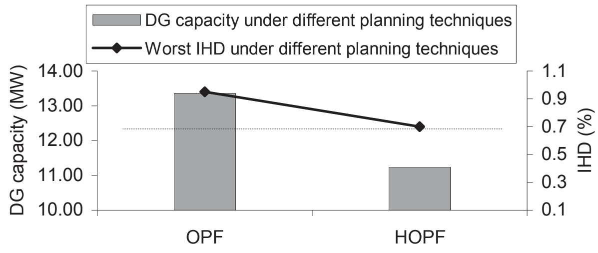

Fig. 5 DG capacity for ANM case under different constraint considerations

Mitigation With Active Filters

This reduction of DG capacity with HOPF reflects the potential value of introducing sufficient harmonic filter facilities, here specifically to treat the 25th order harmonic. To illustrate the influence of active filters a sequence of HOPF analyses were run for the full ANM case with the filter capacity increasing progressively from zero. Fig. 6 shows the impact of these active filters on the hosting capacity. It demonstrates that the hosting capacity initially increases linearly with filter size as larger filters offset more of the 25th harmonic. The leveling off of hosting capacity despite larger filters indicates that the harmonic constraint has become non-binding where other constraints dominate.

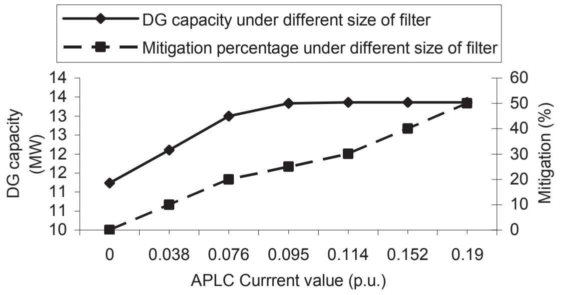

Fig. 6 Impact of different sized filters for full ANM case

CONCLUSION

In this paper, harmonic distortion limits are introduced as new constraints for the assessment of hosting capacity of active distribution networks to accommodate DG. A harmonic-constrained OPF provides additional information to guide DG developers and DNOs in maximising DG capacity. The harmonic propagation results following a time-series optimization suggest that violation of statutory harmonic limits and consequently impractical DG capacity levels occur when ANM 'frees up' sufficient new capacity. Directly incorporating THD and individual harmonic planning level limits into the optimization of DG capacity sees a substantial reduction in connectable capacity. Based on the proposed HOPF techniques, potential harmonic mitigation solutions such as active filters are briefly explored in terms of their ability to free-up capacity. The cost of filter installation and maintenance should not be neglected, however.

Further work is required to evaluate the harmonic emissions from different DG technologies as well as the substantial increase in complexity that arises from handling multiple DGs and the influence of nonlinear loads in the distribution network. The HOPF formulation can be further extended to incorporate economic factors for the purpose of conducting cost-benefit studies.

ACKNOWLEDGMENTS

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INFLUENCE OF GENERATOR CURTAILMENT PRIORITY ON NETWORK HOSTING CAPACITY

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ABSTRACT

Increasing penetration of distributed generation in distribution networks requires active constraint management to provide greater flexibility and use of existing network assets. Curtailing DG output under worse case scenarios to keep the network operating below voltage and thermal limits will play a major role in active network management. While a number of curtailment priority schemes are established there is a need to demonstrate the benefit of different priority schemes for curtailing multiple DGs. Comparing with 'first in last out' and other priority methods, this paper proposes and demonstrates that optimal setting of DG curtailment priority using multi-period OPF is not just technically appropriate but also economically beneficial. By extending this idea into the planning arena, the impact of curtailment management schemes on network hosting capacity is evaluated.

INTRODUCTION

In the transmission network, generation curtailment is an established methodology to tackle congestion. In passive distribution networks, curtailment is rarely used as the hosting capacity is largely determined by the 'worst-case' conditions, typically maximum generation and minimum demand. This guarantees the network can operate without any additional control requirement but it reduces the potential energy that can be harvested from distributed generation (DG). Given the infrequent occurrence of the worst case conditions, the introduction of active network management (ANM) can provide technical and economic benefits, and facilitate DG connections.

Operating for non-firm DG connections requires that the curtailment of multiple DG be governed by a set of priority rules that dictate the sharing of the curtailment between each DG. Current ANM systems such as the UK's Orkney scheme are operated on the 'first in last out' (FILO) rule where earlier connections will enjoy preferable treatment over later connections. A risk with FILO is that the last connection may be located at a network position where managing the output of DG has limited impact on relieving network constraints whereas the same voltage or thermal control effect could provided by other DG connections for less curtailment. Under certain conditions, inappropriate management schemes may reduce or 'sterilise' available hosting capacity for non-firm connections by over-curtailing production to uneconomic levels.

Several other curtailment priority schemes have been mooted including: 1) proportional reduction where all DG output is decreased equally and; 2) a 'technically most appropriate' approach where the minimum overall curtailment is delivered by curtailing the most appropriate DGs. Jupe *et al*. [1] and Zhou and Bialek [1, 2] use sensitivity methods to operate such schemes; however, these will not deliver truly optimal outcomes. Boehme *et al*. [3] analyse extensive renewable generation time series for both schemes: the proportional scheme is modelled using stepwise reductions using a load flow engine and the technically most appropriate reductions are determined by an optimal power flow (OPF) engine dispatching each DG up to the limits of the network based on equal (pseudo) costs for each renewable generator.

While the operation of an ANM with a known set of DG generators can be explored using time series simulation, planning connections to ANMs is highly complex. When a DG developer is looking to connect to an active network they will need to undertake very detailed assessments of the likely output of other generators and the resulting power flows in order to estimate their own likely generation and extent of curtailment. These values depend on the capacity of each generator, resource levels at each location, the technological and economic characteristics of the DG and any access rules governing operation of the ANM. The complexity of networks and competition for network access among developers makes this process extremely challenging. The process may be simplified using the network 'hosting capacity' as a guide.

The hosting capacity indicates the extent to which one or more DG may be connected across a network under specific conditions. A framework for analysing this for active networks was outlined by Ochoa *et al*. [4] using a multi-period OPF to determine DG hosting capacity for a series of ANM controls including curtailment. The analysis assumed controls would accommodate DG in the technically most effective manner and the extent of curtailment was limited to a pre-specified proportion of energy generation in order to avoid excessive curtailment and unreasonable volumes of capacity added. However, there was no explicit consideration of whether curtailment was economically viable nor did it cover other priority schemes.

In this paper the extent to which the financial viability of DG plants and different ANM access priority schemes affect network hosting capacity is outlined.

PROBLEM FORMULATION

Given the characteristics of the demand and variable distributed generation, the assessment of DG behaviour within active distribution networks presents several complexities when considering hosting capacity. The multi-period OPF developed in [4, 5] was adopted in the work to formulate the DG optimal planning and operational problem. The multi-period formulation is based around a process of describing a series of time periods m in which the coincidence of DG output and demand are similar.

The new development in this paper is the re-framing of the hosting capacity problem such that it is driven by the financial viability of each DG as determined by its capacity, the curtailment priority rules and the extent of curtailment. The hosting capacity is measured by maximising economic benefit:

$$\max \sum_{g \in G, m \in M} (P_g - P_{g,m}^{curt}) \times R \times M - C_{inv} - C_{om} \qquad (1)$$

where P_g is the capacity DG g and $P_{g,m}^{curt}$ is the extent of energy curtailment in period m summed across the whole time period M. The revenue for each DG is obtained from selling the energy produced R (which may include a subsidy as well as the wholesale price). The DG costs are a function of DG capacity: capital cost C_{inv} and operations and maintenance cost C_{om}.

The optimisation is subject to a range of basic network constraints: real and reactive nodal power balance; voltage level constraints; and thermal limits (lines and transformers). Different from the hosting capacity formulation in [3] which pre-defined constraints on the total amount of curtailed energy for each DG, here the economic performance acts as the constraint.

Three strategies for prioritising curtailment of multiple DG are considered in this work and embedded into the OPF framework:

1) ‘First in last out’ (FILO), where an extra constraint is added in the optimisation to ensure the preferable treatment of earlier DG connections (b) over later connections (a):

$$P_{a,m}^{curt} = \begin{cases} 0 & \text{if} \quad P_{b,m} > 0 \\ P_{a,m}^{curt} & \text{if} \quad P_{b,m} = 0 \end{cases} \qquad (2)$$

where, in period m, as long as the output of DG b ($P_{b,m}$) is not completely curtailed, there is no reduction in output of DG a ($P_{a,m}$).

2) Proportional curtailment, where all the DGs share the same percentage reduction to their production:

$$P_{a,m}^{curt} / P_{a,m} = P_{b,m}^{curt} / P_{b,m} \qquad (3)$$

3) Optimal curtailment setting (or technically most appropriate), where the reduction of each DG’s output is directly optimised by the OPF to maximise economic benefit. It is simple in the formulation since this control scheme excludes equations (2) and (3).

CASE STUDY

A typical rural section of a medium voltage distribution network with a radial topology and large R/X ratios is used as a case study It has been selected as it is simple to illustrate the effect of different curtailment schemes on hosting capacity analysis and offers potential to compare with results in [6]. The one-line diagram is shown in Fig. 1 and the line data is given in [6]. The feeders are supplied by one 31.5MVA 110/38kV transformer. The Grid Supply Point (GSP) voltage is assumed to be nominal and voltage limits are taken to be 10% of nominal. The maximum demand of the network is 15.12MW. The network has five potential locations at which new DG can be connected: buses gA, gB, gC, gD and gE in Fig. 1. To keep the illustration simple, all DG are assumed to operate at constant full output and to operate at unity power factor. The demand however varies with time as shown in Fig. 2 and is processed into a range of representative bins to reduce the computational burden. The optimisation of total hosting capacity is determined across the whole period (year). The DG economic parameters are given in Table 1.

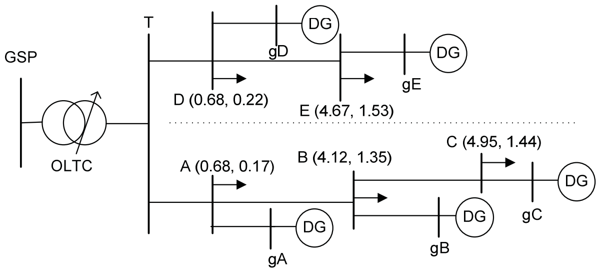

Fig. 1 Five-bus example network`

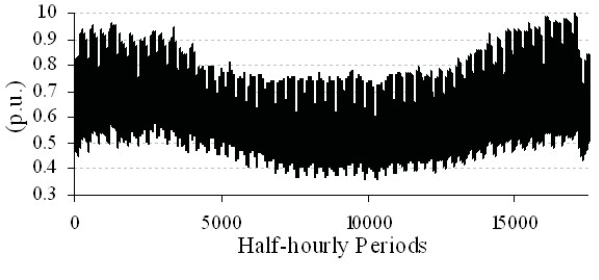

Fig. 2 Half-hourly demand data

Table 1 Economic parameters used in financial evaluation

Parameter	Value

Revenue from sales and support	£100/MWh
DG capital cost	£1000/kW
Annual operations and maintenance cost	£50/kW

The first analysis estimates the total capacity of the five DGs that can be accommodated in this network without any active generation management scheme being present. The results are given in Table 2 described by ‘Base’. This assumes a passive network without curtailment so the “worst-case” scenario when the coincidence of minimum demand and maximum generation occurs is the main constraint on capacity. The total capacity is 27 MW and the largest DG can connect nearest to the GSP (at location A) with progressively less towards the end of the feeders. Since the limitation on DG capacity is mainly imposed by the “worst-case” conditions, the curtailment of generation during these periods will alleviate the constraints (here voltage rise) allowing installed capacity to increase and overall energy production to rise.

The analysis was re-run for the different priority schemes. A set of four curtailment methods are examined:

1) FILO curtailment – assumption A: for each feeder, the curtailment is assumed to preferentially apply to DG that is further from the GSP (i.e. DG A is curtailed before B and B before C);
2) FILO curtailment – assumption B: for each feeder, the curtailment is assumed to preferentially apply to the DG that is nearest to the GSP (i.e. DG C is curtailed before B and B before A);
3) Proportional curtailment: all DG is curtailed equally;
4) Optimal setting curtailment: the objective is to maximise the total economic benefit obtained from all the DGs, as given in equation (1).

It can be seen in Table 2 that all studies that employ curtailment allow much more generation capacity able to be connected than the passive network analysis: the hosting capacity increases between 17 and 30%. With more capacity accommodated, curtailment schemes control production to guarantee the network operates below the voltage and thermal limits under low demand scenarios. However, the differences in curtailment between the four schemes and among the DGs are significant. The optimal curtailment setting delivers the largest overall capacity while FILO assumption A delivers the lowest. FILO assumption B and the proportional scheme sit in between. In each case DG A remains the largest generator but capacity increases of almost 50% are seen for other DG under some cases.

FILO assumption A favours DG located near to the end of the feeder. As such it results in smaller DG capacities overall with the two DGs nearest to the GSP being curtailed (i.e. A and D) while those further away are unaffected. This results in very significant curtailment of generator D (19%) but an 80% increase in capacity at generator D to boost generation. Overall, energy production rises by 12% from the base case. Curtailment at generator A is smaller – as it the increase in capacity. Under the proportional scheme all DG is curtailed equally by 7% with substantial increases in capacity (27%) and energy production (16%).

Optimal curtailment creates 22% extra production with 30% extra capacity, at the expense of 9% curtailment. All DG capacities are higher with most capacity increases coming from the DG at the end of the feeders. They however suffer higher levels of curtailment than under FILO assumption A. The level of curtailment of generator A is modest hence there is limited room to increase its capacity. It is notable that under this scheme the level of curtailment at all DGs other than A is higher than under proportional sharing. DGs B to E are all above the ~7% which is the best global reduction percentage obtained from the proportional curtailment scheme. The only exception is DG A, where four-fifths of its curtailment is avoided if other DGs are able to contribute more.

Although the process differs, FILO assumption B behaves more like the optimal setting scheme and favours DG capacity nearer the GSP. The curtailment of the DG at the very end of the feeders (C and E) is more severe than any other scheme but this allows overall production to almost match the optimal. The capacities of these two generators are allowed to increase to facilitate this.

Table 2 Comparison of DG capacity, production and curtailment under different curtailment priority schemes (OPT stands for the Optimal Setting Curtailment Scheme while PROP for the Proportional Curtailment scheme)

DG	Capacity (MW)					Energy (GWh)					Curtailment (%)				
Location	Base	FILO_A	FILO_B	OPT	PROP	Base	FILO_A	FILO_B	OPT	PROP	Base	FILO_A	FILO_B	OPT	PROP
DG A	15.0	16.3	15.2	15.6	15.8	131	138	133	135	129	0%	4%	0%	1%	7%
DG B	4.2	4.7	6.1	6.4	6.2	37	41	54	51	51	0%	0%	0%	9%	7%
DG C	3.0	3.1	5.7	5.5	4.7	26	27	38	42	39	0%	0%	24%	13%	7%
DG D	2.3	4.2	3.1	3.3	3.4	20	30	27	27	27	0%	19%	0%	9%	7%
DG E	2.4	3.4	4.5	4.3	4.1	21	29	32	33	30	0%	0%	18%	12%	7%
Total	27.0	31.7	34.6	35.2	34.2	237	266	284	288	276	0%	4%	8%	9%	7%

In terms of the net revenue that the DGs deliver, it can be seen from Table 3 that all curtailment schemes ensure more economic benefits from increased DG capacity. The benefits follow the energy production levels with the poorer performing FILO assumption A lowest, followed by the proportional scheme, with the FILO assumption B close to the optimal. The maximum net revenue is delivered by the optimal setting scheme with a 20.6% increase over the Base case, 5% above proportional curtailment and almost double that of FILO assumption A. It demonstrates that this advanced curtailment approach is not just technically efficient but also economically efficient.

Table 3 Net revenue for each curtailment scheme

Curtailment Scheme	**Net revenue(£M)**	**Increase (%)**
None	21.3	
FILO A	23.8	11.6%
FILO B	25.4	19.1%
Proportional	24.6	15.6%
Optimal	25.7	20.6%

DISCUSSION

The objective in this work was to examine how the choice of prioritising DG for curtailment in ANM systems would affect the hosting capacity. The results show that inappropriate choices of priority order – as may happen under FILO – can reduce hosting capacity compared to the optimal schemes. Although each scheme delivered benefits over passive networks, the implementation of the access rules also needs appropriate commercial arrangements and a policy framework to allocate the benefits among the DGs. It has to be fair for the DGs that contributed more in curtailment to deliver more revenue overall. This allocation method is of significance, especially in market environments where DNOs cannot own DG. The issue of fairness would be particularly important where DG has been connected on a firm connection basis and where reversion to non-firm operation would deliver substantial increases in output overall.

The DGs are assumed to be operated at unity power factor as a normal requirement, but this constraint could be easily relaxed. When the reactive power generation capability of DG is exploited, the OPF approach could be more feasible than the sensitivity method since both the active and reactive power have an impact on voltage constraints. Those two interactive factors are not easy to consider by linear simplification of sensitivity analyses.

Another constraint limiting the DG connection is overload of feeders, which is not fully illustrated in the case study. While sensitivity-based curtailment is considered effective to manage thermal congestion problem, it sometimes increases network losses. Due to the radial structure of distribution networks, DG located near to the overloaded line has a higher sensitivity. If this DG is curtailed first under a sensitivity based priority scheme, more losses will occur from the larger generation output elsewhere in the network. It would be logical to consider minimising losses and curtailment together, and therefore embedding DG curtailment control into multi-period OPF framework is more efficient since it can handle those two conflicting aspects simultaneously. It is also important to highlight that although the proportional curtailment scheme needs a constraint to represent the same percentage reduction among the DGs in optimisation formulation, the curtailment setting for each DG and each period is still optimised under this restriction. The difference between the considered schemes here is just limited to this additional control requirement.

CONCLUSION

In this paper, several ANM curtailment priority systems were examined for their impact on network hosting capacity. The hosting capacity evaluation method with curtailment management is extended to consider the economic benefits of active management. It was found that inappropriately chosen priority of curtailment resulted in reduced hosting capacity, lower overall energy capture and lower benefits from ANM. The approach would provide a basis for quantifying the economic incentives during the DG planning process.

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Influence of Generator Curtailment Priority On Economic Hosting Capacity

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***Abstract*—Increasing penetration of distributed generation (DG) in distribution networks requires active network management to provide greater flexibility and use of existing network assets. A number of curtailment arrangement methods are established that determine the order (or priority) in which DG is curtailed to relieve constraints. However, there is a continuing need to study and demonstrate the efficiency and benefit of such priority schemes to enable DG developers to justify their investment. This idea is extended into the planning arena, where the impact of curtailment management schemes on economic hosting capacity is evaluated. A multi-period Optimal Power Flow technique is used to estimate hosting capacity subject to technical constraints as well as the economic viability of schemes participating in the connection arrangements. The paper demonstrates that while curtailment schemes such as 'first in-last out' that enforce connection sequence in determining levels of curtailment are effective in raising overall DG capacity, they may leave much of the network potential unexploited. Alternative arrangements based on technically optimal curtailment alongside compensation for lost generation provides a means of (partially) mitigating this to deliver substantially greater DG capacity and economic benefits.**

***Index Terms*—**Active network management, curtailment priority, distributed generation, generator curtailment, principles of access.

I. INTRODUCTION

In the transmission network, generation curtailment is an established methodology to tackle congestion. In passive distribution networks, curtailment is rarely used on renewable distributed generation (DG) as the hosting capacity is largely determined by the 'worst-case' conditions, typically maximum generation and minimum demand. This guarantees the network can operate without additional active control requirements but it reduces the potential energy that can be harvested from renewable DG due to its non-coincidental pattern with demand and the infrequent occurrence of the worst case conditions. In order to facilitate increased DG connections and avoid high network reinforcement costs under conventional connection agreements, active network management (ANM) has been widely proposed and, in some cases, implemented. ANM is a general philosophy of planning and operating a real-time monitoring and control system to achieve improved management of both DGs and networks. Under ANM, the distribution network could increase its hosting capacity by granting 'non-firm' connections where generators are subject to curtailment to mitigate network constraints.

Planning and operating non-firm DG connections requires that the curtailment of multiple DG be governed by a set of priority rules that dictate the sharing of the curtailment between each DG. The priority rules are also known as 'Principles of Access' in other studies [1, 2]. Several curtailment priority schemes have been mooted including:

1. 'Last in-first out' (LIFO) where earlier connections will enjoy preferable treatment over later connections;
2. 'Proportional reduction' where all non-firm connected DG output is decreased equally; and
3. 'Technically most appropriate' where curtailing the most appropriate DGs delivers minimum overall curtailment.

Current ANM systems such as the UK's Orkney scheme are operated on the 'last in-first out' rule. A risk with LIFO is that the last connection may be located at a network position where managing the DG output has less impact on relieving network constraints. In other words, the same voltage or thermal control effect could be made by other DG connections with less curtailment. Under certain conditions, inappropriate management schemes may reduce or 'sterilise' available hosting capacity for non-firm connections by over-curtailing production to an uneconomic level.

The assessment of curtailment for ANM operations and its allocation under various priority rules have been addressed in several studies. Currie *et al.* [3] proposed a logic-based curtailment scheme for active power flow management considering the operating margins. Under normal operation conditions, once the active power flow on critical branch breaches the pre-set trim or trip margin, output of regulated non-firm generators will be curtailed step by step based on 'LIFO' orders. It presents a relatively simple but practical ANM system which has been proved by implementation on the Orkney network [4].

To minimise the curtailment, sensitivity techniques based on linear programming have been used to specify priority rules. Zhou *et al.* [5] develop an approach using curtailment of generation to manage voltage constraints in distribution networks. The curtailment is based on the contribution of generators to the constraints quantified by voltage-sensitivity factors. Alternative priority rules which equate higher sensitivity factor with more curtailment are proposed. It demonstrated that total curtailments might be reduced and the LIFO rule is least efficient in the case network. The study's

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snapshot analysis, however, makes the long term benefits of the control strategy hard to measure.

Jupe *et al*. [6] outlined a curtailment scheme managing thermal congestion using a contribution matrix calculated from power flow sensitivity factors. Candidate priority strategies are evaluated by historical network data for a set of known DGs. Total energy generated from all DGs for a long term period showed the positive impact of adopting alternative curtailment schemes to LIFO rules. It also demonstrates that the overall revenue is increased but the impact on individual generators is different.

Curtailment approaches based on Optimal Power Flow (OPF) have also been proposed to minimise the curtailment under particular priority rules. Although not the primary focus of the work, Boehme *et al*. [7] analysed the curtailment of extensive renewable generation subject to both thermal and voltage constraints. The proportional scheme was modelled using stepwise reductions using a load flow engine and the technically most appropriate reductions determined by a commercial OPF engine with the dispatch of each DG being based on equal (pseudo) costs for each renewable generator. Dolan *et al*. [8] realised an OPF-based online operation technique to manage thermal constraints. The priority arrangement is based on LIFO and allocates different values to generator cost to reflect its connection order. It optimises the curtailment while maintaining LIFO rights by curtailing more from ‘expensive’ DG representing the later connected units. The control robustness of the OPF approach with regard to its application for real time online operation is further discussed and demonstrated in [1]. Using OPF, other ANM techniques are also considered to optimise the curtailment under ANM schemes. Gill *et al*. [9] developed a dynamic optimal power flow (DOPF) integrating a time dependent variable into the standard OPF formulation. A day-ahead schedule aiming to minimise the curtailment using energy storage and flexible demand is presented. Capitanescu *et al*. [10] comprehensively modelled a wide range of possible controls within an OPF, to manage voltage constraints while minimising the required curtailment. The benefits of comprehensive curtailment optimisation are demonstrated on a snapshot basis. Both works show the total curtailment can be further reduced when alternative control techniques effectively solve network constraints and adopt curtailment only as a last resort.

While the optimal operation of curtailment schemes under ANM with a known set of DG generators has been explored, planning connections to ANM under various curtailment arrangements is generally neglected and highly complex. In the planning context, when a DG developer is looking to connect to an active network they will need to undertake very detailed assessments of the likely output of other generators and the resulting power flows in order to estimate their own likely generation and extent of curtailment. These values depend on the capacity of already connected generators; renewable resource levels and variability at each location; the technological and economic characteristics of the DG; and any priority rules governing operation of the ANM. The complexity of networks and competition for network access among developers makes this process extremely challenging. The process may be simplified using the network ‘hosting capacity’ as a guide.

The hosting capacity indicates the maximum size of DG that may be connected under specific conditions; they apply a range of constraints and degrees of sophistication. Hosting capacity can be directly assessed by searching for the maximum power rating of DG [11] but also by focusing on loss minimization [12] or reactive power support [13]. The work in [14, 15] extended the evaluation of the hosting capacity by improving the performance of multiple objectives. Voltage rise and thermal overload are the most common constraints considered but voltage step [16], fault level [17, 18] and security [19] constraints have been examined. A range of techniques have been proposed.

The basic framework for this study has been outlined by Ochoa *et al*. [11] who developed a multi-period OPF to determine DG hosting capacity for a range of ANM controls including curtailment. The analysis assumed controls would accommodate DG in the technically most effective manner and the extent of curtailment was limited to a pre-specified proportion of energy generation in order to avoid excessive curtailment and unreasonable volumes of DG capacity. However there was no explicit consideration of whether curtailment was economically viable nor did it cover other priority schemes.

This paper formalises a new methodology to rapidly identify the network hosting capacity under different ANM priority rules. It builds on earlier work on determining hosting capacity for ANM [20] by explicitly linking hosting capacity to the financial consequences of different priority schemes for wind power developers. It extends the use of a multi-period optimal power flow tool to compare the differing influence of LIFO, proportional reduction and technically most appropriate priority schemes on the available hosting capacity of an example network. The extent to which the financial viability of multiple DG plants and different ANM priority schemes affect network hosting capacity is examined.

The paper is structured as follows: Section II presents the methodology for assessing economically-optimal hosting capacity with various ANM priority rules. A case study on a generic distribution network is analysed in Section III, followed by a discussion of results in Section IV. Finally, conclusions are presented in Section V.

II. HOSTING CAPACITY PROBLEM FORMULATION

A. *Framework for Handling Variable Renewables*

The assessment of DG behaviour within active distribution networks ideally requires full hourly time-series analysis over at least a year, in order to adequately present the variation of DG output and demand. For optimisation applications, it means a significant volume of time-varying variables and correspondingly additional constraints which unduly increases the computational burden. The multi-period OPF developed in [11, 12] was adopted and enhanced here to formulate the (economic) hosting capacity planning problem. The multi-period formulation aggregates the full sequential time series into a manageable set of generation and demand periods m based on their joint probability of occurrence. This is illustrated in Fig 1 where the original (top) hourly demand and wind power data for Scotland [12] is discretised by rounding to the mean value of its nearest bin range (bottom; arrows indicate hours where demand is 0.7pu and wind is zero). Across the whole time period M the total duration of each period is τ_m. The framework is implemented in the AIMMS optimisation suite using the Conopt 3.14A solver.

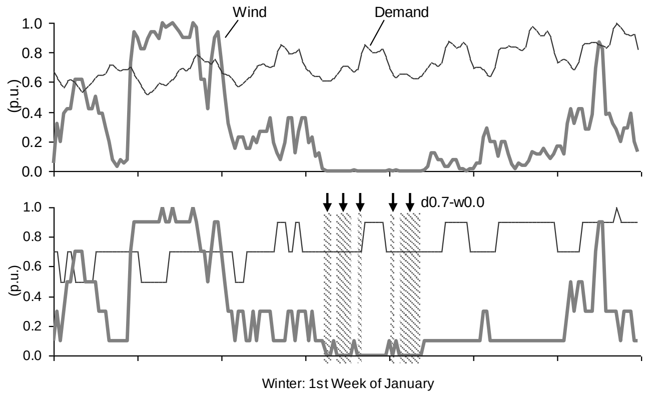


Fig 1: (top) Winter week hourly demand and wind power for central Scotland, 2003; (bottom) Discretised data processed before aggregating the coincident hours of each demand-generation scenario [12].

B. *Evaluating 'Economic' Hosting Capacity*

The unbundled nature of the distribution business in the U.K. and separate ownership of DG means developers compete for network access. Given rational economic behaviour, DG developers will aim to maximise returns from electricity sales. Broadly speaking, this objective tends to be met with increased installed capacity but they are significantly influenced by curtailment priority rules, especially where the network hosting capacity has been largely utilized by earlier connections and the generation of new planning DG might be frequently curtailed.

The new development in this paper is the re-framing of the hosting capacity problem such that it is driven by the financial viability of DG as determined by its capacity, the curtailment priority rules and the extent of curtailment. The optimal hosting capacity p_n is measured by maximising the Net Present Value (NPV) of economic benefits across the lifespan:

$$\max \sum_{g\in G} p_g \quad \rightarrow \quad \max E_{NPV}(p_n) \qquad (1)$$

It is important to note that the re-framed objective function (right) only optimises the economic return of new planned DG ($g = n$), rather than all DG ($\forall g \in G$) from the overall network point of view. This is due to the consideration of separate ownership. Competition for capacity means it must be clear who is charged the costs of curtailment and who benefits from the increased output. Considering the issue of fairness, the evaluation of non-firm connection options for new DG would include potential compensation mechanisms. The generalized objective function to maximise the economic hosting capacity for various non-firm connection options is given as:

$$\max\{(E_n - E_{com})R - C_{inv} - C_{om}\}\kappa \qquad (2)$$

Here the revenue of each new DG, n, is obtained from selling energy E_n. The electricity price R could include subsidy payments as well as the wholesale or power purchase price. Depending on the curtailment arrangement applied, the new connection may need to compensate existing DG for any curtailment imposed, this is modelled as E_{com}. The DG costs are a function of DG capacity: capital cost C_{inv} and operations and maintenance cost C_{om}. An annuity factor κ is used to convert lifetime cash flows into present value. The formulation of DG financial returns can be extended to include the implementation cost of ANM techniques as well, although this is omitted for clarity.

Under the multi-period formulation, the energy E_n produced from non-firm DG n is given by

$$E_n = \sum_{m\in M} (p_n\omega_m - p^{curt}_{n,m})\tau_m \qquad (3)$$

where p_n is the optimal capacity of planned DG n, and in each period m, ω_m is the generation level determined by the renewable resources, and $P^{curt}_{n,m}$ is the extent of energy curtailment of DG n.

The optimisation is subject to a range of standard network constraints: real and reactive nodal power balance, voltage level constraints and thermal limits that apply in each period. Different from the hosting capacity formulation in [11] which used pre-defined limits on the total amount of curtailed energy for each DG, here the DG economic performance and curtailment priority strategies act as the constraint.

The three strategies for curtailment priority of multiple DG are considered and embedded into the OPF formulation.

C. *'Last in first out' (LIFO)*

The aim of the LIFO arrangement is to avoid or reduce the risk of extra curtailment being imposed on an earlier installed DG by one that follows. In an operational context, by curtailing the last connection first, earlier connections are able to operate as they would have before new DGs connected. To achieve the same principle at the planning stage, an extra constraint is added to the optimisation to ensure the preferable treatment of earlier DG connections over latter connections:

$$\frac{\sum_{m\in M} (p_g\omega_m - p^{curt}_{g,m})\tau_m}{\sum_{m\in M} p_g\tau_m} \geq \alpha^{prev}_g, \ \forall g \in G \mid g \neq n \qquad (4)$$

where the output factor (the ratio of curtailed to potential generation) of an existing DG (indexed by $\forall g \in G \mid g \neq n$) following the connection of new DG would be limited to a minimum value α^{prev}_g , which can be equal to its historic production or adjusted based on the resource forecast and other incentives.

Since the LIFO rules attempt to isolate the generation of existing connections from the impacts of new DG, it is not necessary to compensate for pre-existing curtailment (if any). Therefore E_{com} in (2) is assumed to be zero.

D. *Proportional Curtailment*

LIFO favours earlier connection, so it may be considered unfair to later connections that experience reduced hosting capacity and economic viability. Proportional curtailment rules treat all DGs equally as network users contributing the same impact to network constraints. In operation, the proportional curtailment scheme can be implemented by requiring all non-firm DGs to reduce their production by the same percentage. The output factor is also used as the proxy to define the long term impact of proportional curtailment rule. The proportional curtailment scheme here is modelled as a constraint that all non-firm DGs obtain same reduced output factor as a result of curtailment:

$$\frac{\sum_{m\in M}(p_g\omega_m - p_{g,m}^{curt})\tau_m}{\sum_{m\in M} p_g\tau_m} = \alpha^{shared}, \qquad \forall g \in G \tag{5}$$

where the reduced output factor α^{shared} is calculated across the whole time period M. All DG including those already connected share this burden. It is logical to consider a reasonable limit to reductions since increasing penetration may require earlier connections to reduce output to an uneconomic level. To avoid uncertainty and encourage developers, a maximum level of curtailment α^{upper} is enforced:

$$\alpha^{shared} \le \alpha^{upper}. \tag{6}$$

Similar to LIFO, there is no compensation for lost production due to the philosophy of treating all DG equally as network users. It is also important to highlight that although both LIFO and proportional curtailment schemes need a constraint to represent certain priority rules among the DGs within the optimisation formulation, the curtailment setting for each DG and each period is still optimised under this restriction. The difference between the DG is limited to this additional curtailment control requirement.

E. *Technically Most Appropriate*

It is clear that both the LIFO and proportional reduction schemes fail to consider the management of constraints in the overall most electrically efficient way of maximise the hosting capacity. Contributions to network constraints are different across DGs, which implies that the new connection may be located at a network position where managing the output of DG has less impact on relieving network constraints. Curtailing a small amount on an existing DG (and beyond the LIFO or proportional reduction rules) might be sufficient to relieve the constraint, therefore benefiting later connections without heavy loss of generation. This has been demonstrated by [5, 6] using sensitivity methods. Under the optimisation framework here, the reduction of each DG's output is directly optimised by the OPF to maximise the hosting capacity of the later DG, as represented in economic form. The constraint formulation is simple since it excludes (4) and (5). However, an aspect that has been largely neglected elsewhere is that although the performance of new DG is optimised with increased hosting capacity, the loss associated with curtailment of the existing DG needs to be recovered in an equitable manner [6]. Otherwise, this scheme will pose risks of reduced capacity factors on the early connections in the long term and discourage development. It is considered reasonable for later connections to compensate earlier connections for the additional curtailment imposed. Accordingly, the objective function needs to embed the cost of compensation for the extra curtailment imposed on existing DG as despite the payment of compensation it can benefit the later DG. The compensation E_{com} can be formulated as

$$E_{com} = \sum_{m\in M} p_g\tau_m\alpha_g^{prev} - \sum_{m\in M}(p_g\omega_m - p_{\mathrm{g},m}^{curt})\tau_m, \qquad \forall\, \mathrm{g}\in \mathrm{G} \mid \mathrm{g} \ne n \tag{7}$$

where α_g^{prev} is the output factor for DG g which reflects the network condition prior to the new connections.

F. *Coordination with Other Active Network Management*

Whilst controlling DG output under non-firm connection is beneficial in terms of managing network constraints and increasing hosting capacity [11], curtailment necessarily features loss of revenue to DG developers. Accordingly, it is better to consider this as a last resort only when other ANM techniques, such as adaptive control of OLTC or DG power factors, have been exhausted.

The modelling of ANM control approaches within an OPF framework was outlined in [11, 12]. While some control means may have discrete behaviour, ANM approaches and their operation ranges can be represented as additional control variables and constraints in the optimisation while maintaining the main objective function. The formulation can handle a variety of ANM techniques, but coordinated voltage control of OLTC transformers/regulators are used an example here. The secondary side voltage of the substation transformer t is treated as a variable V_t (T denoting the set of OLTC transformers) and dynamically controlled by the OLTC. Its operational range is correspondingly modelled as:

$$V_t^{\min} \le V_t \le V_t^{\max} \qquad t \in T \tag{8}$$

III. CASE STUDY

A typical rural section of a medium voltage distribution network with a weakly meshed topology is used here as a case study. It is based on the Simplified EHV1 Network from the UK Generic Distribution System (GDS) [21], selected as it is simple to illustrate the different curtailment schemes on hosting capacity analysis and allows comparison with results in [11]. The one-line diagram is shown in Fig 2 and the line data is given in [21]. To facilitate DG connections, a coordinated voltage control ANM scheme is deployed to dynamically control the OLTC at the substation and correspondingly the voltage at bus 2 in this case is considered along with curtailment to mitigate voltage constraints. The OLTC control would be fully utilised before any curtailment occurs, since only the cost of energy loss from curtailments is explicitly included in the objective function and minimised.

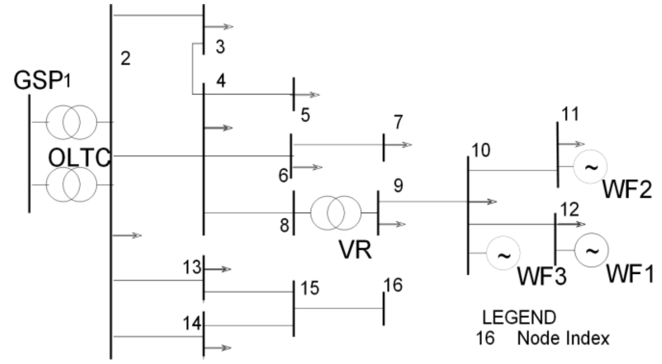


Fig.2 Simplified EHV1 Network with wind farm connected`

Three locations are considered in the network at which DG can be connected: buses 10, 11 and 12. To keep the illustration simple, all DG are modelled as wind farms and operated at unity power factor. Wind Farm 1 (WF1) at bus 12 is assumed to be already operating with installed capacity of 2.8 MW, which is the maximum capacity available under firm connection. For this network, the binding constraint limiting DG connection is voltage rise at the wind farm buses.

The optimisation of hosting capacity for new DG is determined across a year (Fig. 1 shows a snapshot of hourly generation and demand). These were processed to reduce the computational burden down to 74 representative combinations of generation and demand. The same wind pattern applies at all locations. Each wind farm is assumed owned by a different developer, and correspondingly their aim is to maximise their own economic benefits.

The economic parameters for financial evaluation are given in Table 1. The sale of Renewable Obligation Certificates (ROCs) under the current subsidy mechanism in UK is included alongside the wholesale price of electricity. The estimate of NPV is based on a 20 year lifespan and 10% discount rate (annuity factor of 8.51). For clarity, it is assumed that the resource and demand level remains the same over the project lifetime; this could be extended to include more sophisticated assumptions about inter-annual variation.

To draw out the importance of the DNO not having direct control over DG connections, two connection sequences are studied to reflect the possible scenarios from separate ownership of WF2 and WF3:

- Connection sequence A: WF2 is connected before WF3;
- Connection sequence B: WF3 is connected before WF2.

For each connection sequence, the economic hosting capacity is analysed in two 'stages' as outlined in Table 2. It means the new DG optimised at the first stage would act as an existing connection which imposes limits on the optimisation of the DG at stage 2. The order of connection order means new DGs are competing for non-firm capacity to maximise financial return. The consideration of multi-stage expansion offers a manner to investigate the long-term impact of different curtailment schemes from the network point of view. Note that the 'stages' only indicate the connection sequence rather than explicitly defining the connection time.

TABLE 1 PARAMETERS USED IN FINANCIAL EVALUATION

Wholesale price of electricity [22]	£50/MWh
ROC sales price [23]	£51.34/MWh
Wind capital cost [24]	£1524/kW
Operations and maintenance cost [24]	£57.2/kW year

TABLE 2 SEQUENCES OF DG CONNECTING AT EACH STAGE

Connection sequence	Stage 1		Stage 2	
	Existing	New	Existing	New
A	WF1	WF2	WF1 & 2	WF3
B	WF1	WF3	WF1 & 3	WF2

A 'base' case scenario analyses the optimal capacity of WF2 and WF3 that can be accommodated as firm connections together with the 2.8 MW WF1. This assumes a passive network without curtailment so the "worst-case" condition of minimum demand and maximum generation is the main constraint on capacity. As the 'Base' column in Table 3 shows the total hosting capacity is just 3.1 MW where only 0.3 MW is left for the connection of WF2 and no further headroom for WF3. It is clear that the already connected WF1 absorbs most of the available hosting capacity for firm connections and 'sterilizes' the network for DG connections. Since the limitation on DG capacity is imposed by the "worst-case" conditions, the curtailment of generation during these periods will alleviate the voltage rise constraints allowing installed capacity and overall energy production to increase. The three curtailment strategies together with two connection sequences gives a set of six curtailment scenarios to be are examined. In the proportional curtailment scheme the maximum reduction in output factor (α^{upper}) is limited to 10%.

A. *Connection sequence A*

The results from each scenario for connection sequence A at each stage are presented and compared in Table 3.a and Table 4. It can be seen that after the two stage connections, all curtailment schemes have much greater overall hosting capacity than the passive network analysis: 2.4 to 5.5 times larger. With more capacity accommodated, curtailment schemes control production to guarantee that the network operates below the voltage and thermal limits during low demand scenarios. However, the differences of capacities and curtailment percentages between the schemes and among the wind farms in each individual scheme are significant. The technically most appropriate scheme delivers the largest overall capacity. In both LIFO and proportional schemes, WF2 is the largest generator connected resulting in near-zero capacity for the later-connected WF3. However, with the technically most appropriate scheme WF3 is some 60% larger than WF2.

The LIFO scheme protects earlier connections from the effects of later connections, as seen in the zero curtailment of WF1 after connection of WF2. Maximum NPV for WF2 is with a capacity of 4.4 MW and 17% curtailment. At the next stage WF3 cannot connect with any economically viable capacity. The non-firm connected WF2 is enough to double the total energy production from the base case with total curtailment of 10%.

With the proportional scheme, there is no compensation for extra curtailment of previous connections as long as it is within the contractual limits, i.e. (6). At stage 1, connection of WF2 raises the curtailment of WF1 from zero to almost the maximum (9.6%), by increasing hosting capacity at no cost to itself. It delivers the best performance for WF2 with high capacity and low curtailment. When WF3 comes to connect at stage 2, as a result of WF2 and WF1 already operating at the maximum allowed curtailment, a capacity of only 0.2 MW is available for WF3. With equal 10% curtailment, hosting capacity is tripled and production rises 168%.

The technically most appropriate scheme delivers almost double the capacity of the others, at the expense of curtailing 18% of total generation. This scheme dynamically changes the curtailment allocation and delivers cumulative effects through the connection process. The connection of WF2 reaches its optimal capacity when WF1 contributes to curtailment. The same trend of curtailing earlier connections to release more capacity is maintained when WF3 connects. It is notable that WF1 and WF2 would considerably reduce their generation to release substantial network headroom for WF3 which operates without being curtailed. With the compensation settings used here the cost of limiting output from WF1 and WF2 is relatively lower than the benefits from increased generation at WF3. In other words, the connection of WF1 and WF2 at their specific locations did not most effectively utilize overall network hosting capacity. Although bus 10 (WF3) is shown to be the better location to connect DG, only the technically most appropriate scheme will exploit its capacity through curtailment of the prior connections at WF1 and WF2.

In terms of total NPV for all the wind farms, it can be seen from Table 4 that all curtailment schemes deliver more overall economic benefits from increased connection capacity and production. The lifetime NPV from the proportional scheme lies between that of the LIFO and the technically most appropriate cases. Fig. 3(a) shows the split for each farm by scheme. For the proportional scheme WF2 delivers 11% more NPV than the technically most appropriate case. However, it is notable that this is at the expense of a 23% reduction in WF1 NPV arising from non-compensated curtailment. In contrast, the technically most appropriate scheme handles the trade-off between WF1 and WF2 by ensuring no reduction in NPV at WF1 and a marginally lower NPV at WF2. Even with cost of compensation it still delivers a significant increase in NPV at WF3 driving the overall NPV of the three wind farms up by 37% and 81% over the proportional and LIFO schemes, respectively. It demonstrates that the technically most appropriate scheme is most economically efficient in maximising connections.

B. *Connection sequence B*

The analysis is repeated for a connection sequence where WF3 is connected first followed by WF2. The optimal capacity and curtailment level for each priority scheme is presented in Table 3.b. In terms of the total capacity of all three wind farms that can be accommodated, it follows a similar pattern to connection sequence A with all schemes boosting connections and the technically most appropriate scheme delivering most capacity. The obvious difference from sequence A is that the hosting capacity in the technically most appropriate scheme is reduced by 13% but the overall energy production falls by only 6% and curtailment is almost halved. The connection process presents different outcomes for specific wind farms. All curtailment schemes with sequence B see no hosting capacity left for the later connecting WF2, whereas with sequence A the later WF3 still can be connected although its capacity varies by scheme.

The technically most appropriate scheme delivers financial returns significantly better than the others (as Fig 3.b shows) but also exceeds the total returns for sequence A by 14%. It

Table 3 Comparison of DG capacity and curtailment under different curtailment priority schemes
(‘OPT’ is Technically most appropriate scheme, ‘ PROP’ is Proportional Curtailment scheme)

a) Connection sequence A

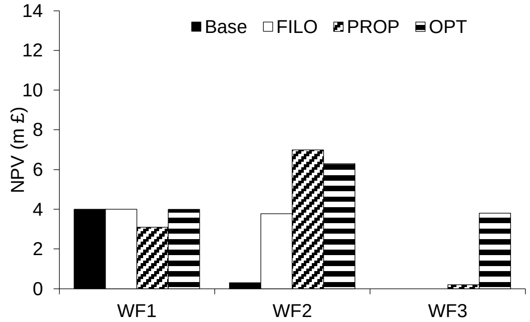
DG (in connection order)	Capacity (MW)				Curtailment (%)					
	Base	LIFO	PROP	OPT	LIFO_stage1	LIFO_stage2	PROP_stage1	PROP_stage2	OPT_stage1	OPT_stage2
WF1	2.8	2.8	2.8	2.8	0%	0%	9.6%	10%	9%	48%
WF2	0.3	4.4	6.3	5.5	17%	17%	9.6%	10%	4%	31%
WF3	0.0	0.0	0.2	8.8	-	-	-	10%	-	0%
Total	3.1	7.2	9.3	17.1		10%		10%		18%

b) Connection sequence B

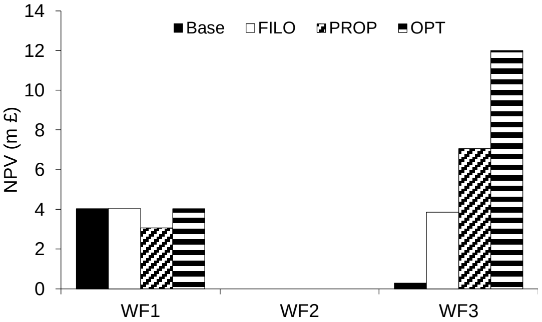
DG (in connection order)	Capacity (MW)				Curtailment (%)					
	Base	LIFO	PROP	OPT	LIFO_stage1	LIFO_stage2	PROP_stage1	PROP_stage2	OPT_stage1	OPT_stage2
WF1	2.8	2.8	2.8	2.8	0%	0%	10%	10%	46%	46%
WF3	0.3	4.4	6.4	12.0	16%	16%	10%	10%	2%	2%
WF2	0.0	0.0	0.0	0.0	-	-	-	-	-	-
Total	3.1	7.2	9.2	14.8		10%		10%		10%

TABLE 4 COMPARISON OF LIFETIME PRODUCTION (E) AND OVERALL NPV FOR CURTAILMENT SCHEMES AND CONNECTION SEQUENCES

Priority rules	Sequence A		Sequence B		Increase (A-B)
	E (GWh)	NPV (m £)	E (GWh)	NPV (m £)	NPV
Base	250	4.3	250	4.3	-
LIFO	515	7.8	517	7.9	1%
PROP	669	10.2	667	10.1	-1%
OPT	1124	14.1	1059	16.0	14%



a) Connection sequence A



b) Connection sequence B

Fig 3 Optimised NPV for each wind farm under different cases

further demonstrates that bus 10 (WF3) is where the hosting capacity can be maximised. When the connection sequence is closer to the optimal sequence (i.e. B in this case), less curtailment is required and greater returns can be obtained.

IV. DISCUSSION

The evaluation approach provides a better understanding of planning non-firm connections, which is highly desirable for both DG developers and DNOs. Using the proposed optimisation technique, the maximum project returns under different curtailment schemes can be quantified and therefore offer a detailed "test bed" for designing connection contracts. As demonstrated in the case study, developments under non-firm connection schemes generally deliver more generation capacity in the network although financial returns for specific DG is determined by its connection order and principles of access. This means it is particularly important for developers to conduct 'what if' analyses of potential investments and for DNOs in monitoring efficient use of their network capacity. The implementation of curtailment schemes still needs appropriate commercial arrangements and policy frameworks, and the specifics of compensation could be different from the assumptions made here, e.g. in/exclusion of subsidies etc.. The issue of fairness is particularly important where DG has been connected on a firm connection basis without curtailment and where reversion to non-firm operation would deliver substantial increases in output overall although that specific DG may see decreases. It has to be equitable in that DGs that contribute to curtailment to deliver more revenue overall see some benefit.

The analysis in the paper is conducted from the developers' point of view in that they effectively compete for hosting capacity and seek to improve their economic benefits. Competition-driven DG development does not guarantee the overall optimization of the network. As in the UK, DNOs cannot directly control the placement of DGs. Therefore there is a risk that initial DG connections occur where they have a detrimental impact on network hosting capacity, significantly reducing opportunities for later developers. Competition for hosting capacity at poor locations only worsens network potential. The technically most appropriate curtailment scheme provides a means to partially mitigate such outcomes in networks where existing DGs connections are substantially different from the 'optimal'. It has been shown in the case study, that by adopting the technically most appropriate curtailment scheme, the network potential can still be exploited through effectively limiting generation from the poorly located DG yet ensuring it remains economically viable through full compensation. While the technical and economic performance is still constrained by connection orders, the technically most appropriate scheme outperforms the LIFO and proportional approaches in terms of greater hosting capacity.

This work raises an interesting point as to the extent of compensating curtailment at early connections given that overall hosting capacity may be disproportionally reduced by its connection. It suggests that DNOs need proper incentive arrangements to encourage developers' connection plans to be more closely aligned with the overall optimisation of network hosting capacity. This is particularly important where regulatory and social pressures on minimising grid expansion are strong. One possible solution could be to adopt location-specific charging mechanisms for DG connections by exploiting shadow pricing.

While the authors believe the approach presented is a valuable step forward in analysis of smart grid planning, there are a number of enhancements that could be made which the framework adopted can effectively handle. First, the optimisation can be extended to include control of DG power factor [10] or alternatively reactive power pricing. Second, with energy loss an important focus for DNOs, the effect of non-firm DG connections on losses can be brought into the analysis, e.g. [12]. Third, the cost of building and operating ANM control systems is not considered in the case study but evidence suggests it is modest relative to the value of the generation capacity released and would have a marginal impact on the precise capacities suggested. Finally, although all wind farms use the same production profile here, the spatial characteristics of the resource can be incorporated [11] and may result in greater hosting capacity with more modest levels of curtailment (as would a portfolio of different resources).

V. CONCLUSION

When DG developers are offered non-firm connections, the priority rules that govern the sharing of curtailment between DGs is key to their economic viability. Here, a multi-period OPF is used to determine the non-firm hosting capacity and curtailment level that obtain the maximum financial return for DG developers. Different ANM curtailment priority schemes are compared using this method. The results clearly show that the technically most appropriate approach has technical and economic advantages for enhancing DG connections over other schemes. Through properly designed compensation rules the economic benefits for later connections can be improved without harming the earlier-connected DG. The approach allows rapid identification of financial return under different priority arrangements, providing better understanding of this issue. The knowledge of economic benefit of different priority settings could also form a basis for incentives and facilitate the DG planning process.

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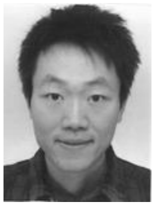
BIOGRAPHIES



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