Contributions of Distributed Generation to Electric Transmission System

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Abstract

Distributed generation (DG) refers to electricity generating plant that is connected to a distribution network rather than the transmission system. At present, small-scale DGs are mostly treated as ‘negative demand’ to the transmission system. However, if their contribution to transmission levels are fully understood and properly assessed, these generators can make into valuable assets to improve operational efficiency and substitute major infrastructure investment. This PhD research aims to addresses this challenge from three key aspects:

1. On assessment methodologies, our current industrial practices to evaluate DG-to-transmission-contribution reveal inherent defects. The method given in the transmission system (SQSS) is not sufficient to reflect today’s dispersed generation technologies; while the method for the distribution system (P2/6) fails to reflect and discriminate between different characteristics of distribution networks that DGs are connected. Overcoming these drawbacks, enhanced frameworks to evaluate DG contribution have been developed in this research.

2. On generator’s contribution, little attention has been paid to photovoltaic (PV) outputs characterization and their integration to the overall evaluation process. Neither SQSS nor P2/6 pays sufficient attention to evaluating PV’s contribution to system. In this regard, an approach aiming at characterizing PV seasonal outputs is proposed. Integrating with the proposed frameworks, this part of the research completes the DG contribution evaluation architecture.

3. On commercial arrangements, conventional business models largely rely on network investment to meet customer demand. Earning a fixed rate of return on invested capital, incumbent distribution network operator (DNO) businesses are encouraged to invest in network assets, very little has been done to support third party service providers for more efficient network development. In the third part of this research, alternative DNO business models and market mechanisms are proposed to further unlock the potential of DG, substantially increase the potential of their contributions to the transmission system.
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Chapter 1. Introduction

1.1 New Environment for Electric Power Systems

1.1.1 Climate Change and Distributed Generation

Traditionally, the electric power supplied to end customers has been centrally generated by conventional power stations and distributed uni-directionally through transmission and distribution networks. Nowadays, due to the adverse environmental impact of energy use, concerns over the security of fuel supply, liberalization of electricity markets and the necessity to defer and avoid investment in networks, the traditional mechanism of power system operation is facing a variety of challenges [1, 2].

As a result, a number of state-of-the-art technologies have been developed and applied. This is illustrated in Fig. 1-1. Among these advances, ambitious targets on Distributed Generation (DG) have been set by governments across the world [3, 4]. For instance, the U.K. government has committed to reduce greenhouse gas emissions by at least 80% below the 1990 baseline by 2050 [5]. According to the fifth carbon budget which is a road map for the UK decarbonisation path suggested by the Committee on Climate Change, today renewables produce more than 20% of the national electricity demand and will increase to 30% by 2020.

Conventional generators, mostly supplied by fossil fuels, have been centrally operated and dispatched for more than 150 years. Centrally located far away from load centres, their generated power is usually transmitted over long distance by transmission systems and then allocated by regional distribution networks before finally reaching end customers. There are a number of merits about such integrated systems, the greatest of which is their efficiency and security. Being centrally operated and dispatched means few people are needed and often the most efficient generating plant could be dispatched. Meanwhile, the considerable high voltage possessed by the transmission systems means minimized generator reserve and limited losses could be expected.
Compared with traditional counterparts, renewables tend to have lower energy density, meaning their corresponding generation plants are mostly small-sized and located adjacent to the sources. For example, due to the lower energy density of biomass materials, biomass power plants have considerable smaller capacities than coal-fired plants. Wind farms appear to be widely spread, since wind turbines are generally located in windy areas. Furthermore, as transporting heat over long distance is not economical, CHPs are usually located closed to heat demand centers, which are in fact the end customers. For all these reasons, a significant part of these renewable plants will be connected onto the distribution levels, hence they are also called distributed generation.

![Figure 1-1 The predicted generation mix to 2030 [6]](image)

By its definition, DG, also known as embedded generation (EG), is small-sized dispersed resources connected on distribution networks (i.e. at voltages of 132 kV or below in the UK) [7, 8]. Typical examples might include wind turbine, landfill gas, combined heat and power (CHP), photovoltaic, and hydroelectric pumped storage systems.

According to different criteria, DGs could be categorized into different groups [23]. From the dispatch point of view, DGs could be divided into output controllable types, which mainly include biomass generation and micro turbines, and uncontrollable ones, typically wind power, small hydro, photovoltaic. On the other hand, based on
the primary sources utilized, distributed generation could be classified into conventional generation such as CHP and renewable generation like wind and photovoltaic.

1.1.2 DGs as Power System Liabilities and Assets

Conceivably, the introduction of DG into existing power systems brings a number of benefits. Typical examples include reduced carbon emission, higher energy efficiency, consequent deregulation and increased competition in the market, energy diversification, and reduced transmission cost and losses. Fig. 1-2 illustrates that the global cumulative installed capacity of PV reached 177GW by the end of 2014, from only 40GW in 2010 [9].

![Figure 1-2 Annual incremental global PV installed capacity [9]](image)

One of the key benefits brought about by the integration of DG is its ability to enhance network reliability [10-13]. The increasing penetration of this small-scaled generation into existing distribution networks will fundamentally change the demand patterns seen at grid supply points (GSPs) which interconnect the national transmission system with each regional distribution network. As a result of this, the conventional responsibility of GSP to provide supply adequacy and security under network normal and contingent conditions respectively can now be shared by DGs embedded inside the network. Thus, being a system asset, DG helps contribute to an improved GSP reliability.
On the other hand, such an introduction to some extent leads to a number of technical, commercial and regulatory issues also [14-17]. As a result of this DG integration, the traditionally passive distribution network has become active now, determining the power flow and voltages by both loads as well as generation. This previously non-existing feature means that various aspects of the distribution network will be impacted, and those conventional methods to analyses power systems will become inadequate.

Firstly, the connection of DGs has direct impact on the distribution network voltage distribution. It is one of the obligations for distribution network operators (DNOs) to maintain the nodal voltage within specified limits. And conventionally, during times of max system demand, the voltage at the end customer has always been ensured by adjusting the taps at the transformers. Now, the introduction of DG changes the network circuit power flow and hence the voltage profile, causing steady-state voltage variations on both system and user sides. Also, it has been shown that such problem is the most onerous when minimum system demand coincides with maximum DG output.

Secondly, the DG integration might contribute to the increase of network fault levels. Network fault level is a product of an open circuit voltage and the current that flows into the short circuit fault. The capacity of current distribution networks has been designed with satisfying such potential system fault levels in mind. However, DGs based on rotating machines will increase the original fault levels and hence endanger components like switchgears. Although by installing an impedance between the generator and the system by transformers or reactors could mitigate such impacts, it will increase system losses and voltage variations inevitably.

Furthermore, power quality might be sacrificed. The connection and disconnection of DGs might cause high current changes on the system, which could lead to transient voltage variations. Meanwhile, for DGs with electronic interfaces or controllers, if not properly designed, might inject harmonic currents into the network, which could lead to significant voltage distortion.
From the perspective of system protection, DGs could complicate or even confuse the smart relay devices. In many countries, island operation, which is a small part of a distribution network being isolated from the main network and supplied by its own internal generators, is unacceptable. As a result, it requires protection relays to trip the DG immediately after a network becomes islanded. However, nuisance tripping might happen, particularly when the relay device is over sensitive to detect islanding rapidly.

1.1.3 Market Arrangements and Business Models

Existing electrical energy systems and markets were built and designed to accommodate large-scale generating plants, with demand traditionally viewed as uncontrollable and inflexible, and with centrally controlled operation and management. At a regional level, currently looked after by distribution network operators, electricity is delivered from transmission to distribution networks and then to end consumers in a unidirectional fashion. Accordingly, power is bought and sold in the national wholesale markets, through the interaction of large scale generators and energy retailers. This is illustrated in Fig. 1-3.

![Figure 1-3 Current market participants](image)

Among these different entities, DNOs’ current business models are to recover network operation and investment costs through the Use of System (UoS) and connection charges. The underlying network investment principle is: network investment is the main option for meeting peak demand, very little has been done to mobilise third party service providers to support more efficient network development.
These current business models appear to contradict with today’s need to incentivize and facilitate network evolutions. With the rapid growth in various distributed energy resources, an increasing number of DGs and flexible demands such as heat pumps and electric vehicles are being connected onto the distribution network. The incumbent business models and market mechanisms are presented with unprecedented challenges and opportunities to manage infrastructure costs, customer engagement and reduce energy costs. For example, this is a vital challenge to revive the traditional DNO business functions – providing secure network to meet peak demand, moving to a more active distribution system operator position. Therefore, updated business models for these incumbent market participants are needed, with the purpose to promote active participation of prosumers with new business models for the entire business ecosystem. And this will ultimately increase the efficiency, flexibility and responsiveness of local resources.

1.2 Research Motivation and Objectives

At present, small-scale generators embedded within distribution networks are treated as ‘negative demand’ to the transmission system. Due to limited penetration, by large they create manageable impacts that are within normal demand fluctuations at present. However, as these the penetration of DGs increase in scale, at some point they will start to cause significant demand and voltage change across the distribution networks and into the national transmission grid, potentially beyond the design capability of the system and resulting in large forecasting errors, operational constraints. On the other hand, these resources could be utilized to substitute significant network investment if their contribution to the transmission system are fully understood [18][19]. Therefore, when comes to evaluating such embedded generation’s impacts on transmission levels, three issues have been identified and investigated by this research:

On methodologies, our current industrial practices to evaluate DG-to-transmission-contribution expose inherent defects. The method given by the transmission system operator is not sufficient to reflect today’s dispersed generation technologies; the method used by distribution network operators fails to reflect and discriminate
between different characteristics and conditions of the examined distribution network [20].

On generation contribution, little attention has been paid to photovoltaic (PV) characterization and their integration to the overall evaluation process. Neither transmission nor distribution system operators evaluate PV’s contribution to system. Among academic researchers various PV output modelling methods are developed, but no single definition of PV’s contribution has been reported.

On commercial arrangements, conventional DNO business models are presented with unprecedented challenges. Earning a fixed rate of return on invested capital, incumbent DNO businesses have been largely determined by the amount of money spent on network investment each year. Under this business model, DNOs would be incentivised to invest in the network to meet the load growth, assuming all load requires the same level of high reliability. A substantial amount of capacities is designed to support the temporary system peak while maintaining underutilised over the majority time of a year. As a result, more efficient DNO business models and market arrangements are needed to facilitate and better capture the asset potential of these integrated DGs, thus maximizing their contribution to transmission levels.

This PhD research carried out in this thesis addresses these above challenges through developing an enhanced framework for assessing DG contribution to national transmission systems and commercial models to better leverage DG’s values.

1.3 Research Contributions

This research aims to establish a comprehensive insight of DG’s contribution to the national transmission grid, particularly from a network asset perspective, therefore responding effectively to the changes facing tomorrow’s power system architecture.

1) With the increasing penetration of DG, a methodology that is able to recognize its contribution at the transmission level becomes crucial. However, tailored for DNOs, the existing approach fails to consider the characteristics of the distribution networks, DG penetration levels and locations. Consequently, its suggested DG contribution values tend to be oversimplified and too optimistic.
In the first part of this research, enhanced approaches to evaluating DG’s regional contribution to the national transmission grid are proposed. Based on the original method, the proposed approaches for the first time take into consideration the effects on DG output imposed by various distribution network conditions. The proposed approaches seek to reflect and quantify the effective capacity of an examined DG as well as the expected DG curtailments consequent upon network conditions like thermal congestion and contingency. Compared with the existing industrial methods, the results derived by the proposed approach can properly distinguish between different situations of DG location, penetration, concentration and network loading level, while provide a more reasonable and clearer visibility of DG for the future grid planning.

2) So far, little attention has been paid to PV characterization and its integration to the overall DG contribution to system evaluation process. Neither SQSS nor P2/6 has paid sufficient to PV’s contribution evaluation. Among academic researchers various PV output modelling methods are developed, but no single definition of PV’s contribution has been reported.

In the second part of this research, it investigates the link between PV generation and the climatological indicator of sunshine duration. For the first time, an understanding of to what degree the daily sunshine duration determines the generation output profile is established, and insights into the extent of such impact at differing months of a year are provided. Contrasting with existing methods, the derived results in this part achieves a well balance between forecasting accuracy and simplicity of implementation. The new finding essentially provides a fresh new perspective on characterizing the uncertainty and variability in PV output.

Based on this correlation identified, a novel two-step hierarchical classification method is also proposed in this work to facilitate PV profiling. A case study on a practical PV plant in Great Britain is presented to demonstrate the application of this method. For each derived group, the degree of variation in PV output at different times and the confident levels of each quantity are
assessed. More importantly, based on the classification results, a weather-based PV profiling guideline is created. This will facilitate PV output forecasting on a granular level, thus providing a powerful tool for the ever increasingly challenging system operation and planning.

3) Meanwhile, this PhD thesis has also proposed a new business model for DNOs, aiming to integrate flexible demand in a cost-effective manner. The new business model incentivises the incumbent DNOs to give up its exclusive access to the network, leasing the spare capacity or back up capacity to a licensed independent party.

Traditional energy markets are established based on the equilibrium between the supply and demand, where the market only trade one energy product – energy meets the security and quality standards defined by national bodies (nearly 100% reliable). This research also has proposed a fundamentally different market arrangement where multiple energy markets exist, each target energy with specific supply quality, ranging from the very low quality supply from renewable energy in its raw form to the very high quality of supply from firm and controllable fossil generators. The new economic principles that will allow for multiple equilibriums to be reaches for energy products with a varying degree of quality.

1.4 Thesis Layout

This thesis is divided into eight parts:

Chapter 2 provides a comprehensive background and literature review of the thesis. In particular, approaches to assessing capacity credit of wind power and PV generation are discussed. And the pros and cons of them are extensively compared.

Chapter 3 proposes a Monte Carlo simulation based approach to evaluating DG contribution to the national grid system. Compared with the current industrial practice, ER P2/6, the proposed approaches incorporate a series of potential
influencing factors, such as network reliability, system capacity constraint, DG penetration and concentration, making the results valuable for transmission-level analysis.

**Chapter 4** introduces an analytical approach to assessing DG locational contribution to the transmission level. The original P2/6 model is improved by considering the respective impacts from distribution networks under both normal and contingent conditions.

**Chapter 5** introduces an approach to tracing individual DG security contribution to grid supply point, which provides system planning with an increased visibility of DGs embedded inside distribution networks.

**Chapter 6** investigates the link between PV generation and the climatological indicator of sunshine duration. For the first time, an understanding of to what degree the daily sunshine duration determines the generation output profile is established, and insights into the extent of such impact at differing months are provided.

**Chapter 7** benchmarks the current DNO business models in three EU countries. The aspects of market, regulation, business and innovation have been analysed. Also, a novel DNO business based on shared network access is developed, and a new market arrangement mechanism for trading electrical energy with multiple supply qualities is proposed.

Finally, **Chapter 8** reviews the main results of the thesis, and discusses the implication of the results to the practical power industry. Lastly, suggestions for future research work and final conclusions are provided.
Chapter 2. Background and Literature Review

2.1 Conventional Generation Capacity Credit Assessment

As mentioned in the previous section, traditionally, large centrally dispatched generators have been mostly supplied by fossil fuels, thanks to which the availability of such sites tends to be binary. In other words, they are likely to generate at full capacity or totally out of service. On the contrary, DERs and particularly DGs, whether supplied by renewable resources, appear to have stochastic output constantly.

The concept of capacity credit, also called capacity factor, has been widely studied in academia particularly. Generally, it is also one of the methods currently available to evaluate the effective contribution of dispersed generation to system adequacy and security. It could be regarded as a benchmark, which is able to measure the effective of various distributed resources. Although difference does exist among all the definitions of capacity credit given by various literatures, the core ideas are similar [21-25]. The capacity credit of a distributed generation could be calculated as the amount of conventional generation capacity, which might be replaced by this newly introduced distributed generation without degrading the previous reliability level of the power network. More specifically, the process could be broken into a few steps:

Firstly, the reliability level of an examined power network (a distribution network in this case) without any DG connected is evaluated. Typical examples of the reliability indices used include Loss of Load Probability (LOLP), Loss of Load Expectation (LOLP) and Expected Energy Not Supplied (EENS). Factors associated with the conventional generation supplying the network like capacity level, forced outage rate and maintenance schedule of the site need to be obtained and taken into the calculation process. At the demand side, characteristics like loading level at each node, the system peak demand level are needed.

Then, the examined DG is added to the examined network. Although being intermittent for most of the time, the introduction of DG still could increase the reliability level of the network. Now thanks to such an integration, to pull the network
reliability back to the previous level, either the capacity of conventional generation could be reduced or the system demand could be increased. Eventually, such capacity change is defined as the capacity credit of the added generation, or in other words the effective contribution to the system adequacy.

Since the evaluation of power system reliability is an essential part of the capacity credit calculation process, a brief introduction to the traditional ways of power system reliability evaluation tends to be imperative.

2.1.1 Reliability Evaluation of Power Systems

It is most important responsibility for system operators to make sure customers are reliably supplied with power under both normal and system outage conditions within reasonable economic constraints. As a result, the reliability evaluation of power transmission and distribution networks appears to be important to system planning.

The reliability of power systems could be assessed by two approaches. While the analytical approach is simple to use, the method based on Monte Carlo simulation tends to provide a more accurate result especially when the examined system is rather complex. Literatures [26][27] provide details on how to perform both approaches.

The analytical approach simplifies the problem by making certain assumptions. Mathematical models for all the components in the system are built, based on which a numerical result could be obtained. Apparently, the main advantage of such approach is its simplicity and relatively shorter computing time. However, it is the assumptions it makes that leads to a number of restrictions. More precisely, since the result is highly subject to these assumptions, such approach cannot reflect all the system operating conditions [28].

By comparison, the approach based on Monte Carlo simulation is much superior when it comes to reliability evaluation of sophisticated systems. Such method calculates the reliability value by taking into consideration and simulating the random status of each component [29]. In other words, conditions like the potential failure of each circuit, the outage of each transformer and other elements, the probable output level of each
generator and the loading level at the moment are all integrated into the evaluation process. It is true that to be able to obtain a reasonable result, simulations over a long period of time is required. As a result, such approach is much more computing intensive. Still, compared with the analytical approach, it is able to evaluate virtually every aspect of power system planning, design and operation.

In order to measure the reliability value of power systems, corresponding benchmarks are necessary. A number of reliability indices have been playing such roles as evaluation criteria. Basically, all the reliability indices could be categorized into two group: the LOL group and the EIR group. Typical examples in the first group include Loss of Load Probability, Loss of Load Expectation (LOLE) and Loss of Load Frequency (LOLF). LOLP shows the probability of the customer demand being higher than the availability capacity of its corresponding generation at the same moment in a certain period of time. LOLE gives the expected period of time, during which the total demand exceeds the generation capacity. LOLF is the number of times that load-loss happens during this examined period. A typical example of EIR index is EENS (Expected Energy Not Supplied), which shows the depth of system failures.

2.1.2 Two Categories of Capacity Credit Evaluation Methods
Although capacity credit calculations based on both LOL group and EIR could be found in previous studies, reliability indices from LOL group have been more often adopted. Taking the case of LOLP as an example, two methods have been used by other studies to evaluate the capacity credit of renewable and intermittent generation.

The first is called effective firm capacity (EFC). If an intermittent generation is integrated into a network, the reliability of the network will increase consequently provided all the other conditions are unchanged. Hence, the previously connected firm generators (mostly thermal generators) could be disconnected while still keeping the reliability level of the network unchanged. The EFC value of the intermittent resource is defined as the amount of the reduced firm generation capacity.

The second approach is called effective load carrying capability (ELCC). In this case, after the intermittent generation is added, the total demand level of the network is
increased instead of replacing firm generators, while still keeping the reliability the same as before. Similarly, the increased network demand is regarded as the ELCC of the newly introduce generation.

2.1.3 An Overview on Previous Work on Capacity Credit

In practice, different capacity credit evaluation approaches are being used by different entities, utilities and system operators around the world. Among these, a number of approaches are solely based on a fixed scaling factor. For instance, in the US, the electric reliability council of Texas chooses 10% as the capacity credit for all wind generators in its area [30]. RMATS uses a scaling factor of 20% for its wind generators during system planning. Since these percentages were derived from the average values during a certain period, the existing differences among them are inevitable. Although such fixed-scaling-factor method is apparently easy to apply, it is very constraint to the specific system condition and situation. To overcome such shortcomings, a few approaches adapt the moving average value of a few years. For instance, PJM is based on a three-year moving average of the wind generator’s capacity factor from 3 p.m. to 7 p.m. from June through August [30].

Although being much more complicated and time consuming than the ones mentioned above, approaches based on ELCC to calculate DG capacity credit appear to have been the most widely adopted and popular.

Literature [30] provides an approach to calculating the capacity credit of intermittent generators. In this study, the system reliability index – LOLE was chosen as the benchmark. Hourly data of the system demand over several years of operation as well as the output level of the examined wind power was collected. As described in its work, in the situations where the generation site is to be installed and has no historical output data, the output profile could be estimated according to the meteorological data.

Also, it also identified the influencing factors that might have an impact on the eventual capacity credit value derived. First and foremost, the timing and seasonal period, based on which wind power and system demand profiles are estimated, has a
direct influence on the result. More precisely, when the period considered is the three months during winter, it is more likely that the wind power capacity credit calculated trends to be slightly higher, since during this period wind-blowing is richer. On the contrary, if the period taken into account is summer, the resulted capacity credit will not be the same.

Secondly, the mix of conventional generators, or in the case of DG capacity credit evaluation, the characteristics of the grid supply point would have an impact on the capacity credit of wind power. The reason behind this is that characteristics like the forced outage rate will directly affect the risk profile of the system, which will further have an influence on the eventual capacity credit derived.

Literature [31] uses a similar approach to calculate the capacity credit of wind power. The result shows the capacity credit value is 45 MW in this case, as shown in Fig. 2-1.

Apart from the ELCC approach, two alternative methods have also been introduced in [31], which require much less computing effort. One of these two simplified approaches uses the top 30% of hours during each year, when the risk of not meeting the load is at its highest and demand is at relatively high levels. As a result, the averaged capacity factor of these hours is assigned as the capacity credit value. The other method is similar to the above one. However, instead of being treated equally, the hours that have higher LOLP values are weighted more in determining the averaged capacity factor value.
As concluded in [31], for the evaluation of long-term capacity credits, Monte Carlo based approach ELCC appears to be the most appropriate, although it requires much more computing effort. In the cases when approximated results are sufficient, these two simplified approaches tend to provide a desirable balance between effort and accuracy.

In [32], the effect of each influencing factor on the value of capacity credit has been identified. Firstly, a strong correlation between the capacity factor and the resulted capacity credit of a wind plant has been recognized. And the penetration of wind generation in the examined network has a direct and significant effect on the capacity credit value. More precisely, when the penetration is at low levels, the capacity credit of each plant is relative higher and when the penetration level increases, the capacity credit drops subsequently.

Meanwhile, it has been identified that dispersed geographical conditions have a positive effect on capacity credit. In other words, then the wind plants are located far away from each other, each plant tends to have a higher effective capacity and is able to make a higher contribution to system adequacy.

Compared with most of the studies on capacity credit, [24] has focused on locational generation, or DGs located on distribution networks. In [24], the capacity credit of wind power connected on distribution systems has been evaluated. Firstly, the output of wind sites has been modelled by a multivariate autoregressive moving average (ARMA) model developed by the University of Bath. Then the reliabilities of the power system with and without wind power integrated have been assessed based on LOLP criterion. One of the merits of [24] over other similar studies is that it has taken into account the status of every electric component in the system. More specifically, not only the characteristics and availability of the generation and load demand have been considered, the probability of failure of the connecting network itself has been taken into the evaluation process. In [24], the specific states of every component have been modelled by Bernoulli approach.
Significant influencing factors have been identified and discussed as well. Apart from penetration, the influence of voltage level and loading level of the DG connected node has also been recognized. Nevertheless, no further generalizations have been given.

2.1.4 Discussions on Previous Works

1). Lack of generalization
Although most of the previous works have given the resulted capacity credit based on certain test systems. Nevertheless, one of major disadvantages is that the result is rather constraint to the specific system condition, which losses its accuracy and even validity when it comes to other situations. As proved by [24], bus loading level and voltage level have an effect on the effective capacity value. As a result, generalized conclusions to some extent needs could considerably improve the applicability of such approach. For instance, it makes sense if DG effective capacity and contribution results are categorized into urban, suburban and rural groups, especially when the individual load profiles and voltage conditions in each category are close to each other.

2). Demand response and energy storage
Demand side response and energy storage have been heavily encouraged by governments around the world to tackle the environmental problems. Apparently, such newly introduced devices would have a direct effect on the operation and planning of power networks. However, so far very few DG capacity credit studies have included the effect of such players, which makes the capacity credit results less realistic.

3). Availability and thermal constraint
Among all the works done in this field, very few have considered the influence and characteristics of the connecting circuits and other components. Compared with transmission systems, distribution networks where DGs are located are relatively more unreliable. Admittedly, according to reliability index values like LOLE being 1 day in ten years, the system seems to be perfectly reliable. It has to be noted that even a reliability of 99.9% still means 9 hours of outage in a year.
In addition, the thermal limit of the connecting circuits could significantly affect the practical DG contribution to power system. The introduction of DG to the end of distribution systems would reverse the direction of power-flow in the network. However, the current distribution systems have been designed to solely satisfy the demand of end consumers without considering the effect of demand side generators. As a result, the thermal limit of the network is very likely to restrict DG export.

Hence, to obtain a reasonable DG effective capacity value, taking into account the availability and constraint of the connecting network appears to be indispensable.

4). Mostly focused on wind power
So far, most literatures on capacity credit evaluation have been focused on wind power. However, it has to be acknowledged that other types of DG like PV, CHP and landfill gas would play major roles in future generation mix as well. The problem is that some aspects of such generators are rather different from wind power. For instance, the output amount and choice of whether to export depends significantly on the heat demand and tariff at the moment. As a result, the capacity credit modelling approaches that have been specifically designed for wind powers would lose their validities when it comes to other types of DG.

5). Mostly focused on planning capacity credit
Based on its purpose, capacity credit could be categorized into planning capacity credit and operating capacity credit. The former gives the effective capacity of DG over long term, which is useful in the context of power system planning. The latter focuses on the short-term operational contribution that could be made by DGs, which could provide extremely valuable information to utilities, DNOs and TSOs. However, so far the studies on capacity credit have been concentrated on the planning aspect.

2.2 PV Capacity Credit Assessment

2.2.1 An Overview of PV Capacity Credit
Due to their intermittency in nature, renewable generators like PV are not dispatchable. This brings a significant amount of challenge on both the planning and
reliability of the conventional system, especially when the penetration of such generation becomes substantially high in the upcoming years. As a result of this, an approach which is able to assess and quantify the contribution of PVs to system adequacy/security is necessary, particularly under such high-renewable penetration conditions. The concept of capacity credit has been widely applied on wind power contribution studies. Generally speaking, it gives the amount of conventional generation which could be replaced by the intermittent generation examined without compromising the existing system reliability level.

Unlike wind power generation, so far there have been few studies on capacity credit evaluation of PV generation. Methods used by PV capacity credit studies can be categorized into:
1) full ELCC analyses [33-36];
2) applications of approximation to ELCC [37-39];
3) averaging of PV capacity factor over selected peak demand intervals [40-44];
4) other methods based on financial analyses [45][46].

The capacity values calculated in these studies varies significantly, ranging from 5% almost 80% in some cases [35]. In other words, it reflects that PV capacity value is strongly linked to its peak-shaving capability, which will vary from one location and timeframe to the other depending on seasonal demand patterns and on their year-to-year variation.

There has been much debate over the definition of PV generation capacity credit, and many researchers and utilities have proposed and implemented various ways to calculate such value.

[47] used the same concept as wind generation capacity credit evaluation, i.e. ELCC. Without the integration of PV generation, the reliability index values, which is in the format of LOLE in this work, is firstly calculated with subject to different system peak levels. Then, the same index values corresponding to different system peak demands are calculated with the examined PV generation added into the same system. Despite of its intermittent characteristic, the integration of the examined PV
generation still can help improve the original system reliability, resulting in lower levels of LOLE across different peak loads. Therefore, if a specific system LOLE level is required, then horizontal distance between the two corresponding points on the original and new LOLE curves respectively is the ELCC of the examined PV, in other words the capacity credit. The brief idea of this evaluation method is sketched in Fig. 2-2.

![Figure 2-2 PV generation ELCC evaluation method [47]](image)

However, a work done by the Department of Energy USA [48] states that all these capacity credit evaluation methods based on ELCC don’t define how much time variant output generation resource is available at the exact moments needed to support a utility’s obligation to serve peak demand. In other words, these methods are not currently capable of using data with a shorter time span. This has not been an impediment to use of these evaluation tools in the past, since traditional dispatchable generation does not typically have time dependence. Consequently, hourly average data is sufficient for accurate evaluation of traditional dispatchable generation resource reliability. However, cloud passings introduce significant time variant solar generation output magnitude changes, in the time frame of seconds. Therefore, use of traditional LOLP, ENS and ELCC evaluation methods to determine capacity credit for solar generation are not appropriate and might result in misleading results, typically overstating the amount of capacity credit that should be assigned by a utility to solar generation. Likewise, hourly average satellite data for solar insolation, while useful for evaluation of general solar trends, is not appropriate for solar generation capacity credit evaluation. Satellite data of time resolution in the range of seconds is needed for such evaluations to provide accurate results.
In this work of [48], it compares a series of PV output profiles with different sample intervals ranging from 1 hour to 10 seconds, which are shown in Fig. 2-3. It is obvious from a comparison of the power output data, that there is considerably more variation in the 15 min average solar generation output data than is evident in the 60 min average solar generation output data. 60 min average solar generation output data does not accurately capture the variations that are possible from cloud passing induced effects in solar generation output. 4 min average data is even better than 15 min, and 1 min data better than 4 min.

As a result, there is a compelling need to include short term cloud passing generation output effect in the method of any PV capacity credit assessment study.

![Figure 2-3](image)

Figure 2-3 (a)-(e) PV output profiles with different sample intervals. (a) to (e) represents sampling intervals of 60min, 15min, 4min, 1min, and 10sec respectively [48]
At the same time, some utilities in the US use mean PV output over selected peak demand intervals, or simply annual capacity factor to estimate the capacity credit [49], as shown in Fig. 2-4. As stated in [50], with this method there is no obvious way of capturing different grid penetration levels and also other loads outside the selected peak time window are disregarded. In addition, this approximation does not pay special attentions to those system conditions when the network is significantly risky. Instead, it assigns the same weight to all hours and an average value is deployed to derive its final result.

An example of such drawbacks explained above is shown in Fig. 2-5. From the figures, it could be seen that for over half of the time, the solar PV has actually zero output.

![Figure 2-4 Monthly capacity factor of PV generation [51]](image1)

![Figure 2-5 Capacity factor of a PV generation during peak interval [51]](image2)
2.2.2 PV Capacity Credit Modelling

One of the inputs of PV capacity credit assessment is detailed information of the examined generation output profile over a sufficiently long period. In order to achieve this, either measured or simulated data is needed.

Some studies on PV capacity credit applied monitored PV output data [47]. [42] simulated PV output using site/time specific hourly insolation data derived from geostationary satellite-based remote cloud cover measurement.

In [49], since hourly monitored data for real PV systems in the examined area was not readily available, PV system output in this study was simulated by computers instead. Similarly, [51] adopted simulated PV output as an input of its capacity credit evaluation work.

Since the output of the PV generation is zero during night, the one-year statistical results show that the probability of low output power, i.e. less than 10% of the installed capacity, is over 60%, which is shown in Fig. 2-6. It could be also seen that the probability of maximum output is only 1.6%, which indicates a rather low PV availability.

![Figure 2-6 Probability of PV output levels during one year [51]](image)

With regard to time, Fig. 2-7 shows the probability of maximum output power of the PV generation in one day. We can identify, for most of the days, the maximum output power appears during 12:00 to 15:00. The corresponding output power statistical
results in these intervals are shown in Fig. 2-8, where the output power ranges from 25% to 100%.

![Figure 2-7 Probability of maximum output of PV generation in a day [51]](image)

![Figure 2-8 Probability of PV generation output during 12:00 to 15:00 [51]](image)

Compared with the models that use real monitored PV profile as inputs to calculated PV capacity credit, the models based on PV output simulation inherently introduces uncertainty and inaccuracy into the eventually resulted capacity values. Furthermore, since most of these studies use relatively simplified approaches to simulate PV profile, factors like correlation between local demand and PV generation become more difficult to be considered.
2.2.3 PV Output Profiling Methods Adopted

Very few studies on PV generation capacity credit adopt comprehensive approaches to modelling PV output. For example, although [47] adopted real monitored solar irradiance as input to its model, the approach it applied to converting solar irradiance to PV output power is rather oversimplified. Firstly, based on the collected solar insolation data, the hourly power output coefficient $C$ is calculated:

$$C_k = \frac{I_k}{1000}$$

where $C_k$ is the power output coefficient at hour $k$, and $I_k$ is the measured solar irradiance at hourly $k$. Then, the PV generation output $P_k$ at hour $k$ is simply a product of its available capacity at hour $k$ ($A_k$) and this hour’s power output coefficient:

$$P_k = A_k \times C_k$$

It could be noted that the modelling approach above fails to take into consideration influencing factors like the correlation between PV output and its corresponding demand data, and the ambient temperature of the examined PV generation.

Meanwhile, prior studies of PV contribution to system have always used hourly average PV output model. Yet, electric utilities must provide reliable electric service to all customers by continuously balancing supply and demand of electric energy on a time scale of milliseconds. With the acquisition of high resolution solar output data in time intervals as short as 10 seconds, there is solid evidence that cloud passing could create very short-time-scale but high impact on PV output which can have adverse impacts on the grid if not managed correctly. The full range of these impacts have not yet been fully evaluated, given that those effects are not a concern at the generally low penetration percentage levels of solar generation currently installed in the service territories of electric utilities.

As identified by [48], future PV capacity credit works should be initiated to develop cloud effect models to study the effects of clouds over a larger geographic area on solar generation. While wind generation output variations are generally reduced by distribution of wind generation over a wider geographic area, it is not currently clear that same effect will universally be observed with solar generation scaled to larger
geographic areas within an area that experiences similar general meteorological patterns.

### 2.2.4 Network Component Reliabilities

Given the fact that most distributed PV generators are connected on the residential side of the network, i.e. at the distribution levels, evaluating their credible contribution to the reliability of the whole system needs to take into consideration availability of different network components. Similarly, for large-scale PVs located in remote areas, evaluation of their capacity credit in terms of supplying far-away loading centres needs to consider the reliability of the interconnection networks.

In [47] the failure rates of PV inverters and transformers have been integrated into its proposed PV capacity credit evaluation model. Table 2-1 shows the PV unit components’ reliability data adopted in this study, where forced outage rate is the probability of unexpected breakdown.

<table>
<thead>
<tr>
<th></th>
<th>Unit Size (MW)</th>
<th>Number of Units</th>
<th>Forced Outage Rate (%)</th>
<th>MTTF (hrs)</th>
<th>MTTR (hrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inverter</td>
<td>1</td>
<td>10</td>
<td>0.0909</td>
<td>2400</td>
<td>240</td>
</tr>
<tr>
<td>Transformer</td>
<td>10</td>
<td>1</td>
<td>0.0909</td>
<td>24000</td>
<td>2400</td>
</tr>
</tbody>
</table>

### 2.2.5 Key Findings from Previous Works

#### A. Influence of PV Penetration

As in the case of wind power capacity credit, there is an obvious correlation between PV generation capacity value and the penetration of it. In the case study section of [47], two scenarios of PV penetration were investigated: 5% and 20% penetration, as shown in Table 2-2.

<table>
<thead>
<tr>
<th>Penetration</th>
<th>PV Size (MW)</th>
<th>Unit Size (MW)</th>
<th>Number of Units</th>
<th>Capacity Value (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>5%</td>
<td>50</td>
<td>10</td>
<td>5</td>
<td>35.33%</td>
</tr>
<tr>
<td>20%</td>
<td>200</td>
<td>10</td>
<td>20</td>
<td>28.5%</td>
</tr>
</tbody>
</table>
Also, the calculated capacity credits of these two penetration scenarios are presented. Noticeably, just like in the case of wind power, for PV generators higher penetration levels lead to lower capacity credits. Similar conclusions have been drawn by [33, 37, 38, 49].

**B. Influence of PV on Year-Round Load Profile**

Particularly, in [51] impact of PV integration on changing the year-round load profile has been studied. The results of low (2.5%) and high (18.9%) penetration scenarios have been given in Fig. 2-9 and 2-10 respectively.

![Figure 2-9 Impact of PV on year-round load profile (2.5% penetration) [51]](image)

![Figure 2-10 Impact of PV on year-round load profile (18.9% penetration) [51]](image)

It could be seen from these two scenarios above, for the higher penetration situation, the difference between the peak and valley demand levels during the examined year becomes significantly larger. In other words, with an 18.9% PV penetration, the gap between peak and valley of year-round load profile could increase from around 200MW in the original case to as high as over 2800MW now. This will be a huge challenge for the planning and operation of future power system. A curve showing the
relation between PV penetration and the amount of such difference is depicted in Fig. 2-11.

![Graph showing the relation between PV penetration and peak-valley demand difference](image)

Figure 2-11 Difference between peak and valley demand with various penetration levels

### C. Influence of Summer to Winter Peak Ratio

Several studies found a strong correlation between PV capacity credit and the ratio of summer to winter peak demand of the network where the examined PV is connected [37, 38, 47]. And it was found that the ratio has a positive effect on the calculated ELCC results.

### D. Difference Between Single and Aggregated PV

PV capacity credit is also dependent on whether the PV output considered is that of a single PV generation or an aggregated output of several PV systems. Investigations in the Netherlands [33] found that PV capacity value tends to increase from between 11-24% to 15-28% when the output of a single PV system is replaced by the aggregated output of five dispersed systems.

One of the reasons behind this phenomenon could be explained as when the PV units are dispersed at different locations, the impact of cloud passing becomes less dramatic as it is relatively unlikely when all the dispersed locations suffer from a single cloud passing. As a result, compared with single location scenarios, aggregated PV location scenarios will have much smoother PV output profile. Fig. 2-12 shows the difference between the solar irradiance at one single location on a partly cloudy day and that of twenty locations in a 100-mile region on the same day [52].
Although aggregation of PV plants is potentially able to reduce the uncertainty of PV output, the effectiveness needs to be evaluated and quantified. [53] investigated the PV uncertainty in Australia to verify the level of uncertainty for individual PV plants and estimate the level of uncertainty through aggregation. It found that after aggregating PV plants the output uncertainty became substantially lower, and the highest levels of reduction in uncertainty occurred in summer and spring.

### 2.3 Chapter Summary

This chapter has reviewed existing methodologies on quantifying DG contribution to the power system. Particularly, academic works on wind generation and PV capacity credit have been discussed, which by definition, is the equivalent capacity of a conventional generation or circuit if replaced by the examined wind or PV, resulting in the same or non-degraded level of power system reliability. Although various approach to assessing such capacity credits have been developed, the results suffer from either over complexity in terms of modelling and calculating process, thus lack of potential generalization opportunities, or overlooking certain practical considerations of the real power system.
Chapter 3. **Assessment of DG Contribution to Transmission Levels**

The transition to a low carbon economy will see a substantial rise of distributed generation (DG) in our energy mix. This will fundamentally change the demand patterns seen from the national transmission system. However, there are currently no reliable tools to accurately assess such contributions to transmission levels.

This chapter proposes an approach to assessing DG contribution to the national grid system particularly. Compared with the current approaches adopted by the UK power industry, the proposed enhancing framework takes into account not only the inherent capability of each DG technology, at the same time the particular characteristics of the examined distribution network have been integrated into the assessment process as well. A case study on a 14-bus grid supply point (GSP) test system is presented to demonstrate this enhanced model and show the advantages of it over its counterparts. The results and sensitivity analysis show that by probabilistically taking into consideration the characteristics of distribution networks, the presented approach is capable of differentiating various conditions of DG penetration, concentration and network reliability, thus obtaining a more realistic and comprehensive DG contribution value, which ultimately provides the future system planning with an increased visibility of these dispersed assets.

### 3.1 Introduction

Countries around the world have set targets for renewable energy and emission of greenhouse gases. For example, the UK and EU introduced legally binding targets to reduce greenhouse gas emissions by at least 80% below the 1990 baseline in 2050. This transition to a low carbon economy will see a substantial rise of renewables in the generation mix. According to the UK government, by 2020 the country is to achieve 15% of its energy consumption from renewable sources, and a great portion of these sources will be embedded within distribution networks particularly, ranging from low-, high- and extra high-voltage levels.
From the system’s point of view, these newly connected resources could be both a valuable asset as well as a network liability. More specifically, the introduction of such dispersed generators brings a number of benefits to the power system, such as improved power factors, reduced network losses and deferral of system reinforcement. On the other hand, the integration of such dispersed units also, to some extent, leads to a number of technical, commercial as well as regulatory issues [14-17]. The latter two are mainly caused by lack of incentives for distribution companies to connect DGs and insufficient governmental policies at this stage to support the transformation of passive distribution networks into active ones; whereas technically, the introduction of DG brings various challenges to the operation and planning of power systems. Issues like thermal limit violation caused by bi-directional power flow, the voltage-rise at the bus of DG connection and the degraded protection performance are all being widely investigated.

Unlike conventional generators, the availability, and consequently the real-time output of DG is subject to a series of uncertainties. Technically, to make an effective output, the DG itself needs to be in working state, which further depends on factors like location, time of the day, time of the year and weather condition. In addition, DG output is usually restricted for commercial reasons. A lack of financial incentives for DG private owners might impact their willingness to put it in service. Yet most importantly, since a large number of DGs are supported by renewable energies, the intermittent characteristics of such primary sources could make the output highly unpredictable.

As a result of such intermittencies and uncertainties, from the perspective of network planning, accurately recognizing the effective capacity of such dispersed units to the system adequacy value is non-trivial: the increasing penetration of these distributed generators will contribute to the planning and operation of conventional networks, thus fundamentally changing the demand patterns seen at transmission-distribution interconnections, i.e. grid supply points. This has aroused the attention of the UK power industry, and some of the state-of-the-art power system guidelines have recognized such issues.
3.2 Current UK Industrial Standards to Assess DG Contribution

3.2.1 Security and Quality of Supply Standards

The National Electricity Transmission System Security and Quality of Supply Standards, i.e. SQSS, is a guideline for the planning and operation of the national transmission system. In its chapter of Onshore Demand Connection Criteria, network security standards for different sizes of demand groups are specified. It also recognizes that wherever network assets are insufficient to meet the security requirements of a specific GSP demand group, certain large generation plants embedded within the distribution network are considered having the potential to meet such deficits. In order to assess such contributions, it also provides a look-up table based method which calculates different DG categories’ expected contribution to the grid’s demand security. Two versions of the SQSS’s take on this issue will be discussed here.

The specific look-up table presented in SQSS (Version 2.3) is shown in Table 3-1 [54]. It could be seen that the DG contribution factor guided by this method is fundamentally a function of the expected annual load factor of the examined generation. Key features of this approach include:

- Two system conditions have been considered separately, i.e. normal and N-1;
- A scaling factor of 67% has been deterministically used across all situations, regardless of differing DG technologies;

<table>
<thead>
<tr>
<th>Expected annual load factor of generation</th>
<th>Initial system conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Intact system</td>
</tr>
<tr>
<td>Over 30%</td>
<td>67% of Registered Capacity</td>
</tr>
<tr>
<td>Over 10% to 30%</td>
<td>Smaller of 67% of Registered Capacity and 20% of Group Demand</td>
</tr>
</tbody>
</table>
By contrast, in an earlier version of SQSS a slightly more comprehensive look-up table was proposed [55]. As shown in Table 3-2, the scaling factors provided by this version distinguished between different generation technologies. For example, for landfill gas embedded generation, which is categorized as non-intermittent generation, the scaling factor given is 63%; while by comparison, for wind power, whose output is apparently intermittent, the scaling factor is lower than 30%. Also, compared with Table 3-1, this version in Table 3-2 takes into account the different persistence times for the evaluation of intermittent distributed generators. Therefore, the key features could be summarized as:

- Two system conditions have been considered separately, i.e. normal and N-1;
- The proposed approach distinguishes between non-intermittent and intermittent generators, and also different types of generation technologies are assessed separately;
- For intermittent DGs, the attribute of persistence time is considered.

<table>
<thead>
<tr>
<th>Non-intermittent EGs</th>
<th>Generation Technology</th>
<th>Persistence Time (Hours)</th>
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<tbody>
<tr>
<td></td>
<td></td>
<td>1/2</td>
</tr>
<tr>
<td>Landfill Gas</td>
<td></td>
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<td></td>
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<td>CHP</td>
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<td>CCGT</td>
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<tr>
<td>Biomass</td>
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<thead>
<tr>
<th>Intermittent EGs</th>
<th>Generation Technology</th>
<th>Persistence Time (Hours)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>1/2</td>
</tr>
<tr>
<td>Wind</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Engineering Recommendation P2/6

As a network-designing standard in the UK, Engineering Recommendation (ER) has been playing a vital role in distribution network planning for decades. The latest version, ER P2/6 shows a methodology on how to treat these DGs and how to quantify their output contribution to security demand at peak times especially [56][57].

#### A. The development of Engineering Recommendation P2/6

To analyse the strengths and drawbacks of the P2/6 method, a good understanding of the data and approaches used in the development of this standard appears to be important [58-60].

The main theory underpinning the P2/6 methodology is called Expected Energy Not Supplied (EENS), which is one of the indices measuring the reliability of power systems. More specifically, a capacity of a perfect circuit is assumed which, when replaced by an examined generation, maintains the same level of power system reliability, keeping the EENE of the group demand (GD), which is the total demand within a specific GSP distribution area, unchanged. And the capacity of the perfect circuit is regarded as the effective contribution of the examined generation. This concept is shown in Fig. 3-1.

![Figure 3-1 Definition of DG contribution utilized in P2/6 development](image)

To calculate the EENE value of a power system with generators embedded inside, information like the capacity outage probability table (COPT) and the load duration curve (LDC) was utilized in the development of P2/6.
1) COPT
The probability value of each state in a COPT is mainly depending on three types of availabilities: technical availability that is depending on the failure characteristics of the examined generation unit; energy availability that is related to the generation’s specific primary energy source; and commercial availability dependent on whether the owner of the generation plant finds it economically beneficial providing service at the specific moment.

For non-intermittent generation units, it is relatively straightforward to assess the reliability by referring to the capacity outage probability table directly. However, for intermittent plants, such as wind farm and solar power, due to their fluctuating outputs, it is necessary to have the chronological pattern of each unit represented. Fig. 3-2 shows the approach used in [59] to achieve intermittent generation’s COPT.

![Figure 3-2 Time dependent generation pattern for an intermittent generation [59]](image)

As shown in this figure above, one of the main differences between the modelling of intermittent and non-intermittent generation is the minimum persistence time, in other words the minimum time that an intermittent generation is expected to be capable of generating for it to be considered as contributing to the group demand security. To assess the state probabilities of intermittent plants, firstly the occasions when the output is at least equal to a specific generation level $G_i$ and lasts longer than the
persistence time $T_m$ are identified, as shown in Fig. 3-2. Then the probability that the generation output is higher than level $G_i$ could be calculated as:

$$CP_i = \sum n_i \cdot t_i / T$$

(3-1)

where $n_i$ is the number of such occasions, $t_i$ is the time duration, and $T$ is the total time period of the chronological pattern considered.

Hence, by this chronological approach a specific capacity state and its corresponding probability of an examined intermittent generation could be achieved. And this calculation was repeated for all generation levels that this intermittent unit has in order to obtain a fully represented COPT table.

2) LDC

With the COPT for both intermittent and non-intermittent generation calculated, each state of the COPT is superimposed on the LDC individually as shown in Fig. 3-3 [59].

![Figure 3-3 Capacity state i superimposed on LDC [59]](image)

More specifically, with the level of state $i$ in LDC curve determined, the energy not supplied could be calculated, which is the area below the LDC and above state level, as shown in Fig. 3-3. Also, this energy not supplied is weighted by its probability of happening, and the weighted values are summated over all capacity states that this generation possesses. Therefore, the EENS could be determined by:

$$EENS = \sum E_i \times p_i$$

(3-2)
where \( E_i \) is the energy not supplied under the condition of \( i \), and \( p_i \) is the probability of being in state \( i \).

Fig. 3-4 and 3-5 show the flowcharts of the exact calculation steps for non-intermittent and intermittent DG contributions respectively [59].

According to the theory underpinning the P2/6 methodology, a perfect circuit with a fixed capacity is then imagined, which creates the same EENS when being superimposed on LDC. And this fixed capacity is the effective capacity or contribution of the distributed generation. A ratio of this effective capacity to the registered installed capacity of the examined DG is then the scaling factor provided in Table 3-3 and 3-4.

![Figure 3-4 Non-intermittent DG contribution calculation steps [59]](image1)

![Figure 3-5 Intermittent DG contribution calculation steps [59]](image2)

### B. The implementation of P2/6
In the standard of ER P2/6, three approaches are provided to calculate the effective contribution of different DGs, one of which is computer software based approach [56][57]. The other two approaches will be the main subject of this subsection, which includes the look-up table approach and a genetic approach.

1) Approach 1 - Look-up table(s)
According to P2/6, for non-intermittent generation, the output contribution mainly depends on the type of generation technology and number of units that such generation has. Table 3-3 shows what percentage of declared net capacity (DNC) each non-intermittent contributes to security demand under the circumstance of network outages.

Table 3-3 Scaling factors in % for non-intermittent DG

<table>
<thead>
<tr>
<th>Technology of generation</th>
<th>Number of units</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Landfill Gas</td>
<td>63</td>
</tr>
<tr>
<td>CHP using spark ignition engine</td>
<td>40</td>
</tr>
<tr>
<td>Waste to energy</td>
<td>58</td>
</tr>
<tr>
<td>CCGT</td>
<td>63</td>
</tr>
<tr>
<td>CHP using gas turbine</td>
<td>53</td>
</tr>
</tbody>
</table>

Table 3-4 Scaling factors in % for intermittent DG

<table>
<thead>
<tr>
<th>Technology of generation</th>
<th>Persistence, (T_m) (hours)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0.5</td>
</tr>
<tr>
<td>Wind farm</td>
<td>28</td>
</tr>
<tr>
<td>Small hydro</td>
<td>37</td>
</tr>
</tbody>
</table>

In the two tables above, the number of units means the number of units contributing to demand security under the condition of system contingency. The value could be obtained by referring to Table 3-5. Undoubtedly, higher number of contributing units means more security demand contribution from the same non-intermittent generation technology in Table 3-3 and 3-4.
It is obvious that when the persistence time is low, in other words, that the required minimum continuously operating time of the intermittent DG is short, the DG could be considered as making a higher contribution to the security demand. However, due to its fluctuating characteristic, even at half an hour persistence time, the wind turbine still is considered as contributing only 28% of its DNC, which is much lower comparing with the non-intermittent counterparts.

Table 3-5 Number of generation units considered contributable

<table>
<thead>
<tr>
<th>Type of generation</th>
<th>Number of units</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Landfill gas</td>
<td>1</td>
</tr>
<tr>
<td>CCGT</td>
<td>1</td>
</tr>
<tr>
<td>CHP using spark ignition engine</td>
<td>1</td>
</tr>
<tr>
<td>CHP using gas turbine</td>
<td>1</td>
</tr>
<tr>
<td>Waste to energy</td>
<td>1</td>
</tr>
<tr>
<td>Wind farm</td>
<td>1</td>
</tr>
<tr>
<td>Small hydro</td>
<td></td>
</tr>
</tbody>
</table>

As for the determination of persistence time, it is depending on the type of network outage and the demand class in the specific supplying area. Table 3-6 shows the persistence time value under differing network situations.

Table 3-6 Determination of persistence time

<table>
<thead>
<tr>
<th>Demand class</th>
<th>Switching</th>
<th>Maintenance</th>
<th>Other outage</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;1MW</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>1MW-12MW</td>
<td>3 hours</td>
<td>2 hours</td>
<td>24 hours</td>
</tr>
<tr>
<td>12MW-60MW</td>
<td>3 hours</td>
<td>18 hours</td>
<td>15 days</td>
</tr>
<tr>
<td>60MW-300MW</td>
<td>3 hours</td>
<td>24 hours</td>
<td>90 days</td>
</tr>
<tr>
<td>300MW-1500MW</td>
<td>N/A</td>
<td>24 hours</td>
<td>90 days</td>
</tr>
</tbody>
</table>

2). Approach 2 - Generic approach

Generally, approach 2 is an extension of approach 1 with a number of more complex tables and charts. And it is especially useful when the examined DG cannot be categorized into any technology type listed in approach 1. Table 3-7 gives the
contribution scaling factors with respect to different availabilities and unit numbers of the examined generation.

Table 3-7 Contribution scaling factors provided by Approach 2 [57]

<table>
<thead>
<tr>
<th>Availability (%)</th>
<th>Number of units</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>5</td>
<td>3</td>
</tr>
<tr>
<td>10</td>
<td>7</td>
</tr>
<tr>
<td>15</td>
<td>10</td>
</tr>
<tr>
<td>20</td>
<td>13</td>
</tr>
<tr>
<td>30</td>
<td>20</td>
</tr>
<tr>
<td>35</td>
<td>32</td>
</tr>
<tr>
<td>40</td>
<td>26</td>
</tr>
<tr>
<td>45</td>
<td>30</td>
</tr>
<tr>
<td>50</td>
<td>53</td>
</tr>
<tr>
<td>55</td>
<td>56</td>
</tr>
<tr>
<td>60</td>
<td>60</td>
</tr>
<tr>
<td>65</td>
<td>65</td>
</tr>
<tr>
<td>70</td>
<td>70</td>
</tr>
<tr>
<td>75</td>
<td>75</td>
</tr>
<tr>
<td>80</td>
<td>80</td>
</tr>
<tr>
<td>85</td>
<td>85</td>
</tr>
<tr>
<td>90</td>
<td>90</td>
</tr>
<tr>
<td>95</td>
<td>95</td>
</tr>
<tr>
<td>98</td>
<td>98</td>
</tr>
</tbody>
</table>

It should be noted that the actual contribution of a DG is highly influenced by the availability of it. More precisely, when the availability of the plant is high, the security contribution made by the generation is considered high. The approach 2 provided in P2/6 was developed on this relation. And it could be observed from the table that for generation with higher availabilities, higher contribution scaling factors are suggested.

Table 3-8 Number of contributing units [57]

<table>
<thead>
<tr>
<th>Availability (%)</th>
<th>Number of units</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>30</td>
<td></td>
</tr>
<tr>
<td>35</td>
<td></td>
</tr>
<tr>
<td>40</td>
<td></td>
</tr>
<tr>
<td>45</td>
<td></td>
</tr>
<tr>
<td>50</td>
<td></td>
</tr>
<tr>
<td>55</td>
<td></td>
</tr>
<tr>
<td>60</td>
<td></td>
</tr>
<tr>
<td>65</td>
<td></td>
</tr>
<tr>
<td>70</td>
<td></td>
</tr>
<tr>
<td>75</td>
<td></td>
</tr>
<tr>
<td>80</td>
<td></td>
</tr>
<tr>
<td>85</td>
<td></td>
</tr>
<tr>
<td>90</td>
<td></td>
</tr>
<tr>
<td>95</td>
<td></td>
</tr>
<tr>
<td>98</td>
<td></td>
</tr>
</tbody>
</table>

40
Similarly, the expected number of contributing units of each generation plant is considered depending on the availability of it. The relations are summarized in Table 3-8.

For contribution evaluation of intermittent generators, two figures showing the relation between the contribution and persistence of wind and small hydro respectively are recommended in approach 2 [57].

![Figure 3-6 Wind farm contribution by Approach 2 [57]](image)

![Figure 3-7 Small hydro contribution by Approach 2 [57]](image)

### 3.2.3 Discussions
By the comparisons between the DG contribution assessment approaches provided by SQSS and ER P2/6, it could be found that the latter offers a more comprehensive guidance on how to assess DG security contribution. More particularly, contrast to the
oversimplified and deterministic guideline specified by the SQSS, characteristics of the examined DG such as generation plant size and generation availability have been inherently taken into account by the P2/6 method and reflected in the ultimate DG contribution scaling factor results.

It is true that the suggested contributing values in P2/6 are relatively more accurate, and also the methodology adopted in it permits a number of attributes to be assessed, including number of units, capacity of units, technology of units etc. However, there are still a number of drawbacks, which could potentially lead to small or big mismatches when comparing with real situations.

1) Remote generation effect

For the P2/6 method, it implicitly assumes that the examined DG that are supposed to provide security contributions are close enough to the supplying load centre. Also, it assumes that the connecting networks between the generation and its supplying load centre, whether they are overhead lines, cables or transformers, are 100% perfectly reliable.

Nonetheless, this is far from the real situation. The exact amount of power received by the load during outage situations not only is depending on the suggested percentage of each DG’s nameplate rating, it is also related to the reliability of the connecting network, the figure of which is variable depending on the configuration and attributes of the network. Therefore, without taking into account the reliability of the connecting media between the generation and its load centre, merely using the suggested values given in P2/6 could potentially lead to huge mismatches.

2) Network configuration factor

As for power system parameters, P2/6 adopted deterministic ones, treating all components equally. More specially, it failed in taking into account reliability differences like:

- Cables compared with overhead lines;
- Heavy construction compared with light;
- Short lines compared with long ones;
• Calm environmental locations compared with adverse;
• Urban areas compared with rural; and
• Valleys compared with hilly regions.

Without considering these differences, the relatively lower failure rates of the former ones are not taken into account, and this would inevitably lead to inaccurate results.

3) Influence of DG penetration level

The penetration level of DG could be expressed as the ratio of installed DGs to the peak load value in that examined distribution network area.

With an increasing level of penetration of DGs, the effective contribution of each tends to drop, and this has been observed by a number of studies. For instance, it could be clearly seen from Table 3-9 that the wind turbine contribution as a percentage of its nameplate rating decreases when more wind turbines are used, in other words its effective contribution drops from 28% to 13.6% when installed wind power increases from 100MW to 2000MW [32]. However, this influencing factor was considered by neither P2/6 nor SQSS.

<table>
<thead>
<tr>
<th>Installed wind power (MW)</th>
<th>Penetration level (% of peak load)</th>
<th>DG Contribution</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>MW % of installed capacity</td>
</tr>
<tr>
<td>100</td>
<td>0.9</td>
<td>28 28.0</td>
</tr>
<tr>
<td>250</td>
<td>2.3</td>
<td>64 25.6</td>
</tr>
<tr>
<td>500</td>
<td>4.5</td>
<td>114 22.8</td>
</tr>
<tr>
<td>1000</td>
<td>9.0</td>
<td>184 18.4</td>
</tr>
<tr>
<td>1500</td>
<td>13.5</td>
<td>232 15.5</td>
</tr>
<tr>
<td>2000</td>
<td>18.0</td>
<td>272 13.6</td>
</tr>
</tbody>
</table>

4) Influence of DG geographical location/concentration

Take wind power as an example. In most cases, there is more than one wind farm located in a certain area. In such cases, the geographical dispersal factor tends to play
a significant role in determining the final effective contribution of the wind turbines. When all the wind turbines are close to each other or congested in a small area, it would be highly possible that when the wind condition is not ideal, the output of all the wind turbines might be influenced, making a much less contribution than usual. By contrast, when the wind farms or wind turbines are located dispersedly, under the circumstance of one certain area suffering from undesirable ambient condition, the overall output of all the wind turbine is not likely to be influenced much thanks to the geographically dispersed locations of them.

In addition, when a high density of low-voltage level generation is connected to a distribution network, the interconnection network will be more likely to experience operating constraints such as thermal violations, thus resulting in a much discounted DG contribution to the upper transmission grid levels.

3.3 Principles of the Proposed Method

The core principles underpinning the method proposed in this chapter was inspired by the concept of composite generation and transmission system reliability in traditional power system evaluation. Details of the principles will be introduced in this part.

Reliability has been one of the most important features of power systems and it has been the responsibility of both DNOs and TSOs to provide customers with adequate and secure power within reasonable economic constraints. For the reliability of conventional generators, the approach of hierarchical level II (HL II) i.e. the composite generation and transmission system reliability has been widely applied [61]. As shown in Fig. 3-8, it considers both the ability of a generation to satisfy the system demand and the ability of the transmission network to deliver energy to grid supply points. As conventional generators are remotely located and centrally dispatched, the resulted reliability of the composite system could be calculated as a function of the examined generation unit size, type as well as the availability of the transmission network.
By contrast, distributed generators have rather different characteristics such as lack of dispatchability, heavy dependence on ambient environment and the relatively less reliable while more complex location in networks. Therefore, the net contribution made by generators embedded within distribution networks to transmission systems, i.e. GSPs, is to a large extent determined by two components: the generation component and the network component. While the former includes characteristics of the examined generation such as technical, energy and commercial availabilities, the latter means constraints on power transfer (contingencies, thermal constraints, losses etc.) imposed by distribution branches. Fig. 3-9 depicts the proposed principles of the
proposed assessment framework which particularly takes into consideration the previously neglected influential factors.

Since the majority of distributed generators are supported by renewable sources like wind and solar, the produced energy is highly intermittent and uncertain. As a result, the energy availability and technical availability directly determines how much effective capacity could be accredited to the DG. Meanwhile, since a large amount of these small-scale generation sites are individually owned and operated, commercial availability plays a vital role as well. As a result, a corresponding concept called composite DG and distribution network reliability has been developed in this work. Comparing with its transmission-level counterpart, Fig. 3-10 shows the concept of the newly created concept.

As discussed in the previous sub-section, so far all the industry-adopted practices to evaluate DG contribution are focused only on the generation side, regardless of the configuration and constraints of the interconnecting distribution network. However, in reality, for a GSP or the transmission side to be able to see the contribution made by faraway embedded generators, the interconnection must be available and capable of conveying such flows. In other words, the potential network contingencies or the incurred thermal constraints might directly impose a cap on how much output those embedded generation could actually make, especially given the current DG management practice of ‘last-on-first-off’.

The developed enhanced framework in this chapter for the evaluation of DG contribution to the national grid particularly aims to overcome these major problems.
mentioned above. More exactly, it takes into account not only the generation side; also the potential network influences are considered and reflected in the final results. While based on the original P2/6, the approach presented here takes into consideration a number of distribution network parameters, which were neglected during the P2/6 development. Factors like the reliability of the distribution network, the thermal constraint of the system, the DG penetration level and the DG concentration situation, all of which could potentially influence the eventual results, have been integrated into the calculation process now. With such factors incorporated, it is believed that these updated methods could provide a more reasonable DG security contribution result, which would be beneficial for both transmission and distribution system operators.

3.4 Mathematical Formulation of DG Contribution to Transmission Levels

As stated in the previous section, there are two decisive factors determining the DG security contribution that could be seen by the transmission side: 1) DG inherent capability to make security contribution, 2) impact of the interconnection network. This section introduces the proposed Monte Carlo (MC) simulation-based approach, which incorporates both influencing components.

Traditionally, power system reliability could be evaluated by both analytical and simulation-based approaches [62]. However due to its superior capability to reflect the full range of network operating conditions, simulation-based, especially MC-based, approaches prove more comprehensive in spite of its intensive calculation burden. Considering the complex and numerous conditions of distribution networks containing DGs, in the study of this subsection MC simulation has been deployed.

The main concept underpinning the proposed approach is to find the amount of capacity at the GSP that could be reduced consequent upon the integration of DGs while keeping the reliability level of the existing distribution network uncompromised. Then the resulting GSP capacity substituted, by definition, is the collective security contribution provided by the connected DGs to the transmission system. In order to benchmark the original network reliability, LOLP has been
adopted as the index for this study [62].

The proposed simulation model can be implemented through the following steps.

1). Evaluating original distribution network reliability (LOLP)
For each electrical component in the network, given the expected failure rate (FR) $\lambda$ and mean time to repair (MTTR) $r$, the unavailability $U$, or in other words the forced outage rate (FOR), can be determined from (3-3)

$$U = \frac{\lambda}{\lambda + \frac{1}{r}}.$$ (3-3)

By comparing the derived unavailability with a random number generated, the state of each component is decided. Then optimal power flow (OPF) is conducted, given the state and capacity limit of each component, network nodal demand and the original capacity at GSP.

Based on the concept of MC simulation, with a large number of OPF calculations, the expected LOLP of the original network can be derived.

2). Determining DG security contributing capability
Then, the inherent capability of each examined DG to provide security contribution (SC) is modelled and quantified by $P2/6$. And the results are input into the respective nodal demands where the DGs will be located.

3). Obtaining new GSP capacity which results in the same LOLP
Due to the integration of the examined DGs, an enhanced LOLP of the system distribution network can be achieved. As a result, the capacity at GSP is reduced iteratively until the original LOLP level is reached again.

4). Calculating DG security contribution to GSP
The incremental and collective security contribution of the examined DGs to the transmission level is then the difference in the GSP capacity before and after DG connection:

$$\text{Contribution} = GSP_{\text{before}} - GSP_{\text{after}}.$$ (3-4)
The flowchart depicted in Fig. 3-11 shows the framework of the proposed approach.

Figure 3-11 Framework of proposed model

3.5 Influencing Factors Analysis

A. Overhead line/cable availabilities

As the main medium connecting generation resources and load points, recurrent failures of such overhead lines or cables would apparently influence the normal power transmission in between, leading to higher load curtailment values. In other words, the failure rates and availabilities of overhead lines or cables have a big influence on the ultimate DG contribution value.
Therefore, such parameters need to be input as influencing factors to the calculation in Fig. 3-11. Given the annual failure rate $\lambda$ and repair time $r$, the specific availability of each component could be obtained as

$$\text{Availability} = \frac{8760 - \lambda \cdot r}{8760} \quad (3-5)$$

### B. Line capacity constraints

Another influencing factor to results is the capacity limit of the connecting lines within the distribution system. The lines of the existing distribution network have been designed to merely satisfy the net demand of the customer connected at each bus, without considering any generation roles contributing to the system reversely. On the other hand, according to P2/6, DGs within a distribution system will have the capability to supply the group demand in the area under N-1 or N-2 outage circumstances at the GSP point.

The problem of such a contradiction is obvious. The originally low-capacity planned distribution lines at a DG bus bar might not bear a large amount of outward power flow. This issue becomes even more manifest when N-2 outage happens that DGs are expected to make an even higher contribution and supply a much larger proportion of the demand group. So, the practical DG contribution to the security demand of the system is also depending on the capacity limit of the distribution lines.

### C. DG penetration level

By definition, DG penetration is expressed as

$$\text{Penetration} = \frac{\text{Capacity}_{\text{Total, DG}} \%}{\text{Demand}_{\text{Peak}}} \quad (3-6)$$

where $\text{Capacity}_{\text{Total, DG}}$ is the capacity of all DGs connected in the system and $\text{Demand}_{\text{Peak}}$ is the peak value of the group demand.

Apparently, the change of either of these two parameters could lead to a different power flow situation, which could then affect the load curtailment. Generally, under
circumstances of higher DG penetration levels, influencing factors like line constraints and failure rates are more likely to result in comparatively lower DG contribution results.

D. **DG concentration**

Different degrees of DG concentration would result in different DG contribution values as well. In other words, a higher level of DG concentration tends to result in a higher chance of generation output being restrained by line limits, which eventually results in a higher load not supplied value. Therefore, conditions like the same number of distributed units located at one busbar only, at adjacent busbars and at geographically dispersed busbars pose various influences on the final contribution results calculated.

### 3.6 Demonstration of the Proposed Framework

In this subsection, the proposed approach is demonstrated on a modified IEEE 14-bus GSP test system, given in Fig. 3-12. Also under different scenarios, the results derived are compared with the deterministic figures provided by the original P2/6, thus strengths of the enhanced model can be illustrated.

In the test system, nodal demand information has been adopted from [63]. The GSP is rated at 400 kV, while the remaining buses in the distribution network are rated at 132 kV and 33 kV. Table 3-10 shows the parameters of the test system branches, and the adopted failure rates and MTTRs for the components in the studied system have been given in Table 3-11 [64].

<table>
<thead>
<tr>
<th>Branch No.</th>
<th>From bus – To bus</th>
<th>Thermal rating (MWA)</th>
<th>Length (km)</th>
<th>Branch No.</th>
<th>From bus – To bus</th>
<th>Thermal rating (MWA)</th>
<th>Length (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1-2</td>
<td>260</td>
<td>28.47</td>
<td>11</td>
<td>6-11</td>
<td>25</td>
<td>7</td>
</tr>
<tr>
<td>2</td>
<td>1-5</td>
<td>260</td>
<td>93.8</td>
<td>12</td>
<td>6-12</td>
<td>22</td>
<td>9.5</td>
</tr>
<tr>
<td>3</td>
<td>2-3</td>
<td>125.7</td>
<td>82</td>
<td>13</td>
<td>6-13</td>
<td>28</td>
<td>4.2</td>
</tr>
<tr>
<td>4</td>
<td>2-4</td>
<td>83.3</td>
<td>67</td>
<td>14</td>
<td>7-8</td>
<td>20.5</td>
<td>5.67</td>
</tr>
<tr>
<td>5</td>
<td>2-5</td>
<td>97.1</td>
<td>65</td>
<td>15</td>
<td>7-9</td>
<td>33.5</td>
<td>-</td>
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<td></td>
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<td></td>
</tr>
<tr>
<td>6</td>
<td>3-4</td>
<td>98</td>
<td>71</td>
<td>16</td>
<td>9-10</td>
<td>32.6</td>
<td>2.7</td>
</tr>
<tr>
<td>7</td>
<td>4-5</td>
<td>151.4</td>
<td>18</td>
<td>17</td>
<td>9-14</td>
<td>34.3</td>
<td>7.64</td>
</tr>
<tr>
<td>8</td>
<td>4-7</td>
<td>45</td>
<td>-</td>
<td>18</td>
<td>10-11</td>
<td>23</td>
<td>5.6</td>
</tr>
<tr>
<td>9</td>
<td>4-9</td>
<td>60</td>
<td>-</td>
<td>19</td>
<td>12-13</td>
<td>14</td>
<td>6.2</td>
</tr>
<tr>
<td>10</td>
<td>5-6</td>
<td>90</td>
<td>-</td>
<td>20</td>
<td>13-14</td>
<td>18</td>
<td>10.5</td>
</tr>
</tbody>
</table>

Table 3-11 Power component failure rates and mean repair times

<table>
<thead>
<tr>
<th>Network component</th>
<th>Voltage level (kV)</th>
<th>FR-λ under extreme conditions (failures/km-yr or failures/PC-yr)</th>
<th>MTTR-r (hrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Overhead Lines</td>
<td>132</td>
<td>0.0038</td>
<td>19.1</td>
</tr>
<tr>
<td></td>
<td>33</td>
<td>0.034</td>
<td>20.5</td>
</tr>
<tr>
<td>Cables</td>
<td>132</td>
<td>0.0277</td>
<td>222.7</td>
</tr>
<tr>
<td></td>
<td>33</td>
<td>0.034</td>
<td>338.4</td>
</tr>
<tr>
<td>Transformers</td>
<td>132/33</td>
<td>0.0392</td>
<td>250.1</td>
</tr>
</tbody>
</table>

Figure 3-12 14-bus GSP area test system

3.7 Results and Discussions

A. Comparison with P2/6 Under Different Penetrations

One of the major drawbacks of the original P2/6 is that its results are not able to discriminate between different situations of DG penetration. For this subsection,
different DG penetration scenarios have been created, which has been given in Table 3-12.

Consider the GSP test system with an 8 MW landfill gas, a 35 MW wind farm and a 10 MW CHP connected at bus 13, 2 and 3 respectively. Given the 259 MW system peak demand, the DG penetration under this circumstance is around 20%. According to P2/6, the collective security contribution from these three DGs is 22.7 MW, which is identical to the result obtained by the proposed approach, which is shown by the first pair of bars in Fig. 3-13.

Table 3-12 DG penetration scenarios

<table>
<thead>
<tr>
<th>DG penetration</th>
<th>Wind at Bus 2 (MW)</th>
<th>CHP at Bus 3 (MW)</th>
<th>Landfill gas at Bus 13 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>20%</td>
<td>35</td>
<td>10</td>
<td>8</td>
</tr>
<tr>
<td>40%</td>
<td>70</td>
<td>20</td>
<td>16</td>
</tr>
<tr>
<td>100%</td>
<td>175</td>
<td>50</td>
<td>40</td>
</tr>
<tr>
<td>150%</td>
<td>262.5</td>
<td>75</td>
<td>60</td>
</tr>
<tr>
<td>200%</td>
<td>350</td>
<td>100</td>
<td>80</td>
</tr>
</tbody>
</table>

Nevertheless, as shown in the result, when the penetration level increases, the results derived by the proposed enhanced model starts to deviate from the deterministic P2/6 values. And particularly when the DG penetration level for the specific network passes the threshold of 100%, the obtained DG contribution values are less than 85% of the corresponding P2/6 specified levels, making the over-simplified P2/6 method almost 20% more optimistic than the proposed comprehensive approach. This could be explained as for higher penetration conditions, network thermal limits are more likely to impose negative impacts on DG outputs, which the deterministic and oversimplified P2/6 failed to take into account.

B. Comparison with P2/6 Under Different Concentrations

Apart from being able to distinguish between DG penetration levels, another key feature of the proposed model is its capability to recognize the specific DG concentration condition in the network and provide results accordingly.

As given in Table 3-13, three DG concentration scenarios for the GSP test system
have been simulated and analysed in this part, while the result under a specific penetration condition has been provided in Fig. 3-14.

![Figure 3-13 Matching of differences comparing with P2/6](image_url)

**Table 3-13 DG concentration scenarios**

<table>
<thead>
<tr>
<th>Network DG concentration</th>
<th>DG connected bus No.</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Landfill Gas</td>
<td>Wind</td>
<td>CHP</td>
<td></td>
</tr>
<tr>
<td>High</td>
<td>13</td>
<td>13</td>
<td>13</td>
<td></td>
</tr>
<tr>
<td>Medium</td>
<td>12</td>
<td>13</td>
<td>14</td>
<td></td>
</tr>
<tr>
<td>Low</td>
<td>6</td>
<td>13</td>
<td>9</td>
<td></td>
</tr>
</tbody>
</table>
It is noticeable that regardless of the specific concentration of DG in the network, the P2/6 dictates the same results for all three scenarios. Yet, this is far from the truth, as higher DG concentration actually leads to higher chance of network congestion, which subsequently affects DGs actual output and their contribution to transmission levels. By contrast, the blue bars depict the results with the enhanced model, by which the examined three concentration circumstances have been clearly discriminated.

C. Comparison with P2/6 Under Different Network Reliabilities

Conceivably, the reliability of the interconnection network has a direct impact on both DG outputs as well as customer supply. Hence, for the same DG, when it is connected in a rural area via relatively weak interconnections, the actual contribution to the grid should be lower; while if it is located in a highly reliable meshed urban network, higher contribution from the DG could be expected.

In order to investigate the DG contribution variant as a result of different network reliabilities, three conditions based on Table 3-11 have been created and evaluated, the result of which has been given in Fig. 3-15. Again, similar attributes to the previous subsections could be observed. Compared with the oversimplified P2/6, the proposed approach is able to differentiate between various network reliabilities and reflect that in its ultimate result accordingly.
3.8 Chapter Summary

The transition to a low carbon economy will see a substantial number of DGs penetrating into existing distribution networks. From the perspective of national grid system planning, what is of interest and importance is if the security contribution from these dispersed sources can be recognized and accurately quantified. However, currently there are no reliable tools to accurately determine this, particularly considering the effects of DG penetration, location and concentration across all three distribution voltages.

In order to reflect the uncertainties in DG contribution evaluation on transmission level, an enhanced evaluation method has been introduced in this chapter, which incorporates a series of influencing factors into the existing P2/6 methodology, thus making the originally deterministic approach suitable for transmission-level analysis. Extensive analysis of the impact of each potentially influencing factor on the contribution value has been performed. Also, a worked example has been showed using the proposed methodology.

The result proves that by taking into consideration a number of previously neglected influencing factors like DG penetration, concentration, network reliability and thermal limit, the originally over-optimistic P2/6 results could be improved, and different
network circumstances, configurations and DG locations could be differentiated. Therefore, result of this study could help increase the visibility of DG for the transmission grid particularly, and thus contributing to the future planning and operation of electrical systems.
Chapter 4. Decomposition of DG Contributions

Distribution network states like thermal constraints and contingencies could directly affect the output of DGs, which consequently leads to a discounted contribution received on the transmission side. Yet, concentrating solely on the local generation side, neither SQSS nor P2/6 is able to reflect and discriminate between different characteristics and conditions of the examined distribution network. Meanwhile, assumptions like perfectly reliable distribution circuits with unlimited thermal capacities make those previously derived results unreasonable for transmission-level analysis [65]. All of these defects will become highly consequential especially when the DG penetration reaches thresholds in the foreseeable future.

In the last chapter, a Monte Carlo simulation based approach to assessing DG contribution has been introduced, given specific conditions of DG penetration, concentration and network availability. However, one of the major downsides of this approach based on simulation is that the results is highly specific to the given examined network and context. In other words, it is extremely hard to adjust different elements within the calculation process. A direct consequence of this is that a whole new time-consuming Monte Carlo simulation needs to be carried out to derive the new DG contribution results under even a slightly adjusted network situation, thus almost impossible to quantify the effect of different network factors on DG-to-transmission contributions.

In this chapter, an enhanced approach to evaluating DG’s locational incremental contribution to the national transmission grid is proposed. It seeks to reflect and quantify the impact of network on DG to transmission level contributions, particularly the expected DG curtailments consequent upon network conditions like thermal congestion and contingency. Compared with the existing industrial methods, the results derived by the proposed approach can properly distinguish between different situations of DG location, penetration, concentration and network loading level, while provide a more reasonable and clearer visibility of DG for the future grid planning.

4.1 Introduction
An accurate recognition of DG contribution on transmission level appears of considerable value to transmission system operators. Security demand of a distribution system is required to be satisfied under GSP outage conditions. To meet such requirements, the conventional way has been redundant planning at GSP and substantial investment in its capacity, whereas with the introduction of DG nowadays, a more cost-effective way could be achieved and substation-expanding investment could be deferred. Yet, an area of concern is the proper amount of GSP assets that could be replaced by the integration of DG, which essentially depends on an accurate DG contribution assessment. Unreasonable values would lead to either over-invested GSP or incapability to satisfy the system security demand.

More important, when it comes to assessing DG contribution from the viewpoint of transmission system specifically, the interconnection, i.e. the distribution network, cannot be neglected. So far, a number of transmission-level studies have recognized the constraints and effects of distribution systems. In the case of DGs reversely supplying a transmission system, the influence of possible distribution component failures on the reliability of the load point has been analysed in [66]. In this work, the failure rate of each component is updated constantly based on factors like its historical outage data, weather conditions, age of the component, and system loading level; while the power-flow consequences of cascading and dependent failures on the distribution network are provided by Monte Carlo simulation. According to [67], the connection of DGs could have a major impact on the reactive power demand and consequently the voltage of transmission systems. Aimed at minimizing such influences, an optimization method has been proposed, in which both the configuration and voltage limits of the examined distribution system have been taken into consideration.

With respect to evaluating DG contribution from the perspective of transmission levels, one of the main drawbacks of P2/6 lies in the concept underpinning the development of it. During the process, an assumption has been made that each distributed resource is sufficiently close to its load centre [58-60]. In other words, the connecting lines between the DG and its load centre have been assumed as perfectly reliable, so that possibilities of DG output being restricted by failed outward transportation routes have been ignored.
Nevertheless, this is apparently not the case in present-day systems. Most of the times, distributed resources are located some distance far away from the corresponding load centres and connected via relatively weak networks and single protection points [59]. As a result, high unavailability of the connecting media might directly increase the uncertainty in the actual DG contribution to system demand. Hence, in order to obtain a more reasonable result, it is believed that the availability or failure rate of the connecting network of each DG should be combined with the existing P2/6 proposed values.

4.2 Decomposing DG Contribution into Two Components

There are two major influencing factors determining how much DG security contribution could be seen from the transmission side:

1).  *DG Effective Capacity*

The contribution a DG could make to transmission system depends greatly on the output profile of the studied generation plant. Comparing with conventional counterparts, DGs exhibit rather distinguishing characteristics, one of which is that they are mostly supported by intermittent renewable sources (wind, solar, hydro, etc.). Such an attribute makes the DG output highly variable and unpredictable. Also, the fact that DGs are usually non-centrally dispatched by utility but privately owned means the ability to derive power from these generators is constantly affected by the commercial incentive and market condition at each moment. Due to these reasons, a comprehensive modelling of DG effective capacity is needed to reflect the technical, energy and commercial availability of each studied DG.

2).  *Network Effects*

Interconnection networks in-between a DG and its supplied buses have a direct impact on the actual DG-contribution experienced by networks, especially for remote DGs which are connected to loading centers via relatively weak networks [65]. In other words, conditions like distribution network congestion or failure are very likely to constrain DG output, thus discounting the expected DG contribution seen by the transmission grid.
For the simple GSP network shown in Fig. 4-1, the examined DG and its load center are located next to the GSP. The DG in this example has an effective capacity of 10 MW, while the peak demand is 2 MW. It could be noted that after satisfying the 2 MW local demand which otherwise has to be fed by the GSP, the remaining 8 MW from DG is exported reversely to the transmission side through GSP. Hence the DG-contributed benefit seen from the transmission system consists of these two parts, i.e. contribution = 2 MW + 8 MW = 10 MW, which is exactly the effective capacity of the DG.

![Figure 4-1 DG contribution without interconnection considered](image)

By comparison, the GSP network shown in Fig. 4-2 brings a number of uncertainties. In this network, the DG and its loading center are connected to the GSP via a paralleled interconnection network. In this scenario, after supplying the local demand, how much surplus could be actually received by the GSP depends on the nominal capacity as well as the condition of the interconnection.

Fig. 4-2(a) shows the situation when the total capacity of the parallel network is less than 8 MW, where each line in this case has a thermal capacity of 2 MW. The original dispatch as in Fig. 4-1 would apparently cause congestions. As a consequence, the generation in this case has to be curtailed in order to relieve network thermal violation, which consequently discounts the total contribution from the previous 10 MW to 6 MW. Fig. 4-2(b) illustrates the impact of network contingency. In this case, when a single circuit fails, to avoid thermal constraint on the other, the connected
generator needs to be curtailed even more. The resulted contribution to the grid is $2 \text{ MW} + 2 \text{ MW} = 4 \text{ MW}$, which is 6 MW less than the intrinsic capability of the DG.

Therefore, these two components: DG effective capacity and network effects form the core of the assessment approach proposed in this chapter. For an examined DG $N$, the locational contribution to transmission system $LIC$ is then given by

$$LIC_N = EC_N - NE_N$$  \hspace{1cm} (4-1)

where, $EC_N$ is the effective capacity of DG $N$, and $NE_N$ is the expected network effects on the output of the generation.

### 4.2.1 ‘Generation’ Component Modelling

Firstly, the mathematical model of the first component in equation 4-1 is formulated.

As a network-designing standard in the UK, engineering recommendation has been playing a vital role in distribution network planning for decades. The latest version, ER P2/6, specifies the required security level for different classes of distribution.
network, which all DNOs must comply. More importantly, it also provides guidance on security contribution values that could be provided by different DG types across the UK specifically. The required data and DG information underpinning the developed guidance was collected from DNOs, generation operators and trade associations within the UK [68].

As shown in Table 4-1 and 4-2, the scaling factors provided indicate how much, in terms of percentage, of the declared net capacity (DNC) of an examined DG could be regarded as contributory to network security [57]. For non-intermittent generators, the resulted effective capacities are depending on the specific type of DG technology and number of units of the DG site; while for intermittent DGs, the contribution values given by P2/6 are subject to DG type and persistence time (the minimum time for which the examined intermittent DG must be continuously available if it can be regarded contributory [56]). Noticeably, comparing with non-intermittent DGs, the lower effective capacities of intermittent generators due to lower energy availabilities have been properly built in and reflected in the tables.

![Figure 4-3 P2/6 demonstration on a simple GSP network](image)

**Table 4-1 Scaling factors in % for non-intermittent DGs**

<table>
<thead>
<tr>
<th>Technology of DG</th>
<th>Number of units</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Landfill Gas</td>
<td>63</td>
</tr>
<tr>
<td>CHP using spark ignition engine</td>
<td>40</td>
</tr>
<tr>
<td>Waste to energy</td>
<td>58</td>
</tr>
<tr>
<td>CCGT</td>
<td>63</td>
</tr>
</tbody>
</table>
Accordingly, the security contribution capability of a DG $N$ is calculated by multiplying its DNC with the scaling factor for the specific DG technology

$$ SC_N = DNC_N \cdot SF_N $$  \hspace{1cm} (4-2) 

Where, $EC$ represents the effective contribution provided by the examined DG, while $SF$ is the scaling factor given in the corresponding look-up table.

Therefore, if the simple GSP network depicted in Fig. 4-2 is considered, where a 4-unit landfill gas and a wind farm with a persistence time of 0.5h are connected, the capability of each to make contribution to network security could be determined

$$ SC_{landfill} = 4 \times 2 \times 75\% = 6 \text{ MW} $$

$$ SC_{wind} = 35 \times 28\% = 9.8 \text{ MW} $$

It is worth noting that by this point the impact of interconnection networks has not been considered.

### 4.2.2 ‘Network’ Component Modelling

DG injections in a distribution network might cause reversed power flow on certain circuits, which could lead to network congestion. Conceivably, networks with high DG penetration are more likely to experience such issues. Under such conditions, DGs involved are required by network operators to curtail their output in order to relieve network pressure [69-72].
In this subsection, the mathematical formulation of component 2, distribution network effects on DG contribution, is introduced.

A. **Network Elements Availability Modeling**

The connecting networks between each distributed generation and its corresponding load centres could have a variety of combinations of electrical assets. It could be a transformer only, a transmission line only, two transformers in parallel, or two transmission lines in parallel. Fig. 4-4 shows the situations that the connecting network is a single transformer or a transmission line.

![Figure 4-4 One component with connecting network](image)

In the configuration shown in this figure, it is apparent that the availability of this connecting network is the availability of the component itself, which could be obtained as long as parameters like its annual failure rate and repair time are provided. And undoubtedly, longer lines would lead to higher probabilities of failure [27].

As for the situations that the connecting components are placed in parallel, which is shown in Fig. 4-5, the total network availability could be calculated by converting parallel components into a single component:

\[
A_p = A_1 + A_2 - A_1A_2
\]  

(4-3)
Where:

- \( A_p \) is the whole availability of the paralleled connecting network;
- \( A_1 \) is the availability of component 1;
- \( A_2 \) is the availability of component 2 in the connecting network.

Figure 4-5 Paralleled connecting network

B. **Calculation Steps**

To obtain the expected level of DG curtailment across all network potential states, the network state enumeration technique has been adopted in the proposed model. More specifically, the component of ‘network effects’ in (4-1) could be modelled through the following steps:

1). Enumerating the mutually exclusive states and probabilities of the examined distribution network

The probability of the examined network residing in state \( s \) is calculated by

\[
P(s) = \prod_u U_u \prod_s (1 - U_s)
\]  \hspace{1cm} (4-4)
\[ U = \frac{\lambda}{\lambda + 1/r} \]  

where, \( m \) and \( n \) respectively are the number of components in down and up state for network state \( s \); \( U \) is the unavailability of a component; \( \lambda \) is the expected failure rate (FR), and \( r \) is the mean time to repair (MTTR) of a component.

2). Evaluating the DG curtailment situation for each specific network state
Currently, the DG output management strategy adopted by DNOs in the UK follows a ‘Last-on-first-off (LOFO)’ criterion \([71][72]\). According to this strategy, should a circuit overload happen, the most recently installed DG needs to be constrained first. However, sometimes the last-on generation might be hardly be much responsible for the overloading power flow, contributing little to mitigating circuit congestion. Consequently, LOFO appears to be uneconomical for such situations.

A more efficient strategy based on power flow sensitivity is developed and embedded in the proposed assessment method in this chapter. Power transfer distribution factor (PTDF) is a sensitivity matrix, which relates circuit active power flows to network nodal power injections. In the case of distribution network congestions, which are attributable to DG injections, firstly the most overloaded circuit is identified. Then referring to the PTDF of the examined network, among all DGs embedded in the network, the most sensitive one that has the greatest impact on the power flow along that circuit is selected to be curtailed. The amount of curtailment is calculated by

\[ Curtailment = \left( P_l - C_l \right) \frac{\partial P_l}{\partial P_{DG}} \]  

where, \( P_l \) is the power flow through the selected overloaded circuit before curtailment; \( C_l \) is the capacity limit of the circuit; and \( \partial P_l/\partial P_{DG} \) is PTDF of the overloaded circuit with respect to the selected DG.

Under network state \( s \), to fully mitigate the congestion on each overloaded circuit \( l \), the cumulative output curtailment of DG \( N \) is given by \((4-7)\)

\[ Curtailment_{N,s} = \sum_l Curtailment_{N,l,s} \]  

3). Calculating the magnitude of network effects

67
The expected network effects on DG $N$ will be the summation of expected curtailment of the examined DG over all network states, given by

$$NE_N = \sum_s (P(s) \cdot \text{Curtailment}_{s,N})$$  \hspace{1cm} (4-8)

### 4.3 Demonstration on Simple Networks

#### A. Two-busbar Test System Demonstration

The proposed approach to evaluating DG contribution to transmission level is firstly carried out on a simple network shown in Fig. 4-6(a). It is assumed that the circuit $L$ connecting GSP and the DG connected busbar is rated at 100 MW, and has an unavailability of 0.01. The integrated DG has been assumed as a 10-unit landfill gas with a DNC of 100 MW. According to Table 4-3, the $LIC$ is calculated as:

$$EC = 100 \times 80\% = 80 \text{ MW}$$

$$NE = 0 \times 99\% + 80 \times 1\% = 0.8 \text{ MW}$$

$$LIC = EC - NE = 80 - 0.8 = 79.2 \text{ MW.}$$

![Figure 4-6 Two-busbar test system](image)

**Table 4-3 State enumeration for two-busbar network**

<table>
<thead>
<tr>
<th>Number</th>
<th>Network state</th>
<th>DG curtailment</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>L Up</td>
<td>0 MW</td>
<td>99%</td>
</tr>
<tr>
<td>2</td>
<td>L Down</td>
<td>80 MW</td>
<td>1%</td>
</tr>
</tbody>
</table>
B. Different Extent of Network Use Demonstration

One of the key influencing factors determining the amount of DG contribution seen by the transmission level is the location of the generation plant. Taken the DG-integrated network shown in Fig. 4-6(b), assume both circuits $L1$ and $L2$ are identical, each having a rated capacity of 100 MW, while the DG connected at bus 2 is the same landfill gas as in the previous two-busbar case. The LIC is calculated as:

$$LIC = 80 - 1.6 = 78.4 \text{ MW}.$$  

It is noticeable from the result that for the same DG, when it is located far away from its supplying node and supported by higher extent of network facilities, power transfer interruptions are more likely to happen, leading to a more significant $NE$. Hence, its locational contribution becomes lower.

<table>
<thead>
<tr>
<th>Number</th>
<th>Network state</th>
<th>DG curtailment</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>L1, L2 Up</td>
<td>0 MW</td>
<td>98.01%</td>
</tr>
<tr>
<td>2,3</td>
<td>N-1</td>
<td>80 MW</td>
<td>1.98%</td>
</tr>
<tr>
<td>4</td>
<td>N-2</td>
<td>80 MW</td>
<td>0.01%</td>
</tr>
</tbody>
</table>

C. Different Network Security Demonstration

The proposed LIC evaluation approach can also be extended to reflect the security level of the connecting network in between an examined DG and its supplying node. Compared with the radial network depicted in Fig. 4-6(a), the meshed network depicted in Fig. 4-6(c) provides the DG bus with a N-1 resilient network structure. The calculated LIC is 79.98 MW.

The higher level of connecting network security dictates that the expected magnitude of network effects on the integrated DG becomes considerably minimal, and thus results in a higher level of transmission-level contribution.

The results of these three simple network demonstrations above have been summarized and compared with the original P2/6 in Table 4-5. Noticeably, the original P2/6 cannot distinguish between different network configurations, specifying the same contribution value for these differing cases. By contrast, the proposed
approach respects examined network characteristics. As could be identified from the table, case B has the highest mismatch while case c has the lowest among all three cases, reflecting that the network configuration in Fig. 4-6(b) has a higher expected impact on DG output than the meshed configuration in Fig. 4-6(c).

<table>
<thead>
<tr>
<th></th>
<th>By original P2/6 (MW)</th>
<th>By proposed approach (MW)</th>
<th>Mismatch (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Case A</td>
<td>80</td>
<td>79.2</td>
<td>0.8</td>
</tr>
<tr>
<td>Case B</td>
<td>80</td>
<td>78.4</td>
<td>1.6</td>
</tr>
<tr>
<td>Case C</td>
<td>80</td>
<td>79.98</td>
<td>0.02</td>
</tr>
</tbody>
</table>

4.4 Demonstration on A 14-Bus GSP Network

In this section, the proposed DG contribution evaluation approach is demonstrated and compared with the original P2/6 on a 14-bus GSP network, given in Fig. 3-12 [73]. Bus 1 in the original system has been assigned as the GSP for this demonstration. It has also been assumed that the GSP is rated at 400/132 kV, while the remaining buses in the distribution network are rated at 132 kV and 33 kV. The adopted failure rates and MTTRs for the components in the studied system have been adopted from [74]. The DG contribution assessment in this part will focus on the system peak demand, which is 259 MW. And the majority of the group demand is aggregated at the 132 kV level.

A. DG Locational Incremental Contribution to the GSP

In this section, the proposed DG contribution evaluation approach is demonstrated and compared with the original P2/6 on the previous 14-bus network Fig. 3-12. Bus 1 in the original system has been assigned as the GSP for this demonstration. It has also been assumed that the GSP is rated at 400/132 kV, while the remaining buses in the distribution network are rated at 132 kV and 33 kV. The adopted failure rates and MTTRs for the components in the studied system have been adopted from [74]. The DG contribution assessment in this part will focus on the system peak demand, which is 259 MW. And the majority of the group demand is aggregated at the 132 kV level.

In this base case, it is assumed that 5 landfill gas distributed generators, each having
the capacity of 32 MW, have been connected at buses 10, 11, 12, 13, and 14 respectively. For investigating the locational contribution at different nodes, an examined landfill gas, whose DNC is 50 MW, is connected at each node in the 132- and 33 kV buses in the system. For the examined DG, the derived locational contributions to GSP from different buses are given in Fig. 4-7, also the decomposition of each contribution value is depicted.

As for each node, the locational contribution assessment is applied to the same examined landfill gas, the DG effective capacity for each bus is unchanged across all scenarios as illustrated in Fig. 4-7.

More importantly, it is noticeable that the connecting network has a substantial impact on the eventual contribution values. For buses at the higher voltage level, the influence of network effects tends to be minimal. For example, when the examined DG is connected at bus 3, the NE component is almost zero, as a result of which the locational contribution from this specific generation is very close to the P2/6 provided DG effective capacity value. Whereas, when the same DG is located at lower voltage buses, the impact of network becomes significant. For buses like 10 and 11, the scale of the negative impact from network is more than half of the original effective capacity of the examined DG.

![Figure 4-7 DG locational contribution from different buses](image-url)
B. Impact of Network DG Penetration

One of the key drawbacks of the P2/6 approach is that it fails to take into consideration the exact DG penetration level of the examined distribution network. To validate the merit of the proposed approach over the original P2/6 on this point, different penetration scenarios have been evaluated.

In the base case, the DG penetration level of the test system was set at 62% (32×5/259).

Compared with the base case, in this subsection the size of the network existing DGs, which are connected at bus 10 to 14, have been changed to various levels. The examined DG is identical to the base case landfill gas, whose effective capacity according to Table 4-1 is 40 MW.

Fig. 4-8 shows the comparison between the proposed approach and P2/6 when different DG penetration scenarios are evaluated. It could be seen that not only the oversimplified and deterministic P2/6 cannot provide specific locational results for different buses, also its results cannot reflect the penetration level of distributed generation within the examined network. By comparison, the proposed model is able to distinguish between low DG penetration scenarios, which will result in relatively high locational contributions and high penetration situations, which lead to considerably smaller results.

Another key feature of the proposed method is its ability to distinguish DGs located in generation-dominated areas from those located in demand-dominated areas. As the majority of system demand in the 14-bus test system is aggregated at bus 3 and bus 2 while the network-integrated landfill gas generators are connected at low voltage buses from 10 to 14, the lower and upper half of the test system in Fig. 3-12 could be regarded as demand- and generation-dominated respectively.

It could be noticed from Fig. 4-8(a) that when the locational DG is from the generation-dominated area, the resulted contribution value of the examined DG is rather sensitive to the influence of network DG penetration. By contrast, high DG penetration appears to have a limited impact on locational contributions from demand-
dominated area as illustrated in Fig. 4-8(b).

The difference could be explained as for the latter situations the output could be easily consumed by adjacent customers, thus contingencies or congestions on the distribution network have very little impact. In the case of generation-dominated area, the locational DG output needs to be exported to load centres via connecting networks. As a consequence, potential constraints or interruptions happened somewhere on the network might impose a direct impact on the actual DG output.

![Graph](image)

**Figure 4-8** The impact of penetration on DG contributions. (a) Generation-dominated area. (b) Demand-dominated area.
C. Impact of DG Concentration

So far, it has been assumed that the 5 existing DGs in the GSP test area are connected at bus 10 to 14. In this subsection, in order to investigate the impact of concentration on the result, three different DG concentration scenarios have been studied: low-, medium- and high-concentration. To create a lower-than-the-base-case concentration, the same 5 DGs existed in the test system have been distributed to bus 2, 4, 6, 9, and 13, which covers a much wider area of the examined network. While for the high-concentration scenario, the DGs have been concentrated in a relatively small area, located at bus 12 and 13 only.

Firstly, a 50 MW landfill gas, which falls into the category of non-intermittent generation, has been connected to each node, and the contribution evaluation analysis has been conducted and compared by both the original P2/6 and the proposed approach. Fig. 4-9(a) shows the results derived by the P2/6 for bus 3, 6 and 12 specifically. It can be observed that besides the incapability to provide locational results, the existing P2/6 method cannot distinguish between different network DG concentration conditions. In this case, it comes up with an identical contribution value, which is 40 MW, under all three circumstances for the examined locational landfill gas. As a comparison, Fig. 4-9(b) gives the results obtained by the proposed approach. For all three buses shown, a higher concentration clearly imposes a negative impact on the locational contribution seen by the transmission side. At the same time, the influence of concentration tends to be even more significant for locational DGs placed in a generation-dominated area. More precisely, in the case of high concentration, for bus 12, which is closest to a number of network DGs, the locational contribution is less than 10% of the figure specified by the original P2/6.

In addition, the impact of DG concentration on intermittent generators has been assessed in Fig. 4-9(c) and (d). In this case, the locational DG examined has been changed to a wind farm, whose DNC is also 50 MW. However, the key difference is that effective capacity is much smaller, which according to Table 4-2 is only 14 MW. Similar to the non-intermittent generation case, the approach proposed in this paper proves to be superior to the existing P2/6 on intermittent DGs as well. For each bus, the enhanced approach distinguishes between different concentration conditions, and reflects the corresponding variances in results. Also interestingly, the proposed
approach shows that for DGs with the same DNC, the contribution of intermittent ones tends to be less sensitive than its counterparts to the influence of DG concentration, which could be explained by the smaller effective capacities.
D. Impact of Network Loading Level

In this part, the loading level (LL) of every system nodal demand will be both scaled up and down, in order to investigate the impact of network demand level on DG locational contributions and also to make a further between the proposed approach and the original P2/6.

Fig. 4-10 shows the utilization level of each branch under base case. For the high
system loading level, all loads have been scaled up by 20%, while for the low loading level condition they have been scaled down by 20%. Higher local demands tend to drive network branch utilizations higher. Conceivably, for the traditional downward power flows through distribution network circuits, greater utilization will actually be beneficial for the export of locational DGs.

Table 4-6 summarizes the locational contribution results of each bus under different loading levels and penetrations. It can be easily observed that for most locational DG situations, higher loading levels tend to lead to a higher DG contribution results. The reason behind this is that for higher locational demand scenarios, higher DG outputs could be consumed locally, thus avoiding exporting reversely through the distribution network and resulting network congestions. On the other hand, it could also be seen that for locational DG at bus 11, higher loading levels actually leads to a lower contribution values. This could be explained by the specific PTDF sensitivity of that specific bus.

Meanwhile, from the perspective of penetration and location, similar conclusions to the previous cases could be drawn. Compared with the 46% penetration scenario, the results for the 77% penetration condition are significantly lower. As for DG locations, the result again proves that the proposed model can differentiate between demand- and generation-dominated DG scenarios. Although the contribution from demand-dominated area DGs are sensitive to network loading level and DG penetration as given in Table 4-6, the impact is rather limited: for the 50 MW locational landfill gas examined, the results under all conditions are very close to 40 MW, which is its inherent effective capacity. On the other hand, the impact on generation-dominated area DGs is significant.

<table>
<thead>
<tr>
<th>Bus No.</th>
<th>46% Penetration</th>
<th>77% Penetration</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>46% Penetration</td>
<td>77% Penetration</td>
</tr>
<tr>
<td></td>
<td>Low LL</td>
<td>Base case</td>
</tr>
<tr>
<td>1</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>2</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>3</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>4</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>5</td>
<td>40</td>
<td>40</td>
</tr>
</tbody>
</table>
### Chapter Summary

Distribution network states like thermal constraints and contingencies could directly affect the output of DGs, which consequently leads to a discounted contribution received by the transmission side. Yet, concentrating solely on the local generation side, neither SQSS nor P2/6 is able to reflect and discriminate between different characteristics and conditions of the examined distribution network. Meanwhile, assumptions like perfectly reliable distribution circuits with unlimited thermal capacities make those previously derived results unreasonable for transmission-level analysis. All of these defects will become highly consequential especially when the DG penetration reaches thresholds in the foreseeable future.

This chapter has introduced a two-component based approach to identifying the contribution of distributed generators to the national transmission levels. More important, respective understanding and insights on the influences of DG technology and effects of the distribution network especially under different network contexts have been established. Based on the extensive analysis, the following observations can be reached:

<table>
<thead>
<tr>
<th>Branch number</th>
<th>Utilization (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>40</td>
</tr>
<tr>
<td>7</td>
<td>40</td>
</tr>
<tr>
<td>8</td>
<td>20.92</td>
</tr>
<tr>
<td>9</td>
<td>40</td>
</tr>
<tr>
<td>10</td>
<td>15.03</td>
</tr>
<tr>
<td>11</td>
<td>28.63</td>
</tr>
<tr>
<td>12</td>
<td>37.40</td>
</tr>
<tr>
<td>13</td>
<td>24.75</td>
</tr>
<tr>
<td>14</td>
<td>38.39</td>
</tr>
</tbody>
</table>

Figure 4-10 Branch utilization of the test system. (a) Base case. (b) 20% scaled-up case. (c) 20% scaled-down case
1) The enhanced approaches differentiate between different configurations of networks which interconnect the examined DG and its loading centres. For DGs whose output requires higher extent of network use, results show that the interconnection network tends to impose a greater impact, resulting in a much lower contribution to GSP. While for DGs interconnect by meshed networks, the contribution values derived by the proposed approach are rather close to the original P2/6 guidance.

2) As demonstrated in the 14-bus GSP system, for local DGs connected at lower voltage buses, the mismatch between the results obtained by the proposed model and the original P2/6 are more significant. For certain locations, such mismatch could be even higher than 50% of the guidance dictated by P2/6.

3) While DG penetration tends to have a negative impact on the contribution values calculated, the network loading level has a positive effect. Also for DGs at different areas, magnitudes of such influences are different. Compared with the demand-dominated area generators, contributions of DGs located in generation-dominated areas are more sensitive to the influence of penetration and loading level.

4) The degree of DG concentration has an impact on both intermittent and non-intermittent DGs, although non-intermittent ones are more heavily influenced. For high concentration scenarios, the results could be significantly deviated from P2/6 levels, 80% lower than the original value. Again, DGs at demand-dominated areas are less affected by this influencing factor.
Chapter 5. Tracing DG Contribution

With the increasing penetration of distributed generators connecting within regional distribution networks, a clear understanding of the GSP usage allocation among various DG sites becomes imperative. This chapter seeks to answer the question of at a given examined timing point, how much bottom-up power supply at the GSP is being contributed from which individual DG embedded within the distribution network respectively. An approach to tracing individual DG contribution to GSP at a snapshot particularly is introduced, also a case study on a practical GSP network in the UK is presented to demonstrate the application of the proposed model.

5.1 Introduction

One of the key benefits brought about by the integration of DG is its ability to enhance network reliability. The increasing penetration of this small-scaled generation into existing distribution networks will fundamentally change the demand patterns seen at grid supply points which interconnect the national transmission system with each regional distribution network. As a result, the conventional responsibility for GSP to provide supply adequacy and security under network normal and contingent conditions respectively can now be shared by DGs embedded inside the network, and thus contributing to an improved GSP reliability.

Reliability has been one of the most important features of power systems and it has been the responsibility of both DNOs and TSOs to provide customers with adequate and secure power within reasonable economic constraints. For the reliability of conventional generators, the approach of hierarchical level II has been widely applied [18]. It considers both the ability of a generation to satisfy the system demand and the ability of the transmission network to deliver energy to grid supply points. As conventional generators are remotely located and centrally dispatched, the resulted reliability of the composite system could be calculated as a function of the examined generation unit size, type and the availability of the transmission network. By contrast, distributed generators have rather different characteristics such as lack of dispatchability, heavy dependence on ambient environment and the relatively less
reliable while more complex location in networks. Consequently, a methodology for DG reliability evaluation appears to be vital.

As a tool for analysing network cost allocation, the power tracing method has been utilized by various studies [75-78]. Essentially, it attributes the power flow to generators and loads based on the Kirchhoff Current Law [79]. In the new context of high DG penetration, it is of extreme interest from the transmission system’s perspective how much power is coming from specific distribution-connected generators, i.e. how much security supply is contributed from the examined resource to benefit the whole national grid system.

5.2 Determination of Network Thermal Constraint on DG Contribution

When the DG penetration level in a distribution network is sufficiently high, the distribution system could find itself not only able to satisfy the internal demand group, but also capable to export power to other adjacent distribution networks through transmission-level interconnections. As a result, from the perspective of a TSO, a reasonable quantification of such DG contribution should take into account both the loading level of the examined distribution network as well as the impact of the potential amount of DG curtailment, which is consequent upon distribution system thermal constraint. For conventional networks, the system adequacy and security evaluation has been focused on the timing of maximum system demand. Similarly, in this section the analysis of DG contribution to transmission system adequacy has been concentrated on the point of maximum GSP demand, which is of the most interest from the system planning perspective. Hence, the DG contribution to the transmission level could be calculated as

\[ P_{\text{Con}} = \sum P_{DG,n} - D_{\text{Group}} - \sum P_{\text{Curt},l,n} \]  \hspace{1cm} (5-1)

where,

\[ P_{DG,n} = P_{DG,n}^{DNC} \times SF_{DG,n}^{P2/6} \]  \hspace{1cm} (5-2)
In Eq. 5-1 and 5-2, $P_{Cont}$ is the aggregated DG active power contribution to the transmission system; $P_{DG,n}$ is the effective capacity of DG $n$ according to P2/6, which is a product of the declared net capacity of DG $n - P_{DNC}^{DG,n}$ and the P2/6-provided scaling factor for such DG technology $- SF_{DG,n}^{P/6}$; $D_{Group}$ is the group demand level, or in other words the aggregated peak demand of the examined distribution network; $P_{Curt,l,n}$ is the associated amount of output curtailment on DG $n$, which serves to relieve the thermal violation on network component $l$.

### 5.2.1 Computational Process

Mathematically, the aggregated thermal violation incurred DG output curtailment (the $\sum P_{Curt,l,n}$ element) could be calculated through the following steps.

1) **Sensitivity of Component Power Flow to DG Injection**

Since the DG integration might change the condition of system power allocation and flow direction, the power flow and utilization level of each component is directly depending on the situation of network DG connection at the moment.

Specifically, the effect of DG injection $P_{DG,n}$ on the active power flow along component $l$ between nodes $i$ and $j$ could be obtained by

$$
\frac{\partial P_{ij}}{\partial P_{DG,n}} = \frac{\partial P_{ij}}{\partial V_i} \frac{\partial V_i}{\partial P_{DG,n}} + \frac{\partial P_{ij}}{\partial V_j} \frac{\partial V_j}{\partial P_{DG,n}} + \frac{\partial P_{ij}}{\partial \theta_i} \frac{\partial \theta_i}{\partial P_{DG,n}} + \frac{\partial P_{ij}}{\partial \theta_j} \frac{\partial \theta_j}{\partial P_{DG,n}} \quad (5-3)
$$

Where, $P_{ij}$ is the active power flow between points $i$ and $j$; $V_i$, $V_j$, $\theta_i$ and $\theta_j$ are voltage magnitudes of nodes $i, j$ and bus angles of nodes $i, j$.

In (5-3), elements $\frac{\partial P_{ij}}{\partial V_i}$, $\frac{\partial P_{ij}}{\partial V_j}$, $\frac{\partial P_{ij}}{\partial \theta_i}$ and $\frac{\partial P_{ij}}{\partial \theta_j}$ could be derived from circuit power flow equation (5-4)

$$
P_{ij} = V_i^2 G_{ij} - V_i V_j (G_{ij} \cos \theta_j + B_{ij} \sin \theta_j) \quad (5-4)
$$

where $G_{ij}$ and $B_{ij}$ are electrical conductance and susceptance of the between $i$ and $j$.

As for the remaining elements in (5-3), they could be obtained from (5-5) based on the inversed Jacobian matrix.
\[
\begin{bmatrix}
\Delta \theta \\
\Delta V
\end{bmatrix} = [J]^{-1} \begin{bmatrix}
\Delta P \\
\Delta Q
\end{bmatrix}
\] (5-5)

Hence, after a DG with an effective capacity of \( P_{DG, n} \) is connected at bus \( n \), comparing with the original \( P_{ij}^0 \), now the power flow between \( i \) and \( j \) is

\[ P_{ij} = P_{ij}^0 + \Delta P_{ij} \] (5-6)

where,

\[ \Delta P_{ij} = \frac{\partial P_{ij}}{\partial P_{DG,n}} \cdot P_{DG,n} \] (5-7)

2) Identification of the Most Thermally Vulnerable Component

For distribution networks already characterized with high DG penetration, an additional nodal DG connection might lead to a number of circuits being overloaded simultaneously. Meanwhile, it should be noted that a single DG curtailment action to relieve the thermal violation on a specific circuit is very likely to benefit other overloading circuits. As a result, to make sure all the component-overloading issues are fully eliminated while no generators are over constrained, a reasonable reference for the calculation of DG curtailment amount appears to be essential.

In this work, the most seriously overloaded component has been chosen as the reference and measurement to decide how much DG output needs to be curtailed. The utilization of circuit \( l \) between bus \( i \) and bus \( j \) could be calculated as

\[ U_{ij} \% = \frac{P_{lj}}{C_l} \times 100 \% \] (5-8)

Where, \( U\% \) is the utilization level of \( l \) at the moment, \( P_{lj} \) is the active power flow along circuit \( l \), which could be calculated by (5-6) and \( C_l \) is the capacity limit of \( l \).

Accordingly, the most thermally violated component, which is the one that has the highest utilization level among all overloaded components, could be recognized by comparing the result of (5-8) of each overloaded circuit.

3) Calculation of the Amount of DG Curtailment

As mentioned, due to the altered direction of power flow, the introduction of DG, especially in the case of high DG penetration, might cause thermal violation to the
examined distribution system. In other words, when an increasing number of DGs are expected to export and contribute reversely to the transmission level, the network circuits in between the DGs and the GSP, which were originally designed solely to satisfy the end customers, are rather vulnerable to becoming overloaded. For this reason, it is rather apparent and reasonable that these new comers should be responsible for the violation.

The amount of DG curtailment in practice is subject to a series of factors and a number of curtailment approaches have been proposed [69, 72, 80]. Referring to the sensitivity of circuit power flow to nodal injection, the amount of DG output that needs to be curtailed to eliminate the thermal violation of a specific component could be derived. For instance, to relieve the overloaded component \( l \), DG \( n \) needs to curtail its output by

\[
P_{\text{Curt},l,n} = \frac{P_l - C_l}{\partial P_l/\partial P_{DG,n}}
\]

(5-9)

Where, \( C_l \) is the capacity limit of component \( l \); \( \partial P_l/\partial P_{DG,n} \) is the sensitivity of the power flow on \( l \) to the active power injection of DG \( n \), as shown in Fig. 5-1.

![Figure 5-1 Simple two-bus network with DG connected](image)

The total DG curtailment value \( \sum P_{\text{Curt},l,n} \) will be the summation of the curtailed output of all participating DGs in order to eliminate all the overloading condition in the examined distribution system.

Fig. 5-2 illustrates the framework and modeling of the computational process, which has been explained in subsections \( A \), \( B \), and \( C \).
5.2.2 **Network Constraints on A Two-Busbar System**

Firstly, the proposed approach has been applied to the simple two-busbar system as shown in Fig. 5-1. It is assumed that the circuit connecting bus $i$ and $j$ is rated at 10 MW and the declared net DG capacity at the end of the network is 20 MW, supplied by landfill gas.

According to the values provided by P2/6, such DG could have 80% of its capacity as security contribution to the system. Hence, in this case, the element $\sum P_{DG,n}$ in (5-1) is

$$\sum P_{DG,n} = 20 \times 80\% = 16 \text{ (MW)}$$

Table 5-1 compares the DG contribution values as derived from the conventional P2/6 methodology and the approach proposed. The group demand $D_{Group}$ is varied from 2 MW to 10 MW to reflect different loading levels as well as circuit utilization conditions.
Table 5-1 DG contribution to transmission level

<table>
<thead>
<tr>
<th>Group Demand (MW)</th>
<th>Circuit Utilization (%)</th>
<th>DG Contribution By P2/6 (MW)</th>
<th>Constraint-considered DG Contribution (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>100</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>8</td>
<td>80</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>6</td>
<td>60</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>4</td>
<td>40</td>
<td>12</td>
<td>10</td>
</tr>
<tr>
<td>2</td>
<td>20</td>
<td>14</td>
<td>10</td>
</tr>
</tbody>
</table>

For the purpose of concept demonstration, extreme conditions of 100% circuit utilization have been presented and contrasted in this table. As shown in the table, by the original P2/6 approach, the calculated DG contribution to the upper transmission level increases monotonically as the system loading level reduces, completely ignoring the capacity limit of the transmission line. In comparison, by the proposed approach, the thermal limit of the connecting network could be successfully recognized and have been successfully reflected in the final results.

5.2.3 Different Extent-of-Network-Use Situations

In reality, power networks could have different degrees of complexity both vertically and horizontally. More precisely, the configuration of a given distribution network could be radial-, paralleled- or meshed-connected. As a result, questions may arise as to whether the specific distribution network configuration could have an influence on DG transmission-level contribution.

As could be seen in Fig. 5-3, group demand $D_{Group1}$ and $D_{Group2}$ are supported by different types of connecting network. While the former is supported by a single circuit, the latter is supplied by two circuits in parallel, which is horizontally more complex and thus is able to provide a higher degree of security. In this case, it is also assumed that all the circuits are rated as 10 MW, and both DGs are landfill gas generation with a declared capacity of 20 MW.
Similarly, a change in the loading level of either group demand or the utilization level of the circuit would lead to a change in the value of DG transmission-level contribution. And a comparison of the effect of extent-of-network-use on DG contribution value has been shown in Fig. 5-4.

It could be clearly seen from Fig. 5-4 that the extent-of-network-use, or in other words the complexity of the examined distribution network, does have an impact on the final results. Although given the same DG injection and group demand input, these two examined situations make quite different contributions to the upper transmission network.
system, especially when the utilization level of the circuit is low and the DG penetration is relatively high.

This established insight into network thermal constraint’s influence on DG contribution above could then facilitate the contribution power tracing work in the next subsection, integrating with the downstream-looking algorithm and the P2/6 standard.

5.3 DG Contribution Tracing Using Downstream-Looking Algorithm

Downstream-looking power tracing method was firstly introduced by J. Bialek back in 1996 [76]. Back then it was mainly used for assessment of how much of the real and reactive power output from a particular station goes to a particular load, thus provides evaluation of the impact of certain generators and loads on power system under a deregulated and privatized circumstance.

The main principle underpinning this downstream-looking method is proportional sharing assumption, which is illustrated in Fig. 5-5. For a given node $n$ in power system, it links two input branches and two output branches, with power flows being 40, 60, 70 and 30 respectively, as shown in the figure. The proportional sharing principle assumes that each node is a perfect mixer, thus proportionally allocates inflow electrons to outflow paths. According to this assumption, in the case in Fig. 5-5, out of the 70 power flow along $n-c$, $40\% \times 70 = 28$ is from inflow $a-n$ or node $a$, and $60\% \times 70 = 42$ is contributed by inflow $b-n$ or node $b$. Similar conclusions could be drawn on outflow $n-d$. 
With locational DG contribution and network nodal demand information determined for the examined system state, network power flow can be derived, based on the result of which GSP exporting flow could be traced using the downstream-looking algorithm [76].

The nodal through flow for bus $i$ is obtained by aggregating its outflows:

$$P_i = \sum_{j \in \alpha_i} |p_{i,j}| + \text{Load}_i = \sum_{j \in \alpha_i} \left| \frac{p_{i,j}}{P_j} \right| P_j + \text{Load}_i .$$  \hspace{1cm} (5-10)

Where $\alpha_i$ is the set of buses that are receiving power from $i$ and $\text{Load}_i$ is the demand located at $i$. Rearrange, we have:

$$P_i - \sum_{j \in \alpha_i} \left| \frac{p_{i,j}}{P_j} \right| P_j = \text{Load}_i ,$$  \hspace{1cm} (5-11)

which can be represented in the form of matrices:

$$DP = \text{Load} ,$$  \hspace{1cm} (5-12)

where $D$ is the $(n \times n)$ downstream distribution matrix, $P$ is the vector nodal through flows, and $\text{Load}$ is the vector of nodal demands. The $(i,j)$ element of matrix $D$ is:

$$[D]_{i,j} = \begin{cases} 1 & \text{if } i = j \\ -\left| \frac{p_{i,j}}{P_j} \right| & \text{if } j \in \alpha_i \\ 0 & \text{otherwise} \end{cases} .$$  \hspace{1cm} (5-13)

Rearrange (5-12), we have:

$$P = D^{-1} \text{Load} ,$$  \hspace{1cm} (5-14)
the $i$th element of which is:

$$P_i = \sum_{j=1}^{n} [D^{-1}]_{i,j} Load_j .$$  \hspace{1cm} (5-15)

Equation (3-15) shows how the nodal through power at bus $i$ is distributed between all nodal demands across the whole distribution system. Hence, for a DG connected at bus $i$, its aggregate security contribution is:

$$SC_i = \frac{SC}{P_i} P_i = \frac{SC}{P_i} \sum_{j=1}^{n} [D^{-1}]_{i,j} Load_j .$$ \hspace{1cm} (5-16)

If the exporting flow from the GSP to the transmission level is considered as the nodal demand at bus GSP, then the security contribution by the examined DG at $i$ to GSP at the examined moment could be derived:

$$SC_{i\rightarrow GSP} = \frac{SC}{P_i} [D^{-1}]_{i,GSP} EF_{GSP} .$$ \hspace{1cm} (5-17)

Where $EF_{GSP}$ is the exporting power at the GSP, flowing from the distribution side to the transmission side.

The flowchart depicted in Fig. 5-6 shows the framework of the proposed model.
5.4 Demonstration on a Real UK GSP Network

In this section, the proposed DG contribution-tracing model is demonstrated on a practical GSP area taken from the UK distribution network, as shown in Fig. 5-7 [71]. The demonstration network is located in Aberystwyth Wales, which mainly consists of approximately 200km of overhead lines and 20km of underground cables. This test network has two voltage levels: 132 kV and 33 kV, where the GSP point couples the 132 kV distribution side and the 400 kV national grid side. And the half-hourly 33kV
load absorptions and DG outputs are available for the whole year of 2006, and there are 17,520 operating states. The minimum total demand and maximum DG output are 18.8MW and 85.8MW, respectively.

As could be seen from the diagram, in this system there are a few existing intermittent generators connected, including wind farms and a hydro power as depicted in the figure. Thanks to the relatively high penetration of DG compared with its peak demand, the selected GSP network is capable of exporting power upwards to its transmission side.

5.5 Results and Discussions

A. DG contribution to GSP variance with different capacities
Firstly, the security contribution by an additional landfill gas DG to the GSP is investigated, and the impact of its capacity on the final result has been demonstrated. The examined landfill gas generation, whose SF is 80% referring to Table 4-1, has been located at bus 5017 as shown in the diagram. Fig. 5-7 depicts the proportion of contribution to the GSP specifically. It clearly shows that when the integrated generation is larger than 12 MW, the contribution to GSP stops increasing and saturates, which means that higher generation output than this level will lead to network congestion so such additional contributions need to be curtailed. It should be noted that in the original P2/6 such influence of network thermal constraint has not been inherently taken into account.

![Figure 5-7 Contribution with different generation sizes](image)

**B. DG contribution to GSP variance with different locations**

One of the merits of the proposed model is that it is able to differentiate between DGs connected at different locations. In this subsection, the same landfill gas DG has been placed at 4 different nodes in the test system, and respective contribution to GSP has been shown in Fig. 5-8. It is obvious that higher capacities of the integrated generation generally lead to higher GSP contributions for all locations examined.

Bus 5017 and 5005 are located in a generation-dominated area, while bus 5021 and 5023 are in a demand-dominated area in the test network. As shown in the result, for
generation-dominated area DGs, the security contribution to GSP is rather decent even in the case of small injection sizes; whereas for demand-dominated ones, when the injection size is small, there is barely any contribution to GSP. This could be explained as demand-dominated generators have the priority to supply its adjacent loads, thus having little left for the far away GSP.

![Graph showing contribution with different generation locations](image)

Figure 5-8 Contribution with different generation locations

C. **DG contribution to GSP with different network loading levels**

The utilization level of the examined network has a direct impact on the DG contribution received by the GSP. Table 5-2 shows the results under various network utilization circumstances, where the difference between generation- and demand-dominated generators could be identified. For the DG located at bus 5017, which is again in the generation-dominated area, the resulted GSP contribution decreases monotonically with increasing network loading level. By contrast, it appears that for the demand-dominated generation examined, the highest GSP contribution is when network loading level is around 90% of the base case. Fig. 5-9 visually depicts such features distinguished by the proposed approach.

D. **DG contribution to GSP with different penetrations**

Finally, a series of different penetration scenarios have been investigated for three DG technology mix cases. For the same examined landfill gas at bus 5017 as previously, the technology supporting existing DGs in the network have been assigned as all landfill gas, all wind, and a mix of landfill gas and wind. As could be seen from the
results in Table 5-3, DG penetration of the examined network tends to have a positive effect on the derived contribution to GSP, since higher penetration means more local demands could be supported by adjacent resources and more remaining DG outputs could be sent to the GSP. However, there is an apparent difference between the results of non-intermittent and landfill gas and the intermittent wind power. As shown in the last column of the table, due to the low security contributing capability of wind power, even for high penetration scenarios, there is still zero contribution to the GSP.

Table 5-2 DG contribution to GSP at different loading levels

<table>
<thead>
<tr>
<th>Loading level comparing with base case</th>
<th>Bus 5017 (MW)</th>
<th>Bus 5021 (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>50%</td>
<td>7.33</td>
<td>2.65</td>
</tr>
<tr>
<td>60%</td>
<td>7.19</td>
<td>4.95</td>
</tr>
<tr>
<td>70%</td>
<td>6.99</td>
<td>5.94</td>
</tr>
<tr>
<td>80%</td>
<td>6.67</td>
<td>6.46</td>
</tr>
<tr>
<td>90%</td>
<td>6.07</td>
<td>6.61</td>
</tr>
<tr>
<td>100%</td>
<td>5.43</td>
<td>5.60</td>
</tr>
<tr>
<td>110%</td>
<td>4.54</td>
<td>4.57</td>
</tr>
<tr>
<td>120%</td>
<td>3.69</td>
<td>3.61</td>
</tr>
<tr>
<td>130%</td>
<td>2.90</td>
<td>2.75</td>
</tr>
<tr>
<td>140%</td>
<td>2.18</td>
<td>1.99</td>
</tr>
<tr>
<td>150%</td>
<td>1.51</td>
<td>1.34</td>
</tr>
</tbody>
</table>

Table 5-3 DG contribution to GSP at different penetrations

<table>
<thead>
<tr>
<th>DG penetration</th>
<th>Landfill gas (MW)</th>
<th>Landfill gas &amp; Wind (MW)</th>
<th>Wind (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>40%</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>60%</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>80%</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>100%</td>
<td>1.03</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>120%</td>
<td>2.21</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>140%</td>
<td>3.26</td>
<td>0.59</td>
<td>0</td>
</tr>
<tr>
<td>160%</td>
<td>4.1</td>
<td>1.29</td>
<td>0</td>
</tr>
</tbody>
</table>
5.6 Chapter Summary

In the near future, when the DG penetration in distribution networks becomes sufficiently high, such dispersed resources will have the capability to feed power back to transmission systems. From the perspective of transmission system planning, what is of interest and importance is a reliable quantification of such contribution. On the other hand, it is also at this time that the capacity limit of the distribution circuits tends to put a ceiling on the actual export of these distributed generators.

In this chapter, firstly an insight and understanding of the impacts of distribution network’s thermal constraint on DG to GSP contribution has been established, then an approach to evaluating and tracing individual DG security contribution to the grid supply point has been presented. More precisely, the DG contribution tracing model answers the question of how much contribution at GSP point is coming from and thus should be credited to each embedded DG exactly at a specific moment. And extensive demonstrations of the novel model on a practical UK GSP network have been performed in this chapter. Similar to the utilization of power tracing algorithms in the traditional network charging works, the application of downstream-looking approach
in this DG to grid supply point study provides a clear understanding of the usage allocation of transmission level asset among different embedded generation sites.
Chapter 6. Integration of PV to DG Contribution Assessment Framework

The previous chapter have established extensive insight into the contribution to the national transmission system from various DG technologies, especially considering factors of network thermal constraint, network configuration, DG penetration, and concentration. However, a big missing point in both the current industrial methods, P2/6 and SQSS, is that nothing about PV’s contribution to the system has been recognized or quantified. In other words, during the development of SQSS and P2/6, little attention has been paid to PV characterization and their integration to the overall contribution assessment process by either approach.

This chapter aims to establish a connection in between the existing DG contribution look-up table and PV generators. It investigates the link between PV generation and the climatological indicator of sunshine duration. An understanding of to what degree the daily sunshine duration determines the generation output profile is established, and insights into the extent of such impact at differing months of a year are provided. The new finding essentially provides a fresh new perspective on characterizing the uncertainty and variability in PV output.

Based on this correlation identified, a novel two-step hierarchical classification method is also proposed in this work to facilitate PV profiling. A case study on a practical PV plant in Great Britain is presented to demonstrate the application of this method. For each derived group, the degree of variation in PV output at different times and the confident levels of each quantity are assessed. More importantly, based on the classification results, a weather-based PV profiling guideline is created. This will facilitate PV output forecasting on a granular level, thus providing a powerful tool for the ever increasingly challenging system operation and planning.

6.1 Introduction
For over 100 years, the principles behind Britain’s electricity sector had remained largely unchanged. The last decade has seen the beginning of a revolution: it has been grappling with the triple challenges of decarbonization, maintaining security of supply, and affordability to customers. This has triggered a paradigm shift in the way electricity is produced. In the U.K., there is currently over 4GW of solar PV generators. By the end of this decade, another 20GW will be installed on the grid, of which a significant portion will be connected on distribution levels, ranging from low-, high-, and extra high-voltage levels [81].

This will bring unprecedented level of uncertainty and variation to the future planning and operation of the national transmission grid. With small volume, generation connected to the distribution levels looks much like ‘negative demand’ to the power system, thus creating limited impacts that are within normal demand fluctuations. However, as these distributed sources increase in scale, they start to cause significant reverse flows across the distribution and into the transmission system, potentially beyond the design capability of the system and resulting in operational constraints. For instance, when clouds cause shadows to pass across high penetrations of large solar PV installations, additional balancing actions will be required considerably. This has just been recently observed by National Grid, the transmission system operator (TSO) in Britain. It lately saw its load forecasting errors reached almost 4GW, which was largely attributed to the massive installation of such invisible and intermittent resources [82].

The following of this chapter investigates the relation between PV output and daily sunshine duration (SD). Although the fact of being one of the key climatological indicators provides SD with both easy accessibility and broad public understanding, its impact on PV output characteristics has not been fully explored or quantified. To fill this gap, this work seeks to answer the question of to what degree the daily sunshine duration determines the profile of PV daily output, thus proposing a novel perspective over traditional studies on the issue of PV output characterization.

The correlation identified in this work is then extended and implemented to facilitate PV daily output profiling. A two-step hierarchical classification approach is
developed and applied to a practical PV plant in Britain. Based on the results, a PV profiling guideline is finally created, which specifies PV output hourly variation and confident levels. Comparing with conventional approaches to PV profiling which tend to suffer over complexity as higher accuracy is required, the look-up table guideline created here requires neither detailed modelling of each component nor simplifying assumptions, thus achieving a well balance between method complexity and result accuracy.

6.2 PV Output Profiling and Characterization

In recent times, PV output prediction has received considerable attention with most of the research efforts dedicated to forecasting PV chronological profiles based on parametric or nonparametric approaches.

6.2.1 Parametric Models

The parametric approaches fundamentally model each subsystem of PV generation using a collection of parameters. Some of the sub-models include: decomposition model that estimates diffuse and beam components with the global irradiance on a horizontal plane; transposition and shading models that estimate the effective irradiance on the PV generator; PV generator model that estimates power output with the effective irradiance on the generator plane and the ambient temperature as inputs; inverter model that estimates AC power output with DC power as input; wiring and electrical equipment models that interconnect the PV generator and the power grid.

Many studies on PV output modelling in this category, especially for the purpose of system planning, have assumed that PV outputs follow beta distributions, as normally weather factor indices are beta-distributed [83-88]. Alternatively, a number of researchers have modelled the probability of cloudiness based various empirical parametric distribution curves which were derived based on information collected from temperate or tropical areas [89-94].

The solar irradiation on an arbitrarily sloped surface outside the atmosphere can be predicted exactly. Such exact prediction is not possible, however, inside the
atmosphere, mainly due to the irregular presence of clouds. The solar insolation arriving at PV modules mainly consists of two components: the direct and diffuse fraction component [95]. Corresponding to these two components, indices representing global irradiance and diffuse fraction have been created in [96-101] to characterize the stochastic influence of clouds on PV, and each index has a predetermined probability density function.

Meanwhile, increasing effort is currently spent on PV output modelling based on meteorologically forecasted solar irradiance [102-104]. Depending on the forecast horizon different input data and forecasting models are appropriate. Forecasts based on cloud motion vectors from satellite images show a good performance for a temporal range of 30 min to 6 h, while for forecast horizons above 6 h, forecasts based on numerical weather prediction models typically output-perform the satellite based forecasts.

Apparently, the parametric approaches require detailed information about the characteristics and behaviour of each relevant component of the PV generation system. Under the circumstances when such information is unavailable, simplifications and assumptions become inevitable. As a consequence, the accuracy of the results by parametric approaches could be seriously affected.

### 6.2.2 Nonparametric Models

The nonparametric approaches to modelling PV output overcome these disadvantages mentioned above by considering the PV generation system as a black box. As a result, no knowledge of internal characteristics and processes of the system is presumed. Instead, it utilizes historical time series of meteorological variables and PV output measurements collected from the real world.

Many researchers have implemented the method of kernel density estimation to model and predict the chronological output profile of PV generators [105][112]. Particularly in [112], an approach to modelling time sequential PV output has been proposed. In contrast to other types of PV profiling methods, the proposed model captures the
chronology, randomness, and the correlations among PV outputs in adjacent moments.

At the same time, the concept of classification and clustering, which has been widely used in the field of load profiling, has been deployed by [87][106][107]. As the attributes of PV generation units in practice differ with each other, it has been recognized that developing a universal equivalent model to represent all the PV generation units might be impractical. Instead, classification/clustering methods resolve such challenge. By grouping PV output data on the basis of similarity or dissimilarity between individual samples, the items in the same group are as similar as possible while the items in different classes tend to be as dissimilar.

Among studies that utilize the classification method, differing classification criteria have been deployed. In [108], the PV system power output is classified into four types according to weather condition: cloudy, foggy, sunny, and rainy. [109] divides PV output estimation into two parts: low-frequency and high-frequency components, where the high-frequency component is estimated based on the frequency classification of feeder power flow. At the same time since cloud moving presents the most primary influence on PV generation, [110] forms the classification and recognition of different kinds of clouds as the basis of its PV power forecasting method. This work analyses the influence on irradiance under clouds of different shapes and distributions in a sky image, based on which four different classes of clouds are developed.

6.2.3 PV Output Characterization
Comparing with conventional plants and other forms of renewable sources, the uncertain and variable characteristics of PV generation could be summarized as [112][113]:

1) Uncertainty caused by cloud passing: At each moment, the solar radiation received by a PV plant is determined by weather circumstances like cloud passing and wind direction, thus affecting its produced power. Therefore, at each timing point the output level of an examined PV generation is random and uncertain.
2) Random start/end timing points: The daily start and end moment of solar insolation are determined by the moments of sunrise and sunset respectively. As a result, the start/end timing points of a daily PV profile are random and distinguishing at different seasons.

3) Self-correlation on output profile: PV outputs at adjacent times are strongly correlated to each other. The weather condition in the last moment has a direct influence on the weather condition in

4) Time frame for energy production: While wind power can produce output at any time during the day, solar PV has limited time period of power generation depending on the position of the sun. In other words, PV plants export nonzero power during daytime, and produce zero energy during night-time.

The PV generation geographical location and climate have a significant impact on the overall power output variability and uncertainty. Numerous studies have evaluated the correlations between PV output and such influencing factors. A summary of these literatures is given in Table 6-1.

<table>
<thead>
<tr>
<th>Literature</th>
<th>PV output characterization investigated</th>
</tr>
</thead>
<tbody>
<tr>
<td>[100]</td>
<td>Level of PV output uncertainty and variability through multiple sites aggregation</td>
</tr>
<tr>
<td>[107]</td>
<td>Correlation between PV output and weather forecast</td>
</tr>
<tr>
<td>[109]</td>
<td>Correlation between PV output and solar irradiance</td>
</tr>
<tr>
<td>[110]</td>
<td>Correlation in PV generation output changes at timescales ranging from 1 sec to 5 min</td>
</tr>
<tr>
<td>[111]</td>
<td>Correlation of the power output between several PV sites within a system and the impact of geographic diversification</td>
</tr>
</tbody>
</table>

### 6.3 Overall Flowchart of the Classification Method

A two-step classification method is proposed to investigate the characteristics of PV generation output. Firstly, the monitored daily output data is classified into 12
monthly groups, and for each group an averaged profile and the corresponding variation could be derived. Then the daily ‘Sunshine Duration’ is utilized to further classified the output profiles within each monthly group into three clusters. The overall flowchart is summarized in Fig. 6-1, which has two major steps.

Step 1: Monthly classification. The monitored PV daily profiles are firstly classified into different months. The distinguishing seasonal solar irradiance determines not only the height of the output profile curve, also it directly influences the start/end timing point of every day’s PV generation.

Step 2: Classification according to daily ‘Sunshine Duration’. Within each monthly group, the relationship between the shape of daily PV profile and the examined day’s meteorological sunshine duration is characterized. In this study, three groups particularly have been created, representing the situations of low, medium and high sunshine duration.

Figure 6-1 Flowchart of PV output classification
6.4 Example Demonstration

The proposed classification method to investigate PV output characteristics is demonstrated on a PV plant at Cambridgeshire UK, as shown in Fig. 6-2. The parameters of the generation are given in Table 6-2. Half-hourly monitored output data, which covers the period from 01/01/2012 to 31/12/2012, are utilized for this demonstration. Fig. 6-3 depicts the daily maximum output level during the whole year, and the results have been presented in a per unit format.

In this demonstration, the daily sunshine duration information at the studied PV location has been approximated by adopting the archive data collected at Cambridge in the year 2012. A variety of Cambridge meteorological data including sunshine duration, wind direction, wind speed, and humidity has been closely monitored by the Digital Technology Group with the University of Cambridge [114]. Fig. 6-4 shows the daily sunshine duration over the year of 2012 at Cambridge. Noticeably, the season of summer presents higher probability of significantly sunny days.

Table 6-2 Parameters of selected PV generation

<table>
<thead>
<tr>
<th>Capacity</th>
<th>Location</th>
<th>Postcode</th>
<th>Latitude</th>
<th>Longitude</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.76 kW</td>
<td>Newmarket</td>
<td>CB8</td>
<td>52.23°</td>
<td>0.37°</td>
</tr>
</tbody>
</table>

Figure 6-2 Geographical location of the demonstrated PV generation
6.5 Results and Discussions

A. Unclassified Year-round Daily Profiles

The daily PV output profiles over the whole year of 2012 are plotted in Fig. 6-5. From the illustration, the PV energy production variation between daytime and nighttime is distinguishable. For those considerably sunny days, the PV peak output could be as high as 50% of the installed capacity.

Nonetheless, the PV generation characteristics of (1) to (3) listed in section 2.3.3 cannot be reflected. In other words, from a year-round perspective, no clear
conclusions about daily PV output characteristics could be drawn, particularly regarding its diurnal variation, seasonally differing starts/ends, and correlations between adjacent timing points.

![Figure 6-5 Daily PV output over a year](image1)

![Figure 6-6 Monthly average PV profiles](image2)

**B. Monthly Classification**

Firstly, the monthly average PV generation curves are given in Fig. 6-6. Compared with winter months, the monthly curves during summer present both longer periods of daily energy production and higher peak values.

To analyze the seasonal variance of PV output characteristics, Step 1 in Fig. 6-1 is firstly applied, and the year-round PV output profiles in Fig. 6-5 are classified into 12 monthly groups. The results are presented in Fig. 6-7. Like the base case in Fig. 6-5,
these monthly classification results are able to distinguish between characteristics of daytime and nighttime. Meanwhile, the seasonal variance of the daily start-end timing points could be identified from the classified groups. For June and July, the output profile starting point could be as early as 4:00 in the morning, while ends around 20:00 in the evening. By contrast, the winter months present much shorter time frame of energy production every day, with start/end points in December and January being around 8:00 and 16:00 respectively. This could be explained by the significant variation of the length of daylight between summer and winter, particularly at the British Isles (latitude between 50° and 60°).

Although the classified monthly groups shown above are able to characterize the shape of PV output curves horizontally, vertically it does not depict a precise picture of the most probable altitude of PV generation at each moment. Take the month of December as an example, the daily maximum output as shown in Fig. 6-7 ranges from 5% to 30% of the PV capacity. This uncertainty could lead to significant challenges for power system planning and operation. To resolve this, a tool that is able to show the probability and confidence of interval of output level is needed.

In this work, a concept of ‘probability amplitude profile’ (PAP) has been proposed and applied to each classified month in Fig. 6-7. It visually maps and colors the areas where PV output is most likely to occur. The application results are given in Fig. 6-8. In the results, the color bar represents range of probability, where red in this study is assigned as 100% certainty of occurrence and grey means 0% probability of occurrence. Apparently, during nighttime, PV produces no power. Hence, for this frame of each group, a straight line of red could be identified.
In order to assess the diurnal output variation, again, take the month of December as an example. Compared with the information provided in Fig. 6-7, the PAP of December given in Fig. 6-8 illustrates a much clearer picture. It shows although midday output does range from 5\% to as high as 30\%, actually for most of the days the outputs concentrate on the 5\% level, thus this range being heavily colored; and in contrast, the area near 30\% are almost plainly grey, thus presenting a significantly low probability of happening. In other words, instead of planning and operating the system based on the huge uncertainty ranging from 5\% to 30\%, the result given here is able to provide a much narrower interval which should be focused on with great confidence.
C. Sunshine Duration Classification

One of the drawbacks identifiable from the monthly classification results above is that for some months the PAP cannot give a single mostly likely output interval. According to the PAP of March, it could be found that both 5% and 45% per unit outputs level are highly likely to occur at middays. In other words, it is not able to accurately reflect and quantify the uncertainty caused by cloud passing.

To tackle this problem, a further classification based on ‘sunshine duration’ is performed for each month. Due to the limited space here, the classification results of March specifically are presented here. Fig. 6-9 shows according to the sunshine duration of each examined day, the daily PV profiles are classified into three groups.
And in this work, 50% of the monthly maximum sunshine duration (12h) has been adopted as a criterion, which is 50% × 12h = 6h. The detailed classification criteria and results are provided in Table 6-3.

<table>
<thead>
<tr>
<th>Group number</th>
<th>Daily solar insolation</th>
<th>Daily sunshine duration (hours)</th>
<th>No. of days</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Low</td>
<td>0-1</td>
<td>9</td>
</tr>
<tr>
<td>2</td>
<td>Medium</td>
<td>1-6</td>
<td>11</td>
</tr>
<tr>
<td>3</td>
<td>High</td>
<td>&gt;6</td>
<td>11</td>
</tr>
</tbody>
</table>

Table 6-3 Sunshine duration classification results

Figure 6-9 Sunshine duration classification of March

Compared with the figure in Fig. 6-8, it could be seen that the results presented in Fig. 6-9 distinguish between ‘sunny’ and ‘cloudy’ days. Also, as illustrated in the PAPs of group 1 and 3, much more consistent confidence intervals have been achieved for the low and high daily solar insolation conditions respectively. As an application to
system operation, in this case, if the sunshine duration for the next day is predicted to be over 6h or less than 1h, the corresponding PV output profiles respectively could be predicted with a good confidence.

**D. Hourly Output Prediction by the Proposed Hierarchical Classification**

To further verify the results achieved by the proposed hierarchical classification method, the results are compared and contrasted with typical monthly classifications. Three test points are selected to fully assess the practicality of the proposed approach: one in the morning, one around midday when the PV output tends to be the highest, and the other in the afternoon. Fig. 6-10 to Fig. 6-12 show the results of 9:00, 13:00 and 15:00 respectively. Comparisons of both probability density and cumulative probability distribution for each examined hour are presented. The detailed mean and deviation values of both classification methods are shown in Table 6-4.

For first row of each figure shows the result when only using the monthly classification. Take 9:00 as an example. It could be noticed from the output probability density histogram, all the output intervals have almost equal probabilities, thus making it impossible to come up with a single confident prediction. As for cumulative probability density, the curves provide no practical information. By contrast, the results achieved by the proposed hierarchical classification (HC) generate a PV output prediction with high confidence. For the hour of 9:00, given the forecasted daily sunshine duration, it could be confidently predicted that the actual output factor is around 5% or 12%. Or referring to the cumulative probability, it could be concluded that if the sunshine during for the examined day is over 6 hours, there is 90% probability in the actual generation factor being between 10% and 12%, and next to 0% possibility of it being below 8%. Sadly, all the information above could not be derived by the simple monthly classification results given in the first row.
Figure 6-10 March 9:00 hourly output probability density
Figure 6-11 March 13:00 hourly output probability density
Figure 6-12 March **15:00** hourly output probability density

Table 6-4 Mean and standard deviation of both classification methods

<table>
<thead>
<tr>
<th></th>
<th>9:00</th>
<th>13:00</th>
<th>15:00</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Mean</td>
<td>Dev.</td>
<td>Mean</td>
</tr>
<tr>
<td>Monthly</td>
<td>7.59%</td>
<td>0.0353</td>
<td>23.83%</td>
</tr>
<tr>
<td>Group1 (HC)</td>
<td>4.16%</td>
<td>0.0236</td>
<td>5.42%</td>
</tr>
<tr>
<td>Group3 (HC)</td>
<td>10.67%</td>
<td>0.0109</td>
<td>40.23%</td>
</tr>
</tbody>
</table>

6.6 **Application: A Weather-Based Guideline on PV Profiling**

The link discovered between PV daily output profile and daily sunshine duration could be used to facilitate and guide future system planning/operation. It could be seen from the previous section that under on clear and cloudy days, PV output
profiling based on the hierarchical classification tends to produce a very desirable result. More importantly, instead of applying rather complex forecasting models and making simplifying assumptions, all needed by this guideline approach is accessible from commonly available weather information, thus achieving a round balance between complexity and accuracy.

As an example of using this identified relationship to guide PV forecasting and system operation/planning, two look-up tables are provided in Table 6-5 and 6-6. Due to the limited space here, only the results for the month of March are given here. As shown, Table 6-5 and 6-6 represent the conditions of clear and cloudy days respectively, which in this work correspond to days with high and low sunshine hours. Noticeably, for both situations, the look-up table guidance provides granular PV output forecast, i.e. the possible output levels at the examined hour as well as the confident level of such prediction.

Take 10:00 in a given day D in the month of March for example. If the weather forecast information indicates day D will be a clear day, then we can have 80%+ confidence in saying that the PV output level at 10:00 will be between 20% to 25% p.u. By contrast, if D is to be cloudy, according to the look-up table guidance provided, there might be a 75% possibility that the PV output at 10:00 would be no more than 7% p.u.

Table 6-5 PV output confidence levels in cloudy days

<table>
<thead>
<tr>
<th>Confidence level (%)</th>
<th>&lt;0.01</th>
<th>0.01-0.02</th>
<th>0.02-0.03</th>
<th>0.03-0.04</th>
<th>0.04-0.05</th>
<th>0.05-0.06</th>
<th>0.06-0.07</th>
<th>0.07-0.08</th>
<th>0.08-0.09</th>
<th>0.09-0.10</th>
<th>&gt;0.10</th>
</tr>
</thead>
<tbody>
<tr>
<td>7:00</td>
<td>0</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
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<td>14:00</td>
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<td>12.5</td>
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</tr>
</tbody>
</table>
Table 6-6 PV output confidence levels in clear days

<table>
<thead>
<tr>
<th>Confidence level (%)</th>
<th>PV output intervals (p.u.)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>&lt;0.05</td>
</tr>
<tr>
<td>7:00</td>
<td>100</td>
</tr>
<tr>
<td>8:00</td>
<td>66.7</td>
</tr>
<tr>
<td>9:00</td>
<td>0</td>
</tr>
<tr>
<td>10:00</td>
<td>0</td>
</tr>
<tr>
<td>11:00</td>
<td>0</td>
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<td>12:00</td>
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<td>15:00</td>
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<tr>
<td>16:00</td>
<td>0</td>
</tr>
<tr>
<td>17:00</td>
<td>8.3</td>
</tr>
</tbody>
</table>

6.7 Chapter Summary

This chapter presents a number of new findings on PV characterization and profiling:

- For the first time, the impact of daily sunshine duration on PV output profile is quantified. A probability amplitude profile tool is developed to visualize the degree of variation in PV outputs across differing seasons, and a novel two-step classification method is developed and implemented on a practical PV plant. The results show that the indicator of daily sunshine duration has a significant influence on the shape of PV daily output. This effect appears to be the most obvious for especially clear and cloudy days, and under these conditions PV daily outputs almost perfectly follow a fixed profile.

- Based on the strong correlation identified, a guideline approach to facilitating PV hourly output forecasting is proposed in this work. Two look-up tables applying to cloudy and clear days respectively for the month of March specifically is presented in this work, from which easy-to-use PV hourly output prediction could be reached.

The PV generation profile classification method developed in this work only generates valuable information under the situations of low and high sunshine duration.
However, the magnitudes of output profiles and their probabilities of occurrence when it is medium sunshine duration need to be known. A further PV generation profile magnitude and variation identification based on clustering method will be discussed in the future work.
Chapter 7. Commercial Arrangements to Unlock DG Contributions

Recognizing the asset value of distributed generators to the transmission system particularly, the previous chapters have developed and demonstrated a couple of novel approaches to evaluating and quantifying the incurred benefits of such dispersed assets. It has been widely acknowledged that appropriate and efficient commercial and market arrangements within the electricity sector could hugely facilitate and capitalize the asset attributes of various dispersed energy recourses [115-118].

Earning a fixed rate of return on invested capital, distributed network operators’ (DNOs) has been largely determined by the amount of money spent on network investment each year. Under this business model, DNOs would extravagantly invest in the network to meet the load growth, assuming all load requires the same level of high reliability. A substantial amount of capacities is designed to support the temporary system peak while maintaining underutilised over the majority time of a year. More critically, this current DNO business model does not conform with flexible resources increasingly connected to the edge of the system.

This chapter looks at commercial mechanisms to incentivize and better utilize DG assets. It firstly benchmarks the current DNO business models across three EU countries. Aiming to overcome some of the major drawbacks inherent in the current business models, it then proposes an innovative DNO business model to further facilitate the connection differing distributed energy resources and flexible demands within a new electricity context. Finally, it introduced a new local energy market concept, which better leverage the specific characteristics of DGs and further ensure the capture of such values.

7.1 Benchmarking of Current DNO Business Models

DSOs’ current business models are to recover network operation and investment costs through the Use of System and connection charges. There are wide differences in
charging methodologies between countries with varying degree of sophistication. However, the underlying network investment principle is the same – network investment is the main option for meeting peak demand, very little has been done to mobilize third party service providers to support more efficient network development. Current business models thus cannot provide adequate incentives for DSOs to move towards smarter energy grid and guarantee they can survive in the energy revolution.

Therefore, it is essential to summarize and compare the features of DSO business models across different states, in an effort to address the gaps and improve respective network performances. The following criteria have been set up to facilitate the business model benchmarking process in this section:

- Overall summary of DSO markets, such as market sizes and structures
- Regulations of DSOs, such as the revenue limit and penalties
- Business model performance, including asset ownership structure, business unbundling, revenue evaluation, revenue recovery and revenue adjustment
- Incentives of innovations

### 7.1.1 Current DSOs across GB, Spain and Finland

At the time of privatisation of the electricity industry there were fourteen Public Electricity Suppliers (PESs) in the UK who replaced the old area and Scottish electricity boards. Today, while distribution has been separated altogether from supply, the former PES areas are used as the basis of current distribution areas.

In Britain, distribution remains a monopoly business and under the Utilities Act and it is now a licensed activity, and regulated by Ofgem [119]. Whilst this applies throughout the UK, the structure in England and Wales is different than it is in Scotland. In England and Wales, as at 2015, there are six distribution companies operating twelve licensed distribution areas. While, in Scotland distribution is operated by two vertically integrated energy companies who, in addition to operating their respective distribution businesses, are also responsible for generation and transmission functions throughout the Scotland area.
More particularly, there are six licensed DNOs in the UK and responsible for a total of 14 regional distribution service areas [120]. The six existing DNOs are:

- Electricity North West Limited;
- Northern Powergrid;
- Scottish and Southern Energy;
- ScottishPower Energy Networks;
- UK Power Networks;
- Western Power Distribution.

There are also 8 licensed independent distribution network operators (IDNO) in the UK. They own and operate smaller networks located within the areas covered by the DNOs, i.e. the ‘last mile’ of the network with less than 100,000 customers. IDNO
networks are mainly extensions to the DNO networks serving new housing and commercial developments. The eight licensed IDNOs currently in the UK are [121]:

- Energetics Electricity Limited;
- ESP Electricity Limited;
- Harlaxton Energy Network Limited;
- Independent Power Networks Limited;
- Peel Electricity Network Limited;
- The Electricity Network Company Limited;
- Utility Assets Limited;
- UK Power Distribution Limited.

The eight IDNO listed above are regulated in the same way as DNOs and altogether they charge customers at a level broadly consistent with the DNO equivalent charge [121]. The size of distribution area is shown in Fig. 7-1 and Table 7-1 [122]:

<table>
<thead>
<tr>
<th>No.</th>
<th>Electricity DNO groups</th>
<th>Electricity DNO area</th>
<th>Households (million)</th>
<th>% of total households</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Scottish and Southern Power Distribution</td>
<td>North Scotland</td>
<td>0.7</td>
<td>3%</td>
</tr>
<tr>
<td>2</td>
<td>SP energy Networks</td>
<td>South Scotland</td>
<td>1.8</td>
<td>7%</td>
</tr>
<tr>
<td>3</td>
<td>Northern Powergrid</td>
<td>North East England</td>
<td>1.5</td>
<td>5%</td>
</tr>
<tr>
<td>4</td>
<td>Electricity North West</td>
<td>North West</td>
<td>2.2</td>
<td>8%</td>
</tr>
<tr>
<td>5</td>
<td>Northern Powergrid</td>
<td>Yorkshire</td>
<td>2.1</td>
<td>8%</td>
</tr>
<tr>
<td>6</td>
<td>SP energy Networks</td>
<td>Merseyside and N Wales¹</td>
<td>1.4</td>
<td>5%</td>
</tr>
<tr>
<td>7</td>
<td>Western Power Distribution</td>
<td>East Midlands</td>
<td>2.4</td>
<td>9%</td>
</tr>
<tr>
<td>8</td>
<td>Western Power Distribution</td>
<td>West Midlands</td>
<td>2.2</td>
<td>8%</td>
</tr>
<tr>
<td>9</td>
<td>UK Power Networks</td>
<td>Eastern England</td>
<td>3.3</td>
<td>12%</td>
</tr>
<tr>
<td>10</td>
<td>Western Power Distribution</td>
<td>South Wales</td>
<td>1.0</td>
<td>4%</td>
</tr>
<tr>
<td>11</td>
<td>Scottish and Southern Power Distribution</td>
<td>Southern England</td>
<td>2.8</td>
<td>10%</td>
</tr>
</tbody>
</table>

¹ Merseyside and North Wales refers to an area that includes Liverpool, Cheshire and North Wales. It is called ‘Manweb’ by Scottish Power.
<table>
<thead>
<tr>
<th></th>
<th>UK Power Networks</th>
<th>London</th>
<th>2.1</th>
<th>8%</th>
</tr>
</thead>
<tbody>
<tr>
<td>13</td>
<td>UK Power Networks</td>
<td>South East England</td>
<td>2.1</td>
<td>8%</td>
</tr>
<tr>
<td>14</td>
<td>Western Power Distribution</td>
<td>South West England</td>
<td>1.4</td>
<td>5%</td>
</tr>
<tr>
<td>Total</td>
<td>--</td>
<td>--</td>
<td>27.0</td>
<td>100%</td>
</tr>
</tbody>
</table>

In Spain, there are 336 DSOs. However, the market structure is rather consolidated. The five biggest distribution companies distribute 80% of the total energy. The rest are small firms with less than 100,000 customers, who develop their activities in the historic areas where they were established. The distribution areas covered by the large DSOs in Spain vary from large areas like Andalucía (almost all the south of Spain) to small cities like Ceuta or Melilla (isolated systems both placed in the north of Africa). Conceivably, compared with those large counterparts, the size of the areas covered by the rest of DSOs are much smaller.

In Finland, there are 80 DSOs and 12 high voltage distribution networks (HVDNs). There is also one DSO operating a closed distribution network (Kilpilahden Sähkönsiirto Oy) for an industrial centre. Typically, in contrast to the corporative structures of DSOs in the UK and Spain, DSOs in Finland are usually small and publicly owned with less than 10,000 customers. The DSO distribution situation of different countries is summarized in Table 7-2.

For a horizontal comparison across the DSO sectors in the examined three countries, Fig. 7-2 depicts the number of current registered DSOs in GB, Spain, and Finland respectively, from which rather diverse characteristics of the electricity distribution sector of these three countries could be seen. While the six licenced DNO groups own and operate different areas on similar scales across the whole country geographically, the five largest distribution corporations in Spain dominate 80% of the market, with over 300 small DSOs sharing for the rest 20%. Among these three countries, Finland is the country with the mostly evenly distributed DSO responsibilities. Although the size of a typical Finnish is relatively small comparing with the other counterparts, the distribution business nationally is being shared by 80 of them, far more distributed comparing with UK but less large-participant-dominated than Spain.
Table 7-2 Comparison of DSO sizes in three countries

<table>
<thead>
<tr>
<th></th>
<th>GB</th>
<th>Spain</th>
<th>Finland</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Distribution size</strong></td>
<td>14 DSOs within 6 groups and 7 small IDSOs</td>
<td>336 DSO</td>
<td>80 DSOs and 12 HVDN</td>
</tr>
<tr>
<td><strong>Distribution share</strong></td>
<td>6 network operators own 14 distribution regions separately. Share ranges from 3% to 12%. 7 IDNOs’ distribution share is minor</td>
<td>5 distribution companies shared 80% of the total energy. The rest are small, less than 100,000 customers</td>
<td>Typically small and publicly owned with less than 10,000 customers</td>
</tr>
</tbody>
</table>

Figure 7-2 Number of DSOs across the examined countries

7.1.2 DSO Business Regulations Across Examined Countries

Regulations and price control are necessary as DSO businesses are natural monopolies and there is no realistic way of introducing competition across the whole sector. Two frameworks in particular are of central importance in influencing outcomes: economic regulation and industry codes and standards, which regulate connection, charging and network planning. Particularly, in the GB market, DNOs’ operations are regulated under the distribution licence by Ofgem, under which distribution network operating companies’ income is generated subject to a price cap regulatory framework that provides economic incentives to minimise operating, capital and financial costs. Table 7-3 compares the regulations of DSOs in three countries.
Table 7-3 Regulation comparison of DSO in three countries

<table>
<thead>
<tr>
<th>Responsibility</th>
<th>GB</th>
<th>Spain</th>
<th>Finland</th>
</tr>
</thead>
<tbody>
<tr>
<td>Distribution network operators are under a duty to:</td>
<td>Operate network assets effectively to ‘keep the lights on’;</td>
<td>Provide technical expertise and the availability of the network to meet the customers’ peak demand with the quality and security of supply and at a reasonable cost.</td>
<td>Finnish legislation decrees three major obligations for electricity system operators: 1) obligation to develop the electricity network 2)obligation to connect 3)obligation to transmit electricity [124].</td>
</tr>
<tr>
<td>1)</td>
<td>2)</td>
<td>Responsible for the operation, maintenance and, if applicable, the development of the distribution network.</td>
<td></td>
</tr>
<tr>
<td>3) Fix damaged and faulty assets;</td>
<td>4) Upgrade existing networks or build new ones to provide additional electrical supplies [123].</td>
<td>Provide data from their meters to the correspondent retailers.</td>
<td></td>
</tr>
<tr>
<td>Unbundling</td>
<td>Network operation is legally unbundled from generators and retailers. The network company ownership may share with generators, retailers and transmission operator, such as Scottish and Southern Power Distribution and Scottish Power Energy Networks.</td>
<td>Network operation is legally unbundled from generators and retailers. The network company ownership may share with generators and retailers.</td>
<td>Network operation is legally unbundled from generators and retailers. The network company ownership may share with generators and retailers.</td>
</tr>
<tr>
<td>DSO Revenue Stream</td>
<td>Use of Network charges and Connection charges</td>
<td></td>
<td></td>
</tr>
<tr>
<td>DSO Revenue Allowance</td>
<td>Earn fixed rate of return from capital and operational expenditure. The current rate of return is 5.6% and incentives or penalties from RIIO model [125].</td>
<td>Regulated profit since there is maximum limit in the annual remunerated investment and also a cap in the total revenue.</td>
<td>The Finnish Energy Authority calculates and notifies the DSOs every year of the reasonable rate of returns. On average, the DSOs’ profit is about 8% [126].</td>
</tr>
<tr>
<td>Revenue Check</td>
<td>Under RIIO-ED1, revenue check will be made by the regulator for each regulator year in respect of the licensee’s network business</td>
<td>The government had inherited a massive imbalance between the regulated costs and revenues of the electricity system. This imbalance had been accumulating since 2001, began to spiral out of control after 2005 [127].</td>
<td>Checked by the Energy Authority at the end of the regulatory period. Through lower network charges or allows the network prices to be raised with the appropriate amount [128].</td>
</tr>
<tr>
<td>Revenue Adjustment</td>
<td>The annual adjustment of the next year to the licensee’s base revenues</td>
<td>The electricity market conducts a comprehensive reform by mid-2015 to</td>
<td>Through lower network charges or allows the network</td>
</tr>
</tbody>
</table>
will be calculated based on the updated variable values. New revenue = old revenue + modified value

reached aims: the sector’s costs and revenues are back in balance, and the accumulated deficit, which peaked at the end of 2013 at EUR 29 billion or 3% of GDP, should gradually disappear over the next 15 years [129].

prices to be raised with the appropriate amount [130].

| Innovation incentives | There was incentives for connecting distributed generation prior to 2015, at 1£/MW, this has ceased to exist. Other incentives, such as RIIO-ED1 model, emerging from 2015, to reward network operators for innovations. [131, 132] | Strong financial Incentives were implemented to support the development of renewables and are reflected in the grid component of the tariffs. Economic incentives (€120 million per year) for investments in more energy-efficient technologies have been implemented with the NEEAP. | An innovation incentive in force for the DSOs to create innovative technical and functional solutions to their network operations [128] |

| Penalty | DSOs incur penalties when the security of supply standard is breached, i.e. if there are customer interruption, customer minutes loss and worse affected customers in their distribution areas [133]. | The breach of the quality of supply for individual customers, oblige the DSOs to compensate customers, through a discount in their electricity bill, limited to a 10% of the annual amount of those bills. If the Regulator decides, when investigating an incident or blackout, that the DSO has not comply with any of its obligations, it could also be fined with amounts of up to €9 Million | Penalty is applied mainly for power outage and disruption. DSOs pay penalty through the reduction in the bills of the customers who are affected by the outage or disruption [126]. |

7.1.3 Business Model Analysis

A. Asset Ownership Structure

In the EU countries, all DSOs operate the grid, but they do not always at the same time own it (network operators might e.g. also hold concession contracts with municipalities or leasing contracts with an asset manager). Britain and Spain have rigid system where the DSOs both operate and own the distribution network asset.

By comparison, the ownership of network assets in Finland is more flexible. The electricity system operators usually have the economic ownership of the assets, but there are some companies operating with leased network assets. At the end of 2013
there were seven DSOs operating over a distribution network leased from their parent company. There are also cases where only parts of the network assets are leased [130].

B. Business Structure

In the EU countries, according to Directive 2009/72/EC, DSOs are required of legal unbundling, which means DSOs are demanded legal, functional and operational (staff) separation from other actors in the supply chain, such as generators, retailers. In Directive 2009/72/EC, it says “Where the DSO is part of a vertically integrated undertaking, it shall be independent in terms of its organization and decision making from the other activities not related to distribution”. However, the requirement does not create “an obligation to separate ownership of assets of the DSO from the vertically integrated undertaking.” Member States should also monitor the activities of vertically integrated undertakings in order to prevent the distortion of competition. In particular, vertically integrated DSOs “shall not, in their communication and branding, create confusion in respect of the separate identity of the supply branch of the vertically integrated undertaking.” Member States may, however, decide not to apply this rule to integrated electricity undertakings serving less than 100,000 connected customers.

Therefore, in the studied three countries, the DSOs are legally unbundled from generation plants and retailers. In particular, in Finland, the network operations must be legally unbundled if the annual transmitted quantity through the operators 0.4 kV distribution network has been 200 GWh or more for three consecutive calendar years [126, 134].

In Great Britain, two DSOs, Scottish and Southern Power Distribution and Scottish Power Energy Networks (SP Energy Networks), share the ownership with generator, retailer and transmission network operator. In Spain, the 5 DSOs with largest market share have the same ownership with the 5 largest generation company [135]. In Finland, most of the legally unbundled DSOs still belong to the same group of companies as electricity retailers and/or generators. For example, a generator or a retailer is the parent company of the legally unbundled DSO, or a group of DSOs can own an electricity retailer.
C. Revenue Evaluation and Regulation

1) Expenditure Analysis

The business expenditure of DSOs across the three examined countries are all regulated. The total expenditure (totex) of typical distribution network operations’ businesses consists of two components: operating expenditure (opex) and capital expenditure (capex) which is the network investment determined by the most critical peak demand. An understanding of the comparative scales of opex and capex of DNO businesses could be established referring to the Electricity Distribution Annual Report by Ofgem [136].

Fig. 7-3 illustrates the breakdown of expenditure for each DSO during 2010-2011 and compares the difference between capex which is defined as the sum of network operating cost (NOC), closely associated indirects (CAI), business support costs, and non-op capex. It could be seen that on average across all the DNOs in the UK, capex accounts for around 40% of the total expenditure, whereas the remaining 60% is actually attributed to opex.

Table 7-4 lists various categories of DSO’s business costs [137], and the planned expenditure for the period between 2015 and 2023 of the six DNOs in GB is summarized in Fig. 7-4.

![Figure 7-3 UK DSO expenditure breakdown across regions [136]](image-url)
Table 7-4 Various types of DSO business costs [137]

<table>
<thead>
<tr>
<th>Type of business expenditure</th>
<th>Expenditure content</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load related investment</td>
<td>Network reinforcement costs</td>
</tr>
<tr>
<td>Non-load related investment</td>
<td>Asset replacing and refurbishing costs, expenditures associated with improving safety, reducing environmental impact and making improvements to network performance</td>
</tr>
<tr>
<td>Network operating costs</td>
<td>Expenditure on inspection and maintenance, responding to and repairing faults, and other network operating costs</td>
</tr>
<tr>
<td>Closely associated indirects</td>
<td>Costs of managing projects, control centres, contact centres, stores and other activities related to delivering work programmes</td>
</tr>
<tr>
<td>Businesses support costs</td>
<td>Corporate activity costs such as human resources and finance</td>
</tr>
<tr>
<td>Vehicles, IT, property and small tools</td>
<td>Expenditure on non-operational items</td>
</tr>
<tr>
<td>Non price control costs</td>
<td>Expenditure on network related work that is not funded through DUoS, which includes fully funded diversions and service alterations.</td>
</tr>
<tr>
<td>Non activity based costs</td>
<td>DSO uncontrollable costs, including transmission exit charges, business rates and licence fees</td>
</tr>
<tr>
<td>Special considerations</td>
<td>Expenditure forecast influencing factors such as real price effects and efficiency assumptions</td>
</tr>
</tbody>
</table>

In Spain, there is also a maximum cap on the annual remunerated investment by DSOs. The Network Reference Model minimizes the costs of DSO business investment, operation and maintenance, while ensuring satisfying the supply quality requirements established by regulations. In Finland, the authority notifies the DSOs regarding the implementation of sufficient investment level. According to Gulich (2010), the markets are still forming in Finland in many areas/levels of the emerging smart grid and different markets are attracting different levels of investment.

2) Revenue Recovery Methods

In the UK, the DSOs charge use of system and connection charges from network users, predominantly retailers and sizable generators. Also known as DUoS,
former is the charge levied to suppliers for distribution network’s costs which can be recovered from customers. Instead of being determined by market forces, the amount of DUoS that can be recovered by the monopolistic network operators is specified by regulatory price control reviews.

![Figure 7-4 Planned expenditure by GB DNOs over 2015 to 2023 [138]](image)

The latter, the connection charge, usually occurs when customers require an electricity supply to domestic or business premises or wish to export the power from an embedded generator. More specifically, the connection charge has two main types: controlled and uncontrolled. When the customer funds the required network assets, these assets are installed exclusively for the asset owner, with the customer being the sole user. Under such circumstances, the incurred connection charges are out of regulatory price control. By comparison, when the customer and DSO fund the required network asset altogether, the charges become under the price control process. This usually happens when it is to increase the capacity of existing network components to enable new customer connections while maintaining original network security.

Hence both DUoS and connection charges are eventually recovered from network users and accounts for around 16% of electricity bills paid by end consumers. The use of network charge is based on the peak demand for EHV connected customers and they are subsequently used to develop time periods. The DSOs earn profit with
specific rate of return from capital and operational expenditure. The current rate of return in the UK is 5.6%.

In Spain, there is also a cap on the total revenue which could be earned by Spanish DSOs. The payments for distribution network activities are considered as a regulated cost of the System and so, it is recovered through access tariffs included in the electricity bills of the customers through use of system charge and connection charge.

In Finland, the Finnish Energy Authority calculates and notifies the DSOs every year of the reasonable rate of returns and realised adjusted profit from network operations. The network pricing is under ex-ante regulation in Finland as required by the Electricity Directive (Energy Authority 2014). On average, the DSOs’ profit margin is kept around 8%.

3) Revenue Regulation
In the UK, the revenue and expenditure made by DSOs are currently regulated by the RIIO-ED1 [139] price control arrangement, which is developed by Ofgem as a new performance based model for setting the price controls for distribution network operators from April 2015 to 2023. According to the regulated authorities, the aim of replacing the previous price control DPCR5 with RIIO is to facilitate improved strategic planning and long-term approach to electricity distribution infrastructure management across all GB DNOs. Under the circumstance of this new arrangement, the DNO companies in Britain will face unprecedented challenges of securing substantial investment to satisfy network reliability and security, while coping with the dramatically changed characterises of demand and supply such as heat pumps, electric vehicles, solar PVs and wind generators in the upcoming future.

More specifically, the RIIO arrangement is expressed as

\[ \text{Revenue} = \text{Incentives} + \text{Innovation} + \text{Outputs}. \]

a) Incentives
The incentives part of the new RIIO price control regime consists of the following aspects:
• Safety incentives: the incentives that drive compliance with health and safety law.
• Reliability incentives: the incentives that drive improvements to network reliability.
• Environmental incentives: the incentives that will contribute to network losses reduction and lower carbon footprints.
• Connection incentives: the incentives that drive an improvement to the service for customers connecting to the network.
• Customer satisfaction incentives: the incentives that contribute to enhanced customer satisfaction.
• Social obligation incentives: the mechanisms that will be used to reward improvements in the services provided for vulnerable customers.
• Innovation incentives: the additional allowances that are available through a competitive process to fund projects that generate new solutions to management the transition to a low carbon economy.
• Efficiency incentives: the mechanisms that drive DSOs to be more efficient.

b) Innovations

The innovations strategy of each DNO in GB is assessed by Ofgem based on the following criteria:

• How effectively the previous price control arrangement (DPCR5) innovation funding, such as Low Carbon Network Fund, has been used, and how it has been applied to generate improved outcomes for customers;
• The expected high-level challenges in the near future, and the justification of initiating projects to address these challenges;
• The consequences of innovations not occurring;
• Identification and justification of potential challenges in consultation with stakeholders;
• Discussion of relative priorities, risks, benefits, value for money and potential customer impacts;
• Deliverables and potential deliverables from the research or development or trials, such as defined learning on an issue, revised codes, new charging methodologies etc;
• A description of the business’s processes for reviewing and updating their innovation strategies within the price control period;
• A description of the business’s approach to ensuring the efficient roll-out of successful innovation into business as usual.

More particularly, under the RIIO arrangement, all licenced network operators have submitted their respective future business plans as required by Ofgem. As an example, the innovation strategy section submitted by Western Power Distribution is given below in Fig. 7-5.

Figure 7-5 Innovation strategy by Western Power Distribution [137]

c) Outputs
The outputs of distribution network operators are delivered as a consequence of their respective investment programmes, network management decisions and customer engagement initiatives. More particularly, the output part in the RIIO control regime is defined from the following six aspects:
• Safety outputs: the outputs related to compliance with the legislative and regulatory framework regulated by the Health and Safety Executive (HSE);
• Reliability outputs: the outputs that will be achieved in relation to network performance and the service provided when faults occur;
- Environmental outputs: the outputs that will be achieved in relation to economically facilitating the growth of low carbon technologies connecting to the network and reducing DNO’s carbon footprint;
- Connection outputs: the actions that enhance services for customers connecting to the distribution network;
- Customer satisfaction outputs: the actions that improve customer satisfaction and engagements;
- Social obligation outputs: the new and enhanced services that provide benefits for vulnerable customers and those who are fuel poor.

Figure 7-6 Planned expenditure/cost of UK DSOs over 2015-2023 [137, 140-154]

Under the new RIIO control regime, the expected revenues across those six DNOs in GB could be found in their respective business plans for the period 2015-2023. In order to show the expected profitability of each DNO under the new regime, Fig. 7-6 gives a comparison between the expected revenue and expenditure of each company [137, 140-154].

Also with the information of expected revenue and planned expenditures across the six DNOs in the UK, a figure showing the expected profitability and EBIT margin of DNOs under the current RIIO regime has been created. The result is depicted in Fig. 7-7.
4) Revenue adjustment

Apart from controlling the revenue that network operators could recover under price control regimes, regulatory authorities also have proposed annual adjustment mechanism where revenues of DSOs are adjusted corresponding to impacts like tax change etc. This essentially creates a dead band, within which the annual revenue of the examined DSO needs no adjustments.

In the UK, the new RIIO-ED1 model provides the revenue adjustment each year [139]. Under the previous ‘DPCR’ price controls, base revenue allowances, were set up-front for the whole price control period, changing only with RPI indexation, requiring certain adjustments to reflect activity levels and varying financial conditions in every 5 years. Under RIIO-ED1, these adjustments along with RPI indexation, will be made each year in respect of the licensee’s network business. This new approach involves an annual iteration of the ED1 Price Control Financial Model (FCFM)\(^2\) using updated variable values, by which, annual adjustment to the licensee’s base revenues will be calculated. This gives rise to a requirement for licence conditions and methodologies to govern the determination of revised PCFM Variable Values and the

\(^2\) The Price Control Financial Model (FCFM) is the financial model deriving the incremental changes to base revenue of DNOs.
Annual Iteration Process (AIP)³. In detail, the adjustments fall into three broad categories:

1. Financial adjustments covering tax, pension and cost of debt issues;
2. Adjustments relating to actual and allowed total expenditure (Totex) and the Totex incentive Mechanism;
3. Legacy price control adjustments: the close-out of schemes and mechanisms from preceding price control periods.

The incremental changes on the base revenue (MOD) of year $t$ are calculated at year $t-1$, and will then applied to the base revenue of year $t$. The calculations result in a PCFM output value for the term MOD is applied shown in the simplified formula:

\[
\text{Base Revenue for year } t = \text{Opening Base Revenue Allowance for year } t + \text{MOD for year } t
\]

In Spain, the electricity market conducts a comprehensive reform by mid-2015 to reached aims of making the sector’s costs and revenues back in balance. Since 2001, there was a tariff deficit in Spain and the deficit keeps accumulating and spiral out of control after 2005. The deficit peaked at the end of 2013 at EUR 29 billion or 3% of GDP. After the government introduced electricity market reform package, the tariff deficit should gradually disappear over the next 15 years [127].

In Finland, at the end of the regulatory period the Energy Authority confirms separately for every DSO the absolute amount by which the DSO’s realised adjusted profit for the entire regulatory period exceeds or falls below the level of return that is considered reasonable. If the accrued earnings of the network operator have exceeded or fallen short of the reasonable earnings defined by the Energy Authority, the Energy Authority includes in its supervision decision obligation for the network operator to return any surplus profit to the customers through lower network charges or allows the network prices to be raised with the appropriate amount.

---

³ The AIP is the formal process of the annually updating the variable values in the PCFM and for the calculation of the incremental change, positive or negative, on base revenues (MOD).
The financial models of DSOs across GB, Spain and Finland are summarized in Table 7-5.

<table>
<thead>
<tr>
<th>Table 7-5 Cost/Revenue comparison of DSOs in three countries</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Capita Cost</strong></td>
</tr>
<tr>
<td><strong>Evaluation</strong></td>
</tr>
<tr>
<td><strong>Revenue Stream</strong></td>
</tr>
</tbody>
</table>

| **Revenue Allowance** | RIIO model from Ofgem, where revenue is directly related with incentives, innovation and outputs | RD 222/2008 from CNE | The electricity market conducts a comprehensive reform by mid-2015 to reach two key aims: the sector’s costs and revenues are back in balance, and the accumulated deficit, which peaked at the end of 2013 at EUR 29 billion or 3% of GDP, should gradually disappear over the next 15 years |

| **Revenue Calculation** | The annual adjustment of the next year to the licensee’s base revenues will be calculated based on the updated variable values. New revenue = old revenue + modified value. Any surplus or deficit in a year will be rolled into next year | Return any surplus profit to the customers through lower network charges or allows the network prices to be raised with the appropriate amount. |

5) Impact of DNO revenue on customer electricity bill

Fig. 7-8 shows the proportion of a typical GB consumer electricity bill which is attributable to the revenue recovered by DNOs on national average level [145]. Since there is regional difference on the network charges, the electricity bill payments to different DNOs are different. Table 7-6 gives each DNO’s revenue breakdown to its customer [140].
7.1.4 Incentives for DNO Business Model Innovations

Innovations are largely driven by the need to improve the network efficiency, and network security whilst facilitating the connection of low carbon technologies timely and economically.

In the UK, the regulator set out £500m between 2010 to 2015 to trial out innovative commercial and network solutions to address new challenges emerging from the low carbon transition [146]. The innovative projects can be largely grouped into three categories: i) making extra network capacity from the existing assets, ii) increasing demand flexibility and efficiency to match renewable outputs, iii) open electricity markets to mass consumers to allow them to address network and energy pressures. There were incentives for connecting distributed generation prior to 2015, at 1£/MW,
this has ceased to exist. In the new price control model, RIIO-ED1, the DSO will be rewarded by innovations.

In Spain, strong financial incentives were implemented to support the development of renewables and are reflected in the grid component of the tariffs. Economic incentives (€120 million per year) for investments in more energy-efficient technologies have been implemented with the NEEAP [147].

In Finland, there has been an innovation incentive in force for the DSOs to create innovative technical and functional solutions to their network operations between 2012 - 2015 [128]. The planning of policies and regulation relating to the distribution operations requires careful planning because of the idiosyncrasies of the business. There is also energy efficiency (EE) schemes for municipality and community in which DSOs can be involved and receive tax reduction.

7.2 A New DNO Business Model Based on Sharing Economy

7.2.1 Multiple Network Operators with Shared Network Access
As increasing number of DG and flexible demand (such as EV and HP) are being connected in the distribution networks, the prospective demand increase and bi-directional power flow will bring severe network pressures in terms of thermal and voltage violations.

Under the conventional business model, DNOs would invest in the network to meet the load growth, assuming all load requires the same level of high reliability. A substantial amount of capacities is designed only to support the temporary system peak while maintaining underutilised over the majority time of a year.

The telecom industry was in a very similar situation during the last decade [148]. The recent fast growing mobile broadband has aggravated the already scarce spectrum resources. In order to avoid excessive investments in infrastructures from different incumbent users (spectrum owners), the communication regulator developed a
Licensed Shared Access (LSA) strategy to allow mobile network operators to borrow the incumbent users’ spare spectrum with the agreement of giving it back when the incumbent users need it. Such business model takes full advantage of any spare spectrum in the channel and allows different operators to use it in a competitive manner, thus leading to improved efficiency of spectrum.

Inspired by the LSA in telecom, this subsection proposes a new concept of Shared Network Access (SNA) for the distribution network. It incentives incumbent DNOs to give up their sole access to the network and share any unused network capacities with licensed independent parties, secondary DNOs. As the incumbent DNO can withdraw these spare capacities when needed, the service from secondary DNOs is less reliable but with lower cost. By differentiating demand based on their flexibility levels, different DNOs can provide service with selective reliabilities and competitive costs. Incumbent DNO can continue to be the primary network operator, who owns the infrastructure and focuses on providing reliable supply for fixed demand at higher cost. Meanwhile the secondary operators can target on flexible network demand by taking advantage of spare capacity or back up capacity in the network.

This section proposes an option for network sharing between the incumbent and secondary DNOs. By assuming secondary DNOs could maximize the use of spare capacities, the simulation demonstrates the benefits of SNA under different penetration levels of flexible demand with different reliability requirements.

### 7.2.2 Quantification of DNO’s Benefits under Shared Network Access

The present value of network investment cost is determined by the time horizon to which the loading of network component reaches its maximum rated capacity [149]. Under the SNA mechanism, such future investment is delayed by 1) incentivizing independent parties to provide customized reliabilities for flexible demands and 2) taking advantage of back up and spare network capacities. This contributes to a lower present value of eventual cost. The financial benefit received by incumbent DNOs, i.e. network infrastructure owners, can be quantified by the following steps.
1) Deriving the Time Horizon to Reach Network Capacity under Conventional Business Model

If a network component $l$ has a normal capacity of $C_l$, a back capacity of $B_l$, and supports a power flow of $D_l$, then the number of years it takes to grow from $D_l$ to $(C_l + B_l)$ for a given load growth rate (LGR) $r$ can be determined with

$$(C_l + B_l) = D_l \cdot (1 + r)^n$$  \hspace{1cm} (7-1)$$

where $n_l$ is the number of years taking $D_l$ to reach $(C_l + B_l)$.

Rearranging (7-1) and taking the logarithm of it gives

$$n_l = \frac{\log(C_l + B_l) - \log D_l}{\log(1 + r)}$$  \hspace{1cm} (7-2)$$

2) Deriving the Time Horizon to Reach Network Capacity under SNA Business Model

Assume that within the aggregate power flow of $D_l$ the flexible demand accounts for $F\%$, thus the proportion of fix demand being $(1 - F\%)$. As the fix demand must be supplied reliably all the time, assuming the same LGR the time to future reinforcement will change

$$(C_l + B_l) = (1 - F\%) \cdot D_l \cdot (1 + r)^{n_l}$$  \hspace{1cm} (7-3)$$

Equation (7-3) gives the investment horizon to meet the fix demand reliability under SNA

$$n'_{l1} = \frac{\log(C_l + B_l) - \log(1 - F\%) - \log D_l}{\log(1 + r)}$$  \hspace{1cm} (7-4)$$

If the flexible demand is supplied by an independent party with a promised reliability of $R$, the number of years it takes until such supply reliability cannot be met is defined as

$$(1 - R) \cdot F\% \cdot D_l \cdot (1 + r)^{n'_{l1}} = D_l \cdot (1 + r)^{n'_{l1}} - (C_l + B_l)$$  \hspace{1cm} (7-5)$$

where the reliability for simplicity is defined as the ratio of satisfied amount over total flexible demand.
Equation (7-5) gives the investment horizon to meet the supply reliability of flexible demand under SNA

\[ n_{i2} = \frac{\log(C_i + B_i) - \log(1 - F\% + R \cdot F\%) - \log D_i}{\log(1 + r)} \]  

(7-6)

The smaller of (7-4) and (7-6) is taken as the new time horizon to future reinforcement \( n' \) under SNA

\[ n' = \min\{n'_{i1}, n'_{i2}\} \]  

(7-7)

3) **Difference in Present Value as a Result of SNA**

For a given discount rate of \( d \) is chosen, the present values of the future investment in year (7-2) and (7-7) respectively will be

\[ PV_i = \frac{\text{Asset}_i}{(1 + d)^{n_i}}, \quad \text{and} \quad PV'_i = \frac{\text{Asset}_i}{(1 + d)^{n'_i}} \]  

(7-8)

where \( \text{Asset}_i \) is the modern equivalent asset cost.

Hence, the change in present value as a result of SNA is

\[ \Delta PV_i = PV_i - PV'_i = \text{Asset}_i \cdot \left(\frac{1}{(1 + d)^{n_i}} - \frac{1}{(1 + d)^{n'_i}}\right) \]  

(7-9)

4) **Calculating the Financial Benefit for Incumbent DNO**

The financial benefit for incumbent DNO under SNA mechanism is the summation of incremental benefits over all network components:

\[ \text{Benefit} = \sum_i \Delta PV_i \]  

(7-10)

### 7.2.3 Demonstration of SNA Business Model

The demonstration is on a simple two-busbar network shown in Fig. 7-9. The normal and back up capacity of circuit \( l \) are rated at 25 MW and 20 MW respectively, and both cost £3193400 at modern equivalent asset value. The initial \( D_l \) is 20 MW. Assuming a discount rate of 6.9% and a LGR of 1.6% per annum, Fig. 7-10 gives the financial benefits received by the incumbent DNO under different flexible demand penetrations and reliabilities.
It shows by SNA mechanism the incumbent DNO financial benefit becomes significant when the flexible demand penetration increases. At the same time, a lower reliability requirement of flexible demand presents a positive effect on the result. An extreme scenario where the flexible demand requires uncompromising supply reliability is also shown in the demonstration. Conceivably, under this condition the SNA mechanism brings no additional financial benefit to the incumbent DNO.

7.2.4 Philosophical Discussions on SNA Business Model

To persuade the incumbent DSOs to give up its exclusive access to the network, market/regulation interventions and incentives need to take place. Measures such as harmonization across countries and standardization of technology are needed. Regulators need to see the benefits including increased competition, lower shared investments, while make sure to avoid de-facto competition restrictions resulting from sharing.
Meanwhile, reciprocity of sharing is a precondition. Potential benefits brought by SNA will attract new parties to act as secondary DSOs: possibility to reciprocity in the access to serve new customers, additional income stream from new services and customers, and savings in infrastructure investment and network reinforcements.

### 7.3 A Local Energy Market Mechanism with Multiple Supply Qualities

Traditional energy markets are established based on the equilibrium between the supply and demand, where the market only trade one energy product – energy meets the security and quality standards defined by national bodies (nearly 100% reliable). This subsection proposes a fundamentally different market arrangement where multiple energy markets exist, each targets supplying energy with certain supply quality, ranging from the very low quality supply from renewable energy in its raw form to the very high quality of supply from firm and controllable fossil generators. The new economic principles that will allow for multiple equilibriums to be reached for energy products with a varying degree of quality.

The key attributes of this market arrangement is recognising that demand has differing degree of tolerance to supply interruptions, each can trade in the market with the appropriate supply. For demand with high degree of tolerance to supply interruption, they can trade in market with low supply quality and can directly tap into (or respond to) cheap, low quality of supply. For demand with high quality requirement, they would have to enter into the traditional market where the very high quality of supply is traded. In the new market arrangements, there will be multiple equilibriums for markets with different supply quality. This will shift the supply industry from the current position, where the low quality supply must be converted to the high quality of supply through expensive back up generation before they can be sold to energy customers. This new arrangement essentially extends the traditional supply and demand equilibrium from cost and quantity to quality.
7.3.1 Local Energy Market with Differing Supply Qualities

Many communities across the country are aspired to increasing the use of sustainable energy and becoming self-sufficient in meeting their energy needs. An independent modelling undertake for DECC suggests that under some scenario, community energy could meet the electricity needs of 1 million homes by 2020 [150]. For community energy to grow and stay for many years to come, current business models have to be fundamentally changed to achieve two goals: i) to increase the financial value of local energy for the community, considering that the government subsidies to green energy would reduce over time, and ii) to minimise the impact to the supply system when community energy becomes wide-spread.

The current business models disadvantage community energy producers (particularly those of renewable nature), and increase the overall supply cost. This is because that energy from community renewable energy in its raw form - intermittent low quality supply, cannot be directly sold to a third party. Instead, it is exported to the grid at a considerably cheaper rate (4.77p/kWh), the supply system would then act as a giant energy storage to increase its supply quality to a level that meet the supply standards. In doing so, it places a significant burden to the supply system particularly when the penetration of PV and wind becomes significant. On the generation side, they would increase the balancing cost as more expensive and flexible generation needs to be brought online to mitigate intermittency. On the infrastructure side, it will reduce network headroom particularly at the local level, and substantially reduce the distributor’s ability to connect new community projects. The current commercial arrangements thus place little value for community energy, relies on significant government subsidies and grid support for its growth.

This section will develop fundamentally different economic principles that would create alternative market routes/business models for community energy, able to significantly increasing its market value and reduce its dependence on the grid support and government subsidies. Instead of going through the grid, the new economic principle will allow low quality of supply from the communities to be directly traded with a third party in the local area, but recognising and reflecting the quality of supply in energy prices. The new business models will thus provide more energy choices for
local consumers, ranging from low cost, low carbon, low quality local renewables to high cost, high carbon, and high quality central supply. This will ensure that parties in the local area that have a higher tolerance of supply interruption will directly benefit from community energy.

Existing work in opening up more options for electricity consumers are limited in taking advantage of prices differentiations in whole-sale energy markets, they thus do not promote a fundamentally different market that can directly trade a low quality supplies between interested parties. Whilst the market with a diverse range of supply quality has less an appeal for the traditional demand, in this paper, emerging loads that have a higher degree of tolerance to supply interruptions are exploited, such as electric heat and transport, smart appliances and home area energy storage. These new load would present ideal demand for poorer quality of supply at a cheaper rate, and absorb the burden from excess local renewable which would otherwise be borne by the supply system.

### 7.3.2 Supply Curves for Differing levels of Supply Qualities

Similar to any other commodity, electricity price is a major determinant in the quantity local energy resources are willing to sell at each moment. In this subsection, we will take the perspective of a local energy supply that tries to maximize the profits it derives from the sale of electrical energy produced by its generating unit \( i \). For the sake of simplicity, this part will consider a single settlement period, which is one hour in this paper, and it is assumed that all quantities remain constant during the studied period. For the local energy supply, the maximization of the profit from unit \( i \) during this hour can be expressed as the difference between the revenue resulting from the sale of the energy it produces and the cost of producing this energy:

\[
\text{Max } \text{Profit}_i = \text{Max } (\text{Revenue}_i - \text{Cost}_i) \tag{7-11}
\]

If the only variable over which the supply has direct control is the power generated by its unit, the necessary condition for optimality corresponding to (7-11) is:

\[
\frac{d\text{Profit}_i}{dP_i} = \frac{d\text{Revenue}_i}{dP_i} - \frac{d\text{Cost}_i}{dP_i} \tag{7-12}
\]
The first term in (7-12) represents the marginal revenue \((MR)\) of local supply \(i\), which is the revenue it would get for producing an extra megawatt during this hour. The second term represents the cost of producing such extra megawatt, i.e. the marginal cost \((MC)\). From the perspective of this local supply, to maximize profits, its production must therefore be adjusted up to the level at which its \(MR\) is equal to its \(MC\):

\[
MR_i = MC_i
\]  \hspace{1cm} (7-13)

To keep it simple, the local energy markets introduced in this paper are assumed to be perfectly competitive. Hence, the market price \(\rho\) is not affected by changes in any local supply. Under this condition, the \(MR_i\) in (7-13) can be expressed as:

\[
MR_i = \frac{d(\rho \cdot P_i)}{dP_i} = \rho
\]  \hspace{1cm} (7-14)

Substituting (7-14) into (7-13), we have:

\[
MC_i = \frac{d\text{Cost}}{dP_i} = \rho
\]  \hspace{1cm} (7-15)

Key components constituting the term \(\text{Cost}\) in (7-15) are directly determined by the specific local supply technology. In this work, the marginal cost of electricity from different local sources is quantified using the levelized cost of energy \((LCOE)\). By definition, \(LCOE\) represents the economic evaluation of the average total cost to invest in and operate an energy resource over its lifespan divided by the aggregate energy output it might generate over that lifespan. As a result, (7-15) becomes

\[
LCOE_i = \rho
\]  \hspace{1cm} (7-16)

In this paper, three local supply scenarios corresponding to three differing levels of supply quality have been selected to demonstrate the development of supply curves. Table 7-7 shows the respective \(LCOE\) information.

1) \textit{Low supply quality – Local PV}

Thanks to the zero fuel cost of PV generation, the marginal cost of the electricity output of a PV unit contains no fuel expenses. However, one of the biggest drawbacks of PV is its intermittency and unpredictability. Hence, for the local supplies, in particular renewable ones, which are trading on local energy markets with specific
supply qualities, a penalty charge would occur and be imposed on the market participating supply resource when its output fails to meet the supply quality required on the market. In this paper, it has been assumed that when output deficit happens, the shortage will need to be filled by purchasing energy from the traditional retail market with 100% reliability. For a PV generation, its $MC$ could be represented as:

$$MC_{PV} = C(\Delta P_{PV})$$  \hspace{1cm} (7-17)

and

$$C(\Delta P_{PV}) = \Delta P_{PV} \cdot RP(\Delta P_{PV}) \cdot \lambda$$  \hspace{1cm} (7-18)

where $C(\Delta P_{PV})$ is the penalty charge, which is a function of the PV output mismatch between the required supply quality and its actual output level, $RP(\Delta P_{PV})$ is the risk probability of $\Delta P_{PV}$ output deficit actually happening, and $\lambda$ is the unit price of electricity sold on the traditional retail market.

Table 7-7 Local supply output variability information for a selected trading period

<table>
<thead>
<tr>
<th>Local supply type</th>
<th>PV</th>
<th>CHP</th>
<th>PV + Battery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supply quality of its trading market</td>
<td>50%</td>
<td>70%</td>
<td>90%</td>
</tr>
<tr>
<td>20% output deficit probability</td>
<td>3.23%</td>
<td>4.62%</td>
<td>6.45%</td>
</tr>
<tr>
<td>40% output deficit probability</td>
<td>6.45%</td>
<td>4.25%</td>
<td>2.50%</td>
</tr>
<tr>
<td>60% output deficit probability</td>
<td>9.68%</td>
<td>6.33%</td>
<td>4.71%</td>
</tr>
<tr>
<td>80% output deficit probability</td>
<td>3.23%</td>
<td>1.20%</td>
<td>0%</td>
</tr>
<tr>
<td>100% output deficit probability</td>
<td>1.29%</td>
<td>0%</td>
<td>0%</td>
</tr>
</tbody>
</table>

2) **Medium supply quality – Local CHP**

Local CHPs produce electricity and domestic heating simultaneously using typically natural gas as the input fuel. This is in contrast to the zero marginal fuel cost of renewables such as solar PV introduced above. Hence, apart from potential penalty charges due to output volatility, the marginal cost of CHPs is also to a large degree influenced by the marginal fuel cost $FC_{CHP}$:

$$MC_{CHP} = FC_{CHP} + C(\Delta P_{CHP})$$  \hspace{1cm} (7-19)

where,

$$C(\Delta P_{CHP}) = \Delta P_{CHP} \cdot RP(\Delta P_{CHP}) \cdot \lambda$$  \hspace{1cm} (7-20)
3) High supply quality – PV + Battery

To compensate the unpredictable volatility of PV generation output, domestic battery storage has been considered by many as an effective solution. However, this inevitably leads to higher marginal cost, as daily charging and discharging consumes the remaining lifespan of batteries. They lose capacity as the number of charge cycles increases, until the batteries are eventually considered to have reached the end of their useful life. As a result of this, the calculation of the marginal cost in this scenario needs to take into consideration the levelized cost of electricity (LCOE) of battery storage:

\[ MC_{PV+CHP} = LCOE_{Battery} + C(\Delta P_{PV+Battery}) \] (7-21)

where,

\[ C(\Delta P_{PV+Battery}) = \Delta P_{PV+Battery} \cdot RP(\Delta P_{PV+Battery}) \cdot \lambda \] (7-22)

To demonstrate the development of respective supply curves of the three scenarios above, monitored local supply data over has been utilized, based on which the information of a snapshot trading period on differing reliability markets is given in Table 7-7. The assumed values of the parameters above are listed in Table 7-8.

<table>
<thead>
<tr>
<th>Parameter assumptions</th>
<th>$\lambda$</th>
<th>$FC_{CHP}$</th>
<th>$LCOE_{Battery}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>£0.15/kWh</td>
<td>£0.13/kWh</td>
<td>£0.2/kWh</td>
<td></td>
</tr>
</tbody>
</table>

Using the equations above, the supply curves describing the selected three scenarios with differing supply qualities above could be derived. The result has been depicted in Fig. 7-11.
7.4 Chapter Summary

Existing electrical energy systems were designed and operated to accommodate large-scale generating plants, with demand traditionally viewed as uncontrollable and inflexible, and with centrally controlled operation and management. At a regional level, currently looked after by distribution network operators, electricity is delivered from transmission to the distribution networks and then to end consumers in a unidirectional fashion with very little active control and management.

With the increasing penetration of new energy components, incumbent DNOs, retailers and new service providers are presented with unprecedented opportunities and challenges. This is a vital challenge to revive the traditional DNO responsibilities – providing secure network to meet peak demand, moving to or creating more active DNO role. The key purpose is to promote active participation of prosumers with new business models for the entire business ecosystem, which will increase the efficiency, flexibility and responsiveness of local resources.

This chapter has firstly analysed the current business models of DNOs across three EU countries: GB, Spain and Finland. It was found that the underlying distribution
network investment principles are fundamentally identical, with DNO network investment playing the dominant role in meeting customer peak demand. This leads to limited incentives in terms of innovation to mobilise third parties to support more efficient network development and installation of flexible demands and recourses, and it cannot provide adequate mechanisms for network operation companies to move towards energy grid and facilitate the revolution of the whole industry.

Aiming to overcome some of the issues especially under today’s power industry context, a new business model based on shared network access for incumbent DNOs has been introduced. Instead of owning and operating network assets rather inefficiently in today’s fashion, the introduced model incentivizes the incumbents to lease their spare network capacities to secondary DNOs, thus creating new revenue streams and more importantly facilitating further connection of various dispersed energy resource technologies. More precisely, by taking advantage of the unreliable capacities to provide cheap alternatives for the integration of flexible demand, the demonstration results in this chapter shows that the proposed model is substantially cost-effective when the flexible demand penetration is high and reliability requirement is low.

Finally, a new market arrangement concept has been developed in the third part of this chapter. Compared with the traditional market where only the 100% reliable supply is traded, the new market mechanism provides DG owners and flexible demand customers in particular various options to trade. As a result, it offers a superior over current markets a platform to better exploit the asset attributes of DG technologies and their application within the power system.
Chapter 8. Conclusions and Future Work

This research aims to establish a comprehensive insight into DG contribution to the national transmission grid from the following three areas, therefore responding effectively to the changes facing tomorrow’s power system architecture.

 Ø DG contribution to transmission levels

An understanding of the contribution of embedded generators to the national transmission grid has been established in this PhD research.

Firstly, it has documented the key findings, including similarities and differences between the current industry’s aggregation modelling of distributed generation, i.e. SQSS by National Grid and ER P2/6 applied by DNOs. The effectiveness, limitations and key contributing factors to potential mismatches of both approaches have been analyzed in this thesis. Comparing with SQSS, the ER P2/6 appears to take a more comprehensive view on the characteristics of the examined DGs, thus outperforming the oversimplified SQSS on assessing the security contribution of embedded resources to the transmission level. Generation availability and plant size are incorporated in the evaluation process by P2/6, and influencing factors like the correlations between load and DG output and persistence time of intermittent resources were inherently built in the P2/6 development.

One of the common limitations inherent in both industrial practices above is that neither takes into account the potential effects of distribution network on the evaluation of EG contribution. In this thesis, alternative modeling methods and their respective degrees of improvement over conventional approaches are developed and presented. Contrast to conventional approaches, the enhanced assessment methods developed from this work integrate distribution network effects with the original P2/6 guidance, thus taking into account both DG intrinsic capability as well as distribution network characteristics when assessing DG contribution. While candidate techniques currently adopted by the industry can merely provide deterministic and oversimplified results, the derived contribution values by the proposed models respect and differentiate between conditions of DG concentration, penetration, locations and
network loading levels etc. Based on the extensive comparisons with traditional methods, the following observations have been reached:

- The enhanced approaches differentiate between different configuration of networks which interconnect the examined DG and its loading centres. For DGs whose output requires higher extent of network use, results show that the interconnection network tends to impose a greater impact, resulting a much discounted contribution to transmission level. While for DGs interconnected by meshed networks, the contribution values derived by the proposed approaches are rather close to the original P2/6 guidance.
- As demonstrated in the test system, for local DGs connected at lower voltage buses, the mismatches between the results obtained by the proposed model and the original P2/6 tend to be more significant. For certain locations, such mismatches could be even higher than 50% of the original results guided by P2/6.
- While DG penetration tends to have a negative impact on the contribution values calculated, the network loading level has a positive effect. Also for DGs at different areas, magnitudes of such influences are different. Compared with the demand-dominated area embedded generators, contributions of DGs located in generation-dominated areas are more sensitive to the influence of penetration and network loading level.
- The degree of DG concentration has an impact on both intermittent and non-intermittent DGs, although non-intermittent ones appear to be more affected. For high concentration scenarios, the results could be significantly deviated from P2/6 levels, 80% lower than the original value. DGs at demand-dominated areas are less affected by the influencing factor of concentration.

➢ Characterization of PV generation

It has also been identified in this PhD thesis that within the framework of DG contribution assessment, insufficient attention has been paid to solar photovoltaics by both the industry and academia. Neither SQSS nor P2/6 provides contribution evaluation guidance for PVs embedded within distribution networks, while no single definition of PV contribution has been reached by academia.
Aiming to address this challenge and integrate the assessment of PV contribution into the enhanced framework of DG evaluation which has been presented in the first half of this thesis, current state-of-the-art approaches to characterizing PV generation output and modelling PV capacity credit have been reviewed in this thesis as well. Compared with its well-studied counterpart of wind power, the assessment of PV capacity credit appears to be relatively blank. Not only rather distinct definitions of PV capacity credit could be identified across the globe, also agreements haven’t reached upon a single proper way to model necessary inputs and calculate outputs.

In order to establish an understanding of PV output characterizations, a novel two-step hierarchical classification method is proposed in this research. It consists of two major steps: monthly classification and sunshine duration classification. By demonstrating on a practical PV generation in the U.K., the following observations have been reached:

- 12 monthly PV profile groups are produced representing distinct characteristics of PV output across various seasons.
- A probability amplitude profile tool is developed to visualize the degree of variation in PV outputs and quantify confident levels at different times.
- For the first time, the relation between the profile of PV daily output and the meteorological daily sunshine duration is investigated. And in this work PV output profiles have been classified based on this attribute, from the result of which superior than conventional PV hourly output predictions have been achieved.

The developed two-step hierarchical classification method for PV output profiling could facilitate the investigation of seasonal PV output characterization and ultimately contribute to achieving a more accurate assessment of PV capacity credit. More importantly, incorporating the proposed PV profiling method with the developed enhanced DG contribution evaluation framework, the previously neglected impacts of distribution networks and solar PV generators are integrated, and a complete package for identifying the collective contribution of various DGs on the national transmission system is delivered.
Commercial tools to unlock DG contributions

Existing electrical energy systems were designed and operated to accommodate large-scale generating plants, with demand traditionally viewed as uncontrollable and inflexible, and with centrally controlled operation and management. At a regional level, currently looked after by distribution network operators, electricity is delivered from transmission to the distribution networks and then to end consumers in a unidirectional fashion with very little active control and management.

With the increasing penetration of new energy components, incumbent DNOs, retailers and new service providers are presented with unprecedented opportunities and challenges to unlock the contribution of DG assets. This is a vital challenge to revive the traditional DNO responsibilities – providing secure network to meet peak demand, moving to or creating more active DNO role. The key purpose is to promote active participation of prosumers with new business models for the entire business ecosystem, which will increase the efficiency, flexibility and responsiveness of local resources.

In this last section of the thesis, it has firstly analysed the current business models of DNOs across three EU countries: GB, Spain and Finland. It was found that the underlying distribution network investment principles are fundamentally identical, with DNO network investment playing the dominant role in meeting customer peak demand. This leads to limited incentives in terms of innovation to mobilise third parties to support more efficient network development and installation of flexible demands and recourses, and it cannot provide adequate mechanisms for network operation companies to move towards energy grid and facilitate the revolution of the whole industry.

Aiming to overcome some of the issues especially under today’s power industry context, a new business model based on shared network access for incumbent DNOs has been introduced. Instead of owning and operating network assets rather inefficiently in today’s fashion, the introduced model incentivizes the incumbents to lease their spare network capacities to secondary DNOs, thus creating new revenue
streams and more importantly facilitating further connection of various dispersed energy resource technologies. More precisely, by taking advantage of the unreliable capacities to provide cheap alternatives for the integration of flexible demand, the demonstration results in this chapter shows that the proposed model is substantially cost-effective when the flexible demand penetration is high and reliability requirement is low.

Meanwhile, a new market arrangement concept has been developed. Compared with the traditional market where only the 100% reliable supply is traded, the new market mechanism provides DG owners and flexible demand customers in particular various options to trade. As a result, it offers a superior over current markets a platform to better exploit the asset attributes of DG technologies and their application within the power system.

➢ Future work

- **DG contribution to transmission levels**
  Future works in this field will focus on extending the developed DG contribution assessment methodology to other formats of DERs, such as EV and DSRs, thus examining the transmission level contribution from this increasing penetration of LV level elements.

- **Characterization of PV generation**
  As has been demonstrated in this thesis, the PV characterization method developed currently can only provide satisfactory results for low and high sunshine duration cases. Future research on this topic will focus on developing further classification methods or other profile characterization for the medium-sunshine-duration cluster.

Another field worth considering will be to apply the key findings and derived method to other PV locations. So far, in this work the demonstration has been applied to a single PV case in the region of Cambridgeshire using the annual PV and meteorological data of 2012. Given the fact that presumably different PV and climatological environments will lead to different PV output
characterizations, it will be interesting to implement the method and essential concept underpinning this work to other geographical locations. And further classification and generalization on these differing scenario results are also promising directions.

- Commercial tools to unlock DG contributions
  
  In terms of future work on this topic, there would mainly be three directions. The first one would be to look at alternative business models and opportunities for other energy market participants. The implementation of new DNO business model will involve and influence a significant number of other stakeholders within the whole ecosystem, such as ESCOs, TSOs, Aggregators, and Communities. How to adjust the core business models of these entities and development proper business opportunities for them will be an important question.

The second direction would be to further extend the SNA DNO business model to more complex system situations. So far, in this thesis, the SNA concept has been applied to a simple two-bus network to demonstrate the inherent benefits and advantages of this model. It could be interesting to see what scale of benefit this model could bring in a practical system scenario. Also, future quantification of the SNA benefits could focus on the net benefits of not only in terms of reinforcement deferral from the view point of DNOs, but also the financial benefits brought by this model to consumers and independent network operators which are involved by this novel business model.

The third direction might be to develop demand curves on the demand side and see the equilibrium situations given differing market parameters. The new market arrangement with different supply qualities introduced in the last section of the research thesis has only established the supply curves in such a commercial mechanism. To realize the crossing-points of supply-demand balancing, equivalent demand curves will also need to be modelled, which will involve evaluating flexible demand customer’s willingness to shift under changing price signals.
Publications


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