Customer-Led Network Revolution Commercial Arrangements Study

Review of existing commercial arrangements and emerging best practice

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Acronyms

AEMC	Australian energy market commission
ANM	Active network management
AONB	Areas of outstanding natural beauty
BAU	Business as usual
BCA	Bilateral connection agreement
BM	Balancing mechanism
BMRS	Balancing mechanism reporting system
BSC	Balancing and settlement code
BSUoS	Balancing Services Use of System
CAF	Cost apportionment factor
CCCM	Common connection charging methodology
CCL	Climate change levy
CDCM	Common distribution charging methodology/Model
CERT	Carbon emissions reduction target
CHP	Combined Heat and Power
CLNR	Customer-led network revolution
CRC	Charge restriction condition
CUSC	Connection and use of system code
DC	Distribution code
DCUSA	Distribution connection and use of system agreement
DECC	Department of energy and climate change
DG	Distributed generator / generation
DNO	Distribution network operator

DPCR	Distribution price control review
DSM	Demand side management
DSR	Demand side response
DUoS	Distribution use of system
EDCM	EHV distribution charging methodology/model
EDF	Electricité de France
EHD	EHV distribution
EHV	Extra high voltage (22kV nominal and above)
EMR	Electricity market reform
ENA	Energy networks association
ENWL	Electricity North West Limited
ER	Engineering recommendation
ERCOT	Electricity reliability council of Texas
ESCo	Energy service company
EV	Electric vehicle
FCDM	Frequency control by demand management
FERC	Federal energy regulatory commission
FFR	Firm frequency response
FiT	Feed-in tariff
GB	Great Britain
GC	Grid code
GEMA	Gas and electricity markets authority
GHG	Greenhouse gas
GSM	Generation side management
HH	Half-hourly
HV	High voltage (1kV to 22kV)
I&C	Industrial and commercial
ICP	Independent connections provider
IDNO	Independent DNO
IFI	Innovation funding incentive
IHD	In-home display
IIS	Interruptions incentive scheme
IQI	Information quality incentive
ISO	Independent system operator
kV	Kilovolts
LCNF	Low carbon networks fund
LDNO	Licensed DNO (a DNO operating networks outside its distribution services area or an IDNO)
LEC	Levy exemption certificate
LV	Low voltage (below 1kV nominal)
MIC	Maximum import capacity
MPAN	Metering point administration number
MPAS	Metering point administration service
MRA	Master registration agreement
MRASCo	MRA service company

NERL	National energy resource laboratory
NETS	National electricity transmission system
NG	National grid
NGET	National grid electricity transmission
NHH	Non half-hourly
OFGEM	Office of gas and electricity markets
OTSO	Offshore transmission systems operator (National Grid)
PPA	Power purchase agreement
RAP	Regulatory assistance project
RHI	Renewable heat incentive
RIIO	Revenue = Incentives + Innovation + Outputs
RO	Renewable obligation
ROC	Renewable obligation certificate
RPI	Retail prices index
RTO	Regional Transmission Operator
SSC	Standard settlement configuration
SGF	Smart grid forum
SHEPD	Scottish and southern energy power distribution
SHETL	Scottish hydro electric transmission limited
SM HAN	Smart meter home area network
SMIP	Smart metering implementation plan
SMS	Smart metering system
SPTL	Scottish power transmission limited
SLC	Standard licence condition
SO	System operator
SONI	System operator for Northern Ireland
SSE	Scottish and Southern Energy
SSEG	Small-scale embedded generation
STC	System operator-transmission owner code
STOR	Short-term operating reserve
TNUoS	Transmission network use of system
ToU	Time of use
TSO	Transmission system operator
UK	United Kingdom
UKPN	UK Power Networks
UMS	Unmetered supply
USA	United States of America

1. Introduction

Objectives

This report has been commissioned to feed into the Customer-Led Network Revolution (CLNR) project, which is supported by Ofgem's Low Carbon Network Fund. The main premise of the CLNR project is that the reinforcement of electricity distribution networks required to cope with large-scale take-up of low carbon technology can be delivered most cost-effectively and efficiently by using a combination of new network technologies and flexible customer response from both demand and generation. While many of the technical solutions exist, they have not been deployed at scale at the distribution level in an electricity market with the degree of vertical separation as that operating in Great Britain (GB). This report provides a detailed assessment of the legislative framework and commercial arrangements currently operating in the GB electricity market in order to understand what barriers existing arrangements pose both to the deployment of network management and demand response technologies and also to innovative commercial offerings, such as time of use tariffs and load control incentives.

Background

The coming decades are expected to witness a revolution in the way we generate and consume electricity. The distribution networks will be at the centre of this revolution, serving the changing electricity consumption patterns of end-users and, increasingly, connecting local distributed power generation. These changes are expected to impose a rate of load growth on distribution networks that far outstrips the historic trend. The major drivers of this change are expected to be shift of heating from gas and oil to electricity and the electrification of transport. Distribution connected generation technologies, such as photovoltaics and small to medium scale wind turbines present the possibility of reverse power flows, particularly under periods of low load, which distribution networks have not traditionally been designed to cope with. There have been a number of recent studies aimed at forecasting the level of investment in distribution network infrastructure required to meet the growing and changing electricity demand. A recent study published by the Smart Grid Forum put this figure at between £20bn to £60bn across all GB networks over the period to 2050, depending on the assumptions around scale of uptake of low carbon technologies and the network reinforcement strategy adopted (i.e. business-as-usual or 'smart').

It is incumbent on distribution network operators to develop network investment strategies to meet the challenges of distributed generation and accelerated load growth in the most cost-effective manner, while always ensuring very high levels of security of supply. The CLNR project seeks to field-test a range of innovations, both technical and commercial, in order to identify optimum solutions to resolve network constraints. The technical solutions trialled will include enhanced automatic voltage control, network storage and real time thermal ratings, while the efficacy of commercial offers such as dynamic and static time of use and direct load control tariffs in changing end-users' patterns of load and generation will be explored. Having identified an optimal set of solutions, the CLNR project will finally consider the requirement for new commercial arrangements, policy, tools and guidance for network operators to transfer these solutions from field-testing to adoption as business-as-usual practice.

This report begins the process of identifying the changes required to the commercial and regulatory framework by understanding the current market arrangements in detail. The main focus of the study is the impact of the commercial framework on the distribution network operators and their ability to adopt smart solutions, within the current industry framework. However, to understand the barriers to these smart solutions, particularly smarter commercial offerings, it is necessary to understand more broadly the commercial arrangements between market participants and, crucially, the relationship with the end customers. The scope of the study includes the commercial arrangements for demand customers at all scales, domestic to industrial, and also generation customers, mainly focussed on distribution connected generation.

The study forms a baseline from which the changes to the commercial and regulatory framework required to facilitate adoption of the favourable network and commercial solutions can be assessed. In this report we begin this process by identifying some of the clear barriers to adoption of smarter networks and markets inherent in the current arrangements. The intention is that this will feed into a more detailed Phase 2 study of the requirements for reforms in the electricity market, which will be undertaken once the field trials have produced results and optimum solution sets can be identified.

Structure of the report

The report is structured into the following chapters:

Ch. 2 Overview of the UK electricity market – A summary of the overall market structure, from generation to end-use, and the role of the key market participants.

Ch. 3 Description of legislative and regulatory frameworks – A detailed description of the key regulation governing the UK electricity market, including the market codes that each participant must adhere to, the key charging methodologies for access to the network (transmission and distribution) and the price control regime.

Ch. 4 Detailed analysis of current commercial arrangements – A detailed analysis of the commercial arrangements between market participants, including generators, suppliers, the system operator, distribution network operators and the customer.

Ch. 5 Identification of successful models and barriers in the current arrangements – Analysis of how appropriate the current commercial arrangements are to meeting the challenges of large-scale take-up of low carbon technologies and distributed generation. Identification of where barriers exist in the current arrangements.

Ch. 6 Analysis of emerging commercial arrangements – Assessment of the new commercial models currently being trialled through the Low Carbon Network Fund and that are expected to stem from the Electricity Market Reform.

Ch. 7 Review of international best practice – International review to identify markets where smart technical and commercial interventions have been trialled or adopted as part of business as usual practice.

Chapters 2 to 4 are a review of the current market whereas chapters 5 to 7 provide more analysis and insights on commercial arrangements in the context of the aforementioned challenges faced by distribution network operators. **Chapter 8** provides a summary of the report and comments on the next steps.

2. Overview of the UK electricity market

The UK electricity market (overview in Figure 1) is regulated by the Gas and Electricity Markets Authority (GEMA), supported by Office of gas and electricity markets (Ofgem). Ofgem issues five types of licences: generator, interconnector, transmission operator, distribution operator and supplier. These are described in this section in terms of stakeholders, services offered and market size. Grid balancing and associated actors are also briefly presented, with an emphasis on services related to distribution networks. Licence exemptions are also introduced, where relevant to distribution networks[1]. Finally, a quick perspective on demand is given highlighting the changes new load such as heat pumps and electric vehicles will bring.

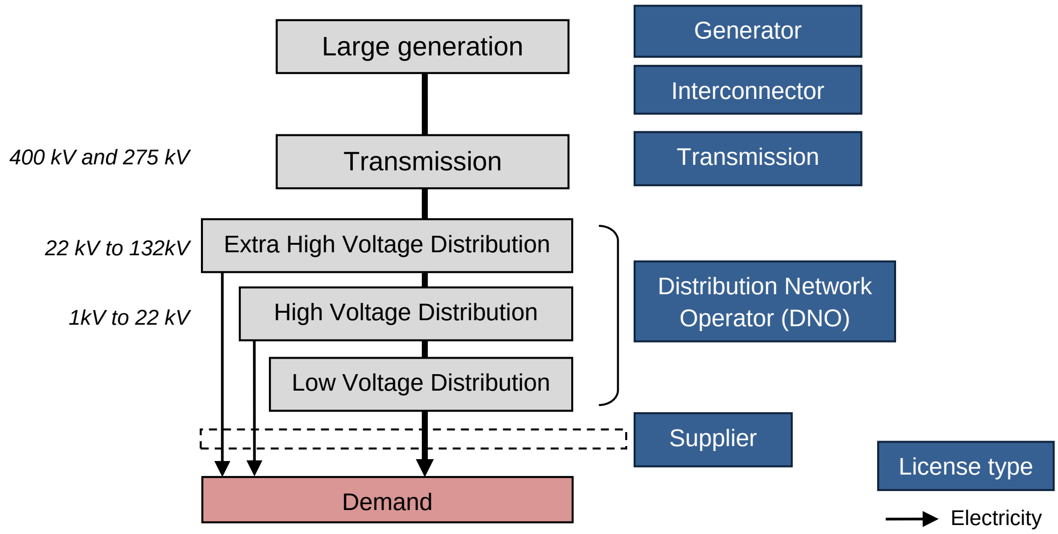


Figure 1: Overview of the UK electricity market – not showing distributed generation[2]

2.1 Generation and national interconnection

The UK has ca. 89 GW of electricity generation capacity. Table 2-1 shows the main plant and fuel types that contribute to the total capacity.

Maximum demand over the winter of 2011/2012 was 57 GW, or 70% of the UK capacity of major power producers[3]. Over the whole of 2011, the capacity factor

[1]Further detail is available on the Ofgem website http://www.ofgem.gov.uk/Licensing/Work/Pages/Work.aspx

[2] Voltages are quoted as defined in the Distribution Connection and Use of System Agreement (code maintained by UK DNOs). Note that network definition (naming and voltages) vary across countries.

(the actual output divided by the total capacity) of all of the UK major power producers was 43%.

Whilst conventional steam stations and combined cycle gas turbine stations dominate in capacity terms, it is worth noting that small generators (i.e. less than 5 MW) are much more numerous than large generators. Figure 2 shows a histogram of UK electricity generators; excluding the micro generation that falls under the Feed-in-Tariff scheme (further detail on the FiT scheme is given in section 4.2.1). If this micro generation were included, there would be 331,200 generators smaller than 1 MW connecting. This has impacts for the distribution network, as smaller generators are much more likely to connect to the distribution network (known as distributed generation) than to the transmission system.

Table 2-1: UK generation capacity in 2012 by type of plant.
Source: DECC DUKES Chapter 5 Table 5.7

Generation capacity	MW
Total capacity:	89,115
Composed of:	
Conventional steam stations	34,729
Combined cycle gas turbine stations	32,091
Nuclear stations	10,663
Gas turbines and oil engines	1,532
Hydro-electric stations:	
Natural flow	1,545
Pumped storage	2,744
Wind	2,727
Renewables other than hydro and wind	3,084

The total capacity of distributed generation is significant at just under 10% of the generation capacity (8,964 MW in 2011)[4], although the contribution to production is less than 10%, having typically lower capacity factors then large generators.

[3] As defined by DECC, includes all companies whose primary purpose is to generate electricity, and excludes those companies who produce electricity as part of manufacturing or other commercial activities.
4 National Grid, 2011 National Electricity Transmission System Seven Year Statement

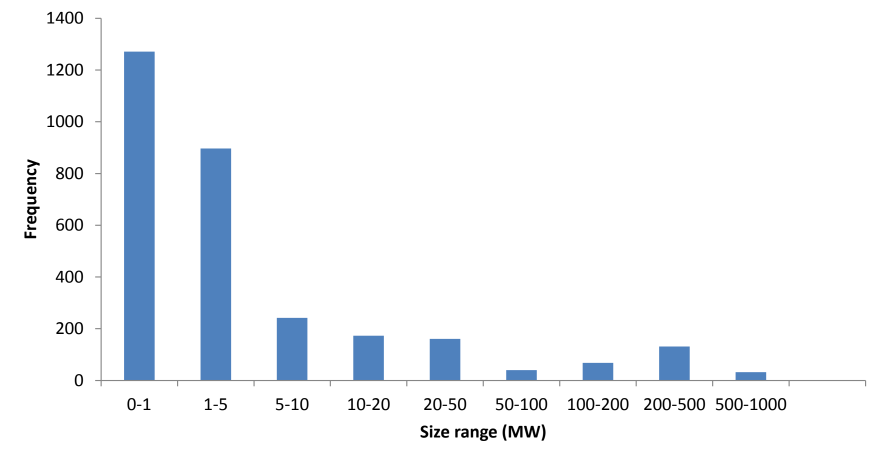


Figure 2: Histogram of sizes of UK electricity generators. Source: Platts UDI World electric power plants database, 2011.

The number of connections and capacity of distributed generation is expected to grow significantly over the coming years, in response to targets for renewable generation. DECC estimates that by 2020, there will be 2.6 million connections of small scale[5] solar PV generation alone, and capacity of 12.5 GW[6].
In addition to the generation capacity available in the UK, electricity can be imported and exported via four interconnectors:

- The England – France interconnector has the largest capacity at 2,000 MW (jointly owned and operated by National Grid Interconnectors and Réseau de Transport d'Electricité)
- The Dutch interconnector between England and the Netherlands (1,000 MW, owned and operated by BritNed Development)
- East-West interconnector between Wales and the Irish Republic (500 MW operated by the Irish Transmission System Operator, EirGrid Plc), commissioned in late 2012.
- Moyle interconnector between Scotland and Northern Ireland (500 MW, owned and operated by Moyle Interconnector Limited).

In general, the UK is a net importer of electricity from the continent, and a net exporter to the Republic of Ireland. Interconnector operators make the transmission capacity available for third party access for trading electricity,

5 Section 4.2.2 contains more detail on classifications for small scale generation.
6 DECC, Impact Assessments - Government Response to Consultation on Feed-in Tariffs Comprehensive Review Phase 2A: Solar PV Tariffs and Cost Control (2012), and Comprehensive Review Phase 2B – Consultation on Feed-in-Tariffs for anaerobic digestion, wind, hydro and micro-CHP installations (2011).

example of agreement frameworks for access and auction mechanisms can be found on their website[7].

Licensing

All electricity generator operators must have a licence, but there are some exemptions. Generators whose production does not exceed 100MW, those who only produce electricity at an offshore installation, and generators who have never been subject to central despatch requirements from the system operator can all be exempt from holding an electricity generation licence[8]. It is therefore likely that generation plants that connect into the distribution system, being smaller than those which connect into the transmission system, will be exempt from the licensing regime.

An interconnector licence cannot be held in addition to any other licence. Seven companies hold interconnector licences, including BritNed Development Limited, Channel Cable Limited, East West Cable One Limited, EirGrid Plc, Imera Hydragrid, Moyle Interconnector Limited and National Grid Interconnectors Limited.

2.2 Transmission and system operation

National Grid Electricity Transmission (NGET) is the Great Britain System Operator, responsible for managing the operations of both the England and Wales transmission system (owned by NG) and also the two high voltage electricity transmission networks in Scotland. Operation of the electricity transmission system involves the continuous real-time matching of demand and generation output, ensuring the stability and security of the power system, and the maintenance of satisfactory voltage and frequency. NGET also co-ordinates connection offers to new Generators. The system operator for Northern Ireland (SONI) manages the electricity system and flows in Northern Ireland.

Scottish Hydro Electric Transmission Limited (SHETL) owns the transmission network in Northern Scotland, and Scottish Power Transmission Limited (SPTL) owns the network in Southern Scotland. The grid in Northern Ireland is owned by Northern Ireland Electricity.

It is important to note that definitions of the voltages that constitute a transmission network and a distribution network vary between England and Wales, and Scotland:

[7] For example: http://www.mutual-energy.com/Download/Moyle_Interconnector_Capacity_Framework_Agreement.pdf ; http://www.eirgrid.com/media/East%20West%20Interconnector%20Access%20Rules%20-%20approved%20September%202012.pdf

[8] The Electricity (Class Exemptions from the Requirement for a Licence) Order 2001.

- Transmission grid voltages are normally 275KV and above in England and Wales, but 132 KV and above in Scotland and offshore.
- Distribution network voltage levels are normally 11KV, 33 KV, 66 KV and 132 KV (132 KV in England and Wales only), with some historic exceptions.

Licensing A transmission licence cannot be held in conjunction with an electricity interconnector licence.

Grid balancing services

The term “balancing services” is used to describe a range of services procured by National Grid Electricity Transmission as System Operator, in order to balance electricity demand and supply and to ensure security and quality of electricity across the GB transmission system. Balancing services include buying or selling electricity as part of the balancing mechanism in the wholesale market (described in more detail in Section 4.1.1), but also a range of ancillary services to cover the following issues[9]:

- Ensuring a stable frequency of transmitted electricity. NGET has an obligation to maintain frequency to within 1% of normal system frequency (50Hz). If demand is greater than generation, frequency falls, and vice versa;
- Ensuring there is reserve provision to increase supply or reduce demand in case of a sudden loss of a significant generation plant;
- Maintaining real and reactive power balance to stabilise the voltage profile across the transmission system; and
- Maintaining the security of the system, e.g. a system fault event may require the rapid reduction or disconnection of generators to maintain system stability.

The table below gives an overview of the main balancing services, and further detail is provided in Section 4.5. The current response requirement is met by around 4GW of flexible generation and demand, and NGET predict that this requirement could increase to around 8 GW by 2020[10], due to increasing intermittency of low carbon generation.

[9] Further detail can be found on the following website: http://www.nationalgrid.com/uk/Electricity/Balancing/services/
[10] Policy brief: Operating the Network in 2020. National Grid, 2009.

Table 2-2: Main balancing services remunerated by the System Operator

Firm frequency response (FFR)	Firm frequency response is an automatic change in active power **output or demand** in response to a frequency change. Services are procured through a competitive tender process, where tenders can be for low frequency events, high frequency events, or both.
Frequency control by demand management (FCDM)	FCDM helps to manage large variations in frequency, caused by e.g. the loss of a significantly large generation plant. The response is provided by an automatic interruption of **demand** customers, when the system frequency transgresses a low frequency relay setting on site.
Short-term operating reserve (STOR)	The provision of **extra power** through standby generation, and/or **demand reduction**, in order to be able to balance unforeseen mismatches in supply and demand.
Fast Reserve	This service requires a faster delivery than STOR, and can be used to balance supply and demand and control the frequency.

Aggregators

A large proportion of the NGET's requirement for Balancing Services is met by large generators that operate within the Balancing Mechanism (BM). However, a significant part of the requirement is met by non-BM generators and a small contribution is provided by demand sites. The charts below show the National Grid's current and 2020 forecast requirement for STOR services under the Gone Green scenario[11]. The charts highlight the need for new participants to enter the market in order to meet National Grid's anticipated future requirements.

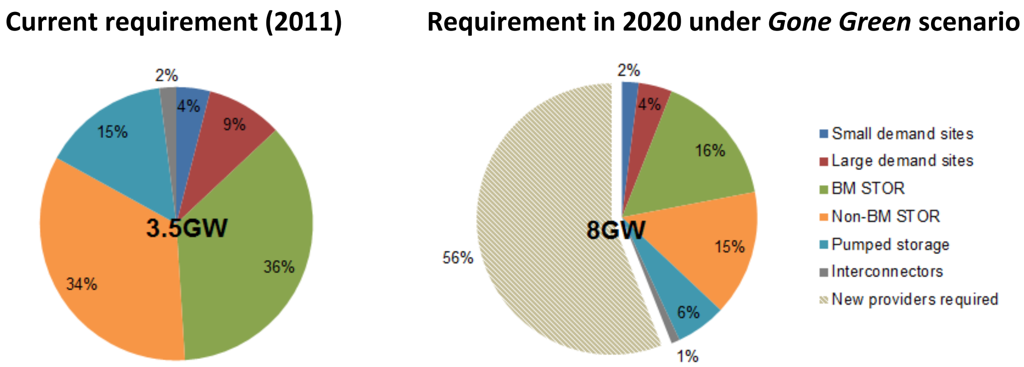


Figure 3: National Grid's current STOR requirement and their 2020 projection under the Gone Green scenario (note this assumes that current sources make the same contribution in 2020 as in 2011)

The provision of balancing services outside the balancing mechanism has created a role for aggregators. Aggregators provide balancing services, including STOR, fast reserve and frequency response, by aggregating the response of a number of

[11] UK Future Energy Scenarios, National Grid, November 2011

generation and demand sites. In order to provide STOR services; a minimum response of 3 MW is required, hence the need for smaller sites that cannot provide this level of response individually to use aggregator services. Organisations with large sites that could provide a 3 MW response may still choose to use an aggregator, due to the complexity of the contracting arrangements with National Grid Electricity Transmission.

The bulk of the aggregator's services are currently sourced through contracts with onsite generators, although increasingly aggregators are entering into turn-down contracts with demand sites (in the case of frequency response services the contracts with demand customers will include the ability to both turn down and increase demand). The increasing requirement for balancing services, as shown in the figure above, and the significant but disaggregated potential of demand side resource (i.e. there is significant untapped potential but it is spread over a large number of customers), promises a growing role for aggregators in future.

Currently there are a small number of aggregators operating in the GB electricity market. Some of the more established actors include:

- Flexitricity
- KiwiPower
- Open Energi
- EnerNOC
- Energy Pool

Typically these aggregators provide balancing services to NGET and also additional services to demand customers, such as TRIAD management (further detail on TRIAD is provided in section 3.4.1). There is also interest from DNOs to use aggregator services to reduce peak loads on the distribution network, either through turn-down of demand customers or use of onsite generation. While these contracts are not commonly part of business-as-usual for DNOs, they are increasingly being trialled through LCNF contracts.

2.3 Distribution

Distribution network operators are responsible for providing the network which transports electricity from the transmission systems and generators that are connected to distribution networks to industrial, commercial, and domestic customers. There are fourteen DNO licence areas, covered by six DNO groups (see Figure 4 below). Each of the fourteen DNOs has a monopoly in its designated area and they are regulated by Ofgem to ensure consumers receive value for money network services.

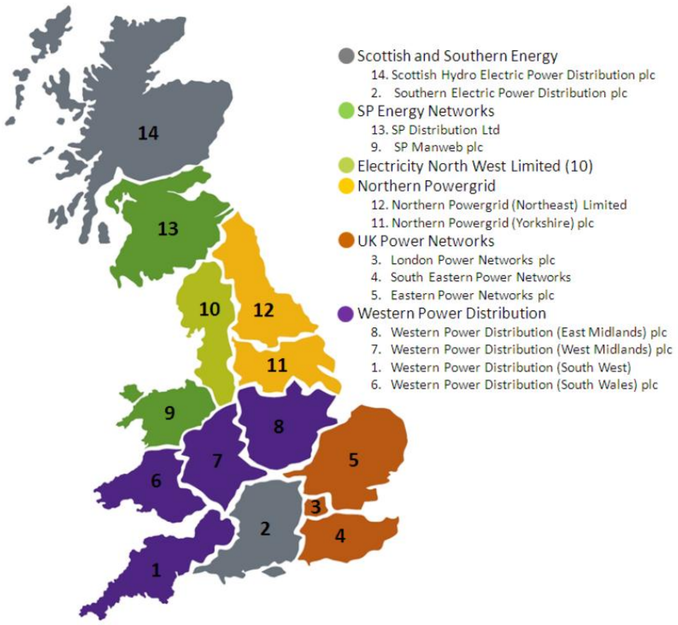


Figure 4: DNO location and ownership in Great Britain. Source: Ofgem

DNOs effectively carry electricity from the transmission system, or from distributed generation, to the exit point where the customers are. Meter Point Administration Numbers (MPAN) are used to uniquely identify each exit point receiving power from the distribution network (an Import MPAN), and each generation point feeding power into the distribution network (Export MPAN). In practice an MPAN can have several meters associated with it or indeed none where it is an unmetered supply.

The DNOs came into existence in 2001, evolving from ex-Public Electricity Suppliers. These DNOs have areas corresponding to the area in which they were formally the incumbent. An Independent Distribution Network Operator (IDNO) is any electricity distributor whose licences were granted after 1 October 2001, and IDNOs do not have distribution service areas. IDNOs own and operate distribution networks that are predominantly network extensions connected to the existing distribution network, e.g. to serve new housing developments. Six distribution licences have been issued: Scottish and Southern Energy; SP Energy Networks; Electricity North West Limited; Northern Powergrid; UK Power Networks; and Western Power Distribution.

It is also possible for DNOs to operate networks outside of their distribution service areas – the term “embedded licensed distribution network operators” (LDNO) refers to both this type of DNO operation and IDNOs. LDNOs capture only a very small part of the market, covering only 0.4% of MPANs in the Low and High Voltage (LV-HV) system. Different charging tariffs apply, but there is no specific licence for an LDNO. Instead there are DNO and IDNO licences. Whilst there are some standard conditions between the two, there are also differences, in particular concerning price control conditions. There are six licensed IDNO in the UK:

- Energetics Electricity Limited
- ESP Electricity Limited
- Independent Power Networks Limited
- The Electricity Network Company Limited
- UK Power Networks (IDNO) Ltd (wholly owned subsidiary of UK Power Networks)
- Utility Assets Limited

Licensing
Distribution and supply licences cannot be held by the same entity. There are some exemptions to the licensing for DNOs, including distributing small amounts of power (less than 2.5MW) to domestic customers, and distributors who distribute electricity only to non-domestic consumers.

2.4 Supply

Electricity suppliers purchase electricity on the wholesale market and then supply it to consumers. There are a large number of electricity supply companies, but six large supply companies dominate the UK domestic market: British Gas, Electricité de France (EDF), E.On, Npower, Scottish Power, and Scottish and Southern Energy (SSE). Since deregulation, new entrants have appeared in the market, but they tend to have subsequently exited for a variety of reasons. In 2008 it was estimated that new entrants served less than 1% of the market[12].

Licensing
A licence can be held either for supplying both domestic customers and non-domestic customers, or supplying non-domestic customers only. Within Great Britain, distribution and supply licences cannot be held by the same entity. Exemptions from the requirement to hold a supply licence exist for:

- Small suppliers (those who do not supply any energy they generate themselves and who supply less than 5MW in total, with less than 2.5MW to domestic customers;
- Resale of electricity originally purchased from a licensed supplier;
- On-site supply, where electricity generated is used by only one consumer, or group of consumers on the same site as the electricity is generated;

[12] Ofgem energy supply probe: Initial Findings Report, 2008.

- Suppliers who only supply electricity which has been generated at an offshore installation, and will be used at an offshore installation.

2.5 Current and future demand

The peak load on the GB electricity network is currently around 55 – 60 GW[13]. The rate of growth of this peak load is anticipated to accelerate rapidly over coming decades, driven by the increasing electrification of our heating and transport systems and far outstripping the historic rate of load growth. A projection for the increase in peak electricity demand over the period to 2050 is shown in the figure below. This plot is based on the Smart Grid Forum's Scenario 1, which combines DECC's high projection for the uptake of heat pumps and DECC's moderate projection for the uptake of electric vehicles (EVs) and photovoltaics. This scenario has been selected as it is consistent with meeting the Fourth Carbon Budget[14]. The contribution of heat pumps and electric vehicles to the demand increase can clearly be seen.

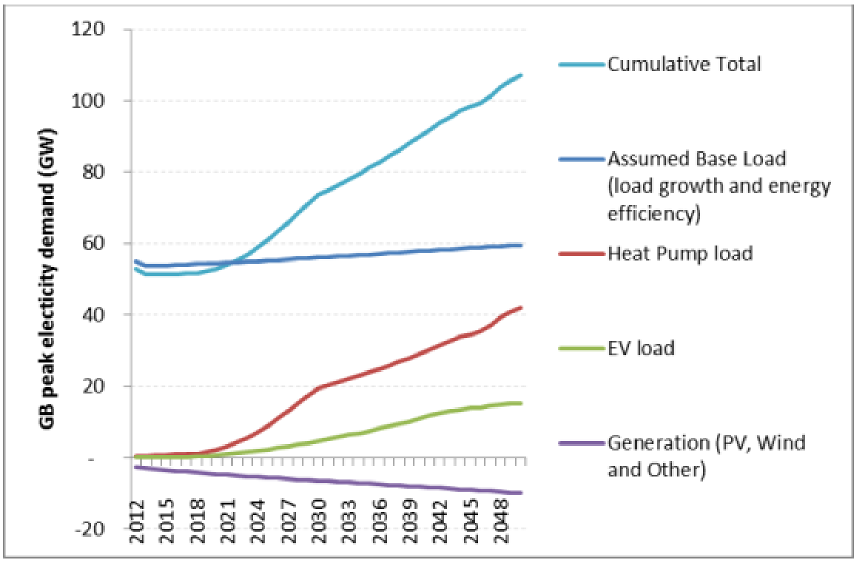


Figure 5: Projected increase in peak demand on the GB electricity system and the contribution from increasing uptake of electric vehicles and heat pumps under the Smart Grid Forum Work Stream 3 Scenario 1. 15

Demand growth of the scale shown in the figure above will create significant challenges for distribution network operators and the electricity system as a whole. The SGF Work Stream 3 analysis has shown that the networks have

13 See http://www.nationalgrid.com/ for live demand data
14 Carbon Plan, DECC (2011), http://www.decc.gov.uk/en/content/cms/tackling/carbon_plan/carbon_plan.aspx
15 'Assessing the impact of low carbon technologies on Great Britain's power distribution networks', Smart Grid Forum Work Stream 3 report, July 2012

sufficient headroom to accommodate modest levels of low carbon technologies, but that as uptake of these technologies increases, very substantial investment will be required.

The scale of the required investment is highlighted in Figure 6, which is also taken from the SGF Work Stream 3 report. In this plot the upper and lower bound projections of investment in the distribution networks related to the integration of low carbon technologies is shown, based on the demand growth shown in Figure 5. The upper bound case relates to a business-as-usual approach to network reinforcement. In the lower bound case, it is assumed that a full complement of smart technical and commercial interventions is available. The smart approach to network reinforcement is shown to offer the opportunity to very substantially reduce the required investment.

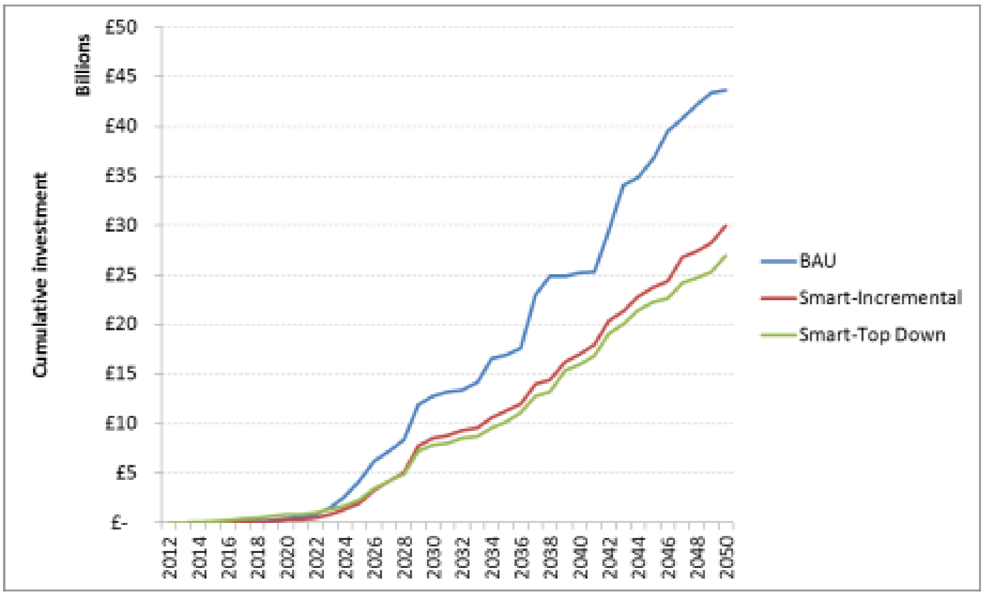


Figure 6: Projection of the cumulative investment required in distribution networks related to the increasing connection of low carbon technologies under various conventional and smart reinforcement strategies. The plot is reproduced from the Smart Grid Forum Work Stream 3 report (see Figure 8.11, pg. 96 of the Smart Grid Forum report).

3. Description of the legislative and regulatory framework

This section gives a brief overview of the electricity market codes (3.1), followed by a more detailed description of the contractual agreements most relevant to DNOs (3.2). Codes and agreements define the charging methodologies that DNOs can apply to generators connecting and suppliers using the system; these methodologies are discussed in section 3.3, along with regulated revenues DNOs will levy in 2012-13. Other charges which affect the incentives for DNOs, as well as the incentives for distributed generators are also introduced (3.4). The last section presents the price control regime and incentives DNOs are subject to, set by Ofgem.

3.1 Electricity market codes

Electricity market licensees have an obligation to maintain codes that set out technical parameters and/or rules related to the use of the electricity system. Ofgem reviews and approves code modifications.

The schematic below lays out the scope of codes describing governance rules and/or contractual agreements (round shapes) in terms of parties. It also shows the ownership of codes focusing on technical specifications (square shapes); these are relevant to several stakeholders. Table 3-1 gives a brief description of the codes, highlighting the relevance to DNOs.

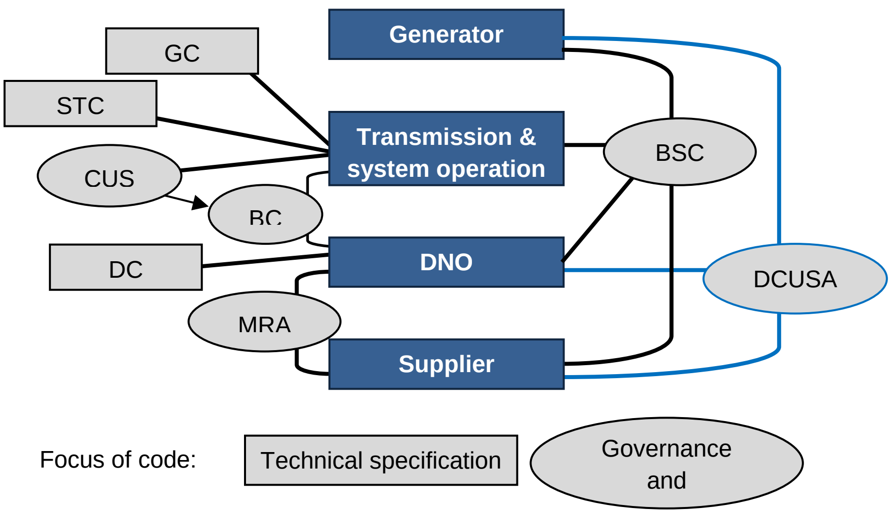


Figure 7: Main codes in place: ownership of technical codes and scope of governance codes

The most relevant code for DNOs is the Distribution Connection and Use of System Agreement (DCUSA), which is described in more detail in the next section.

DNOs and other licensees are also expected to comply with the Fuel Security Code and the Revenue Protection Code. The Fuel Security Code describes the licensees' roles and duty when, under exceptional circumstances, the Secretary of State decides that a generating station is to be operated in a certain way (under section 34(4)(b) of the Electricity Act).

Table 3-1: Codes in force in the electricity market in GB. Sources: Ofgem, NG, ENA, MRASCo

Code	Scope of document and relevance to DNOs
Distribution Connection and Use of System Agreement (DCUSA)	It governs connection and use of system arrangements on the distribution networks, namely the Common Distribution Charging Methodology (CDCM) and the Extra High Voltage Distribution Charging Methodology (EDCM). These methodologies define how DNOs calculate the charges generators and suppliers pay to use the distribution networks. The CDCM also lays out the compensation payment DNOs may have to pay to customers in case of network outages.
Master Registration Agreement (MRA)	DNOs must be a party to and comply with the MRA, a multi-party agreement between all licensed DNOs and suppliers. It provides a governance mechanism to manage the processes established between suppliers and DNOs to enable electricity suppliers to transfer customers, and sets out terms for the provision of Metering Point Administration Services (MPAS Registrations). The MRA is administered by MRA Service Company (MRASCo), a joint-venture company established and maintained by all MRA parties.
Distribution Code (DC)	DNOs must implement and comply with the DC. It details the technical parameters and considerations relating to connection to, and use of, electricity distribution networks. It specifies day-to-day procedures that govern the relationship between the distribution licensee and users of its distribution system for planning and operational purposes in normal and emergency circumstances.
Balancing and Settlement Code (BSC)	DNOs must be a party and comply with the BSC. It contains the rules and governance arrangements for electricity balancing and settlement in GB. It provides the mechanism through which the system operator recoups its costs and is managed by a company called Elexon.
Connection and Use of System	DNOs must be a party and comply with the CUSC, it is owned by National Grid Electricity Transmission. It is the contractual

Code (CUSC)	framework for connection to and use of NGET's high voltage transmission system. DNOs must be a party of the CUSC Framework Agreement and sign up to the CUSC in order to connect to the National Electricity Transmission System (NETS). Bilateral Connection Agreements (**BCA**) describes the arrangements between NG and the DNOs, including transmission exit charges.
Grid Code (GC)	Owned by National Grid Electricity Transmission. It covers all material technical aspects relating to the planning, operation and use of the NETS. DNOs must comply with the Grid Code.
System Operator Transmission Owner Code (STC)	Owned by National Grid Electricity Transmission. Sets out roles and responsibilities of the transmission System Operator and each Transmission Owner with regard to the planning and operation of the NETS. Not directly relevant to DNOs.

3.2 Contractual agreements

The main contractual agreement relevant to DNOs is the **Distribution Connection and Use of System Agreement (DCUSA)**; it applies to suppliers as well as distributed generators. DGs and DNOs also sign bilateral connection agreements (BCA).

The DCUSA is a multi-party contract between several electricity market licensees: distributors and suppliers – who are required to be parties under their licence – as well as the Offshore Transmission System Operator (OTSO, National Grid Electricity Transmission) and generators who want to connect to and use the distribution network.

Launched in 2006, the DCUSA replaced numerous bilateral contracts, giving a common and consistent approach to the relationships between licensees. It defines the conditions of use of the electricity distribution systems and the roles and responsibilities of licensees. It aims at facilitating an effective competition in the sale, distribution and purchase of electricity.

The governance of the DCUSA is administered by DCUSA Ltd, a company established, owned and funded by parties to the DCUSA.

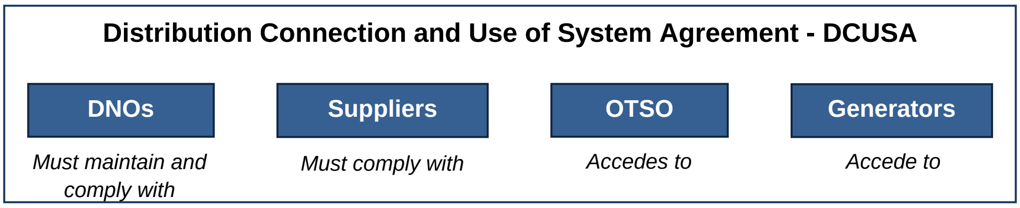


Figure 8: DCUSA parties and their relationship with the DCUSA

Users of distribution networks must pay distribution use of system (DUoS) charges to DNOs; through these charges DNOs recover their regulatory revenue allowances set by the price control review (more details on price control can be found in 3.5).

Before 2010, each DNO had its own methodology to calculate DUoS charges. DNOs have now developed common charging methodologies for low and high voltage customers as well as Extra High Voltage (EHV) customers importing electricity into the network. The DCUSA incorporates the DUoS charging methodologies as well as the Common Connection Charging Methodology (CCCM)[16] (listed in Table 3-2).

Table 3-2: Common methodologies for distribution use of system and connections charges

Charging methodology	Scope	In force from
CDCM: Common Distribution Charging Methodology	Low and High Voltage consumers – suppliers, distributed generators and LDNOs	April 2010
EDCM: Extra High Voltage Distribution Charging Methodology	Extra High Voltage consumers – large distributed generators (who export power to the distribution network), large industrial and commercial customers (import from the network) and LDNOs	Import Charges: April 2012 Export Charges: April 2013
CCCM: Common Connection Charging Methodology	Low to Extra High Voltage consumers – distributed generators and LDNOs	October 2010

3.3 Connection and distribution use of system charging methodologies

It was previously explained that DNOs calculate charges for network users according to common methodologies, namely the CDCM and EDCM. Figure **9** gives a simplified representation of the boundaries of application. Where LDNOs operate, they are also liable for charges but are not represented in the schematic. Note that some DG sites can be both exporting to and importing from the grid, e.g. large industrial sites with Combined Heat and Power systems.

[16] The CCCM came into force in October 2010 and was introduced in the DCUSA at the beginning of 2013.

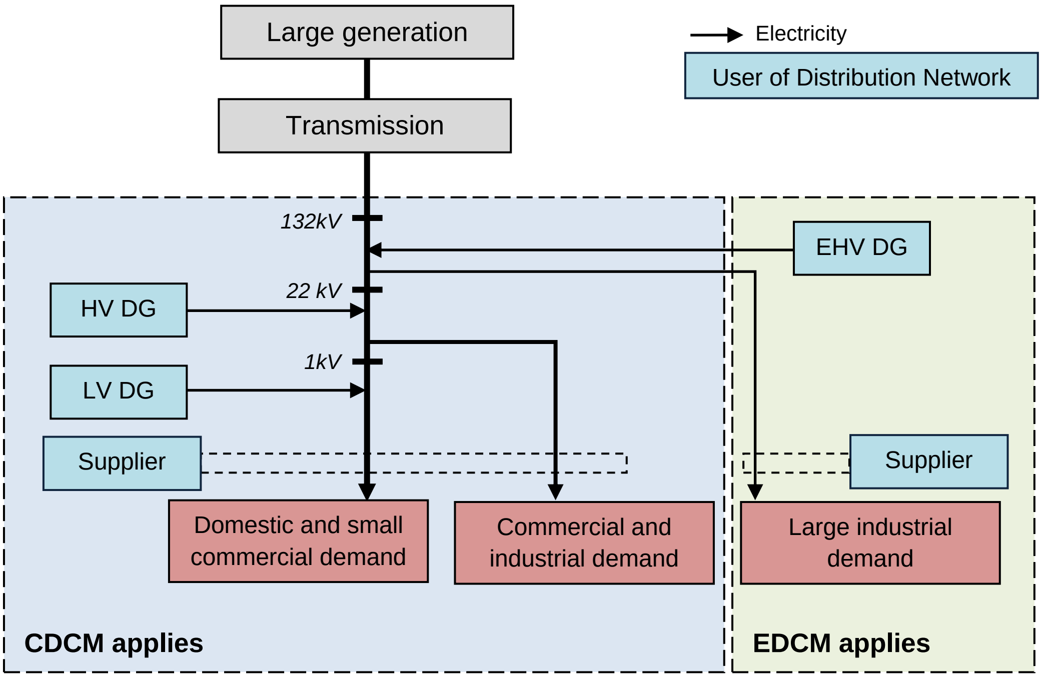


Figure 9: Boundaries of application for DUoS charging methodologies

CDCM - Common Distribution Charging Methodology

The principle of the CDCM is to calculate the costs incurred by DNOs to install, maintain and operate assets and determine tariffs for different users, based on predicted load volume and use of assets. Estimated tariffs are adjusted to ensure the predicted derived revenue matches the allowed revenue, as defined by the price control regime (see section 3.5).

Figure 10 provides an overview of the CDCM. All DNOs use the same Excel-based model to carry out the calculation of tariffs and populated models for each distribution area are publically available[17].

DNOs levy these charges on the registered electricity supplier who in turn have contracts with end customers either on a fixed or variable contract for the majority of low and high voltage distribution use charges, with the demand dominated by LV customers. Tariffs calculated for suppliers and DG are 'all the way' charges, i.e. reflects cost of asset and operation of the whole distribution network; LDNOs (embedded network) receive a discount on these fees.

Distributed generators pay charges related to the MPAN but are currently paid (in the form of use of system credits) for electricity they export to the network. Charges paid and received by network users are detailed in the next sections. The tariff structure is fixed under the CDCM and is common throughout the industry.

[17] http://www.energynetworks.org/electricity/regulation/commercial-operations-group/charging-structure/use-of-system/development/structure-of-charges-cdcm/common-distribution-charging-methodology.html

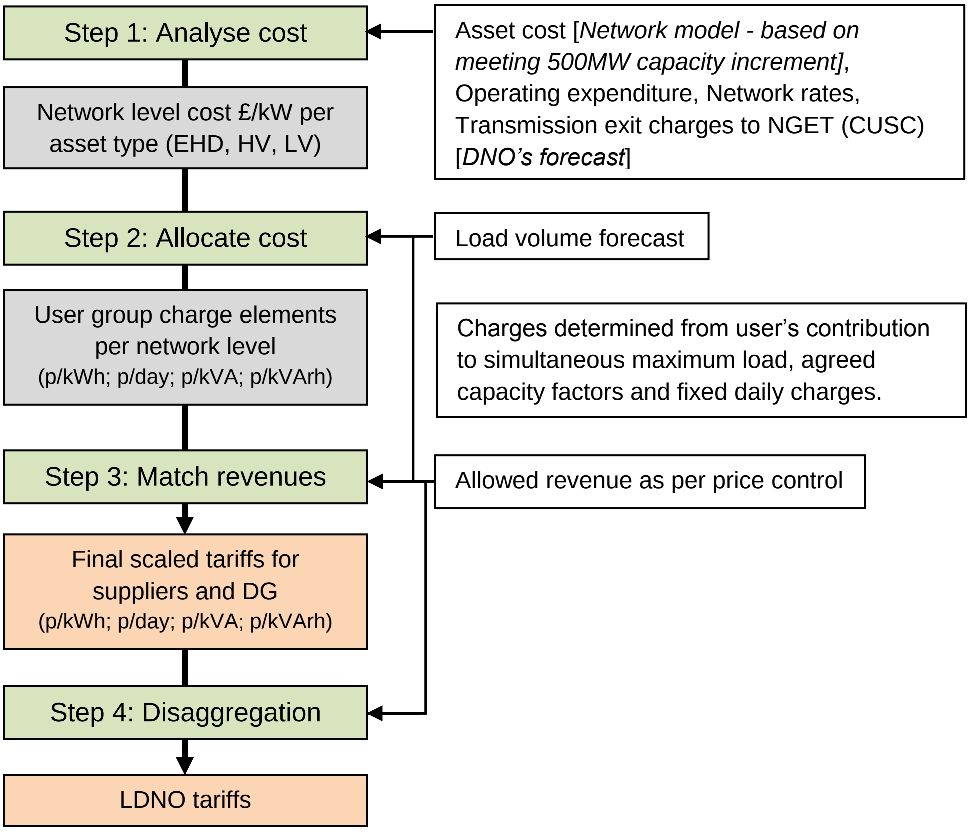


Figure 10: Overview of the CDCM

EDCM - Extra High Voltage Distribution Charging Methodology

The EDCM has been in place for designated EHV demand properties since April 2012 and produced import charges. The methodology for export charges (generators) has been approved and implemented from 01 April 2013.

EHV Distribution (EHD) demand users must pay charges to cover some cost common to the CDCM, e.g. transmission exit charges, but not the cost related to high and low voltage assets. The EDCM is based on a power flow model and is linked to the asset costs detailed in the CDCM.

The use of the network for EHV (demand) end-users may incur any or all of the four types of charges: fixed charge (p/day), import capacity charge (p/kVA/day), exceeded import capacity charge (p/kVA/day) and a seasonal super-red unit charge (p/kWh). The super-red charge is the charge applied for consumption at the time of the DNO peak, for example 16h-19h30 Monday to Friday, November to February.

Conversely, non-intermittent generators[18] exporting to the EHV network may receive extra payment ("super-red credits") for their production during peak time, if their output/site defers reinforcement.

The objective of EDCM is to produce cost reflective charges to encourage existing and new customers to help DNOs to use existing network capacity efficiently and avoid prompting inefficient and costly network reinforcement. Two key features are the locational demand charges reflecting level of network capacity congestion and higher credits for generation in areas where there is little spare capacity.

CCCM - Common Connection Charging Methodology

Generators and IDNO wishing to obtain a Metering Point Administration Number (MPAN, associated with a supply point) and connect to the distribution system must enter into a set of contractual arrangements, including a Connection Agreement, with the area DNO[19]. Connecting to the network incurs a charge[20] calculated as per the DNO's Connection Charging Methodology that comprises, since October 2010, a section common to all DNOs (the CCCM) and a section specific to each DNO (the Company Specific Methodology) . The CCCM also applies to users wishing to increase their capacity.

Connection work is split into two categories:

- Non contestable work: it has to be carried out by the area DNO or their appointed agent. It includes network reinforcement.
- Contestable work: the generator/IDNO to be connected has the option to choose an Independent Connections Provider (ICP). This includes, among others, procurement and provision of equipment, trenching and other preparation of the site.

The CCCM defines what costs must be covered by the generator/IDNO and, in case of reinforcement being necessary, how that cost is apportioned between the user and the DNO. DNOs publish on their website their statement of methodology and charges for connection, which gives practical connection examples and related costs.

[18] Ofgem decision of 05/12/2012 confirmed intermittent generators are not eligible for super credits as their output time cannot be controlled.

[19] It could be a bilateral agreement (usually for larger customers); alternatively the National Terms of Connection cover all types of customers in the absence of a bilateral agreement. Terms can be found at http://www.connectionterms.org.uk/

[20] Note that unlike the other charges discussed, this is a one-off charge at the time of connection

3.3.1 Suppliers' charges

Suppliers pay DNOs for the use of the system as per the CDCM for LV and HV users (or EDCM for suppliers of EHV users). They incur four charges for the **import** of electricity from the transmission system down to electricity end-users:

- A unit rate in p/kWh.
  There are ten different non half hourly (NHH) metered demand tariff structures[21], e.g. 'Domestic unrestricted', 'Domestic off-peak', 'LV Medium Non-Domestic', the highest being under 3p/kWh.
  There are five half hourly (HH) metered tariff structures[22], who have three rates, corresponding to three times of the day, referred to as 'green', 'amber' and 'red'[23]. The green unit rate is typically much cheaper than the domestic rate (<1p/kWh) while the red rate is much higher, up to 20p/kWh, in order to discourage users to contribute to peak demand.
- A fixed charge in p/MPAN/day
  Again the tariff varies with user types, with non-domestic and HV users being charged higher rates. It does not apply to unmetered supplies.
- A capacity charge in p/kVA/day – this applies only to HH metered demand[24]
  This is charged typically 2 to 10 p/kVA/day, varying with voltage level. HH metered businesses agree their maximum import capacity (MIC) with their suppliers who in turn specify the MIC in their BCA with the DNOs. Exceeding the MIC is a breach of the BCA and can incur extra charges (known as excess capacity charges) on the supplier.
- A reactive power charge in p/kVArh – this applies only to HH metered demand. This is charged at 0.2p/kVArh on average across DNOs.

The fixed and capacity charges are used to reduce the unit charges by covering some asset costs[25].

[21] NHH tariffs are allocated to a given user based on the corresponding profile class (standardised load profile), connection level and other industry data, see Appendix 9.1 for more details. From April 2013 there will be 13 NHH tariffs as the NHH UMS tariff has been split into 4 separate tariffs (category A, B, C and D).

[22] HH meters (~117,000 in the UK) are for businesses with high energy usage. They are mandatory for all business users with a maximum demand of 100 kW or more. Businesses with lower demand (but more than 70kW) have the option to have a HH meter.

[23] Examples of time bands: Red 16:00 – 19:30 (Monday to Friday); Amber 08:00 – 16:00 and 19:30 – 22:00 (Monday to Friday); Green – All other times. Each DNO can choose the time band for its network and must give 15 months' notice for amendments. From April 2013 there are also 'green' 'yellow' & 'black' rates for the HH UMS tariff.

[24] NHH tariffs have an element in their fixed charge to reflect that they do not pay capacity charges.

Suppliers pay DNOs charges as defined by the EDCM for EHV users. They incur four charges for the **import** of electricity:

- A fixed charge in p/day – sole use asset charges for direct operating costs and network rates.
- An import capacity charge p/kVA/day – applied to the maximum import capacity. This charge takes into account the location of the EHV user and therefore varies across users. It also reflects the pre-allocation of direct operating costs, indirect costs, network rates and transmission exit charges.
- An exceeded import capacity charge p/kVA/day – applied only if the agreed import capacity has been exceeded, as above it varies with the location of the user.
- A super-red unit rate p/kWh – applied during the seasonal 'super-red time band', which is defined by each DNO to correspond to peak time.

Suppliers also pay charges/receive credits for the electricity DGs **export** to the distribution network; these are detailed in the next section.

Figure 11 gives an illustrative split of charges paid by suppliers (based on the CDCM 2012-13 calculations of the 14 DNOs) and shows DNOs levy revenue from suppliers mainly from the unit charge on LV-HV networks.

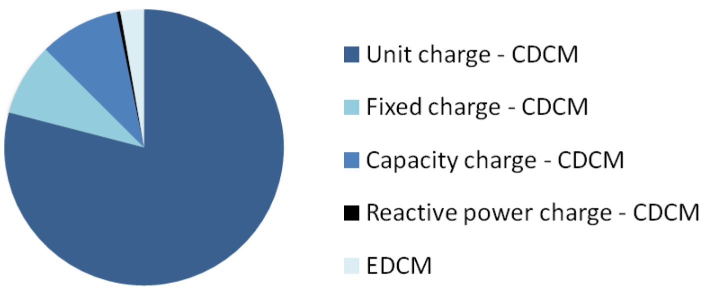


Figure 11: Split of the £5.2 billion DNOs levy from suppliers, based on analysis of CDCM calculations for 2012-13

3.3.2 Distributed generators' charges and payments

DGs pay for the use of the system as per the CDCM for generators connected at LV and HV levels as well as connection charges. Connection charges are paid directly to the DNOs, whereas charges for use of system are passed on through the suppliers.

The use of system incurs two charges and one payment rate:

[25] Full details of charges calculations can be found in the CDCM (Schedule 16 of the DCUSA).

- A fixed charge in p/MPAN/day – this applies only to HV[26] HH metered generation.
  The same tariff applies to all generators (intermittent and non-intermittent), but varies greatly across DNOs (from 6 to 230 p/MPAN/day). As for the fixed charge billed for delivering electricity to the end-user, this fixed charge covers some of the assets involved in the transport of the exported electricity.
- A reactive power charge in p/kVArh – this applies only to HH metered generation. This typically costs under 1p/kVArh.
- A payment unit rate in p/kWh.
  DGs are paid for the electricity they export to the network, reflecting the fact their contribution defers network expansion and could offset some demand. On average, intermittent power receives a reduced payment; see Figure 12 for current average rates. Non-intermittent generators have a 3-part time payment, mirroring the 3-part time rates paid by suppliers.

Suppliers pay DNOs charges and receive credits as defined by the EDCM for EHV generators:

- A fixed charge in p/day – reflects sole use asset charges for direct operating costs and network rates.
- An export capacity charge p/kVA/day – This charge takes into account both local and remote elements of the asset cost.
- An exceeded export capacity charge p/kVA/day – applied only if the agreed export capacity has been exceeded, at the same rate as the export capacity charge.
- A super-red unit credit p/kWh – for non-intermittent generators only, applied during the seasonal 'super-red time band'.

Payments outstrip charges: in the 2012-13 CDCM, DNOs forecast DGs on low and high voltage networks will produce 7.5TWh (<3% of LV and HV demand), giving rise to £34million in payments while paying under £0.5million in charges.

Exemptions

Generators who connected before April 2005 can choose to be exempt from DUoS charges for a period of 25 years from the date of connection, in order to avoid double payments for operation and maintenance charges.

[26] LV generators are generally also users and therefore suppliers already pay their corresponding fixed charge for delivering electricity to them

Generators on LDNO networks get a 100% discount on DUoS charges; they however generate a negligible amount of electricity (<3MWh/yr versus 7.5TWh/yr from all DG).

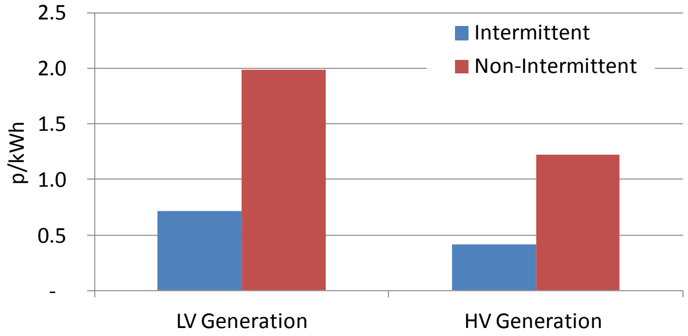


Figure 12: Average unit charge paid to suppliers for DG, based on CDCM calculations for 2012-13

3.3.3 Embedded network charges

The same charges that apply to suppliers (see section 3.3.2) also apply to LDNOs but at a discounted rate; connection charges must also be paid when first connecting up to the main distribution network.

3.3.4 Illustrative network charges

The previous sections detailed the use of system charges that DNOs apply to the distribution system users as well as the payments corresponding to the export of electricity by DG. Total DNO revenues for 2012-13 in GB are projected to amount to £5.257billion, Figure 13 shows a breakdown of this revenue in terms of end-user type (domestic / non domestic) as well as charge type. The revenue split between low, high and extra high voltage users is respectively 82%, 15% and 3%.

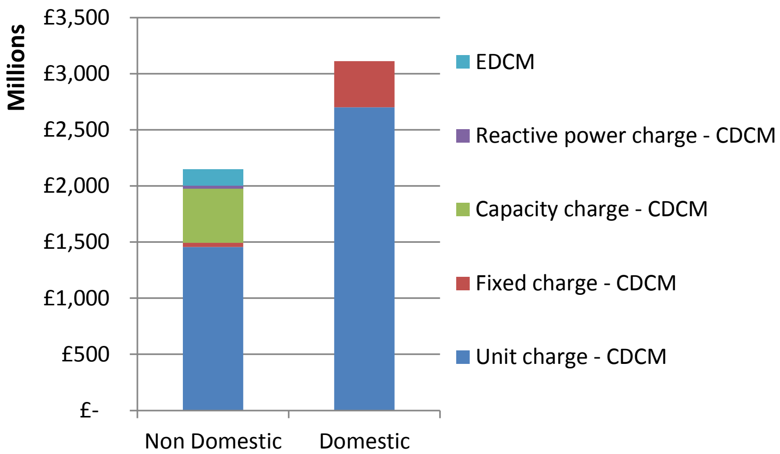
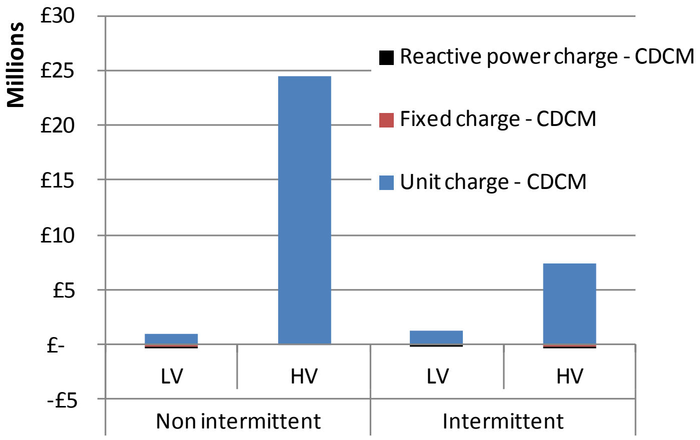


Figure 13: Split of the 2012-13 £5.27billion revenues of DNOs for use of system, by end-users and charge type based on EDCM and CCDM calculations for 2012-13

The revenue levied from DG does not appear in Figure 13; it is however negligible, with a total of approximately £750,000. DGs are paid for the electricity they export by DNOs (indirectly, through payments/charges to suppliers); the total balance amounts to £33.6million; see figure below for breakdown.



Paid to DNOs, £thousands	Reactive power	Fixed charge
Non intermittent DG	17	211
Intermittent DG	16	130

Figure 14: Split of the 2012-13, £33.6million paid by DNOs for LV-HV distributed generation, based on CCDM calculations for 2012-13

3.4 Other charges

There are a range of other charges which are important for understanding the incentives facing DNOs or the incentives facing distributed generators (e.g. transmission network use of system charges) to connect to the distribution system.

3.4.1 Transmission Network Use of System charges

The costs of installing, operating and maintaining the transmission system are recouped through the levying of Transmission Network Use of System charges (TNUoS charges). TNUoS charges are split between generators and users of electricity[27]. Charges are based on the location of the user of the transmission system, and their import and export requirements. As with the DNOs, the charges are regulated by Ofgem so that the transmission system operator can recover costs up to an “allowed revenue” level. The charges are defined in the CUSC.

Generation TNUoS charges

Generators are charged according to their location and connection type. The locational charging intends to reflect whether the generation contributes to or alleviates the need for additional transmission reinforcement and or investment. In general, tariffs are higher for generators in the North of the country, reflecting

[27] DNOs pay on-going charges for their connections to NGET commonly known as exit charges these costs are factored into their allowed revenue calculations and recovered through UoS charges.

the fact that there is currently a north-south flow of electricity. The revenues of generators are not regulated and it is therefore likely that these costs are passed through to suppliers and eventually to consumers.

Demand TNUoS charges

Users of electricity are also charged according to their location and meter type, and use during times of peak demand. Suppliers' charges for half-hourly, metered demand are based on the average of the actual demand supplied during the TRIAD. The TRIAD is defined as the three half-hourly settlement periods of highest transmission system demand during November to February of a financial year. Non-half hourly metered demand charges are based on the energy demand between 16:00 – 19:00 over the entire year. In general tariffs for consumers are higher in the South. Suppliers pay these charges and pass them on to consumers of electricity.

3.4.2 Balancing Services Use of System charges

National Grid Electricity Transmission is allowed to recoup its costs associated with balancing flows over the transmission system through the Balancing Services Use of System (BSUoS) charges. All users registered within the Balancing and Settlement Code are liable to pay BSUoS, based on their energy take from or supplied to the National Grid System in each half-hourly settlement period. Where suppliers pay these charges they are likely to be passed on directly to consumers. Where generators pay these charges it is likely that these are passed through to suppliers and eventually to consumers.

3.5 The price control regime

DNOs have regional monopolies, and therefore are regulated to ensure that efficient distributors can earn a fair return and operate safe, secure and reliable networks, whilst limiting the amounts customers can be charged. Ofgem sets the price controls in Great Britain, where regulation has continued to evolve to protect consumers' interests through a system of incentives to reduce costs, and more recently to encourage innovation to prepare for the future challenges of a low-carbon energy supply system.

3.5.1 Distribution Price Control Review 5

The current price control, which runs from April 2010 to March 2015, is known as Distribution Price Control Review 5 (DPCR5). The price control takes the form of a revenue cap which determines the maximum revenue a DNO can collect from its customers. It allows for revenues to be updated annually for changes in the Retail Price Index (RPI), and for changes in specific cost and revenue items since the price control review, and adjustments for rewards and penalties in relation to DNOs' performance in managing interruptions, losses, and customer service.

Total allowed revenues were set at £16billion, with network investment the major expenditure item at ca. £7.6 billion. Distribution prices were allowed to rise on average 5% p.a. over the period, although this average masks some wide variations in the increase in revenue allowed across the country, from -4% to 11%.

DPCR5 introduced a regulatory framework that addressed three themes: climate change, in particular by facilitating new uses of the networks that will arise as part of the move to a low carbon economy; customers, encouraging DNOs to pay more attention to all aspects of customer service; and networks, encouraging efficient investments that take account of changes in customers' future needs; see Appendix 9.2 for details on the incentive and obligation package.

3.5.2 RIIO-ED1

In 2009-10, after twenty years of incentive-based revenue control (known as RPI-X regulation), Ofgem undertook a detailed review of energy network regulation, known as RPI-X@ 20. The main conclusion of this review was the decision to implement a new regulatory framework, known as the RIIO model (revenue = incentives + innovation + outputs).

RIIO–ED1 will be the first electricity distribution price control review under the RIIO model, and will cover an eight-year period (2015 -2023). The period has been lengthened to increase DNOs' ability to manage more effectively the uncertainties they face in the move to a low-carbon economy. The RIIO model will allow Ofgem to set the outputs that DNOs need to deliver, as well as capping the total revenues. Output-based regulation involves the regulator defining output targets, and providing profit incentives on operators to achieve those targets[28]. It is thought to ensure that companies face more powerful incentives to innovate, and to ensure that stakeholders can engage in the price control process. Ofgem have set out proposals on outputs and incentives, covering six topics: safety, customer satisfaction, environment, conditions for connections, social obligations, and reliability and availability

The overall aim of the RIIO-ED1 framework is to strengthen the incentives to meet the challenges of delivering a sustainable energy sector at a lower cost. DNOs will be responsible for developing long-term strategies for delivering network services that customers value. They will need to connect potentially significant volumes of

[28] See Frontier Economics, RPI-X@20: Output measures in the future regulatory framework , 2010, for a detailed review of output based regulation and how it works

local generation and low-carbon demand without causing network problems. There is uncertainty about the timing, location and impact of this demand. The DNOs will need to manage this uncertainty, build in flexibility, and avoid investing in assets that may be redundant. DNO business plans will need to set out the strategy to combine an appropriate balance of funding, and uncertainty mechanisms, to flex to achieve the different scenarios of low carbon technology deployment at lowest cost.

4. Detailed analysis of current commercial arrangements

This section presents the commercial arrangements currently in place in the electricity market for generators and suppliers. Although centralised generators do not have direct contracts or connections with DNOs, their arrangements are presented along with the wholesale market (4.1) before introducing conditions that are specific to distributed generators (4.2). Arrangements for suppliers and large end-users are presented in 0 while balancing services - that concerns both generators and large end-users – are presented separately (4.5).

4.1 Large generators

Figure 15 shows the main charges and revenues of UK electricity generators. Beyond the investment and operating costs, generators face use of system charges in order to be able to export their electricity (TNUoS, see section 3.4.1).

Generators primarily sell their energy into the wholesale market, through bilateral contracts with suppliers. The value of the electricity is determined by the market, and depends on the amount of supply versus the amount of demand across Great Britain (further explained in 4.1.1). Generators can also establish contracts directly with a third party e.g. the electricity end-user, this type of arrangement is typically sought by users who want to source a particular type of generation, generally renewable – this type of contract is presented in more detail in 4.1.2 as it is also relevant to distributed generators and hence DNOs.

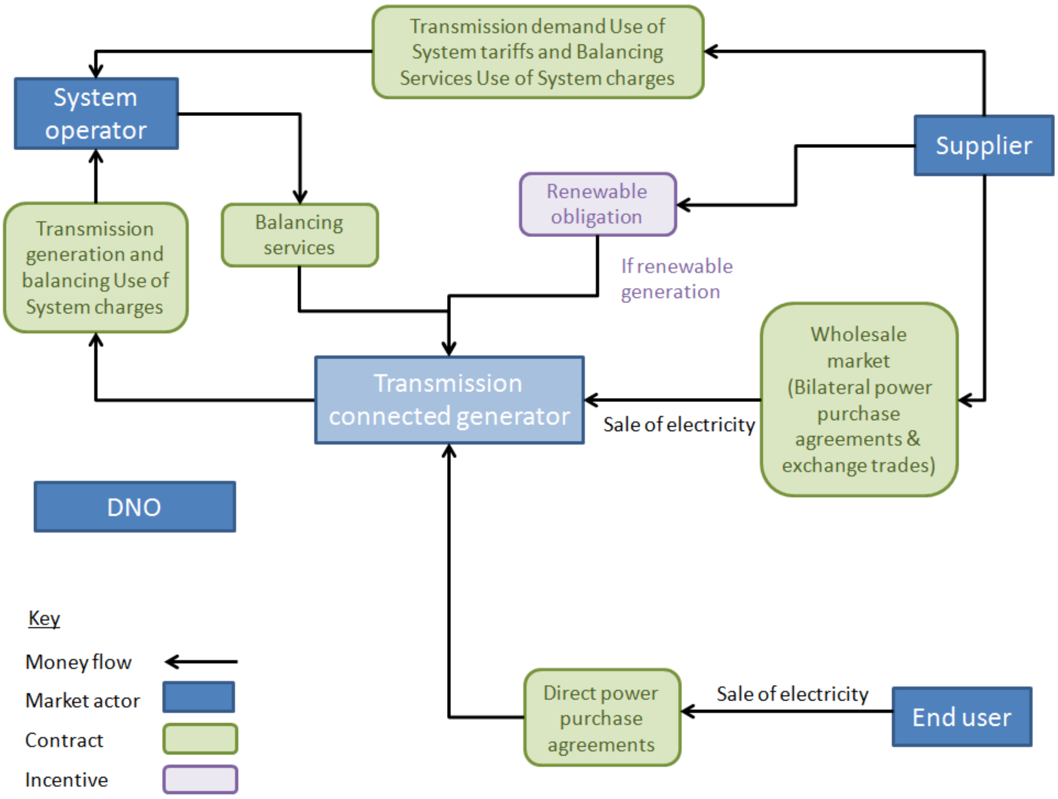


Figure 15: Generators main charges and revenues

There are two other revenue sources electricity generators can access, revenue from providing **balancing services** (see section 4.5) and revenues from the **incentive regime** e.g. payments for generating electricity from renewable sources[29].

Incentive for renewable generation

The UK Government has introduced an incentive regime to encourage the uptake of energy generation from renewable sources. A key driver behind this is the legally binding target of generating 15% of energy from renewable sources by 2020. This means around 30% of electricity will have to come from renewable sources by 2020, a significant increase compared to current levels of 10%[30].

Generators based on renewable energy can gain support from the Renewables Obligation (RO). Ofgem issue Renewable Obligation Certificates (ROCs) to generators in relation to the amount of eligible renewable electricity that they generate. Generators sell the ROCs to suppliers or traders, and hence receive a premium, in addition to the wholesale electricity price. Licensed suppliers are

[29] The impacts of the EU Emissions Trading Scheme and the Large Combustion Directive are out of scope of this study, but are noted here given their potential impacts on the broader electricity system.

[30] The UK Government believe they are on track to meet this target, see 'DECC, UK Renewable Energy Roadmap, 2011', paragraph 2.7

required to source a specified, and annually increasing, proportion of the electricity they supply from eligible renewable sources. In the current year 2012/13 suppliers must surrender to Ofgem 0.124 ROCs per MWh supplied, and this will increase to 0.154 by 2015/16.

Suppliers must submit ROCs to Ofgem to demonstrate their compliance with the obligation, or if they do not have enough ROCs to meet the annual target, they must pay a penalty known as the buy-out price. The buy-out price is linked to RPI, and is set at £40.71 per ROC for 2012/13. Revenues from the buy-out fund are recycled by Ofgem to those suppliers who meet the obligation. Ultimately the RO revenue received by generators is paid for by all electricity consumers, as suppliers pass all of the costs of the scheme on to their customers. The RO mechanism is illustrated in Figure 16.

Support levels for generators vary by technology, according to a number of factors including the technologies costs, relative maturity, and potential for future deployment. Generators receive between 0.25 – 2 ROCs per MWh. The value of ROCs is determined by bilateral commercial confidential negotiations between the supplier and the generator. The nominal value is composed of the avoided buy-out payment plus the portion of the buy-out fund redistributed to the supplier that presented the ROC. For 2010/11 this is estimated to be £51.48.

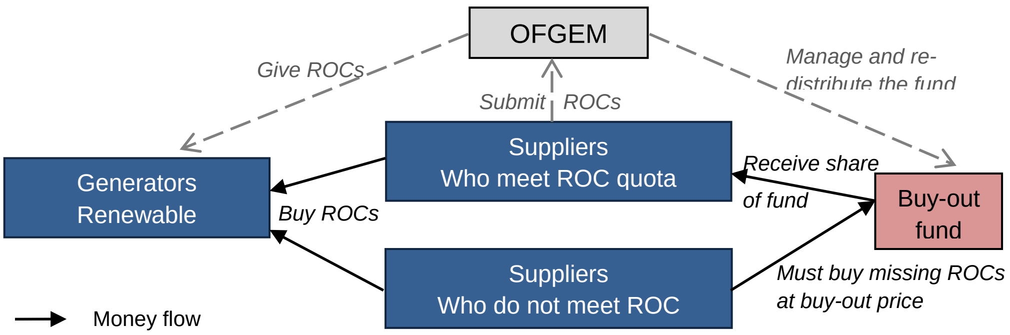


Figure 16: Renewable Obligation mechanism

The RO will not be open to new generators after 2017, although existing generators will continue to be able to access RO support for twenty years after accreditation. The Government's proposed Electricity Market Reform (see section 6.2) foresees a new support structure to replace ROCs, which will expand support to other low carbon solutions (nuclear, carbon capture and storage).

4.1.1 The wholesale market

The wholesale market is the market for the sale and purchase of electricity between suppliers and generators of electricity. The current GB trading arrangements allow suppliers to buy energy from a generating company of their choice, so that it is a competitive market. Prices are achieved through either negotiation directly between suppliers and generators (over-the-counter or bilateral contract) or via an exchange[31].

Figure 17 below shows an overview of the market structure, which is explained in more detail in the text below.

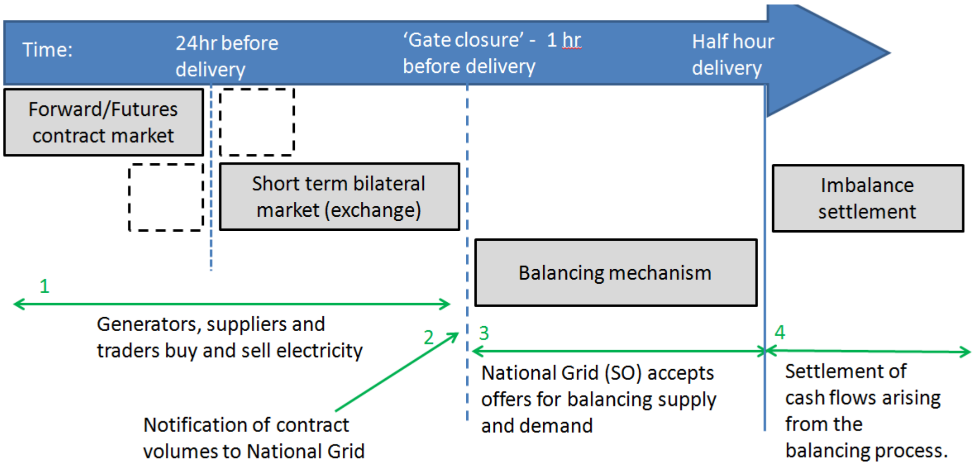


Figure 17: Overview of GB electricity market structure[32]

For the purposes of trading and settlement, half-hourly time periods, known as settlement periods, are used. For each half hour, those with demand for electricity (e.g. suppliers) will forecast what the demand will be. They then contract with generators for that volume of electricity. Contracts can be struck up to an hour before the settlement period that the contract is for. In the half hour itself, generators are expected to generate and deliver their contracted volume of electricity and suppliers are expected to use their contracted volume of electricity.

[31] There are three power exchange platforms in the UK: two for spot trading and day-ahead auctions ('APX-Endex' operated by the Anglo-Dutch APX group and 'N2EX', operated by ASDAQ OMX Commodities and Nord Pool Spot) and one for future and over-the-counter contracts (the InterContinental Exchange).
Ofgem analysis has shown that the UK market is dominated by over-the-counter trading; Ofgem is proposing solutions to encourage a market more transparent and more accessible to new entrants, see Ofgem 'GB wholesale electricity market liquidity: summer 2011 assessment' and ' Retail Market Review: GB Wholesale market liquidity update, July 2012' for more details.
[32] Adapted from the 2011 National Electricity Transmission System Seven Year Statement

However, in real-time, actual energy demand and supply can differ from this due to incorrect forecasts, problems with a generator, or problems transporting the electricity. National Grid Electricity Transmission, as the System Operator, manages the system in real time to ensure that supply matches demand, and to address any issues with transport or delivery.

In order to match supply and demand in real-time, generators might propose to either increase or reduce generation, and set a price for each of these changes. Similarly suppliers that are flexible enough can also offer to reduce demand or increase demand, and set the price for each of these changes. The System Operator will, in real-time, match supply and demand by accepting these offers to change to supply or demand depending on the mismatch.

Afterwards, metered volumes from generators and suppliers are collected for the half hour, and compared against contracted volumes (adjusted for any offers as described above). Where contracted volumes do not match the metered volumes, the supplier or generator must either buy or sell electricity to or from the grid to correct the imbalance. Settlement is the process of calculating these imbalance volumes and prices to be paid.

The system buy price is the price that generators must pay if they have been unable to generate as much energy as predicted. The average price during 2011 was £53.10/MWh. In comparison, the system sell price, the price paid by NGET for power generated that exceeds the forecast averaged £41.49/MWh over 2011. These figures compare with an average price on the wholesale spot market of £47.81/MWh. In practice, the differences between the average wholesale price and the system buy price and system sell price have the effect of being a penalty for intermittent generation, where accurate forecasting of output is difficult.

4.1.2 Direct contracts with third-parties

These are also known as direct power purchase agreements (PPA). Direct PPAs are contracts between electricity customers and generators (as opposed to contracts between electricity suppliers and generators as part of the wholesale market). The customer is able to contract directly with the generator for its electricity requirements. The customer then sells the electricity on to its own supplier, who “credits” the customer’s electricity account with the corresponding amount of electricity.

The figure below shows a schematic of this type of structure. For the electricity customer, these agreements can be more complicated to put in place than a standard supply arrangement, and so they are more suitable for large consumers. The benefits can be reductions in the price, and that a renewable supply source is identifiable.

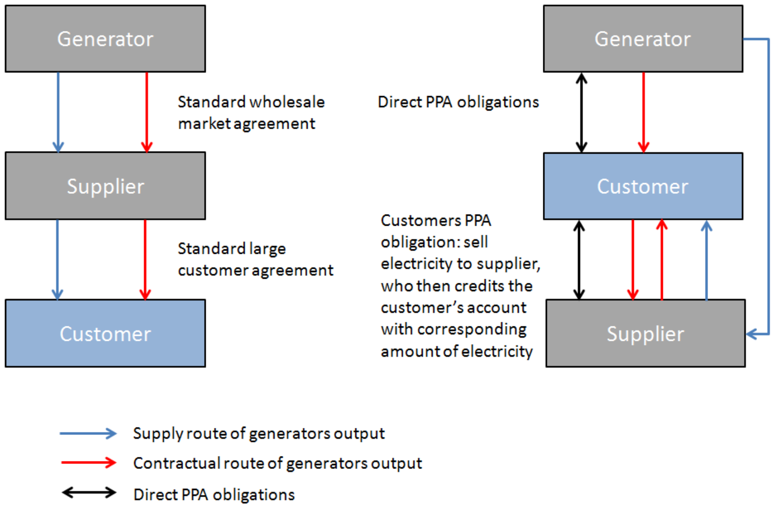


Figure 18: Example of a direct PPA structure

4.2 Distributed generators

The commercial arrangements for DG differ from large generators in various aspects, as the figure below shows: while they can sell their output like large generators, they benefit from more incentives and charge exemptions. They also have a direct relationship with DNOs to which they must pay connection charges (unless they fall under the Small Scale Embedded Generation definition). Incentives and connection agreements are presented in more detail next, followed by an analysis of how all these arrangements impact the DNOs.

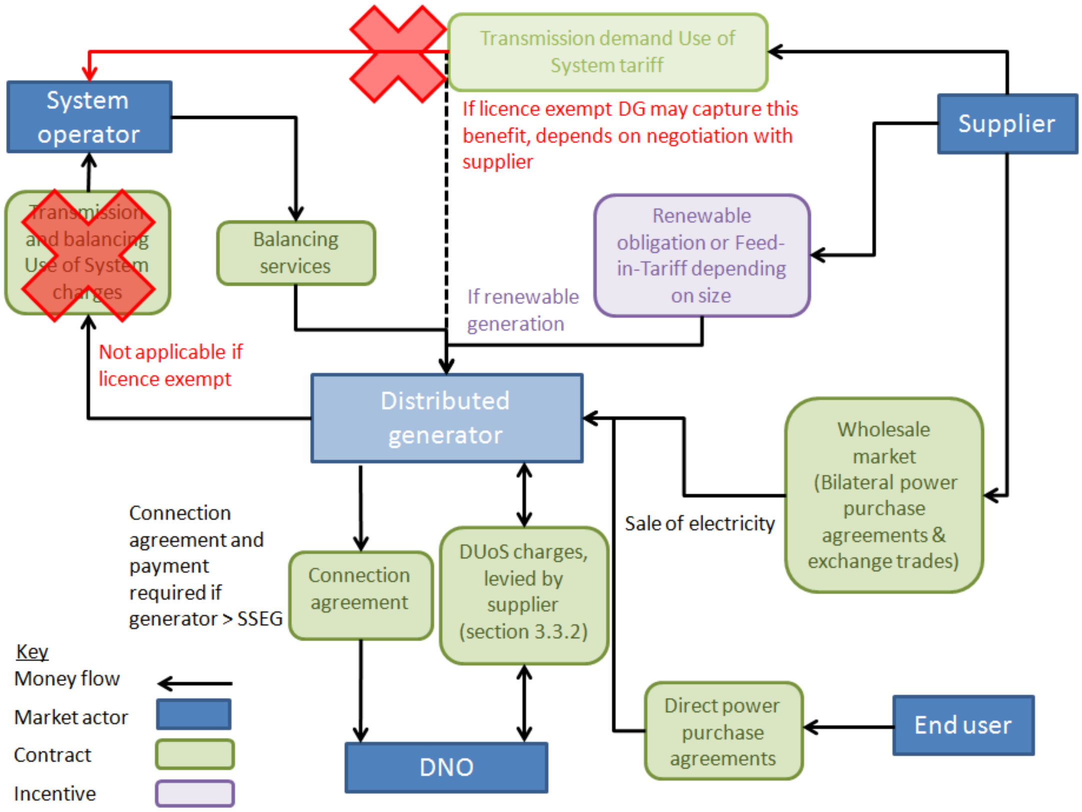


Figure 19: Distributed generators main charges and revenues

4.2.1 Incentives and embedded benefits

Incentives for all distributed generators

There are currently two support systems in place to incentivise DG. Larger renewable projects can gain support from the **Renewables Obligation** (presented in 4.1), whereas smaller projects gain support from **Feed-in tariffs** (FiTs). Projects between 50kW and 5MW in size have the option of deciding whether to use FiT or RO support, whereas those larger than 5MW are only eligible for the RO, and those smaller than 50kW are only eligible for FiTs.

The Feed-in Tariff scheme requires certain licensed suppliers to make tariff payments to households and business on both generation and export of renewable electricity (as well as gas powered Combined Heat and Power) from eligible installations. The suppliers pass on the costs of the FiT to all of their customers.

Generators receive three separate financial benefits from the FiT:

- A generation tariff, based on the total electricity produced and the fuel type. Current tariffs vary between 4.5p – 36p/kWh;
- An export tariff payment, for any electricity that is exported to the grid, of 4.5p/kWh; and
- Lower electricity bills, as less energy is imported from the supplier.

Support is available for twenty years following accreditation, with some exceptions.

Embedded benefits for licence exempt distributed generators

Embedded benefits relate to a mixture of trading and transmission charges for which distributed and licence exempt generators are not liable. Distributed generators are nearer to the point of end-use of electricity, and so they have historically avoided the charges associated with transmitting power over the transmission system, and the costs associated with balancing the transmission system. The Balancing and Settlement Code provides exemptible generation with flexibility in the way that its exports can be traded, allowing these costs to be avoided. These avoided costs are known as embedded benefits. The actual benefits accrue to the party who is responsible energy account which is the distributed generator is a part of. In most cases, this will be the energy supplier with whom the distributed generator has a contract. Whether the actual monetary benefit accrues to the distributed generator or the supplier will be subject to negotiation between those two parties. Further detail can be found in the Elexon document “Overview of Embedded Generation and Embedded Benefits, 2012”.

TNUoS charges

At present, unlicensed DG is treated as negative demand in TNUoS charging. It therefore avoids the TNUoS generation tariff and reduces the registered supplier’s TNUoS demand tariff liability: subject to negotiation between the DG and associated supplier, the DG may be paid the TNUoS demand tariff benefit by its relevant supplier. Ofgem and National Grid have had concerned that these arrangements overestimate the benefits of DG, which are mainly locational[33]. As it is, the TNUoS charge is composed of a locational element (ca. 15% of the TNUoS charge) and a residual element (ca. 85% of the TNUoS charge). Ofgem and NGET intend to change the regulatory regime so that the embedded benefit reflects the avoided costs more accurately, by removing the benefit associated with the residual TNUoS charge. The current embedded benefit from TNUoS charges is estimated at £20/kW[34], whereas a cost-reflective embedded benefit is estimated to be in the region of £6.50/kW - £7.25/kW.

BSUoS charges

There are also benefits in terms of reduced BSUoS charges, which operate in the same way as for TNUoS charging. The embedded generation is paid BSUoS charges, and the supplier is liable for BSUoS charges, so that the net effect is that the reduction in supplier demand due to the distributed generation reduces the suppliers' BSUoS liability.

Transmission losses

Costs of transmission losses are shared between generators who connect to the transmissions system, and demand loads throughout the network. The party responsible for the energy account to which the distributed generator is part (which in most cases will be the supplier) will receive a benefit as they are credited with the cost of the losses they are deemed to have saved. Again, whether the actual benefit accrues to the DG or the supplier who is responsible for the energy account is subject to negotiation between those two parties.

4.2.2 Detailed analysis of current connection agreements and connection charging principles

To connect to the distribution system, generators and loads may need to pay a connection charge to the DNO. This is a one-off cost, as opposed to the on-going charges that DNOs collect via suppliers outlined in section 3. Table 4-1 presents an overview of connection arrangements for generators.

[33] The Future of Britain's Electricity Networks, House of Commons Energy and Climate Change Committee, Second Report of Session 2009-2010, Volume 1.

[34] Pre-consultation, GB ECM-23 Transmission Arrangements for Distributed Generation, National Grid, 2010.

Table 4-1: Connection arrangements for LV – HV distributed generation

Type of connection	Engineering recommendation	Who pays for cost of connection
Single small-scale generation unit	G83/1-1 Stage 1	RIIO-ED1 proposes that connection costs are socialised (spread across all bill payers).
Multiple small-scale generation unit	G83/1-1 Stage 2	Extension of network paid by installer, reinforcement costs shared between DNO and DG
Other DG (mainly HV	G59/2	Extension of network paid by DG, reinforcement costs shared between DNO and DG

Process for connecting a generator

The process for connecting a generator to the distribution network depends on the size of the generator. Small-Scale Embedded Generation (SSEG) is low-voltage generation, and is defined in ENA-ER G83 as a source of electrical energy rated up to and including 16 A per phase, single or multiple phase, 230/400V AC. This corresponds to around 3.68 kW on a single-phase supply, and 11.04 kW on a three-phase supply.

To install a single unit of SSEG, approval is not required from the DNO; however the DNO must be informed by the individual or organisation commissioning the unit within twenty-eight days of the commission date. When multiple units of SSEG are being installed, then approval from the DNO is required. This circumstance may apply to new housing developments, or a housing refurbishment programme in the same road or street. The installer will need to apply to the DNO for approval, and may need to pay connection charges.

Connection charges

Connection charges would apply if the network needs to be extended or reinforced in order to accommodate the connection. The individual or body requiring the connection will be required to pay the full cost of sole use assets and a proportion of any connection-driven reinforcement work, with the proportion determined by the precise nature of the work required.

To understand the principles of charging for connections and cost apportionment, it is helpful to define key terms in the Common Connection Charging Methodology, set out in

Table 4-2.

Table 4-2: Key terms of the Common Connection Charging Methodology

Minimum scheme	The scheme with the lowest overall capital cost solely to provide the required capacity.
Enhanced scheme	In certain circumstances the DNO may decide to design an enhanced scheme, with additional assets, assets of a larger capacity, or assets of a higher specification than that required by the minimum scheme. In this case, the person requesting the connection will be charged the lower of the connection charge associated with the minimum scheme or the connection charge associated with the enhanced scheme.
Reinforcement	Assets that add capacity (either network or fault level) to the existing shared use distribution system.

There are three categories of cost, each of which is shared differently between the person requesting the connection and the DNO:

- Costs for providing the connection to be paid fully by the individual requesting the connection
    - Costs of extending the network to meet the connection (Extension Assets)
    - Any requirements in excess of the minimum scheme (e.g. requirements for additional security, particular load characteristics).
    - Reconfiguration of the distribution system that does not create any additional network or fault level[35] capacity.
    - For generation connection only, reinforcement costs in excess of the high-cost project threshold of £200/kW.

- Costs for providing the connection to be apportioned between the DNO and the person requesting the connection
    - Costs of reinforcement[36].
- Costs paid fully by the DNO
    - The DNO will fully fund reinforcement carried out greater than one voltage level above[37] the voltage at the point on connection to the existing distribution system.

[35] The maximum prospective current or power that will flow into a short circuit at a point on the network, usually expressed in MVA.
[36] There are some exceptions where the cost of reinforcement is not apportioned, but is instead paid in full by the person requesting the connection – e.g. if there is little or no prospect of the capacity created being required within the next five years, or if the reinforcement is above the needs of the minimum scheme. This will act to discourage unnecessary connection requests.

Mechanism for apportionment of reinforcement costs

Works falling under category 2 listed above are apportioned using one of two cost apportionment factors (CAF), depending upon which factor is driving the requirement for reinforcement.

The security CAF is applied where the costs are driven by either the thermal capacity and/or voltage assessed against the relevant standard. The CAF applied to the total costs to calculate the amount paid by the person seeking the connection is:

$$\text{Security CAF} = \frac{\text{required capacity of customer}}{\text{new network capacity created}} \times 100\%$$

The fault level CAF is applied where the costs are driven by fault level restrictions. The CAF applied to the total costs to calculate the amount paid by the person requiring the connection is:

$$\text{Fault level CAF} = 3 \times \frac{\text{fault level contribution from connection}}{\text{new fault level capacity}} \times 100\%$$

An example of reinforcement costs is provided in Appendix 9.3, page 105.

If in order to provide the connection, the DNO proposes using existing distribution system assets that were previously installed to provide a connection for another customer, and that customer has paid the DNO a connection charge for those assets, then the person requesting the connection may be required to make a payment towards them[38].

4.2.3 Impact of distributed generation on network operation

The installation of new DG affects DNO operations in two ways (beyond technical aspects such as voltage control):

1) the electricity produced by DG is exempted of some DUoS charges (unit rate, see section 0), reflecting the lesser utilisation of the network offered by a production close to the point of use. DNO must forecast DG output and integrate it in their CDCM model. An increasing number of intermittent DG is bringing complexity to the forecasting of output and billing of DUoS charges for DG electricity.
2) the new connection might require network reinforcement;

[37] Voltage levels are described in Figure 1 and are low voltage, high voltage, and extra high voltage.
[38] For further details, see Electricity (Connection Charges) Regulations 2002

DNOs have variable power to influence connection in terms of network reinforcement cost efficiency, decreasing with the decreasing size of the DG, as summarized in Table 4-3.

Larger DGs are more likely to involve network reinforcement but they can provide demand side management (DSM) or generation side management (GSM) services, which help DNOs balance and manage their networks (more details on DSM/GSM arrangements are given in 5.1.1).

Table 4-3: DNO scope of impact on DG installation

Type of DG	DNO lever	Comments – size of market
EHV	**Strong** – EHV connection and capacity charges are high, they incentivise efficient siting and design in terms of network reinforcement. DNOs can also contract EHV generators and users for Generation Side Management or Demand Side Management.	~60% of onshore wind turbines. This ratio is expected to stay the same to 2020.
HV and LV (non SSEG)	**Medium** – DGs receive RO for renewable (or FiT for small generation) independently of position on the network but they are also subject to connection charges and capacity payments, which encourage efficient siting.	HV: ~7,300 GWh, ~1,200 DGs
LV SSEG	**Weak** – SSEGs do not pay connection charges[39] and receive strong incentives through FiT: no incentive to site in networks best capable to cope with DG nor to time installations in a given network.	Around 330,000 installations as of Sept 2012[40], predicted to increase to 2.6 million by 2020[41].

[39] DNOs could charge small DGs for reinforcement costs but, in practice they are currently generally socialised. In ED1 (2015-2023), the only option will be socialisation of the costs.
[40] 330,000 SSEG connections: estimation based upon assuming that all installations on the FiT register below 11.4 kW count as SSEG.
[41] DECC, Impact Assessments - Government Response to Consultation on Feed-in Tariffs Comprehensive Review Phase 2A: Solar PV Tariffs and Cost Control (2012), and Comprehensive Review Phase 2B – Consultation on Feed-in-Tariffs for anaerobic digestion, wind, hydro and micro-CHP installations (2011).

4.3 Suppliers and end-users

This section highlights the relationship between suppliers and end-users as well as incentives relevant to suppliers. The schematic below shows the main charges and revenues flows of suppliers as well as the three end-user sectors:

- Industrial and commercial (I&C) customers with large demands, defined as those who are on half-hourly meters. HH meters are for businesses with high energy usage. They are mandatory for all business users with a peak demand of 100 kW or more[42]. Businesses with lower demand (but more than 70kW) have the option to have a HH meter. This sector uses ~50% of GB annual electricity consumption via 117,000 meters[43];
- Commercial customers who are not on half-hourly meters. This sector uses 16% of annual GB electricity consumption, from ca. 2.2 million meters; and
- Households and SMEs consume 36% of GB annual electricity consumption via 27 million meters.

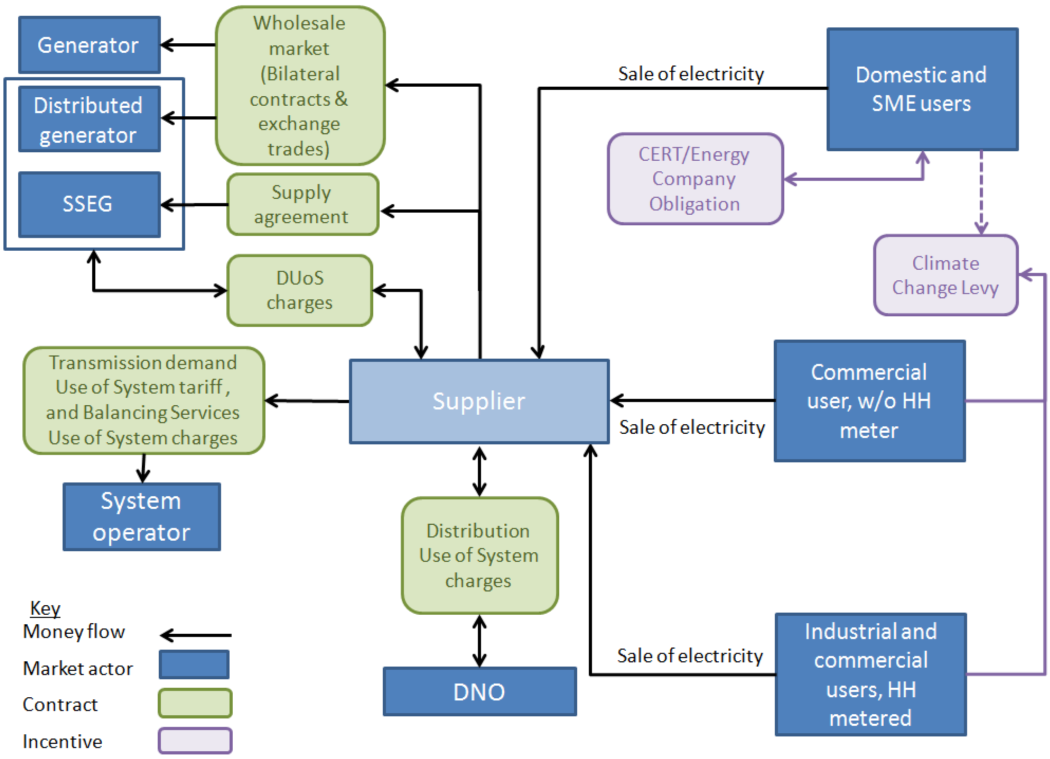


Figure 20: Suppliers main charges and revenues

[42] There is currently a proposal to force all users on load profile classes 5-8, usually with peak demand 50kW, onto mandatory half-hourly settlement. These users currently have to have meters capable of providing half-hourly data. Appendix 9.1 provides more detail on load profiling methodology.

[43] GB electricity demand – context and 2010 baseline data, Sustainability First, 2011.

4.3.1 Commercial models by customer sector

HH settled users – Industrial and commercial customers

The larger the demand, the more likely customers will have bespoke contracts with suppliers or even direct with generators. The time of the day and year that electricity is used – known as the load profile – will have a strong influence on the price paid per unit of electricity.

Non-HH settled users

The chart in Figure 21 outlines the main components of cost in an electricity bill, showing that in 2011 suppliers made a margin of around 4% of the total electricity cost and that distribution charges represent 16% of the cost.

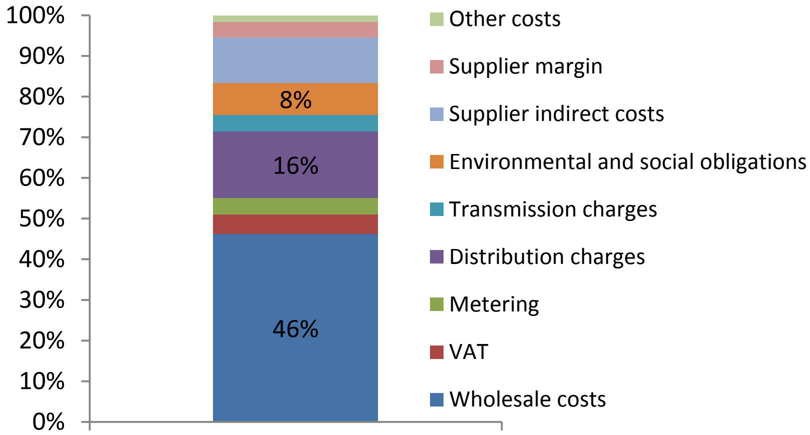


Figure 21: Components of the cost of energy supply[44]

For non half-hourly metered consumers, the exact daily consumption is not known. Instead periodic meter readings (typically a few times a year) are converted – for billing purposes – into half-hourly profiles based on standardised load profiles, referred to as profile classes.

The majority (~80%, corresponding to around 23.5 million households) of non-HH users fall under an 'Unrestricted' profile class. A further ~18% of non-HH users are under a 'Economy 7' class, i.e. they have a two-rate meter that allows for a cheaper off-peak (and higher daytime) tariff. Appendix 9.1 provides more details on the load profiling methodology as well as examples of load profiles. The

[44] Source: Energy supply margins: Update January 2012, NERA. See also Estimated impacts of energy and climate change policies on energy prices and bills, DECC, November 2011 for projected cost breakdowns to 2030

upcoming roll-out of smart meters by suppliers[45] will provide users with more clarity over their daily usage of electricity as well as more accurate billing through remote meter reading.

Most domestic and small non-domestic users are currently billed by suppliers a standing charge (p/day, covering fixed costs) and a unit charge (p/kWh, or two unit rates for users with Economy 7 meters). Each supplier typically offers several tariffs, e.g. 'standard', 'fixed to 2014', 'standard online discount'. The unit charge is defined for each distribution area as a reflection of varying Distribution Use of System charges.

In recent years, the selection of tariffs in offer by each supplier and variation of standing charges across suppliers has been identified as a hindrance to effective tariff comparison and therefore to consumers being able to choose the best deal. This has resulted in the UK government requesting suppliers to simplify their default offer to consumers in 2012[46].

Consumers also have the option to group to bulk buy electricity and hence attempt to reduce their prices. It is a type of aggregator service, common in the US, but less common in the UK. In 2011-2012 a campaign led by Which attracted 36,000 customers[47]. Some UK councils are also negotiating bulk buy contracts on behalf of their residents, e.g. in November 2012 Northumberland County Council launched a call for participants[48].

4.3.2 Incentives for suppliers and end-users

The UK Government has introduced incentives for users of large volumes of electricity to reduce their usage, as well as incentives for suppliers to reduce the energy use of residential customers. These are detailed below:

The Climate Change Levy

The Climate Change Levy (CCL) is a levy on the supply of energy to businesses. As well as electricity, it covers gas, liquefied petroleum gas and solid fuels. The rationale for the levy was to send a signal to significant users to decrease energy consumption, as part of the Government's commitment to tackling climate change. The current rate of CCL on electricity is £5.09/MWh.

Renewably sourced electricity is exempt from the CCL. This exemption operates by way of Levy Exemption Certificates, which are issued to accredited generators

[45] The supply Standard Licence Condition, amended in November 2012, stipulates the roll out must be completed by 2019 to all households and small non domestic users. The completion date has however been pushed to 2020 in May 2013.
[46] Ensuring a better deal for energy consumers, DECC, November 2012
[47] See http://www.which.co.uk/energy/saving-money/guides/the-big-switch-explained/
[48] http://www.northumberland.gov.uk/default.aspx?page=6270&article=2333

for each MWh of electricity that is generated. These certificates are then bought by the supplier, along with the qualifying electricity (LECs cannot be traded separately from the electricity). Suppliers then redeem the LECs to demonstrate the amount of electricity that had been supplied that should not be subject to the CCL.

The Supplier Obligation

Assuming that suppliers charge a profit margin on each unit of electricity consumed, they have an incentive to ensure that consumption remains high, which is counter to consumers' needs to reduce energy bills and the Government's targets to reduce greenhouse gas emissions. The Government has therefore put in place obligations on electricity suppliers to install energy efficiency measures in domestic properties, with a focus on the poorest households.

The current obligation is the Carbon Emissions Reduction Target (CERT), which requires all domestic energy suppliers with a customer base over 250,000 customers to make savings in the amount of carbon dioxide emitted by households. Action has been focused on installing insulation, and ensuring that measures target more vulnerable households, including the elderly and low-income groups, as a priority. It is estimated that suppliers have spent £5.5 billion on achieving CERT from April 2008 to December 2012[49]. It is likely that these costs are passed through to consumer bills.

With the introduction of the Green Deal, CERT will be replaced by the Energy Company Obligation, which will be entirely focussed on lower income and vulnerable groups.

4.4 The relationship between DNOs and domestic electricity consumers

Most consumers only have a direct relationship with their supplier, who sets the overall price. The DNOs currently have very little direct interaction with consumers, and therefore very little leverage to affect how consumers use the network[50]. Large consumers on half-hourly meters are likely to be aware of, and may be influenced by DUoS tariffs, but the majority of users will not be aware of these. Table 8 below shows the percentage of users, and percentage of demand they represent, who are subject to time of use DUoS tariffs.

[49] http://www.decc.gov.uk/en/content/cms/funding/funding_ops/cert/cert.aspx
[50] Although the National Terms of Connection cover all types of customers in the absence of a bilateral agreement, most consumers are unaware of it and of DNOs. Terms can be found at http://www.connectionterms.org.uk/

The only interactions that occur between DNOs and consumers are:

- New loads or generation above the household scale need to connect to the network, when there is a connection process and payment to be made to the DNO,
- Network outages, when customers may be compensated for the inconvenience,
- Customer contact and emergencies. In unusual events like floods and power cuts, DNOs will be in contact with major customers to manage power loads so that demand does not overload the system.

Suppliers pass through DUoS charges to customers, but most consumers are not aware of the level of DUoS charges, or the other costs of operating the network, as they do not generally form a transparent part of billing (unlike HH users who generally see the DUoS charges as an item on their bill).

Table 4-4: Breakdown of user number and demand[51]

User type	MPAN	Demand	DUoS tariffs
HH settled	0.5%	56%	3 unit rates (green/amber/red or green/yellow/black in the case of HH UMS) or super-red tariffs and capacity payment
Non-HH settled	99.5%	44%	Up to 2 unit rates but no capacity payment
including	*82%*	*28%*	*Single unit charge, 'Unrestricted' tariff*
	17.5%	*16%*	*2 unit rates*

4.5 Balancing services

Generators as well as large consumers of electricity can gain revenue streams from providing these services to the grid. Currently, there is no existing market for smaller consumers, including domestic households, to gain revenue from these services (even by aggregating), as the need for suitable metering is too costly compared to the revenue to be gained from such small demands.

Table 4-5 describes the main ancillary services, and their key characteristics. NGET can also set up bilateral agreements for demand management with large users (25MW is required, can be met through aggregation), where users are paid an utilisation fee only.

[51] Based on analysis of CDCM 2012-13 and assuming 100TWh and 10,000 MPANs for EHV users

Some of these services can be provided by either generation (i.e. large generators increasing output) or demand side services. Demand side contributes to ca. 8% of frequency response, 38% of fast reserve (at night, 0% during the day) and 45% of STOR. The STOR demand side services are ultimately provided largely by local generation resources (embedded or back-up generation, mainly diesel and open-cycle gas turbine) mitigating demand, with only 5% being load reduction[52].

Table 4-5: Criteria and value of main grid ancillary services.[53]

Service	Type of provider	Criteria	Indicative value (generally varies as a function of committed MW)
Firm frequency response (FFR)	Generation or demand	Provider must: • Deliver a minimum of 10 MW; • Have the capability to operate in a frequency sensitive mode for dynamic response, or to change their MW level for non-dynamic response.	Availability fee: £34k/MW/year Nomination fee: £22k/MW/year Plus an utilisation fee
Frequency control by demand management (FCDM)	Demand only	Service must be: • Available 24 hours a day; • Provided within 2 seconds of instruction; • Delivered for a minimum of 30 minutes; • Able to deliver a minimum of 3MW.	Maximum potential value in line with FFR
Short-term operating reserve (STOR)	Generation or demand	Service must be: • Delivered no later than 4 hours after instruction; • Delivered for a minimum of 2 hours; • Able to deliver a minimum of 3 MW	Availability fee: £25-35k/MW/year Utilisation fee: ca. £12-18k /MW/year
Fast Reserve	Generation or demand	Service must be: • Delivered within 2 minutes of instruction, and able to switch off service provision within the same timescale; • Delivered for a minimum of 15 minutes; • Able to deliver a minimum of 50MW.	Payments vary in type and structure. Approx. value: £40-50k/MW/year

52 'Overview of National Grid's Balancing Services', National Grid presentation during Ofgem day, 20 November 2012

53 Source: National Grid http://www.nationalgrid.com/NR/rdonlyres/BE8D8515-7325-43C3-A8FB-85249BA9E76B/38375/Demand_Side_Opportunities.pdf and What Demand-Side Services Can Provide Value to the Electricity Sector? Sustainability First, 2012

5. Identification of successful models and barriers in current market arrangements

Previous sections presented the electricity market stakeholders and the current frameworks (regulatory and legislative) and commercial arrangements. The overview of the market showed that generation and demand are projected to change considerably: demand will increase and new load such as EVs and heat pumps will modify the load profile, possibly exacerbating the peak load while an increasing share of renewable central and distributed generation will have to be integrated.

This section reflects on how successful these current arrangements are in delivering an efficient distribution network, i.e. where network reinforcement costs are optimized and consumers receive both reliable service and appropriate costs, in the light of the challenges ahead.

In the first part, the current arrangements are analysed in regards to the control of the electricity demand while the second part looks at the integration of renewable DG. The emphasis is on identifying potential barriers to envisaged solutions such as demand side response (DSR) and other smart grid solutions. This section draws on the work of the Smart Grid Forum[54] (SGF) as well as discussion with DNOs and other industry stakeholders.

5.1 Influencing customers' demand

In the context of increased demand, in particular peak demand, it will become more and more beneficial in terms of network reinforcement cost minimisation to influence the demand, either in terms of when power is drawn (load shifting) or how much is drawn (demand reduction). No demand reduction measures are being trialled under the CLNR project[55]; it is possible however that demand reduction will be a by-product of DSR as consumers become more aware of their consumption patterns. Northern Powergrid's GB Flexibility Market project is

[54] The Smart Grid Forum sprang from DECC and Ofgem objective to facilitate the development of a smarter network, that will contribute to meeting the targets of a secure, low carbon and affordable energy system. Group discussions involve Ofgem and relevant industry players, e.g. National Grid, suppliers, DNOs, aggregators.
For more information see http://www.ofgem.gov.uk/Networks/SGF/Pages/SGF.aspx

[55] Note that demand reduction is on the national agenda; DECC has been running a consultation on energy demand reduction in Nov 2012-Jan2013. At the time of writing, responses are being analysed. https://www.gov.uk/government/consultations/options-to-encourage-permanent-reductions-in-electricity-use-electricity-demand-reduction

exploring ways of reducing the cost and increasing the availability of flexibility services (including DSR) to DNOs, the NETSO and suppliers[56].

The main barriers for DNOs to influence the demand in the current arrangements are the lack of direct relationship with end-users and conflicting interests with other market stakeholders, notably suppliers. It is also the case that the value of DSR in deferring network reinforcement is not well understood, but this is an area where work is being undertaken. Barriers – and successful models – are identified in more details below.

5.1.1 Existing models for load shifting

This section considers demand and generation side management, which we distinguish from balancing services due to the scale at which the service applies. Balancing services are procured by National Grid with the aim of balancing flows on the transmission system, although not all providers of balancing services are connected to the transmission system. Here are considered the DSR/DSM and GSM arrangements that relates to the constraints and flows that DNOs need to manage on the distribution network.

There is a number of **Time of Use tariffs** (ToU) in place (laid out in Table 5-1), notably:

- Economy 7 & 10 for non half-hourly users, covering ~11% of the total GB demand. Users are offered a lower rate over 7 hours at night, encouraging demand overnight. The exact time of the 7 hour period varies across distribution areas and is set by DNOs[57].
- Time of day tariffs for DUoS charges
  - Three rates for HH settled LV-HV users, introduced in April 2010.
  - Seasonal super-red rate (at DNO peak time) for EHV users, introduced in April 2012 to provide an incentive for winter weekday evening peak avoidance.

Another form of time-of-use tariffs for non-HH users is emerging, with suppliers, e.g. British Gas, offering **tariffs for EV users** with 4 hours at peak rate (4-8pm) and 20 hours at off-peak rate.

Interviewed DNOs commented that the recent introduction of time of day tariffs for DUoS charges had very little impact so far, the suspected reason being that

[56] For more information see http://www.ofgem.gov.uk/Networks/ElecDist/lcnf/stlcnp/year3/Pages/index.aspx

[57] It varies across region e.g. there is a Northeast variant that provides 5 hours overnight and 2 hours mid-afternoon

most I&C users do not have the flexibility to adapt – in a cost effective way – their process to vary their power demand. Another contributing factor could be a possible lack of awareness of the time banding regime among customers.

Table 5-1: Summary of DSR based on time of use tariffs already in place

User	% MWh demand[58]	Time of use DSR	Comments
Domestic users	30%	**Economy 7 & 10 rates** for 18% of domestic users , covering 26% of domestic demand	Led by suppliers /wholesale market but time of off-peak set by DNOs
Non domestic non-HH settled	14%	**Economy 7 & 10 rates** for 22% non-domestic users , covering 23% of non-domestic demand	
LV-HV – Half hourly settled users	29%	**Time of day tariffs for DUoS unit rate charges** (3 rates: green, amber, red), introduced in April 2010	*These users might offer balancing services to NG.*
EHV – Half hourly settled users	27%	Seasonal **peak time tariffs for DUoS unit rate charges** ('super-red tariffs'), introduced in April 2012	

There are further indirect mechanisms in place to encourage HH users to manage their load profile through the payments of DUoS **capacity charges** and exceeded capacity charges. Interviewed DNOs reported some EHV users had demanded a reduction in capacity since the introduction of the EDCM. It is not clear however if it was a direct response to the charging methodology or a general effect of the economic climate.

DNO activity in 'direct' DSM and GSM is a small but growing market. With the exception of the aforementioned tariffs, estimates of current DSM procured by DNOs today amounts to a few tens of MW[59]. This is mainly through **contracts for avoided network reinforcement.** This involves contracting I&C demand to respond by switching off in the event of an occasional loss of an incoming circuit. This type of response can either be seen as a management tool in case of faults or as a tool to avoid HV network and/ or primary substation reinforcement[60].

[58] Based on analysis of CDCM 2012-13 and assuming 100TWh for EHV users.
[59] What Demand-Side Services Can Provide Value to the Electricity Sector? Sustainability First, 2012
[60] DNOs generally design the network to keep operating after the first fault. DNOs reinforce not for an intact system but for the first fault, so a tool deployed in case of faults acts to defer that reinforcement.

The value of DSR in deferring network reinforcement is being investigated by a number of studies. One of the most interesting studies[61] combines the analysis of load growth and the value of DSR from a technical perspective, with socio-demographic data to gauge the social acceptance of demand side participation schemes for different types of consumer. This project is not yet complete, but it is clear that further work into these areas is needed in order to pave the way for more active DSR.

EDCM accounts for DSM arrangements between DNOs and users by allowing a reduction of DUoS charges (on the capacity charge and super-red rate[62]) reflecting the contribution to the local network. The amount of reduction is based on the percentage of the Maximum Import Capacity that is interruptible. The EDCM does not however provide detail on the type of DSM agreement required, DNOs specify their approach to DSM in their charging statement. A working group of DNOs has been proposed to standardise the approach and wording of DSM arrangements. Reportedly only a few DSM agreements between DNOs and HH users have been put in place so far.

A new type of arrangement is emerging: **non-firm connection agreements**, described in more detail in section 6.1.

Competition between DNOs and other stakeholders for the DSR market

DNOs have been trialling DSR arrangements for a few years, demonstrating the industry is willing to understand and enter the market. Notably, Electricity North West Limited (ENWL) has successfully trialled DSR arrangements with a small number of HV customers as early as 2009 (Appendix 9.4 provides short descriptions and outcomes of the trials in question). Following these positive experiences, ENWL decided to extend the DSR trials to a larger customer base, with the help of aggregators (who, as of January 2013, are recruiting participants). The wider scope compared to previous trials prompted ENWL to study the potential of conflict with other markets: balancing services for National Grid Electricity Transmission (e.g. STOR and frequency response) as well as DSR led by suppliers who would try to obtain the best wholesale price (e.g. match demand with wind output).

[61] M. Lawson, P. C. Taylor, S. Bell, D. Miller and N. S. Wade, "An Interdisciplinary Method to Demand Side Participation for Deferring Distribution Network Reinforcement", in *Innovative Smart Grid Technologies (ISGT Europe), 2nd IEEE PES International Conference and Exhibition,* Manchester, 2011

[62] Capacity rate: reduction of local element; super-red unit rate: reduction of remote element

The resulting study[63] concluded that, overall, DNOs are in the weakest position in terms of the DSR price signal (with the TSO able to offer higher prices, and suppliers either able to offer higher prices or buy larger volumes). Nonetheless, the study highlighted occasions when the value of DSR would be the highest for DNOs, such as times when there is a network fault, and DSR would be used to avoid bringing on another generator to meet demand.

The study was based on a model of the national system, meaning the full scale of location effects is not always captured. Other studies have concluded on the overall weak position of DNOs on the DSR market too but also pointed to the effect of location[59]: DNOs' requirements vary significantly by location and this could act to strengthen the position of DNOs in the market. DNOs are well aware of the impact of location on DSR value, as illustrated by ENWL past and current trials[64].

Table 5-2 highlights the differences between the three key DSR stakeholders. Note that, at the moment, despite a disconnect in objectives, suppliers and DNOs are often working together to undertake trials. A model such as Energy Service Company (ESCo)[65] could be a platform under which suppliers would implement DSR. This would change the focus for suppliers from increasing kWh sales, and instead encourage demand reduction, but it would not completely reconcile their objectives with DNOs'. Suppliers/ESCos would still try to capture the best wholesale price, which is sometimes at odds with the network constraints, but may reflect the most economic operation of the overall power system[66].

[63] Commissioned by ENWL and National Grid, conducted by Powry "Assessment of DSR price signals", December 2011
[64] See Appendix 9.4
[65] Where a service, e.g. 'warm house' and 'use of appliances' is sold to the end-user as opposed to energy on demand (kWh, as now). An ESCo would implement energy efficiency measures and capture the corresponding savings; DSR could be a way of achieving saving on electricity costs. There is virtually no ESCo operating on the domestic market in the UK as of January 2013. In the industrial sector, some form of energy services are starting to emerge, e.g. with companies offering to finance (often capital intensive) energy saving measures in exchange of a share of the subsequent savings, over several years.
[66] An existing example is "off-peak" economy & tariffs: in areas off the mains gas network, electric heating is very popular, so the network peak is around 2 am, driven by E7 tariffs. Overall, the true cost to the customer remains relatively low, as the extra local network required is more than offset by low overnight generation costs

Table 5-2: Comparison of interests in DSR for three different stakeholders

	TSO	Supplier	DNOs
Objectives	Grid balancing Constraint management (pre and post fault) to avoid transmission network investment	Optimise wholesale market buying price	Constraint management (pre and post fault) to avoid distribution network investment
Commercialisation stage	Balancing services fully commercial, several established aggregators recruiting and interfacing with end-users.	'Static' Time Of Use: a number of tariffs are in place; see previous table 'Dynamic' Time Of Use tariffs, Restricted Hours and Direct Control: under trial in a number of LCN Fund projects	
Relevant unit	MW	MWh	MW
Capturing non-HH users?	No (or negligible numbers)	Aiming to – under trial	

5.1.2 Barriers to demand side response

Load shifting or demand side response refers to cases when some mechanisms allow the electricity end-users to change their demand behaviour, permitting a better use of the network assets, e.g. by reducing the peak demand. The mechanisms that trigger the response can be direct (e.g. Direct Control through secondary metering) or indirect (e.g. users answering to Time of Use tariffs).
Two pathways can be envisaged for DSR arrangements, as illustrated in the next figure: direct arrangements between DNOs and end-users or indirect arrangements (through suppliers). Both DSR arrangements paths have barriers, some common, presented next.

Note that aspects such as consumer engagement and tariff development are not discussed in this report. They are being researched through CLNR intervention trials and will be reported on at a later stage. Barriers of interest here are around the commercial arrangements and regulatory frameworks.

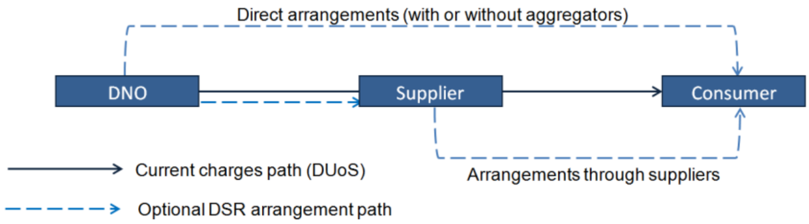


Figure 22: Possible DSR arrangement paths

Barriers to direct DSR arrangements DNOs – end-users

There is a bi-directional lack of visibility between DNOs and end-users that does not facilitate the establishments of direct DSR arrangements:

1) DNOs do not have visibility on where and when new significant loads such as EVs are added to their networks;
2) Most end-users are not aware of DNOs and have no or little commercial incentive to shift their demand. Here large users (HH meters) and non-HH settled users (referred as 'domestic' for simplicity hereafter) must be distinguished.

These two aspects are developed further below.

Lack of DNO visibility on new domestic demand and demand profile

DNOs are not notified when users add new significant loads (e.g. EVs, heat pumps), information that would be valuable to target potential DSR customers. The only notification mechanism in place for domestic users is for SSEG (Engineering Recommendation G83/1-1). Likewise, DNOs do not know the consumption of individual non-HH settled users during peak times, making it difficult to identify which users could contribute most to load shifting.

In the case of domestic users adding a new load (e.g. heat pump) that triggers a need for reinforcement, they would not be compelled to accept DSR for the DNO to avoid reinforcement costs if these are spread over all customers – through DUoS charges. Figure 23 gives an overview of the alternatives, which all have pros and cons.

Because DNOs are not notified of retro-fit domestic load installations, there is no time for DNOs to pro-actively prepare the network ahead of the installations. In the case of new housing developments, DNOs do know the expected capacity but not necessary know the demand breakdown and hence DSR potential.

Currently, if a domestic user triggers the need for network reinforcement, (s)he could be made to bear the reinforcement cost. In practice, DNOs can socialise the costs and this will be made the default option in ED1.

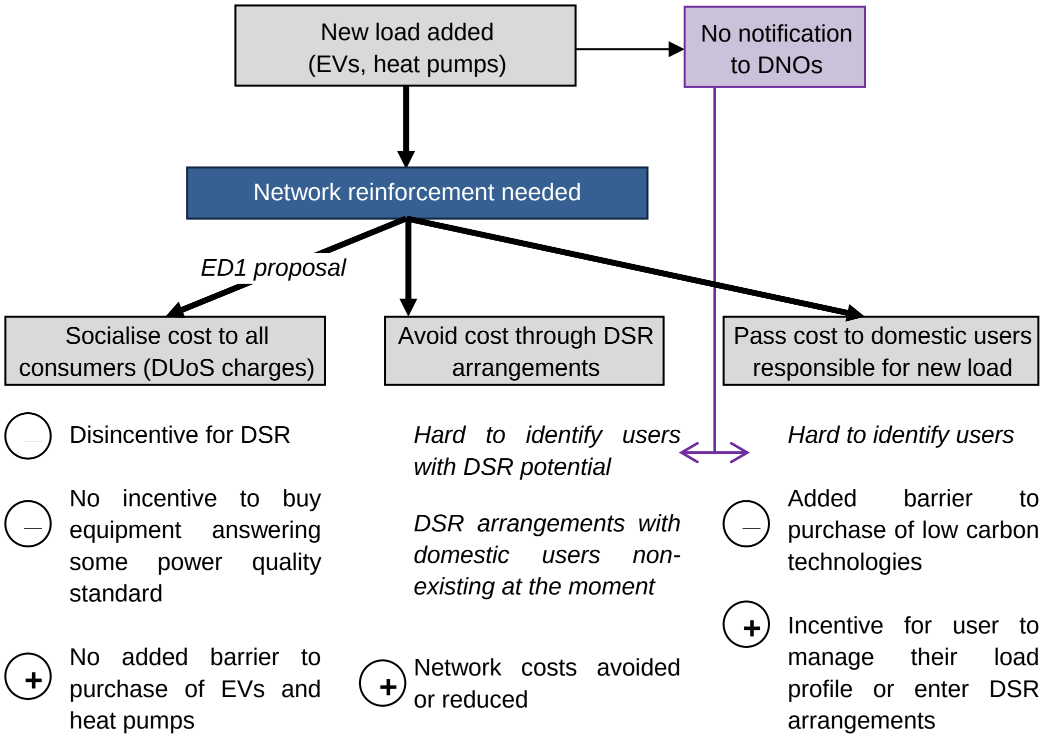


Figure 23: Options for reinforcement costs related to new domestic load

Lack of DNO influence on domestic consumers

While the framework setting the relationship of DNOs and large users (HH meters) allows for DSM; there is currently no relationship – and hence very limited scope for influence – between DNOs and smaller users (~50% end demand). This is illustrated in Figure 24.

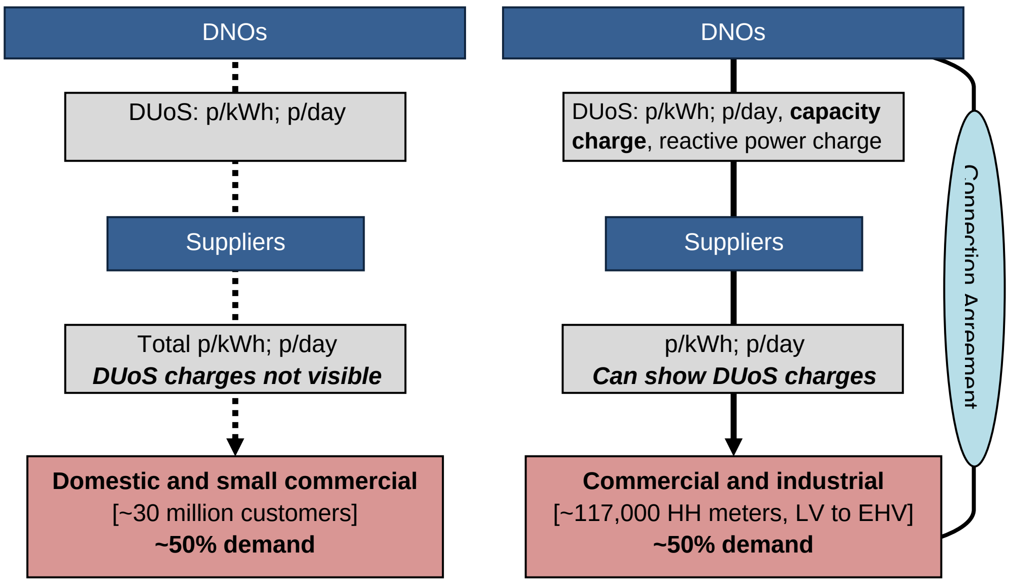


Figure 24: DUoS charges path illustrating the visibility or non-visibility of DNOs to end-users

DNOs and Distributed Use of System (DUoS) charges are visible to large users who are incentivised to respect a given capacity through capacity charges, sometimes made explicit to them on the bill they receive from the suppliers. Furthermore, large users have Connection Agreements with their DNOs, and, in this context, several DSM arrangements can be put in place (presented in 5.1.1) – although in practice DSM arrangements are still limited and often passive (supply cut to avoid fault, no remuneration paid to user).

In contrast, DNOs have no direct contact with non-HH settled users in the current arrangements and there are no incentives for users (beyond Off-peak and Economy 7 tariffs) to avoid consuming at certain hours or to avoid 'peaking' at individual level. Although suppliers are beginning to set out a breakdown of costs as part of the consumer bill (partly motivated by the need to demonstrate to consumers that their bill does not reflect significant profits, and partly for the purposes of providing a new and distinct service offering that gives a commercial advantage), most domestic and small commercial users do not see the contribution of DUoS charges to their energy bill.

Although there are yet no precedents, there are no regulatory barriers to DNOs making direct contact with domestic users by entering in bilateral arrangements with them (as long as electricity is not sold by DNOs). The barriers are more of a change of business culture:

- DNOs are not used to dealing with domestic users, both in terms of type of interface and volume of costumers it represents (e.g. invoicing/payment systems not adequate);
- Thus securing the right volume of users to collate the disaggregated benefit of domestic DSR might require the engagement of a third party such as aggregators;
- If DNOs were to implement DSR arrangement with customers that allows avoiding network reinforcement, they might have to provide a level of flexibility (e.g. right to withdraw for customers) that will make their investments (DSR equipment, payment system) too risky.

The SGF sees this last point as a strong disincentive for DNOs to implement DSR arrangements (with both domestic and larger users)[67]; a sub-group is currently working on this issue and will propose withdrawal arrangements that accommodate both customer flexibility and protect DNOs from inefficient

[67] Smart Grid Forum, Work Stream 6 Report, August 2012

investment. The task group will lay out proposition on who would be liable for reinforcement cost related to DSR contract ending.

If direct DSR arrangements come to the market, a certain degree of simplicity of product will be expected, to not hinder consumer engagement. The diversity of regulatory frameworks might present a barrier to this: there are three 'operators' with interest in implementing DSR – DNOs, IDNOS and Independent Connection Providers – and all fall under different regulatory frameworks, meaning it might be difficult for all of them to offer similar DSR arrangements.

Competition with other stakeholders for the HH settled users

As stated before, DNOs already have direct contact with HH consumers as they enter into bilateral agreements with them (Connection Agreement) and some DNOs have procured DSM through contracts for avoided network reinforcement, i.e. contracting I&C demand to respond by switching off in the event of an occasional loss of an incoming circuit. Furthermore, the EDCM allows for DSM to be accounted for in the calculation of DUoS.

Large HH users already provide balancing services (e.g. STOR, TRIAD, FCDM) to NGET either directly or via aggregators, although this is an early stage market. It means DNOs would possibly have to compete against NG for DSR contracts and NG would have more buying power in terms of volume as well as offer a better price, as mentioned in the previous section.

DNOs entering in direct DSR contract with large users might also impact on suppliers: if suppliers are not kept informed of the arrangements, they would be a risk to overbuy power. Suppliers also have more buying power in terms of volume.

Setting DSR tariffs

There are broadly two options for DNOs to pay domestic customers for their DSR service:

- DUoS charges are taken off the electricity bill and charged directly by the DNOs to the end-user. Customers entering DSR arrangements would get a reduction in DUoS, linked to the level of service they offer.
- DUoS charges are still paid by suppliers and DNOs offer separate DSR payments to customers. This could be funded by the sale of ancillary services to NGET or using avoided investment[68].

[68] The cost of DSR contracts can be included as part of the DNO's regulated asset value, provided that the costs are less than the cost of the avoided network reinforcement.

There are a number of difficulties and barriers with both options. In both cases, a certain volume of customers must contribute to make the scheme viable and worthwhile as well as require some level of individual monitoring, third parties such as aggregators might be used. The two options also present the drawback of increasing the complexity on offer to customers who would interact with both suppliers and DNOs (or aggregators).

Option 1 is the furthest from current arrangements and would require fundamental changes to the charging methodologies. There are no restrictions on using Option 2 to defer distribution network investment, although current arrangements might present some barriers to DNOs selling ancillary services to NETSO, e.g. SLC 29 restricts revenue from non-distribution activity.

Barriers to indirect DSR arrangements DNOs – end-users

This lack of means for the DNOs to engage with end-users could suggest DSR solutions should be implemented by – and thus be compelling for – suppliers.

In other countries, energy intensive users can agree Time of Use and/or interruptible contracts with suppliers. These contracts have largely evolved to allow electricity suppliers to hedge against paying high wholesale prices, by inducing price-responsive demand behaviour such as peak-load pricing, or interruptible contracts. This allows suppliers to interrupt the load sufficiently to avoid paying higher wholesale prices that typically occur during shortages or system peaks.

In the UK market however, suppliers undertake relatively little DSM. Some barriers to suppliers' interest in DSR spring from a disconnection between supplier incentives and DNOs', namely:

1) At wholesale market level, suppliers and DNOs have incompatible interest at times
2) At distribution level, the socialisation of costs means DNO cannot signal benefit of DSR to suppliers and thus end-users.

These statements are developed below.

Incompatible supplier-DNO interest at wholesale market level

Although suppliers could benefit from DSR on the wholesale market, suppliers implementing DSR might be contrary to DNOs' target of peak demand reduction as supplier and DNO objectives are on the whole not aligned. Suppliers are looking to sell as much electricity as possible and buy it as cheaply as possible, whereas DNOs are incentivised to run networks efficiently, and one component of this may well be to reduce demand.

Figure 25 below shows a conceptual example of the optimum time to charge EVs to demonstrate how these incentives might lead suppliers and DNOs to act in different ways. DNOs are likely to want EVs to charge at times of low demand, to reduce the potential for reinforcement. However suppliers are likely to want to encourage EVs to charge at times when they make the most benefit – i.e. when the market price is low at times of high wind, the margin suppliers will make on those units of energy will be greater.

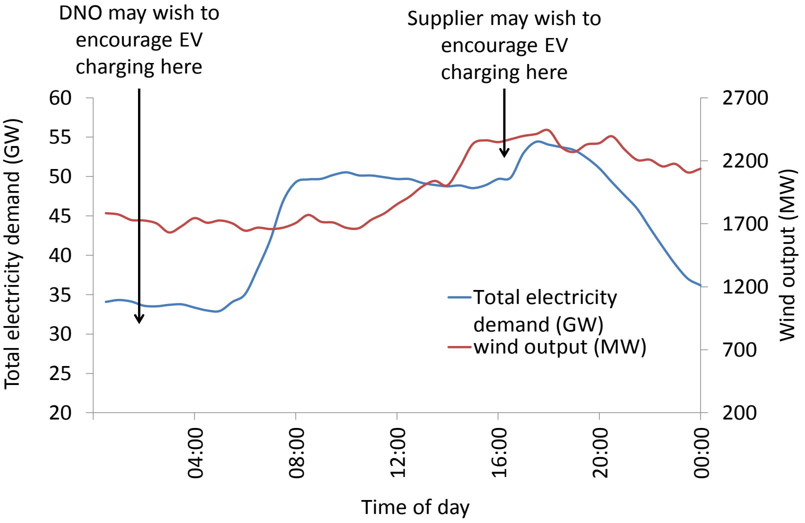


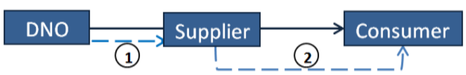
Figure 25: Conceptual example showing the potential conflict in preferences for the time of EV charging – DNO and supplier perspectives

Furthermore, the balancing mechanism price calculation leads to a bias to over-contract for generation, serving to inhibit demand side actions (penalty for under-contracting through system Buy price).

Lack of signal to supplier and end-user at distribution level

At distribution level, the barrier for DNO to signal consumers for DSR is two-fold:

1) DNOs must signal benefit to suppliers
2) Suppliers must signal benefit to consumers



1) How would DNOs signal DSR benefits to suppliers?

For non-HH settled users (99.5% of users, representing 44% of the demand), an assumption is made regarding the load profile. It is applied to all users within a given DUoS tariff and to all suppliers. If users were to actually draw power at a more favourable time during the day (e.g. avoiding peak times) than assumed, the network operation costs incurred by DNOs would be lower than forecasted. This difference would be accounted for in the next CDCM, to respect the allowed revenue; therefore the DUoS charges would become lower. However, it would apply to all suppliers, giving no competitive advantage to suppliers who encouraged their customers to change their demand profile. In effect, DNOs cannot use the DUoS charges of non-HH settled users to signal benefits to suppliers as DSR benefits are socialised through the DUoS charges, giving no incentives to suppliers to facilitate DSR.

For DNOs to be able to reward suppliers who facilitate DSR, a dedicated DUoS tariff would need to be put in place, e.g. based on either the real load profile or through part time banding (like for existing tariffs for HH-settled users) – both cases would require some level of individual load monitoring. As since April 2010 DNOs must apply a common charging methodology, DNOs cannot introduce new tariffs at regional level. The introduction of new tariffs to facilitate DSR signalling between DNO and supplier, would therefore require an amendment of the CDCM (hence of the DCUSA).

For HH-settled users, there is a more direct DNO-end user relationship through the three-part time unit charges and super-red tariffs that are a form of ToU tariffs, giving users an incentive to manage their load profile. However, the benefits of some consumers changing their behaviour are socialised to some extent among all suppliers and all users as it reduces the overall operation costs to be recouped through DUoS charges in the following year.

2) How would suppliers signal DSR benefit to consumers?

If suppliers cannot pass on the benefits to specific customers, they would be socialised across all their customers, rendering the effort of consumers engaged in DSR un-rewarding.

Suppliers currently offer a variety of tariffs to domestic consumers and could in theory propose new tariffs dedicated to DSR. However the impact of developing innovative tariffs would need to be considered along the recent request from the UK government that suppliers simplify their offer to consumers[46].

Barriers common to direct and indirect DSR arrangements

Security of supply standard

SGF work stream 6 identified that the current security of supply standard to which licensed DNOs must conform (Engineering Recommendation P2/6, Standard Licence Condition 24) potentially present a barrier to utilising DSR (and storage). Its definition of measured demand can be interpreted to exclude demand that can be controlled through DSR, meaning DNOs would need to install assets to the level specified in the standard, regardless of having DSR already providing security of supply. SGF WS6 concludes the ER P2/6 may need revising to recognise the contribution DSR can play in network security. The LCNF project “Capacity to customers”, led by ENWL, is trialling technical solutions to use more of the existing network capacity than allowed by current engineering recommendations, while maintaining security of supply. As a result, the project consortium will make recommendations on P2/6 changes by mid-2013. It is worth noting that there is a lack of general consensus on whether ER P2/6 presents a barrier, as some DNOs do not interpret this Engineering Recommendation as excluding DSR (or storage).

5.2 Integration of renewable generation

A first challenge to efficient integration of renewable generation is the lack of incentive for siting of SSEG in networks best capable to cope with DG, as laid out in section 4.2.3: SSEGs do not pay connection charges (cost will be socialised in ED1) and receive strong incentives through FiT. DECC predicts the number of SSEG connections will increase to 2.6 million by 2020, from under 400,000 today.

Solutions envisaged for the integration of renewable generation developed here are the use of storage and DNOs taking on a more active role in the management of the network.

While the barriers to DSR have been identified among current commercial arrangements, solutions around the integration of renewable generally require more technical barriers analysis at this stage. This makes the description of potential barriers from commercial arrangements more general.

5.2.1 Storage

Storage[69] can be used as a form of DSM to reduce/defer reinforcement costs and integrate intermittent generation and it can provide balancing / back up services.

Storage can also help optimise the network power flow, as can enhanced automatic voltage control technologies. These technologies are currently being trialled by various DNOs to assess their real contribution. There are no third parties involved in the installation and use of voltage control technologies, their arrangements are therefore not discussed here.

Storage is currently expensive[70] meaning revenue from ancillary services would be critical for its business case: even then, conventional reinforcement may still be more economic. The SGF WS6 notes there are no regulatory barriers to DNOs

[69] In the context of network support, storage refers to distributed storage such as batteries and flywheels, as opposed to hydro pump storage.
[70] A figure of £1.5m/MW is quoted by DNOs in the SGF storage sub-group.

implementing storage arrangements but rather potential barriers to lever benefit from ancillary services[71]:

- Storage assets could be viewed as generation from a regulatory point of view if it exceeds the licence threshold. DNOs are not allowed to hold a generation licence and hence, in these circumstances, would not be allowed to sell ancillary services.
- SLC 29 restricts revenue from non-distribution activity to 2.5% of the DNO's share capital

These potential barriers are currently deemed secondary as the size of storage DNOs would implement would very likely not exceed the licence threshold nor be restricted by SLC 29.

As with DSR, Engineering Recommendation P2/6 is perceived as a potential barrier to implementing storage by not allowing storage to avoid some reinforcement investment. However, as noted before, there is still a debate within the industry on the interpretation of the wording, with some DNOs not perceiving any barrier to storage (or DSR) in ER P2/6.

Using a third party that owns the storage asset would remove the barriers to sale of ancillary services: DNOs would buy services from the third party instead. It does move the economic case onto the third party who would need certainty of revenue to undertake investment in storage[72].

There are no commercial arrangements emerging around storage yet but DNOs are showing interest by proposing to study the question through LCNF projects. For example the CLNR project is investigating a new application of electrical energy storage (EES) systems and DSR, operating collaboratively to enable voltage control within distribution networks[73]. Modelling and simulation work has been carried out, but field trials are currently underway. For example, UKPN have been trialling a 200 kWh battery under a Tier 1 project, focusing on technical aspects. CLNR is deploying batteries from 50kVA/100kWh to 2500kVA/5000kWh. SSE also

[71] Work Stream 6 Report, Identifying potential barriers to smart grid implementation and laying out possible future direction for developing solutions, August 2012

[72] Revenue would not necessary be coming from the sales of ancillary service, for example, the PATHS project (not awarded) of SSE would have trialled the 3rd party provision of network services (electrolyser producing hydrogen when DNO needs load shedding and turning off when requested) that would sell the produced hydrogen to the transport system.

[73] J. Yi, P. Wang, P. C. Taylor, P. J. Davison, P. F. Lyons, D. Liang, S. Brown, and D. Roberts, "Distribution network voltage control using energy storage and demand side response," in *Innovative Smart Grid Technologies (ISGT Europe), 3rd IEEE PES International Conference and Exhibition*, 2012, pp. 1-8.

has storage as part of NINES *(*Northern Isles New Energy Solutions*).* UKPN's new project, Smarter Network Storage, will be looking at commercial arrangements on top of trialling the technology.

5.2.2 More active role in system management and Distribution System Operator role

The current role of DNOs is often described as 'passive' as they build the network in response to (peak) demand, without scope to influence the demand.

The predicted increase in renewable generation and new heating and transport load is however driving an interest in active network management by DNOs:

- Integrating renewables brings technical challenges (e.g. voltage control) and power flows may become more complex or variable (e.g. DSR and vehicle-to-grid). Therefore, DNOs having a more active role might be required to ensure technical stability.
- Active network management might prove cheaper than network reinforcement.

To conduct an active network management, DNOs would require access to flexible demand and flexible generation, e.g. through DSR, storage or curtailment agreements with DGs.

There are no regulatory barriers to DNOs taking an active role in network management; the following barriers would however arise at a certain scale:

- When the scale is such that it impedes on transmission and balancing, there would be role conflicts between DSO and TSO. They might have conflicting objectives at times, e.g. if DNO needs to reduce generation but TSO need to increase it.
- The role of the TSO might become more complex to balance the grid at national level, if each network is managed locally. The necessary communication frameworks and protocols between TSO and DNOs do not exist at the moment.
- Securing a significant DSR volume – as discussed previously.
- Securing supply side response (GSM); there are emerging arrangements around managed connections which can provide GSM, discussed in more details in section 6.

5.3 Summary of barriers resulting from market arrangements

Although there are no regulatory conditions forbidding DNOs to enter arrangements with end-user, use storage and be active in the local network management, several regulatory conditions have been identified as barriers to implementing viable arrangements; they are summarised in Table 5-3 for clarity.

Two main features have been identified as barriers to setting DSR arrangements with clear incentive:

- The inherent socialisation of DSR benefits – if a group of non HH-settled consumers, through DSR, modify their load profile to the extent that the peak load is reduced on a network, all users on the network will benefit from the reduced reinforcement costs. This is formalised by the CDCM which calculates the DUoS charges that applies to all users of a given network.
- The separation of electricity distribution and supply – suppliers do not benefit from reduction of distribution cost because of the aforementioned socialisation of savings and supplier interest on the wholesale market is at times in conflict with DNOs interest.

Table 5-3 Summary of regulatory barriers to DSR and storage

Code or regulatory condition	Effect	Affect DSR	Storag	Comments
Distribution Code – Engineering recommendation P2/6	P2/6 dictates standard of security of supply. The wording leaves room for interpretation in terms of the status of storage and DSR. If storage and DSR are not included, investment in DSR and/or storage would be redundant with reinforcement.	X	X	Disagreement in the industry: some DNOs do not see P2/6 as a barrier while other DNOs have concerns on its interpretation. LCNF project 'Capacity of customers' will make recommendations for amendments to Eng Rec P 2/6.
DCUSA - CCDM	Current DUoS charges for non-HH users do not allow DNOs to signal DSR benefit to suppliers (benefits are socialised).	X		Not necessarily a barrier if DNOs were to strike direct arrangements with customers.
Connection of new load	DNOs are not notified of new load, making it difficult to identify customers will DSR potential.	X		This will be addressed for ED1 (2015-23) with a registration protocol for heat pumps and electric vehicles.
Distribution Licence Code – SLC 29	Restricts revenue from non-distribution activity	X	X	In practice, this limit might leave enough scope for revenue from ancillary services or DNOs could seek and obtain a derogation. Using a 3rd party avoid this issue.
Separation of generation, supply and distribution licences	Suppliers and DNOs have diverging interests at time and cannot capture each other benefit. DNOs could be limited in the amount of grid services that could sell from stored energy by generation licence exemption.	X	X	The unbundling is unlikely to change as it is part of European legislation (Directive 2009/72/EC). Installations less than 50MW would be licence exempt. For greater capacity, using a 3rd party avoids this issue.
Electricity Supply Licence – provision of smart meter	No explicit inclusion of data access for DNOs.	X		DNOs can theoretically install their own demand control equipment.

6. Analysis of emerging commercial arrangements

The previous section highlighted strengths and weaknesses of the current commercial arrangements for DNOs to tackle the challenges of the integration of new demand and more renewable and distributed generation.

This section presents some of the emerging commercial arrangements put in place by DNOs, notably connection agreements (6.1), before commenting of the effect of the proposed mechanisms of the Electricity Market Reform (6.2). Finally, the roll out of smart meter is presented (6.3) in terms of contribution to barriers to DSR highlighted earlier.

6.1 Connection agreements

Some areas of the UK, in particular Northumberland and northern parts of Scotland, have significant potential for renewable generation, but weak networks due to low population densities. Connections can be expensive, requiring significant reinforcement or cables covering significant distances. In rural areas, issues of transmission lines affecting visual amenity have also proved controversial. For these reasons, some DNOs have begun exploring whether non-firm connections, also known as managed connections, are attractive to generators.

In **non-firm connection agreements**, also known as curtailment agreements for generation, the generator agrees that their output may be subject to reduction or interruption for technical and commercial reasons. These agreements are particularly useful for renewable generators (with low capacity factors), located in areas where the network is sparse and connection costs high. They may also be used for demands connected at the EHV level, as described in 5.1.1. In both cases, the agreements may act to remove the need for network reinforcement, and reduce connections costs and timescales for the customers.

So far these arrangements are between the DNO and generator, and there does not appear to be any significant barriers, other than novelty, in the way of implementing such arrangements. All wind farm connections ever made by Northern Powergrid have been on this basis.

For example, in Orkney, Scottish and Southern Energy Power Distribution (SHEPD) have implemented an Active Network Management (ANM) system, which automatically curtails generation when necessary. This scheme cost £0.5 million, compared with the counterfactual cost of reinforcement at £30 million[74], and SHEPD estimate that it has allowed an additional 51MW of renewable generation to connect, by requiring that this additional renewable generation is occasionally curtailed. Lots of smaller generators are now connecting and threatening to increase the amount of curtailment experienced by the larger generators. Therefore SSE cannot accommodate new connections for generation above 3.7 kW without either grid reinforcement or further network management solutions[75].

The Flexible Plug and Play project is an UKPN LNCF project that is trialling technical and commercial solutions for the connection of distributed generation. The stakeholder engagement as part of this project has so far found that generation developers have no concerns about being offered connections with some form of curtailment, as long as the implementation was transparent and the estimate of curtailment had low uncertainty[76]. Exposure to risk of a severe "bad" year needs to be limited. This is more of an issue for projects funded by project finance, where considerable effort to understand all the risks is needed. The hardest form of curtailment to predict, the active curtailment, is however the most valuable for DNOs in the context of active network management; see Table 6-1 for a brief overview of curtailment types.

This risk of uncertainty in active curtailment estimate could be a barrier to managed connection agreements. There are several ways of sharing this risk (described in more detail in [76]), but if the DNOs are to bear the risk of the uncertainty, one way of financing this would be through DUoS charges[77] and therefore spread across all users. This approach would contravene current regulatory arrangements where the costs of any particular connection should be borne by the generator causing the costs to be incurred.

[74] http://www.smartergridsolutions.com/about-us/our-experience/orkney-smart-grid.aspx
[75] Press release of 12/09/2012 http://www.ssepd.co.uk/OrkneySmartGrid/PressReleases/
[76] Flexible Plug and Play, Stakeholder Engagement Report, GL Garrad Hassan, 2012
[77] Change in DUoS for GSM arrangements might not be allowed, the condition has been removed in the proposed DCUSA as published by Ofgem on the 5th of December 2012, http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=870&refer=Networks/ElecDist/Policy/DistChrgs

Table 6-1: Types of generation curtailment, risk in estimate and value to DNO in terms of more active management of the network

Types of curtailment[76]	Uncertainty of curtailment	Value to DNO
Passive or non-firm – curtailment only occurs on some rare event/s, or planned maintenance of a major item.	Low	Low
Seasonal – appropriate for situations where thermal limits or voltage limits are the driving factor. Likely to be implemented manually by the generator using the generator controller, backed up by manual adjustment of protection settings by the DNO.	Low-medium	Medium
Active – curtailment limits are communicated to the generator in close to real time, and in most cases automatically from the DNO to the generator controller. Limits are calculated as a function of power flows on the network, the voltage at critical points on the network and are affected by weather conditions.	High	High

One of the observations of the Flexible Plug and Play project is that, in case of smaller generators selling under FiT, curtailment uncertainty is not an issue as DG would not see a penalty for additional costs in failing to meet forecast output, as opposed to DG selling on the wholesale market. Stakeholders however noted that coping with curtailment is not attractive to small projects, due to additional communication and management overheads.

Generators who took part in the project expressed no concerns about the technical implementation of curtailment and have confidence in the DNOs ability to run communications systems.

DNOs might find it difficult to decide between innovating with connection agreements or instead connecting generators by reinforcing the network. Table 14 sets out a comparison between standard bilateral connection agreements and managed connection agreements from the point of view of the DNO and the DG.

Table 6-2: Comparison of standard and managed connection agreements

	DNO	DG
Standard Bilateral Connection Agreement	Pay part of the network reinforcement cost for full output capacity	Possibly high connection cost and long process Can export all output
Managed Connection (mostly under trials)	No/less reinforcement cost Can curtail the DG output e.g. for power flow and voltage control	Lower connection costs and shorter process Curtailed output at times

6.2 Electricity Market Reform

The UK Government's energy and climate change policy has three central objectives: ensuring security of supply, keeping the cost of energy down, and decarbonising energy generation. In order to achieve these objectives, it estimates that £110 billion of investment is required between now and 2020[78]. The Government's view is that current market arrangements will not deliver this investment, and so a policy of Electricity Market Reform is being pursued to meet this challenge.

The objectives of electricity market reform are aligned with the three objectives set out above:

- Providing a diverse range of energy sources to ensure security of supply, including demand side approaches.
- Ensuring sufficient investment in sustainable low-carbon technologies to meet renewables and carbon dioxide emissions reductions targets.
- Maximising benefits and minimising costs to the economy, taxpayers and consumers - maintaining affordable electricity bills while delivering the investment needed.

The Energy Bill to enact Electricity Market Reform was introduced into Parliament in November 2012. It introduces two key measures, which the Government anticipate will be up and running in 2014:

1) Contracts-for-difference Feed-in Tariffs, which will replace the Renewable Obligation. These long term contracts will be available to low

[78] DECC 2012, Electricity Market Reform Policy Overview

carbon generators, such as wind and Carbon Capture and Storage. The contracts will provide a guaranteed price (the “strike” price, £/MWh) for low carbon generation, reducing the price risk from volatility which prevents some long term low carbon generation projects from going ahead. Whilst they will change the incentives for renewable generation and distributed generation projects, it is not clear that they will have any significant impact on the interactions between DGs and DNOs.

2) A capacity market will be created. Both generation and non-generation providers of capacity (such as DSR and storage) will be incentivised to provide reliable capacity, and face financial penalties if they fail to do so. The capacity market therefore acts to protect against the risk of inadequate investment and supply shortages. Capacity markets have been used successfully internationally, including in the United States. However, the US experience implies that the extent to which a capacity market will favour high-carbon-emitting generation over demand side response depends on the detail[79], which is not yet available for the UK market.

6.3 DNO perspective on smart meters – benefits and failures of current proposals

With effect on the 30th of November 2012, the standard licence condition for electricity suppliers stipulates suppliers must install smart meters in all premises of domestic and small non domestic users (~29 million premises as of 2012) by December 2019[80].

Smart meters will provide consumers with real time information on their electricity use, through the In-Home Display (IHD) as well as allow more accurate billing. They are expected to help consumers manage and possibly reduce their consumption and, in doing so, contribute to the challenge of increasing domestic demand and emission reduction targets.

In order to develop the technical specification for smart meters, the Smart Metering Design Group was set up under DECC’s Smart Metering Implementation Programme (SMIP). Over 150 industry stakeholders participated in development of the Industry’s Draft Technical Specifications (part of the Extended Statement of Design Requirements). These documents set out a description of the functionality

[79] Regulatory Assistance Program, 2010, The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects
[80] The completion date has been pushed to 2020 in May 2013, and roll out start postponed from 2014 to 2015 as reflection of the delay in getting agreement on the meter specification.

that the smart metering system must deliver, but do not specify how that functionality should be delivered.

As a minimum, the smart metering system (SMS) will comprise the smart electricity and gas meter, communications hub and IHD. These components will be interconnected by the smart metering home area network (SM HAN) and the communications hub will be capable of two-way communication with a wider area network, allowing it to receive and also send back signals to the central data communications company. This basic architecture is shown in the figure below.

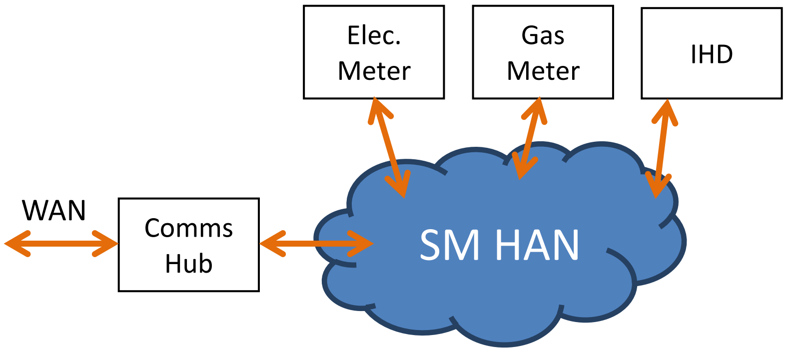


Figure 26: Smart meter system architecture

While smart meters will indeed reveal the real demand profile of each consumer, it is not clear how it will address the barriers to DSR laid out before, namely the disconnect in suppliers and DNOs incentives and the socialisation of network cost through DUoS charges.

In the case of direct DSR arrangements between DNOs (possibly through aggregators) and users, smart meters will be useful only if DNOs can access the data and are allowed to control the meters or use them as a communication channel (e.g. for direct load control).

In the case of indirect DSR arrangements (i.e. through suppliers), smart meters are well suited for suppliers to propose some Time of Use tariffs, however:

- These tariffs could be set to offer suppliers the best buying position on the wholesale market, which is not always the best consumption pattern in terms of local network management.
- Smart meters do not address per se the problem of socialisation of costs that prevent DNOs from signalling benefit of DSR to suppliers and end-users.

Furthermore, there is potentially a disparity between the volume of data smart meters produce and volume DNOs are equipped to deal with. DNOs are currently not equipped to receive and process detailed consumption data from over 20 million households. Some form of data aggregation could reduce the data volume but this would dilute the incentive for individuals to contribute as it would smooth individual contributions.

7. Review of international best practice

The increased share of renewable and distributed generation and predicted rise of new loads such as electric vehicles and heating are creating challenges in many developed countries. It is therefore useful to look into solutions deployed in other markets. This review considers examples from several member states of the European Union, the United States of America (USA) and Australia. The focus of international initiatives tends to be on fostering a market for DSM, i.e. allowing generators, suppliers or third parties to sell DSM service to the TSO, as opposed to DSM led by DNOs. Nevertheless, following these developments brings interesting conclusions on learning opportunities for the UK market.

7.1 Examples from Europe

Within the European Union, the UK is the only country where electricity suppliers are in charge of the metering. In most of other countries, the DNO is responsible. The roll-out of smart meters is very advanced in places; with Italy close to 100% roll-out. Italian DNOs have embraced the cost advantages that smart meters bring, as they do not require individual visits to households for meter reading, and result in a reduction of fraud. Functional specifications of smart meters do however vary across the EU and are still under discussion; from advanced meters in Finland that include load control capabilities and separate measurement of consumption and production to meters that are mainly a way of cutting meter reading costs[81].

Among European countries, the UK has shown most support to innovation in distribution networks, through the Innovation Funding Incentive introduced in 2005 (see page 104) and the Low Carbon Network Fund (£500m over 2010-15 for DNOs to trial new network solutions or arrangements).

In their 2008 survey of 46 DNOs in 13 countries of EU-15, Capgemini found that over 40% of DNOs were involved in DSM activities[82]. The majority of these activities are fault-management measures as observed in the UK. Likewise, virtually all countries have some form of time of use tariffs, for example peak / off peak banding.

Some examples of markedly different approaches to energy challenges – namely tacking energy demand and integration of renewable and distributed energy – have been identified, as summarised in the following.

[81] IEA DSM Task XVII: Integration of Demand Side Management, Distributed Generation, Renewable Energy Sources and Energy Storages. Smart metering report, November 2012
[82] Overview of Electricity Distribution in Europe, Capgemini, 2008

France – tackling energy demand

The focus in France is on reducing energy demand to tackle associated costs and emissions, while networks balancing and reinforcement are not yet perceived as a concern. The French government is taking strong measures to tackle energy consumption: both through building regulations[83] and energy tariffs.

To tackle electricity (and gas) consumption and to reach all consumers, the Government is planning on a reform of electricity and gas tariffs. Under the law proposed in September 2012 (the 'law Brottes') and passed in March 2013[84], each consumer will have, from 2016, an electricity and gas 'base volume', that corresponds to the essential needs of a household. The individual base volume will be calculated based on three parameters: the location, the number of inhabitants in the household and the type of heating system. For kWh under the base volume, the tariff would be low but it would be high for kWh above. There are special arrangements to protect consumers in fuel poverty. There are as well provisions for tenants living in poorly insulated houses to pass on some of the penalty fees to their landlord. No rebate will be attributed for second houses and their threshold will be based on one person occupancy.

It is expected this new approach to energy tariffs will significantly impact on the energy consumption levels. The law does however contain some mechanisms which may be counterproductive (e.g., an exemption on oil heating that might encourage switching to this carbon intense technology and no provisions for EV owners). The table below shows the proposed rebates ('bonus') and penalties ('malus') for individual houses.

Table 7-1: Penalty and rebate on energy usage as in the new Brottes law

Year of usage	Rebate	Penalty for usage between 100% and 300% of threshold	Penalty for usage over 300% of threshold
2015	-5 to 0 €/MWh	0 to 3 €/MWh	0 to 20 €/MWh
2016	-20 to 0 €/MWh	0 to 6 €/MWh	3 to 20 €/MWh
From 2017	-30 to 0 €/MWh	0 to 9 €/MWh	3 to 60 €/MWh

[83] An energy performance regulation for new domestic and office buildings – called RT 2012 – came into force over 2011-2013. RT2012 requires a primary energy consumption three times lower than the previous regulation (50 kWh/m²/year vs.150 kWh/m²/year).

[84] For more details on the law: http://www.assemblee-nationale.fr/14/dossiers/tarification_progressive_energie.asp (in French)

Energy suppliers will be in charge of paying the rebate and collecting penalty payments. If the total rebate exceeds the total payments, they will receive compensation from a government fund specially set up for this program.

Denmark – integration of renewable and distributed generation

The Danish network integrates a large number of CHP (Combined Heat and Power) systems as well as a significant share of wind generation (ca. 20% of electricity) while maintaining a very good security of supply. A number of initiatives have helped achieved this integration and new ones are being proposed, notably: the amendment of rules on district heating (detailed below) and the amendment of taxes and tariffs for electricity, with a move to dynamic taxes and tariffs, aimed at shifting consumption towards time of high renewable generation.

Denmark has an extensive district heating network and more than 50% of heating is generated through CHP systems. Through the 1990s, CHP systems have largely replaced less efficient and more polluting oil and coal heating plants, supported by government subsidies. This increase has however resulted in a negative side effect: because the need for heat does not always match times of advantageous electricity prices, the co-generated electricity has at times been sold to neighbouring countries for less than its production cost. This resulted in a loss for both the generators and the state which provided electricity production subsidies.

To tackle this problem, from 2003 CHPs were exempted from the obligation to co-generate electricity and heat continually in order to qualify for electricity production subsidies. In this way, plants are incentivised to produce heat when there is demand and electricity when the price is favourable, e.g. at times of low renewable generation. The law on heating was further amended to allow district heating to be produced by heat pumps and other electricity based solutions. This allows for the use of renewable electricity for heat, e.g. at times of high wind output[85].

Smart meter roll-out in Denmark has begun and the target date for complete roll-out is 2020. The Danish Energy Association and Danish Ministry of Climate, Energy and Building are planning an information campaign to make consumers aware of the advantages of smart meters, and new possible arrangements.

Providers of home charging solutions (the plug-in post and electricity contract) for EVs, such as Better Place, already offer smart management of vehicle charging,

[85] For more information, see the Danish Energy Agency, www.ens.dk/en-US and Ministry of Climate, Energy and Building website http://www.kemin.dk/en-US/

e.g. the user specifies the next departure time; the charging is guaranteed to be completed in time and is done at the times when the cheapest tariff occurs.

7.2 DSM market & management of inflexible generation in the USA

The electricity industry in the United States contains significant variations in structure, organisation, price drivers, and regulatory oversight. These variations stem from a mix of geographical influences, population and industry make up, and the evolution and interaction of state and federal energy law and policy. Over the latter part of the 20th century the predominant model was based on vertically integrated utility companies, responsible for the generation, transmission, and distribution of power. Some of these were restructured in mid-1990s, in order to develop regional, competitive wholesale (and in some cases retail) markets.

In most US markets there is a single process for energy market transactions and for ancillary services. In some of those markets, in response to fears that this single process would not give peaking generators sufficient revenues, capacity markets have been created to provide an extra revenue stream[86]. These capacity markets are intended to place equal weight on the value of generation or demand response to meet capacity. However auction results suggest that capacity markets encourage the construction and continuing operation of generation over demand response in order to meet targets[87].

Overview of demand response in the US

The US Federal Energy Regulatory Commission (FERC) considers demand side management to consist of two key and complementary components; energy efficiency, and demand response. Demand response has been in place for a number of decades. US utilities introduced direct load control for residential customers and interruptible/curtailable tariffs for large industrial and commercial customers in the early 1970s, in response to the increasing penetration of air conditioning which resulted in significantly increased peak loads and reliability concerns[88]. Problems in many of the restructured markets in the early 2000s (including the California black-outs, but also price volatility and spikes, and issues with perceived market power) led policymakers to place a renewed emphasis on demand response. The Energy Acts of 2005 and 2007 had a significant focus on eliminating barriers to, and facilitating, the participation of demand response in energy, capacity, and ancillary services (balancing services) markets.

[86] Green, 2008. Electricity Wholesale Markets: Designs Now and in a Low Carbon Future. The Energy Journal, International Association for Energy Economics, vol 29: 95-124
[87] Regulatory Assistance Project, Roadmap 2050: A practical guide to a prosperous low carbon Europe, 2010
[88] Cappers et al, Demand Response in US Electricity Markets: Empirical Evidence, 2009

In 2008, FERC estimated that customers enrolled in existing wholesale and retail demand response programs were capable of providing ~38 GW of potential peak load reductions[88], representing around 5% of the peak load of around 750 GW. FERC additionally estimated that this represents less than a quarter of the total market potential for demand response[89]. There is considerable geographical variation in the amount of existing demand response. This variation is due to a variety of factors, including regulatory variation at state level. California, Florida and Michigan have significant activity, others, such as Alaska, Montana and Wyoming have little.

Examples of US demand response programs

It is important to note that the separation of electricity generation, distribution and supply has not occurred in the majority of US states[90]. The examples below are led by utility companies who provide distribution services as well as supplying electricity, and in some cases generating electricity.

California

California was one of the first states to explore and expand demand response. In 1978, the California Energy Commission introduced mandatory time of use pricing for large commercial and industrial customers. Regulations for appliance and building energy consumption are thought to be the main reason that per capita electricity consumption has remained unchanged over the last 3 decades[91].

In 2005, California conducted the Statewide Pricing Pilot, which trialled time of use tariffs with ca. 2,500 residential and small commercial and industrial customers. Many participants elected to continue with the ToU tariffs after the pilot ended[89]. In 2007, regulations were brought into force to mandate that dynamic tariffs become the default for all non-residential customers who have a smart meter.

Arizona

Two major vertically integrated utilities in Arizona have been offering ToU tariffs to residential customers for more than two decades, reflecting the significant use of air-conditioning in very hot summers. The Salt River Project has more than 25% of electricity customers on ToU tariffs (see example tariff in Table 7-2 below), and bills for these customers have been reduced by around 7%[92].

89 National Action Plan on Demand Response, FERC, 2010.
90 Regulatory Assistance Project, Electricity Regulation in the US: A Guide, 2011.
91 California Energy Commission, 2007 Integrated Energy Policy Report.
92 Salt River Project, Navigating change: SRP 2009 Annual Report.

Table 7-2: Example time of use tariff from the Salt River Project. Source: www.srpnet.com

Time of the year	Basic Plan	Time of Use tariff
May – June September – October	First 700kWh = 10.57₵ 701-2000kWh = 11.25₵ More than 2000kWh = 12.31₵	Peak = 19.07₵ (Between 1pm and 8pm, Mon - Fri) Off peak = 7.05₵
July and August	First 700kWh = 11.17₵ 701-2000kWh = 11.78₵ More than 2000kWh = 12.83₵	Peak = 21.22₵ (Between 1pm and 8pm, Mon - Fri) Off peak = 7.17₵
November – April	All kWh = 8.03₵	Peak = 10.12₵ (Between 5am – 9am and 5pm – 7pm) Off-peak = 6.86₵

Florida

Gulf Power, a utility company, has been operating an energy management system for homes since the early 1990's. The system controls four end-uses (air-conditioning, space heating, water heating, and swimming pool pumps) to avoid paying a critical peak pricing tariff, four times greater than the average rate, for the top 1% of the hours in the year in terms of peak load. 8,000 customers subscribe to the system and have saved up to 15% on their energy bills. The utility estimates that the system induces a drop of 40-50% in the customer load during the peak 1% hours in the year[93].

The system has four time bands, as set out in the table below.

Table 7-3: Example time of use tariff for the Gulf Power Energy Select System. Source: www.gulfpower.com

Price	Hour of the day and season that the price applies	
7.3₵	Mon – Sun: 11PM – 6AM	May – October
	Mon – Fri: 11PM – 5AM Sat – Sun: 11PM – 6AM	November – April
8.5₵	Mon – Fri: 6AM – 1PM, 6PM – 11PM Sat – Sun: 6AM – 11PM	May – October
	Mon – Fri: 5AM – 6AM, 10AM – 1PM Sat – Sun: 6AM – 11PM	November – April
15.4₵	Mon – Fri: 1PM – 6PM	May – October
	Mon – Fri: 6AM – 10AM	November – April
59.4₵	The critical price period is not set in advance, but it is guaranteed to cover less than 1% of the hours of the year. Participants in the system have a controller within a thermostat which can programme appliances to automatically switch off during the critical price period.	

[93] Thompson J, Gulf Power, Presentation for the Southeast Energy Efficiency Meeting (2007)

Another utility, Florida Power & Light, introduced one of the largest load management systems in the US. At the end of 2008, 780,000 users were connected, and the system was capable of providing more than 973 MW of load control during times of high demand[89].

Georgia

Since the mid 1990's Georgia Power has operated a real-time pricing program aimed at large commercial and industrial customers[94]. In 2010 it had ca. 1,200 medium and large industrial customers, amounting to more than 4 GW of summer peak demand. The exact contracts can vary by participant according to a combination of the risk exposure and ability to adjust operations. On a high price day, it is estimated that load reductions can be between 7 and 30%[89].

Michigan

Detroit Edison maintains a significant Direct Load Control Interruptible Air Conditioning program, with 280,000 customers, who receive a 2₵ per kWh discount during the summer months in exchange for the possibility of interruption via remote control relays. This discount compares to an average price of 13.25₵ per kWh.

Curtailment of generation

Wind capacity in the US tripled between 2006 and 2010, with an estimated 25 GW installed in 2010. Investment in the electric grid has not increased so rapidly, and the National Energy Resource Laboratory (NERL) identifies two key reasons why wind curtailment is now being used in the US, 1) lack of available transmission during a particular time to incorporate some or all of the wind generation; or 2) high wind generation at times of low load, when generation cannot be exported to other balancing areas due to transmission constraints.

Wind curtailment initiatives are at an early stage of discussion or implementation, but as with demand response they vary across the country and are representative of the regional electricity market that is in place. Below are examples of the wind curtailment practices in place in the US

[94] Further information can be found at: http://www.georgiapower.com/pricing/files/rates-and-schedules/6.20_RTP-DA-3.pdf

Bid-based curtailment

The New York ISO and PJM are allowing wind generators to bid a price that includes their willingness to curtail operations[95]. During constrained operations, the RTO/ISO will curtail generation according to the bids.

Daily operating limits

The Electricity Reliability Council of Texas (ERCOT) previously operated a system with daily operating limits for wind plants in a particular area, as transmission constraints limited transfers from the generation in one part of the region to load centres elsewhere. Under these rules, average annual wind curtailment was ca. 16% in 2009[96]. These rules have been removed in favour of incorporating wind into economic dispatch in order to be treated like all other generators. ERCOT will still call upon wind plants (as well as other generators) to make reductions in output during periods of transmission congestion.

Differences by type of wind technology

ERCOT also distinguish between two types of wind farms – rapid (those that can respond to a curtailment request within 15 minutes, which tend to be newer, with more advance control capabilities), and slow (which must respond within 30 minutes of getting a request). The rapid wind farms were allowed to operate above their daily limit, but had to reduce generation on request if reliability issues arose. In slower time, the slow wind farms were also required to reduce generation by more than their pro-rata share, to allow the rapid farms to recoup some of the lost generation and revenues.

Reserves

Bonneville Power Administration has curtailment procedures included in large generation interconnection agreements for wind projects. They curtail wind output when there is over-generation, and if 90% of the balancing reserves have already been utilized. A maximum generation limit for variable generators is assigned. Once 90% of the balancing reserves have been used, variable generators that have substantially over-generated relative to their agreed schedule will be required to reduce generation to a specific level. As of March 2010, the estimated total amount of wind limited was 2900 MW[96].

[95] NERL, Wind Energy Curtailment Case Studies, May 2008 - May 2009.
[96] NERL, Examples of wind energy curtailment practices, 2010.

7.3 Developing a market for DSR and embedded generation: the case of Australia

The electricity market in Australia differs from the UK one as it is split in eight jurisdictions[97] and the retail side of the market (i.e. the supplier end) is regulated in all jurisdictions but one (Victoria).

The Australia grid and networks are however facing comparable challenges to the UK's (increase in intermittent and distributed generation and increase in load), albeit with a different seasonal pattern: peak demand is in summer, due to an increased use of air-conditioning units. Distribution network charges represent over 30% of the electricity price.[98]

The Australian Energy Market Commission (AEMC) is the national and independent body that makes and amends the detailed rules for, among others, the National Electricity Market and economic regulation of electricity distribution network services. It also conducts reviews of energy markets.

Several changes are being proposed for the network rules and electricity market arrangements, most notably reforms to enable 'demand side participation' (DSP: DSR, energy efficiency and embedded generation) and the integration of EVs while minimising impact on the network. After extensive consultation, the AEMC published amendments to the rules and proposed changes to market arrangements in 2012. A brief overview of these changes is set out below.

Rule amendment - Distribution Network Planning and Expansion Framework[99]

'Demand side obligations' for DNOs have been added to their regulatory framework, with effect on the 1st of January 2013. The aim of these new obligations is for DNOs to give greater consideration to the potential of DSR and DG, and to publish more information to assist potential DSR and DG providers to identify opportunities and understand their value and operating requirements.

The AEMC recognises that additional DSR and DG may complicate the forecasting of network demand for DNOs. To address this, the AEMC has recommended the Australian Energy Market Operator is given an increased role in demand forecasting.

Power of choice review – giving consumers options in the way they use electricity[100]

[97] Australian Capital Territory, New South Wales, Northern Territory, Queensland, South Australia, Tasmania, Victoria, Western Australia

[98] Retail electricity price estimates, Final report for 2010-2011 to 2013-2014, AEMC

[99] Published in August 2012, available at http://www.aemc.gov.au/electricity/rule-changes/completed/distribution-network-planning-and-expansion-framework.html

This report lays out an extensive and innovative reform package that aims at providing "households, businesses and industry with more opportunities to make informed choices about the way they use electricity and manage expenditure" and meeting electricity demand by the lowest cost combination of demand and supply side options.

In the context of this study, recommendations of interest are:

- Reward the DSR as part of the wholesale market and link the DG incentive to wholesale prices

  The AEMC recommends the introduction of a demand response mechanism under which DSR would be paid the wholesale electricity spot price. In participating directly (or through aggregators) in the wholesale market, consumers' reward will be independent of retailers' own commercial interest.

  Regarding distributed generation, the AEMC recommends a review of the feed in tariffs approach, where tariffs could be variable and thus able to encourage export during time of peak demand. DG would also be given the option to sell their electricity to a third party, as opposed to automatically selling through their electricity supplier as they currently do.

- Phase in flexible pricing options for domestic users and small businesses

  Electricity pricing for domestic consumers fosters the same problems as in the UK: the use of load profiles socialises the benefits of DSR, both at wholesale cost and network charges (DUoS) level.

  AEMC recognises that calculating individual DUoS would be too complex. It however recommends the introduction of 'flexible prices' that include variable DUoS charges. In a first phase, flexible prices would be mandatory only for large users. The threshold for 'large users' has not been defined; it would however correspond to a household/office with several heavy load appliances such as EVs, swimming pool pumps and/or large air conditioning systems.

[100] Published in November 2012, reports and updates are available at http://www.aemc.gov.au/market-reviews/open/power-of-choice-update-page.html

This proposed principle of flexible network charges is comparable to the red, amber, green regime of DUoS for HH settled customers in the UK, with the difference that it is proposed for domestic users, albeit 'large users'. Medium and small users would continue to see 'flat prices', i.e. one single DUoS rate, but would, over time, be offered the option to choose a flexible price.

Other recommendations include Government programs to raise consumer awareness on energy consumption, roll-out of smart meters and use smart meters for settlement as opposed to standard load profiles.

There are also proposals for distribution network incentives: a new incentive package for DNOs to implement DSR initiatives as an efficient alternative to capital investment; and an innovation allowance. New pricing arrangements for DUoS are also discussed – this is however less relevant as standardised charging methodologies have already been developed in the UK.

Energy market arrangements for electric and natural gas vehicles[101]

The AEMC recommends several amendments to market arrangements to mitigate the network cost impact of the forecasted uptake of EVs, i.e. to encourage charging of EVs outside peak times. Recommendations relevant to the UK case include:

- All EVs should have a metering installation with interval read capability to enable ToU tariffs as well as to help consumers manage their consumption.
- Price signals, as recommended in the 'Power of choice review' should be designed to capture most EV owners.
- Technical standards for direct load management should be developed.

It is also worth noting that the AEMC is currently running a consultation on the **connection rules of embedded generators**. Some amendments being discussed correspond to aspects already developed in the UK (e.g. standardisation and transparency in connection cost calculations, definition of connection timeframe) while others might provide useful examples, notably whether efficient siting of embedded generators can be influenced by DNOs publishing annual reports that identify network capacity constraints. The consultation runs until June 2013, and the resulting proposed amendments will be accessible on the AEMC website[102].

[101] Published in December 2012, available at http://www.aemc.gov.au/market-reviews/completed/energy-market-barriers-for-electric-and-natural-gas-vehicles.html
[102] http://www.aemc.gov.au/Electricity/Rule-changes/Open/connecting-embedded-generators.html

7.4 Learning opportunities for UK market

The examples described in the sections above show that there is significant scope for the UK to learn from trials and projects in other countries. Within the UK, the results of the LCNF projects will be made available over the coming months and years, and will form an important source of information for all DNOs.

Fostering a DSR market

US experience shows that it is not a capacity market alone that will encourage DSR. The most successful demand side response programs have been introduced at the retail level by utility companies (most are equivalent to the supplier and the DNO in the UK).

In the US there are a substantial number of projects demonstrating a significant amount of demand response. In the domestic sector, direct load control of large loads (often air conditioning units) by utility companies is relatively common, and is often used alongside ToU tariffs. ToU tariffs tend to send stronger signals than the current time of use tariffs in the UK, either by incorporating more bands or higher peak pricing. The planned changes to electricity tariffs in France will result in a stronger price signal to consumers and are expected to have a significant impact on energy consumption.

In the large industrial and commercial sector, supplier-led real-time pricing has been used successfully in a number of states to induce peak load reduction. UK DNOs may benefit from exploring these models and trials in more detail.

The effect of the planned reforms of the Australian electricity market and distribution rules should be watched with interest over the next years as they are very innovative and have the clear goal of enabling the domestic users to take part in demand side response services as well as minimizing the impact of EVs.

Facilitating distributed generation and integrating renewable generation

Denmark provides an example of an integrated approach, with amendment of district heating laws to integrate wind generation and avoid losses on CHP electricity.

In the US there are a number of examples of different ways to organise the curtailment of wind generation. These examples show that it is possible to incorporate wind curtailment successfully both in terms of the network and in terms of the economics for the wind generator. Some of these models may not be relevant to the UK market given the different market structure (e.g. including in the bid price an element of the willingness to curtail), but the others may well be relevant, and warrant further exploration of the commercial arrangements.

8. Summary and next steps

The previous sections have covered in some details both the current features of the market and the barriers to new arrangements such as DSR and storage. This section aims to provide a summary of both the review of the market and the analysis of barriers.

8.1 Overview of the UK electricity market

The UK electricity market is regulated by the Gas and Electricity Markets Authority. The five types of licences are: generator, interconnector, transmission operator, distribution operator, and supplier.

The UK has ca. 89 GW of electrical generation capacity, and just less than 10% of this is generation that is connected directly to the distribution network. The number of connections and capacity of distributed generation (DG) is projected to grow significantly over the coming years, in response to targets and incentives for renewable generation. DECC estimate that by 2020, there will be 2.6 million connections of small-scale solar PV alone, representing a capacity of 12.5 GW.

National Grid Electricity Transmission operates the transmission system for Great Britain, and owns the transmission network in England and Wales. As system operator (SO), the NGET procures a range of balancing services, in order to balance supply and demand across the network, and to ensure the security and quality of electricity. Generators and large users of electricity can gain revenue streams from providing these services, but there is no existing market for smaller consumers to participate. In Scotland, some of the transmission network is owned by SHETL and some by SPTL. In Northern Ireland, the grid is owned by Northern Ireland Electricity but operated by SONI.

Distribution Network Operators are responsible for providing the network which transports electricity from the transmission system and generators, to customers. There are 14 licensed DNO areas, covered by 6 DNO groups.

Electricity suppliers purchase electricity on the wholesale market and then supply it to consumers. They cannot be the same entity as a DNO. Six large supply companies dominate the UK market.

The peak load on the GB electricity network is currently around 55-60 GW, and this is expected to increase rapidly over the coming years, to over 100 GW by 2050 (Smart Grid Forum's Scenario 1), driven by the electrification of our heating and transport systems. This will cause serious challenges for DNOs and the electricity system as a whole, and will require significant investment in reinforcing networks.

8.2 Key features of current arrangements

8.2.1 Regulatory framework for distribution network operators

At distribution level, connection and commercial arrangements are governed by the DCUSA (Distribution Connection and Use of System Agreement). It is a multi-party contract between distributors, suppliers, the Offshore Transmission System Operator and generators connected to distribution network.

Launched in 2006, the DCUSA replaced numerous bi-lateral contracts, giving a common and consistent approach to the relationships between licensees. It has undergone significant changes in the last few years, moving charging methodologies towards more standardisation and transparency across all DNOs.

The DCUSA defines the methodologies to calculate the Distribution Use of System charges (DUoS) that DNOs charge to suppliers and the connection charges, that are apportioned between generators connecting to the network and DNOs. The main characteristics and resulting tariffs structure of these methodologies are summarised below.

CDCM and EDCM – Common and Extra high voltage Distribution Charging Methodologies

The principle of the CDCM and EDCM is to calculate the costs incurred by DNOs to install, maintain and operate assets and determine tariffs for different users, based on predicted load volume and use of assets. Estimated tariffs are adjusted to ensure the predicted derived revenue matches the allowed revenue, as defined by the price control regime set by Ofgem.

The next table summarises the DUoS tariffs applied to suppliers (who pass on the charges to final users). Users are differentiated by their meter type, which is either half hourly (HH) settled or non HH settled. The exact load profile of non HH settled users is not known but a standard load profile is assumed (based on yearly measurement on representative sample of users).

Table 8-1: Summary of DUoS charged to suppliers and passed on to end-users

Methodology	Network level	Unit Rate (p/kWh) Time bands	Fixed charge (p/day)	Other charges	% demand	Comments
CDCM	LV to HV Non half hourly settled meter	One or Two	Yes (except for unmetered supplies, e.g. street lighting[103])	None	44% (11% under two rates)	Standard load profiles apply. Two rates correspond mainly to peak/off-peak regime, labelled Economy 7 by suppliers.
CDCM	LV to HV Half hourly settled meter	Three	Yes (except for unmetered supplies, e.g. street lighting[103])	Capacity and reactive power (p/kVA/day and p/kVArh)	29%	Each DNO can define the time bands. They are designed to smooth the load profile.
EDCM	EHV Half hourly settled meter	Seasonal super red rate	Yes	Capacity charge and exceeded import capacity charge (p/kVA/day)	27%	Super red tariffs apply during winter months, to address the evening peak demand.

This pricing structure embeds time of use tariffs (two rates, red-amber-green regime and seasonal super red rate) that cover **67% of the GB demand**. Capacity charges on HH settled users also act as an incentive for end-users to smooth the load profile. DUoS charges at EHV level also comprise a locational element that reflects the level of network capacity congestion.

[103] For unmetered supplies, the DNO calculates the estimated annual consumption, based on an inventory provided by the consumer, and the DNO and supplier charges are based on this estimated annual consumption. Typical unmetered supplies include street lighting.

Similarly, the pricing structure for distributed generation has a time band element for non- intermittent generators, to encourage generation at times most needed: red-amber-green regime at LV-HV level and super red credits at EHV level. DG generation at LV-HV level is marginal at the moment, with a production covering less than 3% of the LV-HV demand.

CCCM – Common Connection Charging Methodology

To connect to the distribution system, generators and large loads may need to pay a connection charge to the DNO. Connection charges apply for the sole use assets as well as a share of the reinforcement costs (if reinforcement is required to accommodate the new connection). The CCCM lays out the rule of the apportionment of costs between DNOs and DGs.

This mechanism is one way that DNOs can influence the siting of DG. DNOs have diminishing influence over the siting of DG as the size of the DG decreases, as shown in the next table.

Table 8-2: DNO scope of impact on DG installation

Type of DG	DNO lever	Comments – size of market
EHV	**Strong** – EHD connection and capacity charges are high, they incentivise efficient siting and design in terms of network reinforcement. DNOs can also contract EHD generators and users for Generation Side Management or Demand Side Management.	~60% of onshore wind turbines. This ratio is expected to stay the same to 2020.
HV and LV (non SSEG)	**Medium** – DGs receive RO for renewable (or FiT for small generation) independently of position on the network but they are also subject to connection charges and capacity payments, which encourage efficient siting.	HV: ~7,300 GWh, ~1,200 DGs
LV SSEG	**Weak** – SSEGs do not pay connection charges and receive strong incentives through FiT: no incentive to site in networks best capable to cope with DG nor to time installations in a given network.	Around 330,000 installations as of Sept 2012, predicted to increase to 2.6 million by 2020.

8.2.2 Current commercial arrangements

The main features of commercial arrangements currently in place in the electricity market for generators and suppliers have been presented in detail in section 4; a brief overview is given here.

Generators

Large generators primarily sell their energy into the wholesale market, via bilateral contracts with suppliers. The trading arrangements are designed to encourage a competitive market, by allowing suppliers to buy electricity from a generator of their choice. Prices are achieved either through negotiation directly between the supplier and generator, or via an exchange.

Distributed generators can sell their output like large generators, but they also benefit from more incentives and charge exemptions, as highlighted by the red crosses in the figure below.

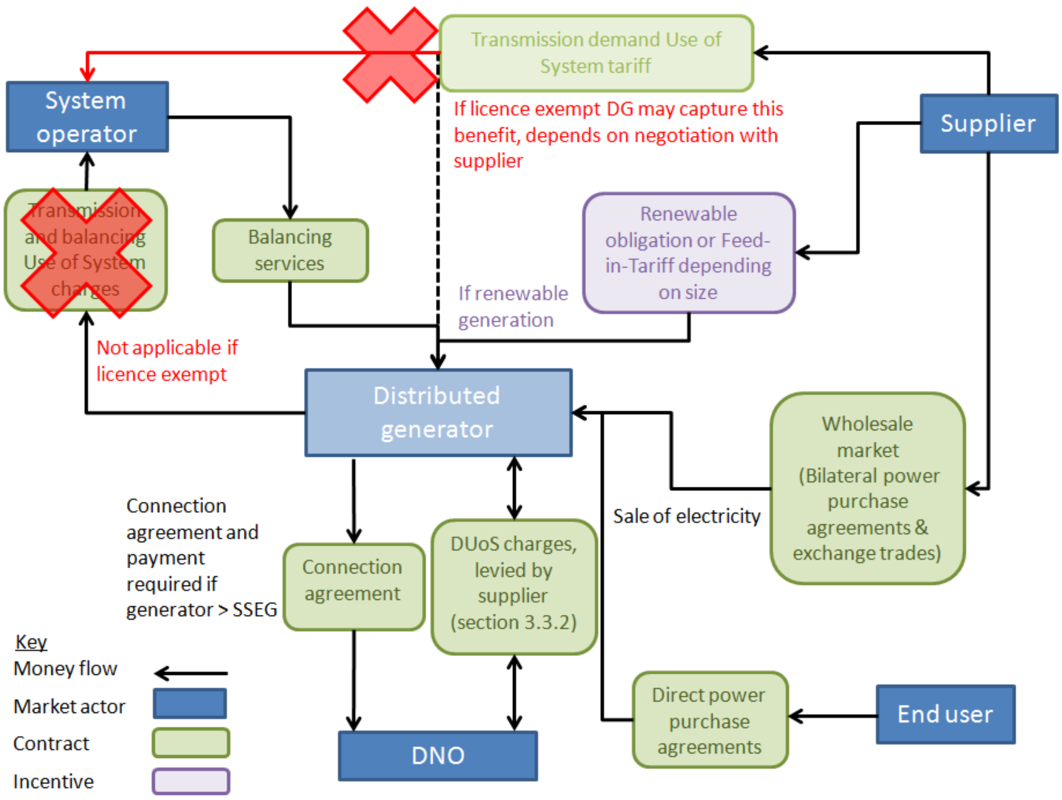


Figure 27: Distributed generators main charges and revenues

Distributed and renewable generation is supported via two incentive programs: the Renewable Obligation and Feed-in Tariffs. The RO incentivises larger scale renewable generation (generators larger than 50 kW can gain support from the RO) while the FiT incentivises smaller renewable projects (less than 5 MW). Projects between 50kW and 5MW can decide whether to gain support from the RO or the FiT.

Distributed generators are close to the point of end use of their output, and so have historically avoided charges associated with the transmission system. These are known as ‘embedded benefits’, and they currently relate to a mixture of trading and transmission charges for which distributed, and licence exempt generators, are not liable.

Suppliers

Figure 28 shows the main charges and revenues for the suppliers. The commercial model employed by the supplier depends on the type of customer. Large industrial and commercial customers are likely to have bespoke contracts with suppliers or even direct with generators, and will have meters that record consumption for each half-hourly interval. For non-half-hourly metered customers, the exact daily consumption is not known. Instead periodic meter readings are converted for billing purposes into half hourly profiles based on standardised load profiles.

There is a levy on the supply of energy to business (the Climate Change Levy), designed to decrease energy consumption. There is also an obligation on electricity suppliers to install energy efficiency measures in domestic properties, with a focus on the poorest households.

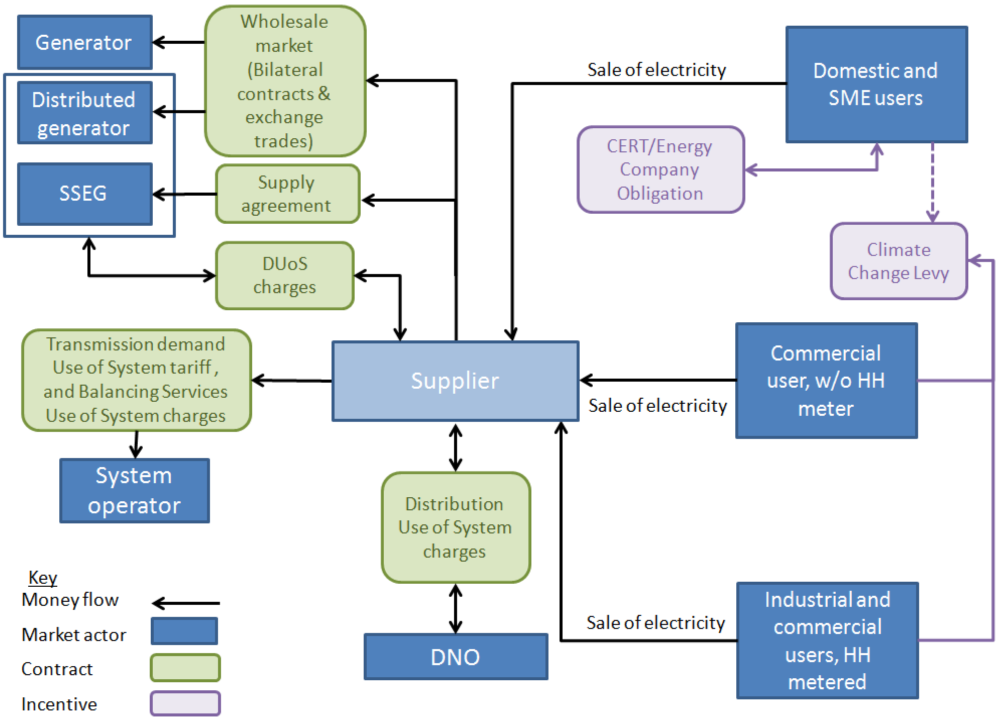


Figure 28: Suppliers main charges and revenues

The relationship between domestic customers and DNOs

Most consumers only have a direct relationship with suppliers, who set the electricity price. DNOs have very little direct interaction with consumers, often only when there is a problem (e.g. network outage), or when a new connection above the household scale needs to be made. Suppliers pass the distribution system charges on to consumers, but most consumers are not aware of the level of these charges, as they are not a transparent part of billing.

8.3 Barriers in current arrangements and emerging arrangements

The challenge for DNOs in the future is to ensure that network development maximises the utilisation of installed network capacity and delivers most cost effective reinforcement when required. Influence over electricity demand patterns and managing the integration of distributed generation will be important to meet this challenge. The existing commercial arrangements have been assessed to identify where they inhibit the ability of DNOs to use commercial offers or apply technical solutions to achieve these aims. Examples of where DNOs are successfully applying these solutions within the existing commercial arrangements have also been identified, along with emerging models.

8.3.1 Existing models and barriers in current arrangements

Achieving demand side response (DSR), either through price signals, direct load control or explicit contracts for interruption of supply, is potentially an attractive means of increasing utilisation of distribution networks. The current mechanisms for DNOs to influence the demand patterns of domestic and non-half-hourly metered non-domestic users are limited to peak/off-peak electricity tariffs, such as Economy 7 & 10. For half-hourly metered users, there is already time of use DUoS charging, although DNOs believe the impact of this variable pricing on the consumption patterns of I&C customers has been limited. In addition, DNOs do enter into interruptible supply contracts with larger users, which require I&C customers to respond by switching off load in the event of the loss of an incoming circuit. This response can assist in fault management and as a means of avoiding network reinforcement. The ECDM provides a further mechanism for DNOs to enter into DSR agreements with EHV customers through reduced DUoS charges. A DNO working group has been proposed to standardise the approach to such arrangements across DNOs, although few such arrangements have been put in place to-date.

There are numerous barriers to DNOs effectively using demand side response to manage load on their networks and reduce reinforcement investment. These barriers are particularly inhibitive in the case of non-half hourly (NHH) settled users (domestic and small commercial users). These barriers are summarised below:

Engineering Recommendation P2/6 – It sets out the security of supply standard that all licensed DNOs must conform to and is perceived as a barrier to DNO engagement with DSR, by some industry stakeholders. The definition of measured demand used in ERP2/6 does not seem to recognise the contribution of DSR (or storage) in managing demand. This would require DNOs to install assets to meet the level of security specified in the standard, irrespective of any DSR arrangements in place. The Smart Grid Forum Work Stream 6 and the ENWL Capacity to Customers project (LCNF funded) are both examining this issue and recommendations for revisions to ER P2/6 are expected in 2013. It is worth noting that some DNOs do not interpret ER P2/6 as excluding DSR (or storage) and therefore do not see that ER P2/6 presents a barrier.

Lack of visibility of end-user demand – Apart from requirements under G83/1 for the connection of small-scale generation, DNOs are not typically informed of where low carbon technologies such as heat pumps and EVs are connected. DNOs also lack any visibility of the electricity consumption patterns of NHH metered users. Without this knowledge it is difficult for DNOs to target DSR offers effectively.

Socialisation of connection charges – Under the current charging arrangements a DNO can in theory charge a customer who wishes to connect a large load such as a heat pump or EV charger for any reinforcement costs required at the voltage level of the connection and one level above. In practice however, due to the lack of visibility of where these loads are connected, the connection costs are socialised across all users. This socialisation of connection charges is expected to become adopted within the regulations.

Lack of relationship with end-users – While DNOs do have a track record of contracting directly with large-users, for example for interruptible supply, and under ECDM will have a mechanism of integrating DSR into the DUoS charges for EHV consumers, they do not typically have any direct relationship to domestic and small commercial consumers. There are no explicit barriers to DNOs entering into contracts directly with these NHH settled users for DSR services, but there is no precedent for such arrangements. To contract directly with small-scale consumers would require a significant change of DNOs current business practices; they do not currently have channels to market commercial offers to consumers and do not have the back office infrastructure for handling payments. There would also be a requirement for investment in equipment to enable DSR in homes and small businesses. The inability to lock domestic customers into long-term DSR contracts is a barrier to DNOs making this investment.

Lacks of alignment with supplier interests – Currently DUoS charges are passed on to end-user through the suppliers. Hence, the DNO is reliant on the supplier to pass through any price signal they may want to send. However, suppliers and DNOs may not share a common view of the preferred demand profile. DNOs are likely to want to shift demand from the evening peak into periods of lower demand, during the day and overnight. The main driver for suppliers will be to shift demand into times of lower cost generation. As increasing levels of non-dispatchable generation such as wind turbine comes on stream, the times of low wholesale electricity price could overlap with times of peak demand.

Lack of incentive for suppliers – In addition to the potential lack of alignment between supplier and DNO objectives, there is also a lack of incentive for suppliers to engage with DNOs on DSR measures. A reduction in network reinforcement costs due to a successful DSR programme would result in a reduction of (or at least constrain) future DUoS charges. Within the liberalised GB electricity market, this benefit still accrues to the suppliers of half-hourly metered customers (about half the demand) but is smeared across all suppliers of non-half-hourly metered customers, who are settled on fixed profiles.

More active management of demand is one means of increasing the utilisation of the distribution networks and ensuring that network investment is cost-effective. Maximising the capacity of distributed generation that can be connected to existing network capacity is a further key aspect of this.

In terms of small-scale distributed generation, DNOs have relatively little influence over where this generation is connected and so cannot incentivise connection in those networks that are better able to cope. For larger-scale generation, however, there seem to be relatively few barriers to DNOs adopting contractual offers, such as non-firm connection agreements, and technical solutions, such as active network management systems, that could be used to increase the capacity of networks for connection of generation. One potential technical solution to increase network capacity for new generation that is subject to certain barriers is electricity storage. As discussed above, storage is not currently recognised within ER P2/6 and therefore does not contribute toward meeting the required security standard. This is a significant disincentive to DNOs investing in electricity storage.

8.3.2 Emerging commercial arrangements

The government is progressing with policies and electricity market reforms aimed at achieving decarbonisation goals and ensuring future security of electricity supply. In parallel, the Low Carbon Network Fund (LCNF) has presented an invaluable opportunity for DNOs to field test technologies and commercial offers that could provide solutions to the challenges that lie ahead. A number of promising technical and commercial solutions are now emerging from these projects.

A substantial share of Great Britain's renewable energy resource is located in relatively remote areas, where the electricity grid is weak. Costs of network reinforcement to provide connections for renewable generation can be very significant and in some cases prohibitive. Non-firm connection agreements for distributed generation are a means of maximising the capacity of generation that connected to existing network capacity. Under these agreements, the generator agrees to have their output reduced or interrupted for technical or commercial reasons. Such agreements can reduce or obviate the requirement for network reinforcement. An example of this is provided by SHEPD and the Active Network Management (ANM) system installed in their network in Orkney, which curtails generation when necessary. This system has enabled an additional 51 MW of generation to be installed, at an ANM system cost of £0.5 M, compared to a network reinforcement cost of £30M. UK Power Network's Flexible Plug and Play project has explored the attitude of generation developers to non-firm connection agreements and found few concerns, particularly if the estimate of the degree of curtailment can be provided with a high degree of uncertainty. This does conflict with active curtailment, where curtailment limits are communicated to generators in close to real-time and are therefore inherently uncertain. The more active curtailment is of greatest value to DNOs.

Smart meters are being rolled out in Great Britain to all domestic and small commercial consumers over the period to 2013. The smart meters will provide better information to occupants regarding their electricity consumption and will enable two-way communication between each meter and a centralised data communications company. This communication facility will permit half-hourly metering, remote meter reading, improved fault diagnostics and also a means of providing pricing signals such as time of use tariffs (the smart metering system could also provide a means for direct load control). The smart metering system could also address some of the barriers to DNO-led DSR that have been identified in the current arrangements, for example, the lack of visibility of pricing signals and lack of knowledge of consumption patterns. However, the benefits of the smart metering programme to DNOs will be highly dependent on the final details of the programme. In particular, the DNOs access to the smart meter data and ability to use the smart meter system as a means to pass through pricing signals (and even to transmit direct load control signals) is crucial and currently uncertain.

DNOs are beginning to trial more sophisticated demand response contracts with large industrial and commercial customers. Whilst DNOs appear to be the weakest market players in terms of the price signal, at time of network fault the value of DSR would be significant to DNOs. The experience of Georgia Power in the US, whilst not directly comparable to the UK market, implies that industrial and commercial customers can see real value in participating in DSR programs. It remains to be seen whether the UK adoption of a capacity market will incentivise demand side response. The US market experience has demonstrated the importance of giving sufficient weight to DSR in the detailed design of the market.

8.4 Next steps

This Phase 1 report identifies the main barriers to the adoption of solutions such as DSR inherent in the current arrangements. Markets that provide relevant examples of implementation of such solutions and amendment of regulations needed to foster them have also been identified.

The CLNR learning outcomes 1 and 2 (LO1 and LO2) will be instrumental in understanding the effect of new and emerging technologies on distribution networks, and in understanding which social and technical solutions could be used to resolve network constraints. LO1 contains an analysis of baseline load and generation characteristics for a range of low-carbon technologies and customer types. LO2 will identify the degree to which these characteristics are flexible; i.e. which components of load and generation are flexible, and what factors enable access to this flexibility. The field trials will provide an understanding of the degree to which customers accept flexibility propositions, and what affects this acceptance. Driving factors for acceptance are expected to include: motivating and demotivating factors; environmental factors; supplier and distributor information provision and communication methods; socio-demographic considerations; technologies. It is expected that this will identify at a minimum three categories of flexibility: firstly, where flexibility is available and where there are no or few barriers to access; secondly, where flexibility is available but where barriers (social, financial, organisational, regulatory) prevent straightforward access; and thirdly, where flexibility is not present in either absolute or in practicable terms.

The Phase 2 study, which will form part of the CLNR learning outcome 4 and 5 analysis, will build on this Phase 1 baseline and the LO1 and LO2 field trial results. LO4 will draw on the results of the field trials to identify the combined socio-technical solutions likely to provide the most effective strategies for network constraint relief, where effectiveness is defined on a cost-benefit basis. Effective strategies are expected to incorporate cost-effective network solutions with promising customer flexibility solutions; however it is likely that some solutions will, as noted above, come up against significant barriers to realisation and will require either modification of existing or the production of new business models and industry codes to enable delivery. Thus the Phase 2 study will focus on these recommended solutions and the business models and industry codes required to deliver them.

9. Appendix

9.1 DUoS tariffs and profile class

The objective of this section is to detail the DUoS tariffs and clarify the relationship between these tariffs and the standard load profile known as profile class.

As explained earlier in the report, there are two types of electricity users: the half-hourly (HH) metered demand, for bigger consumers and non half-hourly (NHH) metered demand, covering over 99% of users.

Half hourly meters

HH meters allow for the measurement of an accurate demand profile. For these meters, the CDCM defines five DUoS tariffs, differentiated by the point of connection in the network; see Table 9-1.

Table 9-1: DUoS tariffs for half-hourly metered demand. Source: DCUSA

<table>
<tr><th>Point of connection</th><th>Unit Rate time bands</th><th>Other charges</th><th>Tariff name</th></tr>
<tr><td>LV</td><td rowspan="5">Three</td><td rowspan="4">Fixed, Capacity (including excess capacity) and reactive power</td><td>LV HH metered</td></tr>
<tr><td>LVS[104]</td><td>LV Sub HH metered</td></tr>
<tr><td>HV</td><td>HV HH metered</td></tr>
<tr><td>HVS[105]</td><td>HV Sub HH metered</td></tr>
<tr><td>LV</td><td>None</td><td>LV UMS (Pseudo HH metered)</td></tr>
</table>

Non half hourly meters

For NHH metered users, the actual demand profile is unknown and standardised profiles are used instead, to settle costs (supply, balancing, use of system charges). There are eight load profiles, corresponding to eight profile classes. Table 9-2 gives the definition of the classes.

[104] LVS refers to applies to customers connected a voltage of less than 1 kV at a substation with a primary voltage (the highest operating voltage present at the substation) of at least 1 kV and less than 22 kV, where the current transformer used for the customer's settlement metering is located at the substation.

[105] HV Sub applies to customers connected at a voltage of at least 1 kV and less than 22 kV at a substation with a primary voltage (the highest operating voltage present at the substation) of at least 22 kV and less than 66 kV, where the current transformer used for the customer's settlement metering is located at the substation.

Table 9-2: Profile class definition. Source: Elexon

Profile Class	Type	Name	Peak Load Factor
1	Domestic	Unrestricted	-
2		Economy 7	-
3	Non-Domestic	Unrestricted	-
4		Economy 7	-
5		Non-Domestic Maximum Demand Customers	<20%
6			20% to 30%
7			30% to 40%
8			over 40%

Load profiles are derived by taking half-hourly measurements on a sample of the population in each profile class; this is done annually in the UK. The next figure shows an example of load profiles.

Suppliers convert (typically quarterly to bi-annually) meter readings into daily HH load profile for billing purposes, based upon load profile shape and regression coefficients. A regression analysis is done on variables linked to parameters such as temperature, sunset time and day type (week / weekend), and gives a set of regression coefficients; this is done for each season (five seasons: four seasons plus 'high summer').

Other information linked to a profile class is the standard settlement configuration (SSC) and Time Pattern Regime (TPR). The SSC defines the configuration of the metering system, e.g. 'unrestricted', '7h E7', 'Evening/Weekend'. An SSC has an associated TPR that defines when the electricity meter is recording data.

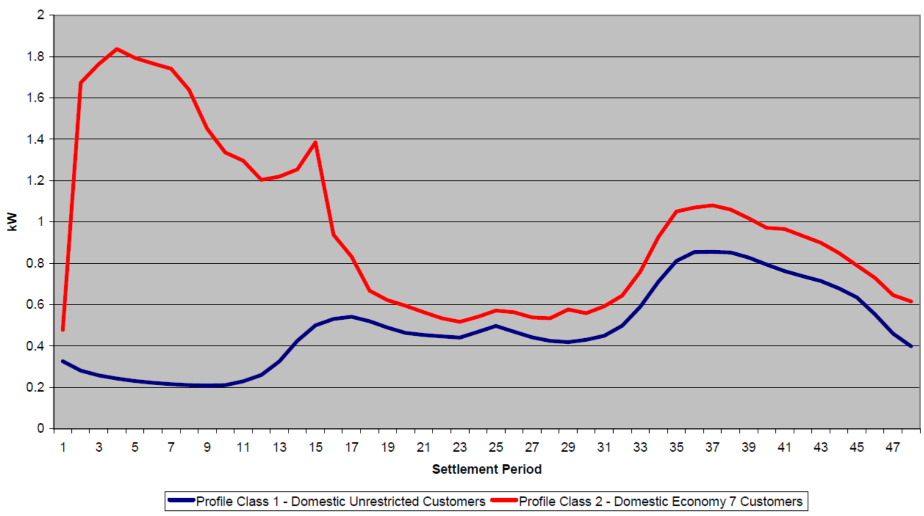


Figure 29: Example domestic load profile shape for of a winter

Based on profile class, SSC, TPR and line loss factor data, DNOs allocate a given NHH connection to a DUoS tariff. The table below lists the DUoS tariffs for NHH demand users, showing the point of connection and corresponding profile class.

Table 9-3: DUoS tariffs for non half-hourly metered demand. Source: DCUSA

Point of connection	Profile Class	Unit Rate time bands	Other charges	Tariff name
LV	1	One	Fixed	Domestic Unrestricted
LV	2	Two	Fixed	Domestic Two Rate
LV	2	One	None	Domestic off-peak (related MPAN)[106]
LV	3	One	Fixed	Small non-domestic unrestricted
LV	4	Two	Fixed	Small non-domestic two rate
LV	4	One	None	Small non-domestic off-peak (related MPAN)[106]
LV	5 to 8	Two	Fixed	LV medium non-domestic
LVS	5 to 8	Two	Fixed	LV Sub non-domestic
HV	5 to 8	Two	Fixed	HV medium non-domestic[107]
LV	1 & 8	One	None	NHH UMS (unmetered supplies) *This will be split into 4 separate tariffs (category A, B, C & D) from April 2013.*

For more information on load profiling, refer to Elexon:
http://www.elexon.co.uk/reference/technical-operations/

[106] Tariff supplementary to a standard published tariff
[107] The current DCUSA proposal is that this tariff will be closed to new customers and all new HV connections will be required to be half-hourly metered.

9.2 DPCR5: incentives and obligations on DNOs

The current price control, the Distribution Price Control Review 5 (DPCR5), includes a package of incentives and obligations on DNOs aimed at meeting three objectives: preparing networks for climate change related challenges, improving customer services and efficient investment in networks.

9.2.1 Climate change measures

Low Carbon Networks Fund

The LCN Fund provides up to £500 million of support for DNOs to run trials and tests in order to gain experience of the type of network changes the UK will need as it moves to a low carbon economy.

There are two tiers of funding available. The first tier allocates £16 million between DNOs annually according to their customer numbers to fund small-scale projects. The second tier consists of an annual competition that allows up to £64 million of funding for a small number of significant flagship projects.

Provision of information to distributed generation

Distributed Generation connections are forecast to increase over the current regulatory period. In order to encourage the roll-out of Distributed Generation, simple and accessible information on the connection process will be required, and there is a licence obligation on DNOs to provide this.

DNOs are expected to obtain stakeholder input on this guidance, and make it freely available to the public on their websites. The success of these guides will be assessed through the broad measure of customer satisfaction.

Distributed generation incentive framework

10 GW of distributed generation is expected to connect during the current regulatory period (compared to 2GW during the previous period). The Distributed Generation incentive is designed to encourage DNOs to facilitate these connectors, and also to protect DNOs and customers from the risks of increased DG connection costs.

The DG incentive is calculated to provide DNOs with an additional rate of return of 1% above the current allowed cost of capital. This results in a DG incentive rate of £1/kW/year.

Transmission connection point charges

Prior to DPCR5, DNOs pay the NGET for financing and operating the assets that connect the distribution network to the transmission network (transmission connection points), and recover these costs from customers via a pass-through. This arrangement was thought to encourage the optimal siting of a transmission connection point from the perspective of the distribution network, but not from the perspective of the transmission network. Ofgem therefore introduced an incentive on the DNOs to encourage effective engagement with the transmission licensees so that the most efficient engineering solutions across the two systems evolve.

Losses incentive mechanism

Electricity losses on the distribution network account for approximately 1.5% of GB GHG emissions. The previous regulatory period had an incentive (a reward or penalty) that was designed to encourage DNOs to implement system improvements in order to achieve an efficient level of losses on their networks. Concerns about the volatility of the data used to set the targets have led Ofgem to decide to not activate this incentive mechanism.

Business Carbon Footprint reporting

This obligation is in place to encourage DNO to consider the direct carbon impact of their operations, and encourage them to manage their emissions.

DNOs are required to report their total CO_2 equivalent emissions (in $kgCO_{2e}$) to Ofgem. This will include direct GHG emissions from the company's own sources, indirect emissions from the generation of purchased electricity consumed by the company, and finally emissions incurred by external contractors, business travel and all other emissions that arise from the development and operation of the DNO. The results (and improvements) are published in an annual league table.

Undergrounding in Areas of Outstanding Natural Beauty (AONBs) and National Parks mechanism

The purpose of this mechanism is to help DNO's to achieve their duty of looking after the visual beauty of AONBs and National Parks, and ensuring the continued and effective engagement with stakeholders. DNOs are allowed extra capital costs for undergrounding of overhead lines in these areas.

9.2.2 Improving customer service

Broad measure of customer satisfaction

The purpose of this incentive is to improve the quality of customer experiences by measuring customer contact with their DNO across the range of services provided.

It is based on scores derived from a customer satisfaction survey, a complaints metric and stakeholder engagement. DNOS will be rewarded for positive stakeholder engagement and positive customer surveys, and punished for unresolved/repeat complaints and negative customer surveys.

Competition in connections

Ofgem have sought to promote competition in the provision of connections, because in most DNO regions many customers do not have effective choice. DNOs are required to provide evidence to demonstrate that competition in regional markets is working well, and that there are no barriers to competition imposed by the DNO. Margins on the contestable elements of the connection charge are regulated, but Ofgem intend to remove the regulation of the margin once effective competition has been demonstrated.

Guaranteed standards of performance

Guaranteed standards of performance are designed to ensure that DNOs to meet certain levels of service for all of their services including connections and fault repairs.

Each service is allotted a maximum timeframe for completion, and DNOs have to pay a service-specific fine to customers for failing to complete a service within the timeframe. Each DNO has an overall revenue exposure cap to these payments.

Customer service reward scheme

This scheme rewards companies that demonstrate best practice for consumers in those service areas that cannot be easily measured or incentivised through mechanistic regimes.

It does not aim to penalise DNOs, but up to £1 million is available annually across all DNOs. Each year Ofgem will update its 'best practice log' and companies that implement a specified proportion of best practice will be eligible for a part of the reward.

Worst served customers

The main Interruptions Incentive Scheme does not incentivise DNOs to target customers who experience large numbers of interruptions over a number of years, but instead focuses on improving the interruptions to the largest number of customers. The worst served customers incentive seeks to address this shortcoming.

It grants each DNO an allowance to improve the reliability of supply for customers who receive a poor quality of service, for example through long interruptions, or a large number of interruptions over a number of years (e.g. more than fifteen outages over a three year period), and targets schemes that deliver a real improvement for customers but would not go ahead under IIS.

Interruptions incentive scheme (IIS)

The IIS encourages DNOs to invest in and operate networks in such a way as to reduce both the frequency of customer interruptions and the number of customer minutes lost during power cuts.

Each DNO is set a target for the number of customer interruptions per hundred customers per year and the number of customer minutes lost per customer per year, and is rewarded or penalised according to their performance against these targets. Under the scheme, the reward or penalty can be up to 1.2% of revenue for customer interruptions and 1.8% for the number of customer minutes lost. There are exemptions for interruptions caused by severe weather or 'one-off exceptional events'.

9.2.3 Efficient investment in networks

Equalising incentives and the information quality incentive

Under the previous price control period, the incentives to manage different types of cost were not equal. The imbalances led to inefficient network development and higher charges for customers in the short or long term. The distortion of incentives has been removed. This has been enacted by applying the Information Quality Incentive (IQI) to all network-related costs, rather than a selection of network related costs. The IQI encourages the DNOs to submit good quality forecasts of expenditure by providing lower returns to companies that over-forecast their expenditure requirements.

Innovation funding incentive (IFI)

The aim of this incentive is to encourage DNOs to apply innovation in the technical development of their networks.

DNOs can pass-through to customers an annual total of 0.5% of network revenue for costs eligible for IFI.

Network output measures

This obligation encourages DNOs to develop and commit to delivering suitable network output measures in return for the revenues they receive from customers. Measuring performance against the network output measures allows comparison between companies that have innovated and found ways to deliver what customers need and expect more efficiently, and those companies who have deferred investment at the expense of network health and performance.

If a DNO is deemed to have not met its outputs, then the gap between the delivered outputs and the network output measures is valued, and an "incentive rate" of 2.5% is applied to reduce the revenues for the DNO.

9.3 Case Study: connection of a new embedded generator that requires reinforcement involving security and fault level CAFs[108]

A customer requires connection of a generator (marked G in the diagram below) with a required capacity of 3MVA. The fault level contribution at the primary substation from the generation connection is 10MVA. The connection requires:

- an extension of the existing network downstream of the point of connection (point B in the diagram below);
- reinforcement of 500m of the HV network upstream of the point of connection (from points A to B in the diagram below); and
- replacement of existing switchgear to increase the fault level capacity.

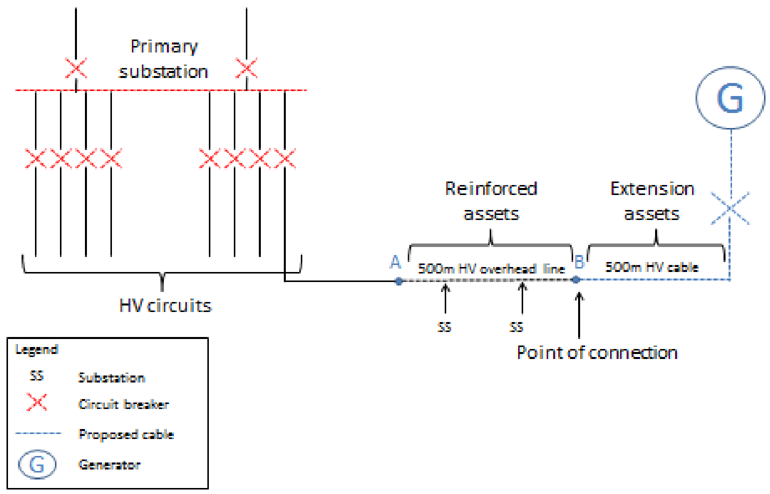


Figure 30: example schematic of a generator connecting to the distribution network

[108] Case study is taken from Statement of methodology and charges for connection to Southern Electric Power Distribution PLC's electricity distribution system, October 2012.

Reinforcement:

	Cost	Apportionment	Customer Contribution
Non contestable work			
Re-conductor of 500m of HV overhead line (A to B in diagram above)	£49,000	Required capacity of customer (3MVA)/new network capacity following reinforcement (7.6 MVA) 3/7.6 X 100% = 39.5% Security CAF	£19,342
Replacement of existing 11 panel 11kV switchgear at substation	£540,000	Required capacity of customer x (Fault level contribution from the customer's new generation connection (10MVA)/Fault level capacity of the local system (250MVA)) 3 x (10/250) x 100% = 12.0% Fault level CAF	£64,800
Total reinforcement cost	**£589,000**		**£84,142**

Extension assets:

	Cost	Apportionment	Customer Contribution
Contestable work			
Installation of 500m HV cable (from point B to generator G in diagram above)	£47,000	n/a	£47,000
HV circuit breaker at customer's substation	£10,000	n/a	£10,000
Non-Contestable Work			
HV pole top termination	£1,400	n/a	£1,400
Total extension asset cost	**£58,400**		**£58,400**

9.4 DNO led DSR trials

Several DNOs are or have conducted trials on DSR, through schemes such as the Low Carbon Network Fund. Not all such trials will be reported here but, as an example, the early trials set up by Electricity North West Limited (ENWL) are described. The information was collected through an interview with ENWL.

HV customer - load reduction at winter peak time

ENWL set up one of the first DNO-led direct DSR arrangement in 2009, with one HV customer to help with a constraint at the local primary substation. The customer agreed to change its demand behaviour over the four winter months of the 2009-10 trial; its target was a 90% load reduction in a defined 4h period across the evening peak.

The contract included a penalty if the target was not achieved and a payment if it was (monthly performance was tracked by ENWL and agreed with the customer). The payment price was calculated using the cost of reinforcement as a cap, expressed as a cost per year per MW of DSR needed to avoid reinforcement (taking into account depreciation over 20 years, operating costs and profit margin). The payment to customer is then set on the basis of its contribution to the needed MW reduction (over the specified time period).

As the customer already had a HH meter, no extra hardware was needed; however it took several months to settle the contract terms.

The overall trial was very positive: the customer reached most of the set targets and network reinforcement was avoided. At the end of the trial, the customer maintained the new load pattern, partly encouraged by new tariffs as by that time the CDCM had introduced time banding tariffs.

HV customer - increase summer on-site generation

A HV load & generation consumer (a manufacturing facility with on-site non-intermittent generation for own consumption) agreed to increase generation, thereby reducing their demand, when a problem occurred on the network. Their generator had previously been used at 70% capacity, giving scope for increased output.

As above, the contract stipulated a payment if the target was achieved for the 3 month trial over the summer 2011. There was however no set time period for the service to be called upon, as it was to be used when an unanticipated problem on the network occurred. As a consequence, ENWL had to monitor the network status and provided forecast data to the customer as way of advanced warning. Again, the outcome of the trial was positive, with the customer able to contribute to the network management as intended.

Lessons learnt from early trials

It has proved difficult to find customers willing or able to participate in such trials: over 40 customers were approached and only one agreed to participate in the first trial. The key characteristic was price, with the price point set too low for the majority of customers connected to those networks. On top of lack of interest from load users, the location of the load is another parameter that reduces the scope for recruitment: not all network sites offer cost effective opportunities for DSR.

A conclusion of the trials was that contracts could be standardised to a point, but there is a location aspect and customer profile aspect meaning some features would be likely to be always unique for each contract, namely the price and price structure.

Current activities

On the back of these positive experiences, ENWL decided to contract a well-established aggregator to recruit customers for further trials in two parts of their network, where constraints have been identified. As of January 2013, the recruitment is on-going and as such the DSR service has not started yet.

ENWL is also running two projects related to network demand:

Capacity to Customers - In December 2011 ENWL was awarded £10.7m from the LCN Fund to undertake the Capacity to Customers (C_2C) project. C_2C targets the release of the inherent capacity of the high voltage network built for security of supply reasons allowing new customers to connect to the network or existing customers to increase their demand without the need for network reinforcement. As the 'security of supply' capacity is used for customers' demand growth alternative arrangements for managing the network at times of fault are needed. ENWL will seek to purchase post fault demand response services from either new customers connecting to the trial networks or existing customers connected to the trial networks.

Customer Load Active System Services - In December 2012 ENWL was awarded £9m from the LCN Fund to undertake the Customer Load Active System Services (CLASS) project. The project explores the use of voltage regulation to provide a change in demand.