UNIVERSITY OF CAMBRIDGE | Energy Policy Research Group

Distributed Generation: Opportunities for Distribution Network Operators, Wider Society and Generators

EPRG Working Paper 1510

Cambridge Working Paper in Economics CWPE-1505

Karim L. Anaya and Michael G. Pollitt

Abstract : This study explores and quantifies the benefits of connecting more distributed generation (with and without the use of smart connections) across different parties (Distribution Network Operators, wider society and generators). Different connection scenarios are proposed (with partial and full interruptible capacity quota, a mix of generation and different technology-specific curtailment levels) for integrating DG units in the constrained area of the March grid (East of England). This constitutes the trial area of the Flexible Plug and Play project, which is being implemented by UK Power Networks. The smart connection option is by far the preferred option across all the scenarios (higher NPV/MW). However, for some generators the results are very sensitive to the discount rate used (i.e. solar PV). The analysis of the distribution of benefits suggests that generators capture most of the benefits while DNOs and wider society capture much less benefit. A *smart connection incentive*, which recreates the benefits to DNOs from an earlier losses incentive, is proposed. In contrast with other societally desirable metrics which are usually incentivised or penalised, there is currently no direct connection between more DG MWs connected and DNO incentive payments. Our proposed *smart connection incentive*, by charging DG for smarter connection may help to distribute more efficiently the benefits for connecting more DG.

Keywords distributed generation, renewable energy, smart solutions, cost benefit analysis, smart connection incentive

JEL Classification **D61, H25, L51, L94, Q40, Q48**

Contact k.anaya@jbs.cam.ac.uk
Publication March 2015
Financial Support UK Power Networks via the Low Carbon Networks Fund's Flexible Plug and Play Project

www.eprg.group.cam.ac.uk

EPRG WORKING PAPER

Distributed Generation: Opportunities for Distribution Network Operators, Wider Society and Generators

---

By

Karim L. Anaya and Michael G. Pollitt[1]

Abstract

This study explores and quantifies the benefits of connecting more distributed generation (with and without the use of smart connections) across different parties (Distribution Network Operators, wider society and generators). Different connection scenarios are proposed (with partial and full interruptible capacity quota, a mix of generation and different technology-specific curtailment levels) for integrating DG units in the constrained area of the March grid (East of England). This constitutes the trial area of the Flexible Plug and Play project, which is being implemented by UK Power Networks. The smart connection option is by far the preferred option across all the scenarios (higher NPV/MW). However, for some generators the results are very sensitive to the discount rate used (i.e. solar PV). The analysis of the distribution of benefits suggests that generators capture most of the benefits while DNOs and wider society capture much less benefit. A *smart connection incentive*, which recreates the benefits to DNOs from an earlier losses incentive, is proposed. In contrast with other societally desirable metrics which are usually incentivised or penalised, there is currently no direct connection between more DG MWs connected and DNO incentive payments. Our proposed *smart connection incentive*, by charging DG for smarter connection may help to distribute more efficiently the benefits for connecting more DG.

[1] The authors wish to acknowledge the financial support of UK Power Networks via the Low Carbon Networks Fund's Flexible Plug and Play Project. The authors are also grateful to Laura Hannant and Sotiris Georgiopoulus from UK Power Networks for the provision of relevant information and clarifications. The views expressed herein are those of the authors and do not reflect the views of the EPRG or any other organisation that is also involved in the Flexible Plug and Play Low Carbon Networks (FPP) project.

1. Introduction

The incorporation of Distributed Generation (DG) into the distribution networks produces important effects on the traditional operation of Distribution Network Operators (DNOs). Existing distribution networks are designed to be passive and to transport electricity from transmission grid off-take points to end customers with a minimal level of control, monitoring and supervision; and were not designed to accommodate generation at lower voltages. Thus, DG introduces new challenges to DNOs but also opportunities that reflect the economic benefits arising from more active networks. These challenges and opportunities are not only technical. Regulation and innovative commercial arrangements have an important role to play in allowing the DNOs to capture an appropriate share of these benefits.

Different studies have evaluated the impact produced by the integration of more DG; however the distribution of these benefits across the different parties is still a work in progress. Through this study we want to know about the distribution of these benefits, who benefits the most and to what extent. A cost-benefit analysis is conducted for this purpose. We evaluate this in a specific constrained area operated by UK Power Networks. The aim of this paper is to evaluate the opportunities across the parties (e.g. DNOs, generators and wider society) when connecting more DG within a distribution network. This study will quantify the most relevant benefits from facilitating earlier and greater quantities of DG by examining the difference between smart connection arrangements and conventional connection arrangements in the face of network constraints. The analysis is focused on a constrained area of the March Grid (East of England) operated by UK Power Networks. This area has been selected (due to increasing DG) by the DNO to be the trial area of the Flexible Plug and Play project[2], see Appendix 1. Benefits are represented by DG incentives and the profits for connecting DG units (including embedded benefits). In addition, the paper introduces a *smart connection incentive* (to be paid by the generators to the DNO) in order to encourage quicker and cheaper connections.

The paper is organised as follows. Section two provides a brief explanation of the regulatory framework associated with DG in Great Britain, focussing on market structure and ownership, incentives and types of connection charges. Section three evaluates the impact that DG produces on distribution networks and wider society, and analyses the most relevant technical, regulatory and commercial challenges and opportunities for DNOs. Section four describes the methodology for quantifying the benefits and shows the results applicable to our case study (Flexible Plug and Play trial). Section five lays out the conclusions of this study.

2. Distributed Generation in Great Britain

2.1 Electricity Market and Ownership

The electricity sector in Great Britain, as elsewhere, is composed of four elements: generation, transmission, distribution and supply. Transmission and distribution are regulated activities and generation and supply are open to competition. The distribution market is operated by 14

[2] For further details see: http://www.flexibleplugandplay.com

licensed DNOs (12 in England and Wales and 2 in Scotland) and each is responsible for a regional distribution service area. The 14 DNOs are owned by six different groups and some of these also own generating and supply operations[3]. In addition, there are Independent Distribution Network Operators (IDNOs) which own and operate smaller networks within the areas covered by the DNOs. National Grid Electricity Transmission (NGET) is the high voltage system operator and there are three transmission firms, one in England and Wales (National Grid) and two in Scotland (Scottish Power Transmission and Scottish Hydro-Electric Transmission).

In terms of ownership, and in agreement with the European Directive 2003/54/EC which defines the rules of the internal electricity market, DNOs must be legally separate from generation plants. The effective separation of businesses helps to increase competition, reduce inefficiencies related to vertical integration and to avoid cross-subsidies. However, and in comparison with generation facilities owned by fully integrated utilities (owning and jointly operating networks and generation)[4] it may encourage an inefficient expansion of electricity infrastructure if there is not an adequate integration between network and generation planning. The European Directive 2003/54/EC suggests that distribution system operators (DNOs in GB) should consider the integration of DG in their network planning. This may facilitate the upgrading or replacement of electricity network capacity.

Following Siano *et al.* (2009), drivers for selecting a specific location and DG capacity differ between non-integrated generators and DNOs. Generators are driven by the availability of renewable resources and by the possibility of higher (but riskier) rates of return (usually higher than those applicable to DNOs). DNOs are mainly driven by cost minimisation (opex and capex), achievement of quality of supply standards (QoS) and regulatory incentives (e.g. network losses, DG incentives). We discuss these in more detail in Section 3. In Great Britain, a DNO is required to connect generators under the terms of its licence, and does not have the option of prioritising connection at specific sites. However, some exceptions may apply if there is a strategic location that DNOs would like to cover (i.e. new customers) by contracting non-utility developers and avoiding network reinforcements. Specific commercial agreements between non-utility developers and DNOs can be negotiated for this purpose.

2.2 Incentive Mechanisms for Distributed Generation Developers

Based on the current regulatory framework, DG developers in GB can take advantage of the different incentive mechanisms that promote the expansion of renewable generation such as Feed-in-Tariff (FIT), Renewables Obligation (RO) and Levy Exemption Certificates (LEC). FITs are available for small renewable generators (up to 5 MW). Developers are offered a guaranteed price (£/kWh) for a fixed period (between 10 and 20 years). There are two types of tariffs, the

[3] One of these groups is UK Power Networks which operates three individual networks: EPN (Eastern Power Networks), Southern Power Networks (SPN) and London Power Networks (LPN). EPN operates the constrained area of the March Grid, which is part of this study. The network constraint is located on the two 132/33 kV transformers at the March Grid substation.

[4] This refers to the vertically-integrated utilities that usually operate the generation, transmission and distribution businesses. For instance, in the USA a significant number of electric utilities are vertically-integrated. These can be either investor-owned or publicly owned.

tariff for every kWh of electricity generated and the export tariff for every kWh of electricity exported (surplus energy) to the grid. Tariffs vary according to the project size, type of technology and date of installation. Tariffs are adjusted based on the retail price index (RPI). A quarterly digression mechanism for new installations has been introduced for solar PV from 1 November 2012 and an annual digression for non-solar PV technologies (e.g. wind, hydro and anaerobic digestion) from 1 April 2014[5].

The RO represents the main financial instrument for renewable generation over 5 MW (and some projects between 50kW and 5MW). Under this mechanism, suppliers are required to acquire renewable obligation certificates (ROCs) from generators in order to prove that a specific share of the electricity they provide to customers is from eligible renewable sources. The share is set each year and increases annually. If suppliers cannot meet this obligation they have to make a buy-out payment to cover the outstanding ROCs. The scheme will close to new generators on 31 March 2017. Based on the project lifetime (20 years) the support will continue until 2037. However, this support will be replaced by the Contract for Difference Feed-in Tariff (CfD FIT) scheme introduced in 2014. Between 2014 and 2017 generators have the option to select the new or the RO scheme (DECC, 2012c). LECs are electronic certificates issued by OFGEM to accredited generators per MWh of electricity generated by renewable energy sources which is exempt from the Climate Change Levy (CCL). Electricity suppliers negotiate the purchase of these certificates with renewable generators in order to claim for the Climate Change Levy Exemption on non-domestic supply (industrial and commercial supply).

2.3 Connection and Use of System charges applicable to DG

There are two categories of charges applied to DG owners: connection and Distribution Use of System (DUoS) charges[6]. Other additional charges such as those related to the use of the transmission grid and balancing services may also apply.

In terms of connection charges, these reflect those costs incurred by DG owners for connecting the generation facility to the distribution grid. Connection charges (one-off payments) are paid directly to DNOs. These cover the costs of works and assets and under specific circumstances; they may include charges to assess any potential impact on the transmission system and additional works to be carried out on the transmission system[7]. Based on the type of regulation, connection charges may include a proportion of or 100% of the reinforcement costs[8]. There are three different types of connection costs: (a) shallow connection, (b) shallowish connection and (3) deep connection. Shallow connection, where DG owners pay only the direct costs associated with the connection (sole-use) and reinforcement costs are socialised among all grid users. Under the shallowish connection, DG owners are required to pay the connection costs and only a

[5] For further details see: http://www.fitariffs.co.uk/eligible/levels/degression-rates/

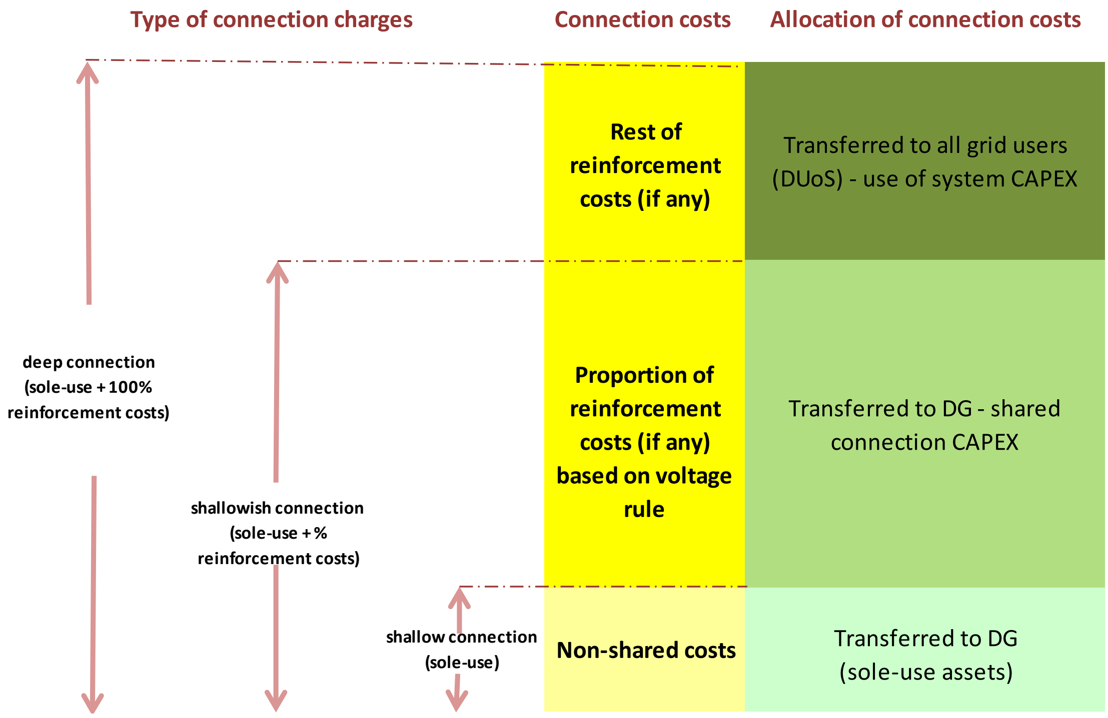
[6] These charges are in agreement with the Electricity Distribution Licence Condition 13 (connection charges) and Licence Condition 14 (use of system charges).

[7] The impact assessment study is classed as “Statement of Works” (SOW).

[8] The impact study conducted by the DNO may or not suggest the need of network reinforcement or upgrade.

proportion of the reinforcement costs (shared costs)[9]. The remaining reinforcement costs are incurred by all grid users (demand and generators) through the Distribution Use of System (DUoS) charges. The deep connection implies that all costs, including 100% of reinforcement costs are borne by DG owners. In Great Britain, the shallowish connection is mandated, thus the proportion of reinforcement costs (if any) should be borne by the DG owners based on the voltage rule. Figure 1 summarises the different categories of connection charges.

Figure 1: Types of connection charges (for DG)



The share of reinforcement costs is determined based on the rules set in the Common Connection Charging Methodology (CCCM) which defines reinforcement costs as those that add capacity (network or fault level) to the existing shared use Distribution System[10]. The CCCM came into force in October 2010 and is part of the DNOs' Statement of Methodology and Charges for Connection to the electricity distribution system. Under the CCCM connection charges can be calculated based on the estimated costs of the Minimum Scheme or an Enhanced Scheme. The first one is the scheme that reflects the lowest overall capital costs and the second one includes additional assets[11] that are not required by the Minimum Scheme. DNOs will charge the DG owner the lower associated costs related to the connection costs under the Minimum Scheme or the Enhanced Scheme. In addition, based on the principle of Competition in Connections (CIC), connection works can be categorised as contestable work (undertaken by an Independent

[9] This also refers to the shallowish connection boundary where generators are expected to contribute to network reinforcement (if any) up to one voltage level above their point of connection. This is often referred to as the voltage rule. For further details see the Electricity Distribution Licence (standard licence condition 14.20).

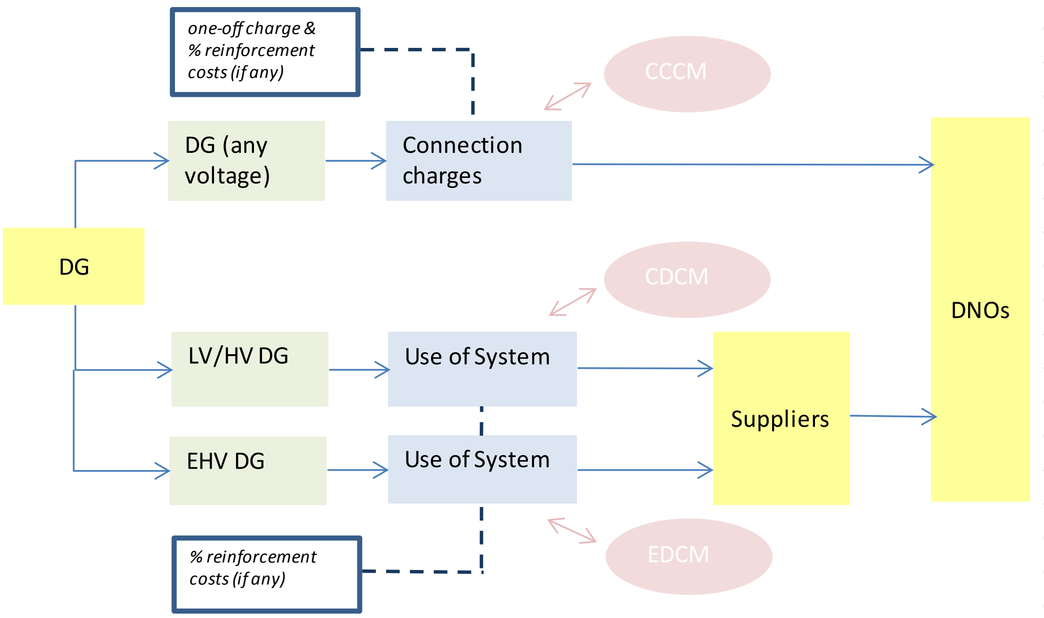
[10] The CCCM defines two types of Cost Apportionment Factors (CAFs) for determining the proportion of reinforcement costs to be borne by the generator: Security CAF (where either thermal capacity or voltage are the main cost drivers) and Fault Level CAF (where fault level restrictions are the main cost drivers). However, there are some exceptions in which the apportionment rules will not be applied (i.e. reinforcement is treated as Extension Assets, which are defined as those assets to connect a party or parties to the distribution network but which exclude reinforcement assets).

[11] These can be: additional assets, assets with larger capacity or assets with different specifications.

Connections Provider-ICP or the DNO) or non-contestable (carried out by the DNOs or appointed agents). The type of works associated with each category can be found in Section 6 of the DNOs' Statement of Methodology and Charges for Connection to the electricity distribution system.

Regarding the Use of System (UoS) charges, these are on-going charges that cover the remaining reinforcement costs and operation and maintenance costs and are paid directly to suppliers. In Great Britain, UoS charges for DG[12] were introduced in April 2005, previous to this date generators were not required to make this payment[13]. However in contrast with Great Britain, in most European countries generators are not mandated to pay UoS charges (Cossent *et al.,* 2009; Eurelectric, 2013). The charging methodology for the UoS depends on the level of voltage where generators want to connect their respective plants. Generation customers connected at low voltage (LV) and most high voltage (HV) are subject to UoS charges under the Common Distribution Charging Methodology (CDCM). This methodology is also applicable to demand, all LV and most HV. Figure 2 illustrates the connection and UoS charges applicable to generators.

Figure 2: DG connection and use of system charges



Own elaboration. Source: Connection and distribution charging methodologies from utilities.

Generation customers at some HV and all extra high voltage (EHV) are required to pay UoS charges based on the Extra High Voltage Distribution Charging Methodology (EDCM). Demand customers connected at most HV and all EHV are also charged based on this methodology. The CCCM and related use of system charges have been integrated into and governed by the Distribution Connection and Use of System Agreement (DCUSA). DCUSA, created in October 2006, is a multi-party contract between licensed electricity distributors, suppliers and generators.

[12] These are also referred to as Generator Distribution Use of System (GDUoS) charges. These can be positive charges (i.e. when reinforcement works are required) or negative charges (credits) (i.e. when the exported power produces a positive effect on the distribution of electricity onto the grid).

[13] Some exceptions are applied to qualifying generators that were connected before April 2005. These generators can be exempt from the DUoS charges up to 25 years commencing from the date of connection of each generator.

DCUSA replaced numerous bi-lateral use of system contracts and focuses on arrangements after customers have been connected.

2.4 Embedded Benefits

Finally, there are some embedded benefits applicable to generators that ask for a connection to the distribution grid. These are represented by the avoidance of charges such as the Transmission Network Use of System (TNUoS) and the Balancing Service Use of System (BSUoS). TNUoS charges allow the recovery of the cost of installing and maintaining the transmission system and are split between generators and demand. The associated tariff depends on the geographical location of the generator and can take positive or negative values (if generators contribute to the alleviation of the need for network reinforcement). The tariffs associated with each zone can be found at the Statement of Use of System Charges. The TNUoS zones' map[14] shows the geographical location of each zone. BSUoS charges are applicable to those generators that participate in the electricity balancing market. These charges allow the recovery of the costs of balancing the system in real time through the balancing mechanism process. The Statement of Use of System Charging Methodology explains the way that TNUoS and BSUoS charges have been calculated. Other embedded benefits are related to the reduction in energy losses (transmission and distribution) and negative Use of System charges or credits (when generation customers are paid to use the network). For a further explanation of embedded benefits applicable to DG see Anaya and Pollitt (2013).

3. Implications of Distributed Generation for the Distribution Network Operator and Wider Society

Different studies have documented the main challenges and opportunities that DNOs face when connecting DG facilities. On the one hand, the introduction of DG can negatively affect the DNO operations in terms of voltage fluctuation and regulation, thermal constraints, frequency variation and regulation, power fluctuations, power factor correction and harmonics (Ochoa *et al.,*2011; Passey *et al.,* 2011; Wojszczyk *et al.,* 2011). On the other hand, potential benefits have also been recognised, especially those related to electrical losses, network reinforcement deferral, security of supply and ancillary services (Gil and Joos, 2006; Mendez *et al.,* 2006; Harrison *et al.*, 2007; Passey *et al.,* 2011; Wang *et al.*, 2009; Hung and Mithulananthan, 2012). However, the challenges and opportunities for DNOs are not only technical. Regulation and commercial arrangements such as those implemented under the different incentive schemes sponsored by OFGEM (e.g. Innovation Funding Initiative - IFI, Low Carbon Network Fund - LCNF) can play an important role in the way that DNOs may internalise the benefits and take advantage of connecting more DG within the distribution grid.

Regulation has supported generators through the implementation of different incentives and subsidy schemes for encouraging the deployment of DG. The subsidies are paid by consumers in their respective energy bills. As previously noted, in Great Britain, Feed-in Tariff (FIT), Renewables

[14] The TNUoS demand and generation zones' maps can be found at: http://www2.nationalgrid.com/UK/Industry-information/System-charges/Electricity-transmission/Transmission-Network-Use-of-System-Charges/Statement-of-Use-of-System-Charges/

Obligation (RO) and Levy Exemption Certificates (LEC) are among these instruments. However, following Gil and Joos (2006), these incentives are not location specific and don't necessarily reflect the real benefits that a particular DG project may produce. For instance in Germany some FIT schemes applied to wind generation take into consideration the local conditions of the site. A maximum tariff is received over the first five years of operation, after this wind generation developers may (or not) keep the maximum tariff depending on the wind generation production which is compared with the production of a reference wind turbine[15]. Some FIT schemes compensate generators by providing specific bonuses to wind generation (in addition to the FIT) for the provision of ancillary services in Germany[16] and balancing costs in Denmark (DEA, 2013). The practice of better designed credits will allow a better distribution of benefits between the generator itself and the DNOs. This means identifying the involved parties, quantifying their benefits and allocating these proportionally to their respective contribution. Other initiatives such as the Innovation Funding Incentive (IFI) and the Low Carbon Networks Fund (LCNF), which are more related to research, innovation and trials of new technologies may encourage DNOs to innovate different ways to integrate DG.

The type of connection charges applied to DG also depends on regulation. Based on the type of connection adopted, the risk allocation impact varies and affects the parties differently. In the case of a deep connection, the generator faces the highest costs and risks; this means that sole-use connection costs and reinforcement costs (if applicable) are 100% borne by the generator. In contrast, in a shallowish connection, the risk and cost is allocated between the generator and the DNO. Reinforcement costs (if applicable) are shared between the two parties. In this situation, specific incentives for DNOs, such as the DG incentives, have been designed in order to encourage efficient and economic investment. The main objective of this incentive is to provide an additional mechanism to manage uncertainty (in forecasting DG connections) however its complexity appears to be a barrier to DNOs making investments associated with DG.

Commercial arrangements with interruptible connections are receiving great attention. DG developers and DNOs are researching different options for connecting more DG in a cheaper and quicker way. OFGEM - through the implementation of LCNF scheme - aims to test not only new technologies for facilitating more DG but also smart commercial arrangements. For further details around these arrangements see Anaya and Pollitt (2014). Depending on the terms and conditions of the connection agreement, DNOs may internalise the benefits that connecting more DG can provide. For instance, in the case of network constraints, DNOs may offer non-firm or interruptible connections to generators. This involves a restriction on the ability of generators to export power in a constrained part of the network in return for a cheaper connection. This will allow the connection of more DG, make a better use of the current infrastructure due to the deferral of network reinforcement, DG incentives (if applicable) and the benefits from losses reduction (to the extent that this effect actually materialises). To ensure this happens, specific commercial arrangements are required. These might include:

---

[15] For further details see the German Renewable Energy Act (EEG), Section 29 and Annex 3.

[16] The Ordinance on Ancillary Services can be found at: http://www.gesetze-im-internet.de/sdlwindv/BJNR173400009.html

a. the specification of a maximum level of the reduction of the generator output (curtailment);
b. an appropriate principle of access which defines the methodology to limit the generation output in the case of networks constraints (e.g. LIFO, Pro Rata);
c. a capacity quota that delimits the maximum capacity reserved for interruptible connections;
d. compensation schemes (if any) in the case of curtailment and different scenarios associated with demand growth;
e. network reinforcement, and;
f. generation mix (e.g. wind, solar PV, and biomass generation plants connected to the same point of connection).

Such commercial arrangements will usually require the implementation of smart technical solutions (e.g. Active Network Management - ANM). The practice of novel commercial arrangements is still in its infancy (excluding, some specific trials such as Orkney ANM Project and Flexible Plug and Play). The challenge that DNOs will face in the short or medium term is to internalise and incorporate into the business as usual practice the offering of commercial arrangements with interruptible connections to potential or existing generators. UK Power Networks has committed to offer this option into its business as usual process by the second quarter of 2015 (UK Power Networks, 2013).

4. Quantification of Benefits

This section quantifies the benefits that DNOs, generators and wider society may be entitled to for connecting more DG within the distribution grid in the context of the Flexible Plug and Play project. The introduction of a *smart connection incentive* is also discussed in this section. The analysis is performed based on the cost benefit analysis (CBA) methodology discussed in Anaya and Pollitt (2015)[17]. Under this project, UK Power Networks, the largest DNO in the UK, is looking at different options for connecting more DG. Developers are seeking connections at constrained parts of the network that operate within the trial area in the East of England (March Grid). According to UK Power Networks, as of December 2014, the number of offers accepted to connect to the March Grid was 12 with a total capacity of 27.63 MW. The constrained area is driven by the excessive reverse power that flows on the existing 45 MVA transformers (132/33kV). Only interruptible connections are now possible in this area without any major reinforcement works (i.e. a primary transformer upgrade).

Three scenarios have been evaluated in this study. In line with Anaya and Pollitt (2015), the diversity of scenarios:

[17] An extended explanation of the methodology and scenarios can be found in the report "Finding the optimal approach for allocating and releasing distribution system capacity: Deciding between interruptible connections and firm DG connections" produced by the Energy Policy Research Group in the context of the Flexible Plug and Play Project (Anaya and Pollitt, 2013). The difference between this version and Anaya and Pollitt (2013) is in terms of (1) the array of generators for each scenario (this one considers the latest list of generators already engaged to be connected), (2) discount rates (technology-specific instead of fixed discount rate across all technologies) and (3) corporate tax (pre-tax figures instead of post-tax figures).

a. illustrates and assesses different connection options in the case of restricted capacity (constrained area);
b. provides insights about the possible solutions (deciding between smart interruptible connections or full connection subject to reinforcement) and the costs of selecting one or other (via the net present value of each solution);
c. contributes to a better explanation of the different connection situations that generators face in the real world.

We have assumed a fixed demand across the project lifetime (set at 20 years), a maximum curtailment level for each type of technology (modelled by Smarter Grid Solutions, a project partner), different sizes of installed capacity (from partial to full interruptible capacity quota) and a combination of types of renewable generation technologies (e.g. wind, solar PV and anaerobic digestion (AD) CHP), see Table 1.

Table 1: Summary of Scenarios

Scenario	Installed capacity (MW)	Generation mix (% installed capacity)		
		wind	solar PV	AD CHP
Scenario 1	14.5	100%		
Scenario 2	27.627	52.5%	43.9%	3.6%
Scenario 3	33.5	60.8%	36.2%	3.0%

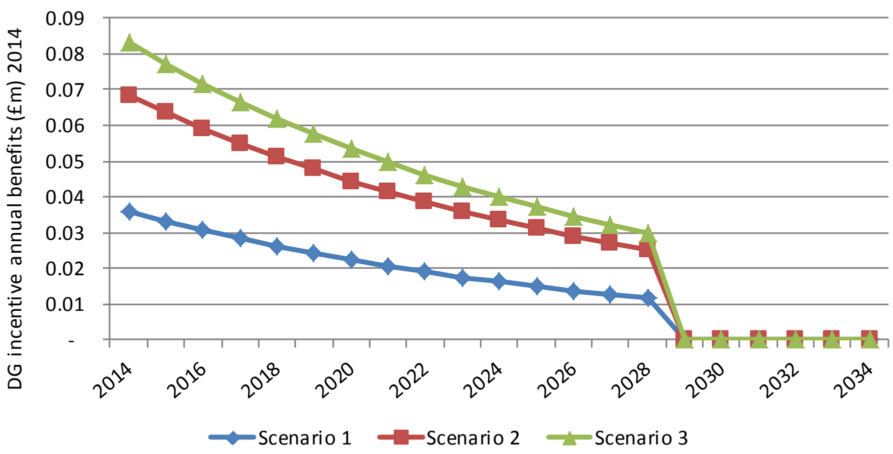
Benefits to DNOs, generators and wider society are estimated in the following sections for each scenario. All figures are expressed in 2014 prices and technology specific discount rates (pre-tax real) have been used for NPV estimations in agreement with the latest generation costs report published by DECC (2013). A project lifetime of 20 years (period 2014-2034) has been assumed regardless of the type of generation plant. The assumptions, formulas and references are shown in Appendix 2.

4.1 DNO's Benefits

These benefits are made up of the DG incentives that DNOs may be entitled to. The DG incentives were introduced in the previous price control review (DPCR4 which ran from 2005-2010). In addition, this study proposes the introduction of a *smart connection incentive* that would encourage the expansion of DG connections using smart solutions. This incentive would be paid by the generators to the DNO.

DG incentives represent a kind of cost-recovery mechanism (or uncertainty mechanism) that contributes to the reduction of uncertainty regarding the volumes of DG connections. Accordingly to OFGEM, DG incentives help to reduce the risks to DNOs and their customers of bad forecasts of volumes and costs which would have otherwise been part of allowed revenues set ex ante with the rest of the price control. The DG incentives represent the incentive revenues for DG and are included in the estimation of the total allowed distribution network revenue. The incentives apply to all generators, on all voltages. In agreement with Harrison *et al*. (2007), Siano *et al*. (2009) and Hung and Mithulananthan (2012) it was assumed that the total benefits arising from the DG incentives are the annual operation and maintenance (O&M) allowance valued at £1/kW and the annual DG capacity allowance also valued at £1/kW in the current price control (DPCR5)[18]. DNOs currently benefit from both incentives regardless of the existence of use of system capex. The incentives are valid for 15 years after the date of connection (for this case study is 2014) and need to be inflation adjusted. Total benefits have been calculated for each scenario. Due to the fact that the incentives provided depend only on the installed capacity, different trends are observed across the three scenarios. Figure 3 depicts the annual benefits.

Figure 3: DG Incentives Benefits over time



It is noteworthy that under the context of RIIO-ED1[19], OFGEM agreed to remove this scheme. This means that DNOs will only benefit from this scheme until 31th March 2015. The principle of grandfathering applies to those connected by that date. Following OFGEM (2013a), one of the main reasons for the removal was that the perceived complexity of the scheme was a barrier to the connection of DG. In addition, OFGEM believes that DG incentives are no longer required given the package of measures sets in RIIO-ED1 (OFGEM, 2012a). It is expected that under RIIO-ED1 the treatment of DG in the price control will be simplified.

4.2 Generators' Benefits

The generators' benefits are represented by the profits that generators get from connecting DG units (revenues minus costs). These include the energy revenues, the generator share of embedded benefits[20] and energy savings (for solar PV)[21]. Revenues are composed of the sale of electricity in the wholesale market and of the subsidies and incentives (e.g. FIT, RO, LEC) received by renewable generators[22]. Costs involve generation and connection costs. Generation costs refer to operating and capital expenses associated with electricity generation which vary depending on the kind of technology. Connection costs include those associated with smart or non-firm

[18] The previous regulatory period (DPCR4) valued the DG capacity incentive at £1.5/kW. These two elements are part of the DG allowed revenue (OFGEM, 2009).
[19] RIIO-ED1 refers to the price control applied to the 14 DNOs in GB.
[20] Refer to those costs that generators may save when they are directly connected to the distribution network instead of the transmission network.
[21] Energy savings refer to those savings that owners of solar PV generators enjoy when the produced electricity is used for own consumption on site.
[22] We have not included in the analysis revenues from heat. Anaerobic Digestor (AD) CHP generators might be entitled to the non-domestic Renewable Heat Incentive (RHI) if specific criteria are met in terms of ownership, type and size of technology, commissioned date, and others (OFGEM, 2014). An estimated value of this revenue is calculated later.

connections (FPP connection costs) and those associated with the network upgrade when a firm connection is preferred (reinforcement costs)[23]. The array of generators for each scenario is the current list of generators (updated to December 2014) that are planning to connect to the constrained area of March Grid before April 2015. Three connection scenarios are evaluated against a total maximum capacity quota of 33.5 MW. These are S1 - wind generation only with partial quota (14.5 MW); S2 - a mix of generation technologies with partial quota (27.627 MW); and S3 – a mix of generation technologies with full quota (33.5 MW). The annual curtailment limit varies across the three scenarios. Scenario 3 is the one with the highest level of curtailment limits (more capacity connected), see Table 2.

Table 2: Array of generators for each scenario

Generators			**Scenario 1 (S1)**		**Scenario 2 (S2)**		**Scenario 3 (S3)**		**Costs (2014 prices)**			
No	Generators	Capacity (MW)	Annual curtailment limit (%)	Estimated annual curtailment MWh	Annual curtailment limit (%)	Estimated annual curtailment MWh	Annual curtailment limit (%)	Estimated annual curtailment MWh	FPP smarter connection costs [1/] (£ m)	Reinforcement costs (£m) S1	S2	S3
1	Wind 1	0.5	0.085%	1	1.63%	21	1.84%	24	0.06	0.15	0.08	0.06
2	wind 2	1	0.085%	2	1.63%	43	1.84%	48	0.13	0.30	0.16	0.13
3	Wind 3	1.5	0.085%	3	1.63%	64	1.84%	73	0.19	0.45	0.23	0.19
4	Wind 4	0.5	0.085%	1	1.63%	21	1.84%	24	0.06	0.15	0.08	0.06
5	Wind 5	10	0.085%	22	1.63%	428	1.84%	484	1.29	2.98	1.57	1.29
6	Wind 6	0.5	0.085%	1	1.63%	21	1.84%	24	0.06	0.15	0.08	0.06
7	Wind 7	0.5	0.085%	1	1.63%	21	1.84%	24	0.06	0.15	0.08	0.06
8	Solar PV 1	4	0.085%		2.15%	84	2.30%	90	0.52		0.63	0.52
9	Solar PV 2	6.927	0.085%		2.15%	146	2.30%	156	0.89		1.08	0.89
10	Solar PV 3	1.2	0.085%		2.15%	25	2.30%	27	0.15		0.19	0.15
11	AD CHP 1	0.5	0.085%		0.53%	19	0.59%	22	0.06		0.08	0.06
12	AD CHP 2	0.5	0.085%		0.53%	19	0.59%	22	0.06		0.08	0.06
13	Wind 8	5.873	0.085%				1.84%	284	0.76			0.76

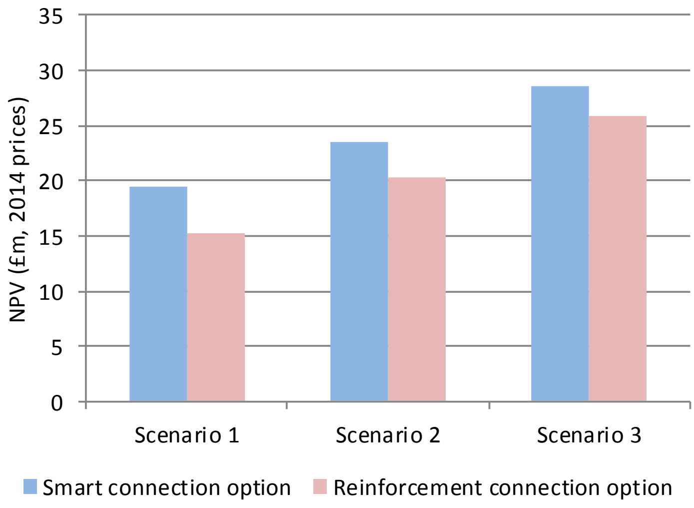
[1/] The cost of the ANM equipment (estimated in £50,000/generator) has been included in these costs.

The results from the CBA suggest that across the three scenarios, the smart connection option is the one preferred by all generators regardless of their size and type of technology. This fact can be explained by the low rates of annual curtailment that generators are subject to, especially in Scenario 1 when less than 50% of total interruptible capacity quota has been allocated to wind generators only. We also observe that the results are very sensitive to the discount rate used in the analysis. A 10% discount rate would produce an important decrease in the net benefits, however the most affected would be the solar PV generators with negative NPV value (in Scenario 2 and 3 with or without embedded benefits). Figure 4 depicts the NPV to the generators from the CBA with the embedded benefits included[24].

[23] FPP connection costs vary by generator, involve smart solutions (i.e. ANM) and include the cost associated with these solutions (£50,000/generator). In addition to the ANM costs from the customer side, the project has spent around £0.48m in mesh network (including licences) and on additional servers to support the ANM. These additional costs have not been included in the FPP connection costs, but would need to be included in a full cost benefit analysis. Reinforcement costs that amount to £4.1m are allocated to generators in proportion to their installed capacity. It has been assumed that reinforcement costs are shared across all DG owners connected to the same point of connection.

[24] As previously mentioned, the results from Scenario 3 do not include the potential revenues that AD CHP would receive for heat under the non-domestic RHI. Assuming a production of 520 KWth (based on the estimations made by the 0.5 MW AD CHP1), the NPV of the additional revenue over the project lifetime would be around £0.22m. This amount would represent approximately 26.6% and 28.2% of the NPV of the total revenue regarding AD CHP1 and AD CHP2 respectively. In agreement with DECC (2014), a capacity factor of 13.7% has been assumed for this calculation.

Figure 4: CBA Results – Generator Net Benefits



4.3 Wider Societal Benefits

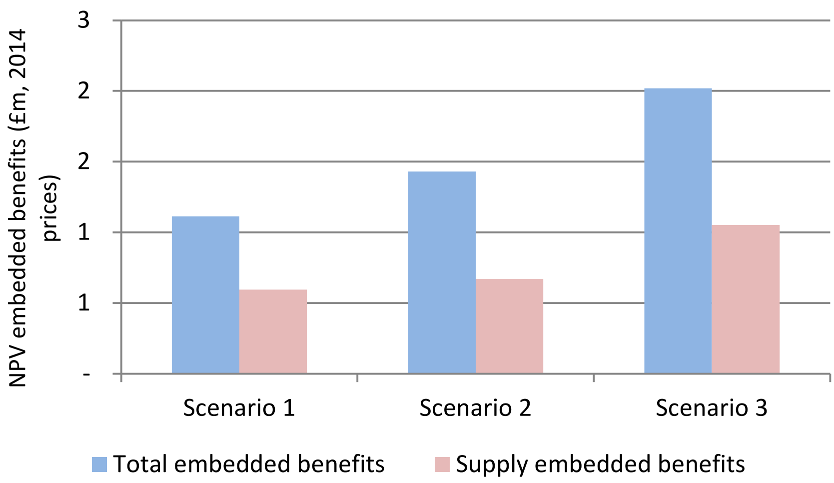
These are composed of the supplier embedded benefits. Benefits from the reduction of carbon emissions due to the decrease in energy losses[25] have not been considered because the electricity prices (which are taken into account for the estimation of revenues) already include an estimation of the price of carbon (Baringa-UK Power Networks, 2013b)[26]. Thus, its inclusion may distort the estimation of benefits due to the potential double counting of savings due to the reduction of carbon emissions originated by the decrease in energy losses.

In agreement with Baring-UK Power Networks (2013a), embedded benefits are related to the benefits associated with the supplier avoidance of balancing system charges, supplier transmission loss reduction and distribution line losses. The respective formulas for the estimation of the supplier embedded benefits are found in Appendix 2. Figure 5 illustrates the NPV of the supply embedded benefits for the smart connection option. We observe that the supply embedded benefits represent on average around 51% of the total embedded benefits (composed of generation and supply embedded benefits).

[25] In the estimation of societal benefits, OFGEM CBA modelling tool for RIIO ED1 (investment decision tool) takes into account this kind of benefits. OFGEM has taken as reference the value of 589.8 gCO2 emission/kWh (UK Grid Electricity Year 2010) estimated by DECC (DECC, 2012a) and a 14.50% p.a. reduction in carbon intensity. Based on these assumptions, a value of 10 gCO2 emission/KWh can be predicted by 2050. In terms of traded carbon price, this varies also over time and were obtained from DECC (2011a, 2012b).

[26] The carbon price used by Baringa-UK Power Networks (2013a) is the greater of the European emissions allowance (EUA) price and the carbon price floor trajectory. It was assume that the carbon price floor follows the trajectory suggested by the Government in the 2011 budget. A constant value of 30 £/t was assumed after 2020.

Figure 5: NPV of total and supply embedded benefits



4.4 Smart Connection Incentive

Comparison of the benefits of the previous results in sections 4.1 – 4.3 suggests that generators are those that benefit the most and DNOs and wider society the least. Thus, we propose the introduction of a *smart connection incentive* which recreates the benefits from an earlier losses incentive (removed in 2012)[27] and may help to balance the allocation of benefits across the parties. The *smart connection incentive,* to be paid by generators to the DNO*,* would also encourage the expansion of DG connections using smart solutions.

Therefore, we would need to quantify first the benefits from losses reduction (MWh) in order to estimate the *smart connection incentive*. As mentioned in Section 3, different studies have evaluated the impact that DG has on electric losses. Most of them have made specific assumptions regarding DG penetration, load factor, generation mix, voltage limits, network load, among others. Similarly, different techniques have been applied such as those based on computational algorithms (Mendez *et al.,* 2006; Siano *et al*. 2009). For our estimations we are going to use a different approach based on the losses associated with the different voltage levels that DG can connect. The contribution (in percentage terms) of the total distribution losses per voltage level is taken into consideration for estimating the reduction of electric losses due to the connection of DG units at 11 kV and 33 kV. Thus, we are assuming that DG will contribute to system losses reduction and that there is a low chance that the injection of power exceeds the local demand.

Following OFGEM (2003), the share of losses across different voltage levels is around 19% (132kV), 14% (33kV), 34% (11 kV) and 34% (LV, including meters). Thus, if a generator is connected at 33 kV, electric losses savings would be around 19% of the average distribution losses. If this is connected at 11kV, savings would be in the order of 33% (19% + 14%). Table 3

[27] The losses incentive was removed due to data volatility which affects the degree of certainty in the estimation of losses (OFGEM, 2012b). Even though general losses incentives have been removed, OFGEM is committed to continue with the incentives for losses reduction in the upcoming price control period 2015-2023 (RIIO-ED1). Around £32m in losses incentive is expected to be awarded in three tranches over the eight years; up to £8m in year 2, up to £10m in year four and up to £14m in year six (OFGEM, 2013a).

shows the list of generators for each scenario and their respective installed capacity and associated voltage connection level.

Table 3: Summary of DG connections for each scenario

Generator	Installed capacity (MW)	Scenario 1	Scenario 2	Scenario 3	Voltage 33kV	Voltage 11kV
Wind 1	0.5	x	x	x		•
Wind 2	1	x	x	x		•
Wind 3	1.5	x	x	x		•
Wind 4	0.5	x	x	x		•
Wind 5	10	x	x	x	•	
Wind 6	0.5	x	x	x		•
Wind 7	0.5	x	x	x		•
Solar PV1	4		x	x	•	
Solar PV2	6.9		x	x	•	
Solar PV3	1.2		x	x		•
AD CHP 1	0.5		x	x		•
AD CHP 2	0.5		x	x		•
Wind 8	5.8			x	•	
Total (MW)		14.5	27.6	33.5		

We have assumed that the initial target loss level is equal to the average distribution losses (period 2005/06-2009/10) estimated at 4.89% for UKPN Eastern Power Networks (EPN)[28]. Losses have been calculated on an annual basis for each generator at their respective voltage level. For example, Wind 1 (Scenario 1) generates around 1,310 MWh per year, the target annual losses would be 64.05 MWh (1,310*4.89%), thus losses reduction are of the order of 21.13 MWh (64.05*33% @ 11 kV). The same procedure is applied to the rest of generators with non-firm and firm connections across the three scenarios. In order to calculate the monetary savings of losses reduction, we have value losses at £48.42/MWh (2012/13 prices). This is in agreement with the value assumed by OFGEM in the CBA modelling for RIIO-ED1. It has been also assumed that this value remains the same (in real values) for the whole project lifetime.

Starting from the above, we calculate that the *smart connection incentive* would take the following values: £15,850/MW (Scenario 1), £12,360/MW (Scenario 2) and £12,395/MW (Scenario 3), with an average value of £13,535/MW. These figures are calculated dividing the NPV of the losses savings over the project lifetime by the installed capacity (related to each scenario). In order to look at how reasonable this incentive is, we have compared this figure with the savings (applicable to generators) due to deferral of investment based on the year when the network upgrade is made (t+1,…., t+20). As already mentioned, UK Power Networks have estimated a gross upgrade cost of £4.1m (2012 prices) which mainly reflects those costs associated with the replacement of specific transformers that will allow the increase of the system capacity related to the March Grid constrained area up to 90 MW. However, UK Power Networks has pointed out that the related network reinforcement costs should be incurred by the generators because they have not been budgeted and are not part of the DNO's allowed revenues. Thus, we find it convenient to use the value of £4.1m[29] as a reference for computing the benefits due to network deferral but applicable to generators. In fact, the expected

[28] The March Grid is situated inside the EPN service area.

[29] This figure represents the savings in reinforcement costs that DG owners are subject to if the smart connection option (interruptible connection capacity) is selected.

investment can be postponed for the generator for months or years, thus the estimation of benefits are related to the value of this investment over time.

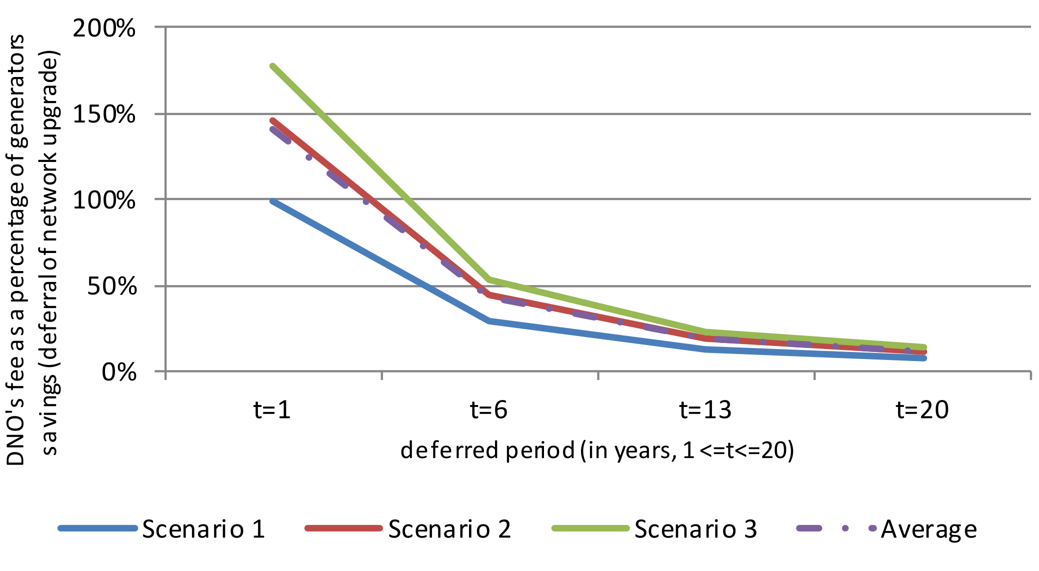
Benefits from network deferral are estimated by the difference between the gross value of the network investment at present time and the gross present value of the deferred investment at specific year[30].

$$Benefits\ (t_i) = NI * \left(1 - \frac{1}{e^{\delta * t_i}}\right) \qquad \text{Eq. (1)}$$

Where NI is the total network investment (£4.1m), δ is the annual interest rate (5.7%)[31], t_i represents the time of investment deferral (in years) from i=1 to 20. It has been assumed that the project lifetime is 20 years.

This is a simplistic assumption in which we are assuming the upgrade of one specific part of the constrained network. Following Gil and Joos (2006), in the presence of groups of feeders[32] total benefits are computed as the sum of benefits obtained in all these groups and the minimum deferral time (of a specific group) is the one that should be used as a reference for the feeders that are part of this group. Taking into consideration the different network deferral scenarios suggested in this study, the *smart connection incentive* may represent between 8% (Scenario 1, t+20) and 178% (Scenario 3, t+1) of total savings due to network investment deferral. The lowest rate corresponds to investment deferral of 20 years while the highest rate relates to an investment deferral of only 1 year. Figure 6 illustrates this dynamic.

Figure 6: Smart connection incentive as percentage of total savings for network investment deferral



[30] Equation 1 is only related to the estimation of the benefits of network deferral. We calculate this figure in order to compare the size of the smart connection incentive with the benefits that generators can get if they agree a smarter connection. The benefits are represented by the savings that generator get due to the deferral of network reinforcement.

[31] This represents the pre-tax WACC applicable to DNOs.

[32] Feeders refer to a segment of the distribution network between two loads.

4.5 Summary and Discussion of Benefits

The summary of benefits, including the allocation of these across the different parties, is shown in Table 4.

Table 4: Total benefits for smart connections

Parties	Type of benefit (£m) [1/]	Unit	S1	S2	S3
DG owners	Non-firm connections (going smarter)	£m	19.00	22.73	27.68
	Embedded benefits (generators)	£m	0.52	0.76	0.97
	(-) Smart connection incentive	£m	-0.23	-0.34	-0.42
DNO	DG incentives	£m	0.38	0.77	0.92
	Smart connection incentive	£m	0.23	0.34	0.42
Wider society	Embedded benefits (suppliers)	£m	0.60	0.67	1.05
	(-) DG incentives	£m	-0.38	-0.77	-0.92
Total benefits		£m	**20.11**	**24.16**	**29.70**
		£m/MW	1.39	0.87	0.89

[1/] Benefits from non-firm connections do not include embedded benefits.

The figures refer only to the non-firm connection option because this is the only one that relates to a smart connection (under the firm connection option, generators export 100% of their electricity and there is no need to manage the generation output actively). It is observed that DNOs and wider societal benefit the least and generators the most. Electricity generation net benefits are the ones that contribute importantly to the total generators' benefits. One of the main factors that contribute to this is the different subsidy schemes that generators are entitled such as FIT and ROC. In relation to DNO's benefits, DG incentives represent around 67% of the total benefits allocated to the DNO; if the *smart connection incentive* also is taken into account.

Under the current price control review (DPCR5) and the forthcoming one (RIIO ED1), apart from DG incentives that related to the MW connected; there are no specific initiatives that promote and encourage DNOs to connect more DG units within their networks (OFGEM, 2013a). In contrast with other metrics which are usually incentivised/penalised (e.g. Incentive on Connection Engagement - ICE, Guaranteed Standards of Performance - GSOP[33]), there is no direction connection between *more* MW and incentive payments. Furthermore, an increase in DG connections, especially those that would require network reinforcement, may affect negatively non-DG customers if these costs need to be socialised. The network upgrade will benefit not only

[33] ICE will encourage DNOs to provide a better level of service where there is no competition in the connection market to encourage better service. In addition, this will motivate DNOs to be more involved in the development of requirements that suit better DG owners' needs. The GSOP sets the minimum levels of service that are required to be met by DNOs regarding reliability and time to connect new demand generation. In addition, the Broad Measure of Customer Satisfaction (BMCS) encourages the level of service by capturing and measuring customer contacts with their respective DNOs across a range of services and activities.

the DNO but also the DG owners; however demand customers will pay for this. These customers don't benefit if performance is rewarded generously by them. A similar picture is observed when OFGEM decides to fast-track DNOs plans. For instance, following NERA (2014), the cost of improving Western Power Distribution (WPD)'s plans involve higher allowance (£770m higher) in comparison with the slow-track view. This excess is borne by WPD customers which represents an increase of £10 on average annual customer bill. Thus, costs are borne by customers but benefits accrue to others.

Therefore, we think that it is important to distribute more efficiently the benefits for connecting more DG. One option could be to implement the *smart connection incentive* as proposed in this study. The size of this incentive is in line with the losses incentives (already removed) that DNOs have received in the past. Our estimations suggest that the *smart connection incentive* only represents a small proportion of the benefits associated with the deferral of network reinforcement. This would be around 11% for Scenario 1 with an investment deferral of 20 years.

From Table 4, we observe that wider society is actually worse off in Scenario 2 and 3 because of the DG incentive payments. This makes a stronger case for charging DG a smart connection fee rather than having an incentive payment paid by DNO customers.

5. Conclusions

This paper analyses and quantifies the opportunities that different parties - namely the DNOs, generators and wider society - may have when connecting more DG within the distribution grid. The case study evaluated in this paper refers to the Flexible Plug and Play trial that is being implemented by UK Power Networks in the March Grid constrained area.

One of the main contributions of this paper is the use of real data in terms of the cost of network investment and electricity delivered for each generator across different connection scenarios (for the amount of DG capacity). Different kinds of benefits have been identified and allocated across the parties. Electricity generator benefits are those with the highest proportion of the total benefits. This means that generators are those that benefit the most when the smart connection option is selected. Our results suggest that the introduction of a *smart connection incentive* payable by generators to DNOs may help to allocate more efficiently the distribution of the benefits from connecting more DG capacity. The *smart connection incentive* we propose may also contribute to the reduction of network upgrade or reinforcement costs which usually are borne by customers.

Overall, this study shows the existence of potential monetary benefits to DNOs (with a focus on UK Power Networks) due to the implementation of DG under a new business as usual DG connection regime. In addition, this study has quantified the benefits that the FPP trial or similar projects may transfer to wider society. The methodology proposed in this paper for the estimation of benefits can be broadly applicable in similar contexts. Our analysis forms part of the calculation of the full NPV to a DNO of connecting more DG. If extra DG means extra operation and maintenance costs (particularly due to the increased requirements for smart DNO infrastructure not recoverable from the DG connection charges) the DNO would need to include this in a full project appraisal.

References

Anaya, K. and Pollitt, M.G. (2013), "Finding the optimal approach for allocating and releasing distribution system capacity: Deciding between interruptible connections and firm DG connections," EPRG Working Paper 1320, Cambridge Working Papers in Economics 1343, University of Cambridge.

Anaya, K. and Pollitt, M.G. (2014), "Experience with smarter commercial arrangements for distributed wind generation", *Energy Policy,* Vol. 71, pp. 52-62.

Anaya, K. and Pollitt, M.G. (2015), "Options for allocating and releasing distribution system capacity: Deciding between interruptible connections and firm DG connections," *Applied Energy*, Vol. 144, pp. 96-105.

Baringa – UK Power Networks (2013a), "Flexible Plug and Play: Reinforcement quota calculation for March Grid", Baringa Partners and UK Power Networks, London.

Baringa – UK Power Networks (2013b), "Flexible Plug and Play: Financial assumptions for the Flexible Plug and Play Reinforcement quota calculation", Baringa Partners and UK Power Networks, London.

Cossent, R., Gomez, T. and Frias, P. (2009), "Towards a future with large penetration of distributed generation: Is the current legislation of electricity distribution ready? Regulatory recommendations under a European perspective", *Energy Policy*, Vol. 37, No. 3, pp. 1145-1155.

DEA (2013), "Outline of the Danish support schemes for electricity generation based on renewables", Danish Energy Agency, Copenhagen.

DECC (2011a), "A brief guide to the carbon valuation methodology for UK policy appraisal", Department of Energy and Climate Change, London.

DECC (2011b), "Consultation on proposal for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012", Department of Energy and Climate Change, London.

DECC (2012a), "2012 Guidelines to Defra/ DECC's GHG Conversion Factors for Company Reporting ", Department of Energy and Climate Change, London.

DECC (2012b), "Updated short-term traded carbon values used for UK public policy appraisal", Department of Energy and Climate Change, London.

DECC (2012c), "Electricity Market Reform: Policy overview, Annex B: Feed-in Tariff with contracts for difference3: draft operational framework", Department of Energy and Climate Change, London.

DECC (2013), "Electricity Generation Costs (December 2013)", Department of Energy and Climate Change, London.

DECC (2014), "Monthly forecast for the non-domestic RHI scheme as at 30 November 20142, Department of Energy and Climate Change, London.

Elexon (2013), "Transmission Losses. Guidance", ELEXON, London.

Eurelectric (2013), “Network tariff structure for a smart energy system. A Eurelectric paper”, Eurelectric, Brussels.

Gil, H.A. and Joos, G. (2006), “On the quantification of the network capacity deferral value of distributed generation”, *IEEE Trans. Power Syst.*, Vol. 21, No. 4, pp. 1592-1599.

Harrison, G.P., Piccolo, A., Siano, P. and Wallace, R. (2007), “Exploring the tradeoffs between incentives for distributed generation developers and DNOs”, *IEEE Trans. Power Syst.*, Vol. 22, No. 2, pp. 821-828.

Hung, D.Q. and Mithulananthan, N. (2012), “A simple approach for distributed generation integration considering benefits for DNOs”, Presented at 2012 IEEE International Conference of Power System Technology (POWERCON).

Mendez, V.H., Rivier, J. and Gomez, T. (2006), “Assessment of energy distribution losses for increasing penetration of distributed generation”, *IEEE Trans. Power Syst.*, Vol. 21, No. 2, pp. 533-540.

NERA (2014), “The implementation of the RIIO Framework”, EPRG Winter Conference, December 2014, Cambridge.

Ochoa, L.F., Keane, A. and Harrison, G.P. (2011), “Minimizing the reactive support for distributed generation: Enhanced passive operation and smart distribution networks”, *IEEE Trans. Power Syst*., Vol. 26, No. 4, pp. 2134-2142.

OFGEM (2003), “Electricity distribution losses. A Consultation document. January 2003”, Office of Gas and Electricity Markets, London.

OFGEM (2009), “Electricity distribution price control review. Final proposal – Incentives and Obligations”, Office of Gas and Electricity Markets, London.

OFGEM (2012a), “Strategy consultation for the RIIO-ED1 electricity distribution price control: Overview”, Office of Gas and Electricity Markets, London.

OFGEM (2012b), “Document A: Decision not to activate the losses incentive mechanism in the fifth distribution price control”, Office of Gas and Electricity Markets, London.

OFGEM (2013a), “Strategy decision for the RIIO-ED1 electricity distribution price control. Outputs, incentives and innovation. Supplementary annex to RIIO-ED1 overview paper”, Office of Gas and Electricity Markets, London.

OFGEM (2013b), “Renewables Obligation: Guidance for Generators”, OFGEM E-Server, Office of Gas and Electricity Markets, London.

OFGEM (2014), “Non-Domestic Renewable Heat Incentive (RHI). Guidance Volume One: Eligibility and How to apply (Version 3.1)”, Office of Gas and Electricity Markets, London.

Passey, R., Spooner, T., MacGill, I., Watt, M. and Syngellakis, K. (2011), ”The potential impacts of grid-connected distributed generation and how to address them: A review of technical and non-technical factors”, *Energy Policy*, Vol. 39, No. 10 , pp. 6280-6290.

Pöyry (2013), “Potential impact of revised Renewables Obligation technology bands: updated modelling”, Pöyry Management Consultancy, Oxford.

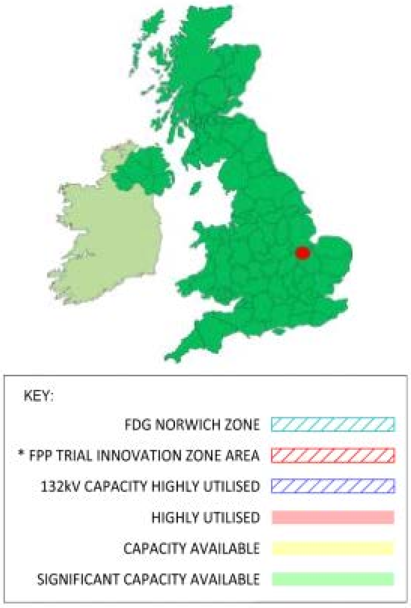
Siano, P., Ochoa, L.F., Harrison, G.P. and Piccolo, A. (2009), “Assessing the strategic benefits of distributed generation ownership for DNOs”, *IET Gener. Transm. Distrib.,* Vol. 3, No. 3, pp. 225-236.

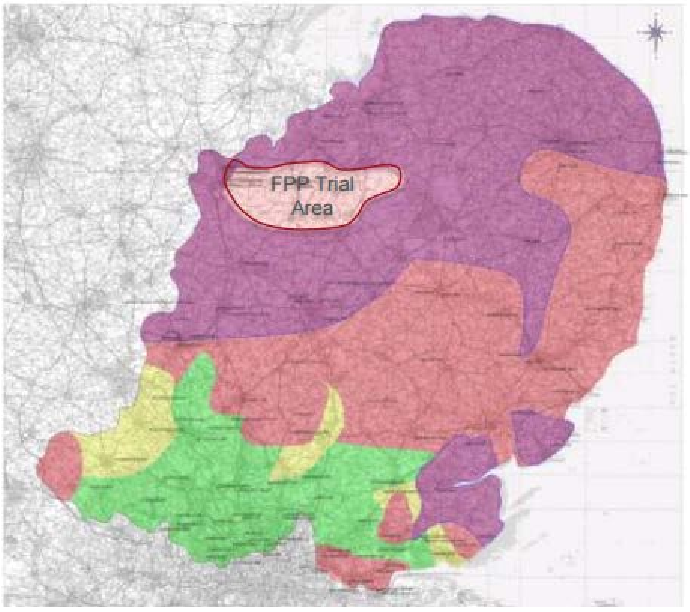
UK Power Networks (2013), “Business Plan (2015-2023) Core Narrative”, UK Power Networks, London.

Wang, D.T.C, Ochoa, L.F. and Harrison, G.P. (2009), “Distributed generation and security of supply: Assessing the investment deferral”, Paper presented at 2009 IEEE Bucharest Power Tech Conference, June 28th-July 2nd, Bucharest, Romania.

Wojszczyk, B. and Brandao, M. (2011), “High penetration of distributed generation and its impact of electric grid performance – utility perspective”, Paper presented at Innovative Smart Grid Technologies Asia (ISGT), 2011 IEEE PES, November 2011.

Appendix 1: The FPP Trial Area (March Grid)





Source: UK Power Networks' website.

Appendix 2: List of variables, formulas and references

Variable	Value/Formula	References
1. Costs		
CAPEX	Depends on technology. It includes construction costs and predevelopment costs	DECC (2013)
OPEX	Depends on technology. It includes fixed and variable opex, insurance, connection and grid charges	DECC (2013), DECC (2011b)
Connection Costs	Depends on type of generator and capacity connected	Provided by UK Power Networks
Reinforcement Costs	Depends on type of generator and capacity connected. Total costs: £4.1m (2012 prices)	Provided by UK Power Networks
2. Revenues/Incentives [1/]		
Wholesale Electricity	£49.82/MWh (at gate, 2012)	Redpoint's reference case (Jan. 2013)
FIT - Wind	Wind 0.5= £133.4/MWh, Wind 1= Wind 1.5=£72.4/MWh	From OFGEM Portal (FIT)
FIT - Solar PV	Solar PV 4= Solar PV 1.2=63.8/MWh	From OFGEM Portal (FIT)
FIT - AD	AD CHP 0.5=£103.7/MWh	From OFGEM Portal (FIT)
ROC&Banding - Wind	Buyout price: Wind 10= Wind 5.873= Solar PV 6.9277.2=£43.3/MWh, Recycle price (10% buyout)=£4.33/MWh	OFGEM (2013b)
	Banding: Wind (0.9 ROC/MWh), Solar PV (1.4 ROC/MWh), RO: (Buyout price+recycle price)*Banding	OFGEM (2013b)
LEC	Initial value: £5.09/MWh, 2012 prices	Redpoint's reference case (Jan. 2013)
3. Other Benefits		
Embedded benefits (generator)		
Generator avoidance balancing system charges	$= annual\ BSUoS\ costs\ (average\ last\ 3\ years) - residual\ cashflow\ reallocation\ cashflow\ (RCRC) = £1.463/MWh$	From National Grid and Elexon Portal. Average figure: 2011/12, 2012/13, 2013/14.
Generator transmission loss reduction	$= generator's\ ratio\ losses * average\ losses * wholesale\ electricity\ gate\ price$	See (2), (4)
Distribution use of system charges (neg.)	$= DUoS\ tariff\ for\ HV = £0.51/MWh$	Baringa-UK Power Networks (2013a)
Embedded benefits (supply)		
Supplier avoidance balancing system charges	$= annual\ BSUoS\ costs\ (average\ last\ 3\ years) - residual\ cashflow\ reallocation\ cashflow\ (RCRC) = £1.463/MWh$	From National Grid and Elexon Portal. Average figure: 2011/12, 2012/13, 2013/14.
Supplier transmission loss reduction	$= supplier's\ ratio\ losses * average\ losses * (wholesale\ electricity\ gate\ price + generator's\ transmission\ losses + BSUoS\ costs)$	See (2), (4)
Distribution line losses	$= time\ weighted\ average\ of\ UKPN's\ line\ loss\ factors\ (LLF) * (wholesale\ electricity\ gate\ price + transmission\ losses + BSUoS\ costs)$	LLF adjusted by % of lossesreduction in DG connected at 11 kV or 33 kV
4. Technical Variables		
Wind capacity factor	30%	Suggested by SmartGrid Solutions (March Grid Case)
Solar PV capacity factor	11.16%	Suggested by SmartGrid Solutions (March Grid Case)
AD CHP capacity factor	84%	Pöyri (2013)
Other assumptions (solar PV)	PV module degradation (0.55%), export rate (85%)	Solar Trade Association
Losses:		
Ratio generator	45%	Balancing Settlement Code
Ratio supplier	55%	Balancing Settlement Code
Average transmission losses	2% (current average)	Elexon (2013)
5. Discount Rate (pre - tax, real)	wind=8.3%, solar PV=6.2%, AD CHP=13%	DECC (2013)
6. Power Purchase Agreement Rate	electricity (85%), ROC (90%), LEC (85%), Embedded benefits (50%)	Baringa-UK Power Networks (2013a)

1/ Revenues from AD CHP plants only make reference to the export capacity of electricity. Revenues from heat have not been taken into account.