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Cambridge Working Papers in Economics

Finding the Optimal Approach for Allocating and Realising the Distribution System Capacity: Deciding between Interruptible Connections and Firm DG Connections

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CWPE 1343 & EPRG 1320

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Keywords **cost benefit analysis, distributed generation, interruptible connections (non-firm)**

JEL Classification D61, L51, L94, Q21, Q40, Q48

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Publication October 2013
Financial Support UK Power Networks via the Low Carbon Networks Fund's Flexible Plug and Play Project

Finding the optimal approach for allocating and releasing distribution system capacity: *Deciding between interruptible connections and firm DG connections*

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Abstract

The aim of this study is to perform a cost benefit analysis of the different options for connecting distributed generation (DG) customers in a specific constrained area (the March Grid), under the context of the Flexible Plug and Play trial. The study shows the importance of the development of levels of understanding and trust among the customers and suppliers of the system-level complexities of an interconnected grid that affect all involved, of the need to achieve acceptability for all involved and the development of a shared, confident forward awareness of future evolution capability, both technically and contractually. This research required a comprehensive revision of the current regulatory framework applied to DG and the search of the most recent estimations of generation costs with a focus on wind, solar PV and anaerobic digestion (AD) generators. Specific assumptions were made in terms of interruptible capacity quota, generation mix, embedded benefits, curtailment levels and load factors. The results are presented in four different scenarios. Two kinds of connection options have been assessed: smart option (non-firm or interruptible) and reinforcement option (firm). Results suggest that in general small wind generators will always have advantage over the large wind generators regardless the type of connection, solar PV would struggle to connect and AD generators would always connect.

[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 and of an anonymous reviewer. 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. We are very grateful to Northern Powergrid, Scottish Power Distribution, Electricity North West and Western Power Distribution for the provision of relevant information and clarifications in the management of interruptible connections.

1. Introduction

1.1 Background

The 2009 Renewable Energy Directive has established specific energy targets for 2020 which have accelerated the connection of more renewable generation to the distribution network, which will contribute to achieving the UK's energy security and carbon reduction objectives. It is expected that 15% of the UK's energy consumption will be from renewable sources by 2020. The transition to low carbon networks requires the implementation of innovative technical solutions and commercial practices in order to meet the growing demand of electricity but also to avoid or reduce high investment costs that are borne by customers. The support of different initiatives that encourage the expansion of renewable distributed generation (DG) will contribute importantly to a smooth transition. Distribution Network Operators (DNOs) play an important role in this transition by facilitating the efficient integration of renewable generation to the distribution networks and by testing innovative connection models that involve smart technical solutions and novel commercial arrangements.

In the context of the Flexible Plug and Play (FPP) trial, UK Power Networks is looking for different options for connecting more DG between Peterborough, March and Wisbech in Cambridgeshire. DG developers are seeking connections at constrained parts of the network that operates within this area. A total of six generators with total generating capacity of 26.2 MW are already engaged with the FPP trial (UK Power Networks, 2013). Connections in constrained areas increase the conventional connection costs which may jeopardise the project viability. Due to this fact, UK Power Networks has proposed the use of smart solutions (e.g. Active Network Management) and innovative commercial arrangements in order to be able to connect more DG in a cheaper and faster way. This approach requires the interruption of the generation output (non-firm connections) under specific rules known as "Principle of Access". The method selected by UK Power Networks is pro rata where generators would be equally curtailed based on their proportion of total connected capacity. A capacity quota of 33.5 MW has been defined in order to limit the interruptible capacity and keep an acceptable curtailment level per generator (Baringa-UK Power Networks, 2013). A concern arises when the maximum quota for interruptible connections is reached. Under this scenario, it is important to make producers (already connected or new) aware about the way how the connection of new capacity would be controlled and managed. UK Power Networks has identified the different scenarios that would trigger network reinforcement. The offer letter sent to producers reflects the terms and conditions for connecting their respective projects to the distribution network. Producers are currently evaluating their offers and it is expected to have a decision from them in the following months. UK Power Networks has stated that they will continue issuing connection offers in the trial area throughout the life of the project.

1.2 Non-firm (interruptible) connections[2] versus firm connections

DNOs are in the search of different options for realising and increasing capacity that allows the connection of more DG in a cost-efficient way. Based on the firmness of the connection, two schemes are identified: non-firm and firm connections. Under non-firm connection, the DNO does not guarantee the full export of the generation capacity to the distribution network. This means that in the presence of network constraints (e.g. voltage and thermal constraints), the DNO reserves the right to reduce the generation output based on the terms and conditions set in the interruptible contract agreement. Sometimes, this kind of connection allows the producer to connect larger capacity in exchange for a reduction of the generation capacity during specific times. For instance, the financial viability of wind generators may not be negatively impacted if a curtailment request is made during summer nights, due to the low price of electricity (Liew and Strbac, 2002). On the other hand, a firm connection is the traditional connection, which allows the export of full generation capacity to the distribution network. The provision of this kind of connection may require the reinforcement of the distribution network in order to guarantee capacity. Following Boehme *et al.* (2010), the option of firm connection is more reasonable for non-variable energy sources due the sustainability of the maximum output for extended periods. In the case of variable energy sources such as wind, wave and tidal, the option of non-firm connections is more applicable to them due to the nature of these sources (i.e. unpredictability, intermittency). Contrary to firm connections, the nameplate capacity associated with non-firm connections is restricted.

These two concepts are also frequently associated with the level of financial compensation that producers receive in case of network constraints. In contrast with generators with non-firm connection agreements, generators with firm connections are usually subject to compensation. In California, under the Renewable Auction Mechanism (RAM), Southern California Edison (SCE) compensates renewable generators that are connected to the distribution network except when the following conditions are simultaneously met: (1) the system operator (CAISO) does not award a schedule to SCE[3], (2) the day ahead price is lower than zero and (3) the number of hours interrupted a year is lower than 50 (SCE, 2012). In GB, DG customers at high voltage (HV) or above that have signed a firm connection agreement receive a payment of £0.002/kW/hour when the distribution network is unavailable, except for planned outages (OFGEM, 2009). At transmission level, a similar practice is observed. National Grid (through Connect and Manage Scheme) and the Single Electricity Market Operator (SEMO) from Ireland and Northern Ireland compensate DG customers in the case of network constraints (DECC, 2010; SEM, 2011). The treatment of compensation for non-firm connections follows a similar pattern at the distribution and transmission level. In the case of Orkney ANM Project, Scottish and Southern Energy Power Distribution (SSEPD) does not provide compensation to renewable generators (Meeus *et al*., 2010). In addition, no market compensation is

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[2] In this study the terms non-firm and interruptible connections are used interchangeably. There is no clear differentiation between these two terms. Based on the terminology used by some DNOs and System Operators, non-firm connections can be related to those connections that are managed actively, non-actively or those that are offered under fault based conditions. The term of interruptible connection (capacity) usually refers to a reduction of the maximum exporting capacity without specifying if they are actively or not actively managed.

[3] This refers to the schedule that the system operator (CAISO) awards to SCE as a result of a bid.

paid out by SEMO to wind generators due to curtailment or network constraints in tie-break situations[4] (SEM, 2011).

These two different schemes have pros and cons. In terms of pros, a non-firm connection allows the possibility of cheaper connection costs, avoidance of reinforcement costs, cheaper system charges (if applicable), faster connections and larger capacity connections. A firm connection increases the chance to guarantee future capacity requirements, guarantees the maximum export capacity (the probability of interruptions is much lower) and allows market compensation in the case of network constraints. However, a non-firm connection may affect the financial viability of the generator due to the interruptible capacity (no payments for energy not delivered and the loss of renewable subsidies) and due to the fact that they are not financially compensated. A firm connection usually requires high connection and reinforcement costs (in case of network constraints), longer connection times (e.g. to build new infrastructure) and is subject to higher system charges in comparison with the non-firm connections. From the previous comparisons, it is observed that both schemes have advantages and disadvantages and represent two different alternatives for DG connections that currently some DNOs are offering. The preference of either option will depend on the DG business model and also on the market and regulatory context. The combination of both schemes can be also an option.

1.3 Our approach

The aim of this paper is to evaluate the different approaches that DNOs exercise for realising capacity and connecting more DG in a cost effective way; by opting for interruptible connections, firm connections or a combination of both. Specific case studies are analysed with a focus on UK Power Networks' recent proposal for connecting more DG under the FPP trial, in order to identify the best practice and evaluate its applicability across DNOs taking into consideration the regulatory and market context. It is important to note that the UK Power Network' case study refers to a specific constrained area of the March Grid with a particular network configuration. The paper is structured as follows. Section two discusses the network access regulation in the UK context with a focus on DG, including the new challenges that DNOs and DG will face in the context of the RIIO-ED1 regulation. Section three explores the different practices that DNOs are applying for increasing DG capacity. Section four performs a cost benefit analysis presented in four different scenarios based on the solution proposed by UK Power Networks for increasing DG capacity in the constrained area of the March Grid. Section five sets the conclusions of this study.

2. Access network regulation in the UK context

This section describes the access network policies for DG in the UK context. A brief discussion of the current regulatory framework applicable to DG regarding connection costs and system charges, and incentives is given first. Additionally, it also provides a discussion of the future DG regulatory framework under the context of RIIO-ED1 and explains the new challenges that DNOs and DG customers will face.

[4] In Ireland the definition of curtailment and network constraints differs. Curtailment refers to a market and system operation issue while constraints are a network specific issue.

2.1 Connection costs and system charges

DG customers that seek for a connection face two kinds of costs. The first one is the sole use asset and the second one (if reinforcement is needed) is a proportion of shared use assets up to one voltage level above point of connection. The remaining costs of reinforcement of shared use assets are incurred by Distribution Use of System (DUoS) charges to customers. This kind of connection policy is classified as 'shallowish'. The proportion of shared use assets that DG customers are subject to is determined by the cost apportionment rules defined in the Common Connection Charging Methodology (CCCM). The CCCM is part of the Statement of Methodology and Charges for Connection document that DNOs publish on their websites. Only generators connected at low voltage (LV) and high voltage (HV) are subject to the use of system charges under the CCCM. Generators whose plants are connected to extra high voltage (EHV) [5] are subject to the use of system charges under the Extra High Voltage Distribution Charging Methodology (EDCM). It is important to note that there is a possibility that a small generator can incur additional costs if the connection may have an impact on the National Electricity Transmission System. National Grid is responsible for assessing the need of reinforcing the transmission network as a result of the new distribution connection. This evaluation is made through the Statement of Works (SOW). The SOW is a study required by the DNOs to National Grid when they believe that the DG connection may have an impact on the transmission grid.

In general, DG customers that seek a connection are subject to the use of system charges applied by the DNOs for the use of the distribution system. However, large generators with a generation license[6] that wish to export to the GB Transmission system but who are not directly connected to this (classified as embedded generators) need to sign a Bilateral Embedded Generation Agreement (BEGA) and have to pay the use of system charges associated with the transmission system called Transmission Network Use of System (TNUoS) charges. The Statement of the Use of System Charging Methodology regarding the transmission system is published by NGET on its website. TNUoS charges depend on the geographic region and can be positive or negative. This agreement provides generators with Transmission Entry Capacity and also gives the right to generators to participate in the energy balancing market. By participating in the energy balancing market, generators can be charged by NGET through the Balancing Services Use of System (BSUoS) charges.

The associated connection costs that the charging methodologies refer usually provide generators to a firm connection (after the respective reinforcement work in case of network constraints). However, cheaper connection costs could be offered to DG or demand in exchange of interruptible capacity (non-firm connections) or a delay in the electricity restoration. These kinds of arrangements are very specific and are usually linked to the trial of low carbon technologies and innovative commercial arrangements. Section 3 will discuss these kinds of initiatives in which some DNOs are taking part.

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[5] LV: less than 1kV, HV: 1kV-22kV, EHV: above 22 kV (ENA, 2011)

[6] Only generators with an export capacity over 100 MW require a generation licence; generators with a capacity between 50 and 100 MW may be given an exemption.

2.2 Incentives

There are different initiatives that encourage the connection of renewable generation to the distribution networks. The most relevant for this study are discussed in the following paragraphs.

a. Feed in Tariff (FIT): This scheme was introduced in 2010 and is focused on small renewable generation (no more than 5 MW). A guarantee price is provided to generators for a fixed period. There are two kinds of tariffs: the tariff for every kWh of electricity generated and the export tariff for every kWh of electricity exported (surplus energy) to the transmission network. The tariffs vary depending on the size of project, technology and date of installation. The technologies covered are solar photovoltaic (PV), wind turbines, water turbines, anaerobic digestion (biogas energy) and micro combined heat and power (micro-CHP). The tariffs are retail price index (RPI) linked[7] and a regression of the tariffs by 5% p.a. is expected from April 2014 for new installations including hydro, wind and anaerobic digestion. In terms of solar PV, a system of quarterly tariff degression has applied from 1 November 2012.

b. Renewable Obligations (RO): This scheme was introduced in 2002 and represents the main financial support for renewable generation over 5 MW (and some projects between 50kW and 5 MW). Under this scheme, UK suppliers are required to purchase renewable obligation certificates (ROC) issued by accredited renewable generators in order to meet their obligations. If these obligations cannot be met, suppliers have the option to make a buy-out payment to cover the number of pending ROCs. The number of ROCs for meeting these obligations is 0.206 ROCs per MWh (England, Scotland and Wales) and 0.097 ROCs per MWh in Northern Ireland for the 2013/14 period. The expected value of the buy-out payment is £42.02 per ROC for the same period (OFGEM, 2013a). Banding was introduced in 2009 in order to support generators based on the type of renewable technology. This scheme will close to new DG on 31 March 2017. Generators will continue to receive the financial support during the project lifetime (20 years). RO will close in 2037 and will be totally replaced by the new Contract for Difference Feed-in Tariff (CfD FIT) scheme. Under this approach compensation will be received when the market price is below the strike price or has to return the excess if the market price is above the strike price. CfD FIT will be introduced in 2014 and generators will have the option to choose between RO and this scheme until March 2017.

c. Levy Exemption Certificates (LEC): Introduced in April 2001. These are electronic certificates that are used to demonstrate the amount of electricity that has been generated and supplied to non-domestic customers (industrial and commercial supply). OFGEM is responsible for issuing the certificates to generators or suppliers (in case of Non-Fossil Fuel Obligations – NFFO, or Scottish Renewables Obligations – SRO) and for accrediting qualifying renewable generators. Electricity suppliers negotiate the purchase of these certificates with renewable generators in order to claim for the Climate Change Levy (CCL) Exemption on

[7] Payments are guaranteed for 20 years after installation regarding solar PV, wind, hydro and anaerobic digestion and for 10 years regarding micro CHP.

non-domestic supply. CCL is a charge (tax) applicable to non-domestic supply of electricity in the UK regarding taxable commodities for lighting, heating and power by consumers (e.g. industry, commerce, agriculture, public administration and other services). The CCL was introduced in 2001. The CCL rate has been set at £5.24/MWh by period 2013/14 (subject to some exclusions, reduced rate and half rate suppliers).

d. DG Incentives: This initiative was introduced at the beginning of the Distribution Price Control Review 4 (DPCR4). The aim of this initiative is to facilitate the DG connections by investing (DNOs) efficiently and economically. The incentive framework for DPCR5 (which runs from 1 April 2010 to 31 March 2015) allows DNOs to (1) recover the connection costs by 80% pass through – annuitized over 15 years, (2) get £1.00/kW/yr for first 15 years, (3) get an O&M allowance of £1.00/kW/yr, (4) get a network access rebate of £0.002/kW/hour, (5) set a cap and collar on DNO returns equal two times WACC and to the cost of debt respectively and (6) get a high cost project threshold (for those projects that require reinforcement costs in excess of £200/kW). It is important to note that RIIO-ED1 has decided not to retain this scheme. Further details are explained in the next section. The principle of grandfathering will be applicable to DG incentives.

e. Innovation Funding Initiative (IFI) and Low Carbon Network Fund (LCNF): Introduced in 2005 (DPCR4) and 2010 (DPCR5) respectively. IFI encourages DNOs to invest in research and development activities related to the technical development of the network. It allows DNOs to recover from customers a proportion of the expenditure from IFI eligible projects (up to 0.5% of combined distribution network revenue) as follows: 80% in 2007/08, reducing in 5% steps to 70% in 2009/10. It was revised upwards to 80% in 2010/11 and will keep this value until 2014/15. Under LCNF DNOs receive support (up to £500m) for testing new technologies, operating and commercial arrangements which will contribute to the transition of low carbon economy. The LCNF is composed of two tiers: Tier 1 (which helped to the partial recovery of those expenditures incurred by DNOs on small scales projects and Tier 2 (which based on an annual competition provides up to £64m to DNOs to innovate projects). The last competition will be run in 2014. These two schemes will be replaced by the innovation stimulus package in the context of RIIO-ED1. Additional details are provided in the following section.

2.3 RIIO-ED1

The RIIO-ED1 model (Revenue=Incentives+Innovation+Outputs) is the first electricity distribution price control review that reflects the new regulatory framework adopted as a result of the RPI-X@20 review. RIIO-ED1 has been set for an eight-year period (1 April 2015 to 31 March 2023). In comparison with DPCR5, this model provides strong incentives to DNOs in order to meet investment and innovation challenges to deliver a low carbon electricity sector at a lower cost to customers. RIIO-ED1 identifies a total of six primary output categories that would need to be delivered by DNOs during the price control period. The categories are as follows: safety, environment, customer satisfaction, connections, social obligations, and reliability and availability. A set of incentives has been identified for each output category. These are in the form of financial rewards/penalties and reputational incentives. A range of secondary deliverables has also been established which allows to monitor companies ‘performance and are leading indicators to ensure long-term delivery and value for money. It is important to note that there is no specific regulation for non-firm connections; in fact what RIIO-ED1 proposes is to encourage DNOs to develop networks that provide sufficient flexibility and capacity to the connection of new loads and generation, which may implicitly involve the practice of innovative commercial arrangements for managing interruptible connections.

In terms of DG, RIIO-ED1 has proposed important changes that comprise incentives and mechanisms to incentivise DNOs to facilitate the connection of DG to the network. RIIO-ED1 will encourage the provision of good level of service, efficient investment, appropriate response to demand from DG customers, and the exercise of more innovate alternatives to traditional reinforcement (OFGEM, 2013b). In contrast with the DPCR5, which proposed specific DG incentives described in section 2.3, RIIO-ED1 proposes a range of incentives and mechanisms that are part of different outputs. This section will discuss those related to connection costs, innovation, level of service and connection applications.

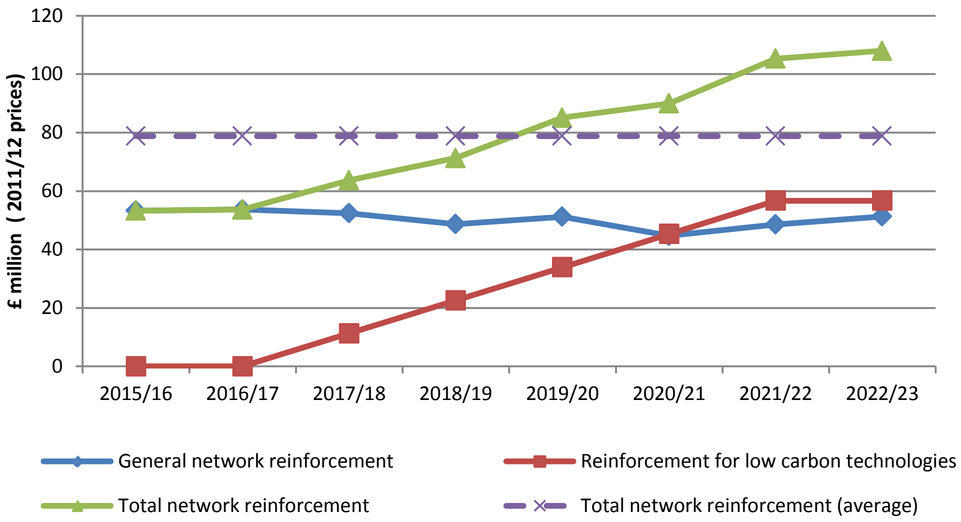
2.3.1 Connection costs

As mentioned before, in case of network reinforcement the proportion of shared use assets that is not funded by the DG customer is funded by the DUoS demand customers. Three elements related to the expenditure on network reinforcement to facilitate the DG connections have been identified.

First, an ex-ante allowance for the efficient investment is needed to connect the projected DG connection requests (DNOs can retain up to 70% of any under spend and fund 70% of over spend against the allowance, customers fund the remaining 30%). The challenge that DNOs face is to provide a good forecast of future volumes of DG connections and their associated reinforcement costs which are partially funded by DUoS customers. DUoS charges represent 18% of an average household end electricity bill (Ward *et al*., 2012). The stakeholder engagement is seen as a key element to predict accurate and justified forecasts of DG connections. Stakeholder investment incentive is set at +0.5% of the base revenue. Due to the fact that future network reinforcement will involve traditional and smart network reinforcement, it would be interesting to analyse the trend of these expenditures over time. It is expected that the transition to low carbon networks will produce an increase in smart network reinforcement expenditure which at some point will exceed those expenditure associated with the traditional network reinforcement. In March 2013, Western Power Distribution (WDP, 2013) launched the RIIO-ED1 Business Plan Draft for consultation. The plan analyses the forecast expenditure that requires to be funded by DUoS. Figures suggest that expenditure related to reinforcement for low carbon technologies exceeds that related to general network reinforcement in the last three price control periods with an average amount of £53m representing 52% of the total network reinforcement expenditure[8]. It also suggests that on average a total of £78.8m per year is expected to incur in reinforcing the network during the 2016-23 period where that related to low carbon technologies represent 36% of the total network reinforcement expenditure. Figure 1 illustrates the previous discussion.

[8] Costs related to network reinforcement represent 10% of the total core expenditure that amount to £6.6bn.

Figure 1: Expenditures on traditional network reinforcement and smart network reinforcement - WPD



Second, RIIO-ED1 proposes to include actual expenditure on network reinforcement in the load related expenditure (LRE) reopener. The LRE reopener includes those additional costs incurred or forecasted to be incurred in order to accommodate changes in levels and patterns of network loading. The reopener can be triggered by DNOs if they can demonstrate efficient expenditure over the whole RIIO-ED1 period is or will be over 20% of the ex-ante allowance. In addition, this expenditure (above the 20% threshold) must be at least 1% of average annual RIIO-ED1 base revenue. The inclusion of actual expenditure on network reinforcement in LRE will protect both DNOs and customers from uncertainty in the investment forecasts. The inclusion of this expenditure in the LRE will mitigate the risk of important changes on the volume of DG connections that DNOs have to facilitate. These changes can be originated for many reasons including policy changes and changes on DG implementation costs. In contrast with DPCR5, RIIO-ED1 considers two additional expenditure categories: secondary network new and modified connections (includes DG that is not connected to customer profile classes 1-4[9]) and fault level reinforcement. The first one complements the expenditure categories already proposed under DPCR5 related to DG (OFGEM, 2013c).

Third, RIIO-ED1 proposes the removal of the DG incentives and suggests that DG will be treated similar to demand. OFGEM believes that this new approach in comparison with DPCR5, will simplify the treatment of DG in the price control (OFGEM, 2013b). Under the current DG incentive scheme DNOs face a maximum of 20% of efficiency incentive of capex (80% of capex is passed through), however incentives on opex are not given. In RIIO-ED1, DNOs will be incentivised on 100% of totex (opex+capex). This allows the equalisation of DNO incentives between capex and opex and promotes better investment decisions (DNOs have more alternatives). For instance, the implementation of low carbon networks can be encouraged in situations when opex rather than capex offers better value for money. The connections that require network upgrades may benefit from this reduction on expenditure in network reinforcement. DNOs are also encouraged to be more efficient due to the increase in the exposure of expenditure that they have to face. This efficiency can be transferred to DG and DUoS customers by offering cheaper and more innovative connections.

[9] These are represented by domestic and smaller commercial customers.

2.3.2 Innovation

RIIO-ED1 proposes the removal of the LCNF and IFI which are part of the current price control. A new innovation stimulus will be adopted in April 2015. Except for any discretionary reward (applied only to LCNF projects), there will not be any overlap between LCNF and the new innovation stimulus. The innovation stimulus is composed of three components which are described in the following table:

Table 1: Innovation Stimulus Components

Scope	Name of incentive/metrics	Maximum reward (% of base revenue)	Maximum penalty (% of base revenue)
Major connections customers	Incentive on Connections Engagement (ICE)	None	Up to -0.9
All connections customers	Guaranteed Standards of Performance (GSOP) - min. service level	None	0/As per GSOP payment value
Major connections customers	BMCS - Complaints metrics	0	-0.5
	BMCS - Stakeholder engagement	+0.5	0

From Table 1 we observe that the three components of innovation stimulus are time-limited. The idea is to introduce the approach of innovation and to facilitate its implementation as part of business as usual. The funding related to NIC has been limited to £90m per year for the periods 2015/16 and 2016/17. The funding cap for the rest of periods will be determined after conducting a learning review of the LCNF outcomes to take place in early 2016 (OFGEM, 2013b). An innovation strategy is required for the NIA. The amount to be awarded will depend on the quality and innovation of the innovation strategy. The default level has been set at 0.5% of base revenues. For instance, WPD has recently requested a NIC of 0.5%, which is £55m throughout the period (WPD, 2013). The set of a proper threshold for each category of stimulus constitutes a key point. For instance, in the case of NIC, there is a risk of not selecting projects that provide value for customers' money if a lower cap is proposed. By contrast, if the cap is higher than the total fund asked for projects that meet the evaluation criteria, there is not concern because OFGEM is not obligated to allocate the total funding available per year.

2.3.3 Level of service

There is a concern about the level of service provided to customers when seeking for connections, which continues to fall below the customers' expectations (OFGEM, 2013b). In practice, DG customers (major connections) are more vulnerable because their requirements are usually more complex than those at lower voltages (minor connections). RIIO-ED1 has proposed a package of new incentives to promote improvements in the connection services. The one that is applicable to major connections customers is the Incentive on Connections Engagement (ICE). This incentive will encourage DNOs to provide a better level of service where there is not competition in the connection market to attend different behaviours. In addition, this will motivate DNOs to be more involved in the development of requirements that suit better for DG customers' needs. In terms of rewards and penalties, the ICE does not allow any reward but a penalty of up to 0.9% of base revenue can be applied. Other initiatives that also encourage the improvement in the level of service and are applicable to DG customers are Guaranteed Standards of Performance (GSOP) and the Broad Measure of Customer Satisfaction (BMCS) which have been introduced before the RIIO-ED1. Table 2 illustrates the different incentives.

Table 2: Incentives related to level of service for DG connections customers

Scope	Name of incentive/metrics	Maximum reward (% of base revenue)	Maximum penalty (% of base revenue)
Major connections customers	Incentive on Connection Engagement (ICE)	None	Up to -0.9
All connections customers	Guaranteed Standards of Performance (GSOP) - min. service level	None	0/As per GSOP payment value
Major connections customers	BMCS - Complaints metrics	0	-0.5
	BMCS - Stakeholder engagement	+0.5	0

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. The BMCS encourages the level of service by capturing and measuring customer contacts with their respective DNOs across a range of services and activities. Similar to the different innovation incentives, a key point is to determine the proper level of reward or penalty associated with each incentive/metric in order to encourage effectively improvements in the level of service provided by DNOs to DG customers.

2.3.4 Connection applications

The provision of quotations for connection applications can be importantly delayed by speculative connection applications which do not allow DNOs to provide better service to customers. The current regulation does not allow DNOs to charge customers for assessment and design (A&D) fees in advance of the formal acceptance of connection offer by the customer. Due to this fact, and under the context of RIIO-ED1, OFGEM is supporting the application to DECC in order to make the respective changes on the current regulation (Electricity Act 1989) that allows DNOs to charge for A&D upfront. The provision of relevant information to DG customers could also help to reduce the number of speculative connection applications and to improve the quality of evaluation performed by the DNOs when a connection is required. Among this information are interactive maps with data regarding availability of capacity, voltage level, constrained zones, others. For instance, Investor-Owned Utility (IOU) such as Southern California Edison (SCE) provides in its website a link to download an interactive network map (on Google Earth) free of charge. This facility is mandatory for all IOUs in California (SCE, SDG&E, PG&E).

3. Distribution network operators practices in connecting distributed generation

This section will focus on a review of different practices applied by DNOs (apart from UK Power Networks) for increasing network capacity by offering non-firm connections or other innovative arrangements to DG customers. Our findings suggest that the offer of interruptible connections can be identified in two different situations: trials and business as usual practices.

3.1 Trials

Different DNOs and DG customers are encouraged to take part through the LCNF (Tier 2) or IFI incentives in which the use of smart solutions (technical and commercial) is normally proposed. Orkney ANM Project implemented by Scottish and Southern Energy Power Distribution (SSEPD) is the first smart project in UK that offered interruptible connections to DG customers. A capacity of 26 MW has been enabled by the ANM scheme for the allocation of non-firm connections (classed as New Non-Firm Generation – NNFG) [10]. Among other recent initiatives that are relevant to this study are Capacity to Customers (C2C), Project FALCON and Accelerating Renewable Connections (ARC). All of them are funded by LCNF in the Second Tier competition. Table 3 summarises the initiatives that re discussed in this section.

C2C is being implemented by Electricity North West (ENW). The project is part of the 2011 Second Tier competition. It runs for three years starting in January 2012. The purpose of the project is to increase capacity by releasing capacity reserved for emergency use which requires network reconfiguration and the use of smart solutions. The potential customers are demand customers (industrial and commercial) and HV generators (DG). Cheaper connection costs (for new customers) or monthly payments (for existing customers) will be provided in exchange for allowing the DNO to manage the timing of re-energisation of the supply after a power cut (with a delay of up to 8 hours). ENW will provide two connection quotas to new customers (interruptible and standard connection quota). Regarding existing customers, payments will depend on the selection of protected days, protected circuits and outage period. ENW has indicated that the conditions (to be specified in a constraint contract) for managing the output of HV generators are in an initial stage and that they are evaluating different scenarios of curtailment allocation methods and capacity quota.

Project FALCON is led by Western Power Distribution (WPD). The project is part of the 2011 Second Tier competition and runs from December 2011 to September 2015. The aim of the project is to facilitate the integration of low carbon technologies by exploring different methods for delivering faster and cheaper connections on the HV network (11kV) and reducing traditional reinforcement. The target customers are demand customers and DG customers. In order to address network constraints, the project has proposed a set of technical and commercial intervention techniques. Among the technical interventions are the design and implementation of dynamic asset rating (for realising capacity), automated load transfer (that allows the redistribution of load at 11kV feeders), meshed networks (implementation and operation at 11kV) and energy storage (deployment of battery technologies).

[10] The capacity represents the maximum economically viable capacity under NNFG. .

Table 3: Summary of Projects

DNO's name	Project Name	LCNF Tier	Project Cost	General descripcion	Target	Project lifetime	Principle of Access	Interruptible quota	Benefits & Compensation
Electricity North West	Capacity to Customers (C2C)	Tier 2, 2011	£10.7m (£9.2m OFGEM)	The project allows the increase of capacity by taking advantage of the latent capacity that exists in the current network (to emergency use). Require network reconfiguration and smart solutions. Cheaper connection or monthly payments (to customers) in exchange of allowing to manage the timing of re-energisation of the supply after a power cut.	Demand (industrial and commercial) and distributed generation in HV. Covering around 12% customer base (North West England).	3 years, from January 2012. Trial period: 18 months (April 2013-September 2014). Two types of contracts: (1) new customers and (2) existing customers.	To be defined.	A delay of up to 8 hours (re-energisation). For generation: to be defined.	Up to £ 20,000/MWh (depends on the selection of protected days, protected circuits, outage period).
Western Power Distribution	FALCON	Tier 2, 2011	£16.19m (£12.4m OFGEM)	The aim of FALCON Project is to facilitate the integration of low carbon technologies by exploring different alternative solutions to the traditional network reinforcement. In order to address network constraints the project has proposed technical interventions (dynamic asset rating, automated load transfer, meshed networks, energy storage) and commercial interventions (distributed generation, demand side management).	Demand and distributed generation focus on the 11kV network (Milton Keynes, East Midlands).	Started in 1st December 2011, completion date 30th September 2015. Trial period: 1st Nov. - 1st March, starting 2013 and for the subsequent 2 years.	To be defined.	Max. event duration: 2h. Min. event duration: 1h. Total hours per year: 40. For generation: to be defined.	Around £300/MWh.
Scottish Power Energy Networks	Accelerating renewable connections (ARC)	Tier 2, 2012	£8.8m (£7.4m OFGEM)	The objective of the project is to evaluate different approaches for releasing generation capacity within the distribution franchise area. The project involves three key areas: (1) coordinated connection application process in order to facilitate the connection to the network (exploration of C&M, staged gate process); (2) delivery of novel commercial arrangements by testing the C&M approach, non-firm capacity connection agreements, minimum export capacity and tri-party agreements (between DNO, generators and demand customers); (3) rollout and trial of innovative technology and engineering tools.	Renewable generation in South and East of Edinburgh (up to 33kV).	4 years, from January 2013 to December 2016.	LIFO (initial stage).	To be defined.	N.A.

Commercial interventions are focused on DG and demand side management. WPD has stated that the specific conditions for managing constraints (such as the curtailment methodology and the determination of the interruptible capacity quota) applicable to DG customers are still under evaluation (as of mid-2013). One of the main outputs of the project is the Scenario Investment Model (SIM) which will be able to find optimal solutions for managing network constraints taking into account different factors such as costs, duration of implementation, impact on network performance and losses.

ARC is being implemented by Scottish Power. This initiative is part of the 2012 Second Tier competition. The project runs from January 2013 to December 2016. The potential customers are those who are looking for a generation connection at the 11kV of 33kV level in the South and East of Edinburgh. Its main purpose is to explore different ways for releasing generation capacity within the distribution franchise area. One of the key areas of the project is the delivery of novel commercial arrangements by testing the Connect and Management approach, non-firm capacity connection agreements, minimum export capacity and tri-party agreements (between DNOs, generators and demand customers). The project proposes the use of ANM solutions for managing network configurations and the output of DG customers. In terms of the curtailment methodology, Scottish Power has indicated that LIFO is the preferred option among generators and it is the methodology that they are planning to implement. The selection of this methodology is supported by generators because this provides more certainty in the way how curtailment will be managed. In terms of the interruptible capacity quota, Scottish Power has stated that (as of mid-2013) they are still in the process of evaluating different approaches.

3.2 Business as usual practice

This scenario relates to a business as usual practice; however this option does not work symmetrically across all the DNOs. Some of these practices are indicated in their respective Statement of Use of System Charging. These are as follows:

a. Western Power Distribution (WPD) provides network rebates for non-firm connections. The condition is set in the Statement of Use of System Charging[11]. The rebates are mainly applied to generators with EHV connections (energised after the 31st March 2005). In terms of non-firm connections, rebates have to be agreed prior to connection and are subject to the baseline availability expected for the connection. Total rebates are limited to the amount paid in export of use of system charges (for a specific connection) in a year period. Even though there is the option of rebates for non-firm connections, WPD recommends firm connections for HV and EHV generators.

b. In the case of ENW, the level of generation export capacity is managed in real time[12]. Generators can have both a firm and non-firm Authorised Supply Capacity (ASC). The non-firm ASC is usually larger. A constraint policy (between 0 and 100%) is applied if customers

[11] See: http://www.westernpower.co.uk/docs/system-charges/Archived-charging-statements/CN-West-UoS-Methodology-Statement-April-2010-W.aspx

[12] See: http://www.enwl.co.uk/about-us/long-term-development-statement/policies-and-technical-references/network-management

export excess generation capacity to the network. Similar to Scottish Power, the Statement of Use of System Charging does not specify the option of interruptible connections.

c. Scottish Power operates a number of technical solutions to constraint generation output in situations when the grid is not able to absorb the maximum export capacity. These solutions are especially applied to wind farms in Wales[13]. The operation of these trials has been confirmed by Scottish Power, however there is no specific methodology for managing curtailment behind a constraint (e.g. such as LIFO or Pro-Rata). A revision of the Statement of Use of System Charging from Scottish Power suggests that the option of non-firm has not been contemplated.

d. Northern Powergrid (NPG) in a Demand Side Management (DSM) context offers the option of interruptible connection for active network management purpose (other than planned or unplanned outages) in the Statement of Use of System Charging[14]. For those customers that enter into this scheme (DSM), a reduction in use of system charges is applicable. This reduction will be assessed on a site-specific basis by the NPG. This scheme is only applied to customers that are charging based on the EHC Distribution Charging Methodology (EDCM). In addition to this, NPG has indicated that the option of non-firm connection is also offered to DG customers, to all types of technologies. The methodology for managing the generation output in case of network constraints (capacity, amps, or voltage) is LIFO. There are no curtailment caps at the moment and DG customers make their own calculations taking in consideration the potential constrained effect on the commercial viability of their schemes. Compensation is not applicable because curtailment cap has not been defined.

Except for Orkney ANM Project, it is difficult to find on-going non-firm connection schemes across the different trials. DNOs are still discussing the technical and commercial conditions that allow the management of interruptible connections. Regarding the business as usual practice, the previous findings suggest that interruptible connections are offered across the four DNOs (to DG customers or/and demand customers), however DNOs do not publicly specify the terms and conditions for managing these kinds of connections.

4. Cost benefit analysis of the preferred UK Power Networks FPP connection proposal

4.1 Introduction

The aim of this section is to evaluate the benefits and costs under different scenarios of the UK Power Network's offer to wind generation developers that required a connection within the FPP trial area. The introduction of solar PV and anaerobic digestion generators within this area has been also

[13] See: http://webarchive.nationalarchives.gov.uk/+/http://www.cabinetoffice.gov.uk/media/cabinetoffice/strategy/assets/scottishpower.pdf

[14] See: http://www.northernpowergrid.com/som_download.cfm?t=media:documentmedia&i=1001&p=file

assessed. We believe that results from this analysis may be extrapolated to other DNOs that are facing a similar situation of network constraints.

UK Power Networks has proposed to different developers a variation of their existing connection offer which requires them to manage the output of generators under an ANM scheme[15] in the constrained trial area (March Grid). The constrained area is driven by the excessive reverse power that flows on the existing 45 MVA transformers and only interruptible connections are now possible in this area. Generators have been informed of the maximum expected curtailed energy, the associated connection costs (FPP connection costs) and reinforcement costs (FPP reinforcement costs) in case of seeking for a firm connection. The maximum percentage of curtailed energy is constant across generators and has been estimated in 5.33% with an average reduction of 1.6% percentage points of the generators' capacity factor (set at 30% for wind generation) with a total of 11.853 MW of micro PV (outside of ANM control). This represents average curtailment over the year. It was assumed that demand is fixed and that there are no network upgrades during the project lifetime. The interruptible capacity quota has been fixed at 33.5 MW (Baringa-UK Power Networks, 2012). The results are presented in four different scenarios. Except for one scenario, it has been assumed that reinforcement costs are going to be paid only by generators (no use of system assets). Finally, this study also involves a sensitivity analysis exercise in which different demand growth scenarios are simulated.

4.2 Data collection and assumptions

Data have been collected from different sources such as OFGEM, DECC, UK Power Networks, Baringa and others. All figures have been adjusted to 2012 prices. The lifetime of the projects has been estimated in 20 years (2014 is the starting year). Some of the assumptions made in this study are based on those proposed by Baringa in the Reinforcement quota calculation for March Grid Report (Baringa-UK Power Networks, 2013). In general, it has been assumed that demand remains fixed over the project lifetime. This means that the size of installed capacity is the same at the beginning and at the end of the project lifetime. Carbon emission savings generated by the renewable projects under the four proposed scenarios have not been estimated because it is assumed that government support schemes (such as FIT and ROC) already include these benefits in their respective rates. The following subsections present the variables that are involved in the Cost Benefit Analysis (CBA) and provide details about data collection, assumptions, formulas and values. Appendix 1 shows the lists of variables, formulas and assumptions.

4.2.1 Generation and connection Costs

Generation costs are composed of capital expenditures (CAPEX) and operating expenditures (OPEX). Generation costs related to wind and anaerobic digestion CHP (AD CHP) generation were obtained from DECC (2012b). The following table summarises the generation costs by type of technology and size of installed capacity projected to 2014 (2012 prices).

[15] FPP customers received the connection offer on 1 March 2013. The offer includes: (1) interruptible connection agreement template, (2) briefing document that explains the rules of FPP and calculation of the capacity quota and (3) curtailment estimates for now and worst case scenario.

Table 4: Generation Costs

Generation Costs (2012 prices) Year 2014	Units	Wind>5MW	Wind<=5MW	Anaerobic Digestion (AD CHP)	Solar PV (250-5000KW)
CAPEX	£/KW	1,198.4	1,188.1	1,919.9	1,053
OPEX					
Fixed OPEX	£/MW/y	30,456.4	25,376.4	363,062.4	
Variable OPEX	£/MWh	3.1	3.1	20	
Insurance	£/MW/y	6,375.5	5,437.8	57,924.4	
Connection and grid charges	£/MW/y	10,008.7	8,536.4	8,646.2	
Marginal OPEX	£/KW/y				22

These cost assumptions have been used in the most recent Renewables Obligation Banding Review Analysis (period 2013/17). There are three project cost ranges: high, median and low for different groups of installed capacity for each renewable technology. For the CBA, low figures instead of median figures have been used[16]. CAPEX include construction and predevelopment costs and it is assumed that for future projections the steel prices remain constant in real terms. OPEX have been disaggregated into fixed and variable costs. Insurance and connection and grid charges have been specified by separately. DECC provides CAPEX and OPEX data for selected years. The respective cost growth rates (capex, opex) computed between periods 2010 and 2030 were used as reference for cost projections. Regarding solar PV, generation costs were collected from DECC (2012a). This report presents the updated solar PV costs that have been used for modelling the UK Feed-In Tariff (FIT). Parsons Brinckerhoff (PB) was appointed by DECC to elaborate this study. Only one range of solar PV costs (capex, opex) is provided.

It is noteworthy that fuel prices regarding AD CHP have not been included in the previous table. DECC has estimated them separately. The fuel cost figure is £ 18/MWh (DECC, 2011). This study assumes that this value will be constant (in real values) over the project lifetime. In terms of connection and reinforcement costs[17], these have been estimated by UK Power Networks for specific customers that required connections within the trial area. Specific cost assumptions have been made in some scenarios when data were not available, especially for some additional wind farm connection costs (Scenario 2, 3 and 4) and for solar PV connection costs (Scenario 3). These assumptions are explained in section 4.3.

4.2.2 Embedded benefits

[16] A review of different sources supports this preference. The average of the median figures estimated by DECC are still quite high (around 1,653 £/kW, 2011 prices). A different number of studies have estimated that CAPEX regarding wind generation developers are between 1,000 £/kW and 1,375 £/kW (Redpoint, 2009; Rubino, 2011). In addition, see report from Ecotricity at the Energy of Climate Change Committee (2012) report. Thus, based on this evidence, we find appropriate to select the low range of costs estimated by DECC.

[17] Reinforcement costs are £4.1m. These costs are associated with the replacement of specific transformers that will allow an increase in the system capacity (applicable to the March Grid constrained area) up to 90 MW.

Embedded benefits refer to those costs that generators may save when they are directly connected to the distribution network instead of the transmission network. Suppliers that contract with distributed generators can also benefit from these avoided costs due to the less use of the national grid and also benefit by the reduction of distribution losses when enter into a connection agreement with a distributed generation customer. In general, the avoided costs are related to the TNUoS charges, to the BSUoS charges and to the transmission and distribution losses. This study considers six specific embedded benefits which have been already identified in Baringa-UK Power Networks (2013).

The first two embedded benefits are related to the avoidance of balancing service costs by generators and suppliers in the same proportion (ratio BSUoS: 50:50). These have been classified as generator avoidance balancing charges and supplier avoidance balancing charges. BSUoS figures are represented by the average of the last three year' annual BSUoS charges. The estimated benefit value is the same for each party and is £1.348/MWh (net of Residual Cashflow Reallocation Cashflow – RCRC[18]). The following two embedded benefits are related to the avoidance of transmission losses. In this case, the ratio is 45% for generators and 55% for suppliers (further details are provided in section 4.2.3). These two benefits are classified as: generator transmission loss reduction and supplier transmission loss reduction. The first one is computed by the product of the respective transmission loss ratio, the average transmission losses and the wholesale electricity gate price. The estimation of the second one is very similar but considers the National Balance Point (NBP) electricity price instead[19]. Embedded benefits from the distribution losses are represented by the product of the time weighted average of UK Power Networks Losses (see section 4.2.3 for further details) and the NBP electricity price. Generators can also benefit from negative DUoS (they are paid to use the network). The value of £0.51/MWh has been taken based on the estimations made by Baringa-UK Power Networks (2013). In agreement with Baringa-UK Power Networks (2013), we have assumed that due to the intermittency of the FPP generators, there are no TNUoS benefits (no triad benefits). Appendix 1 illustrates the formulas for computing the embedded benefits.

4.2.3 Transmission and distribution losses

Following the Balancing Settlement Code (BSC), the ratio of transmission losses is allocated as follows: 45% to non-interconnector BM Units in Delivering Trading Units (generator's share) and 55% to non- interconnector BM Units in Offtaking Trading Units (supplier's share). Based on Elexon (2012) the current average of transmission losses has been estimated at 2%. Line Loss Factor (LFF) accounts for the distribution losses and are estimated by DNOs using a generic method (usually for LV and HV networks) or a site specific method (usually for EHV networks). Similar to Baringa-UK Power Networks (2013), we have used the time weighted average of UK Power Network's LLF value for HV networks based on the values suggested in the Use of System Charging Statement for Easter Power Networks effective from 1st April 2013. This value is 4.9% for period 5 (all year)

[18] See the following link for the BSUoS and RCRC costs historical data respectively: http://www.nationalgrid.com/uk/Electricity/Balancing/bsuos/sfpricescharges/. https://www.elexonportal.co.uk/news/latest?cachebust=71bh7gzck9. RCRC represents the payment/charge that is redistributed amongst all BSC parties in proportion to their volume of credit energy.

[19] $NBP\ electricity\ price = wholesale\ electricity\ gate\ price + generator's\ transmission\ losses + BSUoS\ costs.$

4.2.4 Revenues

Generator's revenues are represented by the market revenue for sales of electricity and the value of incentives such as FIT, ROCs and LECs, if they are not curtailed. The wholesale electricity price projections that this study makes use have been estimated by Baringa (based on the Redpoint Energy's GB Power Market Report). The estimations made specific assumptions regarding GDP and demand, oil prices, gas prices, coal prices and EUA prices. In terms of incentives, FIT were taken from the OFGEM's FIT rates report applied to the period 01 April 2013 to 31 March 2014 for wind generation, 30 September 2011 to 31 March 2014 for AD, and 1 May 2013 to 30 June 2013 for solar PV installations. ROC data (buyout price) for wind installations have been collected from the OFGEM report: The Renewables Obligation buyout price and mutualisation ceiling 2013/14 (OFGEM, 2013a). Total ROC revenue is composed of the buyout price plus the value of recycled revenue. Similar to the exercise made by Baringa -UK Power Networks (2013), the recycle revenue value (recycle price) has been estimated at 10% of the buyout price. ROC Banding data for wind installations were collected from DECC (2012b). This study refers to the renewable obligation banding review for the period 2013/17. In terms of LEC prices, we have used the estimations made by Baringa (Redpoint's Reference Case Study) across the project lifetime.

4.2.5 Load factors

Load factors depend on the type of technology. A load factor of 30% is suggested for wind generation (based on the wind capacity factor recommended in the evaluation of non-firm generation curtailment at March Grid, performed by SmarterGrid Solutions - SGS). For solar PV installations the load factor is represented by the average of the last two years estimated by DECC (period 2012/13 and 2013/14). This average is 9.7%. Generation and capacity actuals (from Digest of UK Energy Statistics and ROC register) have been considered for the estimation of load factors. Regarding AD CHP, we have used the value estimated by Pöyry (2013) in the most recent updated modelling for renewable obligation banding - this value has been estimated at 84%.

4.2.6 Financial ratio assumptions

This study suggests a discount rate of 10%. This value is in line with that set by Baringa-UK Power Networks (2013) and with the rate applied by DECC for the calculation of renewable levelised costs (DECC, 2012b, Annex D) related to the levels of banded support under the Renewable Obligation for the period 2013/17. The corporate tax for the period 2014 has been set in 21% and will remain constant over the project lifetime. This value is in line with the UK corporation main rate to be applied in that year.

4.2.7 Power purchase agreement

Figures such as wholesale electricity, embedded benefits and incentives (ROC, LEC), are subject to power purchase agreements. We have applied the same rates proposed by Baringa-UK Power Networks (2013) that were used to determine the reinforcement quota calculation for March Grid. These values are as follows: wholesale electricity price and LEC (85%), ROC (90%) and embedded benefits (50%).

4.3 Cost benefit analysis

As previously mentioned, four scenarios have been proposed, see Table 5. All scenarios assume a fixed demand and the first three scenarios assume only one level of curtailment across the project lifetime in case of non-firm connections (set at 0.33% with a total interruptible capacity of 18 MW or 5.33% with full non-firm capacity quota). Scenario 3 is the only one which includes solar PV and AD CHP generators. In the rest of the scenarios a 100% wind generation mix has been assumed. In addition, the first three scenarios are scenarios where the option of network upgrade has not been contemplated over the project lifetime. The last scenario (Scenario 4) reflects a more dynamic situation where network upgrade is considered as an option by 2019/2020. The upgrade would allow to increase the system capacity (from 33.5 to 90 MW) to its maximum limit and to offer firm connection agreements to all generators by 2019/2020. Scenario 4 assesses the project NPV under both situations of network upgrades (in 2019 and 2020) and evaluates the value of accelerating the connection of the additional 56.5 MW by comparing the NPV of the projects considering the network upgrade in 2020 and 2019. The following table summarises the previous explanation.

Table 5: Scenarios

Scenarios	Non- firm capacity		Firm capacity [1/]		Generation Mix		
	full	partial	full	partial	wind	solar PV	AD CHP
Scenario 1		18 MW		18 MW	100%		
Scenario 2	33.5 MW			33.5 MW	100%		
Scenario 3	33.5 MW			33.5 MW	82.84%	13.43%	3.73%
Scenario 4	33.5 MW		90 MW		100%		

[1/] Due to the addition of 56.5 MW (33.5+56.5=90 MW) by 2019/2020.

From the previous table it is noticed that even though the maximum firm capacity available is 90 MW after the respective network reinforcement, we observe that for Scenarios 1, 2 and 3 only partial firm capacity has been assumed in order to make comparisons with the option of full non-firm capacity (up to 33.5 MW). Scenario 4 is the only one which considers the possibility to contract 100% of firm capacity (up to 90 MW). Each scenario evaluates the costs and benefits for smart and reinforcement connection options. The smart connection refers to the non-firm or interruptible connection offered to generators under the FPP scheme. The reinforcement alternative refers to a firm connection offer, which involves two kinds of costs: FPP connection costs and FPP reinforcement costs. Cost figures are represented by generation costs, connection costs and reinforcement costs[20] (in case of firm connections). Benefits are represented by electricity revenues, incentives (FIT, ROC, LEC) and embedded benefits. The net present value of each project is

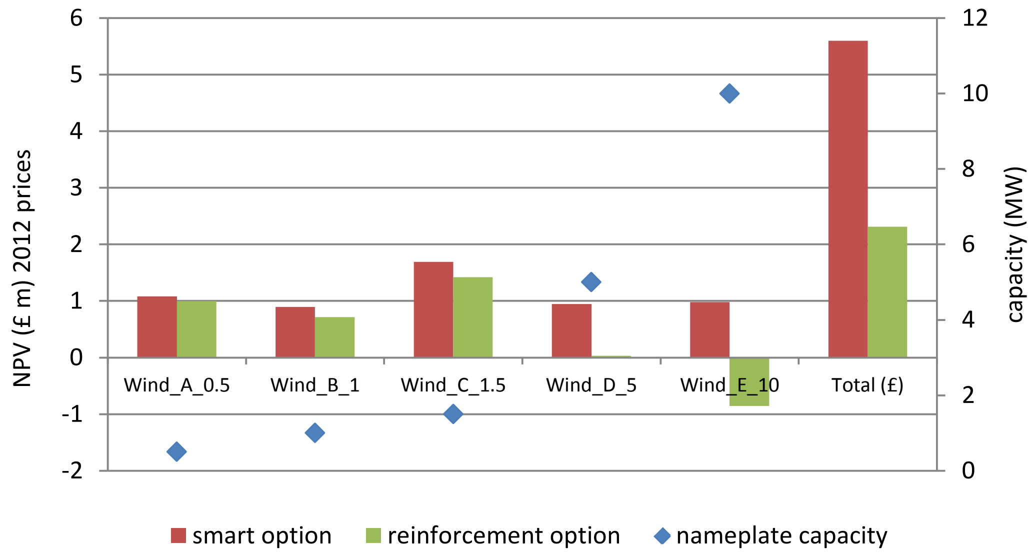
[20] Generation costs depend on the type of technology and are composed of capex, opex and fuel costs in the case of AD CHP generation. Connection costs are those related to the FPP connection offer (to contract non-firm/interruptible capacity) prepared by UK Power Network, which includes contestable and non-contestable associated works. Connection costs regarding the first five wind farms from each scenario refer to real cost figures which have already been offered by UK Power Networks to different wind farms. For the rest of wind generators, we use these costs as reference in order to estimate the respective connection costs. Reinforcement costs (or FPP reinforcement costs) which amount to £4.1m are expected to be shared across all generators proportionally to their respective nameplate capacity only in Scenario 1, 2 and 3 and to be borne by demand in Scenario 4. Thus a generator that asks for a firm connection under the FPP scheme will be subject to FPP connection costs plus FPP reinforcement costs.

calculated by the difference between total benefits and costs (discounted at 10%) over the project lifetime. In addition, for each scenario total savings for selecting the smart connection option or the reinforcement option instead of the Business as Usual option – s16 have also been estimated[21]. Specific scenarios of demand growth and their effect on the project NPV for each scenario are also analysed. Finally, the impact that embedded benefits has on the project NPV is also evaluated. Specific assumptions have been made for each scenario. Appendix 2 summarises the specifications for each scenario.

4.3.1 Scenario 1

The aim of this scenario is to estimate the project NPV assuming a partial interruptible capacity quota. Based on the group of possible connected generators evaluated by SGS in the estimation of curtailed energy, five wind generators with a total installed capacity of 18 MW were selected. Taking into consideration the projections of annual energy estimated curtailment (per MW connected) made by SGS, the value of 0.33% was taken as reference (instead of the average 5.33%) to estimate the curtailed energy for each wind generator. Results suggest that in general the option of smart connection is financially more beneficial than the reinforcement alternative. In this case the project NPV is largely driven by reinforcement costs required for firm connections because these costs (£4.1m) have been fully allocated across the five generators. When the smart connection is chosen, Wind_D_5 and Wind_E_10 are those that benefit the most with an important increase in their respective project NPV. Curtailment costs under this scenario do not affect significantly the NPV of the projects because the percentage of curtailed energy is very low (0.33%). It is observed that under the option of reinforcement all generators, except for Wind_E_10, get a positive NPV. An explanation that supports this fact could be the high share of reinforcement costs that this wind generator is subject to, around 56%. Figure 2 presents the results including embedded benefits.

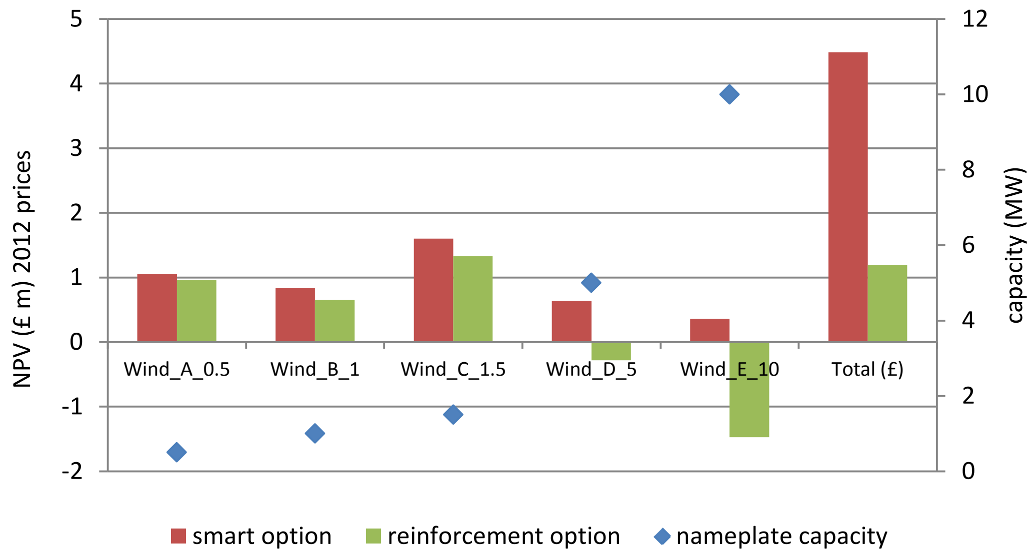
Figure 2: Scenario 1 Results – With Embedded Benefits



[21] BAU offer refers to the s16 connection offer.

The exclusion of embedded benefits produces a different impact across the projects however the smart connection option is still the best option for wind generators. In general, the total project NPV decreases on average 20% (smart connection) and 48% (reinforcement option). Wind_E_10 is the most affected due to an important reduction of its NPV in both kinds of connection options. The least negatively affected are the smallest ones, Wind_A_0.5, Wind_B_1 and Wind_C_1.5. Figure 3 illustrates the project NPV across all generators without considering embedded benefits.

Figure 3: Scenario 1 Results – Without Embedded Benefits



In summary we can say that under Scenario 1:

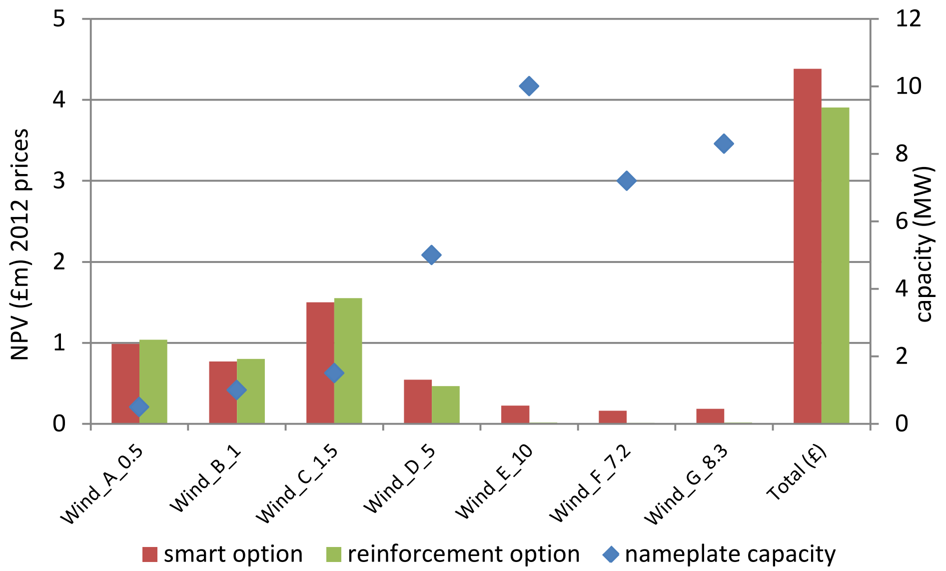
- Under the smart connection option most part of generators connect with total NPV equal to £5.6m (with embedded benefits). The exclusion of embedded benefits reduces the project NPV in 20%.
- Under the reinforcement option 4 out of 5 wind generators connect with total NPV equal to £2.3m (with embedded benefits). A decrease of 48% is observed in the project NPV when embedded benefits are not taken into account.
- The smart connection option is the best option in both cases with or without embedded benefits. This is explained due to the avoidance of high shared costs especially by large wind generators. If the option of reinforcement is selected, a decrease of 59% and 73% of the project NPV is noticed, with or without embedded benefits respectively.
- Total savings for selecting a smart connection offer (instead of the BAU offer) are £9.8m (£0.54m/MW).
- Total savings for selecting a reinforcement connection offer (instead of the BAU offer) are £5.7m (£0.32m/MW).

4.3.2 Scenario 2

The purpose of this scenario is to evaluate the impact that a full interruptible capacity quota (33.5 MW) has on the project NPV. The generation mix is 100% wind shared among seven generators. This scenario includes the five wind generators from Scenario 1 and two additional generators with nameplate capacity of 7.2 and 8.3 MW (Wind_F_7.2, Wind_G_8.3). The average curtailment rate is the one that SGS has estimated (5.33%) when considering a full capacity quota. Cost data regarding these wind generators were estimated based on those costs from Wind_E_10, due to the similar nameplate capacity. Thus, a pro-rata approach was used for estimating these costs.

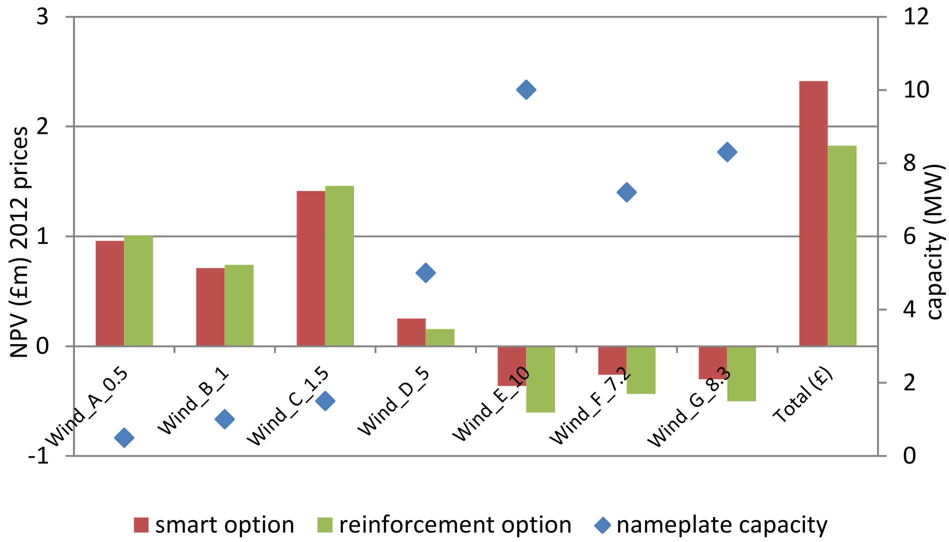
In this scenario, small wind generators with nameplate capacity up to 1.5 MW would be more interested in the reinforcement option. This allows an increase in 5.3% (Wind_A_0.5), 4.3% (Wind_B_1) and 3.3% (Wind_C_1.5) in their respective NPV in comparison with the smart connection option. This is because small generators benefit from the sharing of reinforcement costs over 33.5 MW of total generation. For the rest of wind generators, the option of smart connection would be much more profitable. For instance, the project NPV related to Wind_E_10 would increase from £0.02m to £0.2m if the smart connection is selected. This fact is explained by the avoidance of reinforcement costs. Large generators are subject to a higher share. This also makes that the project NPV of this wind generator be positive when the reinforcement option is selected, in comparison with the previous scenario. We also observe the difference that exists between the total project NPV under the smart connection and the reinforcement option (£0.5m) in comparison with Scenario 1 (£3.3m). This fact may be explained by the decrease in reinforcement costs due the lower share of costs that has been allocated to each wind generator (total reinforcement costs are shared across seven wind generators instead of five wind generators). The following figure illustrates the results.

Figure 4: Scenario 2 Results - With Embedded Benefits



When embedded benefits are excluded from the CBA, the reinforcement option is still the best option for the small wind generators (up to 1.5 MW). Large wind generators are the most affected due to negative NPV in both under the smart connection or reinforcement option. However, the selection of the reinforcement option produces higher losses to theses generators. Total project NPV decreases on average 45% (smart connection) and 53% (reinforcement option) when comparing with the previous results which include embedded benefits. Wind_E_10 is the most negatively affected with losses of £0.4m (smart connection) and £0.6m (reinforcement option). The following figure depicts the results.

Figure 5: Scenario 2 Results – Without Embedded Benefits



In summary we can say that under Scenario 2:

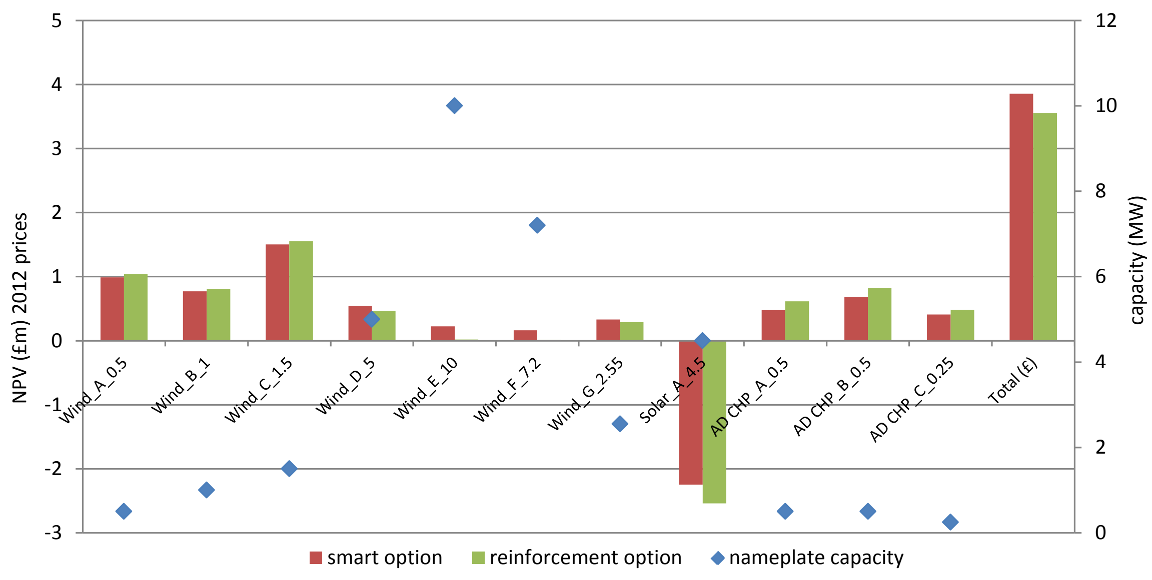
- Under the smart connection option all generators connect with total NPV equal to £4.4m (with embedded benefits). The exclusion of embedded benefits reduces the project NPV in 50%.
- Under the reinforcement option all generators connect with total NPV equal to £3.9m (with embedded benefits). A decrease of 53% is observed in the project NPV when embedded benefits are not taken into account.
- The reinforcement connection option is the best option for small generators (up to 1.5 MW) in both cases including or excluding embedded benefits. Project NPV is higher due to lower share of costs.
- The smart connection option is the best option for large generators (from 5 up to 10 MW) only when embedded benefits are taken into consideration. Project NPV is higher due to the avoidance of the high share of reinforcement costs. If embedded benefits are excluded, large generators are exposed to negative NPV regardless the type of connection option.
- Total savings for selecting a smart connection offer (instead of the BAU offer) are £16.3m (£0.49m/MW).
- Total savings for selecting a reinforcement connection offer under the FPP scheme (instead of the BAU offer) are £12.2m (£0.36m/MW).

4.3.3 Scenario 3

In this scenario, we want to understand to what extent the composition of the energy mix affects the project NPV. The energy mix is composed of wind, solar PV and AD CHP with full interruptible quota (33.5 MW). Five new generators were added in addition to the first six wind farms from Scenario 2, with nameplate capacity of 2.55, 4.5, 0.5, 0.5 and 0.25 MW respectively. Similar to the estimations made in Scenario 2, a curtailment rate of 5.33% was used as reference and the connections costs regarding Wind_G-2.55 and Solar_A_4.5 were calculated based on the connection costs associated with generators with similar nameplate capacity (1.5 and 5 MW respectively). Connection costs regarding the three AD CHP generators were provided by UK Power Networks.

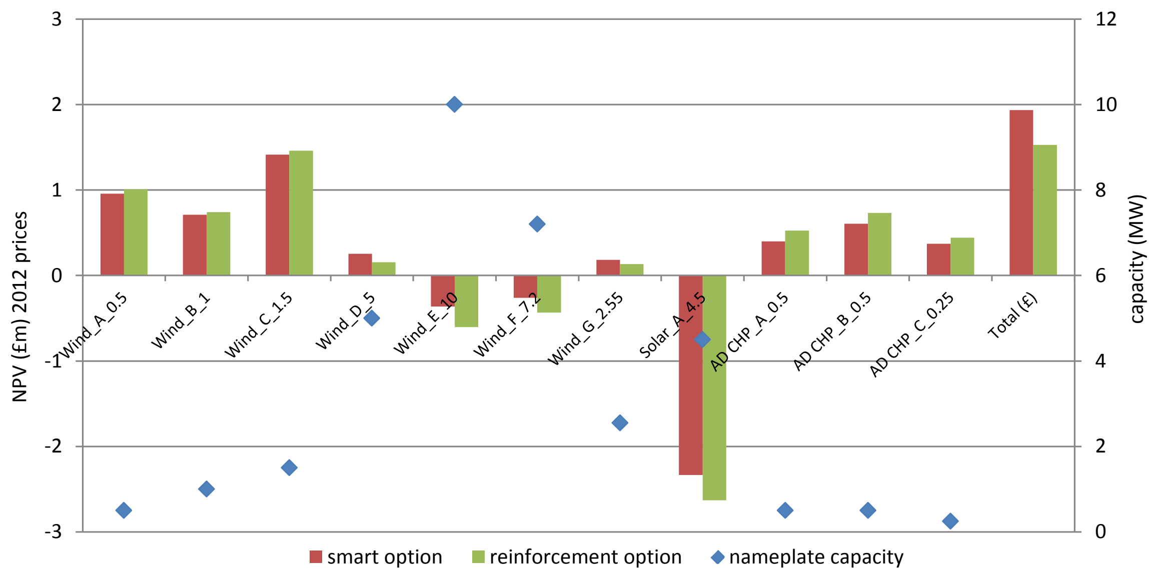
Under this approach, small wind farms (up to 1.5 MW) and AD CHP generators would still be interested in negotiating a reinforcement connection agreement instead of a smart connection agreement. AD CHP_A_0.5 would get the maximum increase (around 28%) in its project NPV if the reinforcement option is selected instead of the smart connection option. The low share of reinforcement costs could explain the preference for small generators in deciding by the reinforcement option. The Solar_A_4.5 generator presents a negative project NPV regardless the type of connection. A sensitive analysis that considers different levels of CAPEX reduction associated with the solar generator shows that even with a reduction of 30% in CAPEX, the project NPV is still negative (£1.1m for smart connections and £1.4 for reinforcement option). This result would suggest that solar PV generators are those that would benefit the least given the current assumptions. Large generators would prefer the smart connection option. In terms of AD CHP generators, the project NPV is moderately driven by fuel costs. A sensitive analysis indicates that if these costs are reduced by 30% (£12.6/MWh), the respective project NPV would increase importantly, by 32% (smart connection) and 26% (reinforcement option). We also observe that the introduction of solar PV and AD CHP generators produced a decrease in the total project NPV regardless the type of connection, in comparison with those figures from Scenario 2. The reason for this reduction is due to the negative NPV of the Solar_A_4.5 generator. Figure 6 shows these results.

Figure 6: Scenario 3 Results - With Embedded Benefits



The exclusion of embedded benefits affects negatively the total project NPV with a reduction of 50% (smart connection) and of 57% (reinforcement option). Small generators (up to 1.5 MW) have still a preference for the reinforcement option. The smart connection option would still be attractive to the rest of wind generators with capacity greater than 1.5 MW, excluding Wind E_10 and Wind_F_7.2. Solar_A_4.5 generator remains with a negative NPV. Figure 7 illustrates these results.

Figure 7: Scenario 3 Results - Without Embedded Benefits



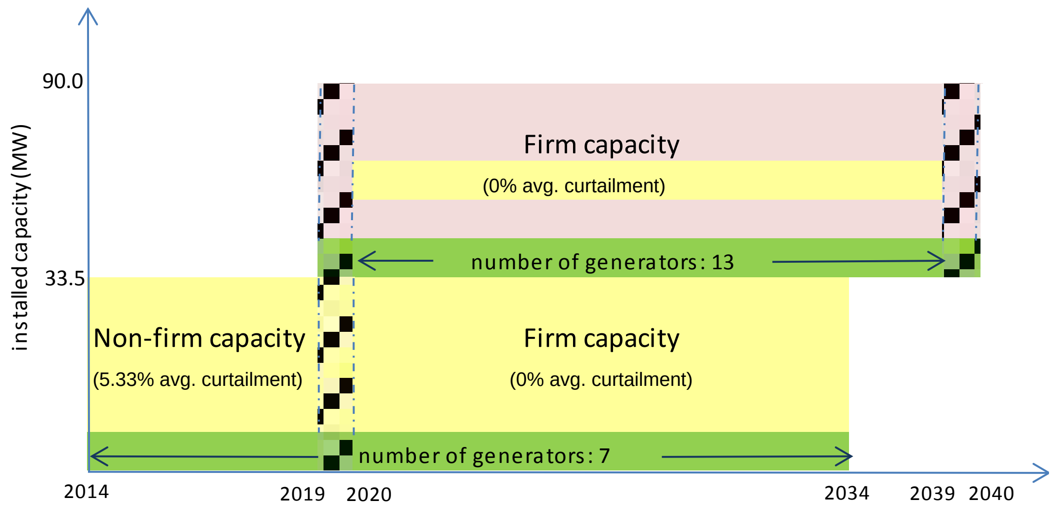
In summary we can say that under Scenario 3:

- Under the smart connection option all generators (apart from Solar_A_4.5) connect with total NPV equal to £3.9m, including embedded benefits. If embedded benefits are excluded, not all generators connect (especially large wind generators) and total NPV decreases in 50%.
- Under the reinforcement option all generators connect (apart from Solar_A_4.5) with total NPV equal to £3.6m, taking into consideration embedded benefits. If these benefits are excluded, again not all generators connect (large wind generators) and a reduction of 57% in total NPV is observed.
- Solar PV generator will not connect regardless the type of connection.
- The reinforcement connection option is the best option for small generators (up to 1.5 MW) with or without embedded benefits. Project NPV is higher due to lower share of costs.
- The smart connection option is the best option for large generators (from 7.2 up to 10 MW) when embedded benefits are included. Project NPV is higher due to the avoidance of reinforcement costs. However, large generators get always a negative NPV if these benefits are excluded, regardless the type of connection.
- Total savings for selecting a smart connection offer (instead of the BAU offer) are £22.3m (£0.7m/MW).
- Total savings for selecting a reinforcement connection offer under the FPP scheme (instead of the BAU offer) are £18.3m (£0.5m/MW).
- Project NPV regarding AD CHP generators is moderately affected by their respective fuel costs. A reduction of up to 30% of fuel costs would produce an increase in the project NPV up to 32% (smart connection) and 26% (reinforcement option)

4.3.4 Scenario 4

This scenario is a variation of Scenario 2 and proposes a more dynamic approach. The purpose of this scenario is to evaluate how the project NPV is affected when considering in the medium term the option of full firm capacity (up to 90 MW) and to value the benefits of accelerating the connection of additional capacity by one year. Thus, this scenario contemplates the possibility of network upgrade (reinforcement) after five/six years of the beginning of operation. This is represented as follows:

Figure 8: Installed capacity and curtailment level over time



The assumptions made under this scenario are summarised as follows:

a. A total of 20 wind generators are expected to be connected after 2019/20. Seven of these are connected by 2014 (which are the generators included in Scenario 2). The rest of generators (13 in total with an aggregated nameplate capacity of 56.5 MW) are additional wind generators that are identical to the previous seven (in terms of installed capacity and connection costs) and that will be connected in 2019/20. Appendix 2 shows these generators.
b. Network upgrade allows to increase the installed capacity (up to 90 MW) and to provide firm connections to all wind generators.
c. Network upgrade costs are fully covered by demand.
d. Curtailed energy is set at 5.33% for the former seven wind generators from period 2014 to 2019/20. After this, a firm connection is offered to all generators (20 in total), thus curtailed energy is 0% from period 2019/20 to 2034 (seven first generators) and from period 2019/20 to 2039/40 (rest of generators).
e. Incentives rates and bandings (FIT, ROC) remains the same in real values.
f. The project NPV is assessed in two consecutive years in order to estimate the value of accelerating the connection of 56.5 MW by one year (and reach the maximum firm capacity equal to 90 MW). These years are 2019 and 2020. The difference of the project NPV under both years represents the value of accelerating these connections. Figure 8 explains the allocation of installed capacity and curtailment over the project lifetime.

The project NPV results (which include a network upgrade in 2019 and 2020) suggest that the project NPV associated with each generator in both situations are financially attractive to all of them. The sum of the project NPV related to the former seven generators represents 34% (with network upgrade in 2019) and 35% (with network upgrade in 2020) of the total project NPV. We observe that even though the second set of wind generators are similar to the former ones, their respective project NPV differ. For instance, small wind generators regarding the first group have a higher project NPV in comparison with those small wind generators from the second group. For example, if an upgrade is made in 2019, Wind_A_0.5 NPV would be £1m and Wind_H_0.5 NPV would be £0.7m, even though having the same installed capacity (0.5 MW). This fact can be explained by different reasons, among these are: (1) the time difference in getting connected (Wind_A_0.5 begins operation in 2014 while Wind_H_0.5 in 2019) and (2) the associated discount factors related to Wind_H_0.5 which are much lower on average during the project lifetime[22].

The difference between the total project NPV considering a network upgrade in 2019 and 2020 respectively provides the value of accelerating the connection of additional capacity by one year. This value is £0.7m which means a ratio of £0.01m/MW. The following table shows the results.

Table 6: Scenario 4 Results – With Embedded Benefits

Generator	Capacity MW	Project NPV (£) upgrade in 2019	Project NPV (£) upgrade in 2020
Wind_A_0.5	0.5	1,046,466	1,039,867
Wind_B_1	1	847,827	839,313
Wind_C_1.5	1.5	1,618,790	1,606,019
Wind_D_5	5	796,153	769,592
Wind_E_10	10	699,686	649,531
Wind_F_7.2	7.2	503,774	467,662
Wind_G_8.3	8.3	580,739	539,111
Sub total		**6,093,436**	**5,911,095**
Wind_H_0.5	0.5	721,377	661,883
Wind_I_1	1	648,663	601,865
Wind_J_1.5	1.5	1,181,308	1,092,173
Wind_K_5	5	1,016,967	985,373
Wind_L_10	10	1,476,269	1,466,226
Wind_M_7.2	7.2	1,061,378	1,054,286
Wind_N_8.3	8.3	1,225,303	1,216,967
Wind_O_0.5	0.5	721,377	661,883
Wind_P_1	1	648,663	601,865
Wind_Q_1.5	1.5	1,181,308	1,092,173
Wind_R_5	5	1,016,967	985,373
Wind_S_10	10	1,476,269	1,466,226
Wind_T_5	5	1,016,967	985,373
Sub total		**13,392,815**	**12,871,667**
Total		**19,486,250**	**18,782,763**

Similar to the previous scenarios, the impact that embedded benefits have on the project NPV is also evaluated. The following table shows the results.

[22] All figures are expressed in 2012 prices. Based on a discount rate of 10%, the discount factor for computing the project NPV applied by 2014 is 0.8264 and by 2019 is 0.5132.

Table 7: Scenario 4 Results – Without Embedded Benefits

Generator	Capacity MW	Project NPV (£) upgrade in 2019	Project NPV (£) upgrade in 2020
Wind_A_0.5	0.5	1,016,129	1,009,634
Wind_B_1	1	787,153	778,846
Wind_C_1.5	1.5	1,527,779	1,515,318
Wind_D_5	5	492,785	467,256
Wind_E_10	10	92,948	44,859
Wind_F_7.2	7.2	66,923	32,299
Wind_G_8.3	8.3	77,147	37,233
Sub total		**4,060,865**	**3,885,445**
Wind_H_0.5	0.5	700,869	642,988
Wind_I_1	1	607,646	564,075
Wind_J_1.5	1.5	1,119,782	1,035,488
Wind_K_5	5	811,880	796,422
Wind_L_10	10	1,066,096	1,088,324
Wind_M_7.2	7.2	766,053	782,197
Wind_N_8.3	8.3	884,860	903,309
Wind_O_0.5	0.5	700,869	642,988
Wind_P_1	1	607,646	564,075
Wind_Q_1.5	1.5	1,119,782	1,035,488
Wind_R_5	5	811,880	796,422
Wind_S_10	10	1,066,096	1,088,324
Wind_T_5	5	811,880	796,422
Sub total		**11,075,340**	**10,736,521**
Total		**15,136,204**	**14,621,966**

The exclusion of embedded benefits in both situations of network upgrade makes the total project less profitable with a decrease of 22% in their respective project NPV. The value for accelerating the connection of additional capacity shows a reduction in comparison with the case in which embedded benefits are taking into account. This value is £0.5m with a ratio of £0.01m/MW.

In summary we can say that under Scenario 4:

- All generators connect by 2014 or 2019/20. All NPV figures are positive.
- Small generators would prefer to be part of the first generation group (connected in 2014) due to the possibility of higher project NPV in comparison with those connected in the medium term (2019/20).
- Total savings for selecting a smart connection offer (instead of the BAU offer) are £42.9m (£0.48m/MW).
- The smart connection option with network upgrade in 2019 shows a project NPV equal to £19.5m including embedded benefits. A reduction of 22.3% is observed if embedded benefits are excluded.
- The smart connection option with network upgrade in 2020 has a NPV=£18.8m considering embedded benefits. The project NPV decreases in 22.1% when embedded benefits are not taken into account.
- The NPV of accelerating network capacity by one year is £0.7m with embedded benefits or £0.5m without these benefits.

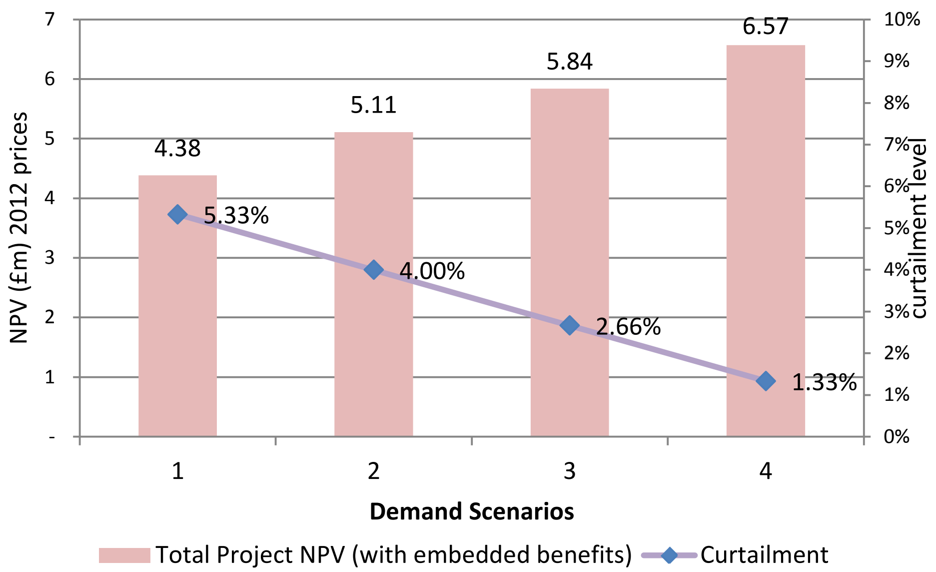
4.3.5 Effect of demand growth on project NPV for scenarios 2 and 3[23]

A sensitivity analysis considering different scenarios of demand growth that produces a reduction in the generation output is evaluated. The scenarios are as follows:

- Scenario A considers a demand growth that allows a reduction of 25% of the curtailed energy (25%*5.33%=4%).
- Scenario B considers a demand growth that allows a reduction of 50% of the curtailed energy (50%*5.33%=2.66%).
- Scenario C considers a demand growth that allows a reduction of 75% of the curtailed energy (25%*5.33%=1.33%).

In relation to Scenario 2, a curtailment level of 4, 2.66 and 1.33% produces an increase of 17, 33 and 50% of the project NPV respectively when embedded benefits are included. If embedded benefits are excluded, the increase would be 29, 58 and 87% respectively.

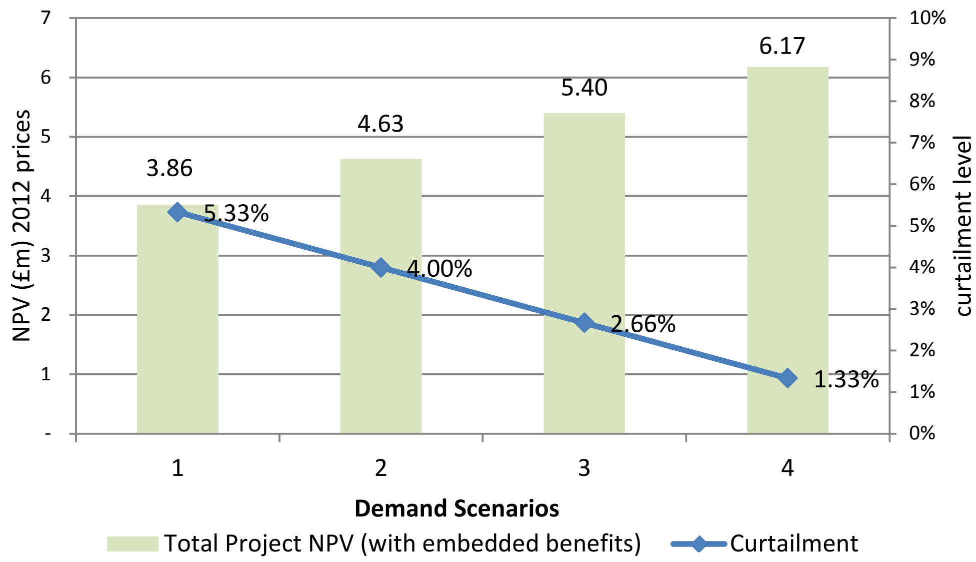
Figure 9: Effect of demand growth (NPV with embedded benefits, smart connection) – Scenario 2



In Scenario 3, the effect of this reduction is more significant. The project NPV would increase in 20, 40 and 60% respectively (including embedded benefits). The no consideration of these benefits would produce an upward trend of the project NPV with an increase of 38, 77 and 116% respectively. The following figure illustrates the effect of demand growth in the project NPV with embedded benefits.

[23] The effect on Scenario 1 has not been analysed due to the low level of curtailed energy (0.33%). Regarding Scenario 4, the option of non-firm connection is only allowed for a short period (5/6 years), thus we find convenient to exclude this from this evaluation.

Figure 10: Effect of demand growth (NPV with embedded benefits, smart connection) – Scenario 3



From this analysis we can conclude that if demand grows up which produces a decrease on curtailed energy, project NPV increases importantly. This effect is more significant when embedded benefits are excluded. Additionally, lower curtailment levels reduce the value of firmness. Project NPV will increase if the level of output decreases, thus there is a point in which the value of a non-firm connection (smart option) exceeds the value of a firm connection (reinforcement option). For instance, in the case of Scenario 2 we observe an upward trend in the number of generators that would prefer the smart connection option when the level of curtailment decreases. Table 8 illustrates this dynamic (green values indicate that the firm connection option would be preferred and red values indicate an opposite effect). With a curtailment level of 1.33% all generators would select the smart connection option.

Table 8: Effect of demand growth on project NPV across generators – Scenario 2

Generator	Capacity (MW)	Difference between firm and non-firm NPV			
		Base - 5.33%	4.00%	2.66%	1.33%
Wind_A_0.5	0.5	52,299	26,581	863	- 24,855
Wind_B_1	1	32,837	- 659	- 34,155	- 67,651
Wind_C_1.5	1.5	49,256	- 988	- 51,232	- 101,477
Wind_D_5	5	- 81,104	- 187,262	- 293,420	- 399,578
Wind_E_10	10	- 207,678	- 408,626	- 609,575	- 810,523
Wind_F_7.2	7.2	- 149,528	- 294,211	- 438,894	- 583,577
Wind_G_8.3	8.3	- 172,373	- 339,160	- 230,456	- 672,734

A similar behaviour is observed in Scenario 3. In general, small generators (up to 0.5 MW) would prefer the option of firm connection. AD CHP generators would select the firm connection option even with a curtailment level as low as 2.66%. All generators would prefer the smart connection option if curtailment level is 1.33%.

Table 9: Effect of demand growth on project NPV across generators – Scenario 3

Generator	Capacity (MW)	Difference between firm and non-firm NPV			
		Base - 5.33%	4.00%	2.66%	1.33%
Wind_A_0.5	0.5	52,299	26,581	863	-24,855
Wind_B_1	1	32,837	-659	-34,155	-67,651
Wind_C_1.5	1.5	49,256	-988	-51,232	-101,477
Wind_D_5	5	-81,104	-187,262	-293,420	-399,578
Wind_E_10	10	-207,678	-408,626	-609,575	-810,523
Wind_F_7.2	7.2	-149,528	-294,211	-438,894	-583,577
Wind_G_2.55	2.55	-41,363	-95,504	-149,644	-203,785
Solar_A_4.5	4.5	-292,464	-333,139	-373,813	-414,488
AD CHP_A_0.5	0.5	132,844	86,990	41,135	-4,719
AD CHP_B_0.5	0.5	132,844	86,990	41,135	-4,719
AD CHP_C_0.25	0.25	73,363	48,701	24,038	-624

4.3.6 Distributional impact of embedded benefits

A distributional impact regarding embedded benefits across generators suggests that embedded benefits related to distribution losses have the highest share (42.5%) and those related to the distribution use of system charges have the lowest share (6.5%). We also observe that suppliers are allocated with the most part of embedded benefits over the project lifetime (69%) and generators are allocated with the rest (31%). Thus, generators would take advantage of this by negotiating cheaper connection costs due the apparent imbalance in the shares of these benefits (between suppliers and generators). The difference in embedded benefits between non-firm and firm is more significant in Scenario 2 and 3 than in Scenario 1, due to the low curtailment rate assumed under non-firm connection (0.33%). The distributional impact also suggests that generators with different technologies but the same nameplate capacity would show a dissimilar share of embedded benefits. This fact is explained by the different load factors that these technologies are subject (30% for wind, 84% for AD CHP). It is expected that generators with the same nameplate capacity and load factors have a similar share of embedded benefits.

5. Final remarks

This study has assessed the different options that UK Power Networks has for connecting renewable capacity (interruptible or firm connection) to the distribution network in the constrained area of March Grid. This study is related to the business opportunities that DG customers could have in deciding between an interruptible or a firm connection. A cost benefit analysis (CBA) was performed taking into consideration the current regulation (subsidies and incentives), the maximum quota capacity for interruptible connection, the generation mix and profile, generation costs and revenues (including embedded benefits), and specific assumptions in terms of curtailment and load factors. A comprehensive review of the main incentives applied to DG and the search of the most recent estimations of generation costs was conducted. In addition, the study also explores the different types of connection (e.g non-firm or firm) and the current initiatives from DNOs that allow interruptible connections. Both types of connection options have advantages and disadvantages and the selection of either connection option will depend on the DG business model and the market and regulatory context. In terms of the current initiatives that involve the offering of interruptible connections with smart solutions, the study shows that these are still in their initial stages across the DNOs. There is no clear evidence of the terms and conditions for managing this kind of connection being part of a business as usual offer.

We aware that results from the CBA performed in this study may be subject to uncertainty due to some static assumptions related to generation mix (and the associated curtailment levels), timescale of network upgrades and demand growth. They also represent a conservative estimate of individual project value, based on the simultaneous connection of all other projects. In reality individual projects that connect early will have higher project NPV due to experiencing lower than modelled curtailment.

Even though the study doesn't specify nor quantify the benefits that DNOs could capture by connecting more DG in their respective networks, we believe that this first exercise is very useful to attract the attention of potential DG customers (especially those in the March Grid Area) searching for new business opportunities. This may contribute to acceleration of DG connection to the distribution grid which brings direct benefits for the society such as the achievement of renewable targets, avoidance/delay of network reinforcement, avoidance/reduction of system charges and reduction of technical losses.

Results from the CBA suggest that under Scenario 1 the smart connection option (with or without embedded benefits) is financially more convenient than the reinforcement connection alternative (with or without embedded benefits) and the BAU option. This is explained by the avoidance of reinforcement costs, which were divided across the five generators. Large wind generators benefit the most due to the avoidance of the high share of reinforcement costs. In Scenario 2, small generators (up to 1.5 MW) would be more interested in the reinforcement option (with or without embedded benefits) than in the smart and BAU options. For generators with a nameplate capacity higher than 5 MW the smart connection option would be more profitable due to the avoidance of reinforcement costs, in both cases including of excluding embedded benefits. Results from Scenario 3 also suggest that small generators will select the reinforcement option and that large generators will opt for the smart connection option. The modelled Solar PV generator got a negative NPV under both connection options, including or excluding embedded benefits, thus this generator will not connect. The project NPV of AD CHP generators are moderately affected by fuel prices however they still got a positive NPV, thus the three AD CHP generators will connect, being the reinforcement option the preferred one. In Scenario 4, the results indicate that the project NPV associated with each generator in both situations (with network upgrade in 2019 or 2020) is financially attractive to all of them. The value for accelerating the connection of additional capacity (56.5 MW) by one year has been estimated in £0.7m and in £0.5m when embedded benefits are excluded. The societal benefit would need to subtract the cost of advancing the additional capacity by one year.

The effect of demand growth on project NPV for Scenario 2 and 3 has been also evaluated. The higher the demand the lower the level of curtailment. The study also demonstrates that lower curtailment levels tend to reduce the value of firmness, being AD CHP generators the ones that are less affected. The CBA also evaluates the impact that embedded benefits have on the NPV project. The distributional impact shows that suppliers are those with the largest proportion of embedded benefits and generators with the lowest. This would increase the possibility for generators to negotiate cheaper connection costs.

In summary, the natural selection of generators will depend on the connection offers that UK Power Networks have agreed and on the projections made for allocating more capacity in the trial area. However, based on our results, it seems to be that, in general, small wind generators will always have advantage over the larger generators (higher NPV/MW). In addition, solar PV generators would struggle to get a positive NPV over the project lifetime and AD CHP generators will connect without any concerns. The challenge for UK Power Networks is to find the best combination of wind generators (in terms of number of generators connected and allocated capacity), the right time to upgrade the network (triggered by generators or demand) and the right cost allocation across generators and suppliers in order to allow cheaper connection costs.

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Appendix 1: List of variables

Variable	Value/Formula
Costs	
CAPEX	Depends on technology. It includes construction costs and predevelopment costs, see Table 4.
OPEX	Depends on technology. It includes fixed and variable opex, insurance, connection and grid charges, see Table 4.
Connection Costs	Depends on type of generator and capacity connected, see Appendix 1.
Reinforcement Costs	Depends on type of generator and capacity connected, see Appendix 1.
Embedded benefits	
Generator avoidance balancing system charges	$= annual\ BSUoS\ costs\ (average\ last\ 3\ years) - residual\ cashflow\ reallocation\ cashflow\ (RCRC) = £1.348/MWh$
Generator transmission loss reduction	$= generator's\ ratio\ losses * average\ losses * wholesale\ electricity\ gate\ price$
Supplier avoidance balancing system charges	$= annual\ BSUoS\ costs\ (average\ last\ 3\ years) - residual\ cashflow\ reallocation\ cashflow\ (RCRC) = £1.348/MWh$
Supplier transmission loss reduction	$= supplier's\ ratio\ losses * average\ losses * (wholesale\ electricity\ gate\ price + generator's\ transmission\ losses + BSUoS\ costs)$
Distribution use of system charges (neg.)	$= DUoS\ tariff\ for\ HV = £0.51/MWh$
Distribution line loss	$= time\ weighted\ average\ of\ UKPN's\ line\ loss\ factors\ (LLF) * (wholesale\ electricity\ gate\ price + transmission\ losses + BSUoS\ costs)$
Losses	
Ratio generator	45%
Ratio supplier	55%
Average transmission losses	2% (current average based on Elexon's figures)
UKPN time weighted average LLF	4.90%
Revenues/Incentives	
Wholesale Electricity	£49.82/MWh (at gate, 2012). Based on Redpoint's Reference case (Jan. 2013)
FIT - Wind	Wind 0.5= £180.4/MWh, Wind 1= Wind 1.5=£97.9/MWh, Wind 2.55=Wind 5= £41.5/MWh
FIT - Solar PV	Solar PV 4.5= £68.5/MWh
FIT - AD	AD 0.25=£151.6/MWh, AD 0.5=£140.2/MWh
ROC&Banding - Wind	Buyout price: Wind 7.2=Wind 8.3=Wind 10=£40.71/MWh, Recycle price (10% buyout)=£4.07/MWh
	Banding: Wind (0.9 ROC/MWh), ROC = (Buyout price+recycle price)*Banding
LEC	Variable across the projects' lifetime (£5.09/MWh, 2012). Based on Redpoint's reference case (Jan. 2013)
Load Factor	
Wind	30% (based on UK Power Networks' March Grid Case)
Solar PV	9.7% (average period 2012/13, 2013/14)
AD CHP	84% (based on Pöyry's estimations, 2013)
Rates	
Discount rate	10%
Corporate tax - 2014 onwards	21% (in line with the UK main rate corporation tax to be applied in 2014)
RPI (2011-2012)	3.2%
Power Purchase Agreement Assumptions	
Electricity	85%
ROC	90%
LEC	85%
Embedded benefits	50%

Appendix 2: Scenario specifications (Scenario 1, 2 and 3)

No	Name	Nameplate capacity	Estimated uncurtailed generation - annual	Estimated curtailment - annual	BAU Connection Costs (s16 offer)	Connection Costs FPP	Reinforcement Costs FPP
Scenario 1							
		MW	MWh	MWh	£	£	£
1	Wind_A_0.5	0.5	1,314	4	1,900,000	234,779	113,889
2	Wind_B_1	1	2,628	9	2,000,000	384,711	227,778
3	Wind_C_1.5	1.5	3,942	13	1,900,000	157,137	341,667
4	Wind_D_5	5	13,140	43	1,200,000	649,788	1,138,889
5	Wind_E_10	10	26,280	86	4,800,000	590,817	2,277,778
		18	**47,304**	**154**	**11,800,000**	**2,017,232**	**4,100,000**
Scenario 2							
No	Name	Nameplate capacity	Estimated uncurtailed generation - annual	Estimated curtailment - annual	BAU Connection Costs (s16 offer)	Connection Costs FPP	Reinforcement Costs FPP
		MW	MWh	MWh	£	£	£
1	Wind_A_0.5	0.5	1,314	70	1,900,000	234,779	61,194
2	Wind_B_1	1	2,628	140	2,000,000	384,711	122,388
3	Wind_C_1.5	1.5	3,942	210	1,900,000	157,137	183,582
4	Wind_D_5	5	13,140	700	1,200,000	649,788	611,940
5	Wind_E_10	10	26,280	1,400	4,800,000	590,817	1,223,881
6	Wind_F_7.2	7.2	18,922	1,008	3,456,000	425,388	881,194
7	Wind_G_8.3	8.3	21,812	1,162	3,984,000	490,378	1,015,821
		33.5	**88,038**	**4,691**	**19,240,000**	**2,932,998**	**4,100,000**
Scenario 3							
No	Name	Nameplate capacity	Estimated uncurtailed generation - annual	Estimated curtailment - annual	BAU Connection Costs (s16 offer)	Connection Costs FPP	Reinforcement Costs FPP
		MW	MWh	MWh	£	£	£
1	Wind_A_0.5	0.5	1,314	70	1,900,000	234,779	61,194
2	Wind_B_1	1	2,628	140	2,000,000	384,711	122,388
3	Wind_C_1.5	1.5	3,942	210	1,900,000	157,137	183,582
4	Wind_D_5	5	13,140	700	1,200,000	649,788	611,940
5	Wind_E_10	10	26,280	1,400	4,800,000	590,817	1,223,881
6	Wind_F_7.2	7.2	18,922	1,008	3,456,000	425,388	881,194
7	Wind_G_2.55	2.55	6,701	357	3,230,000	267,133	312,090
8	Solar_A_4.5	4.5	3,824	204	1,080,000	584,809	550,746
9	AD CHP_A_0.5	0.5	3,679	196	1,900,000	350,000	61,194
10	AD CHP_B_0.5	0.5	3,679	196	2,500,000	100,000	61,194
11	AD CHP_C_0.25	0.25	1,840	98	2,205,750	117,450	30,597
		33.5	**85,949**	**4,580**	**26,171,750**	**3,862,012**	**4,100,000**

Appendix 2: Scenario specification (Scenario 4)

No	Name	Nameplate capacity (2014) MW	Nameplate capacity (2019/20) MW	Estimated uncurtailed generation - annual MWh	Estimated curtailment (2014-2019/20) - annual MWh	Estimated curtailment (2019/20 onwards) - MWh	BAU Connection Costs (s16 offer) £	Connection Costs FPP (2014) £	Connection Costs FPP (2020) £
Scenario 4 - Full quota (wind) + network upgrade borne by demand									
1	Wind_A_0.5	0.5	0.5	1,314	70	0	1,900,000	234,779	
2	Wind_B_1	1	1	2,628	140	0	2,000,000	384,711	
3	Wind_C_1.5	1.5	1.5	3,942	210	0	1,900,000	157,137	
4	Wind_D_5	5	5	13,140	700	0	1,200,000	649,788	
5	Wind_E_10	10	10	26,280	1,400	0	4,800,000	590,817	
6	Wind_F_7.2	7.2	7.2	18,922	1,008	0	3,456,000	425,388	
7	Wind_G_8.3	8.3	8.3	21,812	1,162	0	3,230,000	490,378	
8	Wind_H_0.5		0.5	1,314	-	0	1,900,000		226,960
9	Wind_I_1		1	2,628	-	0	2,000,000		371,899
10	Wind_J_1.5		1.5	3,942	-	0	1,900,000		151,904
11	Wind_K_5		5	13,140	-	0	1,200,000		628,147
12	Wind_L_10		10	26,280	-	0	4,800,000		570,798
13	Wind_M_7.2		7.2	18,922	-	0	3,456,000		410,975
14	Wind_N_8.3		8.3	21,812	-	0	3,230,000		473,762
15	Wind_O_0.5		0.5	1,314	-	0	1,900,000		226,960
16	Wind_P_1		1	2,628	-	0	2,000,000		371,899
17	Wind_Q_1.5		1.5	3,942	-	0	1,900,000		151,904
18	Wind_R_5		5	13,140	-	0	1,200,000		628,147
19	Wind_S_10		10	26,280	-	0	4,800,000		570,798
20	Wind_T_5		5	13,140	-	0	1,200,000		628,147
	Sub total	**33.5**	**90**	**236,520**	**4,691**	**0**	**49,972,000**	**2,932,998**	**5,412,299**

Connection Costs FPP (2020) at 2012 prices. These reflect a cost reduction based on the projections made by DECC (2012b) regarding capex.