Offtake arrangements and market access for small-scale distributed energy generators

A Report for Ofgem

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Executive Summary

1. Introduction

Ofgem is consulting on a range of options to address issues in the market for small scale distributed energy. In general it seeks solutions that allow distributed energy to grow within the existing competitive market. It has asked us to assess the competitiveness of the market for distributed energy, to analyse four particular issues, and to advise on options to address any problems in the market.

2. Approach

Previous studies have measured volumes and prices within a relatively narrow context, or taken a broad look at a few issues. Our study examines in more depth the views and experience over time of a wide selection of market participants.

3. Market context: definitions, market size and contractual terms

Following Ofgem, we here take distributed generation to be small scale renewable generation that is connected to the local distribution network rather than to the national transmission network, plus Combined Heat and Power generation (CHP). As of March 2007 the total capacities of these two types of generation were about 3.6GW and 4.0 GW respectively.

Contracts for such generation typically remunerate distributed generators for:

- wholesale power, somewhere in the range between cash-out prices for spilled energy and prevailing wholesale prices at the time the contract is struck;
- a share of "green benefits" such as Levy Exempt Certificates (Lecs) and Renewables Obligations Certificates (Rocs) where generation is eligible or qualifies for these;
- usually a further share of embedded benefits derived from the avoidance of various network and other charges;
- less an allowance for the various costs and risks incurred by the purchaser, which is typically a licensed electricity supplier.

4. Market context : power prices and other benefits

Between 2002 and 2007, the period over which many of the shorter-term contracts we discussed were struck, the value of energy and of these additional benefits increased significantly: wholesale prices have increased from less than £20/MWh to around £40 - £50/MWh; cash-out prices have also increased and their spread has narrowed; Lec certificates are presently worth over £4.50/MWh; Rocs have varied in the range £40 to £55/MWh, and embedded benefits could now be worth over £4/MWh depending on location.

Thus, after allowing for costs and risks incurred by the purchaser, there has been scope for a significant increase in the value of distributed generation, especially if the output qualifies for Lecs and Rocs. This evolution has considerably improved the prospects for renewable generation since 2002.

5. Generators' questionnaire

Generators provided information, in varying degrees of detail, about how they secured routes to market, their contracts with suppliers, including volumes and durations, quantities and prices in their contracts, the role of NFPA auctions, trends in the market, their perceptions of suppliers and other issues.

Certain common trends emerged. For example:

- offtake terms vary by size, technology and location of generator (among other factors);
- factors such as sector (wider business context, extent of on-site consumption) and size influence how hard certain distributed generators "work" the market, how far they are dependent on market prices but also how hard suppliers seek to attract them;
- generators (or rather their funders) have hitherto required floor prices, though with improvements in prices and benefits these are less contentious;
- most generators seem broadly content with the main pricing terms on offer;
- they are familiar with the bigger suppliers and the market consolidator and expect (and usually get) an offer when one is requested;
- they are concerned about credit issues and generally look for an investment grade credit rating from their preferred offtaker;
- many generators prefer long-term PPAs, while those without PPAs prefer annual or two-yearly contracts;
- those generators going to market can and do change their offtaker; and
- most generators noted they had achieved improved terms and prices over recent years.

At the same time there were differences between generators:

- there are different degrees of unbundling of pricing mechanisms;
- generator entitlements under benefit sharing arrangements vary;
- there are different expectations of what constitutes an acceptable offer and diversity in the contracts that generators enter into and the principal terms, which have evolved;
- a few generators commented on a sameness of approach while others did not mention this; and
- a couple of generators noted disappointment over the terms available, while the majority expressed satisfaction that the terms had improved.

6. Questions to suppliers

Suppliers provided information, also in varying degrees of detail, about their volumes and durations of contracts with distributed generators, affiliated companies with relevant generation investments, the treatment of quantities and prices in their contracts, preferred technologies and target quantities, their attitudes to Rocs and Lecs, their practices on rebate of Roc recycling fee, how they reflected imbalance risk, the role of NFPA auctions, trends in the market, and other issues.

Certain common trends emerged. For example:

- all large suppliers have a mix of ownership interests, PPAs and offtake contracts;
- they have adopted strong goals to increase their presence in local offtake markets ;
- they are actively driven by retail customer volumes and preferences for green or levy-exempt electricity;
- they are not technology-specific in their approach to the market; they are interested in tendering if quantities became available;
- they now rebate higher proportions of Rocs recycling fees to producers;
- they are more comfortable with imbalance risk and pricing than previously, and this has increased the prices they offer to generators; and
- they are conscious of internal resource limitations in their ability to respond to approaches by generators.

At the same time, there was also notable variety in the approaches adopted. For example:

- suppliers had very different ownership interests and different mixes of PPAs and offtake contracts;
- they differ in the size of project that they prefer to consider and in the resources that they make available in this area;
- they have different stances on targets, and on the importance of meeting the RO obligation internally, and on the relative values attached to Rocs and Lecs;
- they see the market as very varied and changing year to year with respect to the bundling or unbundling of prices; and
- they focus on different issues in assessing future trends in the market.

7. NFPA and short-term trading issues

The main focus of the generator questionnaire and supplier questions (and the responses we received) were the terms struck under bilateral contracts between developers and generators on the one hand and suppliers on the other. However the short-term market for facilitated exchanges within year is also an important feature of the commercial landscape. The NFPA has been operating auctions of power (with Lecs and embedded benefits) since 2001 and of Rocs since 2002, These auctions have become a key commercial focus within the market.

Suppliers attach great importance to the NFPA auctions though they differ in their risk attitudes and in their approaches to evaluating the NFPA auction projects and price levels. Several generators also acknowledge that short-term markets are becoming more important as NFFO contracts expire and as additional metered output becomes available outside off-take contracts. There were different views as to how the NFPA auctions might evolve in future.

8. Overview of findings from interviews

All major suppliers are active in the market for offtake power in Britain, and most are active nationally. Increasingly, smaller suppliers are becoming involved too, and some are already participating aggressively. No producer said they had not been able readily to find a counter-party; no supplier commented that they were being excluded from the market.

The emergence of green energy markets, including the market for green benefits, has acted as a major stimulus to competition. Supplier appetite in the market as a whole is increasing rapidly as the "green demands" of consumers have increased. Output from renewables and CHP plant faces strong demand. Many of the problems referenced by earlier surveys and of which we heard anecdotal evidence seem no longer to apply or certainly to a much lesser degree.

Other key findings are:

- several parties suggested that a main source of disappointment by producers, especially small producers, may well have arisen from differences in perceptions of the market value of their power;

- Rocs and Lecs are the primary benefits that qualifying generators can offer, and relatively speaking are now much more significant than embedded benefits. In many respects such benefits are as important if not more important to a generator than the underlying power;

- although some contracts still do not recognise some of these benefits, and different sharing arrangements prevail, nonetheless approaches to sharing of trading benefits and green benefits are tending to converge;

- in general, we do not perceive a state of widespread dissatisfaction on the part of distributed generators, or any single concern or criticism on which most respondents are united; and

- several generators have commented that they have received better offers over more recent contracting rounds, and this is confirmed by pricing data we have seen.

This is not to say that there have been no concerns and criticisms expressed during the review. Among the points made about aspects of the market that were not working well or could be improved were:

- several respondents said that getting a route to market can be difficult (and more difficult than it should be), and highlighted a lack of information for new entrants over the options available;

- a few generators expressed disappointment about prices, though there was a counter-suggestion that any disappointment might have more to do with lack of information and with unrealistic expectations on the part of generators just entering the market; and

- a few generators commented on a lack of interest from some larger suppliers for smaller quantities of output, and/or a sameness of offer (as noted above) and an inflexibility of approach.

9. Assessment of competition

We were asked to investigate claims that the market for small scale generator output is not very competitive. The great majority of small-scale distributed generators do not now claim that this market is uncompetitive, and suppliers argue that it is very competitive.

We find that the market is characterised by phenomena that we would expect to see in a competitive market:

- many buyers and sellers offering differentiated products and actively choosing in the market;

- an increasing number of buyers and sellers in the market;

- evolution of contract prices to reflect underlying movements in wholesale market prices and the value of green and other benefits; and

- evolution of contractual forms to better reflect market conditions, the preferences of market participants, and the increasing understanding of the market.

10. Issues and options

Our terms of reference highlighted four specific issues and options:

- market structure: The evidence suggests that competition in the market for distributed energy, Lecs and Rocs is already vigorous and continues to strengthen. At present the market structure does not seem unduly to impact on the liquidity of the market for third-party distributed generators, although the extent of trading and liquidity is presumably less than there would be if the market were less integrated;

- consolidation: We consider that the existence of a single specialist consolidator is consistent with the underlying economics of a competitive market of the present size. The consolidator seems to be actively responding to the requirements of smaller generators, and the pressure of competing suppliers precludes it from dominating this sector of the market;

- market arrangements and the value of small generation: In 2001 renewable generators were understandably concerned at the impact of the change from the Pool to Neta, in terms of the impact on prices available to them. Since then there has been an increase in the level of power prices (including spill prices), a reduction in the spread of imbalance prices, the introduction of prices for Lecs and Rocs, and a better understanding of the operation of renewable energy schemes. We conclude that market arrangements are now reflecting the value of small scale generation; and

- distributed energy purchaser and a dedicated distributed energy market: These options highlighted by Ofgem/Berr in the December 2007 consultation presumed a problem in the market. However, the market has evolved over recent years and is no longer characterised by the problems reported then in selling output. There is no demand for these measures, and considerable concern at the costs and distortions that they would entail. We consider that there is not a case for the creation of such entities.

11. Further concerns and suggestions

Other concerns and possible remedies were put to us, In the main these were less serious concerns than those addressed in section 10. Several of them were aimed at better facilitating the market. We conclude they are worthy of further consideration. They are:

- information about the market: There is recurring feedback that new and potential entrants especially would benefit from better provision of relevant information. We endorse this view, and suggest that Ofgem facilitate discussion within the industry of the most appropriate way to do this;

- regulatory uncertainty: Several participants expressed concern about various aspects of market rules and regulation, including administration, transparency, complexity and uncertainty of government and regulatory policy. We recommend that Ofgem consider how these issues can be addressed;

- imbalance pricing: This issue is perhaps less emphasised than in the past but it still remains a concern to generators as suppliers seek to pass through this risk to them. We recommend that Ofgem continue to pursue reform of imbalance pricing, which would be beneficial to smaller distributed generators and customers;

- standardised terms and contracts: Ofgem could usefully facilitate a discussion within the industry as to the possibility and merits of developing standard terms and conditions and contracts for the possible use of smaller distributed generators;

- within-year trading: This already occurs through the facilities operated by the NFPA for both power and Rocs. Interested parties should consider the possibility of developing this and how the facilities offered by the NFPA (and conceivably other providers) could be broadened;

- volumes from plant below 100kW: Larger suppliers found it costly to deal with smaller parcels from generators, but there were signs that smaller consolidators offering green services to generators were coming forward. Ofgem should keep these developments under review. The specific needs of smaller generators should be addressed as part of the discussion of information provision;

- arrangements for micro-generation: Ofgem is separately pursuing this issue, and we heard of some emerging market response. We suggest that the discussion of information provision should also include micro-generation; and

- cost of credit: It is likely that this factor continues to limit choice and liquidity in the market. It has been suggested elsewhere that over-collateralisation and double-counting of credit arrangements within the market may be part of the problem. Ofgem could usefully explore credit issues further.

1. Introduction

1.1 Background

The Energy White Paper[3] set out the potential role of distributed energy in meeting Government's energy policy objectives, and indicated the need for further work in this area. In December 2007 Ofgem consulted on a range of high-level options designed to address alleged barriers.

Ofgem and the Government are committed to ensuring that regulatory arrangements do not raise any unnecessary barriers to the wider uptake of distributed energy. They also want to encourage innovation so that new entrants and smaller suppliers, as well as the existing large suppliers, can experiment with new technologies and commercial arrangements in order to discover more cost-effective ways of reducing emissions. In the Energy White Paper Ofgem and Berr undertook to consult later in 2007 on options for more flexible market and licensing arrangements to facilitate distributed energy for implementation by the end of 2008. The December document met the first stage of this commitment by consulting on a range of high-level options.[4]

Ofgem explained that in general it was looking for solutions that would allow distributed energy to grow within the existing competitive market framework. It identified a variety of issues and problems that could arise with small-scale distributed generation, and noted a wide variety of high-level options that could address these issues. These options included supporting community distributed energy, network trial projects, addressing barriers to entry in current market and licensing requirements, the possibility of a dedicated wholesale market for distributed energy, and the possibility of raising licence exemption limits. Ofgem said that it would investigate further the implementation of these options, in conjunction with responses from the consultation, in order to decide which measures to take forward.

As part of its investigation, Ofgem asked us to assist it in understanding the issues faced by smaller distributed generators. In particular we were to assess the competitiveness of the market offtake power, to analyse four particular issues, and to advise on options to address any problems in the market.

1.2 Terms of reference

The relevant terms of reference for our study are as follows:

"Consultancy support is required for The Contracting Authority [Ofgem]'s joint work with Department for Better Economic Regulation and Reform (BERR) in addressing the barriers in the electricity market and regulatory framework to Distributed Energy (DE).

The scope of work for this contract will involve economic support to The Contracting Authority to contribute to our understanding of the issues faced by small generators in selling output to third parties outlined in Chapter 4 of the DE consultation document

[3] Energy White Paper 2007: Meeting the Energy Challenge, Chapter 3 - Heat and Distributed Generation, May 2007
http://www.berr.gov.uk/files/file39567.pdf
See also Review of Distributed Generation: A Joint Government/Ofgem Report, May 2007
http://www.dti.gov.uk/files/file39025.pdf

[4] Distributed Energy – Initial Proposals for More Flexible Market and Licensing Arrangements, Ofgem, 18 December 2007, p1
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=160&refer=Networks/ElecDist/Policy/DistGen.

released in December, *Distributed Energy: Initial Proposals for More Flexible Market and Licensing Arrangements*.

In particular consultancy support will lead further consideration of the issues faced by small generators in selling output to a third party. This work will investigate claims that the market for small scale generator output is not very competitive. The contractor will consider for The Contracting Authority whether there is market failure for the output from smaller generators and if necessary identify workable solutions to address this. The work will require analysis of:

- the effect of the market structure on the liquidity of the market for third party generators. Does, for example, the vertically integrated nature of the industry mean that suppliers are, to some extent, self sufficient in electricity?;

- reasons why there is only one specialist consolidator in the market. We are keen to explore whether the existence of a single specialist consolidator is natural consequence of the size of the market or whether there is something in the arrangements that is reinforcing this situation; and

- the effect of market arrangements on the value of small generation. It is interesting to note that if the "pool" were still in place such small generation would be realising the system marginal price rather than the current spill price.

If there is a problem in the market then the consultant should also identify and assess the options to address this issue, including those set out in the consultation document:

- ensuring there is a purchaser for the electricity; and

- development of a dedicated DE wholesale market

The contractor will assist The Contracting Authority in establishing the most advantageous package of measures that addresses the identified issues. In doing this the contractor will be required to advise on appropriate measures to address the difficulties faced by a range of DG schemes that operate on a commercial basis selling to third parties."

1.3 Structure of Report

The rest of this Report is structured as follows:

- section 2 explains the questionnaire and interview approach we have taken in the context of previous investigations;

- section 3 sets out the market context for distributed energy by way of background;

- section 4 sets out similar background on prices and benefits;

- section 5 summarises the responses to the questionnaire sent to generators;

- section 6 summarises the responses to the suppliers' questionnaire;

- section 7 addresses certain short-term trading issues that exist separately from the mainstream offtake market;

- section 8 describes key aspects of the market that emerge from the questionnaires and our interviews with market participants;
- section 9 contains our own assessment of competition in this market;
- section 10 contains our assessment of the issues and options identified in Ofgem's December 2007 consultation document, and of the concerns and suggestions raised by market participants; and
- section 11 concludes with some further concerns we have noted and suggestions of our own.

There are the following annexes:

A—Questionnaire to distributed generators

B—Respondents to questionnaire and interviews

C—Questions to suppliers

2. Approach

2.1 The 2001 review

We have developed our approach to complement previous reviews of this sector. An earlier review of the experience of smaller generators in 2001 looked at performance under the first three months of Neta.

For that review over 500 survey forms were issued. Forty forms were returned covering 106 sites. Follow-up meetings and interviews were conducted with some generators and representative organisations, with eleven independent generators being interviewed. Experience at that time was based on trading over the first two months of the new trading regime Neta which had just succeeded the Pool. An important point of reference was how detailed terms of trade were different from those experienced with trading under the Pool.

The main conclusions from Ofgem's 2001 review were as follows:

- export prices achieved by smaller generators who responded to Ofgem's survey were 17% below those achieved a year previously under the Pool. These reductions were "somewhat smaller than for generation prices overall";
- output fell substantially, with on-site consumption output declining 22% and exports down 44%. Lower prices were one factor but there was also evidence that higher fuel costs, which had risen 14% in the previous year, had also contributed;
- other than wind power, the output of smaller generators did not appear to be significantly less predictable than for other generators;
- there was widespread comment from smaller generators of the limited consolidation services available during the first months of Neta, a period during which a number of those interested in offering such services did not regard the services as fully operational; and
- Ofgem concluded that consolidation services had at that stage "not yet developed to the extent that would appear feasible".

A study carried out in 2005 by consultants Campbell Carr on behalf of DTI, Berr's predecessor, looked at the scope for increased consolidation in the electricity market. We reference this report in section 10. The issue of terms for offtake power has been a recurring matter of comment in the market, but there has been no further review of this issue.

2.2 The present approach

For the present work, time and resources did not allow a wide-ranging quantitative exercise. Our aim was to secure a more in-depth and qualitative understanding of the state and development of the market.

To that end we prepared a questionnaire that Ofgem issued to a sample of about 40 smaller–scale generators. The sample was constructed to cover a range of different technologies and sizes of participant. The questionnaire is set out at annex A.

We received 19 written responses. A fuller summary of these responses, some elements of which are commercially confidential, has been made available to Ofgem.

There was a strong response from water companies and other established distributed generators. Several of these had a preponderance of landfill gas sites. There were fewer responses from smaller players and parties with newer technologies, though some of the established generators have begun to add wind sites to their portfolios. We nonetheless had a diverse selection of responses, including from several newer entrants and two energy service companies (Escos). We had follow-up discussions with 14 of these respondents plus one verbal respondent, and an operator of trading platforms. These discussions enabled us to confirm our understanding of their responses, to seek clarifications, to ask supplementary questions and to gather further information. We judged that there was sufficient breadth and depth in the responses we received to enable us to reach soundly-based findings for the sector as a whole.

We also sought views from suppliers, who are the buyers of the outputs of distributed generators. We had meetings and interviews with the Big Six vertically integrated suppliers, and with two smaller suppliers. We also met and discussed market conditions and developments with the main consolidator in the market, who is also a licensed supplier. A list of questions sent to these suppliers is at annex B.

The respondents are listed at annex C, and details of parties we interviewed are also at annex C.

We had available to us responses to the Berr/Ofgem December consultation, which have since been published on the Ofgem website. These touched on some relevant aspects of our brief, but only overlapped in a limited way.

3. Market context: definitions, market size and contractual forms

This section sets out background information on the market for distributed generation. It covers the definition of distributed generation, the extent and composition of it, the nature of the commercial benefits that it can provide, and some high-level context on the nature of the typical commercial and contractual arrangements in this part of the market.

3.1 Definitions

The term distributed generation—sometimes referred to as embedded generation—is generally used to describe a power station that is connected directly to the low voltage distribution network rather than to the high voltage transmission network. Distribution networks operate up to 275kV in England and Wales and up to 132kV in Scotland. Consequently distributed generation does *not* include large generation schemes, which are typically directly connected to the transmission network.

These distributed generators are intermediate in size, ranging from 50kW up to 50MW. Generation smaller than 50KW is usually referred to as micro-generation, and is outside the scope of our review. These intermediate-sized generators almost invariably sit outside the central trading arrangements.[5] The purchaser or "offtaker" of their generation is usually a licensed supplier or a specialist consolidator.

The types of generation that most frequently connect to the distribution networks include:

- renewable energy schemes (for example, wind generators);
- waste-to-energy schemes;
- on-site generation involving CHP schemes; and
- peak lopping schemes using back-up generators.

3.2 Extent and types of distributed generation

At the end of March 2007, the installed capacity of distributed generation in Britain was less than 13GW out of a total generation capacity of some 77GW. Figure 2.1 shows that 5213MW (about 41%) of this was conventional generation, primarily combined cycle gas turbines (CCGT), which tended to be larger plant above 50MW and most of which was traded through the Neta market. Another third (3952MW or 31%) comprised Combined Heat and Power (CHP) schemes, again much of which is large[6] and a large part of which was installed for on-site use. The remaining 3592MW (about 28%) comprised various kinds of renewable technologies. Source: the Energy Networks Association (ENA).

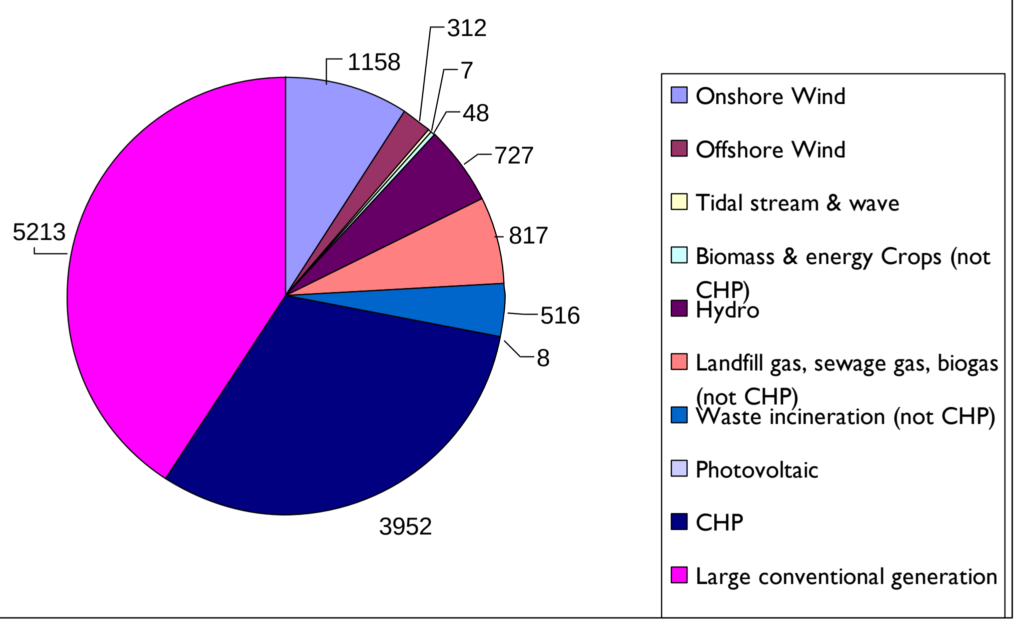
For present purposes, Ofgem's December 2007 paper defines distributed generation as *renewable* energy that is directly connected to the distribution system, as well as CHP schemes of any scale. We therefore do not consider further the conventional CCGT or large CHP schemes shown in Figure 2.1.

[5] There is a handful of plant usually having dynamic characteristics that is registered in the central trading arrangements. Further there is some wind plant in Scotland of less than 50MW capacity that has been similarly registered because thresholds in Scotland are lower and it meets criteria established by National Grid for a large power station.

[6] The grid code terms plant in England and Wales above 50MW as large. They are not usually licence-exempt and are registered in the central trading arrangements.

Figure 2.1 also provides a more detailed breakdown of the renewable technologies The main renewable technologies were onshore wind (7% of the overall total), offshore wind (2%), hydro (6%), landfill and sewage gas (6%) and waste incineration (4%).

Figure 2.1: Distribution generation connected (MW) March 2007



Historically CHP and landfill gas applications have been the main forms of distributed generation as presently defined. CHP developed nationally on a range of large industrial sites utilising process heat. Landfill gas has been a popular development especially since the implementation of the Non Fossil Fuel Obligation (NFFO) in 1990.

3.3 The Non-Fossil Fuel Obligation (NFFO) and the Renewables Obligations

The Non-Fossil Fuel Obligation (NFFO) was a competitive tendering mechanism for the development of renewable generation projects. Introduced in England and Wales by the Electricity Act 1989, it was the main policy tool for promoting the sector during the 1990s. Separate but similar arrangements applied in England and Wales, Scotland and Northern Ireland.

Suppliers were required under the obligation to purchase defined volumes of electricity produced from non-fossil fuel sources. Initially, this was primarily nuclear electricity, but progressively more renewables were added. The obligation was imposed by the non fossil fuel orders, of which there were five between 1990 and 1998. The associated costs were levied on consumers through the application of the fossil fuel levy on their bills.

The NFFO and related arrangements in Northern Ireland were a key driver in the development of distributed generation during the 1990s. They resulted in contracts being awarded to more than 700 individual renewable generation projects of more than 2.9GW capacity in aggregate. Of these 706 projects, 296 had been commissioned as of March 2008, representing 827MW of renewable capacity. Half of this operational capacity is landfill gas, though the later capacity is mainly municipal and industrial waste and wind. Contractual arrangements established under the later orders are still in place and, in some cases, will run through to early next decade.

In 2001, DTI, the sponsoring government department, decided to include live NFFO sites in the Renewables Obligation, which we describe in the next section, with the consequence that legacy schemes constructed under the NFFO earn Rocs on their output. Under the NFFO contracts typically last 15 years. Progressively over the coming years volumes from these contracts will come to market.

The Renewables Obligation replaced the NFFO as a means of incentivising renewable generation from April 2002. The Renewables Obligation Order 2002 placed an obligation on suppliers to source an increasing proportion of electricity from renewable sources. Suppliers can meet this obligation by constructing renewable generation of their own, by purchasing generation from independent renewable generators, or by paying a specified fee. It has had a strong stimulus on development of new distributed generation, as is illustrated by Table 2.2.

Table 2.2: Cumulative eligible RO renewable generating capacity at end of period

	2002-03 (CP1)	2003-04 (CP2)	2004-05 (CP3)	2005-06 (CP4)	2006-07 (CP5)	2007-08 (CP6)*
Number of stations accredited	505	616	787	980	1,360	2,281
Capacity MW	1.68	3.13	3.72	4.38	4.77	5.29

* provisional figures

Source: Ofgem

The connection of wind farms (both offshore but especially onshore) has made the most significant recent contribution to increased levels of distributed generation, especially since the implementation of the Renewables Obligation in 2002. The biomass and energy crops plants and tidal and wave energy installations make up a small proportion of the generation mix, though increasing volumes of biomass are now coming on stream. The amount of micro-generation (solar, micro-wind power and micro CHP) is relatively insignificant, but both types are expected to increase significantly over the coming years. Connections of landfill/sewage/biogas and waste incineration plants have also been notable over recent years.

3.4 Plant ownership

To varying degrees all the large suppliers are investing in renewable generation, and much of it is distributed. Some smaller suppliers, especially niche green suppliers such as Ecotricity and Good Energy have also been involved. The proliferation coincides with the (i) introduction of new incentives available to low carbon generators through the introduction of the Climate Change Levy and the ability to avoid the levy through the presentation of Levy Exemption Certificates (Lecs) and (ii) the imposition on all licensed suppliers of the Renewables Obligation and the requirement to source a defined percentage of power each year from eligible renewable sources. Both these mechanisms are explained more fully in section 4.

While we note these direct investment developments by suppliers by way of background, our review is of offtake terms between third party generators and the trading party through which they secure a route to market.

Both the volume and types of distributed generation connections to the different distribution networks vary significantly. The highest growth over recent times has been in Scotland, East Anglia and the South East. Such developments are closely linked with wind activity, being stronger in Scotland than in England and Wales.

The government's "Restats database"[7] provides details on the progress of renewable energy projects according to funding source, technology type and location.

In all production from distributed plant not owned by the vertically integrated players was estimated at over 30TWh in 2005, or about 10% of throughput across the British system as a whole. It is therefore necessary to keep a sense of perspective in considering each aspect of the total market.

3.5 Commercial context

Commercial arrangements for generators differ according to the connection voltage. Large generators that are transmission-connected tend to be licensed and direct signatories of core industry documentation such as the Balancing and Settlement Code (BSC). In fact they must be signatories if they are licensed and/or above 50MW. They tend to be direct wholesale market participants as a consequence or as a minimum they use another large trading party as their agent to access wholesale markets.

Smaller generators are usually distribution-connected and do not participate in wholesale market trading. Instead, usually they contract for the sale of their generation directly with a supplier (or another BSC Party) who has access to central and traded markets through a bespoke contract. Where this is a long-term arrangement covering the expected life of the assets it is usually known as a Power Purchase Agreement (PPA). Where it is of shorter duration, it is usually known as an offtake agreement.

Most larger generators that are wholesale market participants and BSC parties tend to contract bilaterally using standard contract forms such as the Grid Trade Master Agreement (GTMA). If they trade through a power exchange such as the UK PX, they do so under uniform, posted terms and conditions. However, these standard contracts tend to trade in greater denominations with regard to the size of power than is appropriate for smaller distributed generators. They also place counter-parties under obligations that are not necessarily appropriate for smaller generators. Such obligations may include maintaining prescribed credit ratings and becoming a BSC party, both of which impose costs that many small generators consider excessive.

3.6 Distributed energy products and contracts

Smaller generators have a number of products to sell to suppliers (or other BSC parties). These depend on the individual generator and its technology, but include:

- wholesale power;
- environmental or "green" benefits, including;
    - Rocs;
    - Lecs;
- embedded benefits that arise from costs avoided by the counter-party trading through the central arrangements and who can use a distributed generators output to reduce its reported volumes into settlements.

The PPA or offtake agreement may address any or all of these products. It will usually specify the basis on which benefits *where they are recognised* are to be shared, with the purchasing counter-party often retaining a small portion of the benefit reflecting costs or risks assumed by it.

[7] The database can be found at www.restats.org.uk.

There are no standard contracts for this type of decentralised trading, although the larger suppliers have developed more standardised contracts for their own use. Prices are set on a variety of bases, including:

- an all-in value for these products;
- a value for each item independently; or
- a value for the wholesale generation typically set by reference to a formula or a benchmark price plus pay a share of the outturn value of the renewable, environmental and other benefits.

Alternatively, the sale of some of these products, and often Rocs, may be made under separate contracts, possibly with different counter-parties.

3.7 Costs of suppliers

Suppliers may incur a number of costs in contracting with smaller generators. These costs include:

- imbalance costs through increased exposure to cash-out prices for performance variation by contracted plant;
- trading charges, where the supplier provides a route to market outside its own customer base;
- meter registration charges;
- data collection charges;
- data aggregation and settlement charges;
- metering charges; and
- legal, management and administration costs.

These costs will usually be recovered through the PPA or offtake agreement, with recovery being:

- either within the contract price as a lower price;
- dealt with through an explicit charge or charges;
- as a pass-through of incurred costs; or
- a combination of these approaches.

Imbalance costs are an important feature of the market. They arise as a result of the variability of the generator's output but will be incurred directly by the counter-party (the purchasing supplier), because it will have registered the generator within its own portfolio.

Conventionally, in the past, to minimise these imbalance costs the suppliers tended to place obligations on the generator to nominate a generation or output schedule, and they would often penalise that generator for deviations against that schedule, whether by passing through imbalance charges or at other terms specified within the contract. As we show below, this practice is now changing.

Existing smaller generators who do not have a long-term PPA usually contract for the sale of generation on an annual basis, usually for a financial year running 1 April to 31 March. Some generators have been able to sign longer-term contracts for two to five years, and in a few instances, for longer periods. New projects usually seek and obtain contracts for a minimum five, but usually up to fifteen, years.

There can be an inter-relationship between the form and the length of the contract. Longer-term contracts might be based on a variable formula tied to a market benchmark but might also specify a floor price, which is important to a scheme's lender. Shorter-term contracts might be simpler and based on fixed elements because there is likely to be less uncertainty over valuation parameters. Different approaches must be taken into account in making comparisons. For example a contract that offers an all-in price inclusive of imbalance risk will not be directly comparable to one that explicitly passes imbalance costs through to the generator or one that differentiates between fixed and variable quantities. As mentioned Rocs where these are available are sometimes sold with the power, sometimes without it.

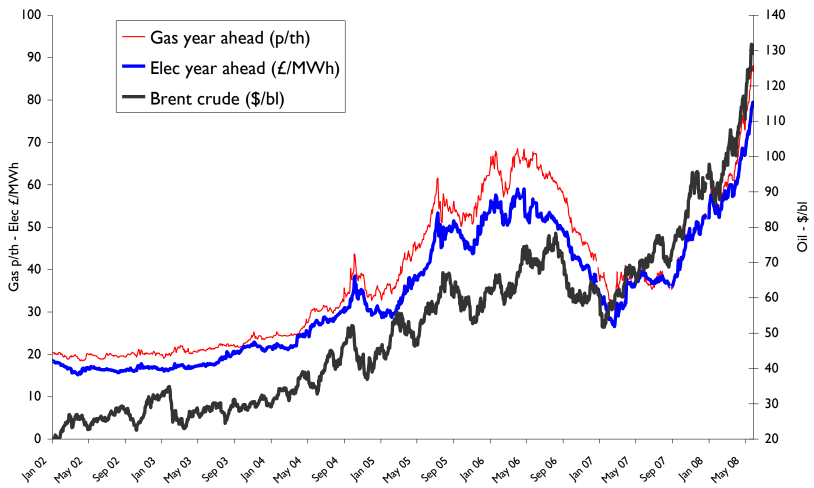
4. Market context: power prices and other benefits

This section provides further market context. It indicates the evolution of wholesale power prices, developments in the arrangements for imbalance pricing, the source and levels of green benefits (Lecs and Rocs) and the nature of embedded benefits.

4.1 Wholesale power prices

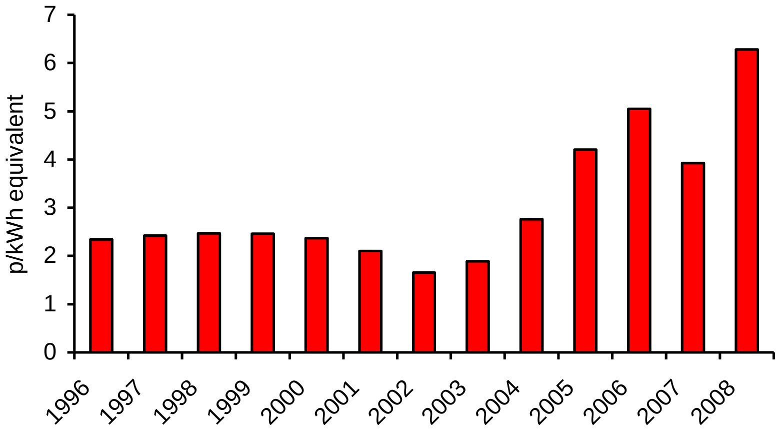
Distributed generators under PPAs and offtake agreements are nowadays paid against a measure of wholesale power prices, with a discount applied to account for the supplier's costs and imbalance risk. (As we see in section 4.2 below, referencing prices against spill prices is no longer the norm.) Sometimes these prices are set on an annual basis, sometimes by reference to the underlying prices within year (variously seasonal, monthly or daily). Figure 4.1 shows in the blue line how average traded prices for the annual contract, which is a common quoted reference contract for baseload power bought by purchasers, have moved over the recent past. The red line shows how the corresponding gas contract has moved over the same timeframe, and the black line shows the quoted daily price for Brent oil, which is considered to be a driver of gas prices and through them the price of electricity.

Figure 4.1—Annual energy price markers



To give a broader perspective, Figure 4.2 shows how power prices have moved on an annual average basis, since 1996.

Figure 4.2—Average electricity wholesale prices



Prices started to decline around 2000. (Some would attribute this to anticipation of the replacement of the Pool by Neta. Others have argued that a more important determinant of the decline in prices were the sales of plant by the major generators and the consequent deconcentration of the generation sector.)

Wholesale electricity prices are presently at levels of over three times their value at the time of the immediate post-Neta period.

4.2 Managing imbalance

The treatment of imbalance against expected operating patterns is an important issue for distributed generators, especially for technologies such as wind because they are largely intermittent (they run when the wind blows).

a) Imbalance risk

Implementation of Neta in March 2001 meant a change in the trading environment within the sector. Most distributed generation is licence exempt and avoids any requirement to trade through the central trading arrangements. However, the Neta market provides parties trading at the wholesale level with incentives to contract. This is because there are two imbalance prices that tend to be volatile, with the System Buy Price (SBP), the top-up price, higher than prices available in the wholesale contracts market and the System Sell Price (SSP), the spill price, lower. So although distributed generation does not trade through the central trading arrangements its operations can nevertheless contribute to the imbalance position of a trading party, who is its counter-party.

A supplier who is balanced with regard to its contracts is therefore exposed to greater imbalance risk when it contracts with a new offtake party, especially where the output from the generator is unpredictable or intermittent. The purchaser will price this risk into contract with the generator.

In the initial period of Neta operation it was commonplace for contracts with distributed generators to include payment at spill prices or to heavily discount the wholesale price to reflect imbalance risks.

b) Consolidation

Consolidation is a means by which the unpredictable outputs of a number of smaller generators who would not otherwise wish to trade their individual positions can be aggregated, in some cases in conjunction with demand, such that the unpredictability of the total is less than the sum of variations for each individual generator/demand.

A "consolidator" has been described as a BSC party who offers services to smaller generators to allow them access to the Neta market mechanisms and to the benefits of consolidation, particularly reduced imbalance exposure. In a sense a supplier who contracts with generation is a natural consolidator as it typically reports its production quantities at the GSP group level and nets this off against demand in that area.

c) Changes to cash-out

There have been many changes to the Neta cash-out rules, many of which have been targeted to remove causes of volatility (P9, P18). In some cases a primary consideration has been to reduce penalties to those that go against the system imbalance (P78) making the system more balanced overall, or to address concerns about "system pollution" in prices (P205). By and large these have increased spill prices and reduced top-up prices, greatly reducing the spread between the two imbalance prices, which many regard as a measure of imbalance risk in the market. There remain significant concerns across the industry largely accepted by Ofgem about the extent to which cash-out is genuinely cost-reflective of the energy imbalance (and the extent to which system costs are included in imbalance prices).

Further consideration of cash-out has been underway since late 2006 when Ofgem initiated a cash-out review, and two further BSC change proposals are in the assessment process with the prospect of others to follow. Other attempts to create rules to modify cash-out arrangements, for instance through the availability of a more benign cash-out price for licence exempt generators or the establishment of tolerance bands, have been rejected to date by Ofgem on grounds of undue discrimination and/ or competitive distortions.[8]

4.3 Green benefits

Incentives are now available to qualifying low carbon technologies, especially:

- Levy Exemption Certificates or Lecs, which have been available under the Climate Change Levy arrangements since 2001; and
- Renewable Obligation Certificates (or Rocs), which have been available since April 2002.

We discuss these in turn.

a) Lecs

On 1 April 2001, the Government introduced the Climate Change Levy (CCL) under the Finance Act 2000. It is chargeable on non-domestic supply of electricity in the United Kingdom. This is the industrial and commercial supply of taxable commodities for lighting, heating and power by consumers in industry, commerce, agriculture, public administration and other services. Electricity is currently (with effect from 1 April 2008) subject to the Levy at a rate of £4.56/MWh (subject to certain exclusions, exemptions, reduced rate and half-rate supplies).

Lecs are issued, one per MWh, by Ofgem, who administers the regime, once it is satisfied that a generator has produced qualifying power from an eligible plant. They form the

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[8] Most notably P26 and P201/2 have sought to impose a more market neutral price within specified dead bands. P95 sought to mitigate cash-out specifically for exempt generators.

evidence required by HM Revenue & Customs to demonstrate the amount of electricity supplied to non-domestic customers in the United Kingdom that does not attract liability for the climate change levy. Once they have been acquired by generators they are sold to suppliers who use them to claim the CCL exemption on non-domestic supply and are allocated by them against relevant supply contracts. In other words a supplier can use a Lec nominated against a business customer's contract to allow it to subtract CCL from the customer's bill. It also allows the supplier to evidence that a "green" supply, that is one from a low carbon source, has been made to that customer.

There are both CHP Lecs and renewable Lecs (dependent on the generation source). Both can be used to claim relief from the levy. Only the renewable Lec can be used to evidence a renewable or "green" supply.

Most distributed generation because it is CHP or renewable is eligible for Lecs. Lecs are sold in combination with the power.

b) Rocs

The Renewables Obligation, the Renewables Obligation Scotland and the Northern Ireland Renewables Obligation (NIRO) are designed to incentivise renewable generation. The RO and ROS were introduced in April 2002; NIRO in April 2005. These schemes were introduced by the Department of Trade and Industry, the Scottish Executive and the Department of Enterprise, Trade and Investment respectively, and they are administered by Ofgem.

The Orders place an obligation on licensed electricity suppliers in England and Wales, Scotland and Northern Ireland to source an increasing proportion of electricity from renewable sources. In 2005-06 it was 5.5% (2.5% in Northern Ireland); in 2007-08 the obligation was set at 7.9% (2.6% in Northern Ireland). By 2010-11 it is scheduled under parliamentary order to increase to 10.4% across Britain (4% in Northern Ireland).

Suppliers meet their obligations by presenting sufficient Rocs. A Roc is a certificate issued to an accredited generator for eligible renewable electricity generated within the United Kingdom and supplied to customers within the United Kingdom by a licensed electricity supplier. One Roc is presently issued for each MWh of eligible renewable output generated. As suppliers seek to meet their increasing obligations, the value of Rocs tends to increase, which encourages more distributed generation into the market with a corresponding increase in the number of associated Rocs.

The value of Rocs fluctuates depending on the demand and supply in the market. Generators are awarded Rocs based on their validated output from accredited renewable plant. In each year licensed suppliers have to meet a renewable obligation whereby they must meet a defined proportion of their supply from Roc eligible sources. They evidence compliance with the obligation by acquiring Rocs in the market and "redeeming" them with Ofgem, who administers compliance with the obligation. Alternatively, suppliers can pay a pre-set buy-out fee for each MWh for which they have not redeemed a Roc.

The buy-out fee was set at £30/MWh in April 2002 and rises by inflation annually. In 2008-09, which is the seventh year in which the RO has been in operation (called compliance period or CP7), it has been set at £35.76/MWh.

There is a second element to the value of a Roc. Those buy-out fees collected from suppliers short against their obligation are then recycled to Roc holders in proportion to their holding of redeemed Rocs. This happens six months after the end of each compliance year when the positions of suppliers have in effect been audited by Ofgem.

So the nominal value of a Roc in any one compliance period will be the relevant buy-out fee plus the value of the recycle payment calculated for that year.

As a consequence of these arrangements the value of the Roc fluctuates depending on the number of Rocs produced in a year and the level of buy-out fees collected (which in turn is related to the level of the obligation in a particular year). The shorter the market relative to the obligation, the higher the Roc price. The construction of the Roc price in all years to CP5 is shown at Table 4.3.

Table 4.3—Buy-out rates and recycle vales under the RO

GB RO	RO MWh	Rocs	Roc %	Total renewables supply %	Buy-out shortfall £	Redistributed £	Per Roc £/MWh	Buy-out £/MWh	Nominal Roc £/MWh
CP1	9,261,568	5,451,449	59%	1.8%	24,239,580	90,063,990	**16.52**	30.00	46.52
CP2	13,627,412	7,610,144	56%	2.4%	9,189,033	174,955,257	**22.99**	30.51	53.50
CP3	15,761,067	10,855,848	69%	3.4%	714,123	153,837,413	**14.17**	31.39	45.56
CP4	18,032,904	13,699,317	76%	4.2%	802,000	139,654,378	**10.19**	32.33	42.52
CP5	21,629,676	14,612,654	68%	4.6%	0	234,439,091	**16.04**	33.24	49.28

In Table 4.3, the first column is the relevant compliance year (that is, CP1=2002-03, and CP5 is 2006-07[9]). The level of obligation across all suppliers is shown in column 2, and the total number of Rocs submitted in the third column. The level of achievement of the target is shown in the fourth column, and the level of total renewables supply from RO eligible sources in the next column. The buy-out shortfall is a deficit realised in certain years because some failing suppliers did not submit Rocs or buy-out fees, meaning that less money was collected than expected. The total amount of buy-out payments redistributed is shown in column 7. Divided by the number of Rocs submitted in each year, this gives the value of recycle payment/Roc (column 8). Adding this to the buy-out fee in that year (column 9), gives the combined value of the Roc in that year.

This all-in price is realised only after the end of the relevant compliance year, but it is their estimates of this figure that suppliers and generators have in mind when they agree on the treatment of the Roc benefit in their contracts.

Because of the extended compliance timetable it is conventional for suppliers to pay for Rocs bought bilaterally in two instalments, corresponding to the two parts of the process. First the supplier makes a payment based on the buy-out fee stipulated for the relevant year. This payment is usually made at the point of delivery *of the Roc* to the supplier, which is usually about three months after production of the associated power. Second the supplier then makes a further payment based on the value of the reported recycle amount in each year to the producer. This is shortly after the recycle payments have been made to the supplier. Consequently it is usual for both PPAs and offtake agreements to specific how each element of the benefit—the buy-out payment and the recycle payment—will be shared between the contract counter-parties where the Roc is traded under the contract.

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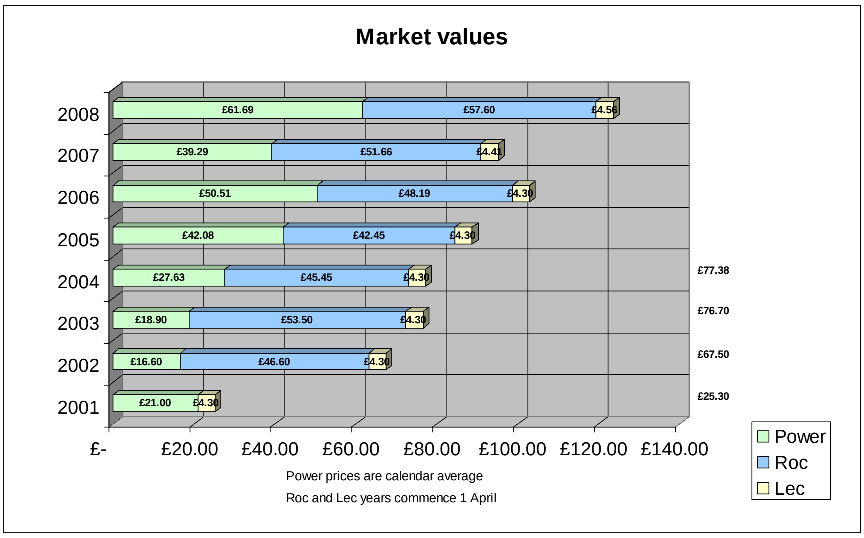
[9] The compliance process for 2007-08 has yet to be competed).

Rocs are separable from the power and do not have to be sold with it. While most PPAs include transfer of the Rocs[10], some offtake agreements do not.

c) Bundled values

The combination of a shift away from spill prices, wholesale power prices increasing from a low of less than £20/MWh in 2002 to around £40 to £50/MWh or more in the last three years to end 2007, plus the Lec value of over £4.50/MWh, plus Roc values in the range £40 - £55/MWh means that there has been scope for a significant increase in the value of renewable distributed generation. The extent to which this has materialised in distributed generators' contracts is discussed in later sections, together with the basis of purchaser adjustments to reflect their own costs and risks. However there is no doubt that these changes have improved the prospects for distributed power considerably and from renewable sourced power in particular. Figure 4.4 shows these maximum values.



4.4 Embedded benefits

The offtake market has been long-established, and an important stimulant to trading used to be the so-called "embedded benefits". These benefits are designed to reflect the costs saved as distributed generators do not make use of the high voltage transmission system, and therefore include:

- avoidance of Transmission Network Use of System charges, known as "triad" benefits;
- avoidance of Balancing Services Use of System (BSUoS) charges levied by National Grid in respect of its costs from managing the short-term operation of the system;
- avoidance of transmission losses, which are levied through the central trading system; and
- avoidance of certain Elexon charges.

The offtaker, in the past usually the successor supply company to the former local incumbent, can net the output from the local generator (who is embedded) from its reported volumes, achieving reductions in these centrally administered charges. If the output

[10] In fact one of the main incentives on the supplier to write a long-term contract is to secure the Rocs.

is available at times of setting maximum demand-based transmission charges, it would attract a particular premium, depending on location (the TNUoS charge varies by region) through the avoided cost to the supplier. These avoided costs are then by convention shared with the generator whose production creates the opportunity for this cost saving.

The "triad benefit" is the most substantial of the embedded benefits. Generators have historically expected to receive 80% to 90% of the total value provided they are operating during the triad periods. The main other benefits are in respect of relief from BSUoS and the costs of transmission losses. Triad benefits can rise to £4/MWh depending on location; BSUoS benefits are now in excess of £1/MWh. Transmission losses are dependent on prevailing power prices and actual losses on the system, but typically are between 1.5-2% of market prices. All these estimates are based on full market values, and are not necessarily the values distributed in offtake contracts.
Since the commencement of Neta in March 2001 a number of changes to market and charging rules have been introduced to allow easier access to embedded benefits. These have had the effect allowing a distributed generator to realise these benefits by trading with any supplier or consolidator within the relevant GSP group. Larger exempt generators also now have the option of claiming some benefits directly provided they are registered in the central trading systems.[11]

[11] Given the cost and complexity involved this is only a realistic option for the largest embedded generators.

5. Key findings from generators

In this section we summarise the main findings from the questionnaire responses and the interviews with generators.

5.1 Contract durations

About 0.8GW of existing distributed plant remains under NFFO agreements. This plant was committed in five contracting round during the 1990s. The NFPA is now being responsible for delivering this output to market. Several of the respondents had NFFO plant.

Progressively some quantities under the NFFP arrangements are coming directly to market as the original contracts, which are typically of 15 year duration, expire. The first two orders were implemented in timescales where 15 year contracts have now expired. The volumes contracted rose significantly during subsequent rounds and the output of those later rounds remains under contract. Many of the sites also now earn Rocs and Lecs.

Several of the developers we heard from had a large proportion of NFFO sites, and had successfully sought new counter-parties for quantities where they are no longer obligated to deliver to the NFPA.

As a guiding principle the new schemes that had come to market sought longer-term PPAs, where possible of between 10 and 15 years duration. This is often stipulated as a requirement by lenders as a condition of finance, as a mechanism to underwrite a generator's cashflows. There were indications that generators had been settling in some cases more recently for shorter contract durations than previously. This may reflect the escalation in power prices seen since the early days of the implementation of the RO and expectations of increased returns on investment.

Those generators with established portfolios indicated they had been keen to stick to one year arrangements to get more certainty over budgets than selling spot, while still allowing since 2004 for a rapidly changing market and volatile prices. A couple of these generators qualified this remark by saying that since 2006 they had been looking to fix revenues further out, to lock in current high power prices.

5.2 Quantities

The combination of a fixed volume at a specified price and a variable volume at a lower price, perhaps tied to SSP, was popular after Neta go-live. This approach, which was described in the *Neta one year on* report, was no longer preferred in new contracts. Offtake arrangements were predominantly based on variable quantities, typically with a uniform negotiated price or a single pricing mechanism.

A few enduring arrangements struck in the early post Neta days or which had been renewed subsequently with the same player still distinguish between a fixed or "baseload" volume and price and then a price for additional quantities in other periods or periods in which unexpected or not nominated spills occurred. For this separately priced variable quantity another, lower price, was used, usually SSP.

5.3 Prices

We were told that prices had improved dramatically over the Neta period. (Unless otherwise stated, quoted rates are for 2007-08.) Most respondents were under shorter-term offtake arrangements, not PPAs, and most were structured around "seasonal time of day" (STOD) differentiated structures. Note for comparative purposes that the average energy price through 2007 was about £40/MWh, which is considerably short of levels in the wholesale market currently.

The lowest price reported to us for energy only was £26/MWh, which was associated with a small spill quantity. The highest was £66/MWh for a micro-PV facility, and is not representative of the offtake market. Most other sites that disclosed price information ranged between £36/MWh and £48/MWh. One producer had a range of £35-40/MWh across its sites; another, £39.50/MWh.

Thus, in broad terms, energy prices quoted for 2007-08 were:

- about twice those of the initial Neta period considered in the first year review; and
- broadly comparable to the average wholesale price in 2007.

Indications from the subsequent financial year are that prices have since improved further, in line with improvements in the wholesale market price.

5.4 Pricing mechanism

At a more detailed level a variety of approaches were evident in terms of the pricing mechanism for energy, though two broad approaches recurred.

First, seasonal time of days arrangements tend to be preferred especially in older contracts. These STOD structures are fairly simple and very similar, with rates often divided into two seasons (winter and summer), with both having separate night/day rates for the week, but sometimes weekend rates and a peak rate for winter. The prices quoted to us were average prices based on the STOD so it was not possible to comment on the different seasonal or daily rates.

The second approach involved the use of a reported market benchmark to establish the price. This mechanism was commonplace in the PPAs. The benchmark is often a seasonal price (winter, summer baseload contract) reported by Heren or Platts or some other recognised price reporter (though as we see in section 6 day-ahead prices are used by some suppliers).

Virtually all generators indicated that the existence of a floor price in the contract and its level was almost more important to them than the basis on which the market price for energy was passed through in terms of getting finance. Virtually all post NFFO contracts had a floor price. However, one developer commented that confidence in power and Roc prices meant that it had been able to bank some contracts recently without a floor price, though this was a recent phenomenon. There was also an expectation from generators that suppliers would discount the price benchmark much less than in the past as they had become much more comfortable with managing imbalance and the associated risks.

5.5 Contract terms

There are no standard form off-take contracts readily available for counter-parties. This is unlike the case with bulk wholesale power transactions and scale Roc transactions with the Grid Trade Master Agreement (GTMA) and the Renewables Trade Master Agreement (RTMA) respectively, where a common, standard term contract has been established, Some generators commented that contract offers were much of a muchness in terms of price and terms. One observed it was possible "to throw a blanket over suppliers" (though it also commented that terms generally had improved across the market). Two others commented on the inflexibility and similarity of suppliers' terms.

We did not have direct access to contract terms. However as we see in the following section all suppliers tend to start from the basis of an offer based on their own standard terms, though they expect to have to vary these terms as a part of the negotiation, especially for larger producers.

One Esco and one generator thought the existence of pro-forma contracts would be beneficial to new entrants.

5.6 Contract fees and charges

Various fees are levied under PPAs and offtake contracts. These were contract specific but typically include:

- a meter (MPAN) specific fee to cover pass-through of the direct addition costs of the meter in central settlement;
- associated data handling and agent fees (e.g. meter operator, data collection and data aggregation costs); and
- sometimes a small monthly administration or management fees.

Few concerns were put to us with regard to these costs. They are mostly function and site specific. Some noted differences between suppliers in some of the detailed aspects of the offers, which from a generator's perspective can complicate the evaluation, but others did not comment adversely on this level of differentiation.

5.7 Procurement approaches

Most generators would approach the bigger suppliers, who are well-known, though they would not necessarily ask all the Big Six suppliers to quote. Some generators felt that it was sufficient to get quotes from maybe three or four suppliers. Legacy issues undoubtedly play a part in the sense that a generator might approach the former incumbent supplier in its area or the supplier from whom it sourced any supply arrangements. Some generators actively also solicit other counter-parties, most usually the specialist consolidator, especially where size (i.e. limited volumes) might be an issue.

There were some limited signs that some of the established generators were adopting more dynamic procurement arrangements. One was developing a framework contract with annual options of when to lock in prices. It thought that it now had a fair baseline with suppliers so that there was better value to be had for it going forward from targeting the point at which to go to market rather than waiting for a fixed point in the procurement calendar.

Others noted suppliers could easily be over-loaded with approaches, and one commented this consideration made it want to engage with suppliers sooner than it had done in the past.

In contrast a large multi-site operator adopted a rigid framework with clearly defined processes and timescales set by the board, which meant that very prescriptive processes had to be followed in how and when it went to market reflecting tender requirements (e.g.

OJEC) on utilities. Other companies in the same sector may be bound by similar requirements.

5.8 Green benefits

Rocs and Lecs are the two green benefits, and they are now key in the market for offtake power from distributed generation. As we saw in section 2 Rocs are awarded to defined eligible technologies; Lecs are also awarded to renewable generation (including certain applications such as large hydro, which is not Roc-able) and also to good quality CHP. In both cases there is a market rate (discovered in different ways), but this value is split between the generator and offtaker through negotiation.

Even where green benefits are packaged with power, it was usual for the different elements of the package to be separately priced, with benefits split on a case-by-case basis. Prices are set by reference to:

- in the case of Lecs, against the legislatively set level; and
- in the case of Rocs, the value of the relevant buy-out price and then separately for the recycle value.

5.8.1 Rocs

We were told of a variety of different arrangements:

- one generator producer received only the buy-out price, but in full;
- another was paid the buy-out fee but an administrative fee was also levied by the supplier;
- one received a fixed price in respect of both elements;
- one who had only recently commissioned had entered into an offtake agreement but was considering how to sell its Rocs;
- one received 90% of both the buy-out and the recycle value; another 100% of the buy-out but a lower proportion of the buy-out; and another similarly received the same but unspecified share on both elements.

In this context most producers acknowledged that shares retained by the generator had improved. They variously suggested that this had happened as competition had increased for Rocs and as suppliers had become more familiar with the RO and the risks under it.

In terms of the commercial terms for acquisition of Rocs, most long-term deals continued to be on a percentage basis. Only one generator from our sample was on a fixed price basis. One received only payment of the buy-out fee, with no recycling element.

5.8.2 Lecs

The Lec has a face value as prescribed under legislation. This was £4.30/MWh in 2001, a level that was constant for a number of years. In the budget of 2006 the value was linked to inflation. Its current value stands at £4.56/MWh for the 2008-09 financial year. Lecs are sold with the power.

Again there were various differing arrangements reported by respondents but there was greater similarity than for Rocs:

- quoted rates ranged from 85%, to 90% to 96%;
- one producer said it received 100% of the face value subject to making available the associated Rego[12];
- no producers indicated they were receiving above face value, though some suppliers suggested that that might now be the case.

5.8.3 Separate markets

Rocs can be included in the offtake power contract, but they are often sold separately, and distinct markets have emerged for the two. In fact as we see in section 6 some suppliers have different appetites for participation in the market for power plus Lecs on the one hand and for Rocs on the other.

Some generators saw the distinction between the markets as advantageous. This was partly because Rocs are a distinct product that were specifically designed to be traded separately and as a compliance measure, but also generators believed that they were able to achieve a better price through unbundling their products. Whether this assumption is correct is hard to say, but one consequence of the separation is that it is possible to go to market at different times and through different routes.

This position did not mean that all generators sold the output separately from the Rocs; indeed several respondents did not. We noted that those producers who sold their power to the specialist consolidator also sold their Rocs to them. There may be an issue here about scale and mitigation of transaction costs, though there was good awareness among the generators we spoke to of the NFPA e-Roc auctions for the purposes of selling unsold Rocs.

5.9 Embedded benefits

As noted earlier, “embedded benefits” is the generic name given to the various benefits that arise from licence-exempt, exemptible and/or distribution-connected generation. Some benefits accrue to the supplier (or other party) responsible for trading the generator’s power rather than directly to the generator itself. In these circumstances some of the value may be shared with the supplier. This sharing is agreed contractually between the generator and the supplier during negotiation of the PPA or off-take contract.

Not all offtake agreements recognised full embedded benefits. We found only two examples of full benefits being accrued, and this involved large generators. In one case this arose because the producer was CVA registered and could claim the benefits direct. One other generator said it received payments for both triad and BSUoS benefits. All other respondents received a share of triad but not of other benefits.

In the round the value of embedded benefits to the generator (where these are paid out) had increased usually in both absolute and relative terms. This was a consequence of the increase in National Grid’s demand charge (which drives the value of the benefit in each GSP Group) in the case of triad benefits, and also reflected the sustained increases in BSUoS since 2005 and Betta roll-out.

[12] Renewable energy guarantee of origin (Rego) certificates are also claimable from Ofgem. They presently have a nominal value.

There was evidence that generators were negotiating larger shares of the available benefits. 80% used to be "the going rate" for the triad benefit. Some were still paid at that level. One generator referenced different shares at different sites. Another with a similar portfolio quoted higher rates at 90%. One recent wind entrant quoted 85%. One larger portfolio operator served by the same supplier quoted 97.5%, and another 95%, and both noted that they had seen a gradual improvement in terms on offer for embedded benefits over recent years. Another two did not give a range but said the pay-out had increased to acceptable levels.[13]

As we will see in the next section some suppliers do not seem to actively solicit embedded power that does not attract green benefits, which is a change on the commercial environment under the Pool. According to one conventional generator we spoke to this reduced appetite for embedded benefits seems to arise not because perceptions of value have changed, but because the relative importance of power with Lecs and ideally Rocs is greater. This generator still felt that there was competition for its output.

Overall many of the established producers regarded embedded benefits as a valuable element of the commercial deal, especially the triad benefit. In contrast some smaller operators and newer developers were either unaware or unconcerned about the payout of embedded benefits.[14]

There were indications from some respondents that complexity in the area of embedded benefits was a concern, and it complicated producer relationships with suppliers.

5.10 Other views

One generator commented that it felt that it was getting poorer deals because of its size, and highlighted the value of consolidators in the market who did not discriminate on the basis of size. However, in the case of this generator the terms of the deal seems to reflect the point at which it went to market, that is 2002, when it signed up to its current supplier. Other generators commented that the small size of some plants did not matter, and they found it relatively straightforward to add new sites to existing agreements.

At the same time several generators commented that the situation had improved. One, who had recently gone to market with a new 15 year PPA, said it was "surprising how far we have been able to push suppliers". Several sensed a real keenness to deal with them owing to their relatively large size in the distributed energy market and the large number of Lecs that went with the portfolio.

One generator was considering options of how to further optimise value through use of intermediaries (who offer trading services between buyers and sellers), though it highlighted credit concerns.

[13] The NFPA auctions are treated differently. Under the auction rules an allowance of 80% is mandated as payment for embedded benefits to the producer under the trading rules, which is additional to the payments made through the e-power auctions, which represents the lower levels of recognition seen in the past.

[14] Two others did not provide answers.

6. Responses to Questions: suppliers

The questions below reflect the questions tabled with suppliers (see annex B). In discussion with the suppliers, further information was put forward under similar headings, and we have grouped this accordingly. Some general comments were also made on the development of the market, which we have tried to capture first.

6.1 General remarks

Suppliers indicated two general aspirations:

- to cover increasing demands for green power especially into the business markets; and
- to be Roc-compliant subject to availability at an acceptable price, though recognising that this was very difficult in a short market.

The Big Six suppliers seemed to aim to contract for as much associated power as possible. Where they specified targets, these tended to be driven by the order books of the supply business for renewable Lecs.

Consequently all of the Big Six would quote in response to an approach from a generator or in response to a published tender. Output from larger distributed generators was particularly in demand, though different suppliers had different views on what constituted large in this context (defining it variously as above 1-10MW).

The smaller independent suppliers had a range of strategies. As a general observation those that did not consider themselves to be specialist suppliers (e.g. green suppliers) had come to the offtake market much more recently. In contrast the green suppliers fully backed off their sales with Lecs and had been fully compliant since inception of the RO. Two of them had "cancelled" Rocs they had acquired.[15]

That said, several of suppliers active in the business markets were very "Lec hungry", especially for renewable Lecs, because of the market in which they operate where increasingly large consumers wanted low carbon energy. Increasingly, businesses and public sector organisations with corporate social responsibility (CSR) objectives have required Lecs associated with their power supply to avoid the CCL but also to evidence green supply. These smaller suppliers tended to be less concerned by Rocs, and were relaxed about a high exposure to buy-out payments, as we explain below.

Not all smaller suppliers were routinely approached by generators. Two of them commented that the onus was on them to make themselves known to generators. They were doing just that and they were now aggressively in the market, especially for power associated with Lecs. Some producers cited credit or reputational issues, that may have acted in favour of the bigger, better known players in the market. This meant that in some cases they would not do business with suppliers who were not able to offer an investment grade credit rating or a parent company guarantee.

We pressed suppliers as to whether there was a threshold below which they would not usually seek output. In general, they do not seem to have articulated such a threshold as a

[15] Roc cancellation is the term used when a supplier exceeds it individual obligation and chooses not to redeem Rocs. It would thus avoid the buy-out but not receive any recycling payment on the cancelled Rocs. It ensures that a supplier can demonstrate that its actions have increased the level of qualifying renewable power in the market above what it otherwise would have been, in conjunction with which it would probably offer a green tariff.

formal commercial policy. One supplier said that 10MW was the point at which it became worth employing external lawyers, and that below that level they would use a standard contract. They would leave smaller generators to someone else. If approached they would always quote their standard terms for anything above 500kW. A couple of other suppliers referenced a 1 MW cut-off point. One supplier said that it would go after most opportunities brought to it, and did not see a 1MW "threshold". Another supplier referenced 100kW. The transaction costs associated with small parcels of power was cited as the main reason for not actively pursuing such parcels.

In some cases discussed with us the position depended on the wider context. For instance, the generator might be a customer on an existing supply arrangement, although suppliers stressed that each business had to be self-standing. Or a deal might be expected to lead to more transactions down the line or an enduring relationship. There was also an implication that strategies were varied depending on other contracting activity at any particular time. It was clear that most of the suppliers have a finite resource in this area. (Front office staff were usually two to three individuals, some of whom had other responsibilities. Middle office support was usually available, but was variable and not dedicated.) We did not hear of any instances where suppliers turned a generator away without a quote, though this of itself does not mean the generator found the quote acceptable.

Overall most suppliers indicated they would "take anything" subject to negotiating an acceptable price and a reasonable volume because of the strength of the market appetite for Rocs and Lecs. In this context less attractive developments (perhaps those that were small and/or had higher imbalance risk) would simply be offered less attractive prices. One supplier said it was less interested in pure embedded power. All suppliers who commented said it was the bundled or overall value at the end of the day that was critical.

The overall impression from suppliers was that the market is "technology neutral" (suppliers do not have technology preferences or dislikes), which is a significant contrast to the views expressed back in 2002. It is noteworthy that:

- owners of landfill gas and biogas, established technologies which saw sustained growth during the 1990s under the NFFO, have seen consistently the best terms, especially where stable exports are involved (often some portion of the quantities are consumed on-site);

- in the early days wind developers clearly experienced difficulties getting prices they considered acceptable, with contract penalties imposed for moving outside of set parameters. However all the big suppliers indicated to us that they now felt much more comfortable dealing with wind output and how to assimilate it into their portfolios; and

- an element of uncertainty seemed to be apparent with regard to biomass, reflecting the relative market unfamiliarity with the technology, which was just coming to market.

Because of the way the market has developed and because incentives such as Rocs have become more important, large volumes of wind generation have entered the market since 2002 (and especially since 2005). Biomass output is beginning to come through. Increasing familiarity with wind output and its impact on plant portfolios has led suppliers generally to be more relaxed about the terms they are able to offer. It is probably also relevant that spill prices that the offtaker sees have also improved consistently, with the implementation of P78 in February 2003 being a landmark.

This increased confidence with wind generation has manifested itself not only in better prices, but also in more flexibility on contract duration and structure and better sharing of benefits with the producers. Biomass too is increasingly being seen as a proven, established technology with only a small discount applied reflecting its stability of output. Conversely some of the newer technologies such as conversion technologies coming to market were seeing less attractive deals from suppliers, probably reflecting the novelty of some of the applications and suppliers' lack of familiarity with them.

Given the incentives provided by imbalance prices under Neta, it is not surprising that suppliers prefer predictability of output. However better understanding of the new trading arrangements and the operational environment, including changes to imbalance price formation, have been important factors in the willingness of suppliers to contract with a range of different, sometimes intermittent technologies.

We turn to the more detailed questions and responses below.

6.2 Contracted volumes

One supplier shared with us its estimate of public domain data that showed the extent of PPA interests of each of the Big Six suppliers. This showed a range of power under contract of between 0 and 13TWh. This data did not gel entirely with comments made by respondents, although few hard data and figures were given, suggesting that there may be definitional differences. But these figures and our discussions highlighted clearly differing strategies between the six major suppliers.

Nevertheless all large suppliers had a mix of direct ownership interests in schemes and offtake power as well as Rocs under contract, and all had strong commercial goals (some quantified) to increase presence in the market. In some cases these were reflected in business plans, with one supplier having both distributed power and green targets.

Smaller suppliers may be divided into two groups:

- those who were specialist green suppliers who were active in all parts of the market; and

- other non-domestic suppliers who had come to the market relatively recently and now saw strong demand for Lecs and (to a lesser extent) Rocs which they were intent on meeting.

6.3 Contract distributions

All large suppliers and specialist suppliers were active across these areas and were seeking to increase involvement in these markets going forward in response to customer demand. Virtually all highlighted that the initial impetus was often customer driven. Smaller, non-specialist suppliers were increasingly involved in the short-term markets and had become active participants in the NFPA auctions.

One supplier noted it had 350MW of onshore wind and 50MW of biomass plant under contracts of longer than 10 years (using the classification above, we would consider these in-house schemes). It had a further 100MW of shorter duration contracts mostly for a year but some on two year arrangements; and a similar amount was committed through the NFPA power arrangements. It considered that it had the largest portfolio of long-term PPAs relative to its peers.

Another supplier had a portfolio of PPAs and offtake agreements, with both renewables and a significant focus on CHP generation.

Supplier [ ] said it had 2TWh of output under contract. 25% was under arrangements of longer than 25%, 70% of durations between 1 to 5 years, and the remaining 5% acquired through the NFPA e-power auction.

Supplier [ ] was more active in the offtake market, typically seeking contracts of between one and three years. It said it was in the process of moving into the long-term market where it could better assimilate the plant into its own portfolio and operational decisions.

Supplier [ ] had contracts for about 4TWh of offtake power, and it estimated it was the third largest procurer in this respect.

Supplier [ ] did not provide comparable information, though we know from wider market intelligence that it is one of the most aggressive players in the market for distributed energy.

6.4 Direct investments

All of the Big Six had equity holdings in distributed energy, though relative standings different widely.

Supplier [ ] had significant interests in renewables schemes through its shareholder, but these assets were in a separate subsidiary. The company provided the route to market through the retail business.

One supplier [ ] said it had "negligible" interests as yet (though we think its treatment of these contracts as external PPAs might alternatively be treated as direct investment).

Supplier [ ] had ownership interests in 2TWh of plant, primarily through two subsidiaries.

Supplier [ ] had some existing renewables holdings and an active CHP business. It also had a pipeline of in-house assets, which it said, would soon start to reach commissioning.

Supplier [ ] had as yet small equity interests, but a number of a schemes were also in the pipeline, and a subsidiary company was actively developing a portfolio based around wind. It recognised it was "catching up".

One smaller supplier also had direct investments in small schemes. But other smaller suppliers we spoke to were focussed as yet only on the short-term markets.

6.5 Quantities and prices

Virtually all purchases now were on a variable quantity, floating price basis, especially under PPAs, referenced typically against wholesale price markers. Fixed price deals were now rare and were usually priced at a premium. In most cases a STOD structure was used though one supplier offered a single average price. Most suppliers (but not all) preferred bundled deals but also bought Rocs separately. All suppliers finessed prices according to technology, location and size, through complex pricing models.

The price offered might vary reflecting other factors, especially size. One supplier commented that it tended to seek lower margins from larger plant, while output from smaller schemes would be discounted. But in most cases the price is set by reference to some market index, often a seasonal contract price. On this basis the supplier would apply its discount to achieve margin and reflect its estimate of offtake risk. In most cases that price would be adjusted to reflect embedded benefits (where these are recognised) on a site-specific basis as well as the discount for imbalance/margin.

Output variation tended to be dealt with by discounting the energy price to reflect any intermittency and the associated imbalance risk (more on imbalance risk below). All suppliers have sophisticated pricing models that carry out such valuation.

All supplier [ ]'s contracts now were for variable quantities. It preferred to have separate Roc arrangements. Each approach was priced individually, reflecting site and technology specific risk and also the size of schemes. Smaller schemes were "difficult to deal with" and this was factored into the price on offer, but it expected specialist consolidators to deal with the smallest schemes.

Supplier [ ] also commented that fixed price offers saw a higher risk premium. Producers were less inclined now to seek floor prices. The company preferred to use day ahead price indexes, especially for wind as it was much more difficult to access a forward value for the power. It would then translate the average price in a STOD tariff structure.

Supplier [ ]'s agreements were primarily for variable output. Pricing was site and technology specific. It preferred not to use STOD arrangements, and in contrast to most competitors offered a single average price.

Supplier [ ] bought variable quantities on a STOD tariff. It recognised the need for floor prices, but observed these were being lowered now lenders were more comfortable with Roc and Lec payouts, with consequent greater flexibility to design other aspects of the contract in a way that was attractive for both parties.

Suppliers [ ] and [ ] said they utilised STOD structures, and would usually include a floor price at the developer's request (which would usually include some adjustment for benefits).

6.6 Procurement strategies

There were few proactive strategies outlined to us in the sense of suppliers going out targeting specific sites, projects or technologies with a clear contracted volume in mind. Increasingly an appetite for Rocs and Lecs had dominated over a desire for the power in its own right, and virtually all suppliers referred to this.

Most commented that they would adopt a target for the year but would update that as needed with information from the retail business, especially where new non-domestic customers were added within year whose supply required offsetting Lecs. These were not technology specific (though Roc eligible technologies were preferred). Virtually all suppliers said if quantities became available they would be interested in tendering.

On supplier would "take anything" subject to reasonable scale. It recognised that the longer-term market was dominated by wind, but biomass was coming through. Landfill gas and hydro tended to appear in the short-term market. It considered that it "needed to be active" in all these subsets of the market.

Supplier [ ] was primarily interested in renewable output, though had a tranche of CHP. It was less interested in pure embedded power. It commented that, while it would contract down to 100kW for hydro out-put, for other technologies there was effectively a 1MW cut-off.

Supplier [ ] said it would offer aggressively for anything in area but probably would not turn down anything out of area either; it all depended on "what came along". In contrast to some other suppliers it was aggressively seeking small parcels of output and had terms with 500 micro-generators. It did comment that, while it was willing to enter an agreement for "any shape or size", things got more interesting above 200kW.

A similar perspective came from supplier [ ], who said the company would go after most opportunities brought to it. It had recently concluded more deals with smaller sites. It did not see a 1MW "threshold". Very similar remarks were made by another supplier.

Supplier [ ] purchased where it could up to defined trigger prices. It considered itself to be very competitive on predictable generation. It acknowledged it was more risk averse on unpredictable technologies where output was purchased on the market (it had fewer qualms over in-house plant), and also commented it was probably weakest in the below 100kW market, but felt there were already specialist players beginning to focus on this part of the market. "Options opened up above 500kW", it noted. Over 5MW they would also seek to tailor trading services with generators.

Supplier [ ] commented it was keen to catch up with its competitors having come to the market late. As a consequence it considered itself an aggressive purchaser in the NFPA auctions, but was actively seeking to grow the offtake business across all timescales.

6.7 Green benefits

Most of the Big Six set an annual Roc quota based on their obligation defined under the order in each year. However few expected to realistically achieve the target given the structural shortness of the market. The issue in this context for the supplier was whether it was prepared to match the robust bid prices that were increasingly expected.

Two of the smaller suppliers we spoke to (who were not specifically green niche players) were less concerned about Rocs, seeing the choice between Roc acquisition and paying the buy-out as a simple one. Rocs were attractive if they could be acquired relatively easily and at comparable cost to paying the buy-out, allowing for their expected value of the recycle payment. Cashflow was also important, especially to smaller suppliers, as Rocs bought bilaterally or on the open market needed to be paid for (buy-out plus recycle allowance, respectively) at the point of acquisition, whereas the buy-out only had to be paid some six months after the end of the relevant compliance period.

Some suppliers had explored and were committing to a form of monetarisation scheme where the developer receives 100% of a fixed amount for both elements (that is above the buy-out rate), thus removing cash-flow exposure to the recycle value. It entailed discounting the fixed payment to reflect the time value of money as it would otherwise not have to pay the recycle element until well after delivery. One small supplier and one Big Six suppliers were certainly offering this approach based on the answers they gave us (and anecdotally there are more).

Imports of Lecs from outside Britain were seen as a valuable procurement route. Four suppliers referred to this, though details were not disclosed.

With Rocs one supplier said it had sought to meet its annual RO obligation, but failed. Additional demand for Lecs might appear within year if it needed to match power sales in the non-domestic market. It had no problem with over-purchasing Lecs as these did not have a maturity date. It was content to import Lecs where they were available.

Supplier [ ] was primarily interested in renewable output for Rocs and Lecs. As noted, it was less interested in pure embedded power. It too noted it was importing Lecs.

Supplier [ ] highlighted the importance of levy exempt sales, and the associated demand, which was tending to push up Lec values. In contrast the company had a clear view on what was an acceptable price for Rocs, and if its valuation was acceptable to a producer it would purchase.

While Rocs and Lecs were important to supplier [ ], it did not consider it was unduly focused on them. It observed that the market had responded favourably to government proposals to strengthen the RO, and that this was reflected in better sharing arrangements.

Supplier [ ] was seeking to grow its participation in all green markets aggressively. "The supply business was at risk", it commented, without such a strategy.

Supplier [ ] also commented on the importance of the supply business in setting targets for green benefits and the associated power. It had been an active participant in the NFPA auctions since 2002, purchasing 1.5TWh through this mechanism. Lecs were increasingly a strong driver of the market.

6.8 Benefit sharing

All suppliers noted that terms from the generator's perspective had tended to improve but that there was no "right value". Ordinarily suppliers retained some element of the benefits because of the costs they incurred, but different judgments were applied, and some suppliers applied transaction fees but others didn't.

Supplier [ ] simply said that the share was a matter for negotiation.

Supplier [ ] noted its pay-out had increased "in line with market practice". It accepted that 90% for the Roc buy-out and 95% for the recycle payment, which was "probably the going rate". Lecs were also becoming more expensive, and it had had to move embedded benefit shares from 80% to over 90%. However, it commented that at the end of the day it was the bundled price that it considered most important, a view it believed was shared with generators.

Supplier [ ] said all benefit sharing had become much more competitive. It was still prepared to offer a fixed price for producers who wanted certainty.

Supplier [ ] had initially preferred fixed price deals, but now preferred a sharing arrangement with a small admin fee.

According to supplier [ ], supply defaults in the early years had undermined the market and led to increased risk perceptions by suppliers. However, generators were now receiving close to full value of any Rocs or Lecs less purchasers' working capital cost, especially now the Roc market had stabilised.

Smaller suppliers said they were now paying par value or in some cases above for Lecs, recognising the heavy demand for these in the business markets and the premium price they could charge for green power. They were less concerned about Rocs.

6.9 Imbalance bids

All suppliers commented that they felt much more comfortable with imbalance risk and pricing it than under the early days of Neta. They had now built up a reasonable track record of operational information. Default rates and surcharges were much less a feature of contracts than under the early days of Neta.

A better understanding of risks had driven down margins, according to supplier [ ], and the onshore wind market in particular was much more “mature and stable”. Biomass was just coming to market and was subject to greater variation in the offers being made. Average prices were around 85% of the relevant wholesale price marker for wind, recognising the imbalance risk issue and the need to mark down to allow for the supplier’s costs and margin; but a better percentage was being recognised on biomass schemes.

Supplier [ ] quoted an average price of 80% of the appropriate marker rate for wind, noting that it had been able to pass through recent improvements in price. Different generators required different packages. This supplier would only default to SSP where there was no notice of operation.

One supplier [ ] also discounted imbalance risk against the nominated pricing marker. It no longer applied forecasting penalties.

Another supplier said the risks in the offtake market were now much better understood and it felt able gradually to offer higher prices both in absolute and relative terms.

Supplier [ ] left pricing to the middle office support staff who ran the pricing model. SSP would still be applied but only where the counterparty operated outside contract parameters without notice. While imbalance risk was much reduced, it felt the issue was still real and could not be hedged, so it had to be passed through to the generator.

Imbalance pricing was less of an issue for non-specialist smaller suppliers as their primary focus was Lecs, not Rocs.

6.10 Top-up and back-up arrangements

These arrangements tended to be the responsibility of a different part of the organisation. (They are usually linked to sales agreements, and are addressed on a site-specific basis on a short-term, typically annual basis.) We therefore did not explore this matter further.

6.11 Pricing and unbundling

Supplier [ ] and supplier [ ] preferred bundled offerings, and felt generators preferred this too. However, supplier [ ] remarked that the market was becoming much more varied, and was changing year-on-year). In some instances there were several different contracts with the same generator, so it was becoming harder to generalise.

6.12 Market trends

Supplier [ ] was “constantly looking at the small end of the market, but it was difficult”. There was probably a role for specialist consolidator of micro-generation and small scale operators. It felt this might be an area where NFPA could be more involved.

Supplier [ ] commented it was likely to much more engaged with independent generators going forward. It was also considering development of an offer to smaller generators, below 1MW. It also commented that transmission and triad issues made the market more complex than it needed to be.

Supplier [ ] said the "market was undoubtedly more competitive", and had moved a long way since the flat market where the generator had to contract with the local supplier on whatever terms were presented. In Scotland Betta had helped, and most generators there would now get around six offers for their output. The company had become much more aggressive in the market, especially since some of its own distributed generation plans had stalled. It was looking closely at the smaller end of the market, especially as it felt some of its competitors would not go below 1MW.

The same supplier commented that existing generators were going out to market at different times and some were now seeking to lock in higher prices in longer-term deals. Further it felt there was little room for intermediaries save for specialist consolidation by smaller players because it was relatively easy to reach the Big Six.

Supplier [ ] said its strategy was to have "as high a percentage of output from distributed energy and the associated Rocs and renewable Lecs as possible, without paying over the odds". CSR programmes were increasingly very important, which probably meant Lecs might be presently undervalued. Some competition was appearing at the smaller end of the market (Tradelink Solutions, Good Energy, Green energy).

Supplier [ ] commented that banks were adopting a much less risk adverse attitude, a point echoed by to others suppliers.

Supplier [ ] was vigorously targeting community scale schemes, including heat. It acknowledged there was some inflexibility at the smaller end of the market, which it defined as below 1MW. It felt there was real added value in consolidation but expected the specialist consolidators to fill the gap.

6.13 Resourcing

All suppliers had between two and four people engaged in front office roles dedicated to contracting with third party generators, the bulk of whom were renewable operators connected at distribution level. They all referenced resource issues and highlighted that they tended to be reactive, dependent on generators approaching them or issuing tender documents. All received middle office support on pricing and contracting.

6.14 Contract terms

Suppliers said they were generally reluctant to vary these from their standard contracts, and would not usually show flexibility unless they had to. 10MW was cited as benchmark by one supplier, as above this level external lawyers might need to be involved anyway. However an important consideration here was the relative experience of the generator.

Most suppliers said that, over time, they had developed terms that were well-understood and usually acceptable to most established players. Requests for variation often stemmed from a lack of understanding or confidence by new entrants. Newer technologies and applications also raised new issues to which they were endeavouring to respond.

7 Short-term markets and the NFPA

This section looks at the discrete part of the market that falls under the administration of the NFPA, and which was the comment of many generators and all suppliers.

The NFPA (see section 3) was established to manage the NFFO arrangements and the renewables contracts established under the orders. With the termination of the Pool, it then took on responsibility for managing the output of the NFFO contracts. It has provided a route to market for NFFO energy quantities, associated Lecs and Rocs through two platforms:

- half year auctions of power with benefits; and
- a separate quarterly e-Roc auction.

Outside of the PPA and offtake markets (one year duration and upwards), there are few options for within year trades. All generators that submitted responses to us looked for a minimum one year contract, and as we noted above all contracts were either based on variable quantities or envisaged reconciliation and settlement of quantities outside of nominated volumes in contracts. The only uncontracted quantities produced were therefore those under NFPA contracts that were based on fixed quantities (termed additional metered output or AMO) or in a couple of instances under old NFPA arrangements that had come to the end of their contract term and for which a successor arrangement had not been established. These volumes have tended to find their way onto the market through the NFPA e-power auctions.

Further, as for Rocs, over-the-counter (OTC) activity, which has always been limited because of the compliance nature of the market, has largely dried up after the supplier business failures of 2002-03 (CP1) and 2004-05 (CP3). Nevertheless as we have noted some producers sell Rocs separately from power, and a popular place to sell those has been through the NFPA's e-Roc auction.

All suppliers we spoke to indicated that the platform was an important source of green power and associated benefits within year. This includes some non Big Six suppliers. Most participate in both the power and the e-Roc auctions, though a couple commented that they saw the facility as a balancing market for Rocs against retail contracts, and therefore assessed it separately.

Of the generators we spoke to, several offered volumes and Rocs through the NFPA facilities. Two generators commented that they waited on the outcome of the NFPA auctions before going to market with its Rocs, to avoid the transaction cost administered by NFPA and because they then had a benchmark for an acceptable price.

We also spoke to the NFPA, who described some of the steps they are taking to increase trading through its auctions. They are currently developing a database of generators who are likely to be interested in a contract for full output, including Rocs, Lecs and Regos, concentrating on the 300kW plus market. They had no early plans to change the structure of the auctions for power: "Currently contract periods are six months because that is what suppliers (who, after all, are the buyers in the auction) have said that they want." However, they recognised that longer terms may be required to meet generators' needs, and the NFPA had it in mind to solicit their views.

We also spoke to suppliers. All respondents highlighted the importance of the NFPA auctions for both power and Rocs. Some felt there was scope for broadening the scope of the facilities and removing inflexibilities in the trading rules.

Supplier [ ] said the NFPA auctions were a significant source of Rocs for it within year, and the market was getting better at forecasting the recycle value. It also increased transparency and offered an accessible platform for smaller suppliers. It was very useful in "mopping up the smaller end of the market". This supplier was comfortable with the process for auctioning power and could readily calculate offer prices on a site specific basis. It commented it would look for a higher margin on newer sites without a track record.

Supplier [ ] was a relatively recent participant in the NFPA auctions. It anticipated it would be much more interested in this going forward as available volumes increased and as the market for both green power and Rocs became shorter. In contrast to the previous supplier it was happy to offer across all sites in a given technology band and saw this as a means of reducing its own analytical effort from participating in the auctions.

Supplier [ ] considered itself an aggressive participant in the NFPA auctions, which it felt provided useful markers on market prices, and were used as a benchmark for other deals, especially for Rocs.

Supplier [ ] saw the NFPA auctions as very useful (but it was the "only game in town"). It considered itself an aggressive purchaser in the auctions, but it felt prices in the latest auctions of Rocs were "too high". It felt the facilities offered a very good route for smaller generators, but from a supplier's point of view it regarded some standard terms as inflexible.

Supplier [ ] had been an active participant in the NFPA auctions since 2002. It felt there was not much margin in purchases through the platform but it had had "nowhere else to go".

8. Overview of findings from interviews

The main findings of our research interviews are summarised in this section, together with some reflections on them.

8.1 Overall assessment

All major suppliers and several smaller ones are active in the market for offtake power in Britain. Most are active nationally. Increasingly smaller suppliers are becoming involved and participating aggressively. No producer said they had not been able readily to find a counter-party; no supplier commented that they were being excluded from the market. The emergence of green energy markets, including the market for green benefits, has acted as a major stimulus to competition. Consequently the degree of change evidenced in the market over the past six years—and especially over the past three years—is considerable. Many of the problems referenced by earlier surveys and of which we heard anecdotal evidence seem no longer to apply or certainly to a much lesser degree.

8.2 Market segmentation

A significant proportion of out-put from distributed generation is off-market in the sense that the generator has an ownership relationship with the offtaker (to a degree vertically integrated as both generator and supplier), providing a direct route to market. Even where the Big Six are involved with third parties in joint ventures, it is commonplace for the utility to provide certainty of price and volumes through its supply business usually in the form of contract between the related entities. Indeed the selection of the utility companies as partners is driven by their ability to provide such market access.

However, the development of in-house capability or equity investments of itself does not seem to inhibit these suppliers from participating in the wider market for off-take power, and it does not seem to constrain activity by their competitors in this market. On the contrary all major electricity suppliers are active participants in the offtake market irrespective of the size of their own investment in distributed energy projects.

Offtake arrangements with third parties are based on a threefold mix: of long-term PPAs, short-term purchase or offtake agreements with established plant, and within-year trades primarily procured through the exchange-based platforms operated by the NFPA.

Activity by other third party providers, such as brokers and other intermediaries is limited, and does not seem to have grown significantly over recent years despite the proliferation of independent distributed generation. We explain this as a consequence of the producers' need to derisk projects by entering into longer-term arrangements where they can. Many developers prefer to do business with companies with an investment grade credit rating, which in effect narrows the field to the Big Six for larger projects. Smartest Energy, the specialist consolidator is also seen as an eligible counter-party as it can offer parent company guarantees.

Furthermore, as contract structures now predominately are based on variable volumes, there are simply few surpluses available for trading as existing contracts already deal with these extra volumes.

The PPA market is based on multi-year contracts, typically around ten or fifteen years. Developers can expect widespread interest when a scheme comes to market, especially where Rocs and Lecs are involved. We were not privy to any contracts but each supplier seems to have its preferred pro forma contract terms. They will contemplate tailoring these at the producer's request if larger quantities are involved.

Probably the main difference between PPAs and shorter-term agreements (other of course than the duration) is that with PPAs the offtaker will usually acquire all the power and the associated benefits.

A common arrangement (but by no means the only one) for the purchase of shorter-term power, usually in the form of annual blocks, is:

- by site, usually including Lecs and embedded benefits;
- separate Roc agreement, sometimes with a different counterparty; and
- prices set by reference to some wholesale market price marker, discounted to provide the supplier margin and to establish a discount for imbalance risk and the supplier's costs.

The NFPA exchange gives a clear route to market for those relatively modest quantities that are uncontracted or produced as surpluses outside of contracts.

A further factor limiting trading is that the Roc market is a compliance market, and it is unusual for a supplier purchasing Rocs from a generator to on-sell them given that the market generally and most suppliers individually are significantly short. In fact the volume of Rocs sold through the e-Roc auctions has declined over the past 24 months at a time when the market has become shorter. In fact several respondents commented to us that they used the e-Roc auction as a price marker and then went to market independently. In these circumstances it is not a surprise that the NFPA is effectively "the only show in town" and that wider trading facilities have not developed in either distributed power and/or Rocs.

8.3 Power prices and terms

The main conclusions here are:

- offtake terms vary depending on among other things size, technology and location of generator, with different degrees of unbundling of pricing mechanisms;
- factors such as the wider business context (perhaps whether any surplus power is produced as a by-product), the extent of on-site consumption and size influence how hard certain distributed generators "work" the market, how far they are dependent on market prices but also how hard suppliers seek to attract them;
- though a number of generator respondents commented on the degree of "sameness" of some offers, we found that different suppliers adopted a variety of different approaches;
- in the past, disappointment by generators may well have arisen from differences in perceptions of the value of their power. This observation applies especially for smaller generators. It may also apply to generators who have significant on-site demand so that they can see market rates through the prices they pay, which tend to be higher than the price they are paid by their offtaker.

8.4 Green and other benefits

The main conclusions here are:

- Rocs and Lecs are the primary benefits and relatively speaking are much more significant to generators than embedded benefits. In many respects they are as important if not more important than the underlying power;

- approaches to trading benefits and green benefit sharing are tending to improve and converge, though it is not possible to say, for example, that “the” market rate for embedded benefits is 90% and Lecs 95%;

- green benefits (Rocs and Lecs), especially Lecs, have increased in importance, and the shares to the generator have grown;

- interest in embedded benefits has diminished and is no longer, after the energy price, the primary focus of commercial negotiation. Within the overall scheme of things embedded benefits are much less important than they used to be.

8.5 Supplier differentiation

The main conclusions here are:

- all suppliers said the market was competitive, a point further evidenced by responses to the DEWG consultation;

- a wider range of suppliers have become engaged in the offtake market in recent years, especially the last three;

- suppliers individually seem to have a mix of different commercial approaches and goals, with Rocs and Lecs positions seemingly a more important factor to many suppliers;

- smaller, non-integrated suppliers are entering the market as understanding of the RO has bedded; and

- supplier appetite in the market is increasing rapidly as the “green demands” of consumers have increased, so the output from renewables and CHP plant is increasingly in demand.

8.6 Producer sentiment

The main conclusions here are:

- in general, we do not perceive a state of widespread dissatisfaction on the part of distributed generators, or any single critical issue on which most respondents are united;

- indeed some generators have commented that they have received better offers over more recent contracting rounds, and this is confirmed by pricing data we have seen; and

- this improved outcome may of course be a function of generally higher energy prices, but an increasing appetite (and prices) for Rocs and Lecs is also certainly a factor.

This is not to say that there have been no concerns and criticisms. Among the points made have been the following:

- several generators have said that getting a route to market can be difficult (and more difficult than it should be), and have highlighted a lack of information for new entrants over the options available;

- some have expressed disappointment about prices, though there is a counter-suggestion that this may have more to do with lack of information and with unrealistic expectations before they entered the market;

- some have commented on a lack of interest from some larger suppliers for smaller quantities of output, and/or a sameness of offer (as noted above) and an inflexibility of approach;

- at the same time they have highlighted credit issues, and they are disinclined to invite some suppliers to procure their offtake; and

- of those that highlighted barriers to progress/ entry, physical issues with the distributor for new sites was a frequent issue though perceptions differed between different distribution companies.

These findings tend to align with experience and anecdotal information from the wider sector, but nonetheless should provide a firmer basis for drawing policy conclusions.

9. Assessment of competition

We have been asked to investigate claims that the market for small scale (distributed) generator output is not very competitive. We have found in section 5 that the great majority of small scale distributed generators who we spoke to do not now claim that this market is not competitive. Although some generators made critical comments (e.g. about the sameness of offers from the larger suppliers), their remarks were typically qualified by an appreciation that the market situation had improved over time.

We have nonetheless considered it important to form our own view on this issue. Ofgem has traditionally used a broad approach in assessing the scope and extent of competition in the supply market, looking at wide variety of qualitative and quantitative indicators of the extent and nature of competition.[16] Increasingly, other regulators too are seeing competition as a dynamic and rivalrous discovery process.[17]

In the present case of small-scale renewable distributed generation, we might expect that a competitive market would be characterised by the following sorts of phenomena:

- ability of buyers (suppliers) to choose among several sellers (distributed generators) offering different products and sellers to choose among several buyers offering different products;
- ability of new buyers and sellers to enter the market (and the exit of unsuccessful ones);
- prices tending towards costs (which themselves may be changing over time), and
- the development of new and improved products and services.

In short, we should see market products and practices gradually evolving to better meet the needs of the market participants.

The evidence put to us as described in the previous sections of this report suggests that the market for small-scale renewable distributed generation does indeed seem to exhibit these phenomena. Looking at the broad picture, all major suppliers and several smaller ones are active in the market for offtake power in Britain. Most are active nationally, and increasingly smaller suppliers are becoming involved and participating aggressively. No producers said they had not been able readily to find a counter-party; no suppliers commented that they were being excluded from the market. The emergence of green energy markets, including the market for green benefits, has acted as a major stimulus to competition. The degree of change evidenced in the market over the past six years—and especially over the past three years—is considerable. Many of the problems referenced by earlier surveys and of which we heard anecdotal evidence seem no longer to apply, or at least certainly to a much lesser degree.

Taking each point in turn, there are six large vertically integrated suppliers plus several smaller ones including a specialist consolidator, and the NFPA is actively interested in auctioning output. There are approaching 100 sellers from over 300 sites. Although one generator referred to a sameness of approach among the larger integrated players, we have observed differences between them in the kind of business they seek, in the nature of their offers and contracts, and in the levels of prices and benefits they offer. Differences are also

[16] For instance, Domestic Retail Market Report – June 2007, Ref 169/07, Ofgem 4 July 2007 and previous reports in that series.

[17] See for example the recent appraisal of Competition in the Provision of Water Services, by George Yarrow and colleagues, Regulatory Policy Institute, April 2008.

manifest in their approaches to purchasing from the NFPA auctions. There is overwhelming evidence of buyers and sellers comparing alternatives, competing for each other's business, and actively exercising choice.

The number of buyers and sellers have both increased over last few years. For example, Bizz Energy has entered the market as a supplier, as has GDF ESS. There is a constant inflow of new small generators, and the NFPA is interested in attracting more business by offering a wider range of services. There has been relatively little exit from the market, and it has evidently become more attractive to market participants over time.

Contract prices offered to distributed generators have evolved over time to reflect changes in market prices for power and imbalance prices, and the new benefits offered by Lecs and Rocs. Renewable generators have enjoyed a significant increase in prices as a result. After adjustment for any uncertain delivery times, costs and risks, scale issues and other factors associated with renewable generation, there is no reason to believe that the prices now offered are significantly out of line with those of a competitive market. In particular, there is no reason to believe that these generators are being exploited.

We received various pieces of evidence and illustrations of evolving practice in this market, reflecting greater knowledge and experience of the participants. For example, suppliers are now prepared to pay higher prices for wind generation because they better understand how it operates or can be operated in the light of market conditions. Suppliers are also paying a greater share of embedded benefits to generators. Many generators for their part are becoming more comfortable with standard conditions offered by the larger suppliers. Many participants, both generators and suppliers, indicated to us that they now felt more informed about this market, that they were constantly learning and understanding it better, and felt more comfortable operating in it.

In our view, therefore, there is evidence that this sector is indeed developing well as a competitive market. Practices within it are continually evolving to better meet the needs of market participants.

This is not of course to deny the role of government and regulation in determining or influencing the renewable and other obligations, which of course impact on the value of associated benefits enjoyed by distributed generators.

Nor is it to say that there have been no concerns and criticisms, or an absence of suggestions for improving the market. In section 11 we set out and discuss at some length the concerns and suggestions made to us.

10. Issues and options

Our terms of reference highlighted several areas where specific feedback was requested. They concerned a) market structure and liquidity, b) the reasons for there being only one specialist consolidator, c) the effect of market arrangements (Neta v the Pool), and d) the case for a dedicated purchaser and/or market for distributed energy. We take these issues in turn.

10.1 Market structure

The terms of reference refer to "the effect of the market structure on the liquidity of the market for third party generators. Does, for example, the vertically integrated nature of the industry mean that suppliers are, to some extent, self sufficient in electricity?"

It is true that the British electricity market is vertically integrated to a considerable extent, and that concerns have been expressed about the extent of liquidity in this market. However, a significant proportion of the industry is not vertically integrated. Figure 10.1 shows the position as it is understood to obtain today. Broadly speaking the vertically integrated Big Six suppliers are self-sufficient with respect to power for their residential and small business customers. To a greater or lesser extent they purchase power for their industrial customers from independent generators that account in total for about one third of total generation output. Other suppliers who do not own significant generation also purchase from these independent generators.

Our focus in this report is the market for renewable distributed energy. The vertically integrated suppliers are indeed investing in renewable energy in a major way, but they are by no means self-sufficient either in terms of meeting the RO or meeting in full the green energy aspirations of their customers, nor likely to be in the foreseeable future. There is a significant market for independent power (with and without Lecs) and a different but also significant market for Rocs. The evidence put to us suggests that competition in the market for Lecs and Rocs is already vigorous and is continuing to strengthen. The Big Six are competing actively between themselves and with other suppliers for the business of the smaller renewable distributed generators. Suppliers also continue to have a strong appetite for embedded power and the benefits associated with it. Liquidity does not appear to be a problem at present, though credit issues may be limiting the market.

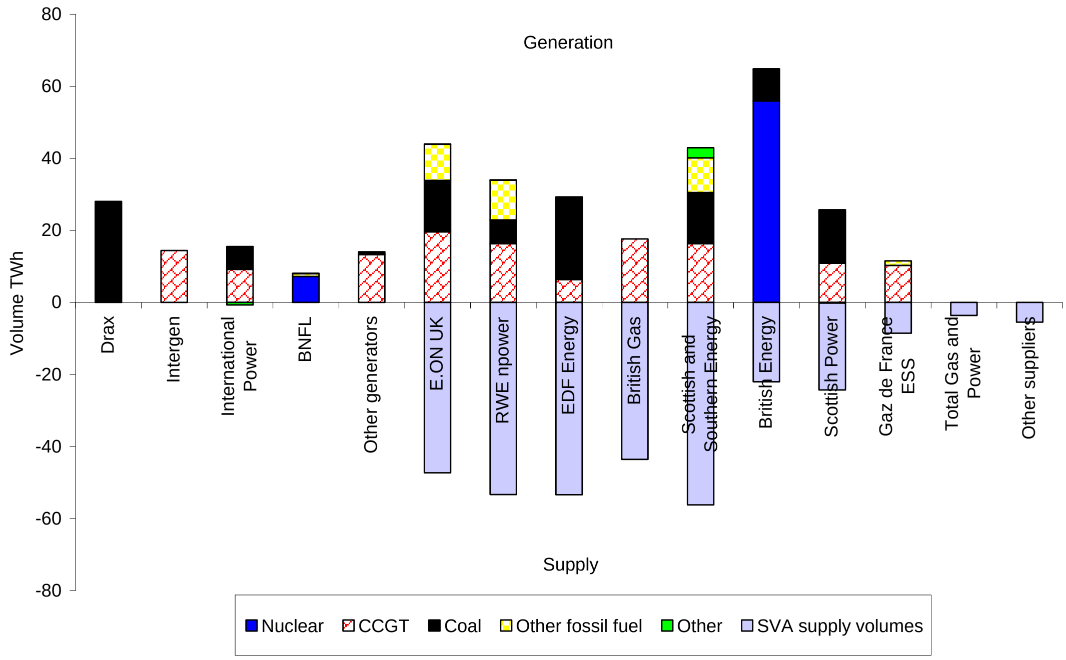
We therefore conclude that at present market structure does not seem unduly to impact on the liquidity of the market for third party distributed generators.

10.2 Consolidation

The terms of reference refer to "reasons why there is only one specialist consolidator in the market. We are keen to explore whether the existence of a single specialist consolidator is natural consequence of the size of the market or whether there is something in the arrangements that is reinforcing this situation".

At the start of the Neta market six entities indicated to Ofgem their potential interest in acting as specialist consolidators. These were TXU, Yorkshire Electricity, Enron, Vattenfall and Smartest Energy. In the event, of these only Smartest has continued in business as a specialist consolidator. This is not because the others entered the market as consolidators and later left or were driven out. Rather, the other firms did not actually become consolidators in the first place: some did not enter the UK electricity market, some left it, some were taken over before they could embark on consolidation.

Figure 10.1—Production and consumption by major parties 2007-08



Several suppliers made the point to us that to focus on specialist consolidators presents only part of the picture insofar as all suppliers are natural consolidators anyway, and therefore competing for the same business as a specialist consolidator. (The consumption of suppliers is measured at the GSP Group level, and for some time they have had strong incentives to buy embedded output because of the value of securing embedded benefits.)

The larger suppliers told us that they were interested in purchasing from any distributed generators, but for reasons of cost and limited resources they had to focus on larger rather than smaller schemes. Views differed as to what constitutes a critical level below which they would find it difficult to give adequate attention to the generator. Some highlighted 10MW as an important size, some half that level and some indicated an appetite for volumes down to 1MW. Another said that 1MW was not a barrier, and one supplier indicated an active interest as low as 100kW. (It is fair to say, however, that that these lower bounds were not set in stone, and in some cases smaller projects could be attractive if a scheme was seen as being the start of the pipeline or part of a wider relationship, perhaps because the supplier combined its negotiations with the offer of a supply contract to a major user.)

Smartest Energy has developed as a specialist consolidator over the past seven years, and appears to have achieved critical mass. It has been successful in attracting distributed generators, especially at the smaller end of the spectrum. Its portfolio presently consists of 1.2GW of installed capacity, with 70+ customers generating from over 350 sites across Britain. It thus seems that Smartest Energy has identified and responded to a niche in the market, by extending its sphere of operation down to 100kW producers.

It should also be noted that some of the smaller suppliers too are giving greater attention to smaller distributed generators in this way.

Is there room for more specialist consolidators in this market? Any entry into the central trading systems is expensive and time-consuming, and this applies no less to consolidators as well as to suppliers. Set-up costs are high. Consolidation also requires specialist skills. At the same time margins seem to be low: about 1% based on Smartest's most recent annual report and accounts. Indeed, to improve margins Smartest Energy has recently decided to move into direct supply to business customers.

In 2005 a consultant retained by FES[18] estimated that Smartest held some 80% of the available market in England and Wales, and it estimated that some 0.6GW of further capacity might become available south of the border by 2007. Betta commencement in April 2005 was expected to bring another 1.1GW into the equation in 2005, and maybe another 300MW by 2007. The report commented that "it should also be stressed that the need of these large suppliers to acquire Rocs would suggest that they would not willingly relinquish control of many of the generators that they already own", and noted the possibility of further acquisitions by these players.

The consultant's conclusion was that "there is no current evidence that [changes in the market] will stimulate another consolidator to enter the market. This is supported by the extent to which the market generally has concentrated with hardly any small suppliers able to compete…". The consultant added "the generation available for consolidation will still be dwarfed by the vertically integrated supply portfolios", concluding "This suggests that a single established consolidator would be able to dominate this segment of the market, meaning that Smartest Energy is most likely to remain the sole consolidator."

While there has been some recent activities with agents moving into aggregation of Rocs under recent changes to the RO, this has been very slight. Trade-Link Solutions is developing "green services" and claims to have purchase arrangements with 300 micro-generators. It then sells the output onto suppliers presumably in the same way as Smartest presently does. With this limited exception, however, we are not aware of any major moves into the mainstream consolidation market.

On the basis of the evidence in our review, we agree that Smartest Energy seems likely to remain the sole specialist consolidator at least for the foreseeable future. We have seen no evidence of others wishing to enter this market as specialist consolidators on a significant scale. However, we would see this as consistent with the underlying economics of a competitive market, and we would not describe Smartest as "dominating" this segment of the market, in the sense of being able to exert any market power. In fact many of its customers expressed satisfaction with the company and its approach. The terms that it offers are severely constrained on the one hand by the costs of operation, and on the other hand by the competitive pressure exerted by all suppliers, who are effectively in the same business.

10.3 Market arrangements and the value of small generation

The terms of reference refer to "the effect of market arrangements on the value of small generation. It is interesting to note that if the "Pool" were still in place such small generation would be realising the system marginal price rather than the current spill price."

Under the Pool, there was a uniform price for energy, paid by all suppliers to all generators. This price made no distinction between predicted or committed demand and generation and unpredicted or uncommitted demand and generation. In contrast, the Neta arrangements

[18] An investigation into the development of consolidation of distributed generation within the wholesale electricity trading, Campbell Carr for DTI, DG/CG/00049/00/00.

recognised that these different categories of demand and generation could be associated with very different costs. In particular, unexpected generation supplied at the last minute could have a much lower value (or occasionally a higher value) than generation committed in advance in the light of expected demand. These differences were reflected in a wholesale market price for generation committed in advance, that differed from imbalance prices for generation purchased or supplied at the last minute. The "spill price" or SSP is the price received by additional generation that is not committed in advance and not provided for under contract.

When Neta began operations, renewable generators were naturally particularly concerned at the impact on them of this change in arrangements. The impact arose not because they are direct participants in the trading arrangements but because the suppliers with whom they had contracts passed through the prices they saw as a consequence of taking the producers power to market. For the most part their output seemed unpredictable, and the divergence between the two imbalance prices was so great at the time that the spill price they received was very low. In they indicated an intention to run but were unavailable they were exposed to very high and volatile "top-up" prices or SBP.

Over time changes have been made to the cash-out arrangements as we saw in section 3 so that the difference between imbalance prices (the "spread") is significantly less than it was initially. With the general increase in wholesale market prices combined with changes to the rules, there has been an increase in the general level of spill prices. In addition, it seems that, with better understanding of the operation of renewable energy schemes, particularly wind turbines, the terms offered to many renewable generators are now closer to the wholesale market price than they were, and they are less reliant on the spill price. Finally, the introduction of prices for Lecs and Rocs has been passed onto renewable generators, together with an increasing share of embedded benefits.

For these reasons, we conclude that market arrangements are indeed now tending to reflect the value to the market of the value of small scale renewable distributed generation.

10.4 Distributed energy purchaser and dedicated market

The terms of reference require us to consider the options set out in the December 2007 consultation document, specifically the possibilities of ensuring that there is a purchaser for the electricity, and the development of a dedicated wholesale market for distributed energy.

We note that these options are prefaced upon the presumption that there might be a problem in the market. In the event, we have found that the market for distributed energy has evolved significantly over the last few years. The great majority of the market participants did not see problems in the market to which the options of an obligatory purchaser or dedicated distributed energy wholesale market might be a solution. Although a few had specific concerns, in general market participants did not complain about a lack of competition in the market. Specifically, they did not find difficulty in selling their output, whether to suppliers or to the specialist consolidator or through the NFPA auctions. Nor did they argue for a dedicated wholesale market for distributed energy, since they had ready access to the existing markets. In fact several of the suppliers drew attention to the costs, risks and other difficulties of providing such arrangements.

We share these views. We do not see evidence of market failure that would warrant such measures. There may be fewer specialist consolidators than some would like, but as explained above we consider that this is explicable in terms of the operation of a competitive market. It reflects the still small size of the market generally, the specialist knowledge required, the extensive established commercial arrangements already in the market, and the extensive competition from other suppliers.

Not only would the creation of such a role for distributed renewable generation be unnecessary, it would be detrimental to parties who are already in this market. This would particularly be the case for those offering innovative consolidating and trading services geared to the needs of smaller scale generators. The operation of such prescribed artificial trading obligations or trading mechanisms could well be costly, inflexible and less sensitive to the needs of other market participants than are present market arrangements. It would also introduce a new source of uncertainty that would discourage other developments in the market.

We conclude that there is not a case for the creation of a specific trader role or a dedicated trading mechanism for renewable distributed generation.

11. Further concerns and suggestions

Although in general generators and other respondents did not complain about the market, they expressed a variety of concerns to us, together with suggestions for dealing with these. The most common issue was a widespread feeling that it would be helpful to provide more information about the market, especially to new entrants. There were various concerns about regulatory uncertainty. Some familiar concerns about imbalance pricing (the cash-out mechanism) and about the cost of credit were repeated. There were suggestions that standardised terms and contracts might be considered, that ways of stimulating within-year trading and consolidation of smaller volumes be explored, and that simplified arrangements should be made for micro-generation metering and settlement. We discuss these eight issues in turn.

11.1 Information about the market

There was recurring feedback that the distributed generation market is a complex one, even more than the wider electricity market. Not surprisingly small distributed generators entering or considering entering the market often lacked a lot of the information necessary to understand how the market worked, what their options for getting a route to market were and how they should set about getting the best deals for themselves. It was suggested to us by some suppliers that generators often had unrealistic expectations, especially in the early days. It was felt that more could be done to provide helpful information about how the market worked—not just about the rules and regulations and institutions, but also about the available routes to market, the identity and interests of the participants operating in the market, the prices that have been obtained in the past, etc. It was variously suggested that trade associations, Ofgem and BERR should be more active in providing such information, and that the government should fund a website to provide such information.

We understand these concerns. The market for local power is complex (which of itself is a reflection of the wider sector, but with the local markets having a number of additional aspects and characteristics). Distributed generators would benefit from more complete, accurate and understandable information. Although there are a number of existing information sources, these are fragmented, not all well sign-posted, and incomplete (and in some cases possibly inconsistent). Further, an interested party would need to hold at least a reasonable degree of industry knowledge to locate them and then understand them.

While trade associations no doubt provide a valuable service to their members, they are funded by coalitions of interests including the major suppliers and do not necessarily provide information of the kind or in the form that would be most helpful to potential entrants. None of them seem to focus on market access and related market information. Access could be improved if such information were openly and freely available for a wide range of sizes and types of technology.

Similarly, a number of government-funded initiatives, through Future Energy Solutions, the Carbon Trust, the Energy Savings Trust and others, are targeted at developers and new entrants. These have led to the development of various guidance and reports. But many of these have been of a technical rather than commercial nature. Where information and advice on commercial structures and choices has been offered it has been partial (for instance describing network charging structures) and tends to become quickly out-dated.

We are therefore sympathetic to the provision of information of this kind. This might include what one participant described as a user guide.

There may also be scope for the development of an open access, web access information exchange. The functions of the Information Exchange could vary, depending on the policy perception of the scale of the problem facing developers. It could, for instance, exercise a number of related functions focused on the delivery of distributed energy schemes, especially given the novelty of applications outside of the conventional power market and especially until local markets become better established. Box 11.1 suggests some possibilities for what this information provided to the market might cover. It distinguishes between basic information provision and more pro-active activities. The exchange would need to be funded in some way, either by existing market participants or by the Government.

We suggest that an exchange of this kind, or some other form of information provision, merits wider discussion in the industry. Such an initiative might be facilitated by Ofgem, for example.

Box 11.1—Information exchange

Potential key functions:

Core information services

- provide Distributed Energy (DE) schemes with contact details for:
  - providers of legal, regulatory, contractual and market advice;
  - providers of "exempt supplier services";
  - providers of consolidation, broker and agent services;
  - details of auctions where DE electricity can be bought and sold;
  - purchasers of DE electricity
  - distribution network operators
  - provides of DE finance
- provide DE schemes with details of any published prices for:
  - "exempt supplier services", "high cost, high competency elements of the supply licence", consolidation services;
- provide DE schemes with details of available benefits, and how to claim them: such as capital grants, tax benefits, Rocs, Lecs, Regos and embedded benefits.

Potential added value services:

- administrative assistance could also be provided;
- helping DE to identify how they can maximise embedded benefits;
- dissemination of standard contract terms and associated guidance;
- share best practice by providing DE case studies.

"Centre of excellence"

- investigate projects that could improve forecasting capability for DE technology, this could possibly be part funded by the agency in partnership with the private sector;
- contribute to the development of technical solutions that will benefit DE, such as virtual private networks;
- liaise with similar organisations in other countries to ensure that best practice is shared globally; and
- act as a DE trade association/ lobby group. Represent the DE community at key events/ on working groups.

11.2 Regulatory uncertainty

Several participants expressed concern about the regulatory framework and/or regulatory uncertainty. (This term is interpreted widely here to include government and the range of regulatory bodies impinging on the sector, rather than simply Ofgem.) Specific concerns included:

- Ofgem's administration of the Roc register, the related websites and the response time to requests for information and queries;

- the lack of transparency in the market, not least with respect to distributed generation, and the political risk associated with future policy by government and regulators;
- the complexity of administrative rules relating to Rocs, Lecs, Regos (and the interactions between them), which were said by one respondent to be so complex that no regulatory body was prepared to provide advice as to their meaning and implications;
- the inadequate costing and lack of clarity on arrangements for district heating schemes;
- uncertainty about the banding of renewables and about the application of new aggregation rules; and
- the complexity of distribution charging arrangements, lack of clarity on generator charging and likely changes and perceptions of habitual change.

It is difficult for us to assess the weight to be attached to these specific concerns as they are largely outside our remit and they are individually complex, but we suspect that they are not without foundation. We therefore recommend that Ofgem in particular give consideration to how they can be addressed.

11.3 Imbalance pricing

Concern about imbalance prices seems to be less than in the past, and generation developers do not seem to consider imbalance risk of itself, though real, as presently constituting a barrier to entry. This may be partly because of the less extreme imbalance prices that have been recently been experienced, but partly because of the higher power prices generally, and partly because of the commercial treatment of imbalance prices in recent contracts. Nevertheless, several participants did mention it, and in particular that present arrangements might well be unfair to small users.

Exposure to imbalance prices under the Neta market remains a key issue for producers and suppliers alike, especially the levels of imbalance risk and the acknowledged possibility that imbalance price pollution is presently distorting prices and incentives in the market. In previous work we have separately highlighted our view that the risk is disproportionate and that the current cash-out pricing rules are in need of modification. We consider that this conclusion still applies.

In the present context the most relevant improvements in the operation of imbalance pricing would be to eliminate or reduce the costs of system pollution and/or the spread between the dual cash-out prices. This would lead to a reduction in imbalance premiums levied by suppliers through offtake terms. This can be expected to be particularly beneficial to newer technologies coming to market especially where there is any uncertainty (perceived or real) over delivery. We therefore recommend that Ofgem continue to give consideration to the reform of imbalance pricing arrangements

11.4 Standardised terms and contracts

A few market participants highlighted the present level of legal and associated costs, and suggested that the distributed energy market might be fostered through the development of standard off-take terms or standard contracts. Even the simplest contracts have provisions addressing TNUoS, BSUoS, embedded benefits, Rocs, Lecs and imbalance prices, which necessitate the use of specialist industry and legal knowledge that can be hard to locate and often expensive.

Some of the larger suppliers were not convinced. They observed that most agreements for larger volumes of power tended to be tailored or bespoke, at the preference of both parties. For smaller volumes of power the larger suppliers tended to have their own standardised contracts, which in principle some suppliers indicated they were willing to modify though it was not really worth spending a disproportionate amount of time, cost and effort.

It was also pointed out that for short-term trades the NFPA had a standard contract which some found acceptable but others found constraining.

Given these pros and cons, we recommend that industry participants should discuss the possibility of developing a set of standard terms and conditions and contracts for smaller distributed generators to help orientate them in their discussions with suppliers. The availability of common terms, if only as a starting point for negotiation, could be beneficial especially at the smaller end of the market. The standard terms would need to be supported by guidance explaining industry structures and terminology. Such a facility might therefore form part of the information exchange mentioned above. Again, Ofgem might usefully facilitate discussion on this proposal.

11.5 Within year trading

A few parties discussed the possibility of within-year trading of power and Rocs. At present, within year trades are predominantly through the NFPA auctions. However, a number of inflexibilities arise from current trading options, in particular the now established round of holding e-power auctions only biannually and for fixed six month volumes. The NFPA is presently considering how these facilities could be developed outside of NFFO surpluses so as to attract non-NFFO participants. NFPA is already contemplating a series of enhancements to both the power and Roc auctions, though the current auctions are not likely to change fundamentally over the foreseeable future.

The issue is likely to become more significant as increasing volumes come to market as the NFFO projects and contracts reach maturity. We therefore suggest that interested parties give further consideration to how developers might deal with uncontracted quantities or surpluses within year, and how brokers acting as agents might get more predictable routes to market.

11.6 Consolidation of small power parcels

We have noted that volumes from plant above 100kW would usually have competing buyers but that the larger suppliers found it costly to deal with smaller parcels from generators. At some point at around the 100kW level and below, we sense the options become fewer, although the generators we spoke to with plant sized at this level tended to be established players with portfolios and were practised at going to market.

Our proposal for the Information Exchange includes, as part of the basic definition, the information, dissemination and sign-posting of trading options, brokers and agents, and this facility should help in this area. There is no legal barrier to third party aggregation at this scale (and restrictions previously associated with the Roc regime and consolidating Rocs have been removed[19]). It is, therefore, early days in the evolution of the smaller end of the market and developments in it should be kept under review.

11.7 Micro-generation

A couple of participants drew attention to the potential increase in the volume of micro-generation and the potential cost of handling large numbers of small quantities of power. They variously suggested the need for mandatory smart metering, and for standardised provisions for credit or payment for such generation.

This is an area where Ofgem has separately directed significant effort[20]. We also heard of emerging market response with the appearance of green service providers, with Tradelink Solutions, Green Energy and Good Energy all being referenced. From a developer's perspective there is not necessarily a clear distinction between micro and larger distributed energy. The discussion we recommend on the role of the information exchange should embrace coverage of micro-generation and overlaps with the smaller end of the distributed generation market and whether their needs differ.

11.8 Cost of credit

[19] To date four agents other than established suppliers have registered as agents that aggregate Rocs on behalf of small generators.

[20] http://www.ofgem.gov.uk/Sustainability/Environmnt/Policy/Documents1/15691-MicroOctFINAL.pdf
And
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=1&refer=Sustainability/Environmnt/Policy/SmallrGens/DomsScMicro

A few market participants explicitly drew attention to the onerous nature of present credit requirements and to the cost of lodging credit. Some mentioned credit issues with the local distributor. Others expressed concern about the credit worthiness of smaller suppliers. It was suggested that this limited the range of parties that could operate in the market and reduced the amount of liquidity in the market. One commented on credit terms in contracts with suppliers.

Many other participants, particularly the smaller ones, no doubt shared this concern even though they did not articulate it. Credit is clearly an important issue in the distributed energy market especially for generators selling to suppliers and also because of risks of non-delivery. Recent changes in the way that imbalance is treated in contracts mean that credit problems for producers have been to some extent been mitigated. Nonetheless, it seems likely that the market would be more active if lenders and developers felt that they could reasonably apply a lesser rigorous interpretation of risk, since a requirement for an investment grade rating from the purchasing supplier effectively limits this part of the market to the Big Six. Smaller suppliers have to some extent adjusted to this by arranging prepayment of Rocs and Lecs, but the market still seems somewhat constrained by considerations of risk to the benefit of the larger participants.

It has been suggested elsewhere that over-collateralisation and double-counting of credit arrangements within the market may be part of the problem. Ofgem could usefully explore this issue further.

Annex A—Questionnaire for generators

Questionnaire

Please complete a form for each site unless this is impractical.

Part One—General details

1.1 Organisation

____

1.2 Address

____

____

____

____

1.3 Telephone _______________________________________

1.4 E-mail

____

1.5 How many sites do you have under your control?

____

1.6 Which distribution network are you connected to?

____

1.7 What is your maximum capacity on the site (in MW and kWh) for:

Export ____________________ Import

____

1.8 What fuel type does your plant use?

Coal Oil Gas Wind

Other (specify) ____

1.9 Is the plant a combined heat and power (CHP) plant?

Yes No

1.10 If the answer is yes, please give details of the heat load:

____

____

Part Two—Central Trading Structure

2.1 Are you a party to the Balancing and Settlement Code (BSC)?

Yes No

Are you:

Owner Operator

2.2 What is the site status under the BSC?

Central Volume Allocation Supplier Volume Allocation

2.3 Does the Balancing Mechanism Unit in which you are comprised participate in the Balancing Mechanism?

Yes No

2.4 If so, what is your BM unity identifier?

____

Part Three—Contract Information

3.1 Please describe the basis on which you sell your energy:

Direct bilateral contracts Broker Exchange Demand customer

Other (specify) ____

3.2 Please give your output in kWh between 1 April 2006 and 31 March 2007:

____

3.3 Please give your expected output in kWh between 1 April 2007 and 31 March 2008: _______________________________________

3.4 What proportion of your output was sold as fixed energy volumes between 1 April 2006 and 31 March 2007?

_______________________________________%

3.5 How many counter-parties have you traded fixed energy volumes with between 1 April 2006 and 31 March 2007?

____

3.6 What was the basic price for your fixed export? (for STOD structures, use the time weighted average price)

_______________________________________£/MWh

3.7 Was this a fixed price?

Yes No

If No, please describe the basis for the price variation:

____

3.8 What proportion of your output was sold as variable output between 1 April 2006 and 31 March 2007? (Do not include energy imbalance volumes)?

______________________________________%

3.9 How would you characterise the purchaser of your variable output?

Energy trader Local supplier Demand customer

Other (specify) ____

3.10 What was the basic price for your variable export? (for STOD structures, use the time weighted average price)

_______________________________________£/MWh

3.11 Was this a fixed price?

Yes No

If No, please describe the basis for the price variation:

____

3.12 What imbalance volumes have you been exposed to?

____

____

3.13 Does your export contract expose you to imbalance prices?

Yes No

3.14 Does your import contract expose you to imbalance prices?

Yes No

If Yes to 3.13 or 3.14, please describe below the nature and extent of exposure

____

3.15 What proportion (if any) of the volumes traded included climate change levy exemption certificates?

______________________________%

3.16 What proportion (if any) of the volumes traded included climate change levy exemption certificates?

______________________________%

3.17 Do your contracts refer to any of the following embedded benefits?

Triad Trading Benefit

Transmission Loss avoidance

Imbalance Surplus Payments/charge avoidance

Balancing Services Use of System charges avoidance

BSC Co Costs avoidance

If yes, please describe below the basis for sharing embedded benefits

____

____

3.18 Have you experienced any changes in the sharing arrangements over recent years? If so how?

____

____

3.19 Does the purchaser impose any other charges or costs?

Yes

No

If Yes, please specify

____

3.20 Has your recent contracting behaviour changed as a result of changes to the BSC over the life of Neta?

____

____

____

____

3.21 Have you noticed an improvement in your ability to negotiate contracts in the most recent contracting round compared to the previous one?

____

____

3.22 Has there been any other discernible changes in commercial options offered by purchasers?

Yes No

If Yes, please specify

____

Part Four—Other issues

4.1 What are the main issues you feel should be addressed?

____

____

____

____

4.2 Can our consultants contact you to discuss your contractual position in more detail?

Yes No

Annex B—Questions to suppliers

Purchase of output from embedded generators

1. What volumes with do you have contracted with embedded generators?

2. What proportion of these contracts is:

+greater than 5 years?
+has a duration between one and five years?
+lasts one year or less?

3. Are any of these volumes with affiliated companies or companies in which you hold an equity shareholding?

4. In the main are the quantities you purchase fixed or variable? Does the pricing differ between the two? Does the price offered differ depending on factors such as location and/or size?

5. Are there any technologies or types of plant you actively seek to procure? Do you have a policy for which tenders you participate in? Do you have any annual targets?

6. How important are Rocs and Lecs? Is there a quota you seek to buy annually in absolute or relative terms inclusive of these "green benefits"?

7. What proportion of the Roc recycling fee do you rebate to producers?

8. How do you reflect imbalance risk in your bids?

9. Are top-up and back-up arrangements separate to the basic supply offers you make?

10. Do you apply additional fees/apply terms in addition to energy/Roc/Lec/embedded benefit purchase terms?

11. Do you offer bundled or unbundled prices? If they are unbundled, what typical values do you offer for splitting benefits arising from (i) Rocs, (ii) Lecs, (iii) embedded benefits (please specify which)?

12. How important do you consider the NFPA auctions as a procurement route? How active have you been in participating in these auctions since Neta go-live?

13. Are there any discernible trends in the market you would wish to highlight?

14. Have there been any notable changes in your procurement policy since Neta commencement?

Annex C—Respondents

Rolls Royce [Producer 1]

BP [Producer 2]

British Sugar [Producer 3-6]

McCain Foods [Producer 7]

Pure Energy Professionals [Producer 8]

Chesterfield Borough Council [Producer 9]

Tranquility, Stroud Renewable Energy Cooperative [Producer 10]

Font Energy [Esco 1]

Balcas Timber Ltd [Producer 11]

Yorkshire Water Services [Producer 12]

UPM Shotton Paper [Producer 13]

Pure Energy Holdings Ltd [Producer 14]

Wessex Water [Producer 15]

Kelda Water Services [Producer 16]

Severn Trent Water [Producer

Purepower [Producer 18]

Milton Keynes Council [Esco 2]

Interviewees

NFPA [Intermediary A]

Novera [Producer A]

Bizzernergy [Supplier A]

Smartest Energy [Supplier B]

EDF Energy [Supplier C]

Centrica [Supplier D]

RWE Npower [Supplier E]

Scottish and Southern Energy [Supplier F]

Good Energy [Supplier G]

E.ON UK [Supplier H]

Scottish Power [Supplier J]

GDF ESS [Supplier K]