

Introducing flexibility in routes to market for distributed energy

Issues and options

A paper by Cornwall Energy

Purpose

The attached discussion paper sets out the background to the present trading options for Distributed Generation (DG). The focus is the 5-50MW segment of the generation market, which is in most cases is of insufficient scale to warrant direct participation in the central trading arrangements administered by Elexon. Usually generation plant with these characteristics is generation licence exempt. Depending on the measure used there is between 3-5% of the market represented by smaller generation, and this proportion is set to grow as policies to stimulate lower-carbon generation bite.

The audience for the paper is the DEWG. In general distributed generation is in a weak position to access energy markets or disinterested in a sector dominated by large vertically-integrated players with diverse portfolios that effectively control access to these markets. The joint Berr/ Ofgem *Review of distributed generation* report issued with the white paper (“the May report”) echoes this theme and it acknowledges that the playing field between centralised and decentralised generation is not level.

The focus of the paper is on the element of the package of proposals identified by Berr/ Ofgem that covers “more flexible market and licensing arrangements for distributed, low-carbon electricity supply, to be implemented by the end of 2008”.

In more detail it:

- summarises basic trading options available to small generators;
- provides an overview of current centralised trading arrangements as they impact on distributed generation;
- identifies where (not whether) these arrangements impose barriers and how;
- illustrates several areas where improvements have already been made; and
- identifies possible ways forward that could assist in addressing barriers and improving market access.

At this stage the paper does not scope options and possible solutions in detail but it is intended to provide a clearer factual basis for the DEWG.

The paper strays into technical matters and the complexities of the current trading arrangements. We suggest it is the key messages rather than the detail that is relevant to the group. Those seeking a relatively simple overview of the central trading arrangements might wish to read the Elexon summary [here](#).

Key messages

The key messages are:

- All distributed generators require access to the market in the sense that they need to be able to sell their power at a fair price. The interaction of industry and market structures means they will remain in a weak position as long as the dual problem of concentration and market illiquidity prevails. Some amelioration could occur should barriers to entry for new entrants—both generators and suppliers—be lowered by reducing their costs and risks, but this is not a short-term or certain prospect.
- The position of distributed generators (and niche suppliers) may well also be enhanced by any changes to imbalance cash-out that further reduce volatility and price pollution. Introduction of any tolerance bands to mitigate the effects of cash-out exposure could reduce the cost of new entrant suppliers and generators by allowing them to trade outside the power exchanges and mitigate exposure to imbalance, but change of this nature raises cross-subsidy issues and presently looks unlikely.

- Even allowing for these two factors it is not logical or commercially viable for most distributed generators to seek direct access to wholesale markets. This situation should not be a surprise because:
 - i) the trading arrangements were developed for centralised/ bulk trading;
 - ii) distributed generators are in the main small and/ or supply locally; and
 - iii) selling into the central arrangements without contract and risk management back-up is not a realistic option, and the costs of trading are anyway excessive for small players.

Overall their position and options for DG are worse than under the Pool.

- At the same time access to retail markets also raises a different type of complexity and in most instances requires the operator to become a licensed supplier, and the 5MW limit for off-site supply is significantly lower than the comparable threshold for generation. The limit for on-site supply provided it is to non-domestics is rather higher. However, the threshold is probably not the critical issue as many if not most distributed generators would not wish to become suppliers anyway.
- The market and regulatory environment is complex and (to quote the May report) distinctly not “user friendly for smaller participants”, and it imposes high fixed costs.
- In recognition of these factors the role of the consolidator has been created under Neta following a series of complex rules changes, and a significant market player has emerged. The large verticos also fulfil this consolidation role either directly or indirectly. It is hard to see how this aspect of the BSC rules can be further flexed. Consequently the scope for further organic development of consolidators under the current Neta framework looks limited.
- Setting aside the need for much more lucid explanation of the current arrangements, the conclusion we reach is that there are no obvious quick wins through modifications to the trading arrangements that would significantly improve the position.
- It is also relevant that considerable effort has also been directed at introducing flexibility to allow exempt distributed generators to access embedded benefits directly, but if anything this may have further complicated the trading options for the many distributed generators for who this route is not an option.

Possible ways forward

The paper flags four broad types of arrangement that may offer the prospect of levelling the playing field. The emphasis in identifying them is what might be feasible, and not necessarily what is desirable. With the possible exception of options a) and b), they would represent considerable change.

The options identified are:

- option a) increased supply licence exemption limits—this would seem to be the easiest route. It would be possible to create an additional class of supply exemption, which effectively increases the scope for exempt supply off-site, especially if this is for the purposes of making a supply into the non-domestic market or perhaps to a related undertaking or local site (which would require definition).

A comparison with the treatment of generation suggests a limit of 50MW (BSC threshold) or 100MW (licence threshold) could be investigated for certain types of off-site supply, particular if generation and supply were ordinarily matched. It is not obvious how these quantities should be treated from the perspective of the central arrangements if generation and supply were not to broadly balance, and in the event back-up supplies were needed. Also there would need to be specific consideration of whether any direct access should be available to embedded benefits.

- option b) simplified or new type of supply licence—the next most straight-forward change assuming it related to specific types of supply (and probably not including domestics). Much of the current boiler plating in the licences would not be needed for non-domestic supply, but requirements to comply with codes could be down-graded or removed (or possibly might be dischargeable through an agent who could be an existing signatory).

In many respects the further carve outs from the exemptions regime contemplated under option a) could be attached instead to eligibility for this decentralised supply licence. It might be possible or desirable to restrict eligibility to supply through certain meters or profile types or stipulate that the supply could only be made in conjunction with a generation exemption. This approach would of course be substantively different if it were to require legislation to create a new class (or sub-class) of licence.

- option c) centralised purchasing role—this would entail significant change and active discrimination in favour of decentralised energy through the central trading arrangements. It might necessitate establishment of a new trading party role, who could register volumes and settle imbalances. Alternatively the role could be vested in the system operator, who already has a preferential ability to settle imbalances on its trades at 0.

There could also be potential harm to the existing and future consolidators operating in this area, suggesting that some relatively low threshold would need to be applied to eligible counter-parties. Such a role may also have to be legislated for, and there would need to be wide-ranging change to the BSC.

- option d) regional agents—more complex than the licence route but probably simpler than c) provided the role were carried out by a supplier. It could see a role created probably by GSP Group, and possibly following an auction. If this were a role carried out by licensed suppliers, they could participate in the BSC as trading parties in much the same way as suppliers currently register embedded quantities in SMRS though there would probably need to be some form of separate accounting. But it is assumed that to make such arrangements work with minimum disruption some form of netting arrangement might be needed before these quantities were registered within the BSC.
- option e) there may be scope for combining elements of b) and d) while minimising the extent of change required provided a regional supply agent were utilised.

All these potential solutions require much further definition and thought, but it is hoped they will stimulate debate. Whether such change is considered proportionate will depend on the scope for development of decentralised energy and the importance attached to it within the policy framework. We also need to clarify what is meant by the term in the May report “within the licensed framework”.

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I. Introduction

This paper sets out the background to the present trading options for Distributed Generation (DG). The focus is the 5-50MW segment, which is typically distribution connected and in most cases of insufficient scale to warrant direct participation in the central trading arrangements administered by Elexon. Usually generation plant with these characteristics is generation licence exempt.¹ But despite its small-scale it is not an immaterial part of the market. In December 2005 National Grid estimated there was 7GW of unlicensed embedded generation, and that this amount would increase to 10GW by April 2007.^{2 3} Depending on the measure used there is between 3-5% of the market represented by smaller generation, and this proportion is set to grow as policies to stimulate lower-carbon generation bite.

The audience for the paper is the DEWG. A starting premise is that distributed generation is in a weak position to access energy markets or disinterested in a sector dominated by large-vertically integrated players with diverse portfolios that effectively control access to them. The joint Berr/ Ofgem *Review of distributed generation* report issued with the white paper (“the May report”) echoes this theme in so far as it acknowledges that the playing field between centralised and decentralised generation is not level.⁴

The focus of the paper is on the element of the package of proposals identified by Berr/ Ofgem that covers “more flexible market and licensing arrangements for distributed, low-carbon electricity supply, to be implemented by the end of 2008”. It takes on board and shares the sentiment that the objective should be to “encourage, where possible, further growth of DG *within* the licensed framework, rather than *outside* it.” It notes the statement in the May report that it is necessary to ensure that “the market and regulatory environment is user friendly for smaller participants”.

It:

- summarises the trading options available to small generators;
- provides an overview of current centralised trading arrangements as they impact on distributed generation both in theory and in practice. In this regard it tries to provide a reasonable complete background—and therefore better understanding—to the statements in the May report that these arrangements act as a significant discouragement to DG;⁵
- identifies where (not whether) these arrangements impose barriers and how;
- illustrates where improvements have already been made; and
- identifies as a basis for possible further development and discussion possible ways forward that could assist in addressing these barriers and improving market access.

At this stage the paper does not scope options and possible solutions in detail but it is intended to provide a clearer factual basis for the DEWG and its stated purpose “to develop a package of measures that reduces the costs and complexities facing small licence exempt generators seeking to supply localised demand”, and address some of the misconceptions surrounding the issues.

This paper has been prepared with some financial support from Ofgem, but the contents and the conclusions are purely the responsibility of the author.

¹ In practice exemption levels are 100MW and below.

² National Grid response to ECADG consultation. According to ENA at April 2006 there was 12GW of distributed generation.

³ Ofgem’s latest connections industry review shows that in 2006-07 there were 151 new distributed generation connections made compared to 68 in the previous year.

⁴ “Due to the nature of the existing industry structure, it could be hard for small generators to connect to and operate in the centralised system. Network operators could do more to accommodate the connection of distributed generators. The cost to suppliers of rewarding small generators for exporting their excess electricity was a disincentive,” the report notes.

⁵ May report, page 30.

2. Routes to market

The trading options available to a distributed generator depend on whether it is licensed or licence exempt, its relative size and also whether it wishes to trade electricity.

At one extreme it is possible in theory for a generator to sell power directly onto the wholesale market bypassing the central arrangements. But this is in practice impossible as market trading is expensive requiring complex credit, risk management and settlement processes and systems. The main short-term traded market, APX Power UK, also requires trading parties to be BSC signatories, and bilateral trading of small volumes is extremely illiquid. Consequently, many licensed generators greater than 50MW do not consider this a valid option.

At the other extreme a generator can spill any surplus power and not receive commercial consideration, which may be an option for a generator with largely matching on-site demand but such circumstances are rare.⁶

Smaller generators typically have three realistic options for trading under Neta, which to varying degrees necessitate interaction with other market participants or intermediaries:

a. Direct participation under the BSC through Central Volume Allocation (CVA)⁷

All generators above 50MW under their licence or exemption must accede to the Balancing and Settlement Code (BSC). Additionally generators less than 50MW can opt to participate in this way. Thus such a generator may contract ahead in the bilateral markets and opt to manage its physical position within the central trading arrangements. This would entail acceding to the BSC, registering its own generation in the Central Registration System (CRS), and participating directly in the balancing and settlement arrangements. In this case, if it were flexible plant that could change its operating parameters in short timescales, it would have the option of changing its output via Balancing Mechanism (BM) bids and offers. It would also need to notify its contractual positions at “gate closure” to enable any imbalance position to be calculated.⁸

Where a generator is CRS registered (either because it must be or because it opts to be) and is the lead party for a generation plant—termed BM Unit (BMU), which is essentially a separately controllable unit at a power station—but wishes to avoid day-to-day participation in the central trading arrangements, it can issue a Meter Volume Reallocation Notice (MVRN) to another trading party that will then take on responsibility for its meter (or a percentage of the volume) and the associated volumes (including any variances against contractual terms). Irrespective of whether it does this any exempt plant defined as large under the grid code would need to be registered and give notifications of its physical position to National Grid.⁹

In a few instances on the supply side, small players, who are subject to a lower exemption threshold, routinely expose themselves to imbalance (essentially they do not have contracts to notify or the contracts they hold are insufficient to cover their expected physical position, and through their physical production and consumption are deemed to sell to or buy from the system). Given that imbalance pricing (cash-out) routinely produces prices that are lower than market prices for sellers and higher than market prices for buyers, this is not a logical steady state commercial strategy. But in defined circumstances it

⁶ That of itself does not mean volumes are entered into central settlement, and to do this there must be a BSC registrant of the meter. If an operator elects to spill, the volumes will find their way into central settlements by default, contributing to the Group GSP correction factor, which is the volume of electricity left each trading period after all measured volumes (metered and profiled) have been taken into account.

⁷ A glossary of BSC terms is at www.elexon.co.uk/glossary/.

⁸ Large generators defined under the Grid Code must also be CRS registered.

⁹ An exempt embedded large power station is defined under the Grid Code as +10MW in North of Scotland, +30MW in South of Scotland and +50MW in England and Wales.

may be a valid option especially if a party is likely to be consistently long, and the principle in theory is applicable to a generator.

b. Registration through a supplier

Most smaller generators (including many deemed to be large under the grid code) are not in a position to actively trade to a contract profile that matches any predictions they have of half-hourly output. Provided it is licence exempt, a generator may contract with suppliers to sell its output locally. These arrangements used to be called “netting off” arrangements, because the existence of a contract enabled suppliers to claim embedded benefits. In this way the generator can bypass the central balancing and settlement arrangements altogether.

In such circumstances, if the capacity were below the specified thresholds for its transmission area, the generator would not need to be registered in CRS; instead the meter would be registered by the supplier in Supplier Meter Registration System (SMRS).¹⁰ In this circumstance the supplier would form a trading unit that would enable it to net off the generation volume against its demand recorded in its consumption account. The expected energy produced and sold to suppliers in such circumstances is taken into account by the supplier when making its contract notifications. In most instances the generator’s volatility is assumed and accommodated through the price negotiated between the two parties.

c. Registration through a consolidator

A generator of less than 50MW may mitigate its risk by the use of the provisions under the BSC that allows it to consolidate its imbalance positions with other generators. Under this option the generation could be centrally registered under Neta, and “MVRN” its quantities as described above. If they are exempt and embedded and contract with a “consolidator” offering commercial consolidation services, then this option need not involve them signing the BSC and they do not have to participate directly in the balancing and settlement arrangements, and the consolidator would register the exempt BM unit on their behalf.

The growth in consolidation of generation under Neta has been a notable feature. Rule changes have addressed impediments to consolidation, and a specialist consolidator has achieved critical mass and has relationships with most of the large embedded plant on the system.¹¹

d. Participation as a supplier

A fourth option, becoming a supplier, is not presently a realistic option for most DG and is further touched on below.

e. Practical effect of these arrangements

The effect of the current trading rules is that no generators less than 50MW directly participate in the trading arrangements in their own right. Volumes are either added directly into another party’s portfolio through the consolidation route (as negative generation as it is embedded) or absorbed into a supplier’s portfolio (and offset against consumption). In the early days of Neta, virtually all exempt sites have opted for the SMRS/ supplier route.¹²

Perceptions of the cost and complexity of Neta have also meant that many developers actively seek to avoid engagement with the central trading arrangements. Ilex conducted work for the National Audit Office showed that the costs of market participation had increased under Neta.¹³ Relative to the Pool

¹⁰ In fact SVA registered parties cannot trade out imbalances.

¹¹ There remains a requirement for a supply licence under the MRA before a consolidator can register meters in SVA, which would otherwise be the preferred registration route for small generators.

¹² A figure of 98% of sites was noted in the Consolidation Working Group’s report of August 2001.

¹³ HC 624 Session 2002-03, 9 May 2003.

Neta has imposed new costs and complexity for no obvious reward for DG, despite the intention that Neta should be a simple and transparent market.

f. Importance of embedded benefits

These are essentially payments in respect of avoided costs that could otherwise be paid by trading parties, and relate to transmission use, transmission losses, balancing service payments and the Elexon charge. They reflect the value to a trading party that local generation can create because of the reduced demand it can notify within a GSP group as a result of its relationship with a generator (and therefore lesser use of the system overall). The main benefit is avoidance of transmission charges, which has been estimated recently at an average £17/kW (or 0.3-3p/kWh dependent on location and technology), but other benefits can also be significant in terms of their market value.¹⁴

However in practice, to claim the benefits directly the generator is expected to have a contract with National Grid, which in effect means registering within the BSC arrangements.

3. Market risks and barriers

There are a number of aspects of the central trading markets that create risks, can be construed as barriers to participation and give rise to costs for the distributed generator.

a. Limited market

The viability and attractiveness of participation in the central trading arrangements needs to be seen within the wider context of access to wholesale markets. Credit and the cost associated with admission processes and trading present a significant barrier to accessing the wholesale market for smaller players. It is outside the scope of this paper, but it should be noted that a lack of liquidity in the market and a lack of market depth pose serious threats to any participant that is not vertically-integrated. In practical terms these factors skew the options so that many distributed generators do not look beyond establishing a netting arrangement with a local supplier, except where they may wish to capture embedded benefits direct.

b. Transaction costs and complexity

Physical parties that wish to participate in the wholesale markets must accede to the BSC and participate in the central trading arrangements. The costs of being a BSC trading party are not significant at £3,000 per annum per registrant. Trading charges depend on levels of imbalance exposure, but also on the number of BM units and meters registered and the number of agents used. The main BSC entry requirements are accession, registration, installation of communication lines and accreditation of agents (meter operators, data collectors, contract agents etc).

There is a parallel registration process for BMUs with National Grid and the requirement to have in place EDT/ EDL communication. Distributed generators that are not licence exempt will be deemed to be using the transmission system and must pay transmission network charges. Exempt embedded parties defined as large must usually submit physical notifications.

But the main cost to the generator participating in the BSC—that does not consolidate—is the on-going one of submitting accurate contract notifications data and to avoid imbalance contracts. To do this the operator must have an active contract and risk management strategy, which, of course, small generators do not usually have. The cost of direct participation starts at £150,000 with on-going costs to the order of £50,000 per annum, net of the cost of any trading activities.

¹⁴ There is a negotiation with the trading party over the sharing of benefits.

c. Balancing risk

The term balancing risk is short-hand for exposure to electricity cash-out prices constructed within the central trading arrangements, either directly or indirectly.

Direct exposure would occur were the generator was a trading party and its metered position in any trading period differed from its notified contract position. The level of risk in each period differs according to whether the system overall is short or long and the generator's own position. The physical imbalance (the difference between the contract and the meter) is then cashed out against the relevant energy imbalance price for that half hour.¹⁵

Non-trading parties also see indirect exposure, with the extent determined by the nature of the commercial relationship with the BSC trading party. Contractual terms will push down imbalance effects to the generator or impose penalties where performance is outside of expected operation. Alternatively prices paid will often reflect the spill price rather than market prices. A supplier's negotiation with a counter-party over the distribution of embedded benefits, Renewables Obligation Certificates (Rocs) and levy exemption certificates will also often be skewed so that the supplier retains a proportion of the benefit to reflect the additional imbalance risk it is taking on with managing an embedded station's performance.

We have no recent data on how suppliers' price in this risk, but in 2005 on a must-take contract where the supplier took on all the imbalance risk the supplier was pricing this energy risk at up to £5/MWh. A consolidator might also impose a tolling fee to cover the balancing costs incurred on a client's behalf.

d. Cross code requirements

Licence exempt generators do not usually need to comply with the BSC unless they have a bilateral agreement with National Grid. But some smaller generators find themselves obligated to comply because they have a Bilateral Embedded Generation Agreement (Bega) with National Grid, probably because they wish to claim embedded benefits directly. If so the party then has to accede to the Connection and Use of System Code (Cusc) to claim the benefits in its own name. Distribution network operators have an obligation under Cusc not to energise an embedded generation connection until appropriate bilateral agreements with National Grid are in place.

Separately the execution of a Bega or Bilateral Embedded Licence Exemptable Large Power Station Agreement (Bella) creates an obligation to accede to the Cusc. In turn under the terms of Cusc a signatory is obliged in turn to accede to the BSC unless the output is dealt with by another party for the purposes of the BSC.¹⁶

e. Supply entry not realistic

Cost of market entry for a supplier, including a consolidator, who must in effect become a supplier to register meters in SMRS, remains considerable. In doing so it also takes on obligations and costs under the Master Registration Agreement (MRA). It would also need to go through the licensing process. The costs are probably prohibitive for a small supplier unless there is an ability to quickly gain market share.

Similarly a distributed generator seeking to enter a niche supply market over 5MW would incur significant costs if it had to become licensed. It would have to accede to the BSC as a supplier and participate in the central trading arrangements, although general compliance requirements under the supply licence have recently been vigorously pruned back as a consequence of the supply licence review.

¹⁵ As a guiding principle single plant operation is significantly more prone to imbalance than a portfolio operator. Similarly intermittent plant is more exposed to imbalance than baseload plant, although the relative risk increased significantly with the reduction of "gate closure"—the point at which contracts have to be notified—from three and a half hours to one hour in 2001.

¹⁶ This position was clarified by CAPI40.

f. Secondary business issues

It needs to be remembered that many distributed generators do not carry out the generation activity as the primary licence business. For even a large CHP operator the electricity is a by-product of the heat, and for many energy from waste operators the objective is to dispose of the waste. Many existing exempt operators have developed generation for on-site supply, and the exemptions regime places emphasis on this. In many instances their customer would be an affiliated or related party.

The practical effect of this context is that most operators do not see the BSC as a realistic market for their power even if the cost, complexity and risks could be made more manageable.

4. Actions taken

There have already been a number of rule changes to the central trading arrangements to facilitate take-up of distributed generation.

a. Licence exemptions have been rationalised

The concept of licence-exempt generation has been critical to the development of distributed generation. It is a critical enabler to permit access to embedded benefits, and it opens up the option of non-participation in the BSC and Cusc governance arrangements. In practice embedded generation below 100MW would be exemptable. At the same time recent changes have tended to establish closer linkages between those distributed generators wishing to claim their benefits direct and address leakage of value to suppliers and the central trading arrangements.

The current exemptions are summarised at [Annex A](#). These were significantly rationalised in 2001 in England and Wales, with the same arrangements extended to Scotland in April 2005 with the commencement of Beta.

The revised 2001 order also rationalised the arrangements for exemption from other licences types and the various classes of exemption available, and it is possible to make an exempt supply, including over a private network, where the total demand does not exceed 2.5MW of domestic supply. There is further headroom for supply where the total supply does not exceed 5MW, again with the subsidiary requirement that the domestic part should not exceed 2.5MW. It is not clear to us what policy considerations led to the establishment of these thresholds. Exemptions are also available for on-site industrial supply effectively up to 100MW.

In this regard it should be noted that there is significant asymmetry in the regime between generation and supply except for on-site industrial production. In most circumstances an exempt generator making an exempt supply would need either a particular setting (with significant on-site demand) or an export arrangement with a supplier if its third party supply exceeded 5MW.

b. Steps taken to facilitate consolidation

These measures have included introduction of BSC modifications P7, P55, P67, and most notably P100. Summary notes are at [Annex B](#).

At the start of Neta it was generally acknowledged there were considerable barriers remaining to consolidation of small generation. The initial design required generators to be registered centrally and trading as individual BM units, although there was some flexibility to consolidate output through meter sharing arrangements. As we have seen, most smaller generators avoided these arrangements and consolidated within a supplier portfolio. An expert group had scoped some enhancements (the so-called option 4), which would have facilitated entry by consolidators but time limitations meant that these were not adopted until after market start.

Important change was effected by a combination of P7 and P100. Prior to implementation BSC trading units could comprise only a single supplier BMU. This situation meant that only the largest offtakes in an

area would have sufficient demand to offset larger embedded generators. This limitation was relaxed allowing consolidators to take a position in the GSP regardless of the level of demand registered to them and still retain embedded benefits. These changes allowed consolidators effectively to operate in the central systems.

c. Changes to streamline cash-out

There have been many rule changes to cash-out, 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 been successful in that they have greatly reduced the spread in the two imbalance prices, though there remain significant concerns about the extent to which cash-out is genuinely cost-reflective of the energy imbalance.

Further consideration of cash-out has been underway since late 2006 when Ofgem initiated a further 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 preferential rules, 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 on grounds of undue discrimination and/ or competitive distortions.¹⁷

d. Measures to improve access to embedded benefits

Prior to a rule change¹⁸ implemented on 1 April 2003, National Grid’s charging methodology treated licence exempt generators according to where their meters were registered for trading purposes and how they traded. The modification changed the methodology for determining liability for transmission (TNUoS) charges, by making all distributed generators capable of exporting less than 100MW exempt from generation TNUoS charges.

Associated changes also introduced the term “exempt export BMUs”. Since April 2003 each distributed generator has paid (or been paid where they create an embedded benefit) demand transmission charges on the basis of their metered volumes during defined half hours used by National Grid in calculating transmission charges, irrespective of where they are registered or how they trade. Hence, if there is a net import over the average half-hourly period, they are now *charged* the relevant kW tariff multiplied by the average export. Conversely, if there is a net export, they are *paid* the relevant kW tariff multiplied by the average export. Therefore suppliers with a netting off agreement in place with a licence exempt generator have seen an increase in their demand charges, and parties to the netting off agreements are now paid or charged directly. It has also been possible to claim Elexon benefits directly.

5. Options

The following broad options are presented for discussion, but it is recognised they represent levels of change that they may not be consistent with existing policy, regulatory or governance constraints.

a. Extended local market/ exempt supply increase

This approach might be enabled by increasing the exemption limit on supply at least for supplies to non-domestic or to affiliated organisations. Certainly making such change for the purposes of supply to a related entity should not be unduly complex, irrespective of whether such supply is made over a licensed network. Some form of notification requirement would be necessary for the local distributor (and

¹⁷ Most notably P26 and P201/2 have sought to impose a more market neutral price within specified deadbands. P95 sought to mitigate cash-out specifically for exempt generators.

¹⁸ UoSCM-M-07.

possibly for BSC purposes) but the scale of such activity could sit outside of the central trading arrangements.¹⁹

An important issue for consideration in this context is the treatment of embedded benefits, especially whether there is a route for payment of embedded TNUoS benefits without meter registration or a direct contract with National Grid. Given the materiality of the transmission use benefit, some mechanism should be developed to provide access to this but it is debatable whether other Elexon benefits should be available as the assumption underpinning such supply arrangements would be that consumption was local.

Nonetheless the issue of meter registration requires further thought, perhaps by enabling a separate class of meter registration without the requirements and complexity associated with the current rules. While this might facilitate access to benefits, the need for registration is driven more by the need to ensure visibility and measurement of this local market.

b. Extended local market/ simplified supply licence

Conversely it might be possible to simplify the compliance requirements that attach to the holding of a licence, perhaps by increasing the off-site threshold to 20MW or even 50MW probably for non-domestic supply. In this regard it is probably more helpful to think less in terms of capacity than customer numbers. A further issue for consideration is whether such an arrangement might incorporate a requirement that eligible customers should fall within defined categories, for instance:

- restricted to half hourly meters (or types of meter); or
- available only to non-domestic profile classes.

The same comments as in the previous section with regard to volume reporting, meter registration, access to embedded benefits and simplifying the interface with the central trading arrangements applies here too.

Obligations in supply licences to comply with market-facing industry codes could be removed for the local or simplified supply licence. Alternatively there may be scope for a supplier to discharge these through another BSC trading party.

While the supply licence is in the process of being radically simplified, it is likely that a further stripping back of conditions would be needed. Distinctions between domestic and non-domestic supplies also need to be factored in.

c. Centralised market—purchase and sale

There may be scope for a carve out of distributed energy quantities from the BSC, with a central sale and purchase role created to interface on behalf of smaller exempt distributed generators. This might guarantee a market neutral price to participating eligible generators in the event of physical imbalance. It is probably more appropriate to see this role as a default role, with an administered price that does not erode incentives for consolidators and innovative players already in the market.

To all intents and purposes this approach would be purchase by the system, and some method of registering meters would be needed that obviated the need to become a supplier (mandatory for SMRS registration) and avoided the complexities arising from CRS registration, possibly creating a separate category of registration.

To operationally make sense of this option a specific agency role could be needed within the BSC. It may probably need to be licensed in some form. Alternatively the role could be subsumed within the energy purchasing role already carried out by the system operator, who is already permitted to buy and sell energy for specified purposes. In both cases some form of bespoke trading arrangement would need to be

¹⁹ We have assumed the domestic supply cap would remain, meaning in effect a threshold to domestic customers of around 5,000 customers.

created to account for the supply and enable its settlement, which might be termed an “exempt trading” unit.

A form of simplified communication arrangement would need to be developed whereby participating generators could notify their likely production profile perhaps at the day ahead stage, and the agent could sell this back into the market, possibly through posting offers into the Balancing Mechanism. Alternatively or additionally the system operator might be under an obligation to purchase the power.

d. Centralised market—regional purchasing agents

Some entity or entities could be created outside the BSC that would register within it as a trading party. Again it is assumed that the thresholds for transacting would be as a last resort in the event that commercial consolidators and suppliers failed to provide a more orthodox commercial outlet.

There are a number of possible variations here. The role might be tendered on a local—probably GSP group—basis probably to a supplier. If so this might be combined with the types of agency role recently canvassed within the report by the Transmission Access Distribution Group (TADG) for managing transmission access.²⁰ Depending on how prescriptive it was considered necessary to be, some form of micro-consolidator could be created either on a regional or a national basis, available to generators of [10MW] or less who usually struggle to attract market-related offers from suppliers. Such measures are not wholly unprecedented—note the changes to the RO to enable Roc consolidation.

A more radical variant of this option might be to vest such a role in the local host distributor that might allocate the costs it incurred in carrying out this role against suppliers in its area (perhaps through an adjustment to the local correction factor). Changes to losses management and other forms of active network management that might be adopted at the distribution level going forward may also open up options, which to an extent can be likened to some form of variable feed-in tariff.

As with option c, mechanisms would be needed within the BSC and trading arrangements to permit meter registration, notification, reconciliation and settlement.

6. Conclusions

All distributed generators require access to the market in the sense that they need to be able to sell their power at a fair price. The interaction of industry and market structures means they are in a weak position and will remain so until the dual problem of concentration and market illiquidity is tackled. Ultimately amelioration could occur when barriers to entry for new entrants—both generators and suppliers—are lowered by reducing their costs and risks, but this is speculative stuff.

The position of distributed generators (and niche suppliers) may well also be enhanced by any changes to cash-out that further reduce volatility and pollution. Any tolerance bands would reduce the cost of new entrant suppliers and generators by allowing them to trade outside the power exchanges and mitigate exposure to imbalance, but change of this nature presently looks unlikely given the rules currently applied to assess industry change proposals. This paper has therefore addressed bespoke mechanisms to support development of decentralised energy markets.

Nevertheless at a lower level the current trading arrangements create a position where it is not logical or commercially viable for most distributed generators to seek direct access to wholesale markets. Their position and options are much worse than under the Pool. That said, this situation should not be a surprise because: i) the trading arrangements were developed for centralised/ bulk trading; and ii) distributed generators are in the main small and/ or supply locally. Selling into the central arrangements

²⁰ In this context the concept is being expanded from managing transmission access to wider market access, though generators seeking the agency service. These are likely to be rather different as they include large embedded generators that are deemed to be using the transmission system and pay for it accordingly.

then without contract and risk management back-up is not a realistic option, and the costs of trading are excessive for small players.

At the same time access to retail markets also raises a different type of complexity and in most instances requires the operator to become a licensed supplier, and the 5MW limit for off-site supply is significantly lower than the comparable threshold for generation. The threshold is probably not the critical issue as most distributed generators would not wish to become suppliers anyway.

The market and regulatory environment is distinctly not “user friendly for smaller participants”, has high fixed costs. They are confusing and impose costs.

In recognition of these factors the role of the consolidator has been created under Neta, and a significant market player has emerged. The large verticos also fulfil this consolidation role either directly or indirectly. It is hard to see how this aspect of the BSC rules can be further flexed. Consequently the scope for further organic development of consolidators under the current Neta framework looks limited.

Setting aside the need for much more lucid explanation of the current arrangements, the conclusion we reach is that there are no obvious quick wins through modifications to the trading arrangements that would obviously improve the position.

It is also relevant that considerable effort has already been directed at introducing flexibility to allow exempt distributed generators to access embedded benefits directly, but if anything this has further complicated the trading arrangements, and for the many distributed generators for who this route is not an option.

Against this background this paper has flagged four broad types of arrangement that offer the prospect of levelling the playing field, but they all with the possible exception of a) and b) represent considerable change:

- option a) increased supply licence exemption limits—this would seem to be the easiest route. It would be possible to create an additional class of supply exemption, which effectively increases the scope for exempt supply off-site, especially if this is for the purposes of making a supply into the non-domestic market or perhaps to a related undertaking or local site. A comparison with the treatment of generation suggests a limit of 50MW (BSC threshold) or 100MW (licence threshold) could be investigated for certain types of off-site supply, particular if generation and supply were ordinarily matched. It is not obvious how these quantities should be treated from the perspective of the central arrangements if generation and supply were not to broadly balance, and in the event back-up supplies were needed. Also there would need to be specific consideration of whether any specific, direct access should be available to embedded benefits;
- option b) simplified or new type of supply licence—the next most straight-forward change assuming it related to specific types of supply (and probably not including domestics). Much of the current boiler plating in the licences would not be needed for non-domestic supply, but requirements to comply with codes could be down-graded or removed (or possibly discharged through an agent who would be an existing signatory). In many respects the further carve outs from the exemptions regime contemplated under option a) could be attached instead to eligibility for this decentralised supply licence. It might be possible or desirable to restrict eligibility to supply through certain meters or profile types or stipulate that the supply could only be made in conjunction with a generation exemption. This approach would of course be substantively different if it were to require legislation to create a new class (or sub-class) of licence;
- option c) centralised purchasing role—this would entail significant change and active discrimination in favour of decentralised energy through the central trading arrangements. It might necessitate establishment of a new trading party role, who could register volumes and settle imbalances. Alternatively the role could be vested in National Grid, who already has a preferential ability to settle imbalances on its trades at 0. There could also be potential harm to the existing and future consolidators operating in this area, suggesting that some relatively low threshold would need to be applied to eligible counter-parties. Such a role may also have to be legislated for, and there would need to be wide-ranging change to the BSC;

- option d) regional agents—more complex than the licence route but probably simpler than c) provided the role were carried out by a supplier. It could see a role created probably by GSP Group, and possibly following an auction. If this were a role carried out by licensed suppliers, they could participate in the BSC as trading parties in much the same way as suppliers currently register embedded quantities in SMRS though there would probably need to be some form of separate accounting. But it is assumed that to make such arrangements work proactively some form of netting arrangement might be needed before these quantities are registered within the BSC; and
- option e) there may be scope for combining elements of b) and d) while minimising the extent of change required provided a regional supply agent were utilised.

All these potential solutions require much further definition and thought, but it is hoped they will stimulate debate. Whether these are considered proportionate will depend on the scope for development of decentralised energy and the importance attached to it within the policy framework and what is meant by the term in the May report “within the licensed framework”.

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Annex A – Exemptions regime

Policy background

Section 4(1)(a) of the Electricity Act 1989, as amended by the Utilities Act 2000, makes it an offence for a person to generate electricity for the purpose of giving a supply to any premises or enabling a supply to be so given unless he is authorised to do so by a licence or by exemption from licensing requirements. Section 5(1) of the Act provides that the Secretary of State may by order grant such exemptions.

The DTI consulted in November 1999 on the principle of class exemptions from generating licensing requirements. This was followed in July 2000 by a consultation on the proposal to lay an order making changes to the licence exemption regime in England and Wales.

The Electricity (Class exemptions from the requirement for a licence) (Amendment) (England and Wales) Order 2000²¹ came into force on 1 October 2000. It exempted certain generating stations from the need to hold a generating licence for a period of one year if they were connected to the system on or before 30 September 2000 and they exported no more than 100MW of power to the total electricity system. The subsequent Electricity (Class exemptions from the requirement for a licence) Order 2001 (“the class exemptions order”),²² which made this specific exemption permanent as Schedule 2, Class C, came into force on 1 October 2001.

Generating stations within England and Wales that export under 100MW of power to the system, and were connected on or before 30 September 2000, are automatically exempt from licensing requirements under Class C of the 2001 exemption order.

Generating stations that meet the criteria for being licence exempt (i.e. those that are automatically exempt and those that have applied for and received an exemption), are described as “exemptable” generating plant for the purposes of the Balancing and Settlement Code (BSC) (Paragraph K1.2.2(c) of the BSC refers). This includes generating plant that remains part of a licensed business. Exemptable generating stations are able to realise the benefits of being licence exempt even if they are operated by a licensed generator. These benefits arise primarily but not wholly, from the fact that exports from embedded exemptable generating stations may be netted off local demand for the purposes of electricity imbalance settlement and certain transmission charges.

The provisions were extended to Scotland with Betta.

Order

Exemptions from the obligation to hold a generation licence are available to:

- small generators (Class A exemptions), which do not provide more than 10MW from a single power station or no more than 50MW from a power station of less than 100MW net capacity provided that power is consumed on site by one or more qualifying consumers;
- offshore generators (Class B), which produce electricity for sole consumption offshore;
- small generators (Class C), which do not normally provide more than 100MW to the public system and were connected on 30 September 2000;
- generators (Class D) which were connected to the public system at 30 September 2000 and were not at that date subject to central despatch.

²¹ The statutory instrument (2000 No. 2424) is available on the [HMSO website](#). The relevant consultation document is also available on the Berr website at www.berr.gov.uk/energy/markets/electricity-markets/licence-exemp/page34529.html is for the Berr electricity exemptions page.

²² The statutory instrument (2001 No. 3270) is available on the [HMSO website](#).

Effectively these exemptions mean that all power stations in Britain that export under 50MW to the public system and have a net capacity less than 100 MW are exempt from the requirement for a generation licence.

These thresholds have a primary influence on the scaling decisions taken by many investors in smaller generating plant, not least because the obligation to hold a generation licence entails mandatory engagement and compliance with key industry agreements and codes as summarised below. They entail significant cost and operational complexity for signatories.

Exemptions from the obligation to hold a distribution licence are available for:

- small distributors (Class A), which do not provide more than 2.5MW to domestic consumers from their own networks;
- onsite distributors (Class B), which do not provide more than 1MW to domestic consumers from onsite generation from their own networks; and
- distribution to non-domestic consumers (Class C) from their own networks.

Exemptions from the obligation to hold a supply licence are available for:

- small suppliers (Class A), which do not supply no more than 5MW of own generation to customers of which no more than 2.5MW is to domestic consumers;
- resale (Class B) – suppliers that sell on electricity sold to them by a licensed suppliers;
- on-site supply (Class C) – where suppliers sell own generation and other supplies to groups of consumers (see below).
- offshore supply (Class D) – supply made to wholly offshore installations.

On-site supply (Class C) exemptions are complex and cover a range of scenarios. They can apply if:

- the electricity supplied is self-generated with top-up purchased from a licensed supplier either by the exempt party or the consumer; and
- the electricity is generated on-site to users on site or connected to a private network where demand is less than 100MW and no more than 1MW is supplied to domestic consumers.

Supply of electricity generated offsite for use elsewhere therefore entails the involvement of a supply licence holder if it exceeds minimal (5MW) levels. A company can therefore become licensed or set up a back to back offtake/ supply arrangements with a party that is. Some value will be traded in return for that party's engagement with industry balancing and settlement arrangements, as well as any top up/ spill requirements.

Annex B – Rule changes to facilitate consolidation

Modification P7: Allocation of supplier demand to the same BM unit in a GSP group for all suppliers in the same company

This proposal was implemented in March 2002 and allowed supplier BMUs of affiliated companies to form trading units (see B.1.2 above) for the purpose of claiming embedded benefits. P7 removed the restriction of trading units to inclusion of only a single supplier-ID. Where a company had several supplier-IDs, individually none might have sufficient demand to net off against the larger embedded generators. P7 partly addressed one aspect of consolidation by allowing more suppliers to contract with distributed generation, improving market access.

Modification P55: BSC conflicts with consolidation of embedded generation in central volume allocation

This proposal was implemented in June 2002 and allowed SVA registered distributed generators to register an additional BMU in CVA as well, for the purposes of trading with consolidators that would not then need to have the requisite supply licence for registering SVA BMUs. To date it has had negligible impact. Some believe that the substantial benefit was already achievable under Modification P7.

Modification P67: Facilitation of further consolidation options for licence exempt generators (DTI Consolidator Working Group 'Option 4')

This came into effect in March 2002. It allowed Licence Exempt Generators (Legs) registered in SVA to split out their output into fixed and variable components to be traded with different suppliers and consolidators in the same GSP group. This seems to have had only a very limited impact. Some parties believe that the functionality achieved by Modification P7 was sufficient.

Modification P100: Extension of demand-side trading units in order to increase the competitiveness of the market for embedded benefits

This came into effect in November 2003. It extends the ability for Legs to realise embedded benefits by turning each GSP group into a single trading unit. Distributed generators can trade with any supplier or consolidator regardless of that party's level of demand in the GSP group. It applies to both CVA and SVA registered generators. This proposal was further facilitated by National Grid's changes to its charging methodology. The proposal was deemed necessary because P7 only seemed to benefit certain supply businesses with multiple supplier identities that tended to own the distributed generation already and so were effectively commercially immune to the imbalance risks that consolidation was designed to mitigate.

Annex C – Grid code requirements

National Grid implemented the grid code as part of its transmission licence under Betta and was first effective from 1 September 2004. It covers all the material technical aspects relating to connections to and the operation and use of the transmission system or the operation of the electric lines and electrical plant connected to it or to a distribution system.

The code also specifies data that system users are obliged to provide to National Grid for use in the planning and operation of the transmission system. This includes: demand forecasts; availability of generating sets; and intended dates of overhaul of large generating sets.

Operational liaison—operating code 7

Generators, other than embedded small or medium power stations, are obliged to provide information regarding operations and/ or events on the total system that have had (or may have or could have) an operational effect.

Contingency planning—operating code 9

All embedded generating units are obligated under contingency planning to achieve restoration of the total system and associated demand in the shortest possible time.

Event information supply—operating code 10

Generators, other than embedded small or medium power stations, are obliged to provide more detailed information of significant incidents, reported under operating code 7.

Pre-gate closure process—balancing code 1

Embedded exemptable large power stations are obliged to submit data to enable National Grid to assess which BMUs or generating units are expected to be operating so that it can ensure the integrity of the transmission system. Embedded units must provide the information at GSP.

Physical Notifications (PNs) must be provided by BMUs with a demand capacity of 50MW or more in National Grid's area, 10MW or more in Scottish Hydro Electric Transmission's area or 10MW or more in Scottish Power Transmission's area. PNs are also required by power park modules; both large and medium power stations.

This data must be provided by 11am each day and can be revised any time up until gate closure.

Post gate closure process—balancing code 2

The post gate closure process applies to embedded exemptable large power stations regarding the physical operation of units, acceptance by National Grid of BM bids and offers, the calling off of ancillary services, issuing and implementing emergency instructions and other operational instructions and notifications.

Annex D – Embedded benefits

Embedded benefits from April 2007

TNUoS – depends on GSP

TNUoS demand and energy consumption charges by zone for 2007-08

Demand Zone	Zone Area	Demand tariff (£/kW)	Energy consumption tariff (p/kWh)
1	Northern Scotland	1.445659	0.183742
2	Southern Scotland	6.362303	0.830136
3	Northern	9.884146	1.287148
4	North West	13.646168	1.734890
5	Yorkshire	13.615270	1.750626
6	N Wales & Mersey	14.084355	1.805802
7	East Midlands	16.370802	2.129626
8	Midlands	17.807318	2.301762
9	Eastern	17.060375	2.240442
10	South Wales	21.537451	2.713949
11	South East	20.076054	2.586190
12	London	22.164365	2.710106
13	Southern	21.100281	2.738161
14	South Western	23.770560	3.000403

BSUoS – around £0.95/MWh

Transmission losses – £0.50-3.00/MWh

Power stations with a bilateral connection agreement and licensable embedded power stations

- no embedded benefits

Exemptable embedded large power stations with a Bega or Bella

- TNUoS demand charge
- BSUoS charge
- transmission losses
- distribution losses

Embedded exemptable medium and small power stations without a bilateral agreement with National Grid

- TNUoS demand charge
- BSUoS charge
- transmission losses
- distribution losses