



Electricity Market Design for a Low-carbon Future

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This paper considers GB electricity market and network regulatory arrangements in the context of transitioning to a low carbon electricity system. By considering some of the primary features of a low carbon electricity system and building on themes raised by a previous UKERC Supply Theme paper (Baker, 2009), the paper attempts to identify what characteristics an appropriate market and regulatory framework would need to possess. The paper goes on to consider how existing market arrangements perform in these areas and the possible need for change.

The aim of the paper is to contribute to the debate on energy market reform that is now underway. Currently, discussion seems to be focussing primarily on how to ensure adequate investment in low carbon and, in the medium term, conventional generation to meet the UK's climate change and security of supply goals. Delivering the necessary generation capacity is clearly crucial and by reviewing some of the mechanisms that could be used to encourage investment, this paper attempts to contribute in this area. However, the paper also addresses other areas where reform may be required but that have, to date, received less attention; issues such as arrangements to ensure efficient dispatch and energy balancing, efficient mechanisms to deal with network congestion and measures necessary to facilitate demand side participation.

The approach taken by the paper is incremental in nature, focussing on how current market arrangements may need to develop in the coming years, rather than proposing radical change. It is likely that successfully decarbonising the electricity sector may ultimately require a fundamentally different market design and that change, particularly in relation to low-carbon investment, may be required sooner rather than later. However, the transition to a low carbon electricity system will be gradual and arguably best served by incremental change in response to demonstrated need.

Contents

1. SUMMARY	3
2. A LOW CARBON ELECTRICITY SECTOR AND ITS IMPLICATIONS FOR MARKET DESIGN ..	4
3. GENERATION INVESTMENT	5
3.1 THE GENERATION INVESTMENT CHALLENGE	5
3.2 IMPACT OF WIND ON ENERGY PRICES	6
3.3 ENERGY-ONLY MARKETS	8
3.4 ENCOURAGING GENERATION INVESTMENT	10
3.4.1 Output-based mechanisms	11
3.4.2 Capacity-based mechanisms	12
3.5 A SINGLE BUYER	16
4. ENERGY DISPATCH AND BALANCING IN A LOW CARBON ELECTRICITY SYSTEM	17
4.1 PROBLEMS WITH EXISTING MARKET ARRANGEMENTS	17
4.2 SYSTEM RESERVES	19
4.3 MARKET LIQUIDITY	19
4.4 A SEPARATE MARKET FOR INTERMITTENT GENERATION?	20
4.5 THE CASE FOR A MORE INTEGRATED APPROACH TO MARKET DESIGN	21
4.6 INTEGRATED MARKETS AND THE NEED FOR PRIORITY DISPATCH	21
4.7 BALANCING MARKET SIGNALS WITH DEPLOYMENT RISKS FOR WIND	22
5.NETWORK CONGESTION AND APPROPRIATE NETWORK INVESTMENT SIGNALS.....	23
5.1 CONGESTION VOLUME	23
5.2 MINIMISING CONGESTION COSTS.....	25
5.3 TRANSMISSION INVESTMENT SIGNALS	26
6. ENCOURAGING DEMAND-SIDE PARTICIPATION.....	26
6.1 REDUCING CAPACITY AND RESERVE.....	27
6.2 SETTLEMENT IMPACTS.....	27
7. NETWORK REGULATION	29
7.1 ENSURING EFFICIENT NETWORK UTILISATION.....	30
7.2 DELIVERING NETWORK INVESTMENT IN A TIMELY FASHION	31
7.3 FUNDING NECESSARY NETWORK INVESTMENT	32
8. CONCLUSIONS.....	33
8.1 ENCOURAGING GENERATION INVESTMENT	34
8.2 ENERGY DISPATCH AND BALANCING	36
8.3 DEMAND RESPONSE	38
8.4 NETWORK REGULATION.....	39

1. Summary

The electricity system will have a pivotal role in delivering the UK's climate change obligations and longer term aspirations. The need to accommodate large amounts of renewable, mainly intermittent, generation by 2020, replace generation expected to decommission in the same timescales and the need to effectively decarbonise the electricity system by 2030 through the introduction of new low-carbon technologies, represent huge challenges to be overcome. In addition, the need to partially electrify the heat and transport sectors with the introduction of heat pumps and electric vehicles will require further investment in generation capacity and could, if not adequately managed, place additional strains on the electricity infrastructure.

If these challenges are to be met, some aspects of electricity network regulation and market arrangements will need to change. While the current arrangements have arguably served us well, delivering secure electricity supplies and driving out unnecessary cost, they are designed around controllable conventional generation capacity serving demand that varies in a predictable fashion. Tomorrow's electricity sector will, however, look very different with a more flexible demand base required to accommodate a low carbon generation fleet that contains large amounts of high capital cost, intermittent and inflexible capacity.

By considering some of the primary characteristics of a low carbon electricity sector, this paper attempts to identify things that an appropriate market and regulatory regime will need to do well. The analysis suggests that the highly disaggregated, energy-only and illiquid nature of the current market, reinforced by asymmetrical and non cost-reflective imbalance charges, may not be the most appropriate arrangement for dealing with intermittent renewable generation. A return to a more integrated market design is proposed, operating seamlessly down to real time in order to provide the liquidity and near real time balancing opportunities necessary to accommodate intermittent generation technologies such as wind. A more integrated electricity market would allow reserves, energy, and potentially, network requirements, to be optimised simultaneously.

The introduction of wind and other intermittent generation technologies will cause energy prices to fall on average, but become far more volatile. This will make financing both capital intensive low carbon and peaking generation more difficult and, given the general scepticism over the ability of emissions trading to fully internalise the costs of carbon, there would seem to be a need for additional measures to support investment. Options include the extension of existing supplier-based obligations, Feed in Tariffs

(FiTs), capacity obligations or capacity payments. In addition, the more radical option of creating a central entity to procure both capacity and energy has been suggested.

The need to retain substantial amounts of conventional plant to back-up intermittent generation can be expected to significantly increase network congestion. The current market arrangements, where network requirements are only considered one hour before real time, arguably encourage practices that increase congestion volumes and make the resolution of that congestion unnecessarily expensive. In addition to incurring unnecessary costs, which are ultimately borne by electricity customers, the current arrangements also cause network investment to appear overly attractive. The adoption of more integrated market arrangements would allow earlier consideration of network requirements and a more cost effective resolution of network congestion.

The development of a more responsive demand side to accommodate a partially intermittent and inflexible generation fleet will be facilitated by the introduction of advanced or “smart” metering, where domestic and small commercial customers are metered on a half-hourly basis. This will require fundamental changes to the settlement processes and it will be necessary to ensure that increased data retrieval, handling and aggregation requirements do not impose unnecessary burdens on small customers or impede the development of a more responsive demand base.

Finally, the paper briefly addresses some regulatory issues and makes the case for a regulatory environment that more effectively supports innovation and equalizes incentives for network investment and operational alternatives. Regulation will also need to ensure that network investments necessary to accommodate renewable and low carbon generation can be delivered in a timely fashion and that those investments can be adequately financed.

2. A Low carbon electricity sector and its implications for market design

If the UK is to achieve the target of an 80% reduction in CO₂ emissions by 2050, the electricity sector will need to be effectively decarbonised by 2030 (Committee on Climate Change, 2008). Furthermore, as the sector is decarbonised, energy consumption is likely to increase as low carbon electricity replaces fossil fuels in the surface transport and heating sectors. It is difficult to be precise about the makeup of the future generation portfolio given the wide range of possible outcomes (UKERC, 2010). However, a plausible scenario (Electricity Networks Strategy Group (ENSG), 2009) is that around 45 GW of wind and other intermittent renewables, 10 GW of new nuclear, together with 12 GW of supercritical coal and gas-fired plant equipped with carbon

sequestration technology will be required by 2030 in order to decarbonise the electricity sector.

Wind, nuclear and CCS technologies all have high capital costs and, as such, may not be plant that investors would necessarily choose to support. An appropriate electricity market design will, therefore, need to ensure that sufficient low-carbon capacity is brought forward. Furthermore, as much of this low-carbon capacity will be intermittent in nature, with output difficult to predict with any accuracy until close to real time, the electricity market will need to accommodate the increased short-term trading and balancing activity necessary to maintain security of supply. In fact it seems likely that these two issues, i.e. the need to ensure adequate investment in low-carbon technologies and accommodate high levels of short-term trading and balancing activity, will be the principle determinants in designing an electricity market for the future.

Other issues influencing market design will be the need to generally minimise emissions, manage network congestion efficiently and accommodate a flexible and price-sensitive demand base. Minimising emissions will require that low-carbon generation has priority of use over conventional technologies and that overall dispatch efficiency is maximised. The need for an effective means of managing network congestion stems from the intermittent nature of technologies such as wind and the consequent need for conventional generation back-up, which would make the provision of sufficient network capacity to accommodate the simultaneous operation of all generation capacity unnecessary and prohibitively expensive. The requirement for market arrangements to facilitate the development of a flexible demand base is also associated with need to minimise the impacts of intermittency, both in terms of generation investment and energy balancing, and to allow the partial electrification of the heat and surface transport sectors to be accomplished in a cost effective fashion.

3. Generation investment

3.1 The generation investment challenge

The UK will need to invest heavily in generation capacity over the coming years. Deploying sufficient renewable and low-carbon generation to meet our climate change obligations while replacing plant expected to close as a result of E U Large Combustion Plant and Industrial Emissions Directives, is likely to require some £140 billion of investment by 2025 (Ernst & Young, 2009). Delivering the necessary investment will be all the more challenging given that many other countries will be embarking on similar programmes. It is estimated that global investment in generation could run at around \$550 billion/year until 2030, with investment in Europe running at some €60 billion/year over the same period (E.on, 2009). This international dimension is particularly relevant given that the UK will be heavily dependent on large European-

based energy companies, operating away from their home markets, to deliver the investment in generation capacity required. The UK will, therefore, need to maintain a regulatory and market environment that is attractive to these companies, who clearly have choices in terms of where they invest.

The following paragraphs in this section consider how the introduction of intermittent generation technologies such as wind make the investment challenge more difficult and why the current GB “energy only” electricity market may not be the most appropriate design to deliver the investment required to achieve our climate change goals. The section then moves on to consider the various options available for encouraging necessary investment, drawing on experience from the UK and overseas.

3.2 Impact of wind on energy prices

Meeting our climate change obligations implies that, by 2020, some 30GW of predominately intermittent renewable generation will be connected to the electricity grid supplying around 30% of our electrical energy, while around 45GW could be required by 2030. As can be deduced from figure 1, injecting such large amounts of zero-marginal cost energy into the electricity market is likely to have a significant impact on wholesale electricity prices, with the displacement of expensive and polluting fossil fuels and the reduced utilisation of high variable cost, low efficiency, plant.

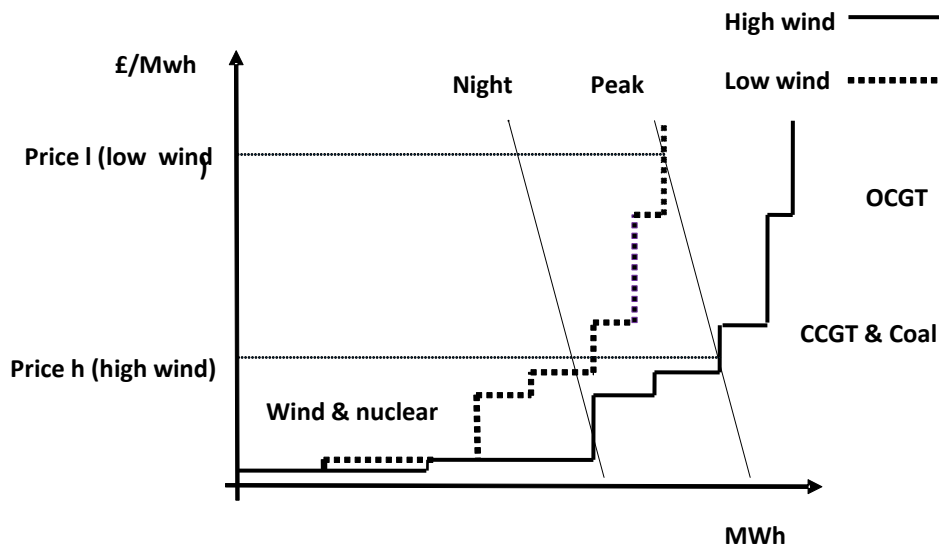


Figure 1. Impact of wind on energy prices

Indeed, as wind penetration increases, spot electricity prices may fall to zero and even go negative on those occasions when windy conditions coincide with periods of low

demand and wind generators attempt to retain access to operational subsidies¹. The negative impact of wind generation on wholesale electricity prices has been observed in countries such as Denmark, Germany and Spain, which have installed large amounts of wind generation as a proportion of their peak electrical demand (Poyry, 2010). In fact, the impact of wind energy on electricity prices could be even more pronounced in GB, due the “island” nature of the electricity system with little interconnection currently available to smooth variations in supply.

While the injection of large amounts of zero–marginal cost energy will tend to reduce average wholesale electricity prices, the intermittent nature of that energy will introduce some additional, offsetting, costs. Intermittent generation such as wind cannot be relied upon to be available at any particular point in time and contributes little to security of supply. “Back up” resources in the form of flexible conventional generation or alternatives such as demand response, storage or support from adjacent systems via interconnection capacity, therefore need to be retained on almost a MW for MW basis² in order to operate when wind output is low. Conventional generation, typically CCGTs, operating in this role will experience decreasing utilisation as wind capacity builds, but be expected to operate more flexibly, i.e. starting and stopping more frequently and being part-loaded in order to provide both “upwards” and “downwards” reserve. These modes of operation will introduce operational inefficiencies and associated costs, which will need to be spread over a reducing number of running hours.

In addition to the impact of these “operational” costs, consumers will also need to bear the costs of retaining conventional “back up” plant in service and of eventually funding its replacement. A sustainable electricity system with high levels of intermittent renewable generation will require far more generating capacity than there is peak demand to be supplied and the fixed costs of this additional capacity will need to be supported through more volatile energy prices or, alternatively, mechanisms that reward capacity explicitly.

¹ Renewable generation receives Renewable Obligation Certificates (ROCs) for each MW of energy generated. These can be sold on to suppliers to help meet their obligation to purchase energy from renewable sources, thereby creating an income stream. During periods when the combination of renewable output and that of inflexible sources such as nuclear exceed demand, it is worth renewable generation paying suppliers to take energy in order to retain access to the ROC income stream. In these circumstances the spot price of energy would enter negative territory.

² Conventional generation is generally held to have a 95% availability forecast error over peak demand periods. For wind to have a similar “firmness”, its capacity would need to be factored down to approximately 4% of installed capacity.

3.3 Energy-only markets

In common with many other jurisdictions both in Europe and elsewhere, GB operates an “energy-only” electricity market where non-subsidised, conventional generation relies on the difference between energy prices and variable cost to service its investment and other fixed costs³. Energy-only markets rely on the theory of “peak load pricing” (Kleindorfer), which describes how generation investment can be optimised through efficient pricing signals. For the majority of time, available generation capacity will exceed demand and wholesale energy prices will reflect the variable costs of the marginal plant. Low variable cost generation such as nuclear or wind will receive excess income when prices are set by higher-variable cost plant such as CCGTs or coal, contributing to their fixed costs. However, marginal and peaking generation will need to rely on periods of high energy prices associated with tight capacity margins, which may only occur for just a few hours per year.

To work effectively, energy-only markets require demand to be sensitive to price. Spikes in energy prices caused by plant scarcity will be attenuated by price sensitivity and the value that different classes of demand place on an additional MWh of supply will be exposed. In this way, the market effectively determines how much generation capacity is required, rather than compliance with some arbitrary generation adequacy standard. In the absence of demand price sensitivity, as is the case in GB, the energy market may become distorted with the GBSO having to impose voltage reductions or physical disconnection to curtail demand in the face of generation shortages. The need to impose operational measures to curtail demand in the absence of any natural response to increasing price may result in some customers losing access to supplies before prices have reached the level where they would restrict consumption voluntarily.

Despite these general concerns, the GB energy-only market in the form of NETA and BETTA⁴ has been relatively effective in bringing forward new capacity. While there was a sharp drop in generation commissioning following the introduction of NETA in 2000, this was probably in part a reaction to the increased plant margins that applied in the latter years of the England & Wales Electricity Pool. The 16 GW of new, non renewable, capacity that is forecast⁵ to commission by 2015/16, suggests that the current arrangements are capable of dealing with the immediate requirements for generation

³ Notable examples of “energy only” markets are Australia (NEM), ERCPT, Nordpool & Ontario

⁴ New Electricity Trading Arrangements (NETA). Introduced to replace the E&W Electricity Pool in April 2000. The bilateral trading arrangements introduced by NETA were extended to Scotland in April 2005 with the introduction of the British Electricity Trading & Transmission Arrangements (BETTA).

⁵ National Grid Seven Year Statement, table 3.8.

investment. However, as wind and nuclear capacity builds, conventional capacity will experience reducing utilisation and marginal prices will increasingly be set by lower variable cost plant. Conventional plant will therefore require ever higher energy prices during non-windy periods in order to recover investment costs. Low carbon technologies such as nuclear can expect to see high load factors, however they will also be disadvantaged as average energy prices decline but become more volatile.

In a recent study to examine how the GB and All-Ireland electricity markets may perform as the capacity of wind and low-carbon plant grows, (Poyry, 2009) suggest that energy price volatility can be expected to increase dramatically, with pricing peaks of almost £8000/MWh necessary by 2030 to support the continued availability of peaking plant. Poyry also conclude that the incidence of extremely high prices will vary significantly from year to year due to normal variations in weather, introducing additional uncertainties for potential investors. It is worth noting, however, that the Poyry studies assumed demand to be insensitive to price. If demand becomes more price sensitive through the introduction of smart metering however, the future pricing peaks predicted by Poyry, which exceed by some margin the accepted value that customers place on maintaining access to supply⁶, would be considerably reduced. Furthermore the Poyry studies take no account of the partial electrification of the heat and transport sectors, a requirement of achieving the UK's climate change goals, which would inject a large amount of controllable demand and allow further demand smoothing. Increased interconnection and storage would have a similar effect.

Notwithstanding this mitigation, the increase in zero and low marginal cost generation will undoubtedly challenge the ability of an energy-only market to deliver adequate levels of generation investment. There must be a limit to the extent to which price sensitivity, particularly during periods of cold weather that often coincide with calm conditions, can be expected to limit electrical demand. Moreover, energy price spikes will still be necessary to adequately reward low merit and peaking plant and there is a concern that periods of extreme, if temporary, energy prices may prove to be unacceptable from a political or regulatory point of view.

Consumers exposed to real time electricity prices seem likely to press for prices to be capped and, given the year to year variability suggested by Poyry, it might be difficult to distinguish between justified price spikes and those resulting from an abuse of market power (Poyry, 2009). There is a danger, therefore, that regulatory or political interventions may result in measures that prevent energy prices from rising to the levels necessary to justify investment in new capacity. Indeed, regulatory and political pressures have resulted in the application of measures to contain wholesale prices in

⁶ Defined as the "Value of Lost Load" or VOLL, currently assumed to be around £4000/MWh.

many electricity markets and, while not currently applied in GB, price caps have been applied in the past. It is also worth noting that there are other mechanisms at work within BETTA that tend to attenuate spot prices, for example the use of contracted reserve contracts by the GBSO as an alternative to accepting more expensive Balancing Mechanism⁷ offers to adjust output in real time.

In conclusion therefore, energy only markets can claim to have the virtue of relative simplicity, with reliability and generation investment set by market participants, rather than arbitrary rules. However, reliance on scarcity pricing to recover fixed costs increases investment uncertainties and finance risk. Furthermore, the ability of scarcity pricing to stimulate adequate investment will be tested to the extreme by the introduction of zero-marginal cost intermittent generation technologies, with the consequent decline in average energy prices and increased price uncertainty and volatility. While studies such as that carried out by Poyry do not, of themselves, make the case against energy-only markets and the need to reward for generation capacity explicitly, they do clearly demonstrate the challenges to be faced.

3.4 Encouraging generation investment

There appears to be an emerging consensus that existing market arrangements are unlikely to deliver the low carbon investment necessary to satisfy the UK's climate change ambitions (Ofgem, 2010), (Committee on Climate Change, 2010), (HM Treasury, 2010). Whereas none of this analysis currently goes beyond presenting options, a common theme is the need to introduce some form of mechanism, external to the main energy market, to encourage investment in low carbon generation capacity.

In their Energy Market Assessment (EMA), HM Treasury/DECC set out five possible models for market reform, shown in figure 2. These models escalate in terms of intervention from simply adding a carbon floor price to existing market arrangements, the provision of additional low carbon incentives, regulation to limit investment in high-carbon technologies, the provision of long-term low carbon payments, and finally the creation of a central buyer for all generation capacity and output. In discussing the relative merits of these five options, the EMA concludes that Option A, which would introduce a floor price for carbon while leaving other market arrangements as they are, is unlikely to drive the pace and scale of investment required. At the other end of the intervention spectrum, the single buyer proposed by EMA Option E is discounted as not having sufficient benefits over less interventionist options that retain a competitive

⁷ Balancing Mechanism (BM). The BM commences at market closure, one hour before real time. Generators (or demand) submit bids and offers to vary output (or demand) and these may be accepted by the GBSO to ensure final energy balancing and that network congestion is resolved.

approach involving incentives, payments or restrictions in investing in conventional technologies.

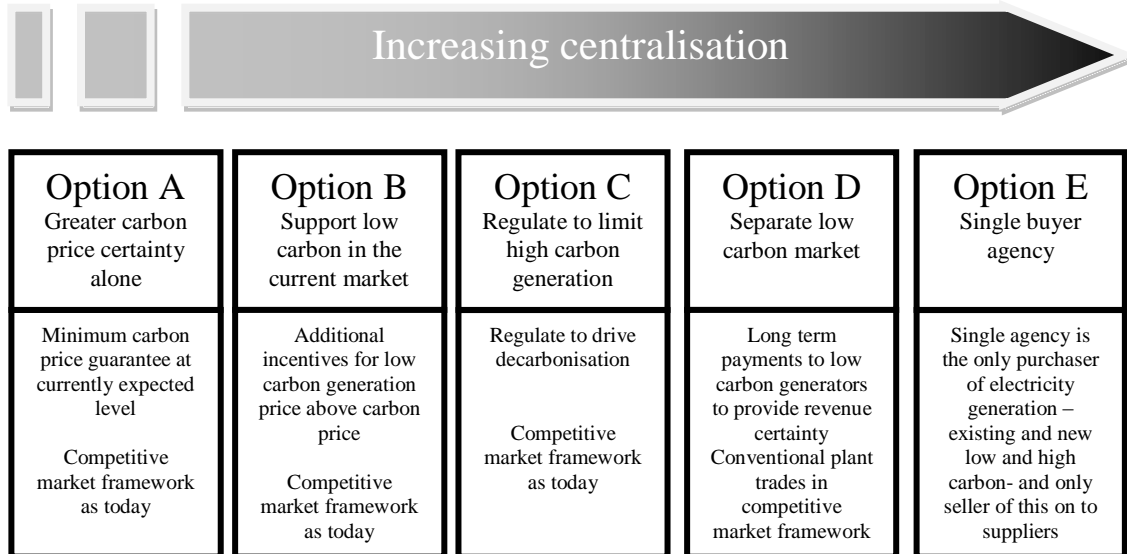


Figure 2. EMA market reform options

The following paragraphs consider some of the alternatives for encouraging sufficient low-carbon and conventional generation capacity in the context of the Energy Markets Assessment Options B & D. The mechanisms considered include energy or output based obligations, such as the GB Renewable Obligation (RO), capacity obligations and capacity payments. In addition, and despite DECC’s rather summary dismissal of their Option E, the possible merits of a single-buyer concept are considered.

3.4.1 Output-based mechanisms.

Since the demise of the Non Fossil Fuel Obligation, support for the deployment of renewable generation in the UK has been via the Renewable Obligation (RO) and, from April this year, via a feed in tariff (FiT) for smaller generation. Both are output-based support mechanisms that reward generators for producing renewable energy, and EMA Option B appears to propose extending this type of arrangement to other forms of low carbon generation. The Committee on Climate Change (CCC, 2010) also recommends an extension of FiTs and the introduction of a low carbon obligation to ease uncertainties over cost recovery, thereby reducing investment costs.

While output based mechanisms have been effective in bringing forward low carbon investment worldwide and provide strong delivery incentives, they are not without problems. “Quantity” based output mechanisms such as the RO, for example, suffer from uncertainties over future ROC prices due to “headroom” issues (i.e. prices decline as the specified “quantity is achieved”) that increase investment risk and can also over-

reward the cheapest low carbon technologies (BERR, 2008). “Price” based mechanisms, such as FiTs, suffer from uncertainty in terms of actual response to the guaranteed price and, if that price is incorrectly set, can result in over or under supply (Cory, 2009).

Output based mechanisms also have the potential to distort the energy market. As indicated in 3.2, increasing wind and nuclear capacity will give rise to the possibility of wind becoming the marginal plant when periods of low demand coincide with high wind output. During these periods, wind generation will seek to retain access to ROC income, driving energy prices into negative territory. Some analysis (Strbac, 2008) suggests that, taking into account the need to carry addition reserves on part-load thermal plant, up to 25% of wind energy may need to be rejected when wind capacity exceeds 30 GW. Clearly, this could have a serious impact of the financial viability of wind as well as other low carbon technologies such as nuclear, which will be dependent on high energy prices to recover investment costs.

In order to avoid or reduce the prospect of negative prices, measures such as curtailing ROC or FiT payments during periods of excess low carbon output could be considered. Some possibility of low and damaging energy prices would remain however and attention is likely to turn to the deployment of additional storage or interconnection capacity in order to artificially boost demand. An alternative approach, albeit involving a degree of central planning, would be to take a more “strategic” view of the interactions between nuclear and wind generation and attempt to optimise the capacity mix.

The “premium” FiTs discussed in EMA Option B, which “top up” revenues from the energy market and provide investors with a guaranteed income, have the advantage over standard FiT designs of keeping generation involved and interested in the energy market. Dispatchable renewable generation would be able to respond to energy price signals and therefore be less likely to contribute to negative price problems. However, intermittent renewable technologies such as wind are not dispatchable in any meaningful way and are less able to respond to price signals (Poyry, Elementenergy, 2009). By supplementing energy market revenues, premium FiTs therefore could still act in a similar fashion to the RO, particularly in the case of intermittent technologies, in encouraging negative bidding during periods of excess low carbon output.

3.4.2 Capacity-based mechanisms

An alternative approach to encouraging investment in low carbon technologies, which would fit comfortably in EMA options B or D, would be to focus on low-carbon capacity rather than output. There are numerous examples world-wide where obligations are placed on suppliers to procure sufficient generation capacity to satisfy demand to some standard of supply security. To date, the focus of such mechanisms has been security of supply alone and they have not therefore been technology specific. However, there seems no reason in principle why such obligations could not be broadened to deliver

both security of supply and investment in low carbon technologies, albeit at the cost of some complexity in design.

3.4.2.1 Capacity obligations on suppliers

There are numerous examples of supplier-based obligations in Europe (often referred to as Public Service Obligations), the US and elsewhere. In the US, capacity obligations are a carryover from the old regional “power pool” structures in which all participating suppliers, referred to as “Load serving Entities” or LSEs, were required to acquire sufficient capacity to serve their peak demand plus a reliability margin set by the pool. With the restructuring of the US electricity system in the mid-1990s, many of these arrangements developed into organized capacity markets (see 3.4.2.2); however, some of the original pooling arrangements remain⁸, with capacity being traded bilaterally to meet obligations in response to demand movements or diversity in demand peaks.

Penalties usually apply in the event of an LSE failing to acquire sufficient generation capacity to satisfy the obligation, although there is concern that there may not necessarily be time for the Independent System Operator (ISO)⁹, to access capacity in the event of shortages. Capacity obligations can and often do allow demand-side participation however, allowing relief in shorter timescales. Some jurisdictions, i.e. California, have addressed this problem by imposing forward obligations to ensure potential capacity shortages are identified in good time.

As with all capacity-based obligations that flow from an administered reliability standard, there are concerns that the value of reliability may not be adequately balanced against the cost of providing that reliability. Concerns have also been raised in the US about a lack of market liquidity and that the prices paid for capacity are not always transparent (Brattle Group, 2009).

Addressing the issue of how capacity obligations might be applied in GB, and taking a cue from the Renewable Obligation, suppliers could be required to purchase capacity certificates in proportion to their demand or pay a buyout price, with the proceeds distributed to certificate holders. As the object would be to ensure both security of supply and decarbonisation, the obligation would need to recognise the carbon-intensity of different technologies, possibly through premium payments for low carbon technologies or selecting successful bids on the basis of low-carbon emissions as well as bid price (Gottstein, 2010).

⁸ For example, Southwest & Southwest Power Pool covering most of the Southern & South-western states except California and Texas.

⁹ Independent System Operator (ISO). A not for profit entity, charged with the operation of the electricity network and who may also administer the electricity market.

3.4.2.2 Capacity markets

Placing obligations on suppliers will naturally lead to capacity trading, as individual parties seek to satisfy specific capacity requirements. However, where a more organised approach is required, or where doubts exist as to the effectiveness of supplier obligations in bringing forward sufficient generation investment, a more reliable option may be to place an obligation on the System Operator. There are a number of examples in Europe, the US and elsewhere of such obligations, which typically involve the System Operator establishing a generation capacity requirement sufficiently far ahead to encourage new investment and procuring the capacity necessary to meet that requirement.

PJM, ISO¹⁰ New England, ISO New York and ISO Midwest are examples in the US of where trading around the original regional pool-based LSE capacity obligations developed into centralised capacity markets, administered by the ISO. Early market designs delivered mixed results for a number of reasons, including an initial focus on short-term supply reliability at the expense of signalling the need for investment in new capacity and the distorting impact of price caps. This short term focus resulted in “bipolar” pricing (Gottstein, 2010), with prices collapsing when a surplus of capacity existed but rising to high levels in the event of capacity shortfalls.

Market designs developed to overcome these initial problems and now include forward capacity auctions, typically three years before the year of delivery. LSEs retain their supply obligation and can choose to contract bilaterally for capacity. However, where participation in the market is mandated, this capacity must be input to the auction with the ISO effectively procuring any residual capacity required. Both existing and new capacity, and in the case of PJM & ISO New York demand response, bid into the auction and the clearing price is paid to all successful bidders. The costs of procuring the required capacity are allocated to LSEs on a pro-rata basis. There is also a locational element to the auctions to ensure that transmission constraints are respected.

Capacity markets operating in the US and elsewhere are essentially non-technology specific in nature, focussing on security of supply alone. However, as is the case with simple capacity obligations, there seems to be no reason why capacity markets could not be designed to take into account the carbon-intensity of generation in order to deliver both security of supply and low carbon objectives

It can be argued that the System Operator or ISO is better placed than individual suppliers to anticipate future system demand and optimize the shape of the generation

¹⁰ Independent System Operator (ISO).

portfolio. Individual suppliers may, for example, be prepared to shed market share rather than commit to new capacity in an uncertain world and might favour one technology over another. An independent System Operator may well take a more holistic view but would be sourcing capacity on the basis of generation adequacy rather than market signals. In the context of the current GB market arrangements, it is difficult to see how investment to satisfy some non-market based adequacy requirement could co-exist with investment on a commercial basis. There is a danger therefore, that placing an obligation on the System Operator to procure capacity, even as “provider of last resort”, could deter normal commercial investment.

3.4.2.3 Capacity payments

A limitation of some early capacity-based obligations and markets was a lack of incentives to ensure real time plant availability. Although financial penalties for non-delivery are now common, these penalties do not always reflect the real value of availability during times of system stress. Capacity payment designs are considered more effective in providing real time availability incentives (Oren, 2000).

Capacity payment mechanisms normally involve a payment being made to every generator that is available to meet demand for each trading period – irrespective of whether or not the generator is actually required to run. Payments, which are normally funded via an uplift on suppliers, are usually linked to the value of capacity, i.e. when the supply position is tight payments will be higher. Capacity payment mechanisms are invariably associated with more integrated scheduling and dispatch arrangements such as the England & Wales Pool, which operated from privatisation of the GB electricity sector in 1990 to the introduction of NETA in 2001.

In the case of the England & Wales Electricity Pool, capacity payments were a function of the loss of load probability (LOLP)¹¹ and the value of lost load (VOLL)¹². If the supply situation became very tight and LOLP approached unity, then capacity payments could reach very high levels, capped only by the value of VOLL (currently assumed to be around £4000/MWh). The all-Ireland “Single Electricity Market” introduced in 2007 also incorporates a capacity payment mechanism but utilising a softer link to the fluctuating value of capacity based on the cost of building efficient open cycle gas fired plant.

¹¹ LOLP is a measure of the likelihood of insufficient generation capacity being available to meet peak demand, varying from zero when there is no risk to unity when there is certainty.

¹² VOLL is an estimate of the maximum price a customer is prepared to pay to maintain access to electricity supplies. In practice, VOLL will vary between customer groups and on other circumstances.

While linking payments to the scarcity value of capacity incentivises additional provision during periods of system stress, perversely it also provides an incentive on portfolio generators to withdraw capacity in order to increase those payments. To some extent this is a criticism that can be levelled at all capacity mechanisms, however the more granular nature of capacity payments compared with capacity obligations provides rather more scope for abuse. Problems associated with the withholding of capacity were a principal driver behind the abandonment of the E&W Electricity Pool and the development of a bilateral market with incentives to contract forward (Patrick, 2001). Other criticisms of capacity payments relate the value of VOLL, which is estimated rather than set by the market, and the usually simplistic methods used for calculating of the value of LOLP. In combination, these issues are almost certain to result in a mismatch between the value of capacity payments and that which would arise from a capacity market.

As is the case with capacity obligations and markets, the application of capacity payment mechanisms to date has been linked exclusively to maintaining security of supply. There seems to be no reason however why a capacity payment mechanism could not be designed to recognise the carbon intensity of generation in order to address both decarbonisation and security of supply objectives.

3.4.3 A single buyer

Although dismissed rather abruptly by the EMA as unnecessarily interventionist and “lacking the disciplines to drive efficiency”, the single buyer model would seem to have some relevance to a low carbon world. A central agency would identify the need for and procure low-carbon, and possibly conventional, generation capacity via a tender process. Successful bids up to a defined capacity requirement would be awarded a fixed annual income over the lifetime of the project on a £/MW basis, or to reflect levelised costs. If capacity was to be rewarded on a £/MW basis, the arrangement would look rather similar to the centralised electricity markets that have developed in the US and elsewhere, and which are discussed in 3.4.2. Energy would be sold into and bought through a spot market, with parallel contracting between generators and suppliers via contracts for differences (cfd), where price certainty was required or to meet any low-carbon obligations that might be imposed. Dispatch priority may need to be given to low-carbon generators in order to avoid any risk of a price-based dispatch process preventing compliance with those obligations.

If, however, generation capacity was procured on the basis of, say, levelised costs, the single buyer model could transform the nature of the electricity market. As revenues would be agreed during the tender process, indexed to cover fuel price variation in the case of nuclear or carbon sequestered plant, there would be little point attempting to dispatch plant on the basis of submitted bids via a spot market. Generation could be dispatched to meet demand on the basis of a carbon-emissions hierarchy and to resolve

network congestion, with differentiation within plant technologies on the basis of marginal cost. The need for a plethora of confusing renewable and low carbon obligations would be removed.

The value of a single buyer approach would be in substantially improving the investment climate. Continuing with the existing market arrangements implies increasing energy price uncertainty and volatility, increasing the cost of project capital. However, the guaranteed income stream associated a single buyer model would improve investor confidence and reduce the cost of capital. Low-carbon generation projects, which have high capital costs, would particularly benefit from a more benign investment climate and the overall costs of decarbonising the electricity sector would be reduced.

The EMA's concern that a single buyer model would lack incentives to drive efficiency seems to some extent misplaced. In addition to the advantages flowing from an improved investment climate, a single buyer approach would bear down on project costs through the tender process. While fuel price risk and risk of generation assets become stranded would ultimately lie with the customer, construction and operational risks would remain with the generator. Overall, the single buyer model would seem to provide a competitive and less complex environment for the delivery and operation of a low carbon electricity sector.

4. Energy dispatch and balancing in a low carbon electricity system

4.1 Problems with existing market arrangements.

Currently, the GB market arrangements make no organised attempt to optimise generation dispatch. Generators and suppliers trade energy in advance on a bilateral basis and, at "gate closure"¹³, present the GBSO with generation or demand schedules necessary to deliver contractual commitments – a process referred to as "self dispatch". Furthermore, as the majority of energy is produced by vertically integrated utilities with both generation and supply businesses, much of this "trading" is internal – i.e. these utilities "self supply" to a significant extent. Self supply limits the competitive pressures on which bilateral markets depend to ensure efficiency (Sioshansi, 2009) and the combination of self dispatch and self supply creates the potential for non-optimised dispatch outcomes.

¹³Gate closure – 1 hour before real time, the energy markets close and the "Balancing Mechanism" commences. Contractual positions at gate closure are compared with outturn in order to determine imbalance.

An additional issue to be considered in the context of dispatch efficiency is the tendency for generators to “self insure”. The asymmetrical and non cost-reflective cash out prices¹⁴ applied to residual imbalances resolved by the GBSO in the Balancing Mechanism, which operates from gate closure, encourages generators to carry reserves in order to minimise imbalance. These reserves are additional to those specified by the GBSO to cover demand or generation uncertainties and result in an energy market that is predominately “long”, with connected generation capacity exceeding the demand to be supplied. Consequently, more generation is part-loaded than is actually required, reducing overall efficiency and causing unnecessary emissions. An indication of the extent to which generation companies self insure is given by the monthly Trading Operation Report¹⁵ published by Elexon, which suggests that there is typically between 1000 and 2000MW of unused reserve available on part-loaded plant over demand peaks and considerably more during other periods.

The extent to which the combination of self dispatch, self supply and self insurance reduces the overall efficiency of dispatch is unclear. However, there is evidence from both the US (Sioshansi, 2009) and GB (ILEX, March 2002) to suggest that fuel inputs could be around 3 or 4% higher than would be the case if an organised attempt were made to fully optimise generation dispatch. Further anecdotal evidence that the current GB market arrangements may produce generation dispatch outcomes that differ from the “optimum” is given by analysis undertaken for Elexon in developing a mechanism to account for transmission losses (Siemens, 2009). This analysis demonstrated that, in some cases, transmission line loss factors calculated from actual line flows differed from those produced using a load flow model that dispatched plant on the basis of marginal cost. In other words, the disposition of generation resulting from existing market arrangements appears to differ to some extent from that which might be delivered by a truly optimised dispatch process based on actual marginal costs.

Although the inefficiencies introduced by self dispatch might currently be of a low order, they do result in unnecessary cost and carbon emissions. Dispatch inefficiency is also likely to increase with the growth of intermittent generation. With relatively little wind capacity connected, portfolio generating companies can “hide” intermittency within their

¹⁴Imbalances that add to the net system imbalance are treated differently than those that reduce net imbalance. For example, a generator whose imbalance adds to system imbalance is exposed to the balancing costs incurred by the GBSO. Generators whose imbalances reduce net imbalance pay/receive prices related to the short term energy prices. This asymmetry encourages parties to self balance and penalizes inflexible or intermittent generators.

¹⁵ Operational Trading Reports are available at <http://www.elexon.co.uk/search/default.aspx?q=operational%report>

settlement “production account”¹⁶ relatively easily. However, as wind capacity builds, “internalising” the impact of intermittency within a generation portfolio will become more difficult. Generators will attempt to trade out intermittency close to real time as wind forecasts become more accurate, however to limit imbalance risk and exposure to cash out prices, generators will need to carry more reserve as the intermittent capacity within their portfolio increases.

4.2 System reserves

In addition to any reserve held by individual portfolio generators as insurance against exposure to imbalance charges, the growth in intermittent capacity will also require the GBSO to procure additional reserves. Currently, system reserve levels are relatively modest at around 4GW (4 hours ahead of real time) and predictable, varying only slightly with demand level and time of day. However, as intermittent wind capacity builds, reserve levels will increase and are predicted to exceed 9GW by the middle of the next decade (National Grid, 2009). The requirement to carry reserves will also become considerably more unpredictable and volatile, increasing when high wind output is forecast and decreasing during periods of relative calm.

Currently, the GBSO procures reserve through a combination of periodic tenders¹⁷, some intra-day power exchange trading together and Balancing Mechanism bid/offer acceptances close to real time. While these arrangements are effective in procuring sufficient reserves to meet current requirements, they are unlikely to produce an optimised outcome or reveal the true real time value of reserve. If the GB market is to deal effectively with an increased and more volatile requirement for system reserves in the future, some means of more formally integrating energy and reserve requirements in the short term and intraday markets will be required.

4.3 Market liquidity

As suggested in 4.1, the growth in wind capacity will significantly increase short term trading as generators attempt to match commitments to updated and more accurate wind output forecasts. This increased trading close to real time will require efficient, liquid short term markets and there are factors which suggest that the current market structures may not be best placed to provide that liquidity or deal with the challenges associated with large amounts of wind generation. The GB market is the least liquid of all comparable European markets (Weber, 2009) due primarily to the vertically

¹⁶ For the purposes of settlement, a generating company has a single production account. In the case of a portfolio generator, imbalance prices are applied to the aggregated production account imbalance, rather than the imbalance of each individual generator in that account.

¹⁷ The GBSO contracts for Short Term Operational Reserve (STORR) via auctions held three times a year.

integrated nature of the sector and the high level of internal trading. Liquidity is also reduced by the “continuous” nature of trading and the existence of alternative trading platforms, which tend to disperse trading activity.

This lack of short term market liquidity acts against the interests of both intermittent generation such as wind and also small independent players, who have a greater need for balancing in the shorter term. Prompted by these and more general concerns about market efficiency, Ofgem has consulted on measures to improve market liquidity and has threatened action by the end of 2010 if the situation has not sufficiently improved (Ofgem, 2010).

4.4 A separate market for intermittent generation?

In the context of the existing, disaggregated, bilateral trading arrangements, there may be some value in creating a separate market for wind and other intermittent technologies. As suggested in 4.1, portfolio generators will find it increasingly difficult to internalise the impacts of intermittency as capacity increases and will need to resort to short term trading. However, internalising or trading out intermittency on an individual generator or portfolio basis is unlikely to take full advantage of the geographic diversity of wind output, which can significantly reduce wind output uncertainty¹⁸.

As wind capacity grows, there may be a case for creating separate market arrangements for wind in order to capture the value of geographic diversity. Wind output could be aggregated across the whole of GB and auctioned into the electricity market, reducing forecast error and overall imbalance. Charging for imbalance on aggregated basis rather than against individual or portfolio generator output would arguably be more cost-reflective, as balancing costs incurred by the GBSO reflect net generation-demand imbalance rather than the imbalance of any particular generator.

Carving out a separate market for wind would be a radical departure from current practice and might, therefore, encounter opposition from portfolio generators. However, the increasing difficulty and inefficiency associated with attempting to manage intermittency on an individual company basis may cause support for a separate market for wind to grow with time. A separate market for wind would be particularly helpful for independent wind operators who, unlike portfolio generators, currently have little opportunity to mitigate the impact of intermittency and reduce imbalance charges.

¹⁸ Aggregating wind output over a wide geographic area significantly reduces wind output forecast error together with associated reserve and capacity requirements. See for example www.nationalgrid.com/.../GBSQSSIntegratedReliabilityAndEconomicsAssessment.pdf

4.5 The case for a more integrated approach to market design

Whereas creating a separate market for wind might be appropriate given a continuation of bilateral energy trading, issues of dispatch efficiency, market liquidity and the need to deal with increasing and more volatile reserve requirements suggest that the existing arrangements may not be appropriate for a low-carbon electricity system. The need for market participants to adjust their contractual positions in response to more accurate short term forecasts needs to be recognised and facilitated, while increased and volatile reserve requirements need to be coordinated more effectively with energy procurement in order to ensure efficient dispatch. The more integrated electricity market designs, as adopted by PJM, New England, New York and, to a lesser extent Spain, seem more effective in dealing with these issues and therefore more appropriate in terms of transitioning to a low carbon electricity sector.

In the integrated US markets, energy is traded via day ahead and near real time auctions run by the ISO, based on bids submitted by generators. The timed nature of the auctions maximise liquidity, contrasting with the situation in GB where liquidity is reduced by the disaggregated and continuous nature of trading. The simultaneous procurement of energy and reserve requirements based on production costs ensures that generation dispatch is optimised and the real time value of plant flexibility is revealed.

With around 17GW of wind capacity currently installed, the Spanish electricity market has evolved to deal with the impacts of intermittency. Market arrangements lie somewhere between the fully integrated designs seen in the US and the disaggregated approach adopted by GB. The majority of energy is traded via timed day-ahead and intra-day auctions in a similar fashion to PJM and other US markets, ensuring high levels of liquidity. Unlike the US however, the auctions are administered by a Market Operator. The System Operator inputs reserve requirements to the multi intra-day auction process, ensuring that energy and reserve requirements are optimised simultaneously and an efficient generation dispatch outcome is achieved.

4.6 Integrated markets and the need for priority dispatch

If the costs of carbon emissions are fully internalised, an integrated dispatch process that attempts to minimise the overall cost of meeting demand securely should also minimise carbon emissions. However, if the cost of carbon remains low, this will not necessarily be the case. While intermittent wind and nuclear generation plant have zero or low marginal costs and will always be dispatched before carbon emitting generation, renewable technologies such as biomass¹⁹ have non-trivial marginal costs and carbon

¹⁹ EU Directive 2009/28/EC requires that member states introduce regulations to ensure that renewable generation is given priority in dispatch over other forms of generation. The UK has not introduced regulations to give effect to priority dispatch as, in the GB electricity market, all generation can “self dispatch” and therefore achieve priority unilaterally.

sequestered generation is likely to have higher high marginal costs than non-sequestered plant due to the associated efficiency penalty.

There is a possibility therefore, that an integrated dispatch process may not minimise carbon emissions if carbon is incorrectly priced. In the transition to a low-carbon electricity system, the introduction of a more integrated dispatch process would need to be accompanied by some means of prioritising low carbon generation. Rather than dispatching generation on the basis of cost, low carbon generation would need to be dispatched on the basis of carbon emissions, or some function of marginal cost and carbon emissions, to ensure that overall emissions were minimised. While low carbon capacity remained at modest levels, there would be little need to differentiate between individual generators or technology for the purpose of dispatch. However, as capacity increased, network or energy-related constraints would become more frequent, and some means of differentiation would be required to ensure that carbon emissions were minimised at the lowest possible cost. Differentiation *between* technologies could be achieved on the basis of emissions, while differentiation *within* technologies could be achieved when necessary on the basis of marginal cost or some other measure, such as transmission losses.

It is interesting to note that there is some experience of non-marginal cost related generation dispatch in the UK, albeit in a rather different context. The Central Electricity Generating Board (CEGB), which operated a highly detailed centralised dispatch optimisation process, was able to move seamlessly from dispatching on the basis of marginal cost to a “heat rate” based dispatch during the frequent fuel emergencies of the 1970’s & 1980’s. Dispatching fossil fired generation on the basis of heat rate rather than marginal cost resulted in a significant reduction in fuel inputs and, as a consequence, would have reduced carbon emissions/MWh of electrical energy generated.

4.7 Market signals v deployment risks for wind.

While a more integrated market design, coupled with priority in dispatch, would create a more benign environment for intermittent technologies such as wind, additional measures may be required given the characteristics of wind generation and the scale of deployment required. The increasingly volatility of energy prices, with wind always likely to be on the wrong side of the balancing argument – attempting to sell energy when wind output is high and energy prices low (or even negative) – will decrease the value that wind can extract from the energy market (Redpoint, 2009) over time. To this erosion of value can be added system integration costs that will also rise steadily as wind capacity builds, further impacting on the viability of future wind projects.

While these market signals may simply reflect the economic consequences of intermittency, they could have a negative impact on deployment or at least on the need for subsidy to maintain the level of deployment required to deliver climate change goals. The extent to which wind generation is exposed to market signals varies across Europe. For example GB chooses to draw no distinction on the basis of generation technology, exposing the full costs of balancing and imposing technical requirements that require wind to behave as any other generation – even though a “system” approach may result in lower overall cost. Germany, on the other hand, protects wind generation from the full rigour of market and technical signals with the costs of integration falling mainly on the System Operator. A question to be addressed by the UK and indeed all jurisdictions that intend to connect large amounts of wind or other intermittent renewable generation is, therefore, how to balance the exposure of that generation to market signals with the risks to deployment inherent in those signals – particularly given the limited ability of wind to respond.

5. Network congestion and the need for appropriate network investment signals.

Commissioning large amounts of wind or other intermittent generation together with the associated need to retain back-up generation will result in far more generation capacity being connected to the electricity grid than there is peak demand to be supplied²⁰. This will result in a significant rise in potential network congestion²¹, indeed that process has already begun and the GBSO is forecasting that the cost of resolving network congestion will approach £600 million by 2011 with the prospect of substantial rises after that time (Redpoint, 2010). A future electricity market will therefore need to be capable of dealing with congestion in a cost-effective fashion. Unfortunately, the current GB market arrangements are not particularly effective in controlling the volume of congestion or minimising the costs of resolving that congestion.

5.1 Congestion volume

In terms of controlling the magnitude of network congestion, the current market arrangements are deficient in two respects. Firstly, market participants can trade energy bilaterally in forward markets without the need to consider the costs that those trades will impose on the electricity grid. The implications of this “unconstrained” trading are

²⁰ The margin of generation capacity over demand is expected to rise from historic levels of around 24% to nearer 90% by 2020

²¹ Congestion arises when potential power flows exceed the capability of network circuits or boundaries. Congestion is resolved either by adjusting generation patterns to reduce power flows, or by increasing network capacity either by investment in primary assets or by operational means.

presented to the GBSO in the form of individual generator dispatch schedules one hour before real time, at which point the GBSO is required to establish counter-flows via the Balancing Mechanism (BM) to ensure that actual power flows do not exceed network capacity. Secondly, the cost of resolving this congestion is recovered via “Balancing Use of System (BUSoS)” charges paid by all trading parties on a per kWh basis and there is therefore no incentive on parties causing that congestion to modify their behaviour.

In fact, it can be argued that market arrangements currently encourage behaviour that leads increased network congestion. The separation of energy trading and congestion management into distinct markets prompts generators to consider how best they can maximise returns. Consider for example a portfolio generating company with a large installed wind capacity in Scotland and conventional generation assets on both sides of the “cheviot”²² network boundary. The company would contract ahead to supply energy assuming, due to its intermittent nature, a modest contribution from wind. If, approaching gate closure, it appeared that wind output would be high, the generator would need to decide what conventional generation to stand down – plant on the export side of the boundary or plant on the import side. If the company stands plant down on the export side, potential congestion across the boundary is eased but that plant earns no income. If however, the company stands down conventional plant in E&W, then congestion across the boundary is increased and the GBSO is likely to accept bids from Scottish conventional plant to reduce output. As these bids are invariably less than variable cost of generation, the Scottish plant earns income by not producing or by producing less. Furthermore, the conventional plant in E&W that was stood down is now free to offer replacement energy at a significant premium to market prices.

Market rules therefore allow, in fact encourage, companies to maximise income by acting in a fashion which is detrimental to the efficient operation of the system (LECG Consulting, 2010). Ofgem appears to consider that such behaviour amounts to an abuse of market power and a Market Power License Condition (MPLC)²³ was passed into law by the 2010 Energy Act. The new Condition gives Ofgem the power to penalise the withholding or manipulation of output however, given the short term market volatility that the deployment of wind at scale will bring, deliberate manipulation of output to exploit network constraints will become more difficult to demonstrate. Furthermore, even if demonstrated, such behaviour is arguably no more than the expected commercial response to a particular set of flawed market arrangements. The MPLC therefore addresses the symptoms of the problem, rather than the problem itself.

²² The “Cheviot” boundary is that which cuts the four transmission circuits connecting Scotland with England, currently having a capacity of around 2.4 GVA.

²³ http://www.opsi.gov.uk/acts/acts2010/pdf/ukpga_20100027_en.pdf

5.2 Minimising congestion costs

Not only are existing GB market arrangements ineffective in managing congestion volume, they make dealing with congestion particularly expensive. This stems from the “energy only” nature of the electricity market and the need for mid-merit plant to recoup a proportion of their fixed costs by extracting a discount or premium on forward market prices through Balancing Mechanism bids and offers. The need for mid-merit plant to attempt to recover fixed costs through the BM in this fashion is reinforced by the fact that peaking plant is able to partially recover investment and other fixed costs through pre-gate closure energy contracts. By utilising contracted plant over demand peaks, the GBSO is able to reduce spikes in energy prices, therefore reducing the income available to non-contracted mid-merit plant (SEDG, 2009).

The impact of fixed cost recovery through the BM can be seen in figure 3, which illustrates the relationship between accepted offers and bids to the market index price (MIP)²⁴. It can be seen that accepted BM offers are invariably at a significant premium to MIP, while accepted bids are invariably discounted. As the cost of resolving congestion is the difference between the associated bids and offers, these costs can on occasion exceed £150/MWh.

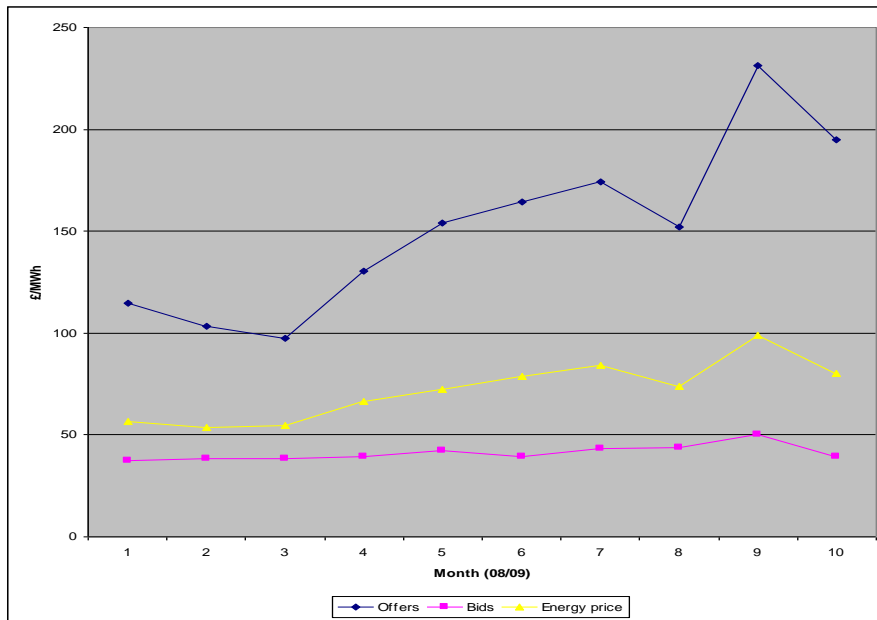


Figure 3. Balancing Mechanism bids & offers compared with market Index price, 2008/09 (National Grid)

²⁴ Market Index price (MIP) is indicative of intra-day market energy prices.

It is instructive to compare the costs of resolving congestion under current market rules with those observed under previous market regimes, for example the England & Wales Electricity Pool, which precede the introduction of NETA/BETTA. Under the old Pool rules, the cost of resolving congestion was essentially the difference between the offers made by generation that was ultimately constrained and offers made by replacement plant at the day-ahead schedule stage. For similar technologies, i.e. where coal plant was displaced by other coal plant in order to resolve a network constraint, the difference in day ahead offers may only have been a few pounds and maybe around £15/MWh where CCGT plant was replaced by coal. Resolving network congestion under BETTA is therefore around ten times as expensive as was the case under the E&W Electricity Pool rules or the old CEGB merit order arrangements which existed before the industry was privatised.

5.3 Transmission Investment signals

Higher than necessary costs of resolving congestion make investment in network assets to remove that congestion appears overly attractive. Transmission reinforcement can be justified up to the point where the marginal cost of reinforcement equals the marginal reduction in congestion costs brought about by that reinforcement. Clearly, if the costs of resolving congestion are at least 10 times higher than necessary, much more transmission reinforcement can be justified than is actually required. This together with network design rules that tend to provide sufficient network capacity to allow the simultaneous contribution of all generation to system peak demands (inappropriate as there will be far more generation connected to the network than there is demand to supply), suggests that rather more network capacity is likely to be built than is actually required. While there is considerable uncertainty around just what network investment may be required to deliver a decarbonised electricity system and the consequences of having too little network capacity are likely to outweigh those of too having much, over-investing due to inappropriate market signals or design rules would impose unnecessary costs on customers and could ultimately undermine the case for connecting renewable generation.

6. Encouraging demand-side participation

Mature electricity systems around the world can be described as having a flexible generation portfolio able to respond to a variable, relatively price-insensitive but predictable demand base. However, with the introduction of large amounts of intermittent renewable generation, this model is likely to be reversed, with the demand side needing to become more flexible in order to accommodate a variable supply.

6.1 Reducing capacity and reserve

Effective demand side participation can facilitate the development of a low-carbon electricity system in both investment and operational timescales. By competing with generation in capacity auctions, the overall requirement for generation capacity will be reduced. Similarly, the impact of partially electrifying the heat and surface transport sectors on network investment could be minimised by effectively managing that demand and utilising its inherent storage capacity. In operational timescales, demand response has the potential to reduce the requirement for reserve to be held on part-loaded generation, while generally reducing the impact of intermittency and energy price volatility which could otherwise reach unacceptable levels.

Currently, demand response in GB is limited to relatively large industrial demand, usually contracting with the GBSO ex-anti to supply load reduction when required, for example in the event of a low unexpected generation loss. To date, response from the domestic or small commercial demand has mostly been limited to shifting demand from peak to off-peak periods through fixed “time of use” (ToU) tariffs such as “Economy 7”, although more flexible demand shifting via tele-switching has been utilised to some extent.

The introduction of smart metering, incorporating communication capabilities and the availability of “smart” appliances that can respond to price or other signals, will make domestic and small commercial customers more aware of their consumption and become more active providers of demand response. This could be achieved through suppliers offering “interruptible” tariffs, with domestic appliances or heating being switched automatically and allowing suppliers to offer aggregated demand response in both investment and operational timescales. Alternatively, dynamic ToU tariffs could be offered, with pricing being set to reflect short term wholesale market conditions and consumers responding to price signals either manually or, more conveniently, by relying on smart appliances.

6.2 Settlement impacts

The delivery of domestic and small commercial sector demand response will have implications for the electricity market settlement process. As demand less than 100kW is currently metered on a summation basis, it is input to the electricity market via a “profiling” process, where customers are allocated to one of eight “demand profiles” for the purposes of settlement. Rather than being charged for the actual half-hourly consumption of their smaller customers, suppliers are charged on the “deemed” consumption given by these profiles.

The settlement process has the innate ability to allocate actual energy consumption to the appropriate settlement periods and profiling could probably be extended to accommodate interruptible demand and ToU tariffs, provided that the shape and timing of those tariffs were known in advance. Individual profiles could be constructed around each ToU tariff, once customer response to those tariffs had been demonstrated by experience. However, while fixed ToU tariffs are an appropriate response to predictable demand characteristics where the timing of demand and price peaks can readily be forecast, they will be less so with the growth of intermittent generation. Dynamic ToU tariffs will be required to respond to variations in energy supply energy prices that can only be forecast with any accuracy in short timescales.

Truly dynamic ToU tariffs will therefore require energy consumption to be settled on a half-hourly, rather than a profiled basis. Profiling will clearly need to be retained though the smart meter rollout process, however it seems likely that there will be a gradual migration of non-half hourly metered demand to half-hourly settlement over time. This will have implications for the settlement process. Firstly, profiling would need to ensure the appropriate half-hourly allocation of energy consumption as the number of customers being profiled diminished and, secondly, that differences in actual and estimated consumption continued to be dealt with appropriately. Differences between actual and estimated energy consumption are allocated to suppliers on the basis of their market share of non-half hourly metered demand and this may no longer be appropriate with ever diminishing customer numbers (Elexon, 2008).

A transition to full half hourly settlement will involve a very substantial increase in the volume of metering data to be processed and the costs of data retrieval, handling and aggregation will clearly increase. While the central settlement systems may not be significantly affected as data will be received in an aggregated form, the need to process half hourly, rather than summated, customer energy consumption will substantially increase the data volumes to be handled by suppliers. Although modifying existing half hourly settlement processes, e.g. by extending the period over which half hourly data may be entered into the settlement system (Frontier Economics, 2007), could mitigate cost increases to some extent, substantial increases in cost seem unavoidable. An indication of scale of these additional costs can be inferred from those incurred by customers who currently elect to be metered on a half-hourly basis. In 2007, the additional costs associated with data aggregation and collection was estimated at around £250 (Elexon, 2010). Although there is evidence to suggest that these costs have reduced, it will be necessary to ensure that overheads are commensurate with the relatively low energy requirements of individual and do not become a barrier to smart metering delivering small customer demand response.

A further settlement-related issue is the extent to which current arrangements will encourage dynamic customer demand response, i.e. response to real time situations.

Suppliers could, by aggregating potential demand response in advance, make offers to reduce demand in the Balancing Mechanism with the resulting revenue funding incentives on customers to participate. However, existing arrangements represent a barrier to the participation of the demand side in real-time (post gate-closure). Essentially, this is because contributors would be unable to access the real value of any demand response, due to dual cash-out pricing²⁵. This issue could be resolved by the introduction of single marginal price for energy (advanced earlier in relation to cost reflectivity), allowing suppliers to access the real-time value of their actions and passing on this value to encourage customers to participate. In addition, it would be necessary to publish price information ex-anti, in order to provide a signal to which customers could respond. Although estimates of supply/demand balance are given in advance, first estimates of settlement imbalance prices only currently become available some 15 minutes after the end of the settlement period.

7. Network regulation

It is clear that considerable network investment will be required if the UK's climate change obligations and goals are to be delivered. The need to strengthen the onshore transmission network to accommodate remotely connected renewables, develop an offshore network and the necessary interconnection capacity to fully exploit the UK's offshore renewable resources while at the same time replacing time-expired assets, is likely to reach around £40 billion by 2030 (Ofgem, 2009).

The scale of this challenge, together with concerns over just what and when investment may be required, prompted Ofgem to consider the need for changes to existing network regulation via the RPI-X@20 review²⁶. Detailed comment on the scope and conclusions of Ofgem's review are beyond the scope of this paper. However, in the context of developing a regulatory environment that will deliver networks capable of allowing sufficient renewable and low carbon generation to access the electricity market, three issues appear particularly relevant. These are;

- ensuring that investment requirements are minimised by utilising network capacity as effectively as possible,
- ensuring necessary network investment proceeds in a timely fashion, and
- that necessary transmission investment attracts the necessary funding.

²⁵ With dual cash out pricing, a supplier who, via dynamic customer response, allowed its aggregate demand fall below that which had been notified at gate closure in order to reduce overall system imbalance would only receive the pre-gate closure value of the reduction – rather than the full value, i.e. the costs avoided by the GBSO.

²⁶ See RPI-X@20 Review parent webpage; www.ofgem.gov.uk/Networks/rpix20/PagesRPIX20.aspx

7.1 Ensuring efficient network utilisation

Existing network regulation favours investment and asset-heavy solutions to network problems, rather than operational or innovative alternatives that may be more cost-effective. Network Owners are regulated via a series of periodic (currently 5-yearly) Price Control Reviews which establish the regulated revenues that can be accrued over the Price Control period. These revenues are directly linked to the size of the Regulated Asset Base (RAB) and it is therefore in the Network Owner's interests to grow the size of the RAB by investing in network assets. The allowed regulated returns on investments are modest and have reduced over time, however they are effectively guaranteed over the lifetime of the assets and Network Owners are perceived by investors as solid, reliable, low risk entities.

While this clearly is helpful in reducing the cost of capital and hence the cost of delivering investments, the regulatory bias in favour of asset investment provides little incentive for Network Owners to innovate or pursue operational alternatives. The development of "smart" grid technologies will be essential to delivering the electricity sector's contribution to climate change and an increasing spectrum of technically efficient and cost-effective alternatives to traditional asset-based solutions are becoming available. The availability of these "smart" network technologies represents a significant opportunity to reduce the high and increasing network investment burden associated with the delivery of a low carbon electricity system. One obvious example is the accommodation of renewable generation technologies such as wind. The issues of intermittency and the requirement to retain back up conventional generation capacity will result in substantially more generation being connected to the electricity networks than there will be peak demand to be supplied. Investing to connect this generation according to current network rules that are designed to allow the near-simultaneous operation of all generation, implies a significant reduction in overall network asset utilisation. Network asset utilisation is already low at around 30% and further reductions would clearly be inefficient, representing an avoidable cost to end users. The alternative to this unnecessary investment is to develop innovative ways of "sharing"²⁷ available grid assets and deploying new technologies that allow asset utilisation to be maximised.

²⁷ During periods of high wind output, wind generation would replace conventional generation as the means of supplying demand. During periods of low wind output, conventional plant would take up that role. However, current network design standards (originally developed in the late 1940's) tend to provide sufficient network capacity to allow the almost simultaneous operation of all connected generation and are therefore totally inappropriate in terms of a low-carbon electricity sector.

In the context of existing regulation however, deploying “smart” technologies than reduce the need to invest in primary assets might be considered to be at odds with the commercial interests of Network Owners. Opportunities to increase regulated income would be lost and Network Owners would be unable to access income from the alternatives to investment beyond the current Price Control period. What is needed therefore is the equalisation of incentives for capital and non-capital external (the costs incurred in managing the operation of the transmission system, i.e. resolving congestion etc) expenditure to ensure that Network Owners are encouraged to make objective decisions between investment and smart, operational, alternatives. Just how this might be achieved is well beyond the scope of this paper, however it most probably involves the retention of some proportion of the savings incurred by not investing being retained by the Network Operator over the long term, or else the costs incurred in deploying smart solutions being included in the RAB and being treated on the same basis as capital expenditure.

7.2 Delivering network investment in a timely fashion

Existing regulation gives a very strong steer that it is the user who must signal when network investment is required. Only investments that are fully backed by “customer commitment” are likely to find their way into the RAB, allowing Network Owners to recover the costs of those investments. While this approach may be appropriate for dealing with large generation projects that have similar construction timescales to that of the infrastructure necessary to accommodate them, it is less appropriate in dealing with numerous, small, renewable projects with relatively short construction timescales or for delivering the major infrastructure development required to facilitate the delivery of a low carbon electricity sector. To ensure that network capacity is delivered in a timely fashion, i.e. in timescales that allow renewable and low carbon generation to contribute towards meeting the UK’s climate change targets and goals, some investment will be required before users can reasonably be expected to provide financial commitment.

Network regulation will in future need to recognize that some investment requirements will be driven more by energy policy, rather than the individual requirements of potential users. In recognition of this need, the concept of a “guiding mind” emerged from Ofgem’s RPI-X&20 review and the work of the Electricity Network Strategy Group (ENSG) in identifying the network implications of the UK’s 2020 renewable targets is a clear example of how this concept may work in practice. Endorsement by a suitably authoritative and expert group could be seen as a proxy for “user” commitment, giving confidence to network owners that endorsed investments would be included in the RAB and costs could be recovered

However, investment ahead of full user commitment raises the possibility of assets being stranded and the guiding mind concept places the risks associated with imperfect foresight firmly with the end-customer. An alternative approach that leaves the risks of asset stranding with the network owner – who is presumably best placed to manage those risks – would be to provide incentives for investing ahead of need when appropriate. Network owners could be offered an enhanced rate of return in cases where investments undertaken without full user commitment ultimately proved to be fully justified, but a reduced rate of return if those assets remained under-utilised. In fact Ofgem proposed such an approach as part of the Transmission Access Review (Ofgem, 2008), but seems to have drawn back from the idea of enhanced rates of return given that previously worked up proposals do not feature in the RPI-X@20 Recommendations document (Ofgem, 2010). Although the recommendations promise incentives to deliver outputs efficiently, they also suggest that large anticipatory infrastructure projects will need to be reviewed and authorised on a stage by stage basis, rather than being delivered through appropriate Transmission Owner incentives.

7.3 Funding necessary network investment

With the electricity networks now entering into a period of high and increasing investment, attracting the funds for that investment from an increasingly constrained financial market will be a major challenge. Meeting that challenge will require a regulatory environment that provides investors with sufficiently secure and attractive returns. In this context, the RPI-X@20 conclusions on “intergenerational equity” appear to risk undermining investor confidence. By aligning depreciation with assumed asset lives in an attempt to ensure that customers who benefit from investment pay for it, returns on capital will be pushed back in time. While this may at first sight appear to reduce costs for existing customers, delaying returns will highlight the issues of regulatory uncertainty and the extent to which investors will be prepared to accept a commitment that revenues will be protected in the long term. Leaving aside Ofgem’s rather dubious view that today’s consumers are somehow not responsible for the carbon emissions that require low carbon generation to be connected to the system, moving from a financeability approach that has worked well in practice and is understood by stakeholders is, of itself, likely to undermine investor confidence (National Grid, 2010).

With returns on investment delayed and confidence in regulatory commitment undermined, the cost of capital seems certain to rise, thereby negating Ofgem’s aim of reducing costs incurred by existing customers and making investment more expensive overall. Evidence that confidence is in danger of being undermined is given by Neil Woodford’s recent open letter to Ofgem (Investco Perpetual, 2010), which threatens to

suspend new investment in the sector until more clarity emerges over the continued availability of reasonable returns on investment.

It seems unlikely, therefore, that the prospect of delayed returns on capital together with vague statements of the principles that might underpin future estimates of the cost of capital will make the network funding challenge any easier. What is really necessary to attract this investment is to maintain the confidence of the financial markets by providing comfort that investment costs can be recovered with returns that are commensurate with the risks involved. To build this confidence it will be necessary to provide strong and credible regulatory commitments.

In carrying out their primary duties, Ofgem are required to have regard to the need to ensure that Licence holders can finance activities associated with their obligations. However, in order to provide the credible regulatory commitment necessary to build investor confidence, it may be necessary to reinforce Ofgem's duties in this area. Rather than simply requiring Ofgem to have regard to the ability of Network Operators to finance their activities, it may be necessary to establish a more explicit right to a reasonable rate of return, as is the case in the US (ENA, 2010).

8. Conclusions

By considering some of the characteristics of a low carbon electricity sector, this paper has attempted to highlight some of the capabilities that a supportive electricity market and regulatory framework would need to possess. It is concluded that the need to facilitate the necessary investment in low carbon and other plant, minimize carbon emissions and deal with increased short term energy balancing requirements imposed by a generation portfolio containing large amounts of intermittent generation, are likely to be the primary determinants of an appropriate market design. The need to deal effectively with increased network congestion that will result from accommodating intermittent generation and accommodate the flexible demand base necessary to mitigate the impacts of that intermittency, will also influence market design. Finally, regulation will need to develop in order to ensure the cost effective development of networks that are capable of supporting a low-carbon electricity sector and to provide the long term regulatory commitment necessary to secure adequate capital investment.

The following paragraphs attempt to organise the arguments put forward in this paper into a case for what those changes to market and regulatory structure may need to be.

8.1. Encouraging generation investment

The UK will need to compete internationally for investment to create a low carbon electricity sector. Delivering the investment necessary to create a low carbon electricity system will be all the more challenging given that many other countries will be embarking on similar programmes. The reliance of the UK on large European-based energy companies, operating away from their home markets, to deliver the generation capacity required may add to that challenge. The UK will, therefore, need to maintain a regulatory and market environment that is attractive to these companies, who clearly have choices in terms of where they invest.

Are traditional electricity markets appropriate for a low carbon electricity system and will they deliver sufficient generation investment? The introduction of large amounts of intermittent wind generation will exert downward pressure on average electricity prices, while increasing energy price volatility and uncertainty. Reliance on energy prices alone to encourage investment in low load factor and peaking generation will require periods of high and possibly extreme prices. There is a concern that this may prove to be unacceptable from a regulatory or political point of view and that price caps maybe imposed, compromising the case for investment. Furthermore, energy price uncertainty will impact negatively on investment in high capital cost low-carbon generation. Project risk will be increased, requiring higher returns on capital and possibly reducing the appetite for investment. The question therefore arises as whether traditional market designs, with energy prices determined by the highest variable-cost plant operating, are appropriate for a low carbon electricity system with large amounts of high capital cost/ low variable cost plant.

Additional support measures should be designed to avoid energy market distortion. In order to deliver the scale of investment low-carbon and other generation required, it seems likely that additional support mechanisms will be required. Various options exist, ranging from an extension of output based obligations to include low-carbon technologies other than renewables, the introduction of capacity obligations on suppliers, capacity payments, or placing an obligation on the System Operator or some other central agency to procure capacity.

Output based obligations such as the RO or FiTs deliver strong incentives for delivery, but have the potential to distort the energy market leading to the need for even stronger incentives and making life increasingly difficult for any non-subsidised plant. If output-based obligations are to be extended to include low carbon generation, it would helpful that those obligations recognised the “temporal” nature of energy prices in order to incentivise appropriate behaviour during periods of excess low renewable or low carbon output.

Capacity based obligations would need to be designed to incentivise actual delivery and to encompass both decarbonisation and security of supply. Capacity-based obligations are less likely to lead to market distortion, but offer reduced incentives for actual delivery. Rewarding capacity explicitly should also reduce energy price volatility with prices closely tracking marginal costs, and should ease the burden of managing network congestion, as marginal and low load-factor plant would no longer need to seek to cover fixed costs via the congestion market. Capacity based obligations would need to be carefully designed to ensure adequate incentives for actual delivery, while interactions between the energy and capacity markets would need to be considered to ensure that generation was not over-rewarded. It should also be noted that capacity obligations in place around the world currently focus on security of supply alone and that designs would need to be developed to recognise the carbon intensity of generation.

Central procurement of generation capacity would not remove the need for supplier obligations. Adding to the growing list of supplier-based low-carbon and energy efficiency obligations hardly seems ideal, while capacity-based obligations on suppliers also raises issues about their ability to forecast long term capacity requirements in a competitive retail environment. An alternative would be to place an obligation to procure capacity with the system operator as is the case with integrated US markets, such as PJM, New York and New England etc. Energy price volatility would be reduced and investments would no longer be entirely be reliant on an energy market where prices would be depressed by the presence of large amounts of zero or marginal cost generation. However, the need for supplier-based low carbon obligations would remain.

A “single buyer” model would offer advantages in terms of simplicity and low cost of capital, while maintaining a competitive environment for investment. The single buyer concept, with a central agency responsible for procuring both capacity and energy, was rather summarily dismissed in the HMT/DECC Energy Market Assessment due to concerns over the ability of such an agency to accurately predict future capacity requirements and as having no particular advantage over the centralised procurement of capacity alone. However, the risk of incorrectly forecasting the future need for capacity are shared by all arrangements where capacity is procured centrally, not just the single buyer model. Furthermore, in addition to providing a competitive approach to the procurement and operation of capacity, the single buyer concept provides a guaranteed income stream over the lifetime of the asset, reducing project risk and financing costs. Provided that the need for future capacity can be accurately assessed, the single buyer model appears to have the potential to deliver the UK’s low-carbon investment requirements at a lower overall cost than relying on a profusion of supplier-based obligations.

8.2 Energy dispatch and balancing

The existing bilateral trading arrangements may cause dispatch inefficiencies to increase with the growth of intermittent generation. The bilateral nature of the current GB trading arrangements, which allows vertically integrated companies to trade internally and self dispatch generation, is likely to give rise to some degree of dispatch inefficiency. This risk is compounded by the tendency for generating companies to self-insure, i.e. carry additional reserve to reduce exposure to imbalance costs. While difficult to quantify and probably of a low order at present, inefficiencies in dispatch will increase with the growth of intermittent generation, resulting in unnecessary cost and carbon emissions.

A single marginal price for energy is preferable to the current dual imbalance pricing arrangements. Incentives on generators to self-insure could be reduced if the current dual imbalance price arrangements were replaced by a single marginal price for energy. While incentives on parties to balance would remain high, removing the penal nature of settlement and uncertainties about which price may apply to individual imbalances, should allow more efficient operational decisions. A single imbalance price should produce a more liquid Balancing Mechanism with clear energy and reserve price signals and would effectively become an extension of the intra-day markets. Discrimination against intermittent generators and small players, who have a little option but to rely on the Balancing Mechanism to resolve imbalance, would also be removed.

A more integrated market design would seem more appropriate for a low carbon electricity system, with increased coordination of energy, reserve and possibly congestion requirements. While moving to a single price for resolving imbalances would be helpful, more needs to be done to address the challenges posed by the introduction of large amounts of wind and other intermittent generation. Currently, large horizontally integrated generating companies are able to accommodate the intermittent nature of wind output within their generation portfolio. However, as wind capacity builds, internalising the impacts of intermittency will become more difficult and generating companies will increasingly resort to short-term trading to balance forecast output with commitments.

Developing a separate market for wind, operating alongside the existing bilateral arrangements for conventional generation, would allow the value of geographic diversity and aggregation to be captured. However, moving to a more integrated market design for all generation offers the prospect of simultaneously and efficiently resolving energy and reserve requirements, with market liquidity increased though the use of a single trading platform.

If administered by the GBSO rather than a Market Operator, an integrated market design, as illustrated in Figure 4, would also allow network congestion to be resolved simultaneously with reserve and energy requirements. In addition to increasing short-term trading and balancing activity, the connection of large amounts of wind generation will result in a significant increase in network congestion and, unfortunately, existing GB market arrangements do not deal with congestion well. The unconstrained nature of energy trading places no obligation on trading parties to take account of the network impact of their activities, potentially adding to congestion volumes. Furthermore, separate arrangements for dealing with network congestion arguably encourage generators to take advantage of congestion to boost revenue. While unconstrained energy trading, the costs of which are smeared across all trading parties on a per kW basis, may be acceptable when congestion volumes are low, it is more difficult to justify when congestion volumes are high – particularly as the energy-only nature of the GB electricity market makes dealing with that congestion unnecessarily expensive.

Not only would an integrated market design allow network requirements to be considered earlier in the scheduling and dispatch process, i.e. at the intra-day market or even day-ahead stage, the costs of resolving network congestion are also likely to be reduced. Congestion costs would reflect the differences in offers to generate submitted at the scheduling stage by constrained off and replacement plant, rather than the “offer minus bid” costs resulting from the current Balancing Mechanism that can exceed £100/MWh – far higher than was the case under the old E&W Electricity Pool. Targeting costs on those parties responsible for causing that congestion would also serve to reduce congestion volumes, as generators in constrained export areas would respond to constraint cost forecasts emanating from the intra-day market scheduling process.

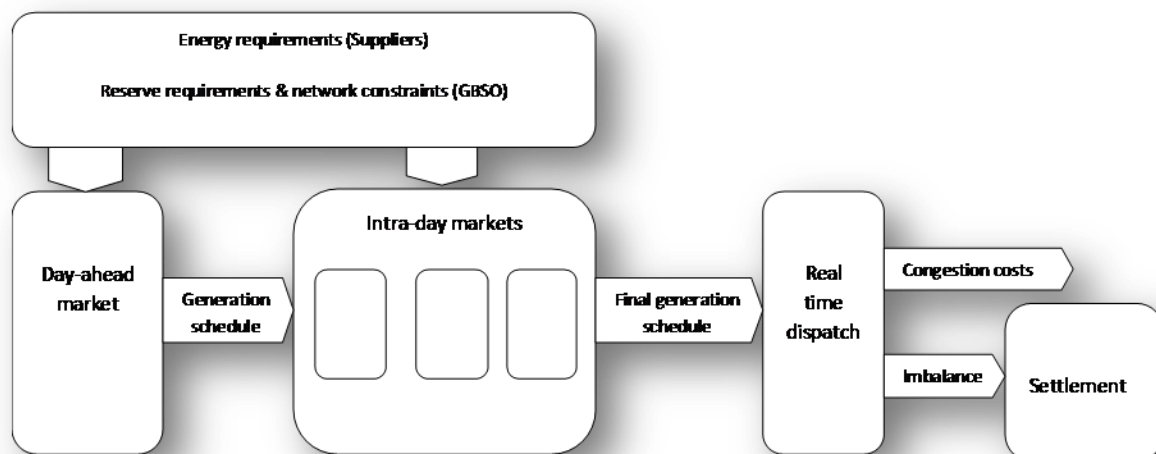


Figure 4. Integrated Market Design

Locational charging should not adversely impact renewable generation. Two options exist for allocating the costs of congestion to those market participants responsible for that congestion. Costs could be allocated ex-post via locational “use of system” charges, maintaining the existing separation between energy and network costs. Alternatively, the more radical option of “locational marginal pricing” as seen in fully integrated US electricity markets could be adopted. Locational marginal pricing produces causes nodal or zonal prices to diverge in the presence of network congestion.

There is concern that allocating congestion costs to parties responsible would mitigate against renewable generation, which is often remotely sited. However, this is not necessarily the case. In the UK, a significant amount of wind generation is likely to be sited offshore and connected to points on the onshore network that would not be subject to high locational costs. While renewable generation in Scotland would experience higher costs, conventional generation in Scotland would be discouraged from operation during periods of high wind output thereby minimizing congestion. Targeted congestion costs would therefore encourage the “sharing” of transmission capacity between renewable and conventional generation depending on need, leading to more efficient network utilisation.

Minimising congestion volume and costs through efficient market design would reduce the need for transmission investment. As investment in transmission is justified up to the point where the annuitised incremental investment cost equals the incremental savings in congestion costs associated with that investment, unnecessarily high congestion costs will result in efficient investment decisions. The network investment necessary to replace time-expired assets and connect low-carbon generation is rising significantly and is estimated to reach £30 billion by 2030 (Ernst & Young, 2009). It would be unfortunate therefore if this already challenging requirement was added to by inadequate market arrangements that made dealing with congestion unnecessarily expensive.

8.3 Demand Response

Delivering demand response via the introduction of smart metering will reduce the need for generation capacity and reserves. As the capacity of wind and other intermittent renewable generation builds, demand will need to become more flexible in order to accommodate the impacts of intermittency. Demand response can provide a cost effective alternative to new generation capacity and can reduce network investment that might otherwise be required to accommodate the implications of partially electrifying the heat and transport sectors. In operational timescales, demand response can reduce

the need for reserves to be held on deloaded mid-merit conventional generation, thereby reducing inefficient operation and carbon emissions.

Settlement design will need to ensure that data handling costs are commensurate with the ability of customers to pay. Currently, demand side participation is limited to relatively large industrial consumers contacting directly with the GBSO to provide demand reduction when required, together with some smaller customer response to ToU tariffs. However, the introduction of smart meters will substantially increase the potential for domestic and small commercial customers to provide demand response. The implications for existing settlement arrangements will be considerable however, with a gradual migration from demand profiling to full half hourly settlement. It will be necessary to ensure that costs associated with the additional data retrieval, handling and aggregation requirements of full half hourly settlement do not impose an inappropriate burden on small customers.

A move to single marginal price for energy could encourage dynamic demand response. While supplier participation in the Balancing Mechanism would allow suppliers to offer demand response as an alternative to response from part-loaded generation, dual cash-out pricing would appear limit the extent to which dynamic demand response could access the real value of its contribution in times of system stress. Moving to marginal energy price, signalled ex-anti, would enable suppliers, or other aggregators, to realise the full value of real time demand response, thereby providing further incentives for participation.

8.4 Network Regulation

Regulation should ensure that capital and operational expenditure incentives are equalised. Existing network regulation favours investment in primary asset based solutions to network problems over innovative or smart technology alternatives. While a high and increasing level of investment will be required to deliver a low carbon electricity sector, this regulatory bias is likely to amplify investment requirements and make an already challenging situation worse. Regulation should be amended to ensure that the commercial interests of Network Owners are best served by making objective decisions between asset-heavy solutions and available alternatives. To this end it seems necessary to ensure that Network Owners are able to retain savings accrued from not investing on the same basis as revenues derived from capital expenditure. Just how this might be achieved requires further consideration.

Regulation should incentivise Network Owners to correctly anticipate investment requirements. For network investment to be considered efficiently incurred, it is currently necessary for that investment to be fully supported by customer commitments. Increasingly, however, investment and investing timescales are being driven by energy

policy, rather than potential user requirements. An insistence that investment is fully backed by customer commitments may also lead to inefficient investment over time, as network solutions are often “lumpy” in nature, exceeding the requirements of individual users. Ensuring that investment is efficient and is delivered in the required timescales requires a move away from customer commitment to arrangements that more fully recognise energy policy imperatives. A “central planning” solution would be the “guiding mind” concept that emerged from Ofgem’s RPI-X@20 review, where the implications of energy policy in terms of network investment are identified by some expert group used as a proxy for user commitment. An alternative “market” solution would be to develop incentives for anticipating the need for efficient investment. This latter solution having the clear advantage of leaving the risks of asset stranding with the Network Owner, who is best placed to manage those risks, rather than the end user.

Regulation must create a favourable investment climate. At a time when network investment is forecast to reach unprecedented levels and when competition for available capital market funding is also increasing, there is a need to maintain an attractive environment for investors. Unfortunately, some aspects of Ofgem’s recent RPI-X@20 review of network regulation are potentially unhelpful in this regard. Proposals to promote “intergenerational equity” by realigning the burden of investment cost recovery from current to future customers, risks undermining the availability of funding for network investments. Delaying returns on investment highlights the issue of regulatory commitment, while proposals to disturb the arrangements for financeability on which previous investment decisions have been made undermines that commitment and its value going forward. If investor uncertainty is not to result in insufficient support from investors or higher costs of capital that would feed through to customers, it may be necessary to reinforce Ofgem’s current responsibilities in terms of network financeability, possibly with a statutory right to a reasonable rate of return as is the case in the US.

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