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Dear Project Manager,

Energy Market Investigation – Competition and Markets Authority (CMA) Initial Statement of Issues

Drax Power Limited (“Drax”) is the operating subsidiary of Drax Group plc and the owner and operator of Drax Power Station in North Yorkshire. The 4,000MW station consists of six separate units which together produce around 7-8% of UK generation, mainly fuelled by coal. However, largely in response to the policies implemented by Government to meet its climate change objectives, Drax is currently embarking on an ambitious project to convert at least half of this capacity to 100% biomass. We successfully converted our first unit in April 2013, and others will follow in the next two-three years. In 2009, Drax acquired an electricity supply business, Haven Power Limited (“Haven”). Haven supplies an increasing number of small and medium (SME) sized business customers and larger Industrial and Commercial (I&C) customers. This provides additional competition and choice in those sectors, as well as an alternative arm’s length route to market for some of Drax’s power output, Renewable Obligation Certificates (ROCs) and Levy Exemption Certificates (LECs).

We support the decision to make a market investigation reference in respect of the supply and acquisition of energy in Great Britain and welcome the opportunity to make some initial comments to the CMA regarding the matters highlighted in the Statement of Issues. We believe the Statement of Issues provides an appropriate and comprehensive scope and, as requested, we have considered below the four theories of harm raised in it. Below, and against the framework set out by the CMA, we evaluate whether these constitute an Adverse Effect on Competition (AEC) based on the counter-factual of what a well-functioning market could be expected to deliver in the absence of an AEC (recognising the fundamental characteristics of the electricity industry). Where applicable, we also briefly note potential remedies to identified AECs.

Theory of Harm 1: Opaque prices and/or low levels of liquidity in wholesale electricity markets create barriers to entry in retail and generation, perverse incentives for generators and/or other inefficiencies in market functioning.

There are in effect two wholesale markets for electricity:

- The market for buying and selling units of electricity and
- The renewables market for buying and selling ROCs for renewable electricity, which is expected to form 18% of the total electricity market in 2014/15. The renewables market is expected to increase significantly over the next five years.

We discuss both these markets and how they exhibit the features described in Theory of Harm 1 below.

The Electricity Market

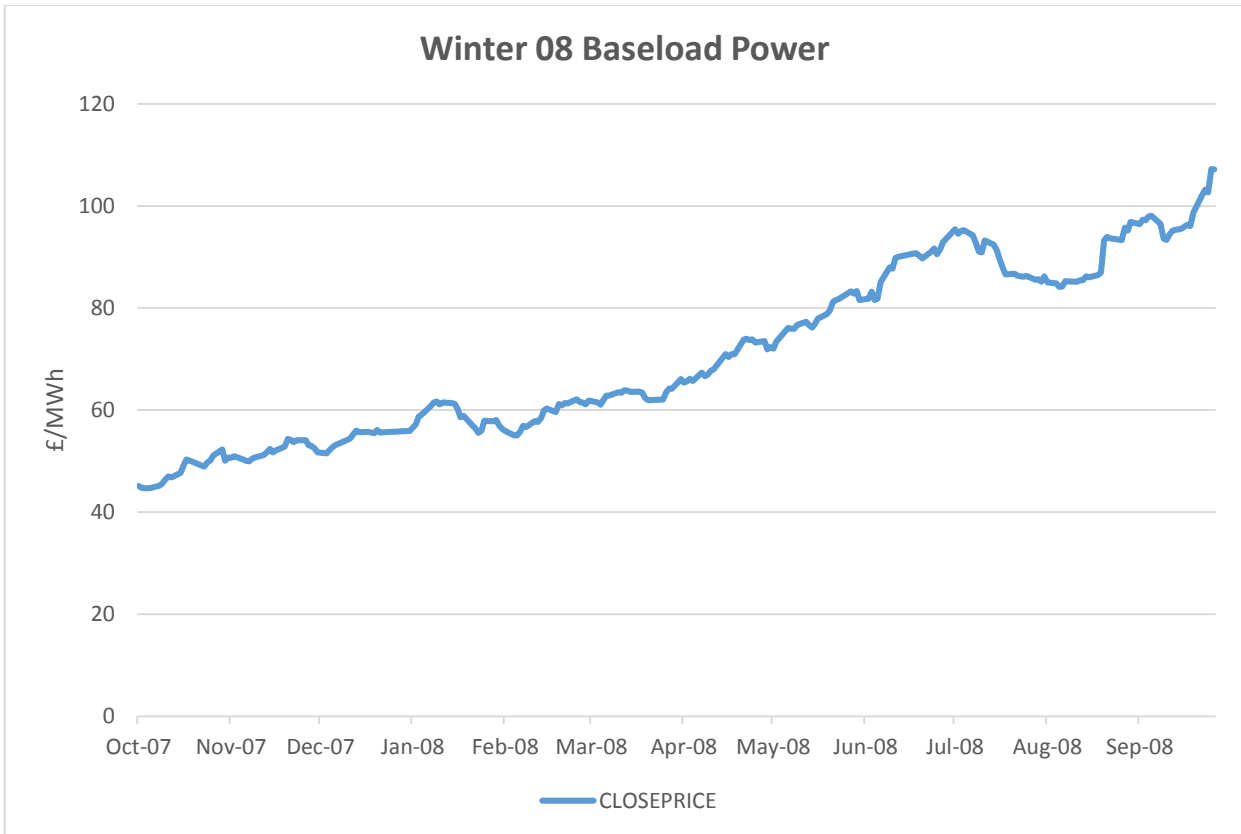
In a well-functioning wholesale electricity market, we agree that we would expect to observe the characteristics described in paragraph 26 of the Statement of Issues¹. However, in addition, tight bid-offer spreads can also give an indication of how well a market is functioning. For trading electricity products in the near term spot and prompt markets (i.e. within day and day-ahead trading and within week ahead trading respectively), we believe that the markets for these products are sufficiently liquid and exhibit these healthy characteristics. However, the same level of liquidity is not observed for the provision of wholesale electricity products in the forward market, particularly for products transacted beyond 18 months to two years in advance. We consider that there are a number of reasons, fundamental to the electricity industry, which can provide some explanation of why forward markets in GB do not exhibit the specified characteristics, and are less liquid than the near term markets.

To some extent generation and demand naturally seek to transact electricity on different timescales. Generation would generally seek to sell over longer timescales reflecting the long economic asset lives of power stations. However, (with the exception of demand for 'sticky' residential customers), suppliers on the demand side of the market tend not to want or need to buy electricity beyond 18-24 months ahead. One reason for this is that, in contrast to the market for residential customers, supply to I&C and SME customers (which together comprise >65% of the overall market) is highly competitive, and customers generally contract for no longer than 18 months. Hence suppliers cannot predict the volumes they may require beyond the tenor of their existing portfolios.

Another key issue is the credit and collateral costs of forward trading, which are high. They reflect the volatile nature of the commodities being traded which drive high mark to market credit requirements for market participants. Ultimately, it is therefore a combination of the high cost of credit and collateral driven by the volatility of the underlying product, together with relatively low demand from suppliers of the I&C and SME markets for longer term pricing, which limits the liquidity of trading in forward wholesale power in the GB market.

To provide an illustration of the high mark to market credit requirements of trading power forward, please see below an illustration of the price of the Winter '08 baseload power contract between October 2007 and September 2008. At the beginning of October 2007 the price of the contract was £45/MWh and at the end of September 2008 the price was £107/MWh. This indicates that the mark to market exposure for a 500MWh contract over this period would be £133m.

¹ "A well-functioning market will produce price signals that are good guides to the decision-making of buyers, sellers, investors and potential entrants. For this to happen, prices need to be a good, true reflection of the fundamental supply and demand conditions facing the sector – now and in the future. Particularly for a homogenous product like electricity, we would expect the wholesale market to be liquid, meaning that trades in these markets can be made without causing a significant change in the price". Statement of Issues, CMA (24 July 2014) p.8



Furthermore, the credit requirements in the industry are becoming more onerous due to the implementation of new EU regulations such as European Markets Infrastructure Regulation (EMIR). This has led to a number of previously very active financial counterparties (such as Deutsche Bank, Barclays Capital, JP Morgan, Morgan Stanley and Bank of America Merrill Lynch) exiting, or announcing their intention to exit, from the wholesale power market. This will inevitably further weaken liquidity, particularly across the forward curve.

Recognising the factors which limit the capacity for market participants to trade wholesale power forward, we now consider whether the market arrangements (and in particular the imbalance arrangements) and/or vertical integration can be attributed as a cause of Theory of Harm 1.

Market arrangements

In isolation, we do not believe that the market arrangements (in particular the imbalance arrangements) are a cause of low forward market liquidity. In fact we expect that the incentives provided via the imbalance arrangements will actually contribute positively to the development of forward market liquidity, as the costs associated with imbalance are highly likely to be more expensive relative to trading in the wholesale market. If the imbalance arrangements were 'relaxed' or removed, we would expect that the incentives to trade in the forward market would reduce, thus adversely impacting on forward wholesale market liquidity.

Vertical integration

Vertical integration is a key feature of the GB market, and it will be important for the CMA to understand why it is so prevalent and what the impact of it is. The Drax perspective is that vertical integration is not necessarily a cause of wholesale market illiquidity in itself. Its impact depends on how it is structured. There are two basic types of vertical integration in the GB market:

- Separate legal entities that each transact at arm's length in the wholesale market
- Internal price transfers where only the net (imbalance) is being priced at prevailing market prices

In the first structure above, both sides will benefit from credit efficiencies which can be passed onto customers, and there is no obvious impact on liquidity. However, the second structure, which we understand may be adopted by some of the Big Six, who have large residential supply businesses with sticky customers, will weaken liquidity. Drax and Haven trade on an arm's length basis on wholesale market terms at prevailing market prices. Fundamentally, if it is more efficient for Drax or Haven to trade with other market counterparties then both are able to do so. However, we believe that some of the Big Six companies, in particular those who operate separate trading arms, may not necessarily transact with outside counterparties even if it might be more efficient to do so. In effect, they only trade their net electricity volumes in the market rather than their gross electricity volumes.

We consider that greater liquidity and especially greater price transparency of wholesale electricity prices for delivery up to three years ahead could be achieved if all the Big Six were obligated to trade in a manner similar to that adopted by Drax / Haven. In addition, and as an initial step, they might also be obliged to purchase a proportion of their residential demand on the open market over the three year timescale, perhaps starting with a small percentage, say three years forward, and increasing this proportion progressively.

This would lead to more transparent prices, more liquidity, and longer tenor on the forward curve. However, it will not necessarily increase all market participants' access to trading these products due to the credit issues for smaller and independent players as noted above, as well as the differences in the way supply and demand naturally seek to sell/purchase electricity. In addition, other regulatory inventions like the carbon price floor also limit forward trading. However, the fact that there is access to prices and products on the forward curve could improve the health of the wholesale market, as the increase in price transparency and tenor are likely to encourage financial counterparties to enter (or re-enter) the market.

It should be noted that vertical integration can provide significant credit efficiencies, particularly for parties with a low (or no) credit rating. This would allow generators and suppliers to trade power forward at lower cost. The resulting efficiencies are passed on to Haven's customers in the form of lower retail prices, which is one of the factors that has allowed Haven to increase its market share. So, if trading between generation and supply businesses in the same group were prohibited, these credit efficiencies would be lost resulting in higher retail prices and less competition and choice for customers.

In conclusion, there is certainly less liquidity in forward electricity markets relative to prompt and spot markets. This is primarily a consequence of high mark to market credit requirements driven by the fundamentally volatile nature of the commodity being trading; the different timescales over which supply and demand naturally seek to trade; the introduction of particular regulations (including the Carbon Price Floor); and the manner in which some of the Big Six vertically integrated parties with large residential supply businesses trade internally. This last point could be addressed in a number of ways, including obligations on the Big Six to trade forward a proportion of their residential demand, and obligations around efficient trading behaviour. As such, we consider that illiquidity in the forward power market is likely to represent an AEC and the issues described above should be looked at by the CMA.

Future developments

It should be noted that the generation investment signals, which the wholesale market could be expected to provide, will be supplemented by several of the DECC interventions under EMR. The capacity market will provide a signal for investment in conventional fossil generation and the CfD FiT/RO etc. will provide a signal for investment in low carbon generation.

Unilateral manipulation

We note the hypothesis that generators in receipt of a CfD FiT may be incentivised to manipulate the reference price in an attempt to maximise CfD FiT top up payments. However, the season ahead and day ahead products used as reference prices for baseload and intermittent generators respectively, were chosen specifically because they are sufficiently liquid and subject to robust competition, such that the ability of generator to manipulate these prices is virtually impossible. For example, in the six months prior to the Winter '13 contract period, over 79,000/GWh was traded for the Winter '13 contract (based on the LEBA/NASDAQ index).

More fundamentally, for CfD FiTs using a season ahead reference price, the index is set by taking a within day volume weighted average and includes all (not just CfD FiT) season ahead trades. Then an arithmetic (non-weighted) average of all those daily averages is used to calculate the index. For a market participant to manipulate the indexation price in its favour, it would have to sell down the price across the indexation period

(c.126 trading days) in order to get a better top up payment. Even if it were able to do this, it would lose on the power sale. However, generators, even large ones, do not have the volume to impact the index across a six month period. A generator could perhaps influence one or two days' (out of c.126) worth of prices by selling large volumes into the market, however there is no incentive to do so as it will run out of power and will be left exposed to the remaining trading days in that period. In summary we cannot envisage a scenario where by a generator could successfully manipulate the index without creating a significant exposure, even if they had the necessary volume to drive down the reference price.

The Renewables Electricity Market

For a brief explanation of the ROC market please refer to the Annex at the end of this response. We believe that the renewables electricity market exhibits a number of the features referred to in Theory of Harm 1.

Opaque prices and low levels of liquidity

ROCs are almost exclusively traded at levels of visibility much lower than other energy commodities, usually traded bilaterally, or as part of a Power Purchase Agreement (PPA) (inclusive of power, and LECs) with only a small percentage (typically 2%) going through visible markets such as the Non-Fossil Purchasing Agency (NFPA) auction. Confidence in pricing, and trading is therefore low relative to other energy commodities with direct consequences for levels of liquidity. Other liquidity providers, including banks, trading houses, present in the power, gas, coal, carbon markets have not entered the ROC market as they are unwilling to trade and take exposure to the ROC without a Renewable Obligation providing the capacity to ultimately redeem the commodity.

Barriers to entry for retail and generation

ROC buying is credit intensive for smaller retail and generation businesses, where cash-flow is a material influence in their commodity buying behaviour. This leads to a natural bias to defer contracting ROCs until late in the compliance period for the retailer/supplier. Correspondingly new-entrant generators aiming to finance the construction of renewable projects are exposed to a delay in their ROC income to meet initial project costs, as well as ongoing delayed income relative to their ongoing variable costs including buying fuel in the case of biomass generation. This ROC income then typically arrives either in one 'lump' at the end of the compliance period, or is subject to loss of value by discounting their ROC price to incentivise suppliers to buy incrementally. This creates fragmentation in the markets with both upstream and downstream new entrants being disadvantaged relative to the established vertically integrated Big Six.

Perverse incentives for generators/inefficiencies in market functioning

The Big Six represent 90% of the ROC buying community. This means that they have significant buyer power relative to the less concentrated renewable generation sector. The structure of the market can be described as an oligopsony. This market power is further reinforced by the RO framework itself which does not actually obligate suppliers to purchase ROCs from ROC generators - there is the option to not submit ROCs to meet the Renewables Obligation and instead pay the buy-out price, which many suppliers utilise to a greater or lesser extent.

Moreover, all the Big Six have their own 'in-house' renewable projects competing for future ROC redemption capacity. While many of these projects fail (for technical, financing, other reasons), companies hold on to this option to self-supply ROCs to meet own target RO level through own projects, and only seek to buy when it is clear that their own projects will not meet their ROC requirements. This concentrates ROC buying activity later in the compliance period, and reduces future trading of ROCs for subsequent compliance periods to levels much lower than power, or gas for instance.

Theory of harm 2: Vertically integrated electricity companies harm the competitive position of non-integrated firms to the detriment of customers, either by increasing the costs of non-integrated energy suppliers or reducing the sales of non-integrated generating companies.

There is a further way in which vertical integration can exacerbate an AEC we observe within the ROC market. In a well-functioning market we would expect that all obligated suppliers would compete to secure the best

available price for ROCs and that this would be provided by the most efficient renewable generators. However, we believe there are impediments within the market to achieving this outcome. This is due to a combination of factors.

The buyer power of the Big Six in the Renewables Obligation market is exacerbated by the impact of vertical integration. In a market with an absence of vertical integration between ROC generators and the Big Six suppliers, one would expect suppliers to exert their buyer power against ROC generators on a non-discriminatory basis so that the value of ROCs would be discounted for all ROC generators. Only sufficiently efficient ROC generators would be able to compete to provide ROCs.

However, significant vertical integration between ROC generators and the Big Six suppliers already exists. This allows suppliers to source their ROC requirements from their own renewable generation plant in the first instance. Vertically integrated companies are able to avoid the ROC discounting which is applied to ROCs generated by non-vertically integrated ROC generators.

Furthermore, suppliers can delay the timing of their ROC purchases, if they choose to meet their obligation in this way, as the alternative buy-out price is only due and payable five months after the relevant compliance period closes. Either significant discounts are applied for early settlement of ROCs or suppliers leave their purchases until close to the buy-out payment being made to either maximise cash flow and/or to take advantage of any potential over-supply of ROCs in the period. This does create significant working capital issues for smaller renewable generators, which require costly financing solutions or the acceptance of a sizeable discount for early cash flow. This is reflected in the sizeable discounts offered by the larger suppliers for long-term ROC purchase agreements to independent renewable generators, which have increased to c. 10% in recent years.

This is likely to represent an AEC because it is not necessarily the case that the most efficient source of ROC generation will be sourced by the Big Six suppliers. In effect, a form of input foreclosure is occurring, restricting the sale of ROCs by non-vertically integrated ROC generators. This will represent a barrier to entry and distortion of competition in the ROC market, which will ultimately result in higher retail prices than should otherwise be the case. The increase in retail prices is exacerbated as we understand the Big Six suppliers in practice pass on most, if not all, of the full cost of the ROC rather than the discounted price they have paid. This is an enduring problem, regardless that the ROC scheme will be closed from 2017, and requires a permanent solution.

There are a number of policy options² that could be implemented to either reduce the buyer power of Big Six suppliers or ensure that ROC generators are treated in a non-discriminatory manner. Options include:

- Earlier implementation of a fixed price ROC (although noting that DECC recently rejected this policy option)
- An obligation to buy and sell ROCs in a mandatory market
- Establish a Purchaser of Last Resort for ROCs

Theory of harm 3: Market power in electricity generation leads to higher prices.

In a well-functioning market we would expect generators to compete to sell their output, with generators operating in merit in accordance with relative fuel costs and efficiencies. The corresponding wholesale prices will reflect the commodity price of the marginal source of generation. Evidence we have seen suggests that this is the case. In general we note that the generation market is relatively less concentrated compared to other sectors of the electricity industry. There was also no evidence that the generation businesses of the Big Six were making profits systematically in excess of Ofgem's preferred WACC metric³.

However, a number of distinct issues are raised by the Statement of Issues which relate to particular circumstances where generators may have temporal market power and where this may result in higher prices.

² We note that the CMA "may review the design of certain policies that have been put in place to meet these [Government] targets, to assess their impact on competition in energy markets and, potentially, consider alternative approaches to achieving the targets if we feel these are likely to lead to better outcomes for energy customers".

³ We note that the WACC adopted for the analysis (7% pre-tax nominal) is too low a rate of return for a market based generation business, particularly those operating on a stand-alone, merchant basis.

The Statement of Issues notes that at particular times and in particular locations certain generators may be in a position of temporal market dominance.

Unilateral market power

The first circumstance is where a generator may have market power behind a transmission constraint and may be incentivised to exacerbate a constraint to maximise returns in the balancing mechanism (known as the 'Inc Dec Game'). While there may be instances where generators have temporal market power due to the existence of a constraint, we believe that the introduction of the Transmission Constraint Licence Condition (TCLC) should act as a strong deterrent to any generator who may be tempted to abuse this market power.

However, the particular implementation of the TCLC should be reconsidered, as we suspect it is likely to dilute investment signals to invest in generation and transmission infrastructure. This is primarily because it is impossible for a generator to know when it is subject to a constraint. Therefore it does not know whether it is in a dominant position.

As generators cannot determine whether they are or are not subject to a transmission constraint, they are likely to err on the side of caution when pricing their services to the SO. This is a similar defect to the one the Competition Commission found when it rejected the Market Abuse Licence Condition (MALC) proposed by Ofgem in 2001. As with the MALC, this will distort the effective workings of the market, and will dilute legitimate investment signals in parts of the network. As such we consider that the SO should publish all constraints to all market participants as they become apparent.

We also note there is the potential for the Capacity Allocation and Congestion Management European Network Code to implement market splitting, effectively reflecting the price of congestion in the wholesale energy price. If market splitting arrangements were adopted this would drastically reduce the incentives for any generator to play the Inc Dec Game.

The second circumstance noted in the Statement of Issues is where a generator has the potential to have temporal market power at times of peak demand. We note that with the introduction of the Capacity Market this will likely reduce occurrences of peak prices. This is because the Capacity Market will likely deliver higher capacity margins relative to an energy only market reflecting the Government's recently implemented Reliability Standard. There are likely to be fewer instances where a generator will have temporal market power.

However, in principle we note that there are a number of risks associated with trying to determine whether price spikes are a result of abuse of temporal market power or a result of genuine scarcity. There is a risk that by attempting to specifically regulate price spikes that legitimate scarcity signals will be diluted resulting in weak generation investment signals. This is one of the principal reasons that the Government committed to introducing the Capacity Market to solve the 'missing money' problem.

Coordinated behaviour

Separate to issues related to the unilateral exercise of temporal market power, the Statement of Issues also highlights that there may be scope for generators to co-ordinate their behaviour in an attempt to raise wholesale prices. However, considering the relatively low concentration levels in the generation market and the diversity of generation technology portfolios, we cannot see how generators could co-ordinate their behaviour in practice without it being obvious to other industry players and the relevant authorities (Ofgem, FCA and Power Exchanges). The incentives on individual generators to 'break from the pack' to maximise returns would be too strong.

Overall, we consider the instances where temporal market power could materialise will be reduced in future. Even where temporal market power does materialise it is unlikely to be abused because of existing or potential regulation that is already in place or could be implemented. Moreover, introducing regulation to target instances of temporal market power will risk diluting important investment signals.

Theory of harm 4: Energy suppliers face weak incentives to compete on price and non-price factors in retail markets, due in particular to inactive customers, supplier behaviour and/or regulatory interventions.

Firstly, we note that the I&C retail electricity market is highly competitive resulting in a wide choice of offerings and very competitive customer prices. As such we agree with Ofgem that the I&C market should not be within the scope of the investigation on the basis that there is little evidence of harmful features.

However, the I&C market represents a good example of a well-functioning market that may be used to assess potential AECs. We thus concentrate our response on the Microbusiness end of the SME retail market in line with Ofgem's reference. Haven have aggressively competed to win all of its customers (both SME and I&C) and observe that the Microbusiness and the general SME marketplaces (for engaged customers) are also very competitive. We often see prices in these markets below our view of costs. This is driven we believe by suppliers taking a lifetime view of cost. This leads to lower sales costs as the lower prices provide a bigger incentive for customers.

In a well-functioning market we would expect to observe customers seeking out (subject to search and switching costs) the best available electricity supply product for their circumstances. This is the case for engaged customers. Only efficient energy suppliers would thrive. However, we agree that competition is likely to be weaker than could be expected in a well-functioning market. This is due to the existence of inactive customers (evidenced by the high former incumbent market shares of the large residential supply companies), but most importantly due to excessive and counterproductive regulatory invention.

Excessive regulatory intervention

The sheer quantity of regulation, and the prospect that this will continue to increase under the current regulatory regime, makes it very difficult for independent suppliers to compete in the market. For example the number of pages in the Supply Licence has more than doubled since 2006. This creates a great deal of regulatory uncertainty, making it more difficult for new entrants to compete in the market. This reflects the lower resource available to these companies to 'manage' the regulatory environment. The costs of simply keeping up with the scale of regulatory change are considerable. The costs of engaging at the right level with these changes are larger still. Smaller suppliers such as Haven simply do not have the people or management capacity to follow all the changes and to contribute fully to consultations and change process. The more resources used to engage with the regulatory process results in fewer resources available to focus on the needs of customers. The increase in regulatory intervention is in stark contrast to the work undertaken by Ofgem in its Supply Licence Review in 2007 where it espoused the merits of reducing and simplifying the regulatory arrangements.

Counterproductive regulatory invention

In addition, while relevant to the residential retail market, Ofgem's RMR reforms limit the ability of new entrant suppliers to differentiate themselves to attract customers from incumbent suppliers. Ofgem's tariff restrictions in the residential market are an example of counterproductive regulation and as such we welcome the CMA's intention to assess the effect of past regulatory interventions. However it must be noted that Ofgem's tariff restrictions are only one component of what has become a 'wall of restrictions' on supplier activity. We have seen increasing prescription of business processes coupled with value judgements that take little or no account of non-cost factors. These are based on a pure commodity model and exhibit no understanding, nor take any account of, service, convenience, supplier differentiation and other non-commodity factors. In addition, the scope of the Micro Business definition is so wide that it covers almost all businesses. The uncertainty in the regulatory landscape, lengthy timeframes for decisions to be reached via industry change processes and the continual re-visiting of regulation has become a large issue for us.

The case for better targeted regulation

While there may be a case for regulatory intervention in some circumstances (for vulnerable customers for example) we note that the best customer outcomes occur where there is the least burdensome regulation i.e. the I&C market. It is especially worrying when it is suggested that the regulatory interventions made in the residential retail market should be extended to the SME market. While these interventions may be warranted for some of the smallest business customers who are very similar to residential consumers, the current definition of Microbusinesses goes well beyond this and covers almost all the market. Therefore, to extend the benefits

associated with the I&C market to the SME market we consider that the level and prescription of regulation should be similar and regulation should be progressively reduced.

Some parties argue that these Micro Businesses need the same protection as residential customers, but these same businesses are subject to a host of other legal requirements ranging from the accounting obligations of the various Companies Acts to the wide range of secondary legislation that businesses have to comply with. It seems wrong to extend residential protection to businesses that are required by Parliament to comply with a far wider and more complex range of obligations.

Finally, we note that much of the analysis in the Statement of Issues heavily relies on past Ofgem publications. It is important that the CMA draws on a variety of different sources of information and analysis to inform the investigation. This will ensure the investigation considers all the relevant evidence to inform its conclusions and ensures it is not heavily biased by one particular viewpoint. It will further demonstrate that the investigation is independent of Ofgem, which is particularly important when assessing the role of past regulatory interventions.

Third party charges

Finally, we note that the volatility and unpredictability of third party charges (i.e. distribution costs, transmission costs, Balancing Services Use of System (BSUoS) costs, Renewables Obligation costs, FiT costs and, in addition from 2015, CfD FiT costs and Capacity Market costs) faced by suppliers in the retail market is a significant concern and increasing costs for customers. All market participants are exposed to these charges and there is little if anything a supplier can do to manage the risks associated with their volatility and unpredictability. This results in significant risk premia being passed on to customers. Whilst not necessarily a competition problem, it does negatively impact customers. It is an inefficient way of delivering Government policy and the costs of network expansion and maintenance. Most of these third party charges are also accompanied by intensive collateral arrangements. This further adds to the costs of participating in the market. To reduce the risk premiums applied by suppliers we recommend that third party charging volatility and unpredictability is eliminated by fixing these costs well in advance and recovering any shortfall/surplus by adjusting the charges in future periods.

Due to the short time available between publication of the Statement of Issues and deadline for consultation responses, there has been limited time to produce further analysis to supplement the points made in this response. We would welcome the opportunity to discuss the points made in the response with you face-to-face and help determine what additional analysis the CMA would find helpful in carrying out the investigation.

If you would like to discuss any of the views expressed in this response, please feel free to contact me. In the meantime, we look forward to hosting the CMA team at Drax on 5th September, when we can discuss the issues raised here.

Yours sincerely,

By email

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Annex 1: CMA Renewables Obligation Briefing

1. Policy Background

The Renewables Obligation (RO) is the Government's principal policy instrument for incentivising renewable power generation in the UK. The RO is being replaced by a new Contract for Difference (CfD) Feed-in-tariff regime, which will begin supporting select projects from 2014, and then completely replace the RO for all new renewable generation projects from April 2017. Between 2014 and 2017, new projects will have the choice of being supported under the Contract for Differences (CfD) or ROC regime.

2. How the Renewables Obligation Works

2.1 Basic Structure

The RO works by placing a legal obligation on all Licensed Electricity Suppliers (Suppliers) to source a specified and annually increasing proportion of the electricity they sell to their end-customers from renewable sources, or pay a 'buy-out' penalty. For England & Wales and Scotland the 2014/15 obligation is 0.244 ROCs per MWhr of electricity supplied. With current banding and generation forecasts, this means that overall Suppliers must deliver approximately 18% renewable electricity to their customers or pay 'buy out' penalties.

The RO is administered by Ofgem who accredit eligible renewable Generators and issue them with the appropriate Renewables Obligation Certificates (ROCs) for every MWhr of renewable electricity generated in each annual compliance period. Compliance periods run from April to March. Accredited generation projects are entitled to receive ROCs for a maximum of 20 years from commissioning. For all coal stations generating from biomass (either by co-firing or by converting), the commissioning was deemed to start in 2007, so any ROC support will end on 31st March 2027.

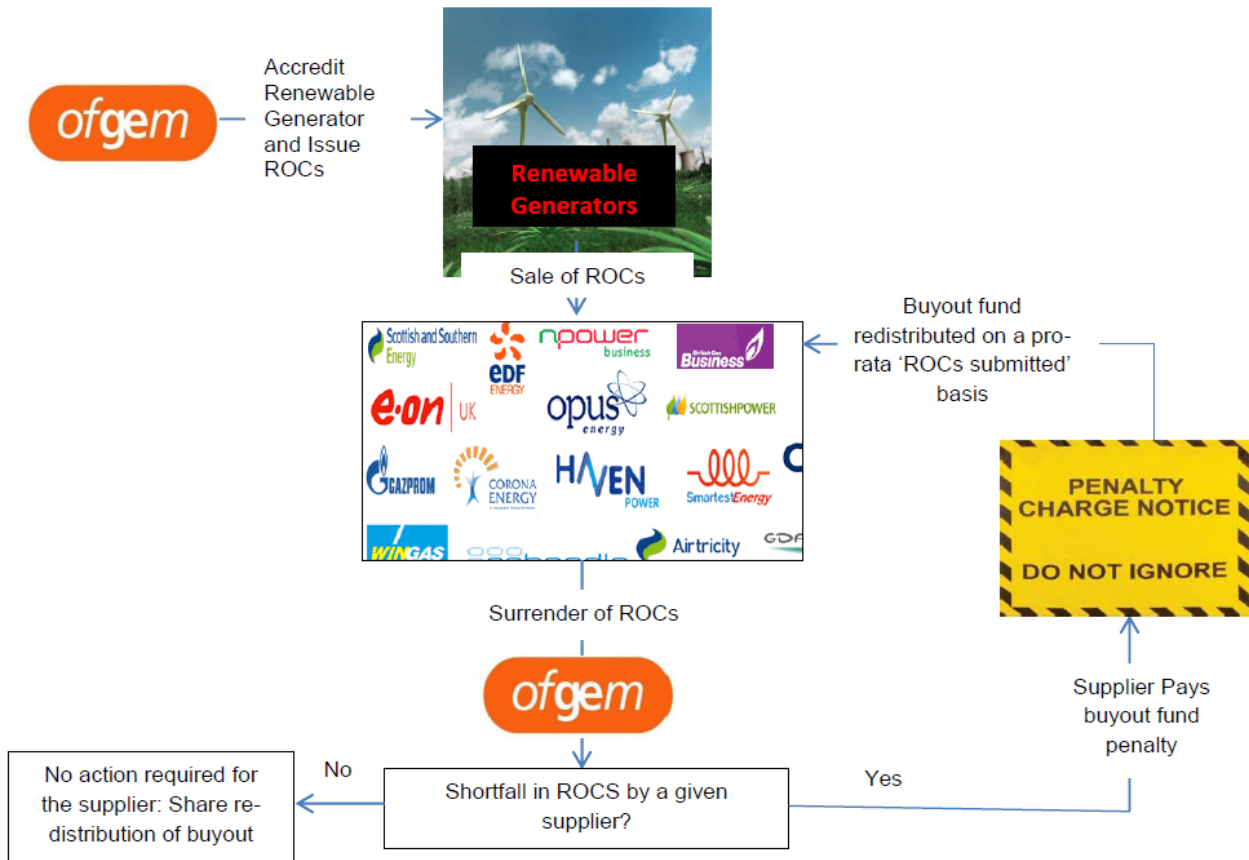
Since only Suppliers have to meet the obligation and only renewable Generators receive the ROCs, the only way in which independent renewable Generators can effectively monetise the potential ROC value is by selling the ROCs to Suppliers who then submit them to Ofgem to meet their obligation. This is done via a ROC ownership register which Ofgem manage.

2.2 RO Recycle Mechanism and Headroom

The annual penalty per ROC paid by Suppliers for failing to meet their obligation is fixed and increases with RPI each year. In the current ROC year it is £43.30. All penalties are collected by Ofgem and paid into the Buy-Out Fund. The Fund is then redistributed by Ofgem to those Suppliers who met all or part of their obligation by presenting ROCs, pro-rata based on the number of ROCs presented. This process is known as ROC re-cycling and is the only real incentive on Suppliers to buy ROCs.

To ensure that there is market for ROCs the obligation is calculated and published annually by the start of October – i.e. six months before the start of each April – March compliance period. It includes a target 10% 'headroom' above the forecast ROC production for the compliance period. This is designed to create a scarcity of ROCs against the obligation so there should always be a re-cycle fund and hence a willing buyer and this enables generators to monetise their ROCs. Greater scarcity of ROCs means more 'buy-out' penalty payments by Suppliers to meet their obligation, increasing the value of the recycle (value per ROC submitted), which is then redistributed against a smaller number of ROCs. Clearly, in any period, the greater the shortfall in actual renewable generation versus the obligation, the greater the value of each ROC. Conversely, as the scarcity reduces so does the Buy-Out Fund and hence value for ROCs will decrease.

ROC Market Process



2.3 Value of ROCs

The full value of a ROC to a supplier is the sum of the buy-out penalty in the compliance period and the recycle payment. To illustrate, the penalty value paid by suppliers in 2012/13 was £40.71 for each missing ROC, and the out-turn recycle value, which is only known around 6 months after the end of the compliance year in question, was worth £3.67/ROC. So the full, effective out-turn value of a ROC to a Supplier in that year was £44.38/ROC (avoided buy-out penalty plus recycle value).

As noted above, ROCs are issued to renewable Generators, but the RO itself applies only to the Suppliers; so to receive any value, independent Generators need to sell their certificates to Suppliers to monetise their ROCs. The RO is not an obligation to buy ROCs; a Supplier has the absolute right to pay the buyout penalty rather than surrender ROCs to meet its annual obligation, and almost all Suppliers do this to some extent. Thus Suppliers are only willing to buy ROCs from independent Generators if they can secure a financial gain over simply paying the buyout penalty. DECC assumed in the RO Banding Review Consultation that an independent Generator receives 89% of the ROC value.

2.4 RO Banding of different renewables technologies

New Generators receive different numbers of ROCs, depending on their technology and potential for large-scale deployment. For the period from April 2013 – March 2017 the bands for the large scale renewable technologies commissioning during this period are:

ROC Band Levels for Key Technologies from 2013/14

	ROC/MW hr	Year
Onshore wind	0.9	
Offshore wind	2.0	2014/15
	1.9	2015/16
	1.8	2016/17
Biomass conversion	1.0	
High Range Biomass Co-firing (>85%)	0.7	2013/14
	0.9	2014/15

2.5 ROC Grandfathering

Grandfathering of ROC levels effectively fixes the ROC support for the full lifetime of a renewable generating project's eligibility for the RO at the prevailing level in force when the project commissions. For Drax, this means that any unit converting, and being supported under the RO, will receive 1 ROC/MW hr until 2027, provided the converted unit is commissioned before DECC implement any reduction in ROC support levels. The current ROC bands are expected to remain in place until April 2017 when the CfD will become the sole support mechanism for all new large scale renewables including newly converted coal units. However, the Government has the right to call an emergency banding review at any time which could lead to a change the banding levels. Any unconverted units at Drax would then be subject to the new bands at the time of conversion. As an example in May 2014 DECC set out plans to close the Renewables Obligation to new solar capacity above 5MW from 2015.

3. Challenges for an Independent in the RO mechanism

3.1 Risk of Oversupply

The level of the obligation is set by DECC and is calculated as:

- DECC's estimate of the amount of renewable generation that will be produced in the compliance period and the resultant ROC production as a percentage of forecast total licensed physical supply of all electricity to end users, plus
- 10% additional to provide the headroom to make the market short.

Each supplier has its own obligation to fulfil. The market structure can be described as an oligopsony.

DECC face a difficult challenge in estimating the ROC market. If they significantly underestimate renewable production then ROC generation will fall well short of the obligation. Suppliers will be forced to make large penalty payments which will then be shared, potentially leading to super normal profits. If DECC underestimate the volume of renewable generation, the market could fail and the ROC value would fall to zero. In the ROC year, 2012/13, we estimate that, if there had been no fire at Tilbury, Ironbridge had not been so delayed in commissioning, and wind speeds had not been below average, the obligation would have been over supplied.

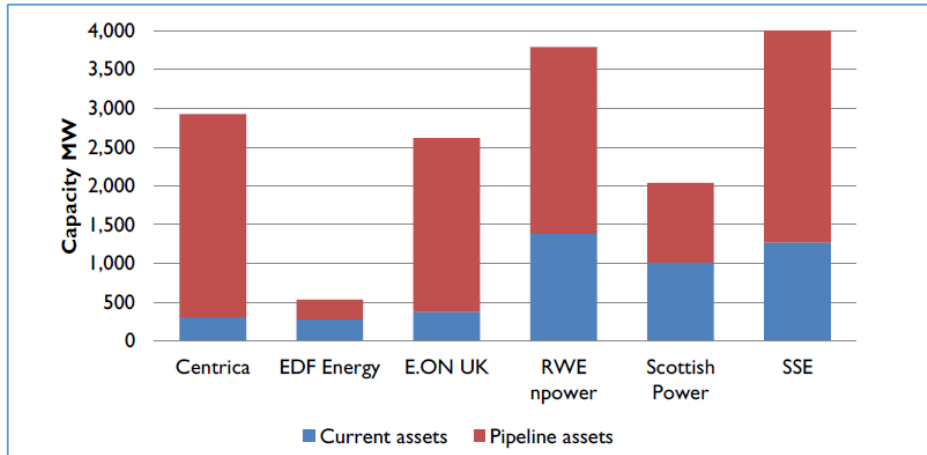
Recent ROC pricing and issuance data indicates that oversupply may have occurred in the last year 2013/14. This is because approximately 62.5m ROCs already issued by mid-August could exceed the total supplier obligation. This volume exceeds the 'headroom' adjusted ROC volume in DECC's October 2013 calculation, which was based on a total volume of 61.5m (55.9m expected + 10% headroom). Contributory factors for this include what appears to be an underestimate of underlying offshore wind load factors, exacerbated by some above average windy winter months.

Under the worst-case scenario some ROCs are stranded with zero value. The only mitigation available to a Generator would be to bank their ROCs into the next compliance period and hope that this period was not also oversupplied.

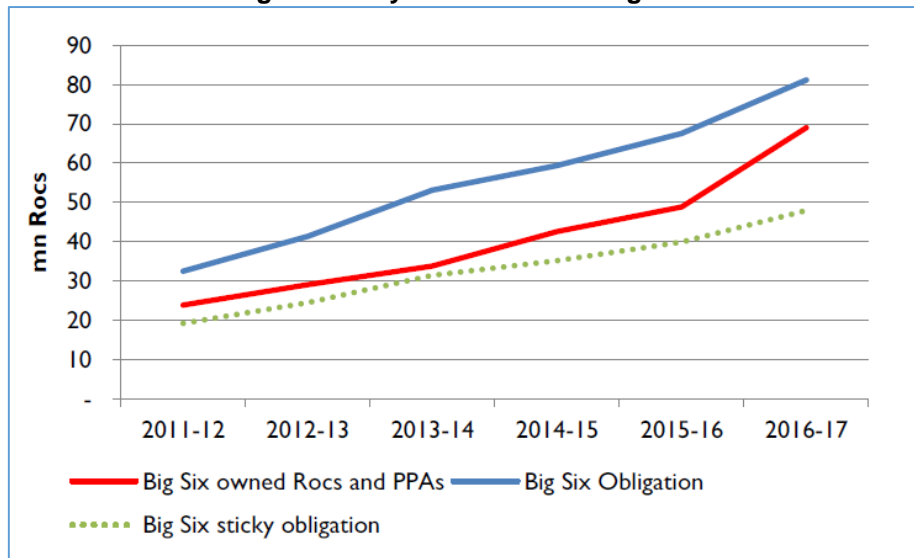
3.2 Supplier Market Power

The UK supply market is concentrated. It is estimated that the Big Six vertically integrated players have over 85% of the total supply market around 95% of the 'sticky' residential market. They are therefore the large scale buyers of ROCs. Over time, the Big Six have covered a significant portion of their RO needs by building their own renewable generation and committing to long term off-take contracts from independent renewable Generators. The charts below (with 2012 data) show this position:

Big Six current renewable assets and project pipeline (MW)



Big Six ability to meet their obligation



As the Big Six have developed their own renewable portfolio through assets or contracts, their collective appetite to buy ROCs from independents has diminished. This overall reduction in effective competition between the Big Six to purchase ROCs (to gain from the share of the Buy-out recycle fund) is already leading to a decrease in achieved ROC values for Drax and other independent renewable generators. If not addressed, it could make it increasingly difficult for independent Generators like Drax to achieve 'fair value' for their ROCs.

It should be noted that (as we understand it) all Suppliers routinely bill their customers for the RO at the full buyout price. So any resulting decrease in the value of ROCs would not benefit end consumers. It would hurt the renewable generation affected, undermine confidence in the UK support mechanism, and result in a gain for the Trading business of the last buyer(s).

4 Some Potential Solutions

4.1 Introduce a fixed ROC mechanism

Drax has been lobbying for many years on the poor access of the independents to the ROC market. Access problems were particularly acute when the co-firing cap was introduced which created a sub-market for co-fired ROCs. In 2009 we held an externally facilitated auction for co-fired ROCs in the expectation that it would fail. The auction did fail. All of the big 6 Suppliers registered to bid but we received no bids despite clear evidence that the co-firing cap would not be met in that compliance year. We presented this evidence to DECC who, over time, have come to accept that the issue is serious.

The issue is also faced by other independent Generators. The best solution for all such parties would be to change the structure of the RO to remove the need to sell the ROCs through Suppliers. DECC already plan to do this by introducing a fixed ROC mechanism in 2027, using powers in the Energy Bill. Under this “fixed” mechanism the obligation structure would be removed and renewable Generators would receive directly a fixed amount for each MWhr of renewable electricity produced.

Drax argued to DECC that to retain investor confidence in the integrity of the ROC regime, they should consider bringing this date forward to 2017, when the RO closes to new projects. DECC consulted on this in 2013 and decided not to make this change. The main argument against doing so was that it might adversely impact on existing PPAs, although we believe that this impact could have been minimised.

4.2 Introduce an obligation to purchase ROCs

This would place a requirement on Suppliers to purchase ROCs to meet their obligation before electing to pay the buy-out price. As such it would immediately give the ROC market more of the characteristics of a well-functioning market, and remove some of the worst distortions of the present arrangements.

4.3 Introduce a purchaser of last resort for ROCs

Any generator who was unable to sell its ROCs at the buy-out price could sell them to an agency (eg. Ofgem) who would pay the buy-out price and recover the money from suppliers pro-rata to the shortfall in the annual RO that was not met from ROCs. This would ensure that renewable generators received no less than the buy-out for their power and would remove any incentive from suppliers not to buy at the buy-out price.