1. What changes may need to be made to the electricity market to ensure that supply and demand are balanced, whilst minimising cost to consumers, over the long-term?

- **What role can changes to the market framework play to incentivise this outcome:**
  - **Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?**
  - **Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?**
- **To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?**

In our view, the key to ensuring that supply and demand are balanced at reasonable cost over the long term is stable policy and the use of market mechanisms and price signals to drive down costs. Some stimulus - subsidy - may be needed in addition of this to develop new technologies in order to meet low carbon targets but it should be tightly focused, restricted to only what is needed, and should supplement the market rather than replacing it. Policy should always prioritise the most cost effective measures, choosing lower cost options where these are available.

Those ideals are very far from what the current market framework currently delivers and this needs to change. Recent policies, in particular the Electricity Market Reform package embodied in the Energy Act 2013, have seen Government intervention in the electricity market become pervasive to the point where no power production technology can be brought forward without some form of public subsidy, whether low carbon (through contracts for difference or feed in tariffs) or high carbon (through the capacity mechanism). This dependence on policy stimulus rather than market signals distorts the market and creates investor signals to chase the investment that provides the greatest guaranteed return from Government rather than that which delivers the greatest benefit to society. Government in turn has adopted contracting procedures which are inefficient both in terms of prioritising higher cost measures where lower cost ones are available, and in failing to adequately introduce competitive stimulus into its procurement processes. The Competition and Markets Authority ('CMA') has suggested that the decision to award a majority of (existing) CfD funding 'outside the competitive process under the Final Investment Decision Enabling for Renewables scheme is likely to have resulted in higher costs to customers of approximately £250-£310 million per year for 15 years,'[1] building on similar criticism already expressed by the National Audit Office.[2] The CMA's energy market inquiry has also provisionally concluded that the Government's ongoing methods of allocating CfDs give rise to an 'adverse effect on competition,' expressing considerable concern that DECC is not supporting its decisions around the allocation of budget into funding pots for different technologies with robust evidence.

In its first CfD auction round, DECC allocated 80% of the available budget to the less established (eg more expensive) technologies pot. This trend to favour the most expensive technologies has since embedded further, as the Government has subsequently announced its intention to preclude new onshore wind projects from receiving CfDs and that the next CfD allocation round will see budget allocated exclusively to the less established technologies pot.

The consequences to consumers of banning cheap technologies and prioritising the procurement of expensive ones are potentially highly material. We commissioned NERA Economic Consulting to model the results of low carbon generation auctions both with and without onshore wind.[3] Its exclusion imposed significant costs on electricity consumers - around £0.5 billion over the term of the CfD auctions awarded in a single auction round. Because auctions may be repeated over a number of years, the eventual costs to consumers could be much higher. We also asked NERA to model what savings could be achieved if the technology pots were merged - eg that low carbon auctions simply focused on buying the cheapest low carbon generation it could. Applying that approach reduced consumer costs by around £1 bn, again, only in relation to a single auction round.

The absence of financial discipline in generation procurement decisions is coming at a significant cost to consumers. Given a budget during the last Parliament rising from £3.5bn this year to £7.6bn by 2020 to build new clean energy generation, DECC is already forecast to spend £9.1bn.[4] This overspend has forced DECC to scale back a range of policies during summer/autumn 2015 with consequential negative effects on

---

[1] 'Energy market investigation - provisional findings report,' CMA, 2015. http://tinyurl.com/hust94q
[2] 'Early contracts for renewable electricity,' NAO, 2014. http://tinyurl.com/h5uygwx
[3] You can find the results of its modelling on our website: http://tinyurl.com/zwr4o5n
[4] 'Written ministerial statement to the Lords on the Levy Control Framework,' 22 July 2015. http://tinyurl.com/q2jkqnd

investor sentiment and confidence in policy durability. This boom/bust approach is a lose-lose situation for both consumers and investors.

In our 2015 report, 'Generating Value', we analysed the effectiveness of current and recent past policies to stimulate low carbon generation and came forward with a range of recommendations for how policy could be improved to keep the lights on and meet carbon targets at lower cost to consumers. We recommended:

- The government should allocate the majority of CfD funding to the most currently cost-effective technologies.
- Instead of barring onshore wind from CfD allocation completely, government should instead lower the cap on strike prices (for example, by changing the previously set administrative strike price cap on auction clearing prices) to a level equivalent to the cost of new build gas generation.
- Any future decision to allocate funding to the less established technologies pot must be accompanied by a rigorous value for money assessment. DECC needs to start demonstrating the value (if any) of keeping the more expensive technology options open. If it cannot, they should not be funded.
- The criteria used to assess bill-funded low carbon deployment should be consistent across impact assessments. They should be heavily weighted towards reducing emissions at the lowest cost. Government can and must do more to quantify currently uncosted externalities given the size of investment it is committing to at consumers' expense.
- If job creation is the principal, or a major, consideration in the government's decision to stimulate a new project or technology, it should fund the job-creating proportion of any needed deployment support from general taxation.
- Where DECC proposes to award a substantive contract that has been bilaterally negotiated rather than competitively procured, it should publish a full impact assessment for consultation.
- As well as ensuring full impact assessments are carried out in future, the CMA should also demand full publication of terms in existing contracts that affect consumers' liabilities.
- The government should set an upper limit for subsidy per MWh as a stop-loss policy. It should degress over time. A medium term target trajectory should be published to allow investors to have confidence that they understand the terms on

which support will, or will not, continue. Competitive procurement processes for new low carbon contracts, such as auctioning, should continue in order to encourage developers to beat the degression curve and not simply to match it.

- Low carbon generation deployment and energy efficiency programme costs should be transferred from levies on bills into tax-funded programmes.
- Re-establishing energy efficiency policy in the wake of the cancellation of the Green Deal should be undertaken as a matter of urgency. Efficiency policies will be essential to mitigate the bill impacts of decarbonising generation. This should include targeting the successor to the ECO scheme towards fuel poor households, and designating energy efficiency as a national infrastructure priority.

We append that report to our submission and suggest that it provides a good starting point for informing your work on how to cost effectively stimulate new generation projects. [5]

We are open-minded regarding proposals to introduce an Independent System Operator ('ISO') function. In principle, we can see theoretical benefits in keeping the System Operator ('SO') and Transmission Owner ('TO') functions of National Grid bundled as they currently are. This is because we see some natural interactions between the two - TO is what you build, SO is how you use it. Trade-offs must exist between the two: eg investing in (TO) capacity (or not) should affect (SO) system constraint costs. As a consumer, one would want those trade-offs to be made in a way that reduces total costs and divorcing these functions into separate bodies could preclude or frustrate those trade-offs from being made. In practice, we acknowledge that theoretical benefit to keeping these roles bundled has not been as manifest as it could be in practice. While TO and SO functions are both price controlled they are subject to separate price controls which may impede the extent to which regulation drives efficient totex trade-offs. In addition to this, while the SO function is at GB level, TO is separated between England & Wales (also National Grid) and Scotland (Scottish Power and Scottish Hydro) which may constrain the synergies.

We think much of the current debate on whether or not there should be an ISO is driven by perceived conflicts of interest between National Grid's role as the EMR Delivery Body and as an advisor to government on issues like volumes to be procured through the

[5] 'Generating Value,' Citizens Advice, October 2015. Also available on our website: http://tinyurl.com/hl8zvmg

capacity mechanism, and the potential that government decisions made on that advice, or delivered through that role, could impact on its bottom line. If these perceived conflicts of interest were to crystallise, this could potentially have an adverse effect on the extent to which the market ensures that demand and supply are balanced at minimised cost. While we do not see evidence that the potential for conflicts of interest is occurring in practice, we recognise the arguments being made here and that this perception could affect investor, political or consumer confidence in the UK market.

We think that alongside consideration of whether there should be an ISO it may also be worth considering whether system balancing should remain the preserve of a single body acting at transmission level, or whether there is a role for distribution networks to take on such a role too - is it enough to have a TSO, or do we also need to develop DSOs? Volumes of (distribution) embedded generation have increased sharply in recent years, and much of the potential for demand side response and storage is also distribution rather than transmission connected. These changes mean that the balancing assets available to keep the lights on in future may not be transmission connected as they were in the past. While a single remote SO may be able to continue to call on such assets through new products and services, there may be a case that the distribution network they are connected to has a better view on how to operate those balancing assets in such a way that the total costs to consumers are optimised. Should DSOs be able to bid in to the balancing mechanism? Should they be able to procure balancing services in the same way that a TSO - whether independent or not - can?

While your consultation briefly mentions demand side management it only does so in the context of 'new technologies' and energy efficiency is not mentioned. This may suggest that you are only interested in new and novel demand side management technologies such as active demand side response and energy storage, and not more established markets like demand reduction through energy efficiency. We think this would be a mistake as energy efficiency has a potentially huge part to play in ensuring supply and demand are balanced at minimum cost. Energy efficiency has proven highly effective in reducing demand in recent years. Weather corrected domestic electricity demand dropped by 13% between 2008 and 2014, with a larger drop still in gas of 19%.[6] Much of this demand reduction will have been through measures that are far less cutting edge than those you are considering - loft insulation, boiler replacement etc - but they are also

[6] DECC Digest of UK Energy Statistics. http://tinyurl.com/pf9vrqv

low cost (when compared to subsidising large new power stations), low regrets and can deliver significant social benefits through helping to tackle fuel poverty and cold related illnesses. Energy efficiency is also essential if you are going to pay for large upstream infrastructure projects through bill levies - because reducing the volume of energy consumers use can counteract some of the inflationary pressures that subsidising power stations will put on unit prices. But government ambition here is low. The Conservative manifesto committed it to making one million homes more energy efficient in the 2015-20 Parliament - but this is a very significant drop on the deployment rate from the last Parliament.[7] The Green Deal has been scrapped and ECO2 is largely delivered with no replacement yet in place. In combination we are currently left with an unambitious energy efficiency target and a lack of credible policies to achieve even that limited ambition. The National Infrastructure Commission could usefully play a role in setting out a more ambitious pathway for UK energy efficiency policy to keep the lights on while minimising consumer costs. Ultimately the UK's buildings are its biggest single infrastructure asset - at the end of 2013, dwellings accounted for 61% of the UK's £7.6 trillion net worth[8] - it would be perverse if the NIC's work ignored our largest asset.

2. What are the barriers to the deployment of energy storage capacity?

- **Are there specific market failures/barriers that prevent investment in energy storage that are not faced by other 'balancing' technologies? How might these be overcome?**

The market for gas storage is considerably more functional than the market for electricity storage. Gas storage assets built under the British Gas monopoly and since unbundled, combine with North Sea production, the gas interconnectors and expanding LNG import infrastructure to provide a robust security of supply environment. This has occurred largely absent any specific policy incentives or mandates for storage nor supply diversification. In particular, it has avoided the risk of 'oversupplying' storage. Consumers have not had to bear the costs of construction and operation of unneeded storage facilities, yet consumers' needs for reliable gas supply has been met, even during times where gas supplies in Europe have been disrupted. We see no reason for the government to change this market-driven approach to gas storage in upcoming years.

---

[7] For example: 860,000 major measures (boiler replacement, loft, cavity wall or solid wall insulation) were installed between October 2011 and March 2012. 'Left out in the cold,' Energy Bill Revolution and the Association for the Conservation of Energy, February 2015. http://tinyurl.com/pkue7en

[8] ONS, 'National Balance Sheet: 2014 estimates' http://tinyurl.com/gtetnbb

Electricity is very different. The technologies that can store electricity are either very new and expensive (including most prominently batteries but also more esoteric storage methods such as flywheels and power-to-gas storage), or very old and expensive (such as constructing pumped-storage hydro facilities).

The electricity market has evolved largely on the basis that electricity cannot be stored, or at least can only be stored at high cost and with low efficiency. The possible emergence of new technologies that can supply electricity storage much more cheaply, especially the reducing costs of large battery systems, fundamentally challenges many of the assumptions and market structures that currently exist. The commercial viability of proposed applications, such as arbitrage between periods of peak renewable energy supply and peak demand, under existing market arrangements is unclear.

The focus of policy should be on enabling efficient and cost-effective investments in storage, and not trying to push investment at any price. As is the case with gas storage, it is not simply that more is always better. Given the uncertainties around future costs we agree that the initial focus of policy assessment should be on removing barriers rather than developing additional funding mechanisms whose need is as yet unknown.

While we are not in a position to provide a comprehensive assessment of all such barriers, some examples may prove instructive.

For example, following unbundling initiatives at a UK, and subsequently at the EU level, network operators have been restricted from operating generation and supply assets. As costs of storage come down, there may be instances where it is cheaper for a DNO to add a storage system to a constrained network than to reinforce it in the conventional way. Yet present regulatory arrangements may preclude this. (There are other ownership models that may allow a storage facility owned by a third-party to provide an equivalent function, but it is unclear whether the current remuneration arrangements for DNOs would provide any incentive for them or a third party to participate in this way.) It is our understanding that these restrictions are under review in Brussels, with the European Commission and ENTSO-E considering the next round of electricity market legislation. The UK Government and Ofgem may also want to consider whether current unbundling arrangements would interfere with cost-effective deployment of storage options. A regulatory regime analogous to the one now in place for interconnection may facilitate the development of storage by networks but outside their regulated monopoly business, or under a cap-and-floor style regime that limit networks' ability to use their monopoly position to drive excessive profitability in a non-monopoly storage business.

Another instance where the regulatory treatment of storage could potentially dissuade new entry is in the charging for balancing services (BSUoS) charges. Storage operators face BSUoS charges twice - once when drawing from the grid to fill up storage, and again when supplying to the grid emptying storage. Conventional load or generation would only face one of these charges.

- **What is the most appropriate scale for future energy storage technologies in the UK? (i.e. transmission network scale, the distributed network or the domestic scale.)**

It is too early to judge the scale that energy storage technologies could interact with the electricity system. It is quite plausible that it could play roles at all the levels suggested, working alongside wind farms and other intermittent generation on the transmission network, being used to avoid distribution grid constraints or reinforcements, and in household applications with electric vehicles, or in combination with solar PV.

At this stage in their evolution we see little merit in government trying to close off any of these options, or trying to steer deployment towards any particular application. Rather, the first stage in ensuring policy is ready for cheaper electricity storage should be to assess whether there are any regulatory barriers that would currently impede any of these applications, or which would distort incentives, such as those described in the response to the previous question.

3. What level of electricity interconnection is likely to be in the best interests of consumers?

- **Is there a case for building interconnection out to a greater capacity or more rapidly than the current ‘cap and floor’ regime would allow beyond 2020? If so, why do you think the current arrangements are not sufficient to incentivise this investment?**

- **Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other 'balancing' technologies? How might these be overcome?**

Interconnection can provide a valuable tool to the UK economy and to its consumers. As intermittent generation comes to form a higher proportion of total generation both within our borders and in neighbouring countries it can help to provide both with a balancing tool and a route to markets. Where the cheapest megawatt, or negawatt, is outside our borders interconnection can provide a route to deliver this benefit to UK consumers. Conversely, it provides export opportunities for our most efficient producers. Interconnection should also help to create deeper, more liquid wholesale markets, reducing total consumer costs. It is hard to see how a single european market could be completed without the integration of markets facilitated by interconnectors.

Notwithstanding these benefits, we are unconvinced there is either a need to prescribe a certain amount of electricity interconnection or a case to conclude that current arrangements will leave us short of the interconnections we need. It is often pointed out that the UK has lower levels of interconnection than the European average, and than the EU's (non-binding) 10% target, but this in part simply reflects a wider trend that is driven more by physical or political geography than market (or policy) signals. Low levels of electricity interconnection are a characteristic of the geographically peripheral EU states - of the 11 EU Member States who fall below the 10% interconnected capacity target, four are islands (the UK, Ireland, Malta, Cyprus), three are peninsular (Italy, Portugal, Spain) and another three are largely physically separate from the rest of the EU (Estonia, Latvia, Lithuania). A flat (10%) aspirational target is never likely to represent the geographical practicalities of individual member states.

According to the European Commission, interconnectors accounted for 6% of the UK's electricity capacity in 2014.[9] There is 4GW of current UK interconnector capacity, of which 1.5GW (37.5%) has entered service in the last 5 years (a 1GW link to the Netherlands and a 0.5GW link to the Republic of Ireland).[10] Another 7.3GW is planned by 2022. It is possible, perhaps likely, that not all of those prospective projects will come to fruition but if even half do the UK should meet the 10% target. This large volume of interconnected capacity either

[9] 'Achieving the 10% electricity interconnection target,' European Commission, February 2015. http://tinyurl.com/j55xmg2
[10] 'Electricity interconnectors,' Ofgem. http://tinyurl.com/jodw2nk

recently built, or in the near term pipeline, suggests that current market arrangements and policies are not a deterrent to interconnectors coming forward. This does not signify that arrangements are perfect and the NIC may be able to identify incremental improvements to the regime. But we would caution it against starting from a position that assumes major reforms are needed to bring forward new interconnection; it is not clear that the evidence supports such a view.

While not necessarily a deterrent to new interconnections - indeed, it may actually stimulate them because it may create arbitrage opportunities - it is worth being aware that the UK's decision to impose a unilateral carbon floor price may distort cross border electricity trading. UK power generators face a higher carbon price than those in our interconnected markets in Ireland and mainland Europe. This may give generators outside our borders a competitive advantage compared to indigenous generation and may undermine the case for investment in UK thermal generation. This problem may get worse if the carbon floor price ceases being frozen and returns to the year-on-year 'escalator' that was envisioned for it on introduction.

"4. What can the UK learn from international best practice in terms of dealing with changes in energy technology when planning to balance supply and demand?"

No comments.