Cost of Energy Review: call for evidence

Response by the UK Energy Research Centre (UKERC)

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ABOUT UKERC

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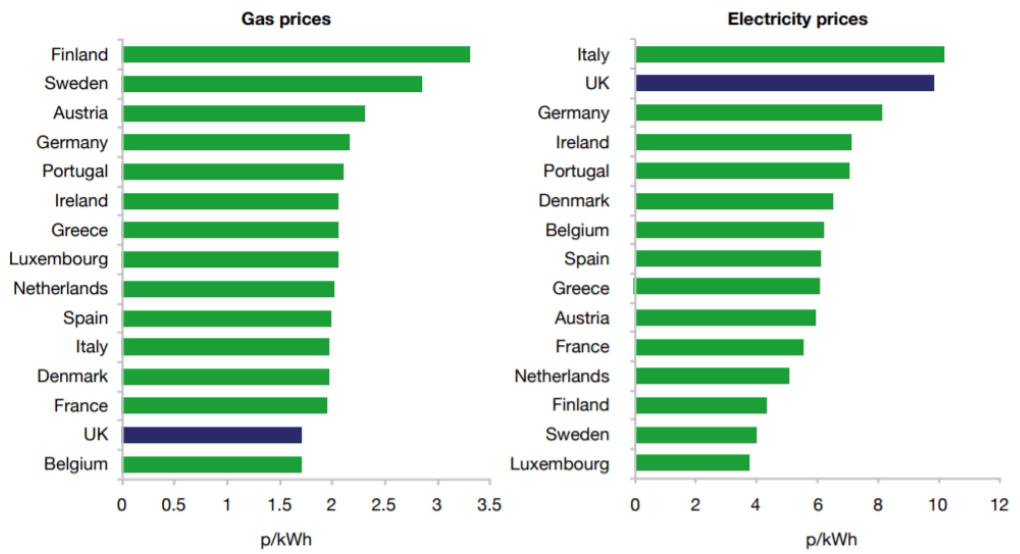
Introduction to our response

The UK Energy Research Centre welcomes the opportunity to comment on the findings of the Cost of Energy Review, conducted by Professor Dieter Helm. In this response, we address most of the questions set out in the Call for Evidence from BEIS. Before turning to these specific questions, we have three general observations about the Review and the Call for Evidence.

First, whilst the review title focuses on the cost of energy, this is misleading. The terms of reference and the Review report make it clear that the main focus is electricity rather than energy in general. We have therefore concentrated mainly on the factors that could influence electricity costs in our response.

This distinction is important since the data shows significant differences in the position of UK electricity and gas costs when compared to costs in other countries. There are also differences between relative costs for households and relative costs for business energy consumers. UK electricity prices are higher up the European league table than prices for gas. As shown in the figure below, electricity prices for energy intensive industries in the UK are particularly high.

Figure 12: Industrial electricity and gas prices for large consumers in the EU15 in 2016, including taxes[135]



Source: BEIS

Source: HM Government (2017) The Clean Growth Strategy.

UKERC is undertaking an evidence review that will help to shed more light on such comparisons, and inform debates on how costs are allocated. The review focuses on electricity price formation and the range of policies that are paid through bills in a variety of case study countries, drawing comparisons with the UK. The results will be published in February. Early findings indicate that there are large differences between prices for categories of consumer. In the UK there is much less differential between domestic and large industrial consumer prices per unit of electricity than there is in other countries. This is partly because some countries largely exempt the largest energy consumers from important policy costs. However there are also differences in network charging, wholesale prices and other factors, some of which reflect historic investments (e.g. nuclear in France), or natural endowments such as availability of large hydro.

Our second contextual comment is that there are important distinctions between prices, costs and bills. Whilst much of the debate focuses on prices, the costs of energy for consumers also depends on their energy consumption. Therefore, it is also important to consider energy efficiency of buildings, appliances and industrial processes since these are a key determinant of costs.

As the Committee on Climate Change has shown, household energy bills (as opposed to prices) have fallen in recent years. Between 2008 and 2016, average household dual fuel bills have fallen by £115. Price increases (including the effect of any policy costs) were offset by improvements in energy efficiency (CCC, 2017).

A recent report by UKERC and the Centre for Innovation and Energy Demand confirmed that the social benefits of cutting household energy use remain considerable (Rosenow et al, 2017). Using standard Treasury methodology, this report showed that a 25% reduction in household energy demand is possible using cost-effective measures. Furthermore, the social gains could be up to £7.5bn to 2030. This figure takes direct rebound effects into account.

This confirms that there is a clear rationale for further government intervention to realise these social benefits. There is a significant policy gap that has been left behind following the failure of the Green Deal. Previous supplier obligations made significant progress in helping to reduce household demand and energy bills, but the rate of progress has now stalled. There is also a need for more attention to energy efficiency policy for households on lower incomes (building on the current ECO scheme) and to SMEs that have not yet benefitted from significant policy attention. Our systematic review of international evidence on what works in energy efficiency policy (Wade and Eyre, 2015) found savings of around 10% from well-designed standards and investment programmes.

Our third comment is that costs need to be considered for the electricity system as a whole. Whilst the separate questions in the Call for Evidence about generation, networks and retail supply are understandable, costs to consumers partly depend on interactions between these components of the electricity system. This compartmentalised approach to the evidence base could mean that some of these systemic interactions are missed.

For example, there is likely to be an important relationship between the extent of flexibility in the electricity system and the costs of integrating increasing shares of intermittent renewable sources (Heptonstall et al, 2017). This flexibility can come from generation (e.g. flexible fossil plant), demand (e.g. via demand side response), networks (via increased interconnections) or via measures which do not fit neatly into any of these categories (e.g. electricity storage). A key question for this specific example is the extent to which falling costs of intermittent renewables and investments in flexibility will – overall – lead to lower costs for consumers.

Electricity generation

What are the longer-term challenges for electricity generation?

Low cost, low carbon generation with ongoing innovation

The principal challenges are to grow power from low carbon sources, reduce the cost of low carbon power and ensure that the wider energy system is reliable. The system needs to be flexible and incorporate low carbon power at minimum cost. Substantial reductions in emissions cannot be delivered merely by closing coal and replacing it with gas. Progress with low or zero carbon options is also essential. It is likely to be necessary to increase the overall supply of electricity in order to meet new loads from electric cars and heat pumps.

Recent growth in renewables and reducing use of coal has reduced GB emissions from around 500g/kWh in 2013 to below 250g/kWh (Staffell, 2017). By the mid-2020s around 4 GW of older nuclear stations need to be replaced and the challenge will be to provide enough *low carbon* power[1] (Rhodes, Gazis, & Gross, 2017). The Levy Control Framework guidance announced in the Autumn Statement effectively freezes new finance until after 2025, but some low cost renewable options could be built without subsidy. This would likely require 'subsidy free CfDs'. Pursuing such low cost options is a policy priority.

Longer term it will be important to continue to promote innovation, to reduce costs in the UK and help provide UK companies with opportunities to benefit from the growing global market for clean, low carbon energy. Despite observations about the 'valley of death', the Review does not explain how it would be overcome if, as Helm suggests, the CfD mechanism and the Capacity Market (CM) were merged.

Cost effective provision of flexible, reliable supplies – a system level issue

Ensuring system security and reliability requires sufficient generation capacity to meet demand. It also requires the provision of a wide range of other system services– including flexibility and ancillary services such as frequency response. It is important that policy does not fixate on only one, simplistic measure of reliability – the de-rated capacity margin (Rhodes et al., 2017).

As the share of variable renewables rises, they begin to impose system costs, often referred to as the costs of intermittency. UKERC has reviewed the international evidence on these costs (Heptonstall, Steiner, & Gross, 2017). Space does not permit a detailed discussion but a number of points are relevant. The first is that it is important not to overstate the magnitude of such costs. UKERC's review suggests the main sources of additional cost amount to less than £10/MWh of variable renewable generation at renewables penetrations below 30% (Heptonstall et al., 2017). Put another way, at current penetrations of around 17% GB

[1] Providing adequate capacity is unlikely to be problematic per se but in the absence of incentives for lower carbon options that new capacity is likely to be gas-fired plant (Rhodes et al., 2017).

electricity from variable renewables, the additional system costs attributable to intermittency add less than 0.2p per kWh of electricity supplied[2].

Security[3] is also provided most cost effectively at the *system level*, because system services have system-wide benefits. Provision of response and reserve services may be shared across a large number of renewable installations, helping to ensure that the system is stable in the event of a fault in a large power station[4], loss of an interconnector, or unexpected spike in demand. Many services required to ensure that the system is reliable are tendered by the system operator. They cannot be left to the market because of operational requirements, access to information, or because the risks associated with lack of flexibility are difficult to reflect in price signals. Because these services are shared across the system as a whole it is not efficient to require individual generators to provide them for themselves.

Helm's proposals require individual generators to 'self-balance' or to enter into contracts to provide 'firm' power. However there is no a priori need for all generators to provide identical capacity credits[5]. Plants that provide secure capacity market contracts do not *all* need to be the same as the plants that provide low carbon energy. It is also not obvious that renewable generators are in a better position than the System Operator to contract for ancillary services. Economic incentives already in place reward firm capacity, and renewables tend to trade at a discount in the wholesale market because of their intermittency (Staffell, 2017; Staffell, et al 2017). Simply put, requiring renewable generation projects to 'self-balance' through the Equivalent Firm Power (EFP) auction is inefficient, would result in over-investment in flexibility and balancing services, and risks *increasing* bills.

What matters should the Government take into account in considering the policy framework for electricity generation?

A recapitulation of principle – the rationale for Electricity Market Reform (EMR)

EMR rests upon two important and well-established principles: First, that long run fixed price contracts can reduce risks for investors in capital intensive and zero marginal cost plant such as wind/solar and nuclear. This can reduce bills compared to other forms of support for such technologies, since a lower cost of capital will lower their generation costs. Second, that 'missing money' may lead to underinvestment in capacity, which may be exacerbated by the impact of intermittent, zero marginal cost plant on wholesale power prices (Newbery, 2016).

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[2] Based on generation and supply data from BEIS November 2017 Energy Trends: Electricity https://www.gov.uk/government/statistics/electricity-section-5-energy-trends (Q1+Q2 2017 VRE generation=29TWh, total electricity supplied=167TWh).

[3] BEIS define security in terms of adequacy, flexibility and resilience but we use security and reliability as shorthand in this submission.

[4] For this reason reserve and response costs also reflect conventional plant characteristics. For example, they are sized to cover the sudden loss of the single largest in-feed (Heptonstall et al., 2017). This is currently Sizewell B or one pole of the France interconnector but will rise in future if Hinkley C or larger interconnectors are built.

[5] One common definition is the ratio between average energy output and expected availability at peak (see Heptonstall et al 2017 for definitions).

Hence, EMR created two complementary policies, each serving distinct policy objectives – CfDs serve to de-risk investment in low carbon generation and the CM to ensure that a key measure of reliability (capacity margin) is maintained.

If there are conflicts between policy objectives then a guiding principal could be to ensure that a least cost outcome is delivered, based upon empirical evidence rather than by recourse to abstract principles of economic theory. There is no a priori reason why removing or simplifying policies will reduce costs. Indeed oversimplification, or trying to meet multiple policy goals with a single policy tool, may render policies ineffective and even increase costs.

The main goal of CfDs is to ensure that zero marginal cost generation such as wind farms and nuclear power stations are insulated[6] from price risk caused by movements in fossil fuel prices feeding through into electricity prices (Gross, Blyth, & Heptonstall, 2010). A key rationale is that in most power systems, flexible plants (usually fossil fuel plants; gas plants in the UK) act as 'price makers'. Investments in new gas fired plant have an inherent hedge against fossil fuel price variability, but renewables and nuclear do not (Gross et al., 2010). The UK is far from alone in providing structures that offer renewable generators long-run fixed price contracts. Internationally, some 82 countries offer a feed-in-tariff (FiT) of some form and 34 countries run tenders, linked to a FiT or power purchase agreement (REN21, 2017).

International experience with capital subsidy instead of FiTs or PPAs has been rather mixed, because of perverse incentives leading to poorly sited and suboptimal developments (Moallemi, Aye, Webb, de Haan, & George, 2017). In contrast, with CfDs/FiTs developers are rewarded for energy output, which creates strong incentives for them to choose the best sites and cheapest technologies. Now that the CfDs are allocated on an auction basis, the potential for this approach to realise cost reductions is being demonstrated through falling CfD auction prices. We return to opportunities to build upon success with CfD auctions below, but first consider the case to merge the CfDs and CM.

What is the problem - taking an evidence based view of policy trade offs

The principal criticisms offered by the Review of CfDs are that past prices were set too high, and that too much capacity was procured when technologies were less mature and more expensive. This is debatable but that debate is irrelevant to the future of the CfDs and CM. The principal reason Helm recommends merging CfDs and the CM is to tackle the costs of intermittency. As explained previously, intermittency costs are a modest share of total costs and best tackled on a system wide level. Requiring individual plants to self-balance, risks overinvestment in balancing capacity or ancillary services[7].

In places the Review reads as if policy should be based upon a justice principle, apportioning 'blame', whether for carbon emissions or particular categories of system cost. However the

[6] The implicit judgement is that in transferring risk from investors to consumers/government the benefits of reduced cost of capital exceed any costs to consumers/government from providing this insurance to investors.
[7] The existence of 'free headroom' in the balancing mechanism (BM) since the New Electricity Trading Arrangements (NETA) were introduced in 2000 suggests that, for many hours of the year, too much operating reserve is being scheduled as a result of each party being responsible for self-balancing, with obvious implications for total system cost.

ultimate objective is to reduce bills, not to create an idealised construct that maximises 'justice'. System costs will be minimised if they are allocated to those best able to manage them irrespective of who 'causes' them. Splitting apart the causes of balancing costs in an equitable way is difficult but, as we discuss below, there are options for allocating more system balancing costs to renewable generators. Doing so does not require that the CfD and CM are merged into a single auction.

It is also not obvious that the EFP auctions would not create new complexities of their own. For example, Helm suggests that the System Operator should score EFP bids against carbon budget constraints, taking into consideration advice from the CCC on opportunities in other sectors. Prima facie this scoring appears to have the potential to be complex and fraught with difficulty, and no less susceptible to lobbying than some of the policies that the Review counsels against. We are not aware of any examples of other countries running carbon adjusted equivalent firm capacity auctions. The UK competes for investment in a global market for clean and conventional energy. Brexit has increased the uncertainty associated with all UK investments. It would not appear a particularly auspicious point in history to engage in a new and experimental approach to encouraging investment in low carbon power.

In the absence of a move to EFP auctions Helm recommends dividing CfDs into construction and operational phases. Annex 1 explains why this approach is flawed and misunderstands why returns may have been excessive and the nature of the problems associated with raising finance for large projects.

Overall, an important empirical question arises for policymakers -whether whole system cost reductions *will* (not might) result from replacing CfDs with an EFP auction. Any potential system cost reductions from the EFPs need to be weighed against additional costs incurred by exposing renewable project developers to system costs, risks and complexities that they may not be best placed to manage. Any reductions in complexity that result from merging the CfDs and CM need to be weighed against the potential for a carbon adjusted EFPs to create new complexities of their own. The questions are complex, need to be answered from a system wide perspective, and cannot be answered *a priori* or by recourse to economic theory alone. It is important to avoid an outcome where efforts to simplify policy serve only to increase risk and complexity, and end up *increasing* bills.

Risk and investment in capital intensive generation – moving to subsidy free CfDs?

There is a wealth of international evidence that support schemes such as CfDs and FiTs, which can attract new entrants and grow markets. Market growth engendered by FiTs has driven economies of scale and innovation – so called 'learning by doing' (UK Energy Research Centre, 2013). As Helm rightly points out, one means to ensure prices are as low as possible is through auctions. But lower prices do not obviate the importance of long run fixed-price contracts in securing investment at minimum cost. For this reason, many commentators have suggested that the UK could offer 'subsidy free' CfD contracts, for example for onshore wind. These would provide investors with a low risk environment, avoid burdening consumers with further policy costs and help to meet carbon reduction objectives. Surprisingly, they are absent from Helm's discussion.

Minimising system costs is also feasible within the broad paradigm of existing policies. There may be opportunities to incentivise renewable generators to minimise some of the costs they impose on the wider system, for example through additional use of system charges. It is also possible to expose renewable generators to short term wholesale market balancing costs. For example, changes to the basis through which the CfD reference price is calculated could encourage operators to forecast output further in advance. Greater coherence in the ways in which balancing services are procured and complement the Capacity Market should also be explored[8]. Government could assess a range of changes to system cost allocation and options for minimising overall system costs.

There's also no reason why the CM could not be extended to those low carbon options which are able to offer firm power, such as nuclear and biomass. Indeed, in principle the CM could also be open to variable renewables who prefer to make provision for back-up[9]. It is possible to allow prospective generators to *choose* between CfDs and the CM rather than closing the CfDs. Retaining CfDs offers several advantages – a low risk environment for particular types of renewables, familiarity to investors, and no need for regulatory change. A further advantage is that a small pot could be retained for early stage technologies, thus overcoming the 'valley of death'.

Finally, the investment environment associated with the CfDs needs to be viewed holistically. The Review notes lower returns on investment for wind developments in Germany, suggesting they result from something similar to a staged approach to CfDs. But this is not the case; Germany does not offer capital subsidies during construction. Rates of return are lower for a range of reasons, including the perceived risk of the wider regulatory environment, what is 'bundled' with the FiT (for example environmental surveys/consents and grid connection), and role of state banks in financing.

Overall it is possible to imagine an approach to cost reduction which uses the tools created by EMR to better effect. The principles would be to retain CfDs, use auctions to drive down prices, ensure some CfDs are subsidy free, retain a small pot for emerging technologies, and to ensure balancing service procurement, CM and CfD design minimise the costs of integrating renewables.

What additional evidence should the Government consider to reduce the cost of generation in the longer term?

See Annex 2.

[8] UKERC evidence to BEIS on flexibility explains further http://www.ukerc.ac.uk/news/ukerc-response-to-beis-ofgem-call-for-evidence-on-a-smart-flexible-energy-system-.html

[9] Analysis by the authors for CXC shows that wind in Scotland does make a material contribution to regional security of supply, including when accounting for spatial correlations. See the report here: http://www.climatexchange.org.uk/reducing-emissions/security-electricity-supply/

Electricity transmission and distribution

What are the longer-term challenges for electricity transmission and distribution?

Post electricity market liberalisation, demand growth has been moderate at best. However, with the 'dash for gas' (1990s) and the growth of renewables over the last decade, there have been significant changes to generation. This presents major challenges to network development, particularly when reinforcement delivery often takes longer than generation developments, and the identification of what is efficient – providing sufficient but not excessive levels of power transfer, whilst minimising stranded assets – is sensitive to the opening and closure of generation capacity. In our highly decentralised market structure with strict separation between generation and networks, the latter creates uncertainty for the network planner.

In recent years, the most striking development has been that of distributed generation (DG) – generation connected within distribution networks. To date, there have been strong incentives for generation developers to connect where there is spare network capacity. However, the definition of 'spare' is influenced by historic 'fit and forget' practices and, as DG continues to develop, 'spare' capacity will be exhausted. When this occurs, it will be necessary for distribution network owners (DNOs) to identify and deliver the most economic and efficient level of reinforcement.

Perhaps the biggest difference between upcoming and past price control periods is that demand for electricity is once again uncertain. Whilst the optimal path to deep decarbonisation of heat and transport is still unclear, at least some degree of electrification will occur. This will impact total electricity demand and the associated generation and network capacity. However, when and how quickly remains unclear.

A major challenge is that many of Britain's electricity network assets are near or beyond the age at which they were expected to be replaced. "Non-load related" capital expenditure (capex) by the network licensees during price control periods has been at a similar level to reinforcement, sometimes higher. Asset replacement planning is difficult and should take into account the condition of the asset, the impact of failure, the availability of finance and appropriate skills, required construction outages and the potential for serving both asset replacement and network reinforcement needs with a single investment.

What matters should the Government should take in account in considering the framework for network regulation, and its associated institutional framework?

Network licensee functions

The figure below depicts the delineation of network functions at the time of writing. Of particular note is that larger distributed generators can provide flexibility to the system operator (SO) at transmission level such that the SO can change their production of power. Because of this, the operability role is held by the SO across different voltage levels, whilst the network ownership role is held elsewhere. However, blurring of responsibilities can happen where a distribution connection is actively managed, meaning that the DNO has some control over output. Blurring also exists where large generators are connected to distribution networks and the generator needs to obtain transmission rights.

	TRANSMISSION	DISTRIBUTION	
SO	provide contracts to connectees	provide contracts to connectees	**DNO**
SO	specify need for new network infrastructure	specify need for new network infrastructure	**DNO**
TO	build and maintain connections to connectees	build and maintain connections to connectees	**DNO**
TO	build and maintain network infrastructure	build and maintain network infrastructure	**DNO**
TO	carry out switching to enable safe working	carry out switching to enable safe working	**DNO**
SO	decide and implement system control settings	decide and implement system control settings	**DNO**

Delineation of functional roles in a power system between System Operator (SO), Transmission Owner (TO) and Distribution Network Owner (DNO) under the current regulatory arrangements in Britain (Bell and Gill, 2018)

Competition in network functions

Although network capacity provision and services that enable network access and operation are regarded as monopolies, markets and competition are active in respect of some of the functions listed above. Parties applying for network connections can have the connection developed by someone other than the incumbent network licensee; licences for offshore transmission ownership are awarded competitively; many balancing services purchased by the SO are procured on a competitive basis; and network owners invite competitive tenders for new plant and maintenance work. An arrangement for major onshore transmission developments to be built and maintained and, to some extent, designed on a competitive basis has been proposed by Ofgem under the 'Competitively Awarded Transmission Ownership' (CATO). Some commentators, including Helm (2017), are now proposing something similar for distribution networks.

Substitutes for network assets and their procurement

The transmission network already considers alternatives to new primary assets, through enhanced control facilities or operational measures such as the purchase of balancing services to manage power flows or voltages. This has yet to be established as common practice among DNOs where a shift away from 'fit and forget' network development is occurring slowly. Moreover, as argued in Bell and Gill (2018), operational risks are often placed on the distributed energy resource (DER) owner with almost none on the DNO. This mainly arises because the services the DER provides, such as reducing power transfers at key times, are not paid for by the DNO.

Where balancing services are paid for by the network licensee, dependency on these opens up exposure to risks such as those of plant closure or price increases. Aside from simple system-level adequacy that is procured through the capacity market and one or two experimental distribution level schemes, we are not aware of any long-term contracting for such services that allow direct comparison with asset-based options for the medium to long-term. We believe this is something that should be considered in such a way that complements the capacity market. When capacity market offers are evaluated, it should take into account factors such as value in reducing network constraints, reactive power capability, ramping speed and flexibility, frequency deviation response times, contributions to short circuit power and the ability to support system restoration in the event of a blackout.

Interaction between transmission and distribution

DERs are becoming increasingly important, they have enormous potential and, when sited appropriately, can reduce the need for additional primary assets. However, they must be both observable and controllable – at present, the smallest DERs on the power system are neither actively monitored nor controlled.

The services that could be acquired from DER could have local or system wide purposes. Examples of the former include management of local or regional power flows and voltages; the latter includes contributions to frequency response and reserve. In an active network management (ANM) scheme, where it acts as a substitute for distribution network assets, the procurer and actuator is the DNO (even if the DNO pays nothing to the DER for reduction of network access). When providing response or reserve, the procurer and actuator is the transmission SO, giving rise to the potential for conflict between the DNO's and the SO's actions.

In order that the potential of DER can be realised, it will be necessary for a clear delineation of control. Controllers require full knowledge of the drivers for action, and associated constraints – at present, neither DNOs nor the SO have this knowledge. It could be envisaged that the SO has full visibility and control down to distribution voltages, leaving the DNO primarily as a provider and maintainer of network assets rather than an operator. This would provide structural simplicity and the potential for globally optimal actions. Alternatively the DNO could take complete responsibility for operational actions on DER connected to their network, consolidating actions into offerings for the SO to purchase in accordance with need at the transmission level. Advantages of this include avoidance of the major ICT roll out that would be required to enable full SO visibility. This option also facilitates innovation and the comparison of similar functions performed by different parties.

Functional separation: access to knowledge

The success of functional separation depends on access to knowledge. Separating network asset ownership from system operation could promote competition among asset providers, reducing the temptation for network licensees to game assets for gain. As already noted, this separation is currently in place in respect of transmission. It may therefore be asked why it would not also be sound for distribution. An SO would be required to make decisions regarding optimal asset and operational solutions, which requires detailed knowledge of both. However they lack knowledge of the network development options on the ground.

The CATO arrangements also have raised concerns among some industry parties that an extra stage of competition and contracting will introduce additional delays. It is also noted that the area in which a CATO could add most value – developing creative solutions to meet the power transfer need – is the one which is not currently regarded by prospective CATOs as attractive as it carries higher risks. Coordination between asset owner and system operator is still required, particularly in respect of coordination of maintenance. Incentives should ensure that asset owners maintain asset reliability, as required maintenance takes assets temporarily out of service. One of the biggest challenges faced by an SO is scheduling maintenance outages such that the system can still be operated at reasonable cost. That can lead to short-term decisions to deny maintenance outages with unknown long-term consequences and, at the very least, conflict between SO and asset owner[10]. The need for coordination in delivery of new assets and maintenance of existing ones entails at least some transaction cost. It may then be asked if such a cost is still justified all the way down to the lowest voltage parts of the network.

Incentives and risk

The profit motive is widely regarded as the main incentive to good performance. In respect of established networks, where industries that are exposed to little competition, this has been left to the regulator to assess what represents 'good' performance. For the most part, this seems to mean that performance is good enough – it meets licence conditions – and costs less than it would have done otherwise. Inevitably, questions arise as to how much lower the cost to consumers could have been.

In recent weeks, suspicions that network licensees have made excessive profits have been growing. This excess has been asserted by Helm as being due to the ability to make capex decisions, and poor cost judgements by the regulator. Part of the problem with the latter is that the future costs are uncertain: expected investments may not materialise, generation capacity may close unexpectedly, whilst material, equipment and human resource costs vary. In principle, income allowances in price controls could be adjusted to take account of changes to background conditions, though judgement is still required as to the size of the adjustment.

The transmission licensees have also started to use least regret analysis to deal with uncertainty in respect of "load-related" capex. Though a reasonable approach, it is sensitive to which scenarios are used. Moreover, we agree with the suggestion by Helm that Ofgem and its consultants have historically lacked the information or expertise to make good judgments on network licensees' capex plans. In part response to this but largely in order to reduce what they see as the opportunity for gaming, a number of commentators have proposed that capex decision making should be taken away from the asset owner and made the responsibility of a not-for-profit SO.

[10] This tension already arises not only between the GB SO and the transmission owners in Scotland but also between the SO and generators.

It should be recalled that a major part of capex relates to asset replacement; is an SO – whether national, regional or local – expected to make decisions on that? It must be assumed that the SO would be holder of the 'purse strings' for capex. Unlike state owned industries prior to the late 1980s, could be it be assumed to have access to the capital it needs free from political interference? Finally, what incentives will there be on an SO to discharge its duties as competently as possible?

What additional evidence should the Government consider to reduce the cost of electricity networks in the longer term?

Informing choices

Once an energy user has made a decision to use, for example, an electric vehicle (EV), further choices exist which impact system cost such as when to charge the EV and at what rate. In principle, cost reflective price signals can influence these choices. However they are only useful if an actor has some flexibility and can interpret signals that might vary significantly hour-by-hour.

Central contracting: acquiring rights; promising a service

Currently, larger generators are subject to price signals in respect of network connection location. In principle, this enables rational decision making, both on location and level of access in terms of maximum power injection. However at present, the signals on whether to connect at transmission or distribution voltage are inconsistent.

A looming problem is quantifying the level of electricity that will be required by users of electric heat and transport. As discussed above, there are choices that users can make. However a danger is that choices in favour of, for example, unconstrained fast charging will introduce adverse impacts for other users, such as tripping of feeders or increased total network costs. Instead, different prices for different levels of network access could enable choice, with users opting for less constrained access or choosing to pay less. In respect of the latter, the hope would be that 'reasonable' use of the network would not be seen as second class or punitive.

These access level payments could entail an annual subscription to the services provided by the network. In principle and if network constraints at different voltage levels and the effects of diversity of use can be understood, this should provide reasonable signals for network development. At the highest system level, it can also contribute to quantification of the need for future generation capacity and inform purchasing in the capacity market.

The current capacity market and a clear quantification of access rights for demand side network users represent forms of central contracting that could bring benefits in terms of improved certainty of future need for the network.

Supply

What matters should the government take into account in considering the longer-term operation of the retail market?

The main perceived difficulty with the retail market is not directly its costs but on the demand side. Because most consumers are not taking advantage of the best deals available, they are charged very different prices.

The UKERC project on Equity and Justice in Energy markets focuses on the distinction between widespread equality of opportunity, or access to the best deals; and outcomes which vary because of differences in consumer response, and are often very variable. While price differences are a fundamental driver of competitive markets, this is not seen as acceptable in the energy sector because of its political salience.

There is particular concern about those who 'cannot' switch for various reasons, including cognitive or circumstantial limits, but also a general feeling of 'unfairness' that those who are active get a better deal than those who are loyal to their own supplier. The lack of consumer response also has implications for the supply side because it reduces the rewards available to companies from innovation and efficiency, which are otherwise driven by the need to attract customers.

The discrepancy between the prices available to 'switchers' and those who do not shop around is a result of marketing strategies on the part of the retailers to attract customers with a 'bargain offer', in the hope that they will stay with the new supplier when the bargain expires. This is a common practice, particularly in financial markets, but is more apparent in the energy market because it is clear that the same product is sold at different prices to different consumers. The energy market has developed with a small number of active consumers switching repeatedly to take advantage of good bargains. The remaining majority switch only occasionally or very rarely, and therefore pay higher prices in the medium or long run. Vulnerable consumers, due to financial circumstances and other reasons, are more likely to be paying the more expensive tariffs, with rising energy prices putting further pressure on stagnant household incomes.

Consumers remain disengaged from the energy market despite many initiatives to involve them. On the supply side, the two tier market benefits suppliers who have a large inherited base of consumers who have not switched in the past, as they can compete with new entrants using the profitability of their core customers. Linking the prices charged by a firm to 'loyal' and 'new' customers would be anti-competitive in a way similar to that of the regional non-discrimination clauses for firms with long established customer bases: it will be more profitable for firms to withdraw the cheap offers and 'retreat' to the large loyal and profitable consumer base. However the many new firms competing in the market, who do not have such a base, may still be able to make attractive offers to those who are prepared to switch. A better relative price cap would link the maximum price allowed by one firm to the prices offered by all the other firms in the market.

An absolute price cap would also raise the lowest prices, since the profitability of low introductory offers is reduced by the lower prospective profits at the end of the offer. Market and research evidence shows that the main driver of switching for those who are active, is the potential savings available, so these consumers are less likely to engage in the market if intervention reduces such savings. To this extent, any price cap will have a detrimental effect on the competitive process, though it will improve outcomes for disengaged consumers, at least in the short run.

The Cost of Energy Review recommends that each supplier be required to offer a default tariff based on the different elements of supply cost (presumably calculated on a common average basis across suppliers) and to which retailers would then add a supply margin. To find the best deal, consumers would only have to compare the supply margins offered by different firms. However given the evidence on consumer inertia in this market, it seems unlikely that such information will generate much additional activity. There would still be choices between different tariff structures, payment methods and types which might deter engagement. Research shows that consumers may also have a preference for their current supplier and that the act of switching is itself costly in terms of time and attention. And while smart meters may help in some ways, they may exacerbate the situation if they provide more choices and information to consumers without the means to translate this into meaningful comparisons between suppliers.

One alternative which does exert some pressure on suppliers by working with the market, is the opt out collective switching auction, when companies are invited to offer tariffs to a group of consumers who will be changed to the winning supplier (cheapest tariff) unless they opt out. Since such an arrangement would almost certainly require legislation, it would be a medium to long term solution to capture the benefit of market forces while delivering good outcomes to the market, including to disengaged consumers.

It seems unlikely that the demand side can be stimulated sufficiently to provide outcomes which are regarded as fair and to discipline the cost side. To achieve these outcomes, regulation may be required, despite its drawbacks in terms of information and innovation.

Cross-cutting issues

Policy simplification

The Review discusses complexity and the number of policy interventions in section 4, arguing that 'in practice, the complexity and inconsistency of current interventions … is a major source of inefficiency and has created excessive costs' (Helm, 2017: 35). Whilst the Review offers a theoretical argument to support this statement, it does not offer empirical evidence to substantiate this claim.

As the Review also argues, there is nothing inherently problematic about having multiple policies and interventions. This is particularly the case in a policy domain such as energy, where government needs to meet (and sometimes balance between) multiple policy objectives. There is certainly scope to make improvements in the policy portfolio, ensuring that objectives are met whilst minimising costs.

The Review does not cite specific evidence to support the changes in policy that are proposed. Arguments are provided from 'first principles', but empirical evidence is largely missing. It could have drawn on the extensive literature on 'policy mixes', which aims to understand interactions between multiple policies and inform better decision making. This literature tends to focus on three features: strategic policy goals; interactions between individual policy instruments; and the need for a dynamic perspective to account for policy change (e.g. Rogge and Reichardt, 2016). All three of these features are directly applicable to the UK electricity market. Also of relevance is Rogge and Reichardt's conclusion that a systems approach to policy mixes is required. This perspective emphasises strategies that provide long term direction (e.g. towards meeting climate change targets), policy processes to influence innovation in the right direction, and characteristics such as policy stability.

Innovation

The terms of reference includes a request to 'consider how technological change in the wider economy, as well as in the energy sector, may transform the power sector, and how energy policy can best facilitate and encourage such developments'. In response, the Review identifies innovation as a key driver of change, and a crucial component of efforts to meet climate change and other policy objectives. It is right to argue that the assumptions that underpinned 20th century electricity systems are being challenged by this innovation. This includes advances in electricity storage, the increasing scope for a more active demand side and the shift towards zero marginal cost sources of electricity generation.

However, the Review loses its way when it comes to what government should do to support further innovation. It fails to take into account the extensive evidence base on how current and past policies have already delivered results (e.g. Grubler et al, 2012; Mazzucato and Semieniuk, 2017; Watson et al, 2015).

Of particular concern is the call for government to avoid setting priorities for energy innovation. Whilst the Review is correct to emphasise uncertainty about the future, this does not mean that government should avoid specific innovation policies. The Review couches its conclusions in terms of the rather tired debate about 'picking winners'. This debate sets up an unnecessary false dichotomy between governments and markets, rather than seeking to understand the relationship between them. As the Review notes in passing, specific technology deployment policies such as feed in tariffs and auctions have provided strong incentives for innovation – and have helped to bring down the costs of some renewable technologies in recent years.

Governments do not always get it right, but experience shows that they have a crucial role to play in supporting innovation at multiple stages: from R&D in laboratories, through demonstrations and trials, to early deployment. Therefore, the key question to answer is not whether government should get involved. Instead, important public policy questions should include: what combination of policy instruments should be used and when?; where can competition have the most impact on cost reductions?; and how can evidence and evaluations of successes and failures inform better decision-making?

With respect to technology deployment, policies such as feed-in tariffs, renewables portfolio standards, auctions and mandates have all helped to develop the market for technologies such as solar PV, onshore and offshore wind and electricity storage. These cost reductions are a product of 'learning by doing' due to cumulative deployment as well as scaling up of manufacturing. UKERC research has explored these drivers in detail, including through a review of cost reduction estimation methods that focused on six electricity technologies (Gross et al, 2013).

Some of these cost reductions have been driven globally. Policy incentives for deployment in a large number of countries have created a global market, with benefits for UK consumers. Examples include solar PV and onshore wind. Others have been substantially driven by UK policy. A particularly good example is offshore wind, where the UK is leading global deployment and has achieved surprisingly low prices in the most recent CfD auction. The case of offshore wind in particular shows the value of patient government support, which may be needed for over a decade before significant cost reductions are achieved.

Such cost reductions are not universal. Significant questions remain about how to bring down costs of large-scale nuclear power technology – a technology that has been consistently characterised by rising costs over time. Carbon capture and storage (CCS) technologies have also failed so far to deliver on industry promises of lower costs – though that may be a product of impatient and inconsistent policy rather than a lack of potential for cost reductions in the medium term.

Given this experience, it is not clear why the Review concludes that 'the future energy policy regime and regulation can therefore look forward to the phasing-out of FiTs and low-carbon CfDs' (Helm, 2017: 66). We draw the opposite conclusion - that such policy instruments work and should continue to play a role in driving innovation and cost reductions. As we have argued in the previous section on generation, it makes sense to build on the existing set of policy instruments rather than moving to a single auction that combines the CfD system with the capacity market.

Some reforms to the current framework are needed given the changes that have occurred since it was implemented. Recent experience from many countries including the UK, Mexico, Germany and the Netherlands have clearly demonstrated how competitive auctions can drive down the costs of renewable electricity technologies. For the UK, this means that there is a stronger case for moving as many low carbon technologies as possible into a single CfD auction over time – including energy efficiency measures, which could be deliverable at a lower cost than low carbon supply technologies.

There are limits to such a technology neutral approach, due to the differences between the low carbon options that this policy framework is designed to support. It is well understood that purely technology-neutral policies only bring forward those technologies that are closest to market, and fail to develop those which are currently less competitive but which may be required for deeper decarbonisation, or which may have the greatest long-term potential. The cost reductions now being experienced by offshore wind would not have happened without other forms of policy support. As the Review notes, more specific arrangements are also likely to be needed for technologies that are complex, capital intensive and characterised by high financial risks (we discuss this in more detail in Annex 1 to this response). A strong case has been made by the Oxburgh report on CCS that these technologies require a more state-led approach to investment that still leaves significant room for competition to minimise costs.

As we have also discussed in the generation section, 'subsidy-free' contracts for difference are worth further consideration, given the magnitude of cost reductions in recent years. There is an important debate about what 'subsidy-free' could mean in practice, and how such contracts would differ from fixed-price power purchase agreements. Further investigation is needed to assess whether this approach could undermine the ultimate aspirations for technology neutral auctions where contracts are simply awarded to the lowest price bidders.

As the Review notes, it is not sufficient to deploy near market technologies if carbon targets are to be met. A systems approach to innovation is required that also includes more fundamental research and development (R&D) on newer technologies, and targeted support for demonstrating, trialling and scaling up these technologies (Watson, Kern and Wang, 2015). Policy makers have recognised for many years that innovation is not a linear process, and that there are important feedbacks between the different stages of technology development – and the policies that support innovation.

A recent UKERC systematic review showed that innovation in the energy sector tends to take a long time. The timescales from early stage R&D to significant commercial deployment typically take 3 – 4 decades for energy sector technologies (Hanna et al, 2015). The review provides some evidence that some consumer or demand-side products may have shorter timescales because they diffuse more rapidly.

Along with many other countries, the UK has signed up to the Mission Innovation initiative, and has pledged to double energy R&D spending between 2015 and 2020. UK energy R&D

spending levels have already recovered from the lows seen in the 1990s, and the portfolio of technologies supported is more diverse. However, it is often argued that the amount of public spending by the UK and other countries is still much too low when compared to the scale of the challenged posed by climate change. Furthermore, the effectiveness of R&D depends heavily on how money is spent whether such R&D spending is complemented by incentives for demonstration and market creation. R&D spending alone will not deliver the innovation that is required to meet policy goals.

The recent announcement of further investments in the 'supply side' of innovation through the Faraday Challenge for energy storage and energy systems demonstrations is welcome. However, the recent Industrial Strategy did not demonstrate how such initiatives reflect the evidence base on UK innovation needs. Significant analysis has already been carried out by government to establish this evidence base – for example by the Low Carbon Innovation Co-ordinating Group, the Research Councils UK Energy Strategy Fellowship and by Innovate UK. This evidence base suggests a number of important criteria that should inform policy priorities, including:

- the potential UK and global market for different low carbon technologies;
- the potential for cost reductions, including the effect of UK policy on such cost reductions;
- the potential value to the UK-based components of supply chains; and
- the extent of existing scientific and industrial capabilities.

One drawback of this evidence base it that it tends to focus on discrete technologies, and pays less attention to the system innovations that are also required (e.g. for smarter electricity grids and low carbon heating systems). Such system innovation will be a key feature of successful low carbon transitions (Watson, Kern and Wang, 2015). Many demonstrations of system innovations have been carried out, supported by government and industry. However, there has been a lack of systematic evaluation of these demonstrations to learn and share lessons. In some cases, risk aversion has limited the amount of experimentation and innovation that has been possible (e.g. Frame et al, 2016).

Use of modelling

The Review correctly argues that there was a belief a few years ago that high fossil fuel prices were here to stay. In hindsight, this provided a poor basis for evaluating the costs and benefits of policies that were introduced as the assumption proved to be wrong.

However, the Review fails to acknowledge the way in which government takes into account inherent uncertainties about future fossil fuel prices. It makes a fundamental error in treating the BEIS fossil fuel price assumptions[11] as forecasts (Helm, 2017: 41). They are *not* forecasts:

[11] Professor Jim Watson, the main author of this section, is a member of the BEIS fossil fuel price assumptions expert panel.

they are developed to provide a plausible, wide range of price scenarios that can be used in assessments of the potential costs and benefits of such policies. BEIS states this very clearly in the introduction to the 2017 fossil fuel price assumptions:

BEIS produces a set of price assumptions based on available evidence around these fundamentals and their potential development over time so as to yield a plausible range for future prices. These assumptions are required for long-term modelling of the UK energy system and economic appraisal. They are not forecasts of future energy prices (BEIS, 2017).

There is an important debate to be had about how to develop fossil fuel price scenarios. However, the review doesn't discuss the methodology currently used by BEIS or suggest any alternatives. Instead it simply states that the most recent set of assumptions 'do not factor in falling fossil fuel prices through to 2030 and beyond', and that 'there are good qualitative reasons for assuming that this is a world of falling oil, gas and coal prices'.

There are two significant problems with this critique. First, it does not acknowledge that the lower bound of BEIS price assumptions (particularly the 'stress test' level for oil prices) include prices that are similar to current levels – or lower. Second, and more important, it appears to take the opposite position to the one that was widely held (including in government) a few years ago. By doing this, it also risks providing false certainty. In our view, the important lesson of the recent past is to ensure that any claims of policy costs and benefits are sufficiently stress tested against a wide range of future prices.

Finally on this issue, it is unclear why the Review argues that the government does not need to undertake any forecasting or modelling if it 'gets out of' many detailed policies. Energy systems modelling and the development and use of long term price scenarios are important tools for policy making utilised by governments and international bodies. As the Review implies, experience shows that forecasting has limited value. But the use of models and scenarios can help governments to understand the range of potential costs and benefits; to identify where critical risks to achieving policy objectives might lie; and to ask 'what if' questions about the impact of future changes. Even if the government were to respond to the Review by implementing a universal carbon price to meet carbon targets, energy system modelling and a range of fossil fuel price assumptions would still be required. This would enable government to understand the impacts of a carbon price and to inform decisions about its level and trajectory over time.

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Annex 1: Supplementary Note on Split Auctions for Power Generation

Helm suggests that energy consumers are funding excess returns to construction phase investors in power generation projects under mechanisms such as the CfD. The suggested solution is splitting the award of support by the use of separate auctions for the construction and operating phases of a project. The problem is real, but misunderstood, and the proposed solution will not be effective.

Nothing in basic finance theory suggests that an operating cash flow in the future should be discounted at a different rate before and after construction, other things being equal. Excessive returns may appear to come from investors applying a higher hurdle rate to all cash flows pre-construction, and indeed that is what they do in practice, however they are solely a function of perceived risk and supply of capital in the construction phase.

Helm is right that refinancing gains post-construction have been large. It is likely that some combination of the lack of a competitive process for awarding support, the use of out-of-date information by governments to set support levels, and gaming by industry are key reasons for this. The impact of such factors has been amplified by the falling costs of renewable energy technologies, meaning that administrative prices have lagged the actual projects costs.

For technologies such as wind and solar which are now well-established and where there is a sufficient and competitive supply of capital for the construction phase, the introduction of competitive auctions has meant that excess pre-construction returns have been competed away. It is clear that developers are bidding auction prices based on their estimates of future technology costs (15MW offshore wind turbines for instance), rather than responding to administrative prices set based on old technology. For such technologies, excessive returns is a problem of the past which the existing arrangements for competitive award have solved, and hence there is no case for change.

For technologies such as nuclear and CCS there is a clear shortage of construction capital, whatever the solution for allocating support. Better solutions to deal with this issue exist, including the government increasing the supply of capital by investing itself in the construction phase, or by contracting to assume specific risks which have the potential to be mispriced by construction phase investors. Such solutions would be consistent with how the government finances other large infrastructure such as high-speed rail; Crossrail; Thames Tideway; and would be consistent with the recommendations of the NAO in respect of the Hinckley Point C project[12] and the Oxburgh report on CCS[13].

It is important to recognise the role of states in financing the construction of complex, large-scale energy infrastructure, due to the persistent scarcity of private sector capital. Hinckley

[12] https://www.nao.org.uk/report/hinkley-point-c/

[13] https://publications.parliament.uk/pa/cm201617/cmselect/cmenergy/497/497.pdf

Point C is financed entirely by majority state-owned enterprises; offshore wind, while highly competitive now, is a market dominated by majority state-owned enterprises as well has having benefited from an injection of EU and UK state capital in the form of the EIB and Green Investment Bank financing.

In short, the theoretical basis for the move to split auctions is weak; for some technologies it is a solution to a problem of the past; and for other more complex technologies it fails to address the core problem of scarcity of private capital and associated excessive pricing of risk for the construction phase.

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