Written evidence submitted by the Institution of Engineering and Technology (IET) / Energy Systems Catapult (ESC) to the National Infrastructure Commission's Call for Evidence on Energy

Introduction

The IET is one of the world's leading professional bodies for the engineering and technology community and, as a charity, is technically informed but independent. This submission has been prepared on behalf of the Board of Trustees by the IET's Energy Policy Panel and takes into account input received from the wider membership, and the views of the Energy Systems Catapult.

The Energy Systems Catapult works with companies that are focused on exploiting the opportunities created by the need to transform global energy systems; not only playing a part in accelerating technology based solutions, but also engaging with Government to address the market mechanisms and business models that will be required to enable such solutions.

The IET and Energy System Catapult are working together to deliver the Future Power Systems Architecture (FPSA) project[1] which follows from the issues raised by the IET the document 'Handling a Shock to the System[2]. The FPSA project is referenced a number of times within this submission.

Summary of views on set up of National Infrastructure Commission

There is no natural market for electricity, or even wider for energy, the "market" is a creation of successive governments, and market mechanisms are used to deliver policy objectives. Investors in both supply and demand side therefore need clarity on long term policy aims, whilst recognising that technological and other change might require policy to be adjusted. The greatest potential benefit from the National Infrastructure Commission (NIC) would be to give a clear sense of direction to energy investors. Investors will generally be understanding of changes resulting from external circumstances such as new technologies, provided they are signalled appropriately, but find change arising from political decisions difficult to assimilate. Such change is seen as introducing arbitrary risk into investment decisions, which is very difficult to price.

Electricity is unlike other infrastructure in that a market is used to make strategic decisions. We do not expect a market to decide where we need a new road. That is something government decides and then we use competition to build (and on occasion finance and operate) that road efficiently.

For the NIC to have a beneficial impact on investment decisions in electricity infrastructure it must develop a track record for three things: **Expertise, Consistency, and Impact**. Without these the NIC will simply add another layer of uncertainty to the electricity infrastructure landscape.

Expertise: Energy issues are complex and interrelated. Electricity, heat, transport, supply and demand have complex relationships which are often poorly understood and caricatured in public debate. For the NIC to gain investor confidence it must somehow develop its own expertise, ideally by consensual working with DECC and industry. It would be badly served if it relies on a series of one off consultant reports into binary issues. A body of expertise is

[1] DECC Future Power System Architecture Project (FPSA)
[2] Handling a Shock to the System, the IET

being created within the Energy Systems Catapult (ESC), and it may be beneficial for NIC to work with and develop the ESC as its expert reference.

Consistency: The proposed five yearly reporting cycles for the NIC would be inappropriate for energy investors. Five years is a long time in energy and the inevitable jeopardy of a major course correction every five years would paralyse investment in some parts of the industry. We strongly advise that the NIC and DECC produce a rolling annual forward view of the expected / desired electricity mix covering near, medium and long term. The long term view would change gradually and be well signalled. The nearer term would be consistent from year to year with only minor changes. This would provide some currently missing confidence to investors.

Impact: If the NIC achieves both the above, ideally with a high degree of industry consensus, then it will make it more likely that future governments will act in line with its recommendations. Over time this will give confidence that the political risk to UK energy investment is low, resulting in lower cost of capital and hence lower consumer bills, and more investment in Britain's energy systems.

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?

Ensuring flexibility services can be acknowledged and rewarded

In a normal market, price signals and high profit margins usually trigger new entrants and new investments however the long term nature of electricity investments and the inevitable political issues involved often makes this difficult. The requirements of the market are also changing given the rise of renewable energy sources, the potential electrification of much of transport and heating, and the transformation of energy usage, storage and production within consumer premises. This requires a much more flexible approach to production, storage and consumption than has been the case up to now, and the electricity market should be developed so that flexibility services can be acknowledged and rewarded. One way of avoiding larger peak electricity demand as heating and transport becomes increasingly reliant on electricity is to create ways in which the demand side can use its natural storage properties (e.g. thermal inertia, or specific energy storage say in vehicle batteries) to allow consumption to be scheduled to some degree to match the capacities of the electricity system. However, creating this capability has many technical and institutional challenges to solve.

A range of commercial and regulatory mechanisms will need to be further developed so storage and other innovative solutions are incentivised to offer products and services to the System Operator (SO) to balance the system. There is a significant volume of work looking at these issues; the following sources of information likely represent the definitive state of the art knowledge:

- Smart Grid Forum Work Streams (WS) 3, 6 and 7, particularly 6. The latest WS6 report addresses changes needed to the market framework to implement Demand Side Response (DSR) into the GB market.
- The IET's and Energy System Catapult's – Future Power System Architecture (FPSA) Project. This project is testing the IET's proposition that the current approach to planning and operating the power system in Great Britain may not be robust to the challenges it will have to meet. The project is carrying out this test by examining the fundamental functions that will be required to plan and operate the power system in response to new user needs.

- <u>What role can changes to the market framework play to incentivise this outcome:</u>

Wide adoption of time of use tariffs that incentivise generation at times of plant shortage and consumption at times of generation surplus

One significant issue with the current market is that the vast majority of demand consumers and small generators have a flat rate tariff and hence have no incentive to schedule their consumption / production to minimise the overall cost of the power system. This could be addressed by the wide adoption of time-of use-tariffs, say half-hourly, that incentivised generation at times of plant shortage and consumption at times of plant surplus. The national roll-out of smart meters is timely to support such a development. The extension of half-hourly settlement to all current profile classes is a prerequisite to Suppliers developing time-of-use tariffs.

The limitations of primary legislation

The electricity sector is governed by the 1989 Electricity Act – which has been amended a few times, although not fundamentally. The fundamental tenets of the Act are to secure reliable supplies of electricity to consumers, to protect consumers and the public from the physical dangers of electricity and to protect the commercial interests of consumers. It does this partially through a licensing regime. Although not explicitly stated, the defacto design assumptions for the Act and its licensing regime reflect the power system of the 1980s with a relatively small number of very large generators connected to the transmission system supplying the vast majority of the energy to passive consumers, with the only formal contact between small consumers and the industry being through suppliers, i.e. the energy retailers. The Act is absent of any notion of generation being local or consumers being active, and such generation or responsive demand trading locally. The assumptions in the Act drive the shape of the market and the licence obligations. Although licensing thresholds etc are in secondary legislation, and therefore in theory more easily changed, it is not immediately clear if this could be a sufficient remedy.

An effective and vigorous market at a local and national level seems to be desirable by current common consent, with local players, generators, communities etc, able to buy and sell power and energy to solve local constraints on networks as well as participating in national energy balancing needs. The technology in terms of small generation equipment, smart domestic appliances, and the very likely near term evolution of affordable storage all point to a very different and much more dynamic arrangement than was envisaged at privatisation in 1989. Additionally, increased competition across the power industry may well be desirable and the opportunities and challenges should be considered. It is not clear if the basic assumptions of the 1989 Act are capable of allowing appropriate growth in local energy services, and a thorough review should be undertaken of the Act and its associated licensing regime. The objectives of the Act are still, of course, completely valid but the way they are enacted risks stifling sensible innovation and development in the sector.

o <u>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?</u>

Effective system operation and engineering integrity should be key to any governance model of the electricity system

The future electricity system is likely to be very different to today if we continue with current trajectories around decarbonisation, smart homes, smart grids and smart cities, and the greater participation of individual citizens and real and virtual communities of interests in the energy economy.[3] Whilst some aspects of this change will make tasks such as system balancing more demanding than currently, the change will also open many new opportunities to balance the system using resources not currently available, and potentially at lower cost. The Future Power System Architecture Project being undertaken by the IET and the Energy Systems Catapult for DECC currently is exploring the functionality required of the future electricity system, and the engineering implications of that functionality.[4]

It is important that whatever governance models are adopted to accommodate the future electricity system that there is facilitation of effective system operation and assurance of engineering integrity. This will help maximise the opportunities for innovation, by and for consumers, will help maintain system integrity and resilience, and will help minimise balancing costs.

There are both some advantages and disadvantages of moving to a true Independent System Operator (ISO) model and there are a number of options for how an ISO could be implemented. Broadly, the advantages relate to removing any potential for conflicts of interest for the System Operator. On the other hand, the disadvantages derive from separating asset risks and system risks/costs into different organisations, making it harder to balance the two effectively.

We understand that DECC is currently taking a whole system perspective when considering a possible ISO and very much encourage this approach, which is aligned with the IET and Energy System Catapult's thinking on whole system issues from an engineering perspective.

Provided an institutional and market environment is developed that delivers these outcomes we have a neutral view on its form, the extent to which government is or is not involved, and how the industry is organised to perform the roles required of it. However, delivery of these outcomes requires significant understanding of the underlying engineering of the whole system. We would be pleased to assist government in coming to this understanding, and would encourage government to work closely with the industry as well.

Further evaluation is required in order to determine whether a true ISO would be beneficial and if so, which specific approach should be pursued. This evaluation should include building an understanding of why the current SO incentive regime is an insufficient tool in the long term, recognising that Ofgem has the capability to modify it to achieve new objectives as they emerge.

- Is there a need to further reform the "balancing market" and which market participants are responsible for imbalances?

Adoption of time of use tariffs and consideration of severe imbalance prices is needed

There is a need for time-of use-tariffs to provide small players with an incentive to contribute to keeping demand and generation in balance. The vast majority of demand

[3] If these trajectories are not followed, and we follow a path of building more large dispatchable power stations, move away from smartness of electricity end use and local energy solutions, and move away from electrification of transport and heat, the future electricity system will change much less. In this case the arguments for change in how the system is operated soften considerably. Such a system could conceivably decarbonise electricity (with nuclear, gas or even coal with CCS and some renewable generation), but would require non-electrical low carbon solutions for heat and transport.

[4] DECC Future Power System Architecture Project (FPSA))

consumers and small generators have a flat rate tariff and hence have no incentive to schedule their consumption / production to minimise the overall cost of the power system. This could be addressed by the wide adoption of time-of use-tariffs that incentivised generation at times of plant shortage and consumption at times of plant surplus. While the smart meter roll-out could be a valuable facilitator here, suitable settlement systems would also have to be implemented. An alternative is that consumers are offered a lower cost flat-rate tariff in return for allowing a Supplier to exercise control over some of the consumer's appliances.

At present the balancing mechanism provides an incentive to contract ahead for expected consumption / production and then to deliver that contracted position. Given that the suppliers currently have few ways of influencing the outcome post-gate closure (and the metering system currently could not record it if they did) there is not a strong case for making imbalance prices more severe. Indeed, if System Buy Price was seen to be more of a risk than System Sell Price (or vice versa) the balancing mechanism would incentivise market participants to go long (or short) and tend to drive up overall system costs.

- <u>To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?</u>

The flexibility potential of demand side management measures and embedded generation is large however to leverage optimal flexibility from such sources, an in-depth understanding into their different characteristics will be required.

Both can provide considerable flexibility in operating the electricity system, both at distribution and transmission level providing they are fully understood, modelled and co-ordinated across the industry. The important factor is the ability to control the generation/demand in an acceptable way. If the generation concerned is a "flow" renewable (i.e. one relying on instantaneous availability of the input energy resource, such as wind, solar or run of river hydro), or nuclear (where there tend to be more costs than savings when output is varied) then it should only be used for balancing when all other options have been explored. Gas fired generation could provide flexibility provided that it was given the correct financial incentives and did not have its flexibility constrained by other factors – e.g. the need to deliver process heat in a combined heat and power scheme[5]. Turning to the demand side, consumers must either have another way of delivering the energy (e.g. dual fuel heating) or storage to allow the demand to be time shifted (charging an EV, hot water tank or thermal store for space heating). There is no incentive for a consumer to engage if they are on a flat rate tariff.

Smart technologies, communication networks, smart appliances and smart meters are key enablers to integrate these types of resources into the electricity system. Many projects and demonstrations have taken place in GB in recent years to prove their ability to provide flexibility; technically both approaches are possible and the evidence is growing that they can make a notable contribution to efficient running of the electricity[6]. We may see market entry from new suppliers in this area, with completely fresh ideas, which may be disruptive. Community energy, smart city developments, and the internet of things are potential catalysts here.

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[5] The same would not be necessarily true for a community heating application, where heat could be produced and stored for later use

[6] Smart Grid Forum Work Stream 7 - DS2030

We would suggest the commercial and regulatory aspects are examined with view to aligning them with these emerging changes. They are perceived to be the main barriers at present. Ofgem's consultation and review of non-traditional business models (NTBMs)[3] will hopefully begin to explore changes to market structures to enable new market entrants to develop new products and services utilising demand side resources and distributed generation.

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?

Electricity and other forms of energy storage can play a range of roles in the electricity and wider energy system. This variety of roles is not always well understood outside the industry, and includes:

- The recognised role of storing energy when it is plentiful, and releasing it when it is scarce, over daily or longer cycles.
- Managing the load in a power network, by reducing peak current flows and hence avoiding the need to reinforce distribution systems, typically over a daily cycle, or by providing sufficient reserve capacity to enable supplies to be maintained in the event of an unplanned network outage.
- Providing a fault ride-through capability or covering a short term loss of generation – which tends to be a short term occasional requirement.

The current retail price of electricity is too crude a mechanism to incentivise storage. Not only does it fail to vary as system marginal prices vary, it also rolls up the fixed costs of the power station and transmission/distribution costs into a single kWh charge. This leads to many anomalies such as a small consumer with gas generation having an incentive to run it when there is renewable generation being constrained off in the balancing mechanism. Rather than focussing on how these issues play out for storage, it would make more sense to attempt to make the whole charging structure more cost reflective, whilst recognising issues of social equity.

A model for storage may be to mimic that of an interconnector, whereby a regulated entity owns and operates the facility under a regulatory mechanism (with performance incentives or a cap and collar mechanism) while 3rd parties and other market parties 'pay' for the capacity and use it for commercial purposes, such as energy arbitrage, balancing, frequency response, network support, etc.

High initial capital cost and an insufficient understanding of the impacts and value of storage to other parties

The high initial capital cost of designing, installing and operating a large scale storage system is a deterrent to potential investors. Furthermore, a reasonably high usage factor is required so that the fixed costs of the installation can be recovered while containing the cost per unit of energy delivered. To make such an investment, investors would typically need some certainty around revenue streams. In the eyes of the market, there are many competing technologies (DSR, interconnectors and new gas or diesel fired power plants), so the risk for any storage owner would be that of having a stranded asset. Other challenges for storage are:

- Insufficient understanding of the value streams a storage asset can capture and how they may be stacked to make a facility economic (especially when some of those revenue streams are regulated and some commercial).
- The benefits of a storage asset often accrue to many stakeholders, the market and regulatory structures currently do not reflect this, however work is underway to understand how they could be.
- A storage asset can act as generation or demand, potentially in aggregation or acting at a specific network point. This cuts across many regulatory frameworks and further consideration should be given to how storage is classified and how its value can me monetised.
- No clear way to value the flexibility storage offers to balance variable renewable generation to maximise low carbon usage on the system.
- The risk of a storage technology being supplanted quite quickly by a future storage technology with lower operating costs (eg through better round trip efficiencies).

- <u>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.)</u>

All three scales of storage have potential; storage has a diverse portfolio of applications for different sections of the electricity network. Storage technologies are developing in a way that suits particular applications. For large scale there are Pumped Storage, Compressed Air Energy Storage (CAES), Liquid Air and flow batteries, for distribution Lithium-ion and a range of other novel battery chemistries while at domestic scale the majority of products centre around Lithium-ion or the storage of heat. Typically for transmission-scale, storage would need to be of the order of 100MW+ and given the barrier mentioned above this is a significant challenge. Storage at this scale is significant infrastructure, tending to require bespoke planning and financing solutions.

Many network applications to date around the work have been in the 10-50MW scale and this is ideally suited to distribution system applications, but also as an aggregated distribution network connected source of frequency response for the System Operator. To date this appears to be the ‘sweet spot’ for early larger scale storage applications. The main driver for distribution network deployment is capacity enhancement and investment deferral. It is also deployed in conjunction with solar PV farms, as a means of managing network-related export constraints without curtailing production, and extending the export window beyond sunset when the market price might be more attractive. The economic case is very network specific and often it loses out to conventional reinforcement, DSR or smart commercial arrangements which curtail renewable output. There are other options at this scale, for example integrating community heat and power schemes so that heat is produced and stored when power is not needed, and the schemes switched to power production at times of high demand. Schemes such as this require systems thinking across energy vectors, but the incremental costs of the additional flexibility will be low.

At the domestic scale there are products available from Moixa, Tesla and Sharp to name a few. At present the economics at domestic scale are challenging, even for PV owners, although with reasonable reductions in cost as manufacturers gain scale such investment could become economic even on current Economy 7 tariffs. Further deployment at this scale at current costs would largely require a significant spread on time of use tariffs and/or the ability for homeowners to receive additional revenues from offering the asset to aggregators for balancing services. The system impacts could be large – a 5% market penetration of the

Tesla Powerwall product could roughly equal the capability provided currently by the Dinorwig pumped storage scheme in Wales.

It is worth commenting on the particular case of storing energy in an electric vehicle. This offers a greater pay back to the owner who avoid the purchase of heavily taxed petrol or diesel and prevents the associated GHG emissions. Whilst the energy is never returned to the electricity system, it does offer considerable flexibility regarding when the energy is supplied. For example, charging electric vehicles (and heating hot water tanks) could be a way of boosting electricity consumption at times when renewable generation would otherwise need to be constrained off due to a shortage of demand, albeit consideration would need to be given to any local network constraints. The benefits that can be realised require further study and analysis. It could be value to consider the returns that could be achieved from commercial fleets for example.

All three scales of application offer value to the electricity system and we would suggest barriers are looked at in each case and removed where possible to allow storage to compete with and complement other technologies. Ultimately, the trade-off between the economies of scale for large scale storage and the network benefits and cost reductions through mass manufacture of small scale storage are likely to dictate the outcome.

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

- <u>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?</u>

Creation of a single European market for electricity using interconnectors creates opportunities to reduce costs to consumers by optimising the use of generation across time zones, weather systems, and geographic boundaries. It does however mean one needs to trust counterparties in other countries to meet their contractual obligations at times of system stress, if supply shortfalls are to be avoided.

The extent of interconnection desirability depends on the access to the new capacity it provides. Simply increasing the capacity connecting two generation-constrained power systems is probably unhelpful, whereas a diversity of interconnectors accessing a diverse range of generation sources could be in consumers’ interest, if provided at reasonable cost.

A further opportunity through interconnection could be large-scale access to renewable energy sources from places like North or West Africa. Such sources have the potential, if developed, to export vast amounts of power to European countries, and could require interconnectors crossing Europe of vastly greater capacity than today. In principle this could assist UK decarbonisation and provide consumers with more cost-effective supplies. However there would be clear geopolitical risks to consider if relying to a meaningful extent on power from African renewables.

An interconnector affects two system operators simultaneously. Hence, a change requires the agreement of two controlling minds. In reality, this could be achieved by allowing/encouraging SO-SO trading post gate closure. However, other market players may not be comfortable with this limitation.

Conversely, interconnector users can (and do) schedule the interconnector to ramp as rapidly as possible to exploit small price changes between the markets. This can cause problems to the SO as the relatively smooth trajectory of changing demand is distorted for a few minutes by the rapid ramping of the interconnector. This causes costs in the balancing mechanism that are picked up by all consumers.

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?

A comparison of certain electricity systems similar to GB's is being undertaken as part of the IET/Energy System Catapult's FPSA Project. For a full understanding of these insights, we would encourage the NIC to view the final report from the FPSA project.

There are examples of other countries/regions adopting varying strategies in response to their changing generation mix. In most cases this has seen the acceleration of market and regulatory changes to bring flexible solutions to market to ensure system stability continues.

For example in California CAISO mandated 1.2GW of storage be built by the IOUs in a range of applications to support the development of the electricity system. Ireland has pursued a strategy of accelerating interconnection and smart solutions to deal with the challenges of falling system inertia as wind generation frequently makes up 50% of the capacity. PJM in the US has pursued a strategy of supporting demand side response programs along with some large scale energy storage.

It's clear a mix of these technologies will all help provide system balancing. It's not clear if there is an overall clear economic preference as the technologies have very different characteristics, and every power system is different.   We would suggest the UK takes a whole-system approach to ensure that we have a suite of technologies that are well co-ordinated and integrated into networks to ensure it remains resilient to system events, integrates significant renewable generation and keeps costs as low as possible.

A whole-system approach will become increasingly important as the character of the national energy system continues to change. These changes are being led by factors such as increasing contributions from renewable energy, the growth of distributed generation and storage, new 'beyond the meter' devices and services, and a fundamental shift to greater consumer and community engagement and empowerment in energy. Many of these developments will need to be controlled using large and complex IT systems. It is likely that the resilience of these control systems will be an important theme in maintaining security of supply for energy in the coming years.

A whole-system approach requires issues to be addressed that are wider than technology alone: these include regulatory and commercial frameworks, industry change controls, governance mechanisms, and consumer awareness and behaviour. All are critical to facilitating practical changes in a timely way and encouraging innovation and entrepreneurial actions and must acknowledge any electricity future is likely to be significantly influenced by the choices we make about the interrelationships and co-dependencies between electricity, gas including heat (thermal comfort) and transport. We note here the need to view the relevant work being undertaken by the IET and the Energy Systems Catapult on the Future Power System Architecture project[7].

<u>Contact details:</u>

Alexander Fare, Principal Policy Adviser – Energy, the IET [email address redacted]

Paul Davies, Head of Policy, the IET [email address redacted]

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[7] DECC Future Power System Architecture Project (FPSA)