Grid-scale electricity storage
using an innovative form of
Compressed Air Energy Storage

A Smart, Flexible Energy System

Response on behalf of Storelectric Ltd
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Summary
The current regulatory system needs to be overhauled radically and holistically, not patched up in places, if it is to do away with most (if not all) subsidies and provides means to incentivise capital investment, greenness, energy security and innovation cost-effectively in our electricity system. It also needs its incentives to be on longer timescales, for example 15 and 30 years (in addition to the current 8 and 2 year periods) in order to ensure the long term integrity of both the grid and the entire energy system.

The electricity system of the future needs to be renewable: emissions targets are so low that our emissions need to be concentrated in those industries (e.g. aviation, chemicals) which are hardest to de-carbonise. For this, government, National Grid and commentators have all established a need for flexibility that extends to many tens of gigawatts, and for durations ranging from hours to weeks. While they are important parts of the solution, distributed and grid connected batteries, DSR and interconnectors must be complemented by massive scale storage. And as other parts of the energy system become cleaner, the proportion supplied by electricity will grow greatly, making these developments even more important to the country.

There are currently many disincentives to introducing large scale storage into the system. The current regulatory regime prevents major capital investment without subsidy; onerous pre-qualification requirements prevent start-ups; lack of regulatory definition of storage prevents both storage specific contracts and the most efficient use of its capabilities; bureaucratic inertia makes the introduction of innovation impossible for all but the most politically influential innovators or backers. Breaking through this requires not only new attitudes but a new regulatory regime – that is, the identity and landscape of the organisations running the regime are unimportant compared with the regulations and contractual structures that they run.

A regulatory definition of storage needs to be supported by appropriate regulatory detailing; the most appropriate starting point is for interconnectors. Without radical overhaul, the ever increasing subsidies will continue to inflate the cost of electricity, and do so with increasing speed:

- The Capacity Market, CfDs, ROCs, CATOs, OFTOs etc.;
- Increasing values, volumes and variety of balancing and ancillary services;
- Increasing spreads between peak and off-peak energy.

We are currently on course to fail every leg of the energy trilemma. Ever increasing proportions of renewables will become prohibitively expensive if backed up by fossil fuelled power stations that will consequently require ever increasing subsidies; and the national security part of energy security is completely overlooked in all planning

and proposals. UK-based back-up with large scale electricity storage, in conjunction with smaller scale storage and DSR is the only way to deliver the entire trilemma cost-effectively, and can deliver such a fully functioning, clean and secure system at similar costs to today's system. But we have to move fast, or the opportunity will be lost: expensive and highly polluting alternatives and their long term contracted subsidies will become too well embedded to change easily, and businesses offering the new solutions will have left the field.

The contractual system is far too complex and changeable. The changeability makes the UK a very difficult market for investors and innovators. The complexity adds to costs throughout the system, barriers to entry, and political and financial risks. This needs to be simplified and stabilised radically.

Companion Documents

This document responds to specific issues within the call for evidence for "A Smart, Flexible Energy System", launched in November 2016. It should be read in conjunction with the following documents which we submit together with it, which respond to most of the objectives laid out in the introductory section "Towards a smart, flexible energy system":

- A 21st Century Electricity System (outlining a regulatory regime that would incentivise major capital investment, eco-friendliness, innovation and dispatchability, all without subsidy);
- Matching the Solution to the Problem (outlining the need for large scale electricity storage within the system);
- CAES or Batteries? (mapping how large scale storage, grid-connected battery storage, interconnectors and Demand Side Response complement each other to for a complete balancing structure for a 30-100% renewable grid).

Between them, these 4 documents outline the physical and regulatory structures that would deliver a smart, flexible energy system at little or no extra cost to the current system – indeed, it may even result in cost reductions.

Ofgem (Deirdre Ball) also stated that they would add my response to your recent consultation on embedded benefits to the responses to this consultation. That too is complementary to this response.

Section headings start with the section number (S#) from the Call for Evidece document, and omit many of those sections responded to by the companion documents.

Towards, s12:

Electricity only accounts for ~25% of the energy consumed in the UK today, the remainder being hydrocarbons for heating, transportation and industry. If these hydrocarbon energy vectors are to be even partially electrified, then the entire electricity system needs to be reinforced to carry between 2 and 4 times the amount of peak energy. The only ways to minimise such reinforcement are distributed locations of generation allied with equally distributed locations of large scale (>50MW, >250MWh) storage, combined with a strong growth in distribution connected generation and medium scale (5-50MW, 10-250MWh) storage.

Towards, s13:
We certainly need to act sooner rather than later. All significant changes should be piloted prior to incorporation within the regulatory regime, so as to avoid / reduce perverse outcomes such as the Capacity Market incentivising a major roll-out of diesel generation. Where there is no technological “first mover” developing a relevant capability, such pilots should be tendered; all the rest would best be tested as bilateral contracts with first movers.

Towards, s17:
Security of supply only addresses one of the two issues, and then only for a short timescale. The issues are:

1. Keeping power in the grid: current contracting regimes are entirely focused around keeping power in the grid, and do this very well.
2. Where the power originates: The origination of the power is completely ignored. Energy security should not depend on imports, whether of electricity by interconnector or its precursor oil, gas and coal. True energy security would enable locally generated electricity, from local resources, to be stored locally for local use and/or export.
3. Future proofing: the success in keeping power in the grid is only for the very short term, up to two years hence. This is because this is the duration of contracts. Little thought is given, and little action taken, to ensure the power in the grid over the next 1-3 decades.

To explain this last point, the cheapest way to provide energy against a 2-year contract is to patch up a clapped-out and fully amortised power station. At the end of that contract, the same is repeated – but the power station is a little more clapped-out, more failure prone and more expensive to both patch up and run; its emissions are also higher. Over repeated 2-year contracts the same is repeated, until the power station dies of old age with nothing having been built to replace it. Over a 20-year period the increasing costs of the system mean that more would have been paid for the energy than if a 20-year contract had been let, which would have been delivered most cost-effectively by building a new and more efficient power station. So over a 2-3 decade horizon, the current system delivers more expensive, polluting and failure-prone electricity than 20-year contracts would provide, while simultaneously failing to incentivise the ongoing investment in new plant that the system requires.

Towards, s24:
Changes should not be undertaken piecemeal to the system, particularly at the behest of large incumbents (ref. the recent proposals on embedded benefits) as such piecemeal changes make for a perpetually uncertain regulatory regime and contractual environment, and remove building blocks to the business cases of some

(particularly the new and innovative) technologies. By all these means such changes benefit incumbents and thereby ossify the system.

We recognise that sometimes changes are needed from time to time, but these should be carefully analysed for winners and losers, and for their effects on the stability of the regulatory and contractual framework, before being adopted.

Barriers are described in the other documents sent with this one, and in the submission to the Embedded Benefits consultation.

Towards, s25:
The "well-functioning price signals" only function well over the durations, conditions and period-to-start-of-delivery of the current framework, as described in the 21st Century Electricity System document. They fail utterly to incentivise major capital investment, especially where new grid connections are required. They also fail utterly to incentivise new technologies if those require significant capital. We propose solutions to these, within that document.

Towards, s26:
It is very plan that there is no means for appropriate reward for the benefits offered by time shifting / storage, or many other technologies either. There is no in-built systematic means for rewarding:

- Actual inertia as opposed to the artificial inertia simulated by EFR;
- Reactive power (in a systematic framework) as opposed to National Grid's construction of Synchronous Condensers;
- Storage reducing grid reinforcement requirements;
- Long duration storage;
- Cleanliness of power generation / storage;
- Storage providing off-peak services, which would require it to re-charge at higher prices;
- And many other services.

Towards, s27:
National Grid has identified a potential of 5GW of DSR potential. If DSR is used twice in a given period, then different DSR assets need to be used: one cannot use a given asset too often. Thus the maximum national DSR potential is 2.5GW, of which 100% is unlikely to be achieved.

Using DSR for up to this amount is very cost-effective and efficient. Using DSR above this level constitutes paying £billions to degrade our first-world grid into a third-world grid, where a first-world grid is defined as "turn on the switch, and the power is there" and a third-world grid is "turn on the switch, and it will think about it".

This calls into question the statement that "The SO aims for 30-50% of balancing services capabilities to come from the demand side by 2020."

Towards, s28:

The Capacity Market as currently designed is a failure, acting merely as a subsidy for keeping old and inefficient fossil fuelled power stations operational.

- The 15-year contracts available for new build have (to date) not incentivised the construction of such plant because it provides such long term financing for only 10-15% of the plant's required revenues.
- It does not incentivise cleanliness – hence the only new build to which it has given rise has been reciprocating engine (usually diesel) farms.
- It also requires delivery of power within 1.5 years of contract, which is not long enough for major plants or for any plants that require a new grid connection.
- Its failures collectively resulted in the incentivisation of new build of reciprocating machines (i.e. diesel and gas powered piston generators) with emissions performance that jeopardises the government's environmental treaty obligations and its own legally enshrined commitments. No other significant new build was incentivised by the Capacity Market.

An alternative system is proposed in the attached 21st Century Electricity System document.

Towards, s29-33:

The energy debate until now has been characterised by four fads, namely

- Distributed
- Virtual (e.g. DSR, smart metering)
- Batteries (both distributed and distribution grid connected)
- Interconnectors

Each of these has been presented by its backers as "the solution". While each of these contributes to the solution, a complete solution requires all of them PLUS large scale storage connected to both transmission and distribution grids. Any viable energy system has to allow for and incentivise both construction and operation of all of these – including large scale storage.

Towards, s34:

New entrants are caught in many Catch 22 situations, for example:

- CfDs are only available after planning permission has been granted, but pre-planning investment (especially of a scale of Nationally Significant Infrastructure) is not available without contractual support of future revenues;
- Oftem, BEIS and National Grid will not consider structuring any contracts for a new service until that service is operating and proven, which will not be funded without appropriate contracts;
- Delivery of all contracts needs to start within 18 months of contract award, yet a new transmission grid connection (especially if involving grid reinforcement) usually takes much longer and cannot be financed without such contracts;
- There is a mechanism (EFR) for rewarding artificial inertia, but not real inertia, so grid costs rise dramatically because real inertia is being closed down and not built;

- Storage is compelled to call itself generation, but is impeded in competing with generation because (a) it has to pay transmission and distribution costs both in and out, both capital and ongoing; (b) many contracts including the Capacity Market have no concept of a finite duration and recharge time; (c) storage may be called upon at off-peak times, meaning that it has to charge at peak times, but the lack of regulatory definition of storage prevents the contract being for storage services, or for a differential cost etc.;
- BEIS will not consider financial support unless and until an amount of work is done that is beyond the means of a start-up, if the technology is large;
- EEF funding is refused if the project is seen as too commercially risky (because BEIS / Ofgem put many blocks in the way of long term contracts), yet public funding should be precisely for economically risky developments;
- EEF funding is also refused if the project is not technically risky enough, even if there remains some technical risk and Ofgem's and BEIS' own rules make the economics unnecessarily risky;
- Funding opportunities are so finely defined that development projects have to be contorted grotesquely and uneconomically to fit in with bureaucrats' ideas, e.g. to include heat networks in an electricity storage project, or to have a completed installation within a maximum £3.5m project.

Towards, s36:
Battery electric vehicles have been proven in trials to potentially overload local and regional grids because there is inadequate grid connected energy storage for when they are charging.

Towards, s37:
Using electric vehicles for grid storage will only happen at the margins – all else is wishful thinking:

- Where they are charged (offices, work etc. using solar power) differs from where the energy is used (homes), without a means for transferring the money accordingly;
- People will not want partially discharged vehicles when they need to use them;
- Battery life is measured in charging cycles, so people will not want one of their most valuable assets worn out by others with inadequate compensation;
- Re-charging following discharge to supply grid services will incur further grid access and usage charges.

Towards, s40:
Cyber security will always remain a major risk for the country. No matter how secure a system is, a determined aggressor will always find a way in. And we're not just talking about criminals, but also about cyber warfare, disabling the country's infrastructure, vehicles and equipment. And this relates not only to disabling equipment / appliances / infrastructure but also to them being recruited into botnets, or infected with sleeping Trojan horses.

And who would be liable for such breaches of security? Not just direct damage, but consequential losses also? What if the grid code itself is flawed – will the country compensate everyone and put everyone's everything right?

Equipment and appliances should be required to be built giving consumers / users the option of disabling internet and other connectivity, and requiring a change of password before use (to avoid a number of bots that seek factory-set passwords to recruit appliances to botnets).

There should also be a new class of controller that prevents direct contact between appliances and the internet: for smart network monitoring, signals are given to and taken from the controller, and after buffering these, the controller gives signals to and takes them from the appliances; but no pathway should exist for external signals to go directly between appliances and the internet / other network.

Towards, s41:
If you want to challenge incumbent and enable new business models, then why do you keep on changing grid codes at the behest of incumbents (e.g. the recent consultation on changing embedded benefits) and prevent the long term contracts for new technologies that would enable new technologies to be built using private capital?

Towards, s42-46:
The main problem is not the responsibility for System Operation, but the regime and incentives under which SO is done.

- Currently they are within a 2-year incentivisation within an 8-year scheme, without a mandate for grid security beyond that.
- Currently the definition of Security of Supply appears to focus on keeping electricity in the grid over the next year or two, not in two decades time, and not concerned with where the energy originates and the extent to which that origination is secure.
- Currently we have a 20th century structure bin which coal and nuclear deliver baseload while gas delivers dispatchable, and everything else is a bauble on top, rather than a 21st century structure based on zero carbon generation and storage at both transmission and distribution scale.
- Currently BEIS, Ofgem and National grid claims to technology neutrality are completely undermined by the perversities of the current contracting regime and the ancient definition of what can and cannot generate revenue (e.g. real and fake inertia, reactive power and reactive load, no contract available for long duration / mass storage, preventing new transmission grid connections by requiring contracts to be delivered sooner than that, and so on).
- Currently there is no set means of establishing any benefits from deferral of investment, or of sharing those benefits with installations that yield such deferral. There should be an established means of doing so, and of incorporating such benefits into operational contracts pre-construction.

Towards, s43-46:
Surely, the more the transmission and distribution systems affect each other, the more they need to be managed by a single System Operator, whoever that may be. This maximises the flexibility of the system to accept changes.

Artificial distinctions should be eliminated, such as the 6MW limit on DNO operated storage and the zero limit on TSO operated storage.

Towards, s47:
Currently both government and Ofgem shy away from catalysing or even providing an opportune climate for large scale innovation or roll-out. Innovation support only seems to extend to what a desk-bound bureaucrat has decided is needed, and dismisses all else by saying that “we’re technology neutral and don’t discourage it” even when it is patently obvious that every possible impediment is left in place. And no means for incentivising capital investment into first-of-a-kind plants is available or even negotiable, so the capital investment can never be funded privately.

Towards, s48-49:
The LCNF and NIC prevent all funding support of anything (including storage) that is defined as generation, with a derogation for storage under 6MW. But large scale storage cannot be scaled down so far, cost-effectively: cost per MW and per MWh rise exponentially as size decreases, while efficiency simultaneously plummets.

The LCNF and NIC also prevent investment if the technology is not risky enough, even if there is no way of funding such developments from the market due to the first-of-a-kind nature of the investment and due to the lack of contractual cover.

LCNF and NIC are geared primarily towards virtual technologies and small-scale technologies that one can drop on one’s foot. Anything larger than that appears to be gravely disadvantaged or even excluded from all support.

Instead, the remit should be widened to cover all innovations that would benefit the grid. The funds should be managed independently of the operators (by Ofgem?) so that system benefits are supported even if commercially detrimental to a given operator – though the operators should be encouraged to submit their needs. It should cover innovation, initial roll-out and testing. Its funds should not be limited: if there are good innovations that deserve funding above the £99m scope, the administrative body should be allowed to increase that scope. Its project size and scope should be negotiable. Projects should be accepted and negotiated when they arise, not according to artificial deadlines that ensure rushing of applications and high numbers of repeat applications. Projects should be discussed with applicants so that evaluators can understand them properly and maybe require modifications to scope, management etc. All these conditions are perfectly compatible with auditably competitive and fair-to-all financing, because this is how regional growth funds are allocated.

Towards, s50:
The additional money for these fields is very welcome indeed, though £50m over 5 years again means that only small technologies will be supported. For example, the EEF Round 5 call requires completed installation of all projects within a rigid £3.5m total project costs. It does not permit funding of a stage of such projects that will have durations too long for installation in the timescale, or that will have higher overall costs. America's and the EU's funding schemes are 100 times larger, though their economies are only 5-10 times larger.

LCNF and NIC funding should be additional to this.

Towards, s53 / Table 1:
Very good, but a timescale to 2020 to make storage pay is far too long, and will entail missing all emissions targets. It needs to be complete in 2017.

In order to deliver good change without incurring large adverse unintended consequences (such as the only investment incentivised by the Capacity Market ending up being into reciprocating engines, mostly diesel), the major changes need to be piloted prior to legislation / regulation, starting very early 2017. Such pilots need to include, with respect to storage (there will be others for other capabilities):

- Scale: distributed, grid-connected battery, larger distribution connected and transmission grid connected storage;
- Duration: short (<15 mins), medium (to 2 hours) and long durations at rated capacity;
- Contract length and structure sufficient to incentivise private capital to pay for each investment;
- Different services: inertia, reactive load, long duration back-up (>2 hours), mass storage (>5 hours), grid investment deferral etc.

Flexibility, 1.1 s1-3:
Real-time balancing of supply and demand is only required without storage. With storage, supply and demand can be separated. Thus storage is a network asset, not a generation or demand asset.

Flexibility, 1.1 s5:
These benefits all need to be remunerated. The only ones that are currently remunerated are a majority (not all) of the balancing services in (e).

Because so many of the benefits are not currently remunerated, investment is not incentivised and the grid incurs considerable additional costs, e.g. four planned synchronous condensers in or near Cheshire, and other grid reinforcements.

Flexibility, 1.1 s8:
National Grid has indeed identified the maximum UK potential for DSR as 5GW. But if DSR is called upon twice in a period (e.g. per evening), the same assets cannot be called upon in both calls. Therefore to permit two calls per period, only half of the

capacity can be called upon at each time. Consequently DSR can only account for 2-3GW of peak demand; any more than that would be paying £billions to degrade our first-world grid to a third-world grid, where turning a switch in a first-world grid turns on power, while a third-world grid will think about doing so.

Moreover, different assets will be available at different times. While refrigeration is 24 hours a day, production assets such as arc furnaces are not. This will reduce the effective available DSR capacity.

Removing barriers, Enabling Storage, 2.1 s1:
The cost of battery cells is falling fast; the cost of the Balance of Plant is falling much more slowly. The two are usually conflated, wrongly.

If you believe the British Government's former Chief Scientist David Mackay's book Renewable Energy Without the Hot Air (www.withouthotair.com), if we use the following assumptions:

1. We can use 100% of the lithium in the earth's crust, no matter how low grade the ore;
2. We never waste any;
3. The efficiency of usage of lithium in batteries doubles (this one is reasonable)
4. Batteries last forever;

Then we have enough lithium in the earth's crust for all the electricity systems of the world, OR all the portable devices of the world, OR all the vehicles of the world assuming that vehicle ownership in less developed countries never rises – but not all three. The reason why lithium prices dropped in recent years is because mining and refining capacity grew faster than demand and grew cheaper due to benefits of scale and R&D, not because the supplies are effectively unlimited. Forward prices of lithium are already rising. It is good that other chemistries are being explored, notably sodium, vanadium and lead based.

The annual output of Tesla's Gigafactory will be 35GWh. One 500MW CAES plant with 12 hours' storage will have a capacity of 6GWh, so 6 such plants p.a. will exceed Tesla's famed output.

Doubling either the size (MW) or capacity (MWh) of batteries increases their costs by roughly 85%. Therefore they are best for smaller sizes (<50MW) and shorter durations (<2hrs).

Batteries also deteriorate very fast. Their lifetimes are 5-20,000 cycles, by which time their storage capacity is ~70% of new, and their heat output (and hence requirement for ancillary loads, especially cooling) is tripled. Cell life is 5-10 years depending on technology, which requires further financial and environmental costs to replace, recycle and re-manufacture them.

The efficiency of grid connected batteries needs to be analysed closely. Whereas most batteries claim 88-97% round trip efficiency, that is in fact the round trip efficiency of the cell. The whole system round trip efficiency is driven by the ancillary and parasitic loads: mainly cooling, secondarily power conversion, with a few minor supplementary loads. Thus the actual measured round trip efficiency of grid connected batteries in Northern Power Grid's Customer Led Network Revolution's Electrical Energy Storage Cost Analysis[1] ranges from 41.2% to 69%. And that was measured at start of operation, not after 5 years.

The requirement for energy storage in the UK is 8-18GW by 2030 according to National Grid's FES 20616. It is 128GWh (in a range that goes up to 521GWh) by 2050 according to the British government's TINA (Technology Innovation Needs Analysis). These forecasts both assume that nuclear or fossil fuels will generate baseload capacity, whereas nuclear is proving to slow and costly, and fossil fuels are warming the planet too much. In order to enable renewables to supply baseload electricity and also to cope with significant periods (1.5 weeks) of adverse weather for generating, then storage capacity will have to be 6-12 times these figures, i.e. 800-1,600GWh in the UK. British requirements are roughly 1/100 of global requirements. Batteries cannot deliver this, on their own. They cannot even deliver the UK's medium term requirements, on their own. They are one part of the solution, together with DSR, interconnectors and probably nuclear; large scale storage (pumped hydro, CAES, and maybe eventually hydrogen) will have to form the bulk of storage even if a lower proportion of energy flows as batteries are best operating fast-in-fast-out.

Additional to batteries, we need energy storage that:

1. Doesn't use scarce materials (i.e. scarce in relation to the scale at which it will be needed);
2. Has far greater economies of scale of both size and capacity;
3. Preferably, is cheaper now per MWh of capacity and at large scale;
4. Is at least as efficient (total round trip) as batteries, with the potential of increasing efficiency still further.

Removing barriers, Enabling Storage, 2.1 s2:
It is evident that the low prices quoted for EFR contracts cannot be sustainable, and will cover the costs of none of the winners. Their quotations were driven by the following factors, among others:

- Buying a place in a future market, effectively subsidising corporate R&D;
- Expecting to receive other payments (e.g. Capacity Market) as well;
- Being able to finance them from balance sheets, i.e. no project finance and therefore no opportunity for new entrants to the market.

These three factors indicate that this is not a level playing field.

Removing barriers, Network Connections, 2.1.1 s4:
If DNOs have 19GW of connection applications for storage, it is plain that only a minority of these will be built. This means that future applications relating to storage that WILL be built will be evaluated on the assumption that the prior applications are

[1] http://www.networkrevolution.co.uk/project-library/electrical-energy-storage-cost-analysis/ p6

also built, and there requiring much more reinforcement. This benefits those who hog connection capacity.

Many of these hogged connections are due to a requirement to have approved grid connections and planning permission to be able to bid for any contracts. If a grid connection application were tied to the contract and expiring if the bid is not awarded (maybe permitting up to 2 attempts), then much less capacity would be hogged. A further constraint could be that some significant work must be done in relation to a given connection application within 2 years of its grant: this may be construction or (e.g. if NSIP is required) work towards planning, or award of funding for the project. Progress could be reviewed annually thereafter to verify that the connection is still being worked on. If a connection application is deemed expired, then a new one could be made – but this time at the back of the queue, rather than at the front.

Removing barriers, Network Connections, 2.1.1 s5:
This work in improving the timeliness and cost of grid connections is excellent.

There are however catch-22 situations for new entrants. For example, a grid connection application is not permitted without planning permission. Planning permission is lengthy and expensive, especially with NSIP, and therefore needs funding. Private sector funding requires grid connection… Maybe an estimate and shorter-term reservation could be provided?

Removing barriers, Network Connections, 2.1.1 s6:
Additional considerations for grid connections (which also apply to transmission connected storage) could include:

- If (and under what operational conditions) storage will create network capacity rather than consume it – which will, in some part, depend on storage size and capacity –
    - Where capacity is created rather than consumed, the DNO / TSO should at least share the benefits, min. 2/3 to the developer;
- Where the pairing of generation and storage will be located, e.g. if there is a substation between the two, then that substation will need to take the peaks and surges of generation, but subsequent ones will not – also depending in part on storage size and capacity;
- DNOs and the TSO should assess neighbouring lines and substations to identify the best connection option.

There is also a case for DNOs and the TSO to incentivise storage to connect at more than one point, the operational point being determined solely by the DNO / TSO. Thus if one line is unable to supply / use the energy, the connection is diverted to the other; or is diverted to whichever line the storage will help most in adding effective capacity.

Removing barriers, Network Charging, 2.1.2 s7-15:

In general, network charging for storage should equate to network charging for interconnection, since it provides neither generation nor demand but rather a network service. The only two viable options are:

1. No network access or usage charges;
2. No network access charges, but usage as demand calculated on net energy consumed (i.e. after deducting energy put back into the system).

Whether storage is classified as intermittent or not is a moot point, and changeable whether one considers its dispatchability or its limited duration. It also relates to the markets on which the storage can trade, and the support (e.g. CfDs) that it can receive, not just to grid charges. This is yet another reason why storage needs its own regulatory definition.

Network charging may be made proportional to the network operator's control of the storage. For example it may provide a dynamic operating margin that would ensure that the storage does not exceed network capacity; or it may actually control the input and output (with contractual payments).

As storage is a network service provider (just like interconnection, or the synchronous condensers that National Grid is planning), why can't DNOs / the TSO lease the plant and use it as needed from time to time?

As an ancillary and balancing services provider, storage benefits the network and therefore should not pay network charges. Even when trading on the markets, because stand-alone storage will tend to buy when demand is low and sell when it is high, this again benefits the network in evening out energy flows.

Removing barriers, Final consumption levies, 2.1.3 s16-19:
Because storage is a service provider, it should only pay final consumption levies on its net energy consumption, if at all. The fairest is not to pay them at all. After all, neither synchronous condensers nor substations nor interconnectors pay the levies.

Inasmuch as storage does not create its own climate change emissions, it should not pay a Climate Change Levy or Renewables Obligation, or for FiTs. Moreover, as it enables renewables to displace fossil fuelled generation, it should be paid for its climate change and renewables benefits.

As it is not generation, it should not pay for CfDs.

As it provides peak capacity to the system, it should not pay CM gross auction cost.

Removing barriers, Planning for storage, 2.1.4 s20-23:
Storage should have its own regulatory classification. Government departments should analyse each technology and provide standard pre-planning data (e.g. environmental impact) relating to the technology that has already been accepted. The balance of data would relate to locality and size of operation, which alone

should be the subject of the planning applications. This could significantly streamline and cheapen the planning procedure.

Removing barriers, Use of storage by network operators, 2.1.5 s24-27:
Storage needs a new regulatory definition, based on that of interconnectors which also provide network services rather than either generation or demand.

However storage has one feature that no other classification has: it can provide a wider range of services, such as in the table below:

Service	Batteries	CAES
Inertia (simulated = EFR)	**Simulated**	**Y**
FFR (1)	**Y**	
FFR (2)	**Y**	**Y**
Reactive power	**Simulated**	**Y**
Reactive load		**Y**
STOR		**Y**
Fast Reserve		**Y**
Demand Turn-Up	**Briefly**	**Y**
Levelling intermittency	**Briefly**	**Y**
TNUoS	**Y**	**Small CAES**
Capacity		**Y**

This wide range of services means that the system operator is in a much better position than the market to decide which is used when. Therefore, although it is workable for storage to trade with multiple such contracts,

1. Consideration needs to be given to enabling storage to deliver as many of these services as possible from any given installation, including modifying the terms and timescales of such contracts;
2. Consideration should also be given as to whether the system as a whole would benefit from the system operator leasing the plant and operating it as circumstances dictate.

The RIIO framework discincentivises new technologies, especially if they require major capital investment and/or new grid connections (especially transmission grid):

- All contracts must be delivered within an 8-year period. No major investment has been funded by the financial markets without 15-year contracts such as CfDs, ROCs, CATOs, OFTOs and cap-and-floor, proving that longer timescales are needed.
- Contracts need to start delivering services within 1.5 years at most, which does not allow for major construction or grid reinforcement work – or any new transmission grid connections.
- Contracts are almost impossible to obtain prior to planning, grid connection and fund raising, which in turn makes fund raising almost impossible (and, if possible, very expensive).

- All RIIO provisions to support storage are geared towards small scale battery storage, distribution connected and deliverable very rapidly as standard pre-configured systems. None support large scale or transmission connected storage, or storage that needs to be built and configured in situ.

If a developer proposes a storage project, then grid reinforcements are assessed for storage at peak rate of output (considered erroneously to be generation) and peak rate of input (considered erroneously to be consumption), maximising grid reinforcement costs. On the other hand, if a DNO proposes a storage project (e.g. Leighton Buzzard, Eigha, Orkney), then it is considered to be enhancing grid capacity and therefore requiring no grid reinforcement whatsoever. Without a regulatory definition of storage there can be no established means for evaluating grid reinforcement / investment deferral, and storage proposed by developers is penalised heavily.

The associated document “A 21st Century Electricity System” indicates ways to overcome all these.

The lack of a regulatory definition of storage means that:

- There cannot be tenders for “storage services” covering a variety of the above services, to be used as required by the SO.
- An SO cannot operate storage as a network enhancing capability; DNOs cannot operate storage above 6MW.
- There can be no systematic or special treatment of storage in, for example, capturing the benefits of grid investment deferral, avoiding double grid reinforcement assessment;
- Grid reinforcement and grid usage charges erroneously consider storage charging to be consumption and storage discharging to be generation, when in reality it’s displacement of energy in time from when it’s not wanted to when it is.
- There can be no contracts that enable storage to deliver ancillary and balancing services at off-peak times because it would have to re-charge at peak times, thereby paying more for its electricity and earning less – even though these services are required at all times.
- For all these reasons, storage is penalised in competition with generation and doubly penalised against interconnectors which pay no grid access or utilisation charges at all, and which also pay no levies.

A definition of storage, and its regulatory, contractual and charging consequences, should be based on (though not a subset of) the definition of interconnectors. The main similarities between storage and interconnectors are:

- While interconnectors displace electricity in location from where it is less wanted to where it is more wanted, storage does exactly the same but displacing it in time;
- Like interconnectors, storage neither generates nor consumes (apart from losses), it provides a series of services;

- Like interconnectors, taking generation through storage to customers would entail triple charging of grid access if charges into and out of storage are added to the charge out of generation;
- Like interconnectors, electricity flows both ways depending on financial / contractual conditions and need;
- Like interconnectors, the output cost of electricity relates largely to the input price of electricity.

Removing barriers, Providing regulatory clarity, 2.1.6 s28-38:
There is an ever increasing rate of change of services, conditions, modifications to network services etc., which makes the British electricity system the least investable in the developed world. Few, if any, are trialled prior to implementation which leads to many perverse unintended consequences. Many (such as the recent embedded benefits review) appear to be instigated by large incumbents seeking competitive advantage by regulatory means, and should be stopped.

Other such changes are the result of identifying and eliminating barriers to entry to new products and services. These are good, but should be trialled prior to implementation.

That the definitions for storage exist is excellent, but one needs bringing into operation throughout the grid, regulatory and contractual codes. We see little difference between the two definitions, but wonder if capacitive storage (which does not convert the electrical energy), as opposed to capacitors used at network nodes, is included. Some storage systems use multiple forms of energy to store electricity, e.g. adiabatic CAES uses both compressed air and heat. There also needs to be a differentiation between distributed, small and large scale storage, as each would fall under different regulatory and contractual regimes.

If we base the definitions on the ESN version,

- … the conversion of electrical energy into a form of energy …" should read "… into *one or more forms* of energy …"
- The first "Energy Storage" bullet should add: Electricity Storage also includes the direct storage of electricity for a substantial period of time, such as by capacitors.
- A third bullet could be added: "Distributed storage is storage located behind the meter. Large scale electricity storage is Electricity Storage with a capacity of 100MWh or greater. Transmission scale electricity storage is Electricity Storage with rates of charging and discharging 100MW or above, and volume of storage 500MWh or above, and connected to the transmission grid."
  - (Note: as an alternative, one could use the ENTSO-E PCI definition of "at least 225 MW installed capacity and has a storage capacity that allows a net annual electricity generation of 250 GWh/year".)

An alternative definition is the European Union's Internal Market Directive for Electricity directive: "*energy storage' means, in the electricity system, deferring an* *amount of the electricity that was generated to the moment of use, either as final energy or converted into another energy carrier*". This would encompass capacitors, but the scale issue would remain to be addressed. Keeping in line with our European partners is always advisable. On the other hand, it is too broad and would appear to include DSR within the definition. Therefore the best outcome would be a revised definition agreed with and held in common with our European partners.

A further concern is that existing CAES is a hybrid between storage and generation. This could be treated, by permitting the combustion of fuel during the regeneration process (maybe with a limit of 60% of the output energy?). Attempting to split output into storage and generation would be unworkable as the two outputs would often fall under different contracts, while they could not be split physically.

The definitions also need developing to define how storage will be treated, which should be very comparable to interconnectors as explained in the previous section.

Option 38d is necessary for the development of a 21st century grid, in which storage enables renewables to power the country (with or without nuclear). It generates no electricity, so should not be a subset of generation. It only consumes as much as its round trip inefficiency, and so should not be related to consumption. It provides a service like interconnectors: just as interconnectors provide displacement of energy in location, so storage provides displacement of energy in time. This is the general principle; many of the practical reasons are listed elsewhere in this document and the associated ones.

Questions: Enabling Storage

1. See my response to Use of storage by network operators, 2.1.5 s24-27, above, and also on System Value Pricing, section 3.1 and 3.2, below.
2. You have only identified some of the issues regarding network connections for storage, and where more progress is required, more of which are identified in my response to Use of storage by network operators, 2.1.5 s24-27, above.
3. Network charging issues, and also issues penalising storage in relation to other providers of flexibility, are also addressed in my response to Use of storage by network operators, 2.1.5 s24-27, above, and also on System Value Pricing, section 3.1 and 3.2, below.
   - Flexible connection agreements can help address issues, but are only a small part of the answer.
   - Connections hogging should also be addressed, whereby a grid connection assessment for a project that is greatly delayed hogs the grid capacity if submitted ahead of a connection assessment for one that will be built soon.
   - No account is taken of emissions in comparing flexibility providers.
   - No allowance for limited duration is permitted in many contracts, making it impossible for storage to compete even when nearly all utilisation is for up to a few hours.
4. We agree that network operators would benefit greatly by using storage to support their networks, but are prevented from doing so by the ban on TSOs

operating any storage and DNOs operating storage above 6MW – and also by the fear of being accused of using storage to compete with generation because there is no definition of how it can or cannot be used.

- There are far too many safeguards, which actively prevent the development of a competitive market for storage, many (not all) of which are in my response to Use of storage by network operators, 2.1.5 s24-27, and to these questions, above, and also on System Value Pricing, section 3.1 and 3.2, below.
- Network operators should be allowed to lease and operate storage, maybe to own it too, because the most efficient modes of operating the grids rely on being able to draw the services they need at any given time without having to refer to a sheaf of different contracts each from a plethora of different suppliers.

5. Yes, your approaches to defining storage are good as far as they go but, as per my response above to Providing regulatory clarity, 2.1.6 s28-38, the definitions need to be embodied carefully into rules based on interconnectors.
6. As my answer to Q5 above.

Removing barriers, Clarifying the role of aggregators, 2.2 s43:
In general, we would advocate that groups of related technologies should be engaged via market mechanisms. This includes aggregators (possibly split by service being aggregated), small scale storage, large scale storage etc.

Very importantly, each market needs to be piloted via bilateral contracts before the market is established, regulated and operated. This is essential to ensuring the minimisation of negative unintended consequences, such as the un-piloted Capacity Market succeeding in funding new investment only in reciprocating engines, the dirtiest of technologies and one entirely counter-productive to the government's legislated desire to minimise emissions.

These are our only views on the role of aggregators, s.39-71. Therefore we do not feel in a position to respond to the questions in this section.

Providing price signals for flexibility, 3, introduction:
The energy system only has a few "well-functioning price signals that shape the profiles of generation and demand". On the contrary, the price and cost of electricity have become largely dissociated: for a commercial user, only about half of their electricity bill is for the electricity while the remainder is made up of charges, levies and other subsidies. The latter part is tending towards 75%, as confirmed to me earlier this week by an energy trader. This makes ever more futile the government's and Ofgem's desire for market signals to determine investment strategy. Over the past 20 years there has been virtually no investment by the financial services industry into major infrastructure without some kind of government underwritten 15-year underpinning of revenues, such as CfDs, ROCs, CATOs, OFTOs and cap-and-floor. Unless such long duration contracts are made available generally, the proportion of subsidies and levies will rise inexorably.

Because there is insufficient storage, the only way to reduce curtailment of renewable generation is to curtail aggressively fossil fuelled generation. Thus if the wind blows hard, a gas fired power station is turned down or off. This makes the power station unprofitable, hence needing subsidies such as the Capacity Market.

Without storage at all scales, the level of utilisation (= load factor) of fossil fuelled power will continue diminishing. Since there are times when the sun doesn't shine and the wind doesn't blow during peak demand, these power stations cannot be closed. Therefore increasing subsidies will be needed to keep them open.

The only way through this mess is to bring in storage at a scale of tens of gigawatts so that all peak demand can be met by a combination of nuclear, clean dispatchable generation and storage. Nuclear is likely to be 5-10GW; clean dispatchable generation is likely to grow to 3-5GW, totalling 8-15GW. Since forecast demand is 75.5GW by 2040 and the desired capacity margin (an additional 5-15%) would bring that to 80-87GW, that leaves a requirement for storage of 65-79GW if the electricity grid is to be powered renewably. And because it can be powered renewably, it should, so we can continue using fossil fuels where really needed such as aviation and the chemicals industry.

The statement above that interconnectors are not reliable is because Ofgem's Winter Outlook 2013 report stated that we cannot rely on interconnectors for our peak demand because (a) our peaks largely coincide with our neighbours' peaks and (b) they are undergoing a similar generation capacity crunch to ours. This is borne out by electricity prices over the last couple of weeks peaking at £2,500/MWh (see report from Aurora Energy Research) due to scheduled outages and breakdowns in French nuclear and other continental generation. Therefore, although they are beneficial in keeping overall energy prices down (especially if we have large scale storage, to import more than we need when continental prices are low and export when they're high), we cannot rely on inward flows of electricity through interconnectors for actual forecast peak demand.

System value pricing, 3.1 s1:
It is true that "to be cost-effective at any given moment, the system should be making best use of the flexibility available". Indeed, to be truly cost-effective, one must maximise the amount of flexibility available.

Unfortunately the system does not do this: it disincentivises long term investment, long term contracts from National Grid, and energy storage at all scales.

The disincentivisation of long term investment includes the following elements:

- All contracts need to start delivery within 1.5 years of letting a contract, which makes new distribution grid connections impossible if a measure of grid reinforcement is need. And new transmission grid connections are impossible in any case, since they take longer than that. The only exception is the Capacity Market (4 years ahead) which only accounts for a grossly insufficient amount of the revenues of a plant to enable the plant to be built – and 4 years are not enough anyway if significant transmission grid reinforcement is needed.

- No contracts other than the Capacity Market are available which offer 15-year underpinning of revenues, except for the subsidies (ROCs, CfDs, CATOs, OFTOs and cap-and-floor). And as stated above, the Capacity Market only accounts for a grossly insufficient amount of the revenues of a plant to enable the plant to be built.
- Markets are being changed with increasing frequency: 4 major changes last year, 3 the year before, 2 the year before that. Tweaks and adjustments such as removing embedded benefits are consulted upon frequently. Regulatory uncertainty prevents investment.

The disincentivisation of National Grid to provide long term contracts is not admitted to by Ofgem, but is in fact very real and strong:

1. They are incentivised over a 2-year period, so it does not pay them to optimise prices over a longer period.
2. They are targeted under the 8-year RIIO framework, so they are not credited with any benefits extending beyond this.
3. The RIIO framework also limits the timescale over which they can receive any level of assurance from yourselves that the y are taking a sensible commercial action for the benefit of the electricity system.
4. Therefore they are opening themselves to substantial commercial risk, for which they are not rewarded in any way, in the unlikely event that electricity prices for the services purchased under the agreement happen to drop rather than rise.
5. There is further commercial risk in case the regulatory framework were to change, leaving them with stranded contractual obligations which do not fit into the new framework.

I quote from the Q&A section on National Grid's publicity for EFR:

> *We recognise that four years is not very long when investing in new assets, however National Grid is a regulated business and therefore sanctioning contracts longer than two years because of the funding arrangement together with the forecasted market conditions involves us taking on an unacceptable level of risk. Four years is seen as a good balance between revenue certainty and risk mitigation. The initial tender is for a service starting Winter 2017/18 for four years, however we are seeing a requirement for this type of service increasing over the next few years, therefore we intend to run regular tender events on an enduring basis. The SOF forecast volume of EFR is going up over the next 10 years.*

We also recognise that from receiving an offer 18 months may not be sufficient time to finalise a connection agreement and be ready for commercial operation; this can be discussed at the time.

The disincentivisation of storage at all scales covers a wide variety of issues:

- It adds or omits rules that make storage unable to compete, for example by allowing no concept of a finite duration, or by charging for network usage for both charging and discharging.
- Various services cannot be monetised, e.g. long term storage, long duration storage, true inertia, reactive load, deferral of grid investment.
- Storage merely displaces electricity in time, just as interconnectors displace it in location. This is NOT generation or consumption: it is provision of a service. As such it should have free grid access and usage, just like interconnectors. If anything is paid for, it should be net consumption, i.e. the carriage of the electricity lost in total round trip efficiency – though that would be hard to calculate with mixed generation and storage such as traditional CAES which regenerates through a gas-fired power station.
- Storage provides more services than any generation, which yields a bewildering array of contracts that have constantly to be bid for and won, providing immense ongoing overhead costs and revenue uncertainty.

System value pricing, 3.1 s2-3:
As presented in the consultation document, flexibility is only considered in relation to benefits for consumers. It is not considered in terms of ability of producers and other service providers to do their jobs and make a suitable profit. It is also considered very much in the short term, not in the medium or long term.

Duration / term considerations:

- National Grid is incentivised to minimise costs over 2 years ahead.
- The cheapest way to procure electricity over that period is with contracts of up to 2 years. This electricity will be provided in the cheapest way possible, which is to patch up a clapped-out and fully amortised plant for the term.
- In the following 2-year cycle, the same will recur, except that the plant will be older, frailer, more expensive to patch up and more failure prone.
- The same repeats, with increasing cost and decreasing reliability, until the plant can no longer be patched up and dies of old age.
- Over a 20-year period the total cost of electricity produced is more than it would have been under a 20-year contract – even though electricity prices would have been higher in the initial years of such a contract. But no new plants have been built, and the system collapses due to lack of major long term investment; we become wholly dependent on imports and on plants / infrastructure / interconnectors built with subsidies such as CfDs, cap-and-floor agreements and zero cost grid charges – all of which apply to interconnectors today.
- The cheapest way to supply electricity over a 20-year period would entail building a new plant or completely refurbishing a mid-life plant. Thus a 20-

year contract would deliver long term cheaper and more reliable electricity and the long term structural health of the electricity system as a whole.

In order to provide investability, revenues need to be assured – at least in part – for investors.

- This could be cheapest via long term contracts with fixed availability prices, minimum agreed utilisation hours / volumes and floor prices for utilisation.
- Without the floor prices, the percentage of cheap debt with which a plant is built will diminish, requiring a greater proportion of more expensive equity, increasing somewhat the overall cost of electricity– but this is doable also.
- Without minimum utilisation hours, then debt can only be funded up to the percentage of required revenues that will be covered by availability payments, increasing the overall cost again but still just about doable.
- Without long term availability contracts there will be no commercial investment in new major plant. Just as there hasn't been over the last 15 or 20 years: some has been done by the big players investing from their balance sheets, but most has been done under subsidised 15-year regimes such as CfDs, ROCs, CATOs, OFTOs and cap-and-floor.

System value pricing, "Operate efficiently for buyers and sellers of flexibility" 3.1 s3:
For as long as over 25% of a consumer's electricity charges are for elements other than electricity price, the market does not operate efficiently because market prices do not reflect electricity generation and transmission costs.

It is fair to have transmission costs accounting for 15-25% of a final bill, for both private and commercial consumers: that is the cost of keeping the grids and systems operating efficiently. Anything above that – the levies and subsidies – distort the market and make investment very difficult indeed without further market intervention and distortion (CfDs etc.).

Unless this issue is dealt with at this level, it doesn't matter how much the flexibility service definitions, market platforms, competitive mechanisms, contractual terms, conditions, roles, responsibilities etc. are tweaked: they cannot deliver the flexibility, minimal cost and long term sustainability of the system that are required.

Moreover, as distributed generation and storage grow, we have increasing numbers of consumers (both private and commercial) who use little electricity but rely on the grid to provide off-take and back-up services. Current charging systems mean that those without distributed generation or storage pay for the maintenance of these services for those with distributed systems. Standing charges (maybe reflective of peak input / output) should be increased, and energy charges decreased accordingly to reflect actual costs of different consumers on the system.

System value pricing, Unremunerated services 3.1 s4:
There are a number of services that are not remunerated. Examples include:

1. Inertia is not remunerated.
   - EFR is pseudo-inertia.
   - EFR still carries a few milliseconds' delay before activation, and needs to be switched on and volume controlled actively.
   - Inertia carries no delay and needs no active management; it is therefore both better and cheaper to manage than EFR.
   - Incentivising real inertia to the same price as EFR will therefore enhance the grid at lower overall cost, and incentivise investment into rotating machines such as biomass and hydro generators, flywheels and CAES.
2. Reactive power is very inadequately remunerated.
   - The grid code makes the free provision of reactive power a duty of traditional generators, but not of interconnectors or intermittent generators. This disincentivises the systems that provide natural reactive power.
   - As a result, artificial reactive power is likely to be purchased from batteries, with the same costs and problems as EFR (above).
   - If reactive power were properly, it would provide further grid enhancement and incentivisation of the same technologies as inertia.
3. Reactive load is not remunerated at all.
4. Long duration storage is not remunerated at all.
   - Therefore all new storage being built is for 0.5-2 hours duration batteries.
   - What happens beyond 2 hours after sunset on a windless day? Or if the wind fails to blow for days at a time – up to a week and a half, quite often?
   - How will electric vehicles be charged overnight if the wind is not strong? This would require either high volume baseload generation (multiples more than the most optimistic nuclear scenario, or highly polluting fossil fuelled generation) or large scale long duration (to 12 hours) storage – and longer duration storage to take into account days with low renewable generation.
5. Long term storage is not remunerated at all.
   - If we start to electrify the provision of heat, e.g. by heat pumps, then we will need to start storing more energy from the summer for winter usage.
6. Grid upgrade deferral is not remunerated at all.
   - Some of this will be one-off, some ongoing; payments should be made accordingly.
   - Pay 2/3 of the benefit to the investor, let the grid operator retain 1/3, to go entirely into other investments but with the 2/3 reduction being reflected in their incentive to minimise grid operational costs.
   - Pay out one-off benefits in advance and ongoing benefits annually, with recharges if the benefits were not delivered in full other than by grid operator decisions.
   - A standard means for calculating deferrals should be established, whereby any proposal in any location can have its benefits assessed.
7. Environmental performance is inadequately remunerated.
   - Dispatchability is inadequately remunerated. If remunerated properly, then attaching storage (at least notionally, i.e. contracting with remote storage) should be more profitable to intermittent generators than not doing so.
   - Storage should benefit from both of these aspects, in that it enables intermittent generation to be used more fully and more beneficially.

- The cleanliness of storage should vary with its efficiency and its consumption of fossil fuels.

8. The remuneration of black start capability is inadequately transparent.

Additionally there are a number of perverse disincentives for storage:

1. If a DNO proposes storage (e.g. Leighton Buzzard, Orkney, Shetland, Eigha), it is deemed to create grid capacity; if a developer proposes it, they are charged for grid reinforcement as they are deemed to consume grid capacity.
2. If a DNO operates storage, it is deemed a network management service; if an independent operator does so, they are charged for both electricity generation and consumption – and network usage charges are added accordingly.
3. However no network usage charges are imputed to interconnectors as they too are considered to be providing a service, the displacement of electricity in location.
4. Storage should be considered a network service: displacement in time and enhancement of controllability.

One aspect that should be considered is contractual complexity. If all the unremunerated services are remunerated separately, they will only add to the 6-12 concurrent contracts which a storage service provider would have to maintain on an ongoing basis. This could be simplified with a new regulatory classification of storage, as it would then be possible to engage “storage services – with inertia” and “storage services – without inertia” contracts, for example.

Questions: System Value Pricing

1. Many enablers, some of which are alternatives, are possible, for example:
   - A definition of storage supported by regulations comparable with those of interconnectors;
   - SO leasing and operating storage plants – which would greatly reduce overheads due to the immense reduction in the number, variety and frequency of tenders and contracts that each supplier has to manage;
   - Long term contracts that provide revenue certainty for commercial investors;
   - Ensuring that all services are remunerated;
   - Ensuring that contracts do not conflict with each other and that revenue streams can be stacked maximally;
   - Enabling contracts for storage services, so electricity is not charged both in and out with attendant mark-ups, grid access charges and levies, and so that storage services can be provided profitably off-peak;
   - Fixing the method for establishing the grid reinforcement costs and benefits of any given storage proposal;
   - Fixing a method of grid access and grid levies charging comparable with interconnectors;
   - Elimination of preferences (e.g. provision of services for indeterminate duration only; and only single charging for grid access) and subsidies (e.g. Capacity Mechanism, and all kinds of levies) that de-couple market needs from market prices;

- ♦ Long term contracts that enable investment by commercial investors into major capital infrastructure.

2. The stacking of storage benefits is outlined in the table in Use of storage by network operators, 2.1.5 s24-27 above.
   - ♦ We keep on coming across little rules in the small print of market mechanisms that prevent the stacking of revenue streams, such as:
     - ◊ Provision of short term (e.g. Fast Reserve) services without permitting a maximum duration of such provision to be set – which prevents storage from bidding;
     - ◊ Conflicts in timescales of service provision, e.g. Demand Turn Up operates on different times of day from all other ancillary services; STOR mis-aligns with embedded benefits;
     - ◊ Banning from multiple revenue streams, e.g. EFR and CM;
     - ◊ Large incumbents seeking to use regulatory restrictions to impede competition, e.g. the recent embedded benefits review.
3. The list of benefits whose provision is not remunerated is large, and even (as in the case of inertia versus EFR) contradictory – see Unremunerated services 3.1 s4 above.
4. Proposed changes to market and regulatory arrangements are throughout this consultation response.

System value pricing, Half-hourly settlement 3.2 s5-10:
See comments above (on 3.1 s3) about how this is only tinkering at the edges of the problem unless the market starts to provide realistic cost and revenue systems by reducing the total of all levies, charges and subsidies to 15-25% of the total consumer energy bill, for both private and commercial consumers, and also on the split between standing charges and energy charges.

The strongest case for short settlement periods is the development of Demand Side Response. However half-hour settlement periods do not coincide with the periods required for DSR to deliver ancillary services (ref. s8). Therefore there is a better case to be made for much shorter settlement periods, such as one minute. It may not be necessary, but consideration must be given to how the settlement periods can be made consistent with the provision of DSR ancillary services.

Another consideration as to whether or not “it is in consumers’ interests to be settled half-hourly” (s9) is that most consumers don’t want the hassle of managing their electricity consumption actively – and of those who would take on the hassle, not all would understand it. Of those who would reject the hassle, large numbers would not understand it. This would leave the less-well-informed and less-capable consumers penalised heavily for sub-optimal load management. It would also put at a disadvantage those in work, away (shopping, visiting others, trips, holidays etc.) or otherwise engaged, against those who can watch their meters on an on-going basis. Therefore services must be enabled that will provide today’s level of simplicity (review the bill only monthly or quarterly) while managing their services well.

System value pricing, Smart tariffs, 3.3 s11-14:
The comments on s9 (previous paragraph) apply to s11-12.

Even larger non-domestic consumers will not want to dedicate significant amounts of time to what is essentially a non-core activity that merely manages one cost among hundreds for the business. It is only a rare business that will consume enough for it to be worthwhile employing someone to do so, and even then such activities are alien to their normal work.

Questions: Smart tariffs

5. Smart tariffs will only happen with Government and Ofgem pushing them and the smart metering roll-out that underpins it. However it will only be beneficial if it is so simple that most can benefit without spending more than half an hour a month looking at their electricity usage and actions: this is likely to be the most fruitful agenda for Ofgem to push if widespread take-up / usage of smart tariffs is wanted. This will require not only smart tariffs but also smart control mechanisms, and simple ways to over-ride them (e.g. if a spin dryer is absolutely needed now, rather than in an hour's time). Note that tariffs need to be understood by those of less-than-average intelligence or understanding of the electricity market.
6. Yes: simple tariffs and control mechanisms, as above.
7. Don't know.
8. People's lives are already very complicated and getting more so. This is increasing stress and burn-out. Simplification is the key.

System value pricing, Smart distribution tariffs, 3.4 s15-24:
Increasing numbers of consumers (domestic, commercial and industrial) generate their own electricity, and even store it. Their net electricity consumption is low, but they are almost as dependent on the grid for back-up as the consumers that have neither generation nor storage. Currently, to a large extent, these early adopting consumers are free-loading on late-adopters because grid usage charges are largely mark-ups of electricity unit costs.

The cost of grid (wire and some back-up services) provision should be estimated and rolled into a basic grid connection charge. The extent to which this is not done is a cross-subsidy to incentivise adoption of these technologies.

Grid use of service charges for installations with batteries should be proportional to the storage volume (kWh) and power (kW) of the battery as compared with the consumption/generation (kWh) and power (kW) of the installation.

Where the battery is considerably larger than the balance of the installation (e.g. a grid connected battery with a solar cell / small turbine to reduce ancillary loads), grid usage charges should be only for the net consumption of electricity, i.e. charging for inefficiency.

With smart meters, use of service charging can be done based on (say) average usage during the 100 peak usage half-our intervals over the year. Ditto feed-in tariffs. This eliminates triads and the system-playing that takes place – though it would not necessarily reduce peak demand and hence limiting grid investment, for which some triad element could be retained.

Your proposals in s19 and s21 look far too complicated, unless all the complication is absorbed by aggregators and service providers.

Questions: Smart distribution tariffs

9. Yes. They compel other users to bear the cost of backing up early adopters' energy supplies (first paras. above); and they mean that storage must pay distribution charges twice for merely providing a time displacement for which they should pay none.
10. Greater standing charges to reflect the cost of providing back-up services (2nd para. above); modifications to reflect installed storage capacity (3rd and 4th paras above); and network usage charges based on smart metering (5th para. above).
11. Making the charges reflect the cost of backing up early adopters is urgent, because the longer it continues, the more losers there will be from a change; however it may politically be considered a good financial inducement for late adopters to adopt the distributed generation and storage technologies. Avoiding distribution charges on storage is both urgent and important, in order to enable the roll-out of storage across the grid.
12. You will always have to determine and charge for maximum usage, whether that's by triads or by other means, because grid capacity and upgrade investment depend on such maximum usage. But current DUoS charges prevent roll-out of storage and should be stopped for storage.
13. A charge can only send out a signal about what it is charging for. However, the trend in that charge says a lot about long term costs and priorities. Therefore an official forecast of DUoS charges would help with long term signals; long term committed prices (e.g. over a rolling future 5 years) would be seen by potential investors as certainty of future revenues, and so encourage private sector investment.
14. Comments in chapter 5.

System value pricing, Other Government policies, 3.5 s25

Renewable generation must be supported for various reasons including:

1. Climate change;
2. Pollution;
3. Developing globally leading electricity and related services industries, with associated manufacturing and exports.

Clean energy generation should incentivise both cleanness and dispatchability. The latter can be storage assisted. Otherwise the fossil fuelled power stations backing up the renewables would pollute more and more per MW of output, and cost more and more in subsidies as their utilisation drops but the need to keep them operational remains. These incentives are compatible with the 21st Century Electricity System proposed with this feedback: the system provides some incentivisation, while further financial incentives can be added to encourage early adoption and development of technologies.

System value pricing, Other Government policies, 3.5 s26
CfDs should be made available for storage. Ideally (and most cheaply and flexibly) they should guarantee minimum price differentials between purchase and sale costs of electricity; otherwise they would still work well based upon sales prices alone.

The RO was a very valuable incentive for fossil fuelled generators to pay for their pollution. This includes distributed generation. They should not be applied to renewable generation. Nor should they be applied to clean (i.e. not consuming fossil fuels other than the fossil share of in-fed electricity) storage; dirtier storage should receive an RO in proportion to the emissions per MWh averaged over any given quarter, maybe with an annual adjustment for accuracy.

System value pricing, Other Government policies, 3.5 s27-30
The Capacity Market (CM) is a subsidy for fossil fuelled generation. It incentivises no new generation capacity other than the worst kind, MW scale reciprocating engines. It tilts the playing field against renewable generation in general, and against storage in particular. It adds to costs and to numbers of contracts that need to be tendered and juggled by generators, with risk premia added to allow for potential loss of a tender. It is too low to incentivise significant new construction, or even the keeping open of existing plant: Eggborough decided that the costs of fulfilling their contracts outweighed the penalty costs of closure, and other existing plants are scheduled for closure without even trying for a CM contract. It is a £1.3bn p.a. failure.

The CM would be rendered unnecessary by full implementation of the 21st Century Electricity System proposed with this feedback. CfDs would also be rendered unnecessary except inasmuch as the government wishes to incentivise the development and installation of specific technologies. But please note that these cannot be removed without full implementation of the proposed System; claiming the benefits without implementing the actions in full will jeopardise the entire system.

If the decision is to tweak the CM rather than to replace it, then storage should be explicitly encouraged, alongside innovation as discussed in the 21st Century Electricity System document.

The only ways to incentivise innovation, start-ups and new entrants in the market are

- Long term contracts;
- Letting long term contracts (at least in principle) before planning and grid connection are established, to break the chicken-and-egg cycle;
- Permitting longer timescales to start of contract delivery, to permit new grid connections;

- Premium prices being awarded to new technologies / first-of-a-kind installations, decreasing linearly in a highly predictable manner for subsequent installations, to zero within a finite number / size of installations.

Questions: Other Government Policies

15. The failure of the Capacity Market is so evident (see the above comments) that it is incredible that "Government is clear that the fundamentals of the CM design are sound at present." The RO very successfully incentivised clean generation and penalised dirty, but the government has stopped it – even more incredible.
    - The biggest problems investors have in the market are all government generated: large scale investment cannot happen without long term contracts; subsidising fossil fuelled generation doesn't help the transition to renewables; increasingly frequent fiddling with the regulatory regime has turned the British electricity market into the least investable in Europe.
16. Abandon the CM in favour of the 21st Century Electricity System as proposed, with one-third of all contracts let for 15+ years for new build only, one-third for 7-8 years provided there is major capital investment or new build, and one-third on short term contracts; with non-price incentives for both first-of-a-kind plants and greenness of technology. Failing that, explicitly encourage storage within the CM, ensure that CM prices are meaningfully high, and incentivise innovation, start-ups and new entrants as described in the above section.
17. All investors who have been keen to invest in large scale storage have balked at the lack of long term underpinning of revenues. Therefore the current system drives away private sector investment into the industry.

A System for the Consumer, Smart appliances, 4.1

The only feedback we have for this is as follows:

- As soon as you have internet connected systems, they are both maliciously hackable (including recruitable to botnets) and liable to incidental infection. Therefore there need to be provisions for:
    - Opting out of all internet connections;
    - Compelling the changing of passwords, when first used.
- People want simplicity, not stress. See the above feedback on half hourly settlement 3.2 s5-10, and on smart tariffs, 3.3 s11-14, above. Most people don't want to have to programme their dishwasher (s1), or "optimise their energy use" (s2), on a day-to-day basis: they want to decide on a way of living, and then just get on with it. Therefore aggregators / suppliers need to be incentivised to simplify their offerings.
- People also want control. If they need the car to be charged because their grandchild is due, they don't want it automatically to delay charging and even to partially discharge during the evening peak. If they're freezing a large joint, they don't want it to go off before freezing. If they need to get clothes clean for immediate wear, they don't want the washing machine or drier to delay its operation. Therefore one-button temporary opt-outs will be necessary on ALL

smart appliances. And because sometimes these situations are permanent (e.g. a chronically ill member of the household who may need help / transport at any time), a permanent opt-out must be provided.

- One helpful introduction would be real information. For example, a washing machine may have an “eco” 30^{O}C cycle that takes 120 minutes or a standard 40^{O}C cycle that takes 80 minutes: does the longer duration consume more electricity than the temperature reduction saves? Put expected energy consumption per cycle on the labels and in the instruction booklets.

A System for the Consumer, Ultra Low Emission Vehicles in a Smart Energy System 4.2 s8-16

Please see the above section on smart appliances for the need for opt-outs to central control.

A key problem with the visionaries’ concepts of vehicles charging from solar during the day and partially discharging at peak to support the grid is that the charging and discharging locations are so often different. The day-time location for charging is likely to be at work or in a car park, while the evening peak location is likely to be at home. There would need to be a large (and probably un-taxed) price incentive for companies to charge up employees’ vehicles to increase their earnings at home – which would also discourage workers from working overtime as they rush home to earn the peak tariffs, again to the detriment of employers.

Moreover, the life of batteries is defined in charge / discharge cycles. If the battery is charged and discharged by the grid / aggregator, who pays for its increased aging?

And electric vehicles are no panacea to the challenge of large scale storage.

- A typical electric car has 50-60kWh batteries.
- Over the life of the battery, the capacity decreases by 30%, so average fleet capacity is always 15% down on nominal fleet capacity, meaning that the grid could use possibly as much as 10kWh, being 20-25% of true available vehicle capacity.
- The government’s TINA (Technology Innovation Needs Analysis) report identifies a need for 27.4GW, 128GWh of storage in today’s market, in a range that extends as high as 286GWh with increasing electrification of transportation, heating and industry.
- Using vehicle batteries for grid storage assumes this top-of-the-range electrification scenario.
- This therefore requires over 28 million vehicles to be actively providing energy back-up to the grid. That’s a tall order – especially if we consider the vehicles that operate during peak demand hours, those that opt out of usage due to need or preference, and also vehicles powered by other energy vectors such as fuel cells and LPG / LNG.

Questions: Ultra Low Emission Vehicles

33. Create options for users to control the extent to which vehicle charging and discharging can be controlled by others. Create a mechanism for remunerating each body: vehicle owners, providers of charging energy, beneficiaries of storage services. Include the wear and tear on the battery within remuneration.
34. Charging and discharging are often in different locations. Beneficiaries and providers of energy and of storage services are different. Priorities of users change from user to user and from time to time. More charge and discharge cycles wear out batteries faster.
35. The issues with electrolysis are primarily the inefficiency of the process, currently 20-30%. This must be addressed to make fuel cells (which are themselves about 75% efficient) viable. There needs to be an incentive to use otherwise-curtailed generation for electrolysis. Standards need to be promulgated for hydrogen storage, filling etc. including nozzle size, procedure, pressure, temperature, liability for accidents.

A System for the Consumer, Consumer engagement with DSR, 4.3 s17-25
Please see the above section on smart appliances 4.1 for the need for opt-outs to central control. Please see the above feedback on half hourly settlement 3.2 s5-10, and on smart tariffs, 3.3 s11-14, above, for the need for simplicity, consumer control and opt-outs. All of these apply in differing degrees to both domestic and commercial (including very large scale) customers.

There are few large non-domestic consumers for whom the benefits that can be earned from DSR would provide a significant impact on their profits – and even fewer who would see it as sufficiently “core business” to dedicate people to managing DSR and other interventions to minimise bills and generate revenues from electricity trading.

Then we can eliminate those whose incurred costs would outweigh the benefits. For example, if the power were cut from a smelter for half an hour, the shift would have to work half an hour later, with attendant overtime and overhead costs; some overnight processes would also suffer knock-on impact, and just-in-time deliveries may also be impacted. The scale of these impacts is such that many DSR participants may drop out when they see its effects.

Additionally, if a DSR resource is used then it cannot be used again soon. This means that two calls upon DSR must be met by different assets. National Grid estimated that total DSR potential is 5% of peak demand: this consideration would halve it.

There are great benefits in DSR, but they should not be over-estimated. DSR has a rightful part to play in balancing the grid, but no more than 2-3% of peak demand. Anything more than that could be characterised as paying £billions to degrade our first-world grid into a third-world grid, if we define a first-world grid as “switch on, and the power is there”, whereas a third-world grid would be “switch on, and it will think about it.”

A System for the Consumer, Consumer engagement with DSR, Questions

36. I believe that almost all have to be approached by aggregators; virtually none find out and look into it proactively.
37. Barriers cited above, in some detail. In summary: additional operational costs could be incurred. Benefits would not be enough to justify the management focus on an essentially non-core part of the business. Volumes called upon at any time should never be such that power is not available when needed.
38. I think that current initiatives are good: it's the proactive aggregators who are likely to provide the best service. Those aggregators could be helped by informing them of big customers within their operational region – but this would fall foul of privacy and data usage laws and principles.
39. Consumer DSR only becomes a priority when smart appliances are widely rolled out. Until then, information on DSR and its providers should be given with all smart appliances when sold.

A System for the Consumer, Consumer Protection, 4.4 s26-29

Please see the above section on smart appliances 4.1 for the need for opt-outs to central control. Please see the above feedback on half hourly settlement 3.2 s5-10, and on smart tariffs, 3.3 s11-14, above, for the need for simplicity, consumer control and opt-outs. All of these apply in differing degrees to both domestic and commercial (including very large scale) customers.

Please DO NOT give away information on consumers to aggregators, or the consumers will be plagued by salesmen who would rapidly give the market the same dreadful reputation as ambulance chasing legal firms. That nightmare scenario would cause a substantial backlash against DSR.

It would make sense to distribute DSR information (including providers' details) to households who have been converted to smart meters, in booklets with approaches such as "how to make the most of your smart meter", or "now you've got a new smart meter, how can you benefit from it?"

A System for the Consumer, Cyber security, 4.5 s30-34

Please see the above section on smart appliances 4.1 for comments on cyber security. Your list of cyber attacks omits recruitment into botnets, which may never be noticed by the owner of the recruited appliance.

Consumer protection and cyber security, Questions

40. Any cyber problems are creating increasing problems for users, whether consumers, businesses, service providers or infrastructure. Compelling changes to as-purchased passwords are necessary. Opt-outs from internet connectivity should be offered on every suitable item of equipment. Don't ever believe that a majority of users have the time, inclination and capacity to be "informed consumers". Assume that everything possible will go wrong, including hacking, infection and recruitment to botnets, and plan accordingly.

Privacy is also a major concern, especially with the extent of user information known by the big IT companies.

41. A malicious user could shut down key parts of the system – or overload them. They could gratuitously increase consumption, or take control from users – and could do so gradually, to prevent detection. They can access user accounts and financial information.
42. The three biggest risks, all of which have very high likelihood, are hacking, infection and recruitment to botnets. The last is of lower impact to the user but high impact to society; the other two are high impact to both. Malicious operators include governments, criminal organisations, individual criminals, politically / economically / environmentally etc. motivated groups, people with grudges, hackers "doing it for kicks" etc.

The roles of different parties in system and network operation, 5
You mention trials (ii), yet every time I mention running trials of new structures, markets and contract types by means of a bilateral contract, BEIS, Ofgem and National Grid scream "can't back winners, must have a level playing field" at me. Without trials, all kinds of problematic outcomes will continue to arise from changes.

This entire section focuses on distributed generation and consumption, to the complete exclusion of centralised generation and consumption. Therefore the only conclusions are distributed actions and distributed storage, ignoring the need for centralised actions and transmission connected storage – or even distribution connected storage at an area or district scale.

Every single distributed scheme incorporates, overtly or tacitly, connection to the grid for back-up. There is no consideration in this entire section as to how the grid is to provide that back-up, or contract for it, or remunerate it adequately. For example, weather systems with low renewable generation regularly sit over the country, and even over the whole of NW Europe, for days at a time. This far exceeds the ability of any distributed storage, DSR or other local measure to make up for the lost generation. This leaves only two options: fossil fuelled back-up with very high subsidies to keep it available when generating very little, and large scale electricity storage, which is not considered by either this document or National Grid's Future Energy Scenarios. Interconnectors cannot be relied upon wholly, as that puts our power system at the mercy of other countries whose systems are undergoing similar patterns of demand, strains, loss of generation capacity and weather systems to our country.

The roles of different parties, The impact of system changes, 5.1 figure 1
Centralised large scale generation will never be entirely supplanted by distributed generation. There will always be large single-point generators (e.g. hydro dams, wind farms) and large single-point consumers (e.g. intensive users, industrial parks, cities). Therefore similarly large scale storage will be required, to complement the distributed scale storage. For this reason, all the emerging system requirements need to be enacted at both transmission and distribution scales. And distribution

scale enactment should include both distributed and centralised (area and district scale) equipment.

Loss of synchronous generation can be at least partly made up by installation of synchronous storage such as CAES and pumped hydro. This can only be ensured by providing a means for monetising inertia and natural reactive power / load. This is highly cost-effective: EFR requires active monitoring, active signals to initiate and terminate (with attendant, if small, delays), and artificial waveforms of energy; inertial systems need no monitoring and control, have no delays to start and stop, and generate naturally sinusoidal wave forms. Thus pricing the two the same will reduce the total system cost because the naturally inertial system is both cheaper to control and better in operation.

The “level playing field” is a myth, in its current form.

- National Grid’s guidance for new grid connections does not offer any new connections in less than 4 years, rising to 10+ years in congested parts of the network; yet no contracts are offered with delivery more than 4 years from contract, and only the Capacity Market (only a small proportion of revenues) greater than 1.5 years. Therefore existing connections are favoured over new.
- There are almost no long term contracts, preventing new investment by the financial services industry: Capacity Market is inadequate for the job. This is why new build in recent years has been done entirely with CfDs, ROCs, CATOs, OFTOs and cap-and-floor subsidies.
- There is no possibility of an indication of willingness to enter into contract, ahead of grant of planning permission and grid connection application, which makes it impossible for new entrants to come forward at the medium to large scale because they cannot therefore borrow money to get the planning permission and grid connection application.
- Generation pays grid access charges once, interconnection not at all because it’s a service provision; storage pays twice even though it too is a service provision.
- Not all services are remunerated, e.g. EFR (pseudo inertia) is remunerated, while inertia itself is not; nor is grid code required reactive power or load; nor are curtailment avoidance or grid reinforcement deferral.
- Companies can sit on grid connection applications without building, while others who want to build have to pay for unnecessary reinforcement as the sat-on applications take up the available capacity.
- A “resilient and secure system” does not currently involve either dispatchability (interconnectors are considered dispatchable, even though they are not; renewable generation is paid the same for energy whether or not it is dispatchable) or security of supply (can we rely on the in-country supply chain, right back to the beginning?).

The roles of different parties, System impacts, 5.1 Table 7:

Top 3 boxes: Many of the constraints listed in the first section can be alleviated much more efficiently by storage at national, regional, area and local (district) scale, to complement developments and storage at distributed scale.

Final box: This increase in the need for frequency response can be alleviated by widespread installation of grid scale, long duration storage that can mirror the short, medium and longer scale variations in renewable generation to balance the grid. This can be done much more cost-effectively if a majority of the capacity is at such scales, thereby limiting the cost to consumers of all kinds.

The roles of different parties, The need for immediate action, 5.2 s10:
All the network planning in the world will fail to deliver a cost-effective, secure, low carbon grid until the playing field really is level and all technologies can be considered for all appropriate functions. The biggest and most glaring omission from this is storage at all grid connected scales: area, local, regional and national. This omission prevents the efficient use of resources at all scales.

The roles of different parties, The need for immediate action, 5.2 s12:
No matter how much you “think the onus is on industry to address these requirements”, industry cannot do so unless and until the playing field is levelled, major capital expenditure incentivised by long term contracts with substantial and variable start dates, innovation is incentivised with early indications of contracts, greenness is incentivised such as by contract length (i.e. without subsidy), and all revenue streams are remunerated. Storage needs its regulatory definition, as explained above.

The roles of different parties, Further future changes to arrangements, 5.3 s15:
Monitoring progress is pointless without first enabling it. See responses to 5.1 Figure 1 and 5.2 s12.

The roles of different parties, Further future changes to arrangements, 5.3 s16:
Please see the associated document “A 21st Century Electricity System”. This is a much simpler, cheaper and more viable system than those models considered. The roles of the SO, DNOs and other parties are very much a secondary or tertiary issue.

We have no preference as to the model, as long as the players are incentivised in cost, emissions and security of supply in the 15-year and 30-year timescales as well as RIIO’s 8-year and 2-year timescales. Without such long term incentivisation, the system will be run into the ground because longer term actions will be, in effect, penalised. See responses to (among others):

- Towards, s42-46
- Removing barriers, 2
- Providing price signals for flexibility, 3, introduction
- System value pricing, 3.1 s1

The roles of different parties, Further future changes to arrangements, 5.3 s17:

These changes to the market mechanisms to decentralise pricing may well have the perverse effect of rewarding imbalances and penalising the storage that could alleviate them. SO revenues are largely a proportion of system costs, so if system costs are higher then so are SO revenues. If storage is offered that would reduce imbalances and constraints, and hence system cost, the SO revenues would drop, providing a major disincentive to network improvement.

The roles of different parties, Further future changes to arrangements, 5.3 s19: Local energy has a place but, like distributed systems, is not a panacea. It all needs to be integrated with equipment, systems, contracts and actions at distributed, local, area, regional and national scales – each roughly a factor of 10 different in scale from the adjacent scales. See comment on The roles of different parties in system and network operation, 5, second and third paragraphs.

Roles and Responsibilities, Questions

43. The emerging system requirements as set out are a small part of the system requirements. They address distributed and local issues in the short term, but omit:
    - Area, regional and national scale challenges;
    - Single-point major generation or consumption;
    - Resolution of grid constraints as opposed to alleviation by contractual means at (sometimes, maybe often) considerably higher overall cost;
    - Balancing services at any duration above an hour or two;
    - Emissions reduction, at any scale.
44. Please see the associated document Matching the Solution to the Problem:
    - (a) The issue of balancing the grid is, if we have baseload generation, of the order of 30GW for a duration of 12-30 hours. If we don't have baseload generation, then the issue of balancing is of the order of 80GW for a duration of up to 2 weeks – the longest duration expected of a low generation weather pattern.
    - (b) The entire system can be balanced, at the cost of today's system, by integrating storage at all 5 scales (distributed, local, area, regional and national) into the system. This is described in the associated document "CAES or Batteries", which also considers the roles of interconnectors and DSR within such a system.
    - (b) (cont'd) To achieve this, incentives have to be provided for first-of-a-kind plants, major capital investment, and remunerating all services provided. Such incentivisation can be achieved, without additional costs or subsidies, using the system described in the associated document "A 21st Century Electricity System".
45. The proposed actions are only a sticking plaster on a gaping wound.
    - (a) This will only work if the parties are incentivised on price, emissions and system integrity on 15- and 30-year timescales as well as on RIIO's 2- and 8-year timescales.
    - (a) (cont'd) It will also only work if SOs are incentivised to minimise whole-system costs over those timescales, without regular re-sets to remove the benefits of previous improvements; maybe such resets are best removed

by a form of amortisation of each action, rather than re-setting the entire framework; the benefits from the actions should be "amortised" over a timescale commensurate with the scale of the action, its costs and its benefits.

- (b) By implementation of a long term strategic, regulatory and contractual framework such as is in the 21st Century Electricity System proposal.
- (c) Yes, vast numbers of legal and regulatory barriers. There are very strong disincentives for capital investment, storage, new technologies, new grid connections, system costs reductions (due to RIIO's 8-year reset schedule), emissions reduction, security of supply improvement, national system resilience (as opposed to reliance on imports of both electricity and its raw materials), innovation, new technology introduction and so on. Contracts cannot be suited to the benefits provided by technologies, and not all benefits can be monetised. Top priority would be to implement the 21st Century Electricity System proposal.

46. Changes to roles and arrangements are irrelevant if the incentivisation scheme is so short-sighted, short duration, narrowly focused and filled with impediments to change. They will never make up for all the system disincentives for capital investment, storage, new technologies, new grid connections, system costs reductions (due to RIIO's 8-year reset schedule), emissions reduction, security of supply improvement, national system resilience (as opposed to reliance on imports of both electricity and its raw materials), innovation, new technology introduction and so on. Nor will they make up for the inability to monetise all benefits.

Innovation, 6 s1-4

Because NIA/NIC scope is rigidly defined, it prevents funding to many valid projects that would benefit the electricity system. For example National Grid has received a number of requests for bilateral contracts to provide the innovation support that NIA/NIC cannot provide, when the latter would be by far the best route.

Regarding large scale energy storage, we have tried on a number of occasions to receive funding towards developing our large scale storage system. The funding is managed by the DNOs and by National Grid: the former is not permitted to support any storage above 6MW, and the latter is not permitted to support any generation - and storage is currently defined as generation. Others in the industry find this incredible. Therefore this highly beneficial (for the grid and the system as a whole) technology risks dying for lack of support.

We propose a change whereby all approaches for funding that claim to benefit the electricity system substantially, but which are deemed out of scope, should be referred automatically to a decision maker and team within Ofgem (or the Energy Innovation Centre) who has the power and the budget to support any suitable proposals. The mechanism would apply equally to schemes submitted to the EIC. This would be a third leg of the scheme, to complement those of the SO and the Network Operator. It could be funded either by adding a separate element to the existing levy, or taking a precept from the SO and NO elements of the levy..

While there is room for competitions, in which the SO and NO define their needs, at least half the budget should be non-competed: anyone with any innovation that benefits the system should be able to apply at any time and receive funding if the project is good enough. This does not violate competition rules: it is how regional funding is allocated, for example.

Innovation, 6 s5-7:
Innovation spaces are good. £50m funding over 5 years is barely enough to support a few small incremental developments, and certainly nothing that requires a pilot at a substantial scale. This is putting us well behind both America and the European Union, both of which spend over 100 times what the UK spends on innovation in energy, with only 5x our GDP.

Despite the headline claims of the Energy Entrepreneurs Fund, it cannot by its own rules fund a pilot project into large scale storage. Such storage systems cannot efficiently be scaled down to within the £3.5m total project size. British funding for energy innovation is completely inadequate, and the more so as the scale of the innovation increases.

Innovation, 6 s8-19:
Defining general objectives is very good, provided that there is an “other innovations beneficial to the system” catch-all category. Such objectives give a good steer as to the priorities and needs of the SO and NO, as perceived by them. But without the catch-all, they would miss out on transformational innovations (or even merely beneficial ones) that don’t conveniently fall into those headings.

The effect of defining projects closely is mostly malign. While it again points to a specific need of the SO or NO, it excludes anything that does not quite fulfil the criteria. The descriptions also tend to add to the constraints rather than remove them. Thus innovators either are excluded or contort their innovation to something grossly sub-optimal in order to fit in with the project definition.

The effect of running competitions is also mostly malign. While again it drives innovation towards specific needs, it does so in timescales that do not suit the innovators: for some the competition timing may be premature, for others too late. So some projects are put forward before they are ready, and others have to linger un-developed until a suitable competition comes along – and that wait may be for many years, bankrupting small innovators such as SMEs and start-ups.

Another wholly malign effect of running competitions is that, because they attract so many unsuitable applications (e.g. premature, contorted to fit the criteria), there are too many for the assessors to liaise with the applicants. This leads to assessors failing to understand projects (even if clearly explained: we’ve had assessors stating flatly that it doesn’t do something that we very clearly and explicitly said it does do) and rejecting projects for either erroneous reasons (we’ve had a few, including an assessor stating flatly that it couldn’t be done when we quoted a very senior manager from Siemens, who would provide the technology, as saying that it both can and will be done using existing equipment) or mutually contradictory reasons (we've had one EEF application rejected as "not risky enough" and the application same [with some verbal tweaks] rejected the following round as "too risky"). Brief liaison between assessors and projects would quickly and simply resolve issues and improve project selection. Let's face it, the qualifications to be an assessor is (a) a certain expertise in the field and (b) they didn't come up with the innovation, so therefore it's beyond their immediate understanding.

Innovation, Questions

47. Support that is:
    - Openly defined as benefitting the electricity system;
    - Able to be applied for and granted without competition, in projects defined by the innovators to best suit the technology rather than contorted to fit a bureaucrat's imagination of what is needed or what it can and cannot do;
    - Able to be applied for and granted when the technology is ready for funding, without premature submission to fit artificial timescales, or having to delay submission and remain "on the shelf" (which may kill a start-up or SME) awaiting a suitable competition;
    - Assessed in liaison with the applicants, to resolve issues and improve project selection, and avoid killing projects because their innovation is beyond the experience or imagination of the assessors.
48. There must be an open classification for innovations that do not fit easily within a category, to enable all beneficial innovations to be assessed on a level playing field. This open classification should be the biggest, preferably accounting for over half of all funding: InnovateUK's Smart Awards regularly had more applications than most of the competitions put together – and the same with Horizon 2020's SME Instrument. This is because bureaucrats, even those working in the field and with great relevant expertise, cannot second guess what innovators will come up with: just look at IBM's infamous prediction that the world market for computers would be 5.

Issues Not Raised in the Consultation

1. Security of Supply

Security of supply means two things:

1. Keeping sufficient power in the grid at all times;
2. Securing the supply chain for electricity.

Unfortunately all regulatory and commercial activities in recent years have focused on the first and ignored the second. As a result, National Grid's Future Energy Scenarios is planning to use interconnectors for well over one-third of the country's peak demand, leaving us vulnerable to those countries' changing political and economic priorities at a time when Brexit is greatly reducing our market access and its legal enforcement through the European Court of Justice (ECJ).

In late November 2016 we already saw UK spot prices rising to £2,500/MWh because of planned and unplanned outages in France. That was while in the European Union, when the French knew that the ECJ would compel them to sell if we bid higher for the electricity than local off-takers. The generation crunch is increasing in gravity in most of our neighbouring countries, especially when a single weather system sits across NW Europe. Meanwhile our LNG supplies are jeopardised by increasing instability in the Middle East and North Africa, and we're not insulated from Russian political shocks either: if Russia were to stop exports, all our neighbours would compete with us to buy from our suppliers, sending our prices rocketing – and all neighbours now have immense LNG capability as back-up to the Russian pipelines.

Storage enables locally generated electricity, from local resources, to be stored locally for local use. Yes, it helps with trade through interconnectors, but it also enables us to operate without them – if we have enough storage.

2. Tweaking the System

On-going tweaks and modifications to the system are getting more and more frequent. 4 new or highly modified contract instruments were rolled out in 2015-16, 3 the year before, 2 the year before and 1 the year before that: the trend is very clear. Repeated consultations have created such uncertainty that the UK is now considered one of the worst environments in Europe for investment into the energy system[2]. Unless the system is addressed as a whole, the rate of changes will increase. Moreover, these changes are inexorably increasing the complexity of the system, raising barriers to entry and thereby deterring new entrants.

3. Subsidies

Continuing as we are, with on-going tweaks and modifications to the system, is resulting in an ever more expensive system. National Grid rejoices publicly that it has reduced the amount of curtailment on renewable generation; however it does so by controlling the output of fossil fuelled power plants ever more aggressively. By turning these power plants down and off so often, they are reducing the megawatts sold (their revenue) while increasing its pollution, fuel consumption and wear-and-tear: it's like driving a car around town instead of down a motorway. And their fuel costs are also increased: an increasing proportion of their demand is during peak demand hours, when gas prices are highest. All this results in ever increasing volume, variety and value of balancing and ancillary services, which are a hidden subsidy to fossil fired power stations to provide the back-up. And event these are not enough, so the Capacity Mechanism was created to shovel even more subsidies into fossil fuelled power stations.

All this is because the system is so loaded against electricity storage that no substantial plant has yet been built in the UK.

[2] http://www.raeng.org.uk/publications/reports/a-critical-time-for-uk-energy-policy, http://www.newstatesman.com/sci-tech/2015/03/uk-one-worst-nations-eu-renewable-energy

4. Contractual Complexity

There are currently 15 different contracts under which balancing and ancillary services are purchased, and this number is increasing steadily. Germany, for all its faults, has 3. This adds to administrative overhead, managerial and control complexity, financial risk, inflated system costs and political risk, as described more fully in the document "A 21st Century Electricity System" in the section entitled Contract Simplicity. This figure needs to be culled enormously, as discussed there.