RWE Response to National Infrastructure Commission Call for Evidence

8th January 2016

Introduction

This document is submitted on behalf of RWE's UK Generation and Retail businesses, RWE Generation UK Plc (RWEG), RWE Innogy UK Ltd (RWEI) and RWE npower Group Plc (RWEN), in response to the National Infrastructure Commission call for evidence.

RWE npower Group Plc is the retail energy supplier for around 5.1 million residential accounts and around 210,000 Small and Medium Enterprise business and Industrial and Commercial customers in the UK. RWE Generation UK Plc owns, operates and maintains a portfolio of gas, coal, oil and biomass stations together with a portfolio of smaller open cycle gas turbine and combined heat and power generation assets. RWE Innogy UK has an operational portfolio of over 2 GW, including wind farms, hydro plant and biomass generation. With a potential development portfolio of over 3 GW.

RWE is active within the energy storage market in Germany where already ca 20,000 – 30,000 domestic storage units have been sold, which are used in conjunction with domestic PV, although the motivation for the investment has been predominantly due to the customer's desire to achieve more energy independence.

In addition, RWE (through its network business) is trialling a 250kW lithium-ion battery to provide peak shaving services to offset high levels of PV feed in , as well as participating in the trials to assess the benefits of adiabatic compressed air storage systems and power to gas systems.

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

(i) What role can changes to the market framework play to incentivise this outcome:

The Government has recently implemented a package of Electricity Market Reform (EMR) that is designed to keep the lights on, to keep energy bills affordable, and to decarbonise energy generation. The key elements of this reform package are:

- A mechanism to support investment in low-carbon generation: the Feed-in Tariffs with Contracts for Difference (CfD);
- A mechanism to support security of supply, if needed, in the form of a Capacity Market;
- The Carbon Price Floor – a tax to underpin the carbon price in the EU Emissions Trading System;
- An Emissions Performance Standard – a regulatory measure which provides a backstop to limit emissions from new fossil fuel power stations; and
- The institutional arrangements to support these reforms.

Electricity Market reform is supported by:

- Electricity Demand Reduction;
- Measures to support market liquidity and access to market for independent generators; and
- Effective transitional arrangements.

In addition, significant progress is being made towards establishing the Internal Electricity Market to achieve an integrated market for electricity in the EU. This requires the adoption and full implementation of the Network Codes developed since 2011, the efficient and secure integration of intermittent generation linked to renewables, and the implementation of a stable regulatory framework for the development of new trans-European network infrastructures.

We do not believe that there is a case for further reform of the GB electricity market.

In the event of further changes to the market framework, this should be subject to a thorough cost **benefit analysis to ensure that the benefits of any change outweighs dis-benefits for all credible scenarios.**

(ii) Is there a need for an independent system operator (SO)? How could the incentives faced by the SO be set to minimise long-run balancing costs?

National Grid as Transmission Owner, System Operator, EMR Delivery Body, Interconnector owner and Capacity Market Delivery Body plays a central role on the GB electricity system. During the development of the EMR package the potential for conflicts of interest between the differing roles undertaken by National Grid was acknowledged and safeguards in the form of special licence conditions were introduced to the Transmission Licence.

National Grid continues to play a pivotal role in the electricity industry and this will be enhanced with the implementation of the Energy Union, the integrated European energy market. We welcome the commitment of the Secretary of State to work alongside the National Infrastructure Commission with National Grid, Ofgem and others to consider how to reform the current system operator model to make it more flexible and independent[1]. In considering how to reform the system operator model, the scope of this review must include a review of how the Distribution Network Operators operate and how they integrate with the System Operator and the Transmission Owner.

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

Ofgem recently completed a major reform of the "balancing market" through implementation of the recommendations of the Electricity Balancing Significant Code Review. From 5th November 2015 the imbalance pricing arrangements have been based on a single cash out price calculated from the most expensive 50MWh of bids or offers dependent on the direction of system imbalance (long or short). In addition, new arrangements for the treatment of reserve and demand control actions have been introduced such that cash out prices can rise towards the value of lost load (a price of up to £3,000 per MWh in a single half hour). These reforms will improve the effectiveness of the electricity market and address a "missing money" problem associated with the reserve procurement and demand control.

Whilst we welcome these amendments, the Supplemental Balancing reserve (SBR) continues to overhang the market and the recent announcement that coal units have been offered SBR contracts for winter 2016/17 serves to dampen prices since the long notice periods and run times mean that such units will need to be instructed well before an event develops.

[1] Amber Rudd's speech on a new direction for UK energy policy, From: Department of Energy & Climate Change and The Rt Hon **Amber Rudd MP**, Delivered on: 18 November 2015, Location: Institution of Civil Engineers, London, First published: 18 November 2015 at https://www.gov.uk/government/speeches/amber-rudds-speech-on-a-new-direction-for-uk-energy-policy

In order to provide value to consumers by enabling the recent balancing amendments to realise their potential to promote an efficient market, the SBR should be abandoned at the earliest opportunity

Implementation of the Energy Union and in particular the Framework Guidelines on Electricity Balancing and Electricity System Operation will have a major impact on cross border trading and electricity balancing. It is expected that these Framework Guidelines will improve reserve procurement and cash out arrangements, and the efficiency and effectiveness of the European electricity market.

(iv) To what extent can demand-side management measures and embedded generation be used to increase the flexibility of the electricity system?

Changes to the GB electricity balancing arrangements and implementation of the Energy Union will provide new opportunities for electricity market participants including demand side management and embedded generation. Improved price signals and reserve procurement will enhance cross border trade and deliver significant improvements for customers.

The extent to which demand side management measures and embedded generation can be used to increase the flexibility of the electricity system cannot be easily stated; although it is likely that its potential will be significantly constrained if policy continues to focus investment on the delivery of more generation capacity and network reinforcement before demand reduction and demand side response measures have been consistently and effectively supported and communicated to customers.

The recent DECC paper "Towards a Smart Energy System" contains a range estimates of the differing potential for DSR (for different customer segments) of between 1.2 – 4.4GW. However, despite the lack of agreement on the likely scale of the DSR potential, it is clear that DSR and embedded generation; if appropriately supported can provide essential sources of flexibility within a smarter energy system, with benefits for all consumers across the value chain.

The critical issue will be to ensure that the policy and regulatory frameworks are developed that provide sufficient clarity and incentive for all stakeholders to invest in these solutions. A key component to facilitate this development (and also for storage) will be to ensure greater exposure of the whole system costs (for both consumers and generators). As highlighted in our response to question 1, ensuring that the market can set the true costs for balancing the system would be a welcome first step.

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

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

In order to drive innovation and to minimise costs of electricity, it is important that storage is treated such that a competitive market emerges that can drive innovation, has the flexibility to access all markets and costs are minimised for the electricity consumer.

In doing so, it must be recognised that storage assets located at different locations within the distribution system, the transmission system, behind the meter or linked with generation assets will provide different services and derive revenues from different markets including energy price volatility, ancillary service provisions and avoidance of network reinforcement costs.

To encourage deployment:

Peak electricity prices need to allow for true value of scarcity to provide cost reflective price signals and to permit greater price volatility. Whilst recent reform of the “balancing market” is a positive step, there remain distorting effects of the SBR (as set out in detail in Q1) which serve to limit the realisation of scarcity pricing and hence undermine the case for investment in storage assets.

In addition, the threat of Regulatory and Policy changes have the potential to undermine investor confidence.

Treatment of Storage:

<u>Payment of system charges:</u>
It is essential that market mechanisms and regulations reflect the true costs and benefits of storage assets to provide appropriate price signals to enable the development and operation of an efficient and competitive market. In principle, the treatment of storage as both demand and generation is appropriate as this clearly reflects the operation of a storage asset and can be made cost effective and transparent.
The payment of system costs (and receipt of benefits) relevant to the storage asset’s location within the system and the time of charging or discharge is entirely appropriate

<u>Payment of energy taxes and levies :</u>
Again, treatment of storage as both demand and generation can be appropriate as this clearly reflects the operation of a storage asset and can be made cost effective and transparent as well as rewarding the use of high efficiency storage solutions.
The payment of consumption related taxes and levies (CCL, RO, FiT, and CfD costs) relevant to the storage asset’s location within the system and the time of charging is entirely appropriate **<u>provided</u>** the issue of double charging of these taxes and levies (ie the application of those taxes and levies on the energy used for charging as well as applying those charges on the of energy discharged from storage devices) to the final end-user.

We would welcome the opportunity to explore further detailed mechanisms such as longer term netting of imports and exports for the purpose of consumption based levies and taxes, and other options such as an examination of the Balancing and Settlement Code for the treatment of storage assets located on the grid could also be considered.

<u>Asset ownership:</u>

Energy storage technologies have the potential to participate in a wide range markets, delivering benefits to the electricity network (at both distribution and transmission levels) and its operation.

Whilst new markets will evolve throughout the life of assets, it is expected that storage can provide benefits including:

1. Reducing the need to reinforce distribution / transmission networks
2. Providing ancillary and balancing services
3. Providing enhanced frequency response
4. Providing peak capacity
5. Providing demand side response
6. Providing electricity price arbitrage
7. Enabling the more efficient use of electrical connections for intermittent generators (particularly renewable technologies)
8. Enabling the increase in self-consumption of energy from embedded generation

To efficiently deploy storage assets, asset owners must be able to access all of the potential markets relevant to the storage assets location within the System.

There are other potential barriers to utilisation by specific organisations such as Distribution Network Operators, Transmission System Operators due to the current classification of storage as a "generation" activity and the current rules preventing Transmission and Distribution Licence holders from also owning generation assets. However, we would caution against noting this as a specific market failure, given the clear need to ensure genuine unbundling within the market to ensure a market based mechanism that is both efficient, open and doesn't lock in actual or potential structural advantage or discrimination either for or against different market participants.

Whilst it is entirely appropriate for network and system operators to procure the relevant services from storage assets on a competitive basis, it is not appropriate for them to directly participate within these markets without losing independence and foreclosing competitive markets and hindering innovation.

One proposal that has been suggested (by ENA and others) is to treat storage as a distinct licensable activity, for which exemptions (by Distribution licence holders) could be made. Whilst this may enable more storage facilities to be developed,the issues would remain as to whether distribution licensees could or should be allowed to offer and procure additional services that extend beyond distribution system requirements.
If storage were to be classified as a distinct licensable activity (as has been suggested by several organisation) then it could remove the barrier to DNOs / DSOs from owning storage technologies which could help with grid operation / avoid grid reinforcement. However, this would solely be one use of the technology and would not enable the DNO / DSO to fully access the associated value of the storage technology – in particular the balancing and reserve services that can be provided to National Grid.
If such a solution were to be considered, it will be vital to ensure that DNOs and potentially the TSO's are required to source associated services through competitive tendering (without DNO / TSO asset ownership), with the procurement managed in a fair and transparent way, to ensure other sources of flexibility (including but not limited to load management / DSR actions and additional distributed generation) are not discriminated against and unable to compete in a fair and transparent market.

We therefore support current structures that prevent direct ownership by Transmission and Distribution licence holders who are a natural buyer of a number of services. However, such entities must be able to procure services from the market.

<u>General barriers to entry:</u>

RWE notes there are some barriers that could prevent investment in energy storage, not least the <u>current</u> cost of the technology. We do expect that some storage systems (battery systems in particular) are likely to continue to benefit from the ongoing reductions in cost of ca 10-20% per annum. that have been experienced in the battery storage market, resulting in part through increased economies of scale , increased participation of automotive companies (which have developing battery storage for electric vehicles) and increased demand. There are however still significant differences in the cost of batteries (dependent upon size), with an expected cost of €700-€1000 per kWh for smaller storage systems, compared to average cost of €400-€700 for larger systems suitable for use by utilities.

The extent to which these barriers can be overcome will depend largely on the particular solution proposed and for purpose of the solution.

Impact of use of system costs

As storage can act as both supply and demand, there is a risk of uncertainty regarding the use of system charges and balancing system charges applied . There is also an additional risk that without a clear methodology for determining the type of storage (and its primary purpose (i.e. peak shaving, ancillary services to grid etc) that (as per generation) storage may be classed as intermittent (or non-intermittent) in a way that reduces the commercial benefits of investing in storage.

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

We believe it is far too early to determine (or even consider) what the most appropriate scale for future energy storage technologies in the UK might be, given the current regulatory, and legislative uncertainty. Based on the experience of our parent company RWE, we believe that there will be sufficient opportunities for utilisation across the range. We note that in Germany, already ca 20,000 – 30,000 domestic storage units have been sold, which are used in conjunction with domestic PV, although the motivation for the investment has been predominantly due to the customer's desire to achieve more energy independence.

In Germany, RWE (through its network business) is trialling a 250kW lithium-ion battery to provide peak shaving services to offset high levels of PV feed in, as well as participating in the trials to assess the benefits of adiabatic compressed air storage systems. We believe that with a well-designed and regulatory approach that recognises the unique status of storage (both as a source of supply and demand) should facilitate the appropriate development and take up of the technologies without risking distortions to the competitive market across all scales, given the different commercial and behavioural motivations that exist. Storage must be treated equally (neither discriminated for or against) in relation to other technologies / sources of flexibility.

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

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

RWE is supportive of efforts to improve interconnection between GB and the continent which will improve market liquidity, competition and security of supply. We expect interconnectors to play a growing role in the integrated European electricity market by enabling balancing of supply and demand as the impact of renewable generation increases.

As we stated in our response to the Ofgem consultation on the Cap and Floor regime it is important that the merchant approach towards DC interconnection is retained as the preferred route towards investment. However, we recognise that interconnectors form part of the transmission system in line with Directive 2009/72/EC. As such interconnectors must comply with all EU Regulations, guidelines and network codes. The cap and floor approach has a role to play in ensuring efficient and cost effective provision of vital infrastructure where such an approach can be properly justified.

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cap and floor approach may have a role to play in ensuring provision of vital infrastructure if such an approach can be properly justified.

However, these “arrangements could result in GB customers underwriting a significant degree of downside risk for interconnector investment (i.e. there is insufficient revenue from flows and customers end up funding the investment through the floor arrangements).

Whilst interconnectors can provide clear solutions in addressing the energy trilemma, we are aware of in increasing body of evidence that suggests that a large proportion of interconnectors provide no advantages with regard to carbon intensity, security of supply or affordability over and above domestic generation. We would therefore propose that the Cost Benefit Analysis, and the scope of the CBA is revisited before additional commitments are made.

(ii) Are there specific market failures/barriers that prevent investment in electricity interconnection that are not faced by other ‘balancing’ technologies? How might these be overcome?

We do not believe that there are specific failures or barriers to prevent investment in electricity interconnection that are not faced by other balancing technologies. We note that under the European Union third package that interconnectors form part of the transmission system and are not considered to be a balancing technology in their own right. Consequently we believe that interconnectors provide a route to market for balancing technologies. In addition, interconnectors can facilitate cross border capacity markets, though further where work is required to ensure the cross border participation of power stations and demand side providers.

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

From an internal review of EU and US energy market transformations, the New York Reforming the Energy Vision “REV” appears particularly relevant. Part of the NY REV seeks to meet existing grid objectives of low cost, reliability, universal access and enabling new technology. The efficient management of peak demand is a key part of this programme, and delivered by aligning demand with distributed generation, and demand side response.

Remuneration for services is based on the system value, as discovered through market mechanisms, potentially dependent upon location within the network. This transparency has been crucial to determine the value of energy efficiency, demand response, solar and storage and enables comprehensive cost-benefit analysis.

As a practical example, Con Edison’s Brooklyn Queens Demand Management Programme initiative highlights the potential of such an holistic approach where an original $1.1bn investment requirements was ultimately reduced to c$0.5bn through the use of the above mechanisms and targeting investment (by providing investment signals to market participants) in embedded solutions to mitigate the need for such an extensive investment in copper.

In addition, the California model provides an example of an effective Distributed System Operator which is a technically neutral market place coordinator. The DSO is itself limited to managing real and reactive power flows. Such a mechanism enables the full range of services to be developed in a transparent way. It is reported that up to 30 different services could be envisaged.

Both examples are particularly driven by a strong focus on cost & value and security of supply.

Common denominators are unbundling of services to enable efficient markets and a distribution service platform provider concept.