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The Rt Hon Lord Adonis PC
Interim Chair
National Infrastructure Commission
1 Horse Guards Road
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*Submitted by email*

8 January 2016

Dear Lord Adonis,

**Response from EnerNOC to the Commission's call for evidence on improving how electricity demand and supply are balanced**

EnerNOC is grateful for the opportunity to contribute to the Commission's consideration of how to future-proof the nation's energy infrastructure.

EnerNOC provides energy intelligence software and services to commercial and industrial energy users and to utilities. As well as helping users manage their energy usage and costs, we work with them to offer their demand-side flexibility into wholesale capacity, energy, and ancillary services markets and utility programmes. In the UK, we employ 26 people and have commitments to provide demand-side flexibility both to National Grid and in the capacity market.

These comments are informed by our experience of providing demand-side flexibility in twelve countries, under a very wide range of market designs. Before addressing the relevant questions in the call for evidence, we first explore the changing nature of the UK's electricity system and clarify what we mean by demand-side management.

## 1 A brief primer on power system planning

Power systems have traditionally been planned by predicting demand, and making appropriate supply-side investments to meet that demand. These days, markets are preferred to central planners, but the principles are similar.

A key consideration is the expected maximum level of simultaneous demand there will be – this, plus a reserve margin to provide adequate reliability in the face of likely contingencies, determines the total capacity needed.

It is also important to consider how often particular levels of demand will be reached, as this is what determines which technologies are appropriate.

There is a trade-off between fixed costs and variable operating costs:

- Capacity which will be needed most of the time is best provided by the generators with the lowest short-run marginal costs (£/MWh), even if those are expensive to build and maintain (£/MW/year). These are typically called "baseload" resources, such as nuclear, coal, and combined-cycle gas turbines.
- For capacity which is needed less often – "peaking capacity" – the short-run marginal costs become less important, as the fixed costs tend to dominate. The lowest total cost is achieved by using technologies which have lower costs to build and maintain, such as open-cycle gas turbines, gas- or diesel-fired engines, or demand-side management.

The-load duration curve is a helpful tool for understanding what is needed. Figure 1 shows (in black) the level of demand for each half-hour of 2014, sorted in descending order of demand.[1] It shows that peak demand was 51 GW. Of this demand, 27 GW is present for 80% of the year – we will call this "baseload demand".

In the absence of a central planner, it is the role of the capacity market to procure the total amount of capacity required at lowest cost, and it is the role of the wholesale energy markets, balancing market, and ancillary services markets to provide the price signals which determine what sorts of capacity become attractive to investors.

## 2 How is the job of the UK's electricity system changing?

Intermittent renewable power sources such as wind and solar photovoltaics provide energy at the lowest short-run marginal costs. The electricity system should therefore use whatever energy these sources provide in preference to any other.

This means that the job of the controllable energy sources is to supply the residual demand: what is left after intermittent renewables have supplied what they can. The blue line in Figure 1 shows a load-duration curve for this residual demand in 2014.[2] The peak residual demand is still 51 GW, but baseload residual demand is 24 GW.

National Grid's most recent Electricity Ten Year Statement shows that the amount of wind generating capacity is expected to double in the next three years and quadruple in six years.[3] The pink and red lines in Figure 1 show approximations to the residual demand with such increased levels of intermittent generation.[4] In

1 Data from EnerNOC analysis of FUELHH data published on the Elexon Portal.

2 The FUELHH data set only covers large generators and interconnectors. Solar and most smaller wind generation appears in this data set simply as a reduction in apparent demand. Hence, in calculating the residual demand, we have only subtracted out the contribution of the large-scale wind generators that were present in the original curve.

3 National Grid, *Electricity Ten Year Statement 2015*, November 2015, Appendix F.

4 Again, since only large-scale wind generation output is present in the data set, we have only doubled or quadrupled this contribution. We have effectively assumed that demand patterns and small-scale wind and

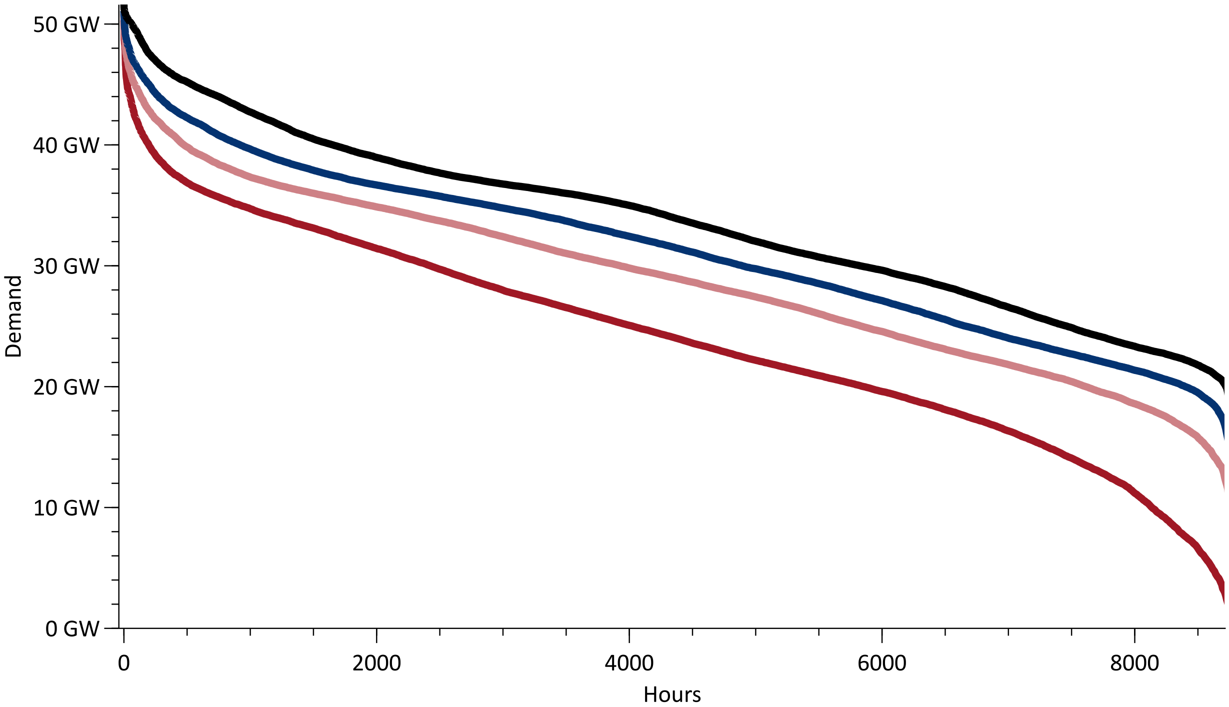


Figure 1: Load-duration curve for 2014, showing total demand (black), residual demand after removing wind (blue), 2x wind (pink), and 4x wind (red).

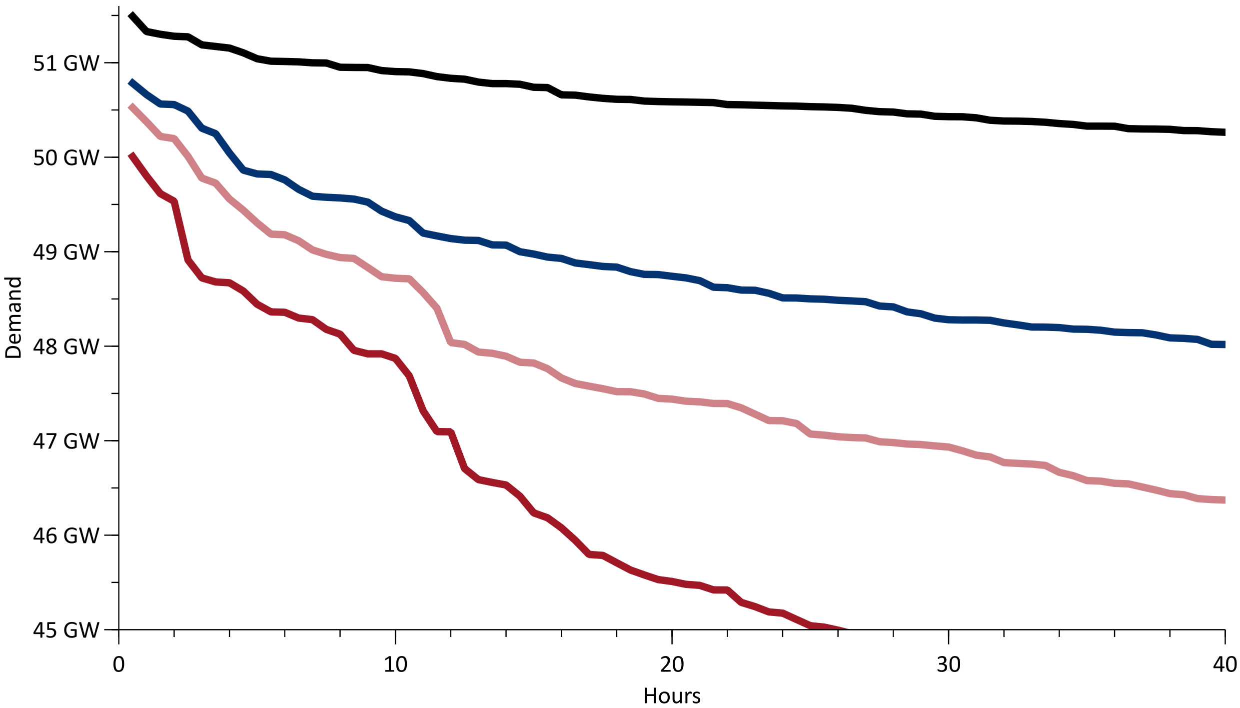


Figure 2: Top 40 hours of load-duration curve.

solar generation levels remain unchanged. This means we are probably understating the change.

these scenarios, peak residual demand barely changes, but the baseload residual demand falls to 22 GW and then to 16 GW.

This anticipated substantial fall in baseload residual demand means that we should not expect to replace retiring baseload capacity with new baseload capacity one-for-one. If we were to do so, the new baseload capacity would be underutilised.

If we look more closely at the top end of the load-duration curves, we see an even more dramatic shift. In Figure 2, we can see that 2 GW of residual demand in 2014 occurred for less than 24 hours of the year. We should expect this to increase to 3 GW when wind capacity doubles, and to 5 GW when it quadruples.

It would be extremely wasteful to build conventional peaking plant that will be used so little. Demand-side management is the most cost-effective means to address this issue.

## 3 What do we mean by “demand-side management”?

Demand-side management is about controlling demand in response to price signals or system needs. This contrasts with the traditional approach where demand is treated as an exogenous input – something that can only be forecast, not controlled.

There has been an unfortunate tendency for UK policymakers to consider everything that is not a transmission-connected generator as “demand-side” – even large peaking plants, if they happen to be connected via a distribution network.

We believe that a more helpful distinction is the involvement of electricity consumers. Demand-side management is about making additional use of existing customer-owned assets – i.e. plant that is there because it is associated with the customer’s demand for electricity. This contrasts with the traditional supply-side approach of building new dedicated assets to serve the electricity market.

Using this definition, we would count as demand-side management:

- A customer reducing (or increasing) their demand.
- A customer shifting their demand forwards or backwards in time.
- A customer transferring load onto an embedded generator on their site, if the primary purpose of that generator is something other than electricity market participation.[5]

[5] For example, a hospital or data centre might install backup generators for use in emergencies. If the asset already exists, or is going to be built anyway, then it makes sense to use it in a way that benefits the wider electricity system. Most generators have to be run for a certain number of hours per annum so as to operate reliably; it is better for these to be hours when the supply is helpful to the system, rather than simply at times that happen to be convenient for maintenance staff.

- A customer transferring load away from a generator in a co-/tri-generation scheme, so as to increase the load seen by the grid at a time when the system has low demand and an abundance of supply.

- The use of battery storage, where those batteries have been installed for some other primary purpose.[6]

This means that we would not consider the following to be demand-side management:

- Generators – regardless of technology or network connection – that are built primarily for electricity market or network operator use.

- Generators that do not respond to market price signals or system or network operator needs – e.g. cogeneration systems that run continuously, or rooftop solar installations.

- Storage that is installed primarily for electricity market or network operator use – even if it is small and sits "behind the meter" on a customer's site.

## 4 Is there a need to reform the balancing market?

Yes.

Although there have been recent reforms to the balancing market to provide much sharper price signals, these signals still do not reach the right participants in some cases.

Specifically, a customer's supplier has balancing responsibility for that customer's demand.[7] The supplier procures supply to meet their prediction of the level of consumption, and they are exposed to imbalance prices ("cashout") on any errors. This could be a cost or extra revenue, depending on the direction of the error and whether the system is short or long at the time.

If the customer is participating in demand-side management through a third-party aggregator, they will occasionally be dispatched to change their consumption pattern in response to system or network operator needs. This unforeseen change puts the supplier out of balance, exposing them to the imbalance price.

There are two problems with this:

1. The supplier did not cause the dispatch, so it makes no sense to expose them to imbalance price for the dispatched volume. This could either be

[6] For example, telephone exchanges and most data centres have batteries to maintain uninterrupted supply between any failure of the mains supply and the starting of emergency generators. Similarly, electric vehicles' batteries could be used while they are connected to their chargers. In both cases, the assets have been installed for some other purpose, but can provide benefits to the wider system if appropriate price signals are provided.

[7] A few very large and sophisticated customers take responsibility themselves, or have it passed on to them by their supplier. This is a minority sport, and it not practicable for smaller customers.

an unjustifiable penalty, or a windfall gain, depending on the circumstances.

2. The third-party aggregator *did* cause the dispatch, so they should be exposed to the imbalance price for the dispatched volume.

The second issue is particularly important: the purpose of sharper imbalance prices is to provide a price signal to stimulate investment in flexible resources. Demand-side management is a highly capable and cost-effective source of flexibility. However, this issue prevents third-party aggregators from participating in the balancing market, so they are not exposed to the price signal.

This has a knock-on effect in the capacity market.

Most demand-side management comes from third-party aggregators,[8] whose capacity does not have access to the balancing market revenue stream, even though it is highly suitable for responding to the balancing market's price signals. This demand-side management capacity therefore has to be offered in the capacity auction at a price which is high enough to make up for the fact that it will not earn energy revenues.

Generators do have access to the balancing market revenue stream, so they can offer their capacity at a lower price, which puts them at a competitive advantage in the capacity market auction.

This tilting of the playing field means that more generating capacity and less demand-side management capacity will tend to clear in the auctions, and capacity prices are be higher than they need be. It takes the system away from the optimal resource mix.

This issue has been resolved in many other electricity markets, in various ways, allowing third-party aggregators to participate in the balancing market (or the local equivalent). The common principle is that, during a demand-side management event, the supplier should be responsible for the normal consumption of the customer, and the third-party aggregator should be responsible for the deviation from the normal consumption pattern.

Within Europe, this has been resolved in France and Switzerland and partly in Belgium.[9] It should be resolved similarly here.

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8 This seems to be the case in all markets where independent aggregators are allowed to compete to procure flexibility from customers. For example, in PJM, over 80% of demand response capacity is offered by independent aggregators; for ISO-NE and NYISO it's over 70%; in Western Australia it is over 60%; and in New Zealand it is around 50%. We suspect this is because successful aggregation requires a very different skill set from that normally found in a supplier or retailer, and suppliers often have conflicts of interest because large-scale demand-side management reduces the value of their generation portfolio.

9 See Smart Energy Demand Coalition, *Mapping Demand Response in Europe Today*, October 2015.

## 5 To what extent can demand-side management increase the flexibility of the electricity system?

To a very large extent.

The current level of demand-side management is quite modest, and much of it does not provide particularly useful flexibility.[10]

We will consider three routes to market for demand-side flexibility: the capacity market, the balancing market, and ancillary services markets.

### *5.1 Capacity market*

Systems with mature capacity markets which properly integrate demand response can have much higher levels of demand-side participation than we currently see in the UK. For example, in the United States, 10.2% of peak demand in ISO-NE and 7.4% of peak demand in PJM can be controlled through wholesale demand response programmes.[11] In Western Australia, the figure is 12.0%.[12]

These successful demand response programmes provide the system operators with a dispatchable resource which they can use as necessary to balance the system. This contrasts with the UK, where the capacity market design fails to provide the system operator with a dispatchable resource, and so only provides a crude form of flexibility. We think it may be unique amongst the world's capacity markets in this respect.[13]

The level of demand-side participation in the capacity market could be improved in two ways:

1. By opening up the balancing market and ancillary services markets to participation by demand-side resources, so that they are not entirely reliant on capacity market revenues.
2. By simplifying and reducing the cost of capacity market participation by demand-side resources.

We will discuss the first point in the following sections. On the second point, issues include unnecessary complexity and cost in metering arrangements,

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10 The bulk of what is typically counted as demand-side management in the UK consists of customers reducing their demand speculatively in an attempt to avoid Triad charges. While this does reduce the peak demand experienced by the system, it does not do so in a way which provides the system operator with a predictable, flexible resource.

11 Federal Energy Regulatory Commission, *Assessment of Demand Response and Advanced Metering*, December 2015, Table 3-3. Quoted figures are for 2014.

12 EnerNOC analysis of data from the Western Australian Independent Market Operator for their 2013-14 capacity year.

13 Since capacity market resources are paid to be available, you would expect that the system operator would be able to issue dispatch instructions to them, specifying what response it needs to balance the system. Instead, the system operator's only recourse is to issue a "capacity market warning", after which each capacity provider will determine whether they think a system stress event is likely to occur, and, if so, they will estimate level of response they will need to provide to avoid a penalty. The system operator only finds out the size and timing of each response when it happens. There does not seem to be any appetite amongst policymakers to improve the design in this respect.

requirements for excessively frequent tests, lack of flexibility in portfolio formation, and no provision for portfolio maintenance. Generally, these issues seem to have arisen from the market having been designed with large, centralised generators in mind, and provision for aggregations of small demand-side resources having been included as an afterthought. Reforms to fix these issues have been proposed to DECC and Ofgem, but it is not clear that they will be implemented.

### 5.2 *Balancing market*

Demand-side management resources should be given access to the balancing market, as previously discussed. At present, customers can take responsibility for their own balancing, either bypassing the normal supplier arrangements or using a pass-through arrangement. However, this approach is only practicable for the very largest, most sophisticated energy users.

To achieve broader participation, it is important that the procurement of demand-side flexibility be unbundled from retail supply so that independent aggregators can compete for customers' business. We are not aware of any electricity market that has achieved reasonable levels of participation without such unbundling.

### 5.3 *Ancillary services markets*

National Grid procures a range of balancing services to help it manage the system. Unfortunately, the way that National Grid has designed the ancillary services products it procures, and the tendering arrangements through which it procures them, show an unintentional bias towards arrangements which are suitable for large centralised generators but unsuitable for aggregations of small demand-side resources.

Demand-side management resources are capable of meeting many of the system's technical needs highly cost-effectively, and, in other markets, they do so extensively. It is unnecessary details of the product designs which preclude, or severely restrict, demand-side participation.

The exact issues vary between products, but examples include:

- Requirements to offer constant quantities for days or weeks at a time, or quantities fixed a long way ahead of real time. This is convenient for a generator of fixed capability, but severely constraining for demand-side management resources, where the quantity of a service that is available varies with the demand patterns of the participating customers.

- Telemetry requirements which may represent a reasonable trade-off between cost and performance when applied to a large power station, but are prohibitively expensive when applied to hundreds of smaller customer sites.

National Grid seems to be becoming aware of the issues through its “Power Responsive” campaign. However, a significant amount of work is required to remove these barriers.

PJM and New Zealand are examples of what can be achieved when ancillary service product and market designs are right. In New Zealand, over 80% of their “Fast Instantaneous Reserves” frequency management service comes from demand-side resources, freeing generation resources for energy production.[14]

## 6 What are the barriers to the deployment of energy storage?

Energy storage is not limited to batteries. In fact, much of what is normally called demand response is really a type of energy storage, and can provide the same services to the system as a battery can. For example, a cold store stores energy in thermal form, and can adjust its consumption up and down as needed, within limits.

Battery storage is likely to be deployed as many small resources on different customers’ sites served by different suppliers. As such, it will suffer the same barriers as other demand-side management capacity: inability to access all the potential revenue streams, and unsuitable product design.

## 7 What is the most appropriate scale for future energy storage technologies?

Nobody knows.

Policymakers should not try to guess, as picking winners rarely ends well. Instead, the best approach is to remove barriers, and to make sure that the appropriate price signals are available to all possible technologies and scales.

## 8 What can the UK learn from international best practice?

We have cited examples of best practice in other jurisdictions above. However, in summary:

- New Zealand and PJM provide examples of best practice ancillary services markets.
- France has fully integrated demand-side management into all aspects of the market.
- PJM, NYISO, ISO-NE, and Western Australia have integrated demand-side management into capacity markets on a large scale.

[14] EnerNOC analysis of cleared market offers in the NZ FIR market, 1 July – 19 October 2015.

I would be happy to provide further detail on these comments, if that would be helpful.

Yours sincerely,

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