Review of the second GB capacity auction

ELECTRICITY MARKET REFORMS

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On the 11th December 2015 National Grid and the Department of Energy and Climate Change (DECC) published the results of the second T-4 Capacity Market auction. In this briefing we examine the results, and comment on potential areas for concern going forward.

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Another low capacity price is good news for consumers but a lack of new generators means the future of our energy security depends on an ever ageing and increasingly unprofitable fleet.

Overview

- The auction cleared at a price of £18.00 per kW, slightly lower than last year and broadly in line with expectations.
- While low prices are good for consumers, the results of the auction still raise potential concerns.
- Plant failing to clear in the 2019/20 auction may choose to close (as evidenced by the closures following last year's auction) putting pressure on security of supply between now and 2018/19.
- Due to closures and possible delays in the commissioning of new plant, a larger than expected amount of capacity will now need to be procured in the T-1 auction for 2018/19 raising concerns about a lack of supply in that auction.
- Once again we have seen a large amount of new-build small-scale diesel and gas generation clear in the auction.
- Our analysis highlights the unfair competitive advantage these generators receive over more efficient generators in the auction - specifically, as a result of revenues from helping customers to avoid TNUoS charges, the large part of which are recovering sunk costs which have already been incurred by society.

Headlines

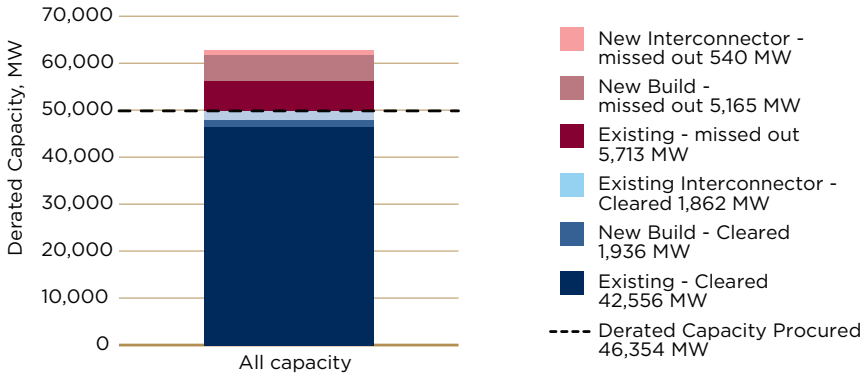
On the 11th December 2015 National Grid and the Department of Energy and Climate Change (DECC) published the results of the second T-4 Capacity Market auction, resulting from a government policy designed to ensure that there is sufficient generation capacity to meet the demand for electricity.

£942m
of capacity payments in 2019/20.

The headline figure was the clearing price of £18.00 per kW which will be paid to all successful participants for providing available capacity in winter 2019/20. This is broadly in line with expectations, and slightly lower than last year's clearing price of £19.40 per kW. The cost of providing capacity payments will be charged back to consumers through their electricity bills with the total cost expected to be £942m in 2019/20. £834m of this cost is for contracts awarded in this auction, with the remainder for multi-year contracts awarded last year to new and refurbishing plant. While this represents a significant cost it is broadly in line with expectations, with the relatively low clearing price reflecting the increased competition from interconnectors participating in the auction for the first time.

1GW
of small-scale new-build capacity secured a 15 year contract. No large-scale capacity secured a 15 year contract.

The final price is good news for consumers and is a result of significant competition between generators. This competition has meant that no large-scale new plant were able to secure a contract (with the exception of the almost completed Carrington), and almost 5.5GW of existing capacity also missed out. In contrast, almost 1GW of small-scale new build capacity received contracts, and existing interconnectors secured 1.8GW of contracts.

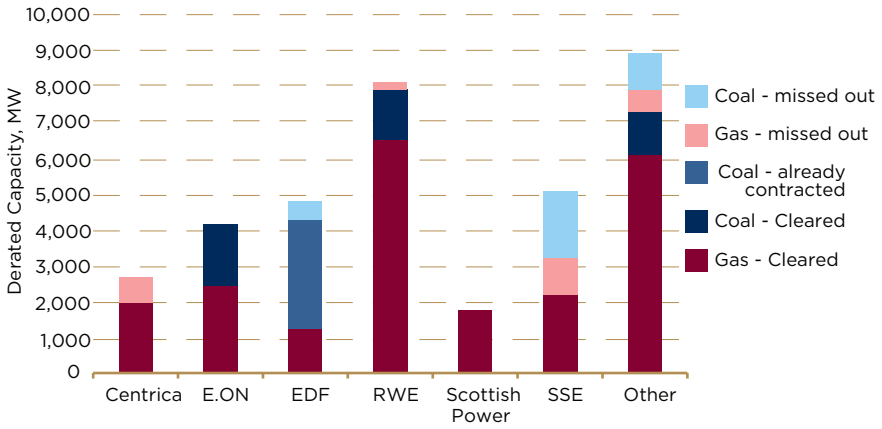


In this briefing, we look at who has (and who has not) received contracts and some of the potential issues this raises for the GB market.

Portfolio by portfolio

As we did in our review last year, by looking at who missed out we can begin to understand the range of strategies and views that the major participants have on the GB market.

As anticipated the majority of existing plant which have missed out is Gas or Coal capacity that had also failed to secure a contract for 2018/19. The chart below shows the results for the existing Gas and Coal units across the major operators.



5.4GW
of installed Gas and Coal capacity missed out on a contract.

The one major case of a plant with a 2018/19 contract missing out this year is SSE's Fiddlers Ferry. All four units, totalling almost 2GW, missed out, despite three of the units securing a contract last year. This would suggest an uncertain future for this plant from 2019 onwards.

Given the low clearing price it is not surprising to see that no new build CCGT secured a contract. The exception to this is Carrington, which is due for completion in 2016 and has cleared with a contract for 1 year rather than 15, perhaps indicating the expectation of higher clearing prices in future auctions. The low clearing price also meant that the only new interconnector in the auction, the Nemo link to Belgium, also failed to clear.

Elsewhere, the story is very similar to last year, with essentially the same plant securing contracts, and the same plant missing out. The only significant changes were contracts for the two existing interconnectors that prequalified, totalling 1.9GW; 1GW of new small-scale capacity; and the 0.8GW from Carrington. This capacity effectively displaces Fiddlers Ferry, and Longannet – who were included in the capacity requirement calculation last year.

Tight margins

While the government is likely to be pleased with another auction that has resulted in a relatively low cost to consumers, the results of the auction still raise concerns. System security for the GB market is already at its lowest level for a number of years, and if the plant that have failed to clear in either of the two auctions now choose to close (as many already have over the past 12 months), the situation is likely to worsen. These concerns apply to both the interim years leading up to 2018/19 and 2018/19 itself:

1. **Interim years.** Margins are already expected to be very tight in the winters between now and 2018/19, particularly in 2016/17. With almost 5.5GW of existing plant failing to clear, National Grid is increasingly reliant on tools such as SBR to ensure enough capacity remains available over this period, with 3.6GW of contracts proposed for 2016/17.

2. **2018/19.** Due to unexpected closures and possible delays to new plant, a larger amount of capacity than initially anticipated will need to be procured through the year-ahead auction. The failure of the 5.5GW to clear in this year's auction raises concerns over where this capacity is going to come from.

Interim years

Concerns over the risk of blackouts over the next few winters have already been making headlines. With almost 5.5GW of existing capacity failing to secure a 2019/20 capacity contract, these concerns are only likely to intensify.

3.6GW
of SBR contracts offered by National Grid for winter 2016/17

To alleviate these concerns, National Grid has proposed 3.6GW of SBR contracts for 2016/17, at an estimated cost of £122m. This is a substantial increase on the 2.5GW contracted for this winter. These contracts are awarded to plant who were not available in the market, and the plant will now be held on standby over the 2016/17 winter.

This represents a significant reliance on standby capacity, and any further closures would still present a risk over the coming winters. There are also concerns on how this amount of standby capacity could affect the efficient operation of the wholesale market.

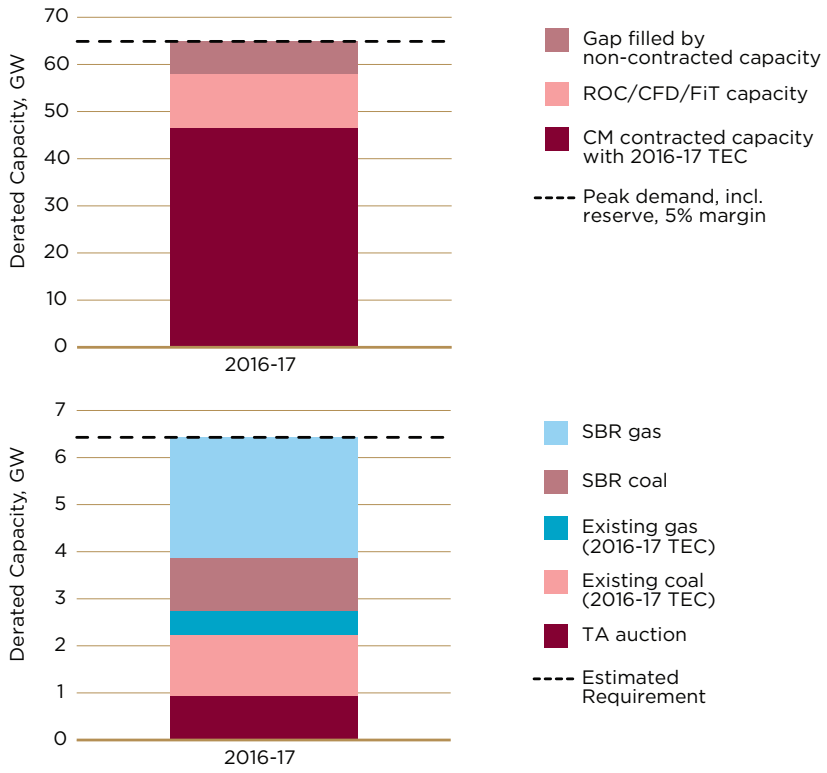
How did we get into this situation, where 3.6GW of plant are contracted to be held on standby outside the market?

Firstly, a number of plant who missed out on a 2018/19 contract have already closed or announced closure (and have not been offered SBR contracts in 2016/17), and as a result did not compete in the 2019/20 auction. These include:

- Eggborough, 1.1GW derated capacity. Closing in 2016. A further 0.7GW of derated capacity has been offered for SBR in winter 2016/17.
- Ferrybridge, 0.9GW. Closing in 2016.
- Killingholme (EOn), 0.8GW. Closed.
- Longannet, 2.0GW. Closing in 2016, opted out of 2018/19 auction.

After the results of this year's auction we may see further closures. Combined with the delay of any new conventional capacity (with the exception of Carrington) until at least 2018, capacity margins for 2016/17 were looking very tight. In order to achieve a 5% derated capacity margin – equivalent to that predicted for this winter – around 6.4GW of derated capacity is likely to be required from plant that do not have a CM contract.

This is shown on the first of the two charts below. The second of the two charts below shows how the 6.4GW is likely to be met. About 0.9GW is expected to be procured through the Transitional Arrangements (TA) auction for DSR. A further 1.9GW of conventional capacity has TEC for 2016/17 so is expected to operate in the market, despite not securing capacity contracts for 2018/19 or 2019/20. This leaves around 3.6GW of required capacity, which is the amount National Grid has offered SBR contracts.



Source: National Grid "Slow Progression" scenario from 2015 FES; National Grid SBR Market Updated for 2016-17; TEC register; LCP calculations

2018/19 year-ahead auction

National Grid will introduce a year-ahead auction for 2018/19 to allow bidders of demand side response capacity to participate in the following year (referred to as a T-1 auction). 2.5GW was originally set aside from last year's T-4 auction for this auction.

To help illustrate the concern over the need for more capacity, we first calculate how much derated capacity could now be required through the year-ahead T-1 auction:

- **+ 2.5GW.** The portion of the capacity requirement that was originally held-back for procurement in the year-ahead auction, with the intention that much of this will come from demand side response (DSR).
- **+ 2.0GW.** Closure of Longannet, which was assumed to be online in 2018/19 when last year's auction requirement was calculated.

- **+ 1.7GW.** Delays in the Trafford plant, which was awarded a 15-year contract in the 2018/19 auction, means it is now unlikely to be online in time for 2018/19.
- Totals approximately **6.2GW** of derated capacity needing to be procured through the year-ahead auction to get us back to the intended level of security for 2018/19.

6.2GW
of capacity could be procured through the T-1 auction for 2018/19.

The concern here is whether enough capacity will be available to bid for contracts when the year-ahead auction is run in late 2017. 9.2GW of large-scale existing plant (including the almost-completed Carrington) missed out on contracts in the 2018/19 four-year-ahead auction, but as described in the previous section over 3.5GW of this has already confirmed closure.

This leaves only 5.6GW of large-scale conventional capacity that could be available to compete for these contracts, alongside an uncertain amount of small-scale plant and DSR capacity.

Of this 5.6GW, only Carrington (0.8GW) has secured a contract for 2019/20. The remaining 4.8GW of capacity faces an uncertain future and is made up of gas plant who will be relying on SBR contracts to remain economic (e.g. Peterhead, Deeside, Corby), and older coal plant (Rugeley, West Burton unit and Fiddlers Ferry unit). Many of these plant reduced their TEC for 2016-17, a strong indicator they do not intend to operate, and if any of them were to permanently close, there risks a lack of supply in the 2018/19 year-ahead auction.

Unfair competition?

DECC has set out on many occasions that the capacity mechanism is designed to ensure sufficient investment in reliable capacity to ensure security of supply during prolonged periods. Many observers had assumed this would result in capacity prices sufficient to bring forward new CCGT investments. In reality, however, in both the 2014 and 2015 auctions, around 1 GW of small gas and diesel plant cleared in the auctions, sparking questions as to whether the capacity auction regime was resulting in the "right plant".

Dan Roberts
Director
Frontier Economics

Small generators are securing an unfair competitive advantage over other more efficient generators in the capacity auction.

From an economic viewpoint, the question as to whether a market is buying the right plant is an odd one. If the demand curve is expressed in a technology neutral manner, and all plants are free to bid on a level playing field, the process of competition should result in the cheapest technologies being selected. Surely this should be in customers' interests?

The answer is no, and the explanation lies with the current structure of transmission charges. Our analysis finds that the current remuneration of small-scale generation in relation to TNUoS charge avoidance is providing a significant competitive advantage vis-à-vis larger more efficient

generation. Specifically, we show that:

- Nearly 60% of revenues for small-scale distribution connected generation comes from helping customers avoid TNUoS charges;
- Over 85% of this revenue stream payment is based on the premise of reducing sunk costs (an impossibility). Hence, from an economic perspective, it is wasteful and distortionary; and
- Absent this revenue stream, small scale generation would require a capacity price of £55/kW, at which level CCGT would be much better able to compete in the capacity auction.

And this in turn means higher costs for customers. While capacity auction prices may be lower:

- TNUoS charges are higher (because there is a smaller charging base over which to recover sunk costs); and
- energy prices are higher, as there are fewer high efficiency thermal plants in the merit order than would otherwise be the case.

How is small-scale generation remunerated?

The smaller units that have been successful in the capacity auction typically secure funding from three principal sources[1]:

- capacity agreements;
- balancing services contracts (e.g. STOR); and
- helping customers avoid TNUoS charges (so called triad benefit).

In the following, we:

- explain what triad benefit is;
- explain why it is leading to inefficiencies and distortions; and
- illustrate the impact on the capacity mechanism.

What is triad benefit?

If generation locates on a distribution system near load, it reduces the need to build transmission infrastructure to serve that load. Triad benefit aims to incentivise generators to make the "right" choice (for society as a whole) between connecting to the transmission and distribution systems.

So, if a distribution-connected generator runs at times of system peak (the triad, the level of demand during which historically drove transmission investment) it can reduce a customer's transmission charges. And since

[1]Some constraints exist on the extent to which generators can access all of these revenue streams at the same time.

transmission charges were deemed to be cost reflective, this meant that the generator and customer collectively captured the value of the avoided transmission investment. All that was left was for the generator and customer to negotiate how they shared the benefit – typically with the generator securing the majority.

What's the problem?

It all sounds quite logical, until you start to unpack the TNUoS charge and think about how it is levied.

There are two components to TNUoS charges:

- The first, estimates the incremental transmission cost resulting from connections to the transmission network at various locations around GB. Were this charge to be levied on all users, however, it would not recover enough money to fund National Grid's total allowed revenue. This is because there is no reason that the forward looking incremental costs of transmission investment should equate to the average costs of past investment, which National Grid must also recover.

- The second part of the charge is therefore a top-up which ensures that National Grid recovers its allowed revenue. Effectively, this charge recovers the sunk costs of the transmission network over and above its forward looking incremental costs.

Unfortunately, distribution-connected generators and customers avoid both parts. And this is where the trouble starts. To maximise the benefit for society, generators should be incentivised to avoid the future costs of transmission infrastructure investment (i.e. the first part of the TNUoS charge). But only the first part of the TNUoS charge is forward looking. The second part relates only to the cost of sunk investments from the past.

There is absolutely no point in incentivising generators to spend more money themselves to avoid these sunk costs. They are sunk – nothing can make them go away! In fact, if generators and customers avoid these charges, the tariffs of other users have to go up to make sure National Grid recovers its allowed revenue. The first rule of recovering sunk costs is to recover them in a way which does not change people's behaviour. And this rule is being broken by triad benefit in its current form, because generators are being over-incentivised to connect to the distribution network.

So, the current triad benefit incentive is:

- Too strong – it benefits generators for notionally avoiding unavoidable sunk-costs;

- Distortionary – it distorts the appropriate allocation of tariffs across network users; and

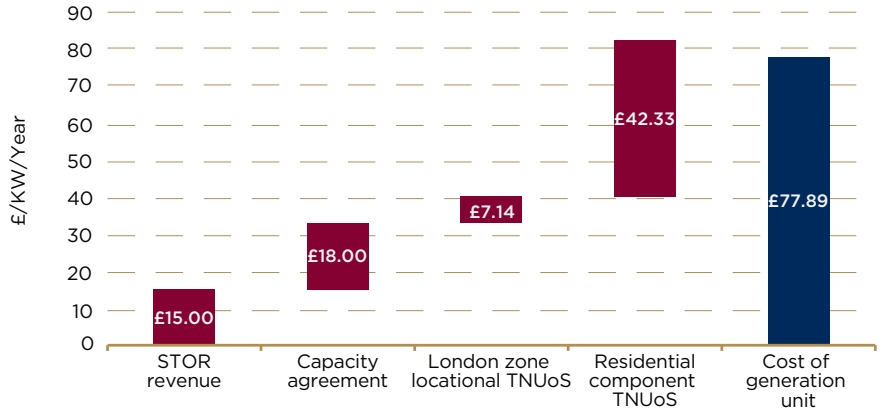
- Inefficient – generators are over-incentivised to connect to the distribution network.

Distorting the capacity market

On top of all the problems identified above, the current triad benefit also distorts the capacity auction. One of the revenue streams which distribution-connected generators get is "too big". This means that they can fund investments with lower revenues from capacity agreements than would otherwise be the case. And this in turn means that they are likely to be able to out-compete transmission connected generators, meaning that many fewer CCGTs get built.

How big is this distortion? The broad orders of magnitude of these different revenue streams are shown in Figure 1.

Figure 1. Relative size of revenue streams



Source: Frontier Economics

Notes:

1. Cost of generation unit assumes $1000/kW unit, 8% cost of capital, asset life of 15 years. TNUoS data taken from National Grid forecasts of London based charge, assuming 80% of triad benefit is captured by generator. STOR revenue taken from Frontier work for DECC . Capacity auction assuming same price as last year

2. It may not always be possible for generators to secure the full value of STOR and triad together. However, STOR products do exist (e.g. flexible STOR service) which would allow participation in both.

The answer is "pretty big"! With almost 1 GW of small generators clearing in this auction, TNUoS charges will have to increase to recover at least an additional £50m. This is because the sunk costs have to be recovered over a smaller charging base, assuming none of these generators would have cleared otherwise.

If the sunk cost component of TNUoS charges was removed from the revenue streams of distribution-connected generators, it could imply a 50% reduction in total revenue. To make the business case positive again would require a capacity price of £55/kW. And at this level, CCGT would be much better able to compete against them in the capacity auction.

Looking forward

Looking forward, it is unclear to what extent the results of the first two years will be a reliable guide to future outcomes. The low clearing prices in the first two auctions have been largely driven by an oversupply of existing capacity. However, in the coming years we would expect to see a significant portion of this existing capacity retire, as the coal fleet faces environmental and economic pressures, and eventually the older nuclear units reach the end of their technical lifetimes. This could lead to much higher clearing prices in the years where there is a requirement for new capacity.

https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/467024/rpt-frontier-DECC_DSR_phase_2_report-rev3-PDF-021015.pdf

LCP INSIGHT CLARITY ADVICE

About LCP

LCP's Energy Analytics practice has been at the heart of Electricity Market Reform (EMR) analysis since the first design proposals. We provide analytic and consulting services that support the industry in understanding the impacts of these significant reforms to the GB power market. We also provide some of the key tools in the industry, including the Dynamic Dispatch Model that is used by DECC and National Grid for analysis such as the final EMR delivery plan and the setting of the capacity requirement for the first capacity auction. More widely we support our clients to understand how these fundamental changes to the market will affect portfolio profitability and risk over the medium to long term. We provide a range of services including asset valuation, impact analysis and strategic advice.

About Frontier Economics

Frontier Economics is one of the largest economic consultancies in Europe with offices in Brussels, Cologne, Dublin, London and Madrid. We use economics to help clients improve performance, make better decisions and keep ahead of the competition. Our expertise is broad, covering not just micro-economics but finance, statistical modelling, game theory, market research and even the psychological side of economics.

We work with a wide range of clients from the private sector, government, regulators, other public authorities and charities. We distil complex issues to focus on what matters to our clients. We help them make credible arguments and good decisions, backed up by robust evidence and analysis. While our analysis may be complex, the advice we provide is clear, honest and delivered using plain language.

Contact us

If you would like to discuss any aspects of the Capacity Market in more detail or any of our wider services please contact Tom Porter (LCP) or Dan Roberts (Frontier Economics) using the details below.

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