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Security of Supply, Capacity Auctions and Interconnectors

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Abstract Energy policy aims to deliver security, sustainability and affordability, but politicians treat security of supply as over-riding. Absent market and regulatory failures, liberalized energy-only electricity markets might deliver adequate capacity. Ambitious targets for subsidized renewables and policy uncertainty have undermined the commercial case for the investment needed to handle increased intermittency and raised concerns for capacity adequacy. In response Britain now holds annual capacity auctions. The paper examines the case for, criticisms of, and the outcome of the first auction, criticizing the decision to ignore the contribution that interconnectors make to security of supply.

Keywords capacity markets, renewables, procurement volume, interconnectors

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Security of Supply, Capacity Auctions and Interconnectors[1]

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Introduction

Energy policy aims to deliver security, sustainability and affordability, but of these three objectives politicians treat security of supply as over-riding. Given the need to instantly balance supply and demand in the electricity system, ensuring short-term security of supply is normally an obligation placed on system operators, while longer term capacity adequacy is often the subject of regulatory and political concern. EU electricity markets are now liberalized, and generation is, for the most part, not subject to traditional utility regulation, but normal competition policy both domestically and under the scrutiny of DG COMP. If investment decisions could be solely guided by strictly commercial decisions and if markets were not subject to policy interventions or price caps, it is plausible that capacity adequacy could be delivered by profit-motivated generation investment without explicit policy guidance.

However, ambitious renewables targets that can only be met at present through support mechanisms, combined with an ineffective climate change instrument in the Emissions Trading System, make predicting future electricity prices subject to substantial political risk, while the large volume of renewables has driven wholesale prices below the long-run marginal cost of supply in many countries, undermining the attractiveness and ability to invest. This paper explains the concept of security of supply for electricity markets, investigates whether energy-only markets could deliver the required standard, identifies market, institutional and political/regulatory failures that undermine confidence that such markets can be relied upon to deliver reliability, and then discusses the way in which the British Government has addressed this problem.

Security of supply

The standard approach adopted by most EU electricity systems is to define a security standard by specifying the "Loss of Load Expectation" (LoLE) in hours per year, and for most but not all EU Member States this is three hours per year. This is to be interpreted

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as a forward looking measure, that taking a representative and large number of possible outcomes (of weather, plant reliability, demand, etc.) for some future period, the electricity system should perform better than averaging “Losses of Load events” of less than three hours per year. Figure 1 shows forecasts of Britain’s security margin made by the regulator, Ofgem, indicating a reliability problem in winter 2015/16.

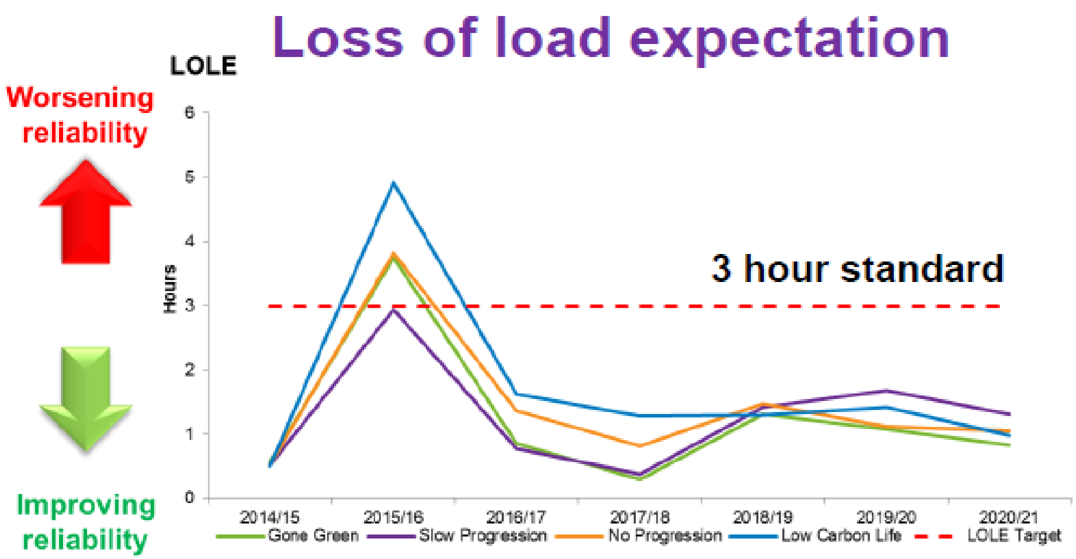

Figure 1 Britain’s projected evolving security under various scenarios
Source: Ofgem Winter Outlook seminar

The LoLE can be determined by calculating the “Loss of Load Probability” (LoLP) in each market period (a half-hour in GB, an hour in most Continental systems) and summing these over the year. This is most easily done retrospectively, usually from the day-ahead calculations, when the actual demand and supply conditions are known – future projections are subject to considerable uncertainty that needs to be taken into account. Its value is important in markets where there is an explicit capacity payment, as the efficient price of electricity is the sum of the System Marginal Cost (SMC) plus a Capacity Payment, CP, where

$$CP = LoLP*VoLL, \tag{1}$$

and VoLL is the Value of Lost Load, a measure of value that should reflect the willingness to pay to avoid a loss of load.

The relationship between the security standard and the VoLL is symmetric, in that if capacity investment decisions are based on revenues determined by (1) and the VoLL is pre-determined, then the resulting capacity will give rise to a LoLE, while if the standard is specified in terms of a predetermined LoLE, then given the cost of investing in capacity, that will imply a cost of delivering the LoLP and hence the value for the VoLL. Britain has followed both models. The English Pool set the VoLL at £(2012)5,000 (€6,250/MWh at £1=€1.25) and allowed the market to determine the capacity, but with the end of the Pool in 2001, the Department of Energy and Climate Change now specifies the LoLE and deduced the 2018 VoLL as £(2012)17,000/MWh (€(2012)21,250/MWh, National Grid, 2014a), a value rather higher than that determined by directly estimating the willingness to pay to avoid disconnections (London Economics, 2013).

Can energy-only markets deliver adequate reliability?

The EU Third Package[3] (of energy market reforms) sets out the Target Electricity Model (TEM) that was intended to come into effect by 2014 (although some parts are delayed until later in the decade and some countries have derogations until later dates). Its core is an energy-only market with a single auction platform, Euphemia, for day-ahead, intra-day and balancing trades, which simultaneously clears bids and offers and the use of all interconnectors across the EU, fragmenting the market into different price zones only after interconnectors are fully used. By the end of 2014 Euphemia had coupled markets from Finland to Portugal, including GB, but not the Single Electricity Market (SEM) of the island of Ireland. As the efficient electricity price includes the capacity payment in (1), the TEM raises the question whether, and if so how, energy-only markets will deliver reliability. The model for the TEM was Nordpool, which has operated a successful energy-only trading system for many years, as have the major power exchanges such as EEX and APX, but not all EU countries have (or once) followed this model. Many markets have made or continue to make capacity payments, and DG COMP has been very critical of this practice, arguing that they often have more to do with compensating generators for stranded assets than delivering reliability.

The legitimate case for a capacity payment is that if generators are required to bid their Short Run Marginal Cost (SRMC, mostly fuel costs), as under the Bidding Code of Practice of the SEM (SEM, 2007), they will fail to recover their fixed costs without such an addition. The Electricity Pool of England and Wales also added a CP of exactly the form of (1), but allowed generators to offer a supply function that was not necessarily their SRMC (and indeed, given the market power of the generators, was often above that level) (Green and Newbery, 1992, Newbery, 1995, Sweeting, 2007).

In an energy-only market of the kind envisaged by the TEM, generators will offer supply functions that should reflect the scarcity value of electricity (and their degree of market power). Figure 2 shows the day-ahead price duration curves for several European power exchanges in 2012. What is striking is that most exchange prices do not exceed €200/MWh, and even the most peaky, France, only does so 0.25 of 1% of the time (about

[3] See e.g. http://www2.nationalgrid.com/UK/Industry-information/Europe/Third-energy-package/

22 hours per year). Given that the VoLL in the English Pool until 2001 was €(2012)6,250/MWh and the implied VoLL in GB after 2001 rose to €(2012)21,250/MWh (both at £1=€1.25), these prices indicate a low LoLP or high reliability.

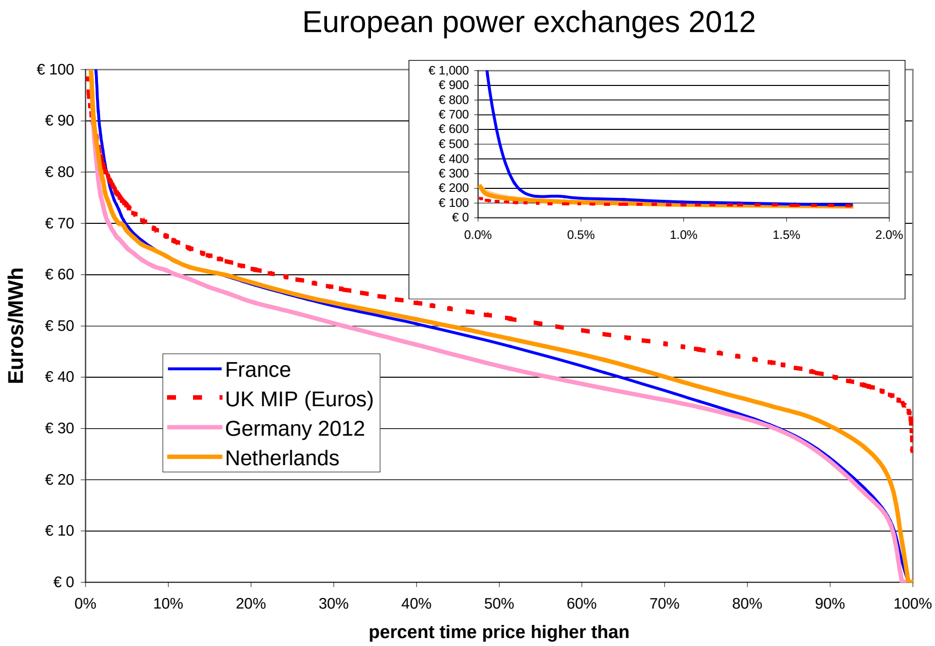

Figure 2 Price Duration curves of day-ahead hourly prices, 2012
Sources: MIP (Market Index Price) and NL prices from APX, Germany and France from EEX

On the other hand, Figure 3 shows that the 2008 balancing buy prices[4] (relevant when the System Operator needs to buy power to balance the system in real time) in the energy-only market that replaced the Pool were considerably peakier than the old Pool prices (which included an explicit CP and also probably reflected at least as much market power). Thus energy-only markets can reflect scarcity, and properly calculated capacity payments may be very low if the reserve margin is adequate (LoLP is roughly exponential in demand less derated capacity, Newbery, 2005). However, by 2013-14, the GB Balancing Mechanism had a price duration curve quite similar to those shown in Figure 2, with prices above €200/MWh for less than 0.25 of 1% of the time, and well below the French day-ahead price duration curve,

On the face of it one might conclude that energy-only markets can deliver sufficiently sharp scarcity prices that should signal the profitability of new investment that, if delivered, would ensure an adequate reserve margin and hence satisfactory reliability. This might be plausible if all investment decisions were taken on commercial grounds, that prices were not capped, that the policy environment were predictable and stable, and that either liquid forward market existed for a reasonably fraction of the

[4] For a description of the British Balancing Mechanism see Newbery (2005).

proposed plant life (i.e. 20+ years ahead of the final investment decision) or credible long-term power purchase agreements could be signed with credit-worthy counterparties. Unfortunately, hardly any of these conditions hold in the liberalized electricity markets in the EU during the period of delivery of the TEM. The US has long argued that there is a "missing money" problem caused by price caps that prevent prices reaching levels that would cover fixed costs of peaking plant that is only required a few hours per year,[5] and now GB is advancing the same argument.

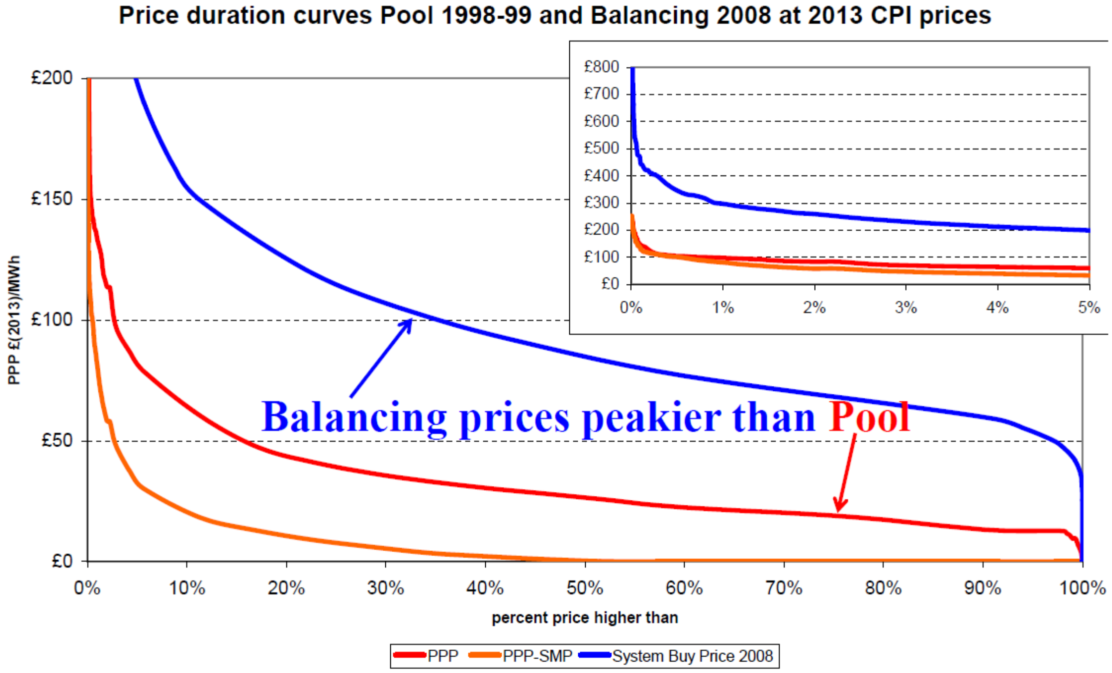

Figure 3 Scarcity pricing in the GB market under the former Pool and in the Balancing Mechanism

Sources: National Grid, Elexon

Notes: PPP is Pool Purchase Price, SMP is the System Marginal Price, so PPP-SMP=CP

Market, institutional and political/regulatory failures

While price caps are set at rather low levels in the US, exacerbating the "missing money" problem, there are still price caps in Euphemia (for day-ahead at €3,000/MWh, a price that France has hit on numerous occasions). The way the GB market operates will be discussed below, but it also has a likely effective price cap of £6,000/MWh (€(2015)8,000 /MWh), both well below the implied VoLL. The lack of forward markets and long-term contracts might not be so critical if the future were reasonably predictable and stable, but this is far from the case at present. EU Climate Change policy aims to

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[5] See e.g. (Joskow, 2103), particularly Cramton, Ockenfels and Stoft (2013), and earlier papers by Joskow (2008), and Joskow and Tirole (2007).

price carbon through the Emissions Trading System (ETS) and support uncommercial renewable energy supply (RES) by mandating ambitious targets for 2020 (through the *Renewables Directive,* 2009/28/EC). These two policies are in conflict, in that under the ETS Member States were granted a set volume of allowances, but these were not scaled back by the additional volume of RES, so that the *Renewables Directive* leads to no reduction in CO_2 emissions but a fall in the allowance price, discouraging further decarbonisation. In addition, the Directive requires Member States to support large and rather unpredictable volumes of renewable electricity, which puts downward pressure on electricity prices, undermining the case for investment in conventional generation. In the past, peaking plant to handle periods of scarcity came from obsolescing old plant, mostly oil or coal, but the *Large Combustion Plant Directive* restricts pollution and binds for plant without Flue Gas Desulphurisation by 2016, while the *Integrated Emissions Directive* requires further clean-up that would be costly and uneconomic for old plant.

Increasing levels of renewable (mainly wind and solar PV) electricity penetration adds little to reliable capacity, as it is intermittent and/or unavailable on still cold dark winter nights, but at target levels in electricity of more than 30% of output, it undermines average wholesale prices. If the average capacity factor of on-shore wind is 25%, then to deliver 30% of total electricity output from wind would require capacity of 30/25 times average demand. In Britain the average demand is 62% of peak demand, so the required wind capacity would be 75% of peak demand. In windy conditions that would often displace all conventional plant and could lead, under present subsidy structures, to negative prices.

Intermittent generation increases the need for flexible peaking plant that can be called up at short notice if the wind falls or the sun fades. In addition, new plant will be needed to replace retiring plant (not just coal, but in the UK, France and Germany, substantial volumes of nuclear plant as well). Even if the carbon price is currently low, the EU has signaled a commitment to an 80% reduction in Greenhouse Gas emissions by 2050 (relative to 1990), and as coal is twice the carbon intensity of gas, utilities are unlikely to commit to building highly durable (40-60 year) coal-fired plant that would likely face high future carbon prices or tight emissions intensity limits. The preferred flexible and reliable plant is therefore low capital cost gas turbines. Unfortunately, the combination of crashed wholesale electricity prices and high gas prices precipitated by the Fukushima Daichi nuclear disaster and the subsequent closure of Japan's nuclear fleet makes the economics of investing in gas turbines commercially very unattractive.

The UK introduced a carbon price floor in the Budget of March 2011 which would support the price of CO_2 starting at £16/tonne in 2013, rising to £30/tonne (€35/tonne) in 2020, and projected to rise to £70/tonne by 2030 (all at 2009 prices).[6]

[6] HM Treasury, *Budget 2011*, HC 836, March 2011

This further threatened the continued operation of existing coal-fired plant, some of which have unsuccessfully attempted to convert to burning biomass.[7] As an example of policy instability, the 2014 Budget froze the price floor from its then rather low level until later this decade – clearly any instrument subject to the passing whim of chancellors setting budgets creates additional uncertainty for those making investment decisions. All in all, it would be a brave politician who trusted the market to deliver reliability in current circumstances, and politicians are not known for their bravery.

The GB capacity auction

In response to the looming capacity crunch anticipated in Figure 1, the UK passed the *Energy Act 2013* setting out the Electricity Market Reform (EMR). This includes a Capacity Mechanism to address this problem and ensure adequate capacity. Great Britain has thus now moved to a world in which the Secretary of State for Energy & Climate Change, advised by the Department for Energy & Climate Change (DECC), sets the security standard and decides how much capacity is required, which is then delivered through capacity auctions. The capacity auction is a single-price descending clock auction with a demand schedule as shown in figure 4.

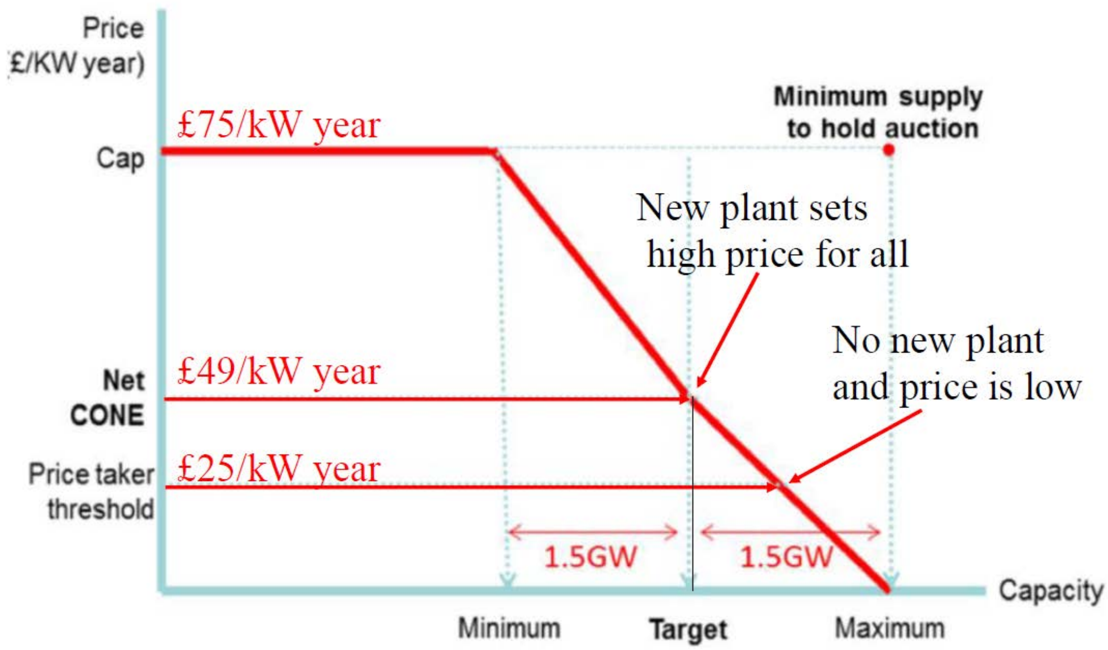

Figure 4 Proposed auction demand curve

Source: DECC (2013)

[7] E.g. Tilbury B closed after it was denied a subsidy to switch from coal to biomass see http://www.ft.com/cms/s/0/50907714-0374-11e3-b871-00144feab7de.html#axzz3SxXlfrfo

National Grid (NG) as System Operator (SO) was charged to recommend the target volume of capacity to secure four years after the auction (which was termed the T-4 auction). National Grid projected that the auction clearing price would likely be set by new plant at the Cost of New Entry (CONE), which National Grid (2014a) estimated at £49/kWyr (National Grid, 2014a). This was the shortfall or missing money that a Combined Cycle Gas Turbine (CCGT) might need after receiving revenues in the wholesale and balancing markets and from various ancillary services and after paying various fixed costs, of which the Transmission Network Use of System (TNUoS) charges in some parts of the country can be as high as £30/kWyr (in NW Scotland), although they can also be negative (-£5/kWyr in Cornwall) (National Grid, 2013). New plant would be given 15-year indexed priced contracts, while existing plant would (mostly) be price takers) granted one-year contracts to defer any decommissioning decisions until the next auction.

Another way of estimating the "missing money" that the auction was designed to cover is to take the VoLL of £17/kWh and subtract the maximum price that the System Operator is required to pay for its balancing actions (£6/kWh) to give £11/kWh, and multiply this by 3 hrs LoLE to give £33/kWyr. Clearly, the higher prices can go in the balancing market the lower is the missing money, and in the past the System Buy Price was effectively capped at £9,999/MWh or £10/kWh, which would suggest missing money requirements at £21/kWyr.

The design of the auction was best-practice (Newbery and Grubb, 2014) but its flaw lay in delegating the recommendation of the amount to procure to the SO and charging the minister to make the final decision. The SO stands to be held accountable if "the lights go out" but does not have to pay for the capacity, while the minister is even more likely to want to avoid the newspaper headlines predicting future blackouts as a result of his decision. They are therefore both likely to err on the side of caution and excess procurement. DECC had appointed an independent Panel of Technical Experts (PTE) to comment on NG's analysis, and they made a number of strong but ineffective criticisms.

The first was that the terminology of Loss of Load (as in LoLE and LoLP) was emotive and misleading. The GB regulator, Ofgem, and the SO define a Loss of Load event as one in which market demand exceeds market supply and as such the SO has to intervene to balance the system. For that purpose the SO can call on a range of increasingly expensive options, such as asking generators to exceed their rated capacity for a short period; invoking 'new balancing services',[8] mainly contracts to reduce peak demand or offer on-site (embedded) backup generation; cutting any interconnector

[8] "The new balancing services are Demand Side Balancing Reserve (DSBR) and Supplemental Balancing Reserve (SBR)." National Grid announced its tender for these new services on 10 June 2014 (http://www.nationalgrid.com/uk/electricity/additionalmeasures).

exports to zero, and requesting imports; and, if these measures are not enough, reducing voltage ("brown outs") before finally resorting to selective disconnections (not widescale blackouts of the kind associated with voltage collapses usually caused by major transmission failures). The crucial point about all these actions is that they cost less, and often much less, than the VoLL which was used to define, or is implied by, the security standard.

The immediate result of overvaluing the cost of "Loss of Load" is to increase the capacity at which the Least Worst Regret cost schedule is minimized, as shown in figure 5. Of the various plausible scenarios indicated, (i.e. ignoring "no progression"), the worst case is "slow progression", and it reaches a minimum of the cost of "unserved energy" (taken at £17/kWh) and the cost of extra capacity (£49/kWyr) at 53.3 GW for 2018-19 delivery. The net amount to procure in the auction is 53.3-*w*-*x*-*y*-*z*-0.4 GW, where the values for *w*, *x*, *y* and *z* refer to various distributed energy resources and opt-out plant and the 0.4 GW is already secured short-term operating reserve.

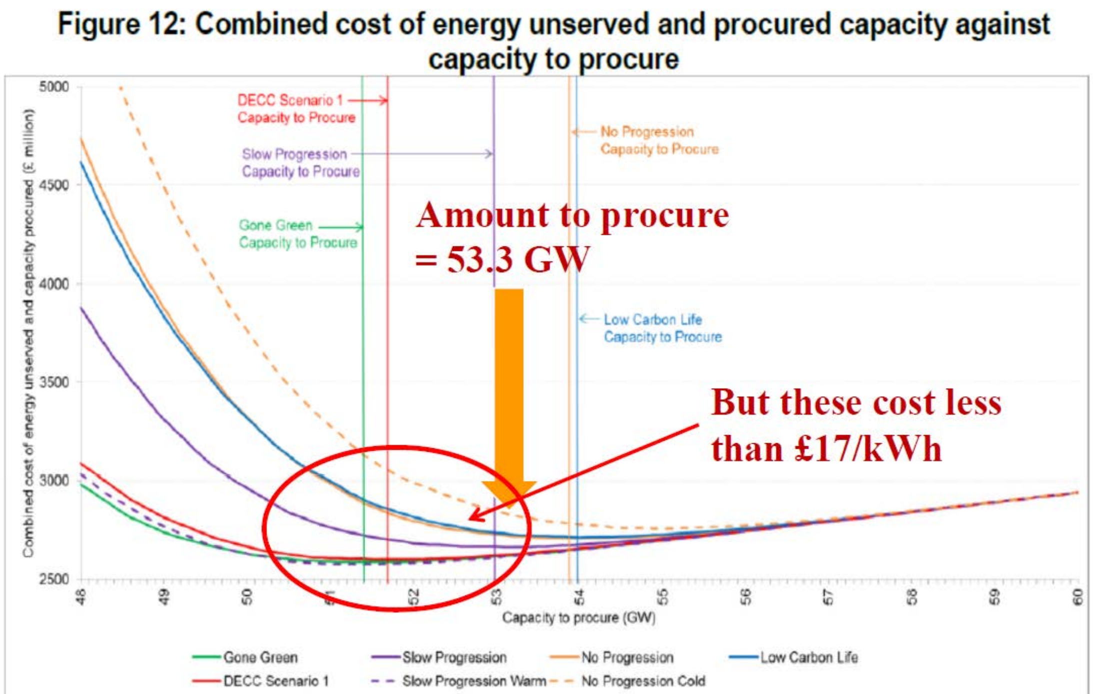

Figure 5 Capacity needed to minimize total cost in the *Slow Progression* scenario
Source: National Grid (2014a, fig 12, p50) with additions by the author

The other major criticism levelled by the PTE (DECC, 2014) was that NG assumed no net imports into GB in stress periods, despite the existing 3.75 GW interconnection capacity and the potential additional new interconnector capacity of 2.25 GW that under optimistic assumptions might be available by the required 2018-19 winter date. The Panel argued that this seemed perverse, as all parties (Ofgem, DECC and NG) agreed that interconnectors increased security of supply, and three reports commissioned by these parties (Pöyry, 2012, 2013; Redpoint, 2013) argued that interconnector capacity could displace domestic capacity by 50-80% of its value. Ignoring such contributions could move the clearing price in the auction from being set by new entry at the CONE of £49/kWyr to that set by existing plant (maximum of £25/kWyr), *increasing* the cost paid by consumers by 53.3GW x (£49m-25m=£24m/GWyr) = £1.3 billion per year.

This oversight seemed particularly perverse as the TEM is all about integrating markets across borders, and market coupling is already dispatching GB interconnectors to the Continent at the same time that the day-ahead market (DAM) is cleared. Flows over interconnectors are thus already reflecting willingness to pay at the DAM stage, and will be extended to the intra-day and real time market as soon as the necessary network codes are agreed.

Possible consequences of excessive capacity procurement

Excess capacity will tend to lower GB wholesale prices, which will have a number of effects, some of which are not immediately obvious. The first is that it undermines the old market design in which investment in conventional generation was at the discretion of private companies making commercial decisions. It would clearly be absurd for any company to invest in conventional generation without a capacity contract, as this would be disadvantageous compared to those with capacity contracts. The volume, if not the type and location, of new plant will therefore be entirely determined by the Secretary of State, arguably ending a key element in the liberalized electricity market. All non-fossil generation will also be granted long-term Contracts for Difference (CfDs) under the GB Electricity Market Reform (EMR), so we will have moved to effectively the Single Buyer model that was ruled out in earlier Electricity Directives.

Second, lower wholesale prices will increase the payments made to low-carbon holders of CfDs, who are granted a fixed strike price and paid the difference between the strike price and the wholesale price. As the Government has restricted the total volume of such payments each year through the Levy Control Framework, the somewhat perverse effect is that the Government will be able to support less renewable electricity, although the EMR was primarily intended to deliver the UK's renewables targets more efficiently.

Third, the case for interconnectors is based in large part on price differences between locations, with GB typically importing from the cheaper markets on the Continent. Lower GB prices will reduce arbitrage profits, undermining the investment case for the additional interconnectors that appear more necessary with increasing intermittent generation that is imperfectly correlated between markets. In short, ignoring the potential contribution from interconnectors risks leading a self-fulfilling but expensive policy of autarky.

Fourth, lower future wholesale prices will reduce the revenue new entrants can expect to make in the energy markets, and will therefore increase the CONE and raise the auction price needed.

Fifth, although the wholesale price in future may be lower, offsetting part of the cost borne by consumers, it will be hard to persuade them that the costs are not as high as the apparent cost of the auction, which on NG's estimate could have been 53.3 GW x £49m/GWyr = £2.6 billion per year. Consumers will be suspicious of claims that compared to the counterfactual they will be partly compensated by lower wholesale prices – in the DECC (2013) *Impact assessment* the claim was that the net cost to consumers would be only about £600 million per year, so wholesale prices were expected to fall by £2 billion per year. This suspicion would be amplified by noting the huge variation in estimates in successive impact assessments, suggesting huge uncertainty in predicting the final impact of the capacity auction.

Finally on 2nd December 2014, after the PTE had published its critical report and the Secretary of State had decided on the amount to procure, but before the auction on 18th December, the Treasury's *National Infrastructure Plan* confirmed that DECC would fulfil its intention of making interconnection eligible for the capacity market in 2015.[9] It would clearly have been easy to have left room for interconnectors (e.g. by adding another element to the -*w*-*x*-*y*-*z*-0.4 GW adjustment to the target volume) and thus lowering the net amount of new capacity to procure.

The outcome of the 2014 capacity auction

The auction closed on 18th December 2014 at 1630 GMT, with the market clearing price of £(2012) 19.40/kWyr published the next day (National Grid, 2014b), shown in figure 6. The auction produced several surprises. First, the auction cleared at less than 40% of the predicted CONE value of £49/kWyr. The estimated CONE was based on new entry of CCGT, and in fact two CCGTs entered, supplying about 60% of the total of 2,795 MW of new entry. Second, the next largest technology of new entry contributing 28% was OCGT/ reciprocating engines with an average size of 11 MW. The third largest contribution was from unproven Demand Side Response (DSR) at 6% (all DSR has a one-year contract while other new entry has a 15-year contract). One new coal/biomass plant of 67 MW gained a new entry contract.

One might expect that DSR and OCGT/reciprocating engines would require a lower strike price, particularly as they can contribute to significantly reducing TNUoS charges for Load in triad periods if they are embedded with major loads, but the low price that CCGTs were willing to accept is surprising, and may be based on optimistic views of gas prices (which were expected to decline by the time of the auction).

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[9] See https://www.gov.uk/government/collections/national-infrastructure-plan

The final point to make is that the auction demonstrates the value of market-based methods of revealing the costs of new entry, and the danger of leaving such decisions to regulators (as in the SEM, where the regulators calculate the CONE, described as the cost of Best New Entry or BNE) periodically and set it at a high price.[10]

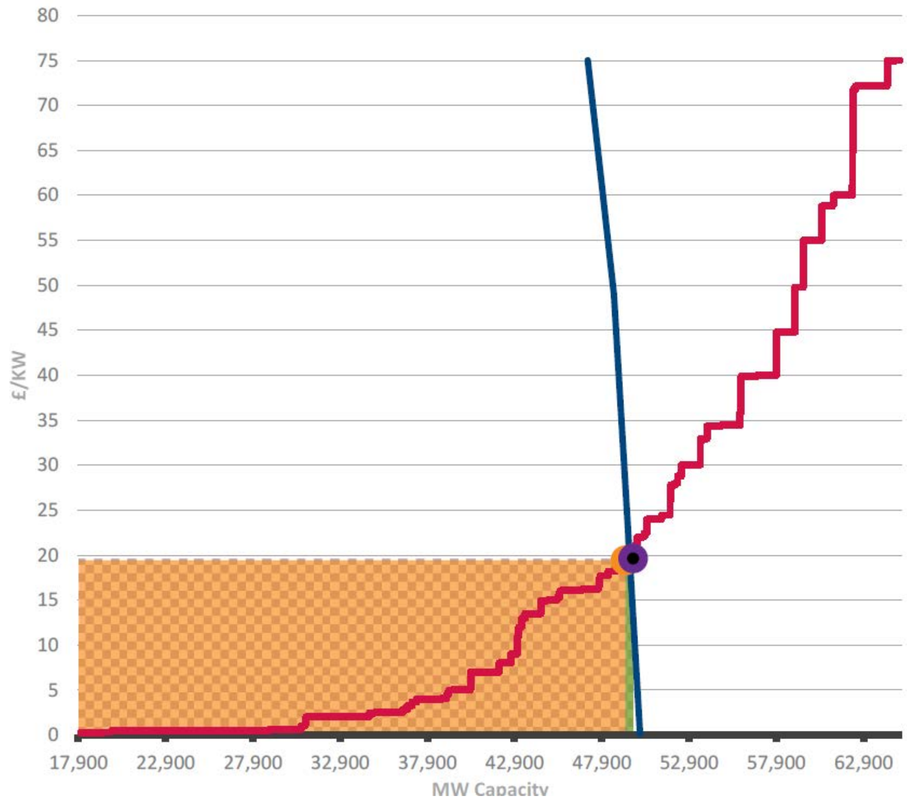

Figure 6 Supply and Demand curve for T-4 capacity
Source: National Grid (2014b)

Conclusions

There are compelling reasons for a capacity payment in competitive electricity markets where new investment is dominated by politically determined and subsidized low-carbon generation and carbon markets are failing to give adequate, durable and credible forward price signals. There is also now compelling evidence that the new flexible plant needed to maintain system security in the presence of massive intermittent generation is best procured through a capacity auction, and there is good evidence on how to design such auctions. The part of this debate that has been neglected is how to, and who should, determine the amount and type of capacity to procure (generation, DSR, interconnection), a problem that is exacerbated by misunderstandings over what a Loss of Load event means and what it might cost.

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[10] See http://www.allislandproject.org/en/cp_current-consultations.aspx?article=75c548a7-34ee-497c-afd2-62f8aa0062df

Whether or not interconnectors should be included in auctions is less important than that their contribution should be taken into account in determining how much domestic generation capacity and DSR to procure. All British interconnectors are HVDC controllable links whose flows can in theory be reversed in 1/50th of a second (although the system normally cannot accommodate such a rapid response) and as such they could provide extra imports at very short notice, but they can also impose sudden large loads on the GB system if they switch to exporting. In the event, the UK Government, possibly under pressure from DG COMP over State Aid concerns, has decided to include interconnectors in the next T-4 auction for delivery in winter 2019-20, and is consulting on how to de-rate them to determine their equivalent reliable capacity.

There remain a number of issues to resolve, not least how the European auction platform Euphemia will determine the direction of flows close to real time, when stress events that the capacity auction was designed to address are likely to emerge. Euphemia has a price cap of €3,000/MWh on the DAM, and has not yet fixed the price caps for intraday and balancing actions, but certainly the DAM price is well below the VoLL that has driven the case for the GB capacity auction. If prices into the real time European markets could properly reflect scarcity, and if the GB market could deliver the true scarcity prices to Euphemia (including the CP of equation (1)) then good market design and pricing would deliver efficient solutions, and other countries with less good pricing would lose out, motivating them to improve their market design. Price caps hinder this aim, and instead good rules will be needed for out-of-market actions when price caps are reached, and/or markets no longer determine flows, and SOs have to intervene. These rules or bilateral agreements between the SOs at each end of interconnectors are currently lacking or incomplete.

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