Security of Supply, the Role of Interconnectors and Option Values: Insights from the GB Capacity Auction

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ABSTRACT

The UK Government has carefully designed a Capacity Mechanism to deliver reliable electricity. This paper criticises the determination of the amount to procure, and argues that the amount set for the first auction was excessive, particularly (but not exclusively) in ignoring the contribution from interconnectors. Too little attention was given to either the political economy or the option value aspects. Procuring too little raises fears of 'the lights going out', but over-procurement increases consumer costs; undermines renewables by transferring capped finance to fossil generators; and impedes the Single Market including by weakening the business case for interconnectors. Making more use of the demand-side and potentially available 'latent' capacity lowers risk and increases options allowing more capacity procurement to be deferred. Capacity markets are intended to address problems of 'missing money' in terms of energy-only market incentives to invest; but over-procurement risks exacerbating the underlying problem, whereas addressing market failures and missing markets, and properly accounting for interconnectors, reduces the underlying problem.

Keywords: Capacity auctions, procurement volume, interconnectors

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1. INTRODUCTION

Britain's first electricity capacity auction closed on 18th December 2014 (National Grid, 2014b). As the first capacity auction to come into effect since the Third Package set out the preferred energy-only market of the Target Electricity Model, the UK experience is therefore of more general interest. The case for and against capacity mechanisms, based on various perceived market, regulatory and political factors, has a long history but is rising in salience with the extent of environmental policy interventions.[1] Almost all the discussion about capacity mechanisms concentrates on whether the various market and regulatory/political fail-

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1. See the extensive academic discussions on investment adequacy, most recently in the *Symposium on 'Capacity Markets'*, Joskow, 2013, particularly Cramton, Ockenfels and Stoft, 2013.

ures are sufficient to justify a capacity mechanism, and if so, what form it should take.[2] While in the US context the main argument for capacity auctions has been the missing money problem caused by price caps set well below the value of lost load, in Europe the main argument stems from its climate change policies. Reducing CO_2 emissions requires government intervention with attendant political risks, and mandates renewable energy whose output is unreliable. The demanding EU *Renewables Directive* (2009/28/EC) requires Britain to deliver 15% of 2020 energy from renewable sources, implying at least 30% of electricity generated. If that comes mainly from on and off-shore wind with an average capacity factor of 30%, the peak wind capacity required would be almost three times as high as the gas capacity that could deliver the same annual output. When the wind blows, this large volume of capacity would reduce the wholesale price, but if the wind is not blowing, the system still needs to meet demand from other sources.

In the past, flexible reserve capacity has come from older, less efficient flexible fossil plant (in the UK, mainly coal-fired), which was worth keeping on the system at low load factors as its capital value had been written off, but that is no longer a viable option. Most of the aging coal plant has been or will be retired in the period 2012-2020, because of the Large Combustion Plant Directive (2001/80/EC) and the more stringent Industrial Emissions Directive (2010/75/EU), which limit the number of hours plant can run unless they are refurbished. The Carbon Price Floor was set in the Budget of 2011 (HMT, 2011) for fuel used in electricity generation to support the price of CO_2 at £16/tonne in 2013, rising to £30/tonne (€35/tonne) in 2020, and to £70/tonne by 2030 (all at 2009 prices). This raises the cost of operating coal-fired plant and makes refurbishment unattractive. Added to the retirement of aging nuclear power stations, Britain faces lower reserve margins than most EU member states, and is more likely to need new, reliable and flexible plant. This plant will be reliant on selling power at high prices for a relatively small number of hours per year to justify its investment. In a liberalized energy-only market it can be difficult to persuade investors that they will be allowed to sell at sufficiently high prices, particularly as the wholesale day-ahead market is now subject to an EU price cap of €3,000/MWh. It is also hard to estimate how many hours the plant would be called on, so that prudence would suggest delaying until scarcity is reflected in adequately high prices, risking shortages until plant is commissioned. This increases the uncertainties and risks facing new plant construction.

Arguably, the problem in Europe is not so much about ‘missing money’ in energy-only markets, but more about ‘missing markets’ (Newbery, 1989; 2015) on which investors could lock in future prices and lay off risks, including political and regulatory risks, whose absence risks inadequate investment. Many EU countries are considering Capacity Mechanisms to address the risk of inadequate investment and so will face the same problem as Britain.

In this paper we focus on the volume of procurement, and in particular the assessment of interconnectors and the option value of delaying some auction procurement. We conclude that concerns of capacity shortfall must be balanced against a real and serious risk of procuring too much conventional domestic capacity too soon, to the detriment of the other goals of UK and European energy policy. Capacity Mechanisms risk undermining some of the logic of

2. See e.g. Adib et al. (2008), Batlle et al. (2007), Battle and Rodilla (2010), Bowring (2008, 2013), Chao and Wilson (1987, 2002), Crampton and Ockenfels (2011), Cramton and Stoft (2008), Joskow (2008), Joskow and Tirole (2007); O’Neill at al. (2006); and de Vries (2007). For a more sceptical assessment in the UK context that looks at the welfare impact, see Platchkov et al. (2011).

liberalised electricity markets, moving back towards a 'Single Buyer' Model. The scale of the risks hinges not only on design, but crucially, upon the volume procured.

Fears about capacity adequacy in energy-only markets are reflected in the *Energy Union Package*, published in February 2015 by the European Commission. Action Point 5 states "Creating a seamless internal energy market that benefits citizens, ensuring security of supply, integrating renewables in the market and remedying the currently uncoordinated development of capacity mechanisms in Member States call for a review of the current market design. The Commission will propose legislation on security of supply for electricity in 2016." (EC, 2015).

This paper examines and criticises the British process for determining the volume of capacity to procure, compares the auction outcome against predictions, and draws lessons for future capacity procurement auctions. Although the auction was substantially better for consumers than fixing an administrative price (revealing again the power of auctions to deliver cost-effective solutions) we argue that the institutional design led to excessive procurement. This paper accepts the case for capacity mechanisms in some form, but directs attention to the previously neglected aspect of the volume—and scope—of capacity to procure.

2. THE RISE OF CAPACITY CONCERNS

Security of supply is both important and inevitably politically sensitive. No politician or system operator wants the lights going out. The more capacity is available, the lower the chance of black-outs. But leaving the capacity choice to politicians or system operators risks excessive procurement, as the consumer, not the system operator, bears the cost. This cost, as we argue, may be higher than a simple impact assessment (e.g. DECC, 2013b) might suggest, in part because it has implications for the whole market design and market integration more generally. One of the main arguments for privatising electricity was to keep politicians out of decision making, leaving the market to make efficient choices of the quantity and type of capacity.

Britain had adequate capacity at privatization in 1990. The attractiveness of gas-fired generation and the slow growth of electricity demand helped maintain adequate capacity margins in the UK and Europe. Recently, reserve margins and confidence about capacity adequacy have fallen as age and environmental concerns are leading to widespread retirement of coal and nuclear plants. Rising and volatile gas prices discouraged new gas generation. Britain replaced the electricity Pool (and its capacity payments) with an energy-only market in 2001 (Newbery, 2005).[3] The EU *Renewables Directive* mandates intermittent renewables which contribute less to supply security whilst reducing operating hours of conventional plant, weakening incentives to invest in reliable capacity.

Combined with uncertain future electricity demand and an unsatisfactory Balancing Mechanism, this has undermined the former consensus that unaided energy-only markets will deliver the right kind and amount of generation. From 2010 on, Britain predicted a serious risk of shortages by 2016 from plant retirements.[4] This eventually prompted Electricity Market Reform (EMR) through the *Energy Act 2013*,[5] which includes long-term contracts for low carbon generation and a Capacity Mechanism for capacity adequacy. Instead of the market,

3. From 1989-2001 the British electricity wholesale price included a capacity payment set at the Value of Lost Load (VoLL) times the Loss of Load Probability (LoLP). VoLL was set at £(2014)5,000/MWh (£5/kWh).

4. E.g. see the regulator's view at https://www.ofgem.gov.uk/ofgem-publications/40354/projectdiscoveryfebcondocfinal.pdf and for a history of policy concerns, Pollitt and Brophy Haney (2013).

5. http://services.parliament.uk/bills/2012-13/energy.html

the Secretary of State for Energy & Climate Change (the Minister), advised by the Department for Energy & Climate Change (DECC), sets the security standard and decides how much capacity to procure through capacity auctions.

Capacity Mechanisms are not new, and are replete with potential pitfalls (e.g. Cramton and Ockenfels, 2011). The EMR devoted tremendous effort in the technical design of the mechanism, drawing on academics expert on capacity mechanisms and international experience from the U.S., particularly PJM (Bowring, 2013). However, less attention was given to the apparently simpler tasks of delivering the reliability standard and determining the amount to procure, which determine the overall cost.

This paper discusses the reliability standard, its widespread misinterpretations, and the Minister's announced intent (on 30 June 2014) to procure 53.3GW in the first auction for delivery in winter 2018-19.[6] We highlight the underlying confusion (and opportunity) around indicators and options and the role of interconnectors, contrasted with the Minister's acceptance of a 'zero net contribution' (imports from the Continent balanced by exports to Ireland).[7] The evidence is British but the issues have far wider relevance. We track progress from the start of the process to the December 2014 auction outcome, noting inconsistencies between the advice offered, the *Impact Assessment*, and the final political decision.

3. THE 'LOSS OF LOAD EXPECTATION' AND THE RELIABILITY TARGET

In December 2013 DECC set as its reliability standard a 'Loss of Load Expectation' (LoLE) of 3 hours/year, implying a 'Value of Lost Load' (VoLL) of £17,000/MWh, over three times the 2013 value used in the electricity Pool,[8] based on London Economics' (2013) study using stated preferences for the willingness to accept (WTA) outages. Domestic WTA was £10,000/MWh but willingness to pay to avoid outages was only £2,000/MWh.

One immediate problem is that a LoLE of 3 hrs/yr does not mean that the lights would go out for three hours each year. It means that on average over several decades *the System Operator would have to* ***take some actions to prevent*** a loss of load for an estimated average three hours a year. According to the GB regulator (Ofgem, 2014) these actions include:

- asking generators to exceed their rated capacity for a short period;
- invoking 'new balancing services', mainly contracts to reduce peak demand or offer on-site (embedded) backup generation;[9]
- cutting any interconnector exports to zero, and requesting imports;
- and, if these measures are not enough, reducing voltage ("brown outs").

The System Operator can thus take such 'mitigation actions' in 'stress periods' (announced four hours ahead by a Notice of Inadequate System Margin, DECC, 2014d, §397) by calling on demand-reduction responses and *latent capacity*—generation that is not part of normal operation or is otherwise not available to the market, but which costs far less than the VoLL

6. At https://www.gov.uk/government/news/britains-energy-security-strategy-now-fully-in-place
7. At http://www2.nationalgrid.com/UK/Our%20company/Electricity/Market%20Reform/Announcements/June%202014%20Auction%20Guidelines%20publication/
8. See note 4. Leahy and Tol (2011) estimated the average VoLL for Ireland at €12,500 (£10,000)/MWh.
9. "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).

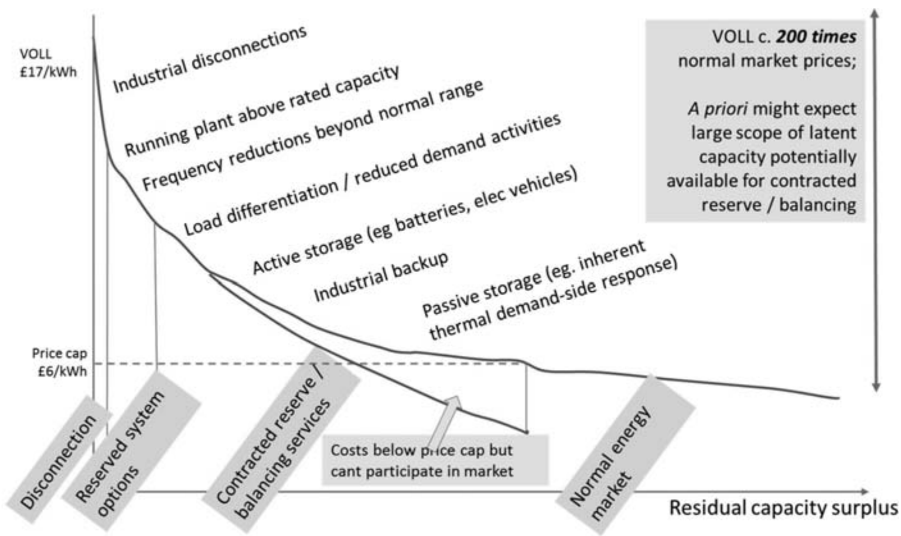

FIGURE 1

Supply curve of options and 'latent capacity' for responding to tight system conditions

or new generation. Figure 1 shows several types of latent capacity, which in total could be very substantial.[10]

These actions would be invoked before finally having to selectively disconnect some loads (NOT switching off all the lights). Obviously, the system should not rely on having to operate 'under stress' for extended periods, since all these options are costly, and some (notably storage) may only be available for limited durations. However, the existence of these various options highlights that '***Loss of Load*** Expectation' is a misnomer for a statistical measure of the probability of invoking out-of-market mitigation measures. Yet *these measures* are implicitly valued at £17/kWh—over one hundred times the consumer price. One might doubt if consumers would be willing to pay £17/kWh rather than experience barely noticeable actions by the System Operator or even occasional brown-outs, particularly as in GB on average the lights actually go out for 1-2 hours per year because of local faults or storm disruptions to transmission.

Given this terminological confusion over "loss of load", perhaps understandably the Minister chose the top of the range recommended by National Grid. This will likely prove excessive, for three reasons:

i. the reliability standard is too high given the range of 'mitigation measures' available;
ii. the range of options can be further broadened; and
iii. National Grid chose to ignore the contribution of interconnectors.

Ignoring interconnectors implies that GB is aiming at autarky when the EU aims to deliver a fully integrated European electricity market (also by the end of 2014). The Target

10. A report (at https://www.npower.com/idc/groups/wcms_content/@wcms/@corp/@iac/documents/digitalassets/iandc_pdf_futurereport2.pdf) notes: "There is no official data . . . but EA Technology has estimated the total capacity of emergency diesel generation at 20 GW." Spees et al. (2013) note that the PJM capacity mechanism procured 4.8 GW of new generation, 11.8 GW of demand response, and 6.9 GW of increased net imports.

Electricity Model integrates markets by coupling interconnectors through an energy-only auction platform. By mid-2014 this had successfully coupled most markets from Finland to Portugal, including GB. The EU *Security of Supply Directive* (2005/89/EC) states that "Member States shall not discriminate between cross-border contracts and national contracts" (Mastropietro et al., 2014).

4. THE CONTRIBUTION OF INTERCONNECTORS

Interconnectors allow physical imports to meet domestic demand. Logically then, interconnectors must enhance security of supply except in the most extreme combinations of contractual and physical circumstances. The benefits of interconnection will tend to increase with the scale and geographical reach of the interconnected countries. Newbery et al. (2013) estimated the value of a fully integrated EU system at €12.5–€40bn/year by 2030—roughly €25 to €80 per capita—compared to the status quo before market integration.

The challenge lies in realising these collective gains. As countries lack control over generation abroad and as they have in the past (understandably) prioritised domestic security, the 'default' is to assume interconnectors make no contribution to national security. Logically this assumes that security equates to self-sufficiency, a philosophy abandoned in other markets (including food) long ago. It conflicts with the European Target Electricity Model as well as the EU *Security of Supply Directive*. Some countries such as Ireland and France now include interconnectors in their security assessments.[11] Moreover, in the UK context DECC's consultation paper stated unambiguously: "The expected contribution from interconnectors will be reflected in the amount of capacity auctioned." (DECC, 2013a, §32). Even more surprising, DECC's *Final Impact Assessment,* published just before the procurement decision (DECC, 2014b), actually estimated the amount of interconnector capacity to include at 2.9 GW, as discussed below. After the procurement decision was published, but before the auction was held, DECC issued a consultation in September (DECC, 2014c) on including interconnectors in the 2015 T-4 auction (for delivery in 2019), and subsequently (on 2 December) announced it would include interconnectors.[12] We argue that they should have left space in the 2018 delivery, and then held an auction for interconnectors in 2015 for delivery in 2018.

5. WHY IT MATTERS

DECC's (2013b) *Impact Assessment* (IA 2013) of the GB Capacity Mechanism showed a large gross consumer cost reflecting the level of payments to generators, shown in Table 1 below. IA 2013 assumed the EMR would be fully implemented, including the Carbon Price Floor. It estimated the 'missing money' at £30/kWyr, consistent with the reliability standard (3 hours/yr) times the difference between VoLL (£17,000/MWh) and the price of System Operator actions (£6,000/MWh). The net Cost of New Entry (CONE) was estimated at £29/kWyr, allowing for other revenues. IA 2013 assumed no net contribution from interconnectors, despite the Pöyry (2012) estimate of a 57% contribution to displacing domestic generation

11. For details see Eirgrid/SONI (at http://www.eirgrid.com/media/Generation%20Capacity%20Statement%202014.pdf) , and for France, http://www.rte-france.com/en/mediatheque/documents/operational-data-16-en/annual-publications-98-en/generation-adequacy-reports-100-en
12. See https://www.gov.uk/government/news/interconnectors-to-participate-in-the-capacity-market-from-2015

TABLE 1
Costs and benefits of a capacity market from successive *Impact Assessments*

Costs and Benefits of a Capacity Market 2012-2030	£m (2012 prices) Oct-13	Jun-14	Change 2014–2013
Carbon cost	854	46	− 808
Generation cost	176	104	− 72
Capital cost	− 1,415	− 116	1,299
System cost	1,184	529	− 655
Interconnection net import cost	44	− 248	− 292
Energy System Costs	843	315	− 528
Institutional costs	32	41	9
Administrative costs	231	112	− 119
total cost	1,106	468	− 638
net benefit	184	380	196
benefits = reduction in unserved energy	1,290	848	− 442
change in consumer surplus	− 10,417	− 117	10,300
change in producer surplus	10,083	542	− 9,541
change in environmental tax revenue	517	− 44	− 561
change in net surplus	183	381	198

Sources: DECC (2013b, 2014b)

capacity (DECC, 2013b, §4.22), arguing "that interconnector flows do not always reflect price differences between markets", and that "spot prices for electricity in the GB Market do not reflect the value of capacity at times of system stress as well as other interconnected markets" (DECC, 2013b, §4.24-5).

On 23rd June, 2014, DECC published its *Final Impact Assessment* (IA 2014) revising some of these critical assumptions as the evidence was being assembled for the Minister to decide the procurement amount. The missing money estimates remained unchanged, but the net CONE was now estimated at £49/kWyr, apparently partly in response to generator complaints at the earlier lower value. The key differences, probably mostly responsible for the large change shown in Table 1, were the assumptions on interconnectors.

Using the same Pöyry (2012) report, DECC now argued "in an efficient market,[13] we can expect to be importing electricity through interconnectors at times of stress—equivalent to around 75% of the total existing capacity of interconnectors to the Continent", arising from a more realistic assessment of these Continental flows at times of system need, together with cautious assumptions on exports to Ireland and expectation of new interconnectors.[14]

13. The market efficiency will be increased to the extent that prices for short term balancing of supply and demand reflect full marginal costs; in April 2015 Ofgem approved measures to sharpen the balancing mechanism in this respect (Ofgem, 2015). In addition, to address security concerns in the near term, Supplemental Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR) are in operation between 2014/15 and 2017/18 (DECC, 2014b, §5.2).

14. Thus the DECC analysis continues: "Pöyry also show that imports from Ireland are possible, but we think it is prudent to continue to assume full exports over the interconnectors to Ireland. We have assumed that it is possible to import up to 1.5GW of capacity (i.e. 75% of 3GW imports and 0.75GW of exports) through existing interconnectors at times of stress. . . . Currently,

What is immediately obvious from the later impact assessment is the (expected) large decrease in *appraised* carbon costs (suggesting a large displacement of fossil generation by low-carbon plant and/or imports), but a large increase in capital cost (more new entry at a much higher net CONE), a fall in system cost because of assumed better incentive regulation, lower import costs (while the CPF raises GB prices above Continental prices, market coupling now ensures that flows follow price differences), leading to a fall in the sum of all these (the Energy System Cost). What is most striking is the distributional impact change—the huge impact on consumers (net present value of £10 billion) falls to a net cost of only £100 million, while producers see their £10 billion windfall reduced to £0.5 billion, as wholesale prices are now lower as a result of including interconnectors.

The central assumption is that the consumer cost of capacity payments to generators would be largely offset as generators pass this revenue through in lower wholesale electricity prices. Reasons for this include more capacity lowering wholesale prices, balancing service reforms deliver more efficient pricing, or simply that industry would price to avoid political risks from windfall profits, if they fail to pass capacity payments on to the market.

The estimated net cost to consumers is thus the difference between two much larger numbers—the gross payments, and the amount passed through. This makes it intrinsically uncertain, but we note that the larger the pass through, the more the wholesale price is reduced by the capacity payments, which then reduce the energy-market incentive to invest—making investment more dependent on capacity payments. A capacity mechanism therefore risks a self-reinforcing circle.

Moreover, the costs (and market impact) may be very sensitive to the amount procured. Suppose that GB could obtain 3 GW in stress periods in 2018/19 from interconnectors and/or other sources, with the result that no new capacity is required. This could reduce the marginal cost—which is then paid to all—to below the ceiling for existing plant of £25/kWyr. At the estimated net CONE of £49/kWyr the extra 3 GW would likely more than halve the bill, with the difference equating to more than £450/kW ***per year***, more than the ***total*** purchase cost of a peaking gas turbine. In the event, the auction cleared at well below these levels and the potential adverse impacts on consumers were mitigated, as discussed below.

Beyond the potential consumer cost, there are additional drawbacks to over-procurement:

Raising the auction price. To the extent that excess procurement lowers the wholesale price and reduces the revenue to be earned in the market, this raises the capacity price needed to cover total costs, and exacerbates the missing money problem.

Impact on renewables: Under EMR, renewable energy generators receive a Contract for Difference that pays the difference between the 'Strike price' and the wholesale price. The extra capacity lowers wholesale prices which increases the subsidy required (the excess of the strike price over the lower wholesale price), putting strain on the Levy Control Framework (LCF) that caps overall payments. The consumer cost is unchanged, but some of the LCF is absorbed by the increased transfer to renewables from conventional plant. This could reduce the support to, and hence volume of, renewables.

we anticipate that 2GW of further interconnection will have connection agreements by the time of the first delivery year (2018/19), which gives an additional 1.4GW of potential interconnection by 2018/19. However, we recognise that the actual commissioning dates for these future interconnection projects are still very uncertain." (DECC, 2014b, §1.10-11).

Demand Side Response (DSR) and Interconnectors. DECC now plans to include interconnectors in subsequent auction rounds (and possibly new potential DSR).[15] If the first auction over-procures, this reduces the volume or value to future interconnectors or DSR.

If every EU Member State adopted a 'self-sufficiency' approach and a Capacity Mechanism, the result would be EU-wide excess capacity. As gas is the cheapest capacity, the result would be excessive subsidies to gas-fired stations. With gas prices increasingly aligned across Europe, and gas operating at the margin, this would cannibalise the value of interconnectors, reducing returns and increasing risks facing interconnector investors. Assuming the need for self-sufficiency could become self-fulfilling in undermining the economics of interconnectors. It would do so at high cost, with excess peaking capacity only needed in each country a few hours per year, when a smaller volume of shared peaking capacity running more hours but supplying over interconnectors would be cheaper. Moreover the cost and market impacts may be very sensitive to conditions. All this points to the central importance of judging carefully the amount to procure.

6. ASSESSING SECURITY OF SUPPLY

Contrary to common perception, security of supply is not an absolute, but a statistical goal. The GB reliability standard is a Loss of Load Expectation (LoLE) of 3 hours/ year, averaged over mild and cold winters. Ofgem (2014, p5) defines LOLE as "the average number of hours in a year where we expect NG may need to take action that goes beyond normal market operations. Importantly, this still does not represent the likelihood of customer disconnections."

LoLE is derived by analysing statistics of all factors causing variations in supply and demand, starting with a probability distribution of *available* conventional generating capacity. This is confronted with variable wind output and demand to give the net demand facing conventional capacity, from which the LoLE is determined by examining the probability (and amount) of any shortfall from the available capacity and its forced outage rate.

National Grid (NG) develops four scenarios for assessing reliability. Scenarios aim to capture different possible future states, each internally consistent and used to explore the robustness of any decisions. In addition, both NG and Ofgem consider various sensitivities: "Even during the relatively short time horizon of this analysis, there is significant uncertainty over the security of supply outlook. We assess these uncertainties using sensitivity analysis around NG's scenarios. These sensitivities illustrate only changes in one variable at a time and do not capture potential mitigating effects, for example the supply side reacting to higher demand projections." (Ofgem, 2014).

Whilst this approach treats demand, wind and generation stochastically, potential imports over interconnectors were considered non-stochastically—with a single assumed level of availability. This discriminates between stochastic domestic supply and the certainty of no net imports in tight conditions. The sensitivities in Ofgem's *Capacity Assessment* show the large impact of positive interconnector imports, as do the differences between successive *Impact*

15. See https://www.gov.uk/government/news/interconnectors-to-participate-in-the-capacity-market-from-2015

TABLE 2
Current and possible GB interconnectors and their capacity[a]

Interconnector	to	2014 GW	Future GW	Date of expansion
IFA	France	2	2	
BritNed	Netherlands	1	1	
Moyle	N. Ireland	0.08[b]	0.5	Nov 2017[c]
EWIC	Rep. Ireland	0.5	0.5	
NEMO	Belgium		1	Oct 2018[d]
Eleclink	France		1	Q4 2016[e]
Total		3.75	6	

[a] See DECC (2014a, Table 1) for the considered assessment (other footnotes are to documents that may have an incentive to exaggerate the speed of delivery of interconnections).
[b] Although Moyle can import 250 MW into NI, at present it can only export 80MW to Scotland because of constraints limiting Scottish exports to England.
[c] See http://www.eirgrid.com/media/Generation%20Capacity%20Statement%202014.pdf
[d] See http://www.nemo-link.com/timeline/
[e] See http://www.google.co.uk/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&sqi=2&ved=0CCAQFjAA&url=http%3A%2F%2Fwww.cre.fr%2Fen%2Fdocuments%2Fpublic-consultations%2Frequest-from-eleclink-for-an-exemption-under-article-17-of-regulation-ec-714-2009-for-a-gb-france-interconnector%2Fdownload-the-appendix-1-eleclink-s-exemption-request&ei=DIyxU6D-BsrD0QXd0YHIAw&usg=AFQjCNETH94MM5mlKQJEm3DBqGwIX-RTKw&sig2=Tjr2Mv6rMNoO41xQlI-YpQ

Assessments demonstrated in table 1. Clearly, this is unsatisfactory and could be done better, as Zachary et al. (2011) show.

7. THE ROLE OF GB INTERCONNECTORS

Interconnection enhances security because none of the three main determinants of potential shortfall—peak demand, wind availability, or conventional plant failure—are perfectly correlated between countries. The 2014 and potential future capacities of GB interconnectors are shown in Table 2 (with their assumed, possibly optimistic, commissioning dates). Thus by winter 2018-19, optimistically GB could import 6 GW in stress periods (about 10% of peak demand). A further 1.4 GW interconnector to Norway, NSN, might be delivered in 2020.[16]

Several factors make imports more likely when needed. Market Coupling has (as expected and intended) increased the responsiveness of interconnector flows to relative price differentials, so that power flows to where most needed. Historically there has been significant surplus collective capacity in countries connected to GB. The minimum collective "margin" at peak demand during 2012 was 16GW:

Almost all peak period de-rating of GB generators is based on forced outages that are uncorrelated with outages abroad so imports can, with high probability, deliver power to replace local losses. National Grid (and Ofgem) clearly recognise that *in principle*,[17] so it is hard to see why their contribution should be ignored when recommending the auction procurement amount. What is required is a measure of the de-rated import capacity of all the interconnectors on a basis of statistically likely availability to import during GB stress events.

16. See http://www.statnett.no/en/Projects/Cable-to-the-UK/ but DECC (2014) does not include this.
17. http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=32371; and Ofgem's factsheets on interconnectors at https://www.ofgem.gov.uk/ofgem-publications/87961/electricityinterconnectorsfactsheet.pdf

TABLE 3
'Minimum margin' statistics for GB + four interlinked countries, 2012

	Max Hourly Load, GW	De-rated Capacity, GW	Lowest margin observed in any hour, GW
2010	178	198	20
2011	172	197	25
2012	184	200	16
2013	173	200	27

Source: Derived by the authors from ENTSO-E data

Indeed, DECC's (2014b) *Final Impact Assessment* included 2.9 GW of interconnection by the delivery date, and showed that this dramatically reduced the cost to consumers, but this timely information failed to affect the recommendations.

DECC's Panel of Technical Experts (DECC, 2014a), writing before the publication of *Final Impact Assessment,* noted that DECC itself had commissioned a report on interconnectors. Pöyry (2012) found that interconnectors provide 2.3 GW of effective capacity or 62% of their nominal 3.7 GW capacity even in the worst case of tight conditions abroad and this formed the justification for its inclusion in DECC's (23014b) *Final Impact Assessment*. Pöyry (2012, p62) also notes: "6GW of additional interconnection leads to about 3GW less firm capacity built." That suggests that the proposed interconnectors in Table 2 have a de-rated value for the Capacity Mechanism of at least 50% and so might contribute an extra 1 GW to the existing 2.3 GW net GB import capacity to give 3.3 GW by 2018. While there is some uncertainty over the commissioning date for this new capacity, Pöyry's estimates suggests that *existing* interconnectors are equivalent to at least 2 GW of domestic de-rated capacity.

Pöyry (2013) reported to Ofgem "GB low capacity margins (below 20%) show a medium level of correlation with low capacity margins in Ireland and France. On the other hand, *very low capacity margins (below 10%) in GB do not show a definite correlation with any of the other systems*." (emphasis added.) This again cautions against using past average interconnector correlations as a guide to importing in GB stress events (i.e. very low capacity margins) where the underlying (and low) stress hour correlations apply (and other market reforms have improved price signals).

Redpoint (2013, p9), also commissioned by DECC, concluded that "greater levels of interconnection are generally associated with better security of supply. Although both low wind and high demand conditions can be correlated across markets, forced plant outages are generally uncorrelated and hence in times of extreme system stress in GB, most interconnectors are likely to be supplying energy to GB at near full capacity." Redpoint also found most interconnectors flowing near full capacity to GB at times of extreme stress, except for France, with an import utilisation below 100%. France (along with Ireland) has the highest correlation of system stress with GB, and has the most interconnection with GB. Full French exports when GB experiences stress are thus more likely to stress the French system.

8. THE COST OF REGRET

National Grid adopted a Least Worst Regret (LWR) approach to capacity requirements, illustrated in Figure 2. As capacity falls below the level that delivers a LoLE of 3 hours so the

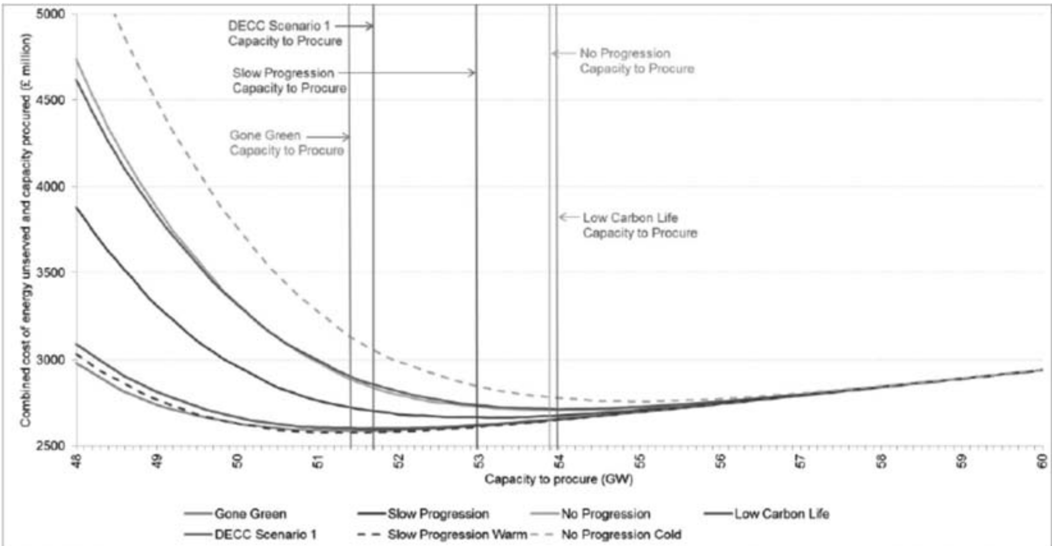

FIGURE 2
Choosing the level of capacity
Source: National Grid (2014, p50)

LoLE increases, with "energy unserved" costed at the VoLL of £17,000/MWh,[18] causing the curves in Figure 2 to rise increasingly sharply to the left of the minimum point. The 53.3GW recommended and chosen is at the flat part of the most pessimistic 'no progression' scenario.

However, the cost of falling short is greatly exaggerated by costing shortfalls at £17/kWh. First, section 3 noted various actions to 'keep the lights on' when demand risks exceeding supply under normal operating conditions. These so-called 'emergency actions' are to be valued (after 2016) at *up to* £6,000/MWh—well short of the £17,000/MWh underpinning Figure 3.[19] At these substantially lower costs, the curves will not rise as soon or as much below the chosen capacity, and the minimum cost will be at a lower capacity level.

Second, the calculations ignore interconnectors. Finally, it should be possible to increase the volume of cheaper demand-side resources and 'latent capacity' in less than four years, making it sensible to defer some future required capacity until we have better information about future demand and supply.

8.1 Option values and the proper treatment of uncertainty

Capacity assessments worry about uncertainty where there are no objective probabilities of various events. Some of the claimed uncertainties should be treated as risks and assigned probabilities, but inevitably there remain genuine uncertainties, which loom larger the further ahead one looks. There is currently very considerable uncertainty about the amount of capacity that will voluntarily exit before 2018/19, as well as whether new capacity secured in the auction

18. National Grid (2014a, p98, point 4)
19. As discussed in Ofgem (2013), Box 1 (p.20), the £6,000 /MWh was the upper range of estimates of the 'Value of Lost Load' from industrial customers in the survey by London Economics (2013). It is also above the level of price caps in most neighbouring systems, so that prices at this level should attract flows through coupled interconnectors.

will experience delays or even cancellations, as the penalty for non-delivery is small compared to the investment at risk. The auction is held four years ahead of delivery (i.e. T-4) to give time to plan for, build and commission a CCGT. If a delay of one or more years would reduce the level of uncertainty about the 2018/19 capacity requirement, and if it were cheap to delay that decision, then such a delay is likely to be valuable and hence cost-effective.

The UK rules allow for some procurement to be deferred from the T-4 auction to later, notably T-1. The amount proposed in 2014 for 2018-19 delivery 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 (i.e, plant that chose not to bid or failed to secure an agreement but would likely still be available at T-1) and the 0.4 GW is secured long-term operating reserve. Although the Government is committed to allowing interconnectors to contribute capacity at some future date, the formula leaves no space in the 2014 T-4 auction, and hence risks over-procuring early and leaving cheap later options on the table.

If one reason for a high procurement was to offset future uncertainties (about closures, demand, DSR, etc.) these uncertainties will be considerably reduced in two years' time. The New Balancing Mechanism should deliver useful information about latent capacity during 2015-16.

Forward contracting to reconnect mothballed plant would also reduce risk and keep options open. New gas-fired plant can be constructed in two years,[20] providing sites are secured with planning permission and connection agreements and finance is available. If such preparatory agreements can be procured cheaply ahead of time (and NG as System Operator would know where such plant would be most valuable), then it would be prudent to under-procure in the T-4 auction, and decide at T-2 whether more plant were needed in the light of better information.

9. THE DECEMBER 2014 AUCTION OUTCOME

The preliminary results of the auction were announced on 19th December 2014 (National Grid, 2014b) with the auction clearing at £(2012) 19.40/kWyr. Just under 65 GW bid and 49.3 GW received Capacity Agreements for delivery in 2018/19 at a cost of £(2012) 956 million. 77 (out of 306) new units, average size 34 MW, were successful, as were 166 MW (out of 595 MW) of DSR. 43.7 GW received 1 year contracts, 6.3% received 3-year contracts (for refurbishing, mostly nuclear stations) and 2.4 GW new entry received 14-15 year contracts. 8.5 GW of existing plant failed to secure an agreement.

Several conclusions can be drawn from the auction results. First, the price was considerably below the estimated net CONE, despite new entry, including by new CCGTs, which formed the basis of estimating the net CONE. Thus, as intended, the auction was able to secure capacity at a much lower price than a central planner might have set. Had DECC suggested an administrative capacity price at the CONE of £49/kWyr, the cost would have been 2.5 times as high, costing consumers an extra £1.5 billion per year, and demonstrating the value of auctions for procurement. Second, the evidence (National Grid, 2014b, fig 1) suggests that including 2.3 GW interconnector capacity might have lowered the price to £16.25/kWyr and saved £155 million. It is interesting to reflect back through the lens of the *Impact Assessments.*

20. Teesside CCGT, then the largest in Europe at 1,870 MW, took 29 months to build (see http://en.wikipedia.org/wiki/Teesside_power_station)

The October 2013 *Impact Assessment* ignored interconnectors and so predicted higher wholesale prices and hence a lower net CONE of £29/kWyr. The June 2014 *Assessment* included interconnectors and predicted lower wholesale prices and hence a higher net CONE of £49/kWyr. Perhaps the CCGT bid was predicated on the earlier *Impact Assessment*, or perhaps the higher CONE reflected successful industry lobbying rather than commercial reality. The fall in future gas prices may also have improved CCGT economics.

10. CONCLUSIONS

Policy makers and system operators fear black-outs but do not have to pay to avoid them, so they tend to over-procure. Consumers probably do not yet appreciate the cost of over-procurement which is delayed for four years. That said, the Government may be hard pressed to explain why an annual payment of nearly £1 billion, mainly to existing conventional power plants, and levied on consumer bills, is worth paying for a very modest increase in reliability, much of which would pass unnoticed as a reduction in System Operator interventions. It is also worth reflecting that one of the reasons for the large decrease in the predicted consumer cost of the Capacity Mechanism between the two *Impact Assessments* was the anticipated improvement in market functioning—in the balancing market and through market coupling of the interconnectors. Correcting market failures (and creating otherwise missing markets) can considerably reduce the missing money problem. Over-procurement on the other hand exacerbates it and risks locking the industry into a Single Buyer Model for all capacity, renewables and conventional, with the Minister setting the rules and amounts. Under-procurement in contrast moves the industry closer to the energy-only model of the Target Electricity Model, and concentrates attention on correcting market failures and enhancing flexibility.

This paper argued that work on the GB Capacity Mechanism concentrated on the technical design, but overlooked the essential political economy of setting the level. However well the Capacity Mechanism itself has been designed, it risks paying incumbent energy companies for more capacity at higher unit cost than necessary as a result of three key factors:

- the terminological confusion over the LoLE and its associated VoLL (since neither refers to losing load by involuntary disconnections) combined with a broadening scope for ‘mitigation measures’ that further reduce the risk of actual disconnection;
- the proposition that security equates to self-sufficiency, reflected in the ‘net zero’ assumption of interconnector contributions; and
- the failure to consider holding options for future more timely procurement.

While reflecting naturally risk-averse political decision-making, the resulting over-procurement is not in the consumer interest and also has other costs.

This raises important governance issues. The hope at privatization was that competitive markets would deliver adequate capacity given the Pool capacity payments, which were scrapped in 2001. Subsequent assessments have shaken confidence that the resulting energy-only market would deliver adequate capacity. At issue is neither the proposal for, nor the design of, a capacity mechanism. It is rather that, as consumers do not directly buy capacity, an authority has to set the required level. This naturally attracts criticism about the politics of public decision-making on what are technically highly complex issues, in which the current arrangement in which the System Operator advises the Government seems likely to lead to overly cautious (and costly) choices. That suggests the need for a technically competent but independent institutional structure—perhaps an ISO, as suggested by Strbac et al. (2014)—to help set the amount to procure.

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