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Paying Peanuts: Will the British Capacity Market Deliver Security of Supply?

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Abstract

Policymakers around the world have subjected electricity markets to imperfect and partial deregulation. Governments have liberalised and privatised electricity generation and supply, but have subsequently intervened to prevent price spikes and load-shedding. Subsidies for intermittent renewable electricity have pushed down average prices and made regulatory risk endemic, further reducing the ability of operators to invest in new capacity and raising the prospect of insufficient supply and, potentially, blackouts.

Governments, including that of the UK, have turned to additional interventions—Capacity Remuneration Mechanisms—in an attempt to ensure that adequate generating capacity is available. The UK government hailed its first Capacity Market auction, in December 2014, a success, primarily based upon the low prices achieved for capacity.

We argue that this low cost may not represent good value, and low prices may instead be the result of flaws in the design of the market. These deficiencies may lead to security of supply falling short of target during the 2018-19 delivery period, as suggested by recent press reports that some declared operational or contracted capacity may not be available in practice. The British experience illustrates the potential pitfalls of intervention to fix earlier interventions, especially the risks of continual policy uncertainty and regulatory capture by incumbents, and thus provides lessons for policy-makers elsewhere in Europe and around the world who are contemplating similar interventions.

Contents

1.	**Introduction**	1
1.1.	Power Markets in Theory	1
1.2.	The “Missing Money” Problem	2
1.3.	Finding the “Missing Money”	3
2.	**The Design Process for the GB Capacity Market**	8
2.1.	Initial Proposals Included Sharpening Cash-Out Prices	8
2.2.	The Proposed Targeted Auction Mechanism	9
2.3.	The Initial Proposals Did Not Withstand Scrutiny	10
3.	**The Initial GB Capacity Market Design**	12
3.1.	Market-Wide and Technology-Neutral	12
3.2.	Capacity Procured through Two Annual Auctions	12
3.3.	Mandatory Pre-Qualification, Voluntary Participation	14
3.4.	Agreements, Delivery and Penalties	15
3.5.	Price Caps, Price Takers and Price Makers	16
3.6.	Cost of the Scheme	16
3.7.	Efforts to Prevent Gaming	17
3.8.	The State Aid Review	19
4.	**The First GB Auction**	21
4.1.	DECC’s Assumptions Ahead of the Auction	21
4.2.	NERA’s Pre-Auction Modelling	22
4.3.	The Main Outcomes	24
5.	**Interpreting the Auction Results**	27
5.1.	Generators Appear to Have Written-Off Interim Losses	27
5.2.	Incentives for the Regulators to Game the Market	28
5.3.	Penalties in Name Only	31
6.	**Lessons from the GB Capacity Market**	33
6.1.	Capacity Markets are Subject to Regulatory Change	33
6.2.	Capacity Markets are Vulnerable to Regulatory Capture	35
6.3.	Conclusion	35
Bibliography		37

1. Introduction

Electorates hold policymakers accountable for failures to keep the lights on. For reasons of efficiency, however, many governments have privatised ownership and liberalised power markets. The lack of government ownership presents a challenge to politicians who want to guarantee adequate power generation and supply and do not trust markets to deliver security of supply. In this paper, we look at how governments can guarantee a secure power supply most efficiently—and why they often fail to do so.

In liberalised and competitive markets, shortages will drive up prices. Rising prices encourage more supply and discourage demand until the balance between supply and demand is restored. Electricity markets, however, present a test for this part of economic theory. Bilaterally negotiated prices cannot keep up with rapidly changing market conditions, so electricity markets set last minute prices according to a single set of rules agreed in advance by the industry and regulated (i.e., imposed or approved) by government. The risk of using the wrong rules raises the spectre of market failure, where supply is inadequate and the electricity system fails to deliver. So consumers should naturally be asking if governments are choosing the right pricing rules and institutions to regulate them.

However, even an efficient market does not serve all demand all of the time. Limited periods of load-shedding and high prices are more efficient than constructing additional capacity, and help ensure generators recover their fixed and sunk costs. On the other hand, the occurrence, or even prospect, of load-shedding carries the risk of unpredictable policy interventions in the market (e.g., to cap prices or force early investment).

Imperfections in market rules and the risk of unpredictable policy interventions provide the rationale for capacity markets (CM), and other similar mechanisms, aimed at ensuring security of supply. These mechanisms offer financial incentives to encourage investment in new generating capacity, or to underwrite the economics of existing power plants that may be decommissioned.

1.1. Power Markets in Theory

In an energy-only electricity market, the cost of building and operating a power plant must be recovered through the market price that the operator receives for selling its output. (Some power stations earn revenue from producing not just electricity but also a number of “ancillary services”, such as supporting weak points in the national grid. Here we focus on the pricing of electricity.) For most of the year, available generating capacity exceeds demand by a comfortable margin. In a competitive electricity market, the wholesale power price that “clears the market” (i.e., the price that balances supply and demand) is equal to the short-run generation costs of the marginal generator (the most expensive generator in the least-cost pattern of generation that meets demand). Most generators operating at any time have lower generation costs than the marginal generator, so they earn a margin, or infra-marginal profit, that contributes to the recovery of their fixed and sunk costs.

In some periods, the electricity system does not have enough available capacity to meet demand, either because demand is unusually high or because of a decline in the output from intermittent generation (windfarms, solar panels, etc.). In such periods, competitive wholesale prices rise until they reach the Value of Lost Load (VoLL), the price at which a customer is prepared to forego some electricity supply rather than pay for continuing to consume. These price spikes to VoLL contribute towards recovering the fixed costs of all generators in the market. They are particularly important for "peaking plants"—plants with the highest generation costs of all—that would otherwise never earn a sufficient margin to cover their fixed and sunk costs.

Electricity demand does not respond to prices as readily as demand in most other markets. Metering consumption by half-hour is expensive (but becoming cheaper as smart meters are rolled out), so at present most retail customers pay a fixed tariff per unit of electricity, rather than the current market price. The services of demand-side response (DSR)—where a consumer agrees to go without supply at times of high system demand or high market prices—tend to be offered only by large industrial and commercial users or by specialist demand-response aggregators on behalf of smaller customers. Experience suggests that markets which offer capacity payments are more successful at motivating engagement by the demand side than energy-only markets.[1]

1.2. The "Missing Money" Problem

Politicians not only fear the lights going out, they also respond to voters who object to perceived manipulation or profiteering by players in the electricity market. The response by governments in many countries is some kind of intervention. Governments may explicitly cap market prices—either setting an arbitrary "fair" maximum price, or acting as a proxy for the maximum price that consumers of electricity would be willing to pay in the market in peak periods (e.g., Euphemia, the EU's market coupling algorithm, uses a price cap of €3,000/MWh). Governments may also cap prices "implicitly" by threatening, or appearing to threaten, that they would cap prices if they ever rose above "acceptable levels".[2] Caps on prices create a "missing money" problem, where prices cannot rise high enough to cover the fixed costs of efficient generation capacity, even in periods where the system is under stress. Such caps put future investment and the security of supply at risk.

Other kinds of government intervention can also depress wholesale prices and undermine incentives for investment by the market, such as widespread subsidies for renewable energy. Wind and solar plants are characterised by high total costs per unit of output and often benefit from subsidy. Once they are built, they operate whenever the wind is blowing or the sun is shining, and almost regardless of the prevailing wholesale power price. Their subsidised output depresses the market price that other generators can achieve.

Subsidised investments in new capacity have had a significant impact on electricity prices. In Germany, for example, renewables met 27.3% of electricity consumption in 2014, up from 6.6% in 2000.[3] Renewables often supply more than 50% of the market at weekends—as of

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1 NERA Economic Consulting (2013), Effective Use of Demand Side Resources: The Continued Need for Availability Payments, October 2013, pp. 22f, 29f.

2 NERA (2011), Electricity Market Reform: Assessment of Capacity Payment Mechanisms - A Report for Scottish Power, March 2011, p. 43; NERA (2014a), The Capacity Remuneration Mechanism in the SEM – Prepared for Viridian, April 2014, p. 14.

3 Agora Energiewende (2015), The Energiewende in the Power Sector: State of Affairs 2014, January 2014.

April 2015, electricity prices averaged €20/MWh at weekends, which is substantially below the €30/MWh operating costs of modern coal- or gas-fired power plants.[4]

A subsidised renewables sector reduces returns to existing and new investors in conventional generation. In principle, however, the market would still be able to ensure the efficient level of security of supply in the presence of renewable subsidies if government interventions were limited and predictable. In practice, frequent changes in government measures and targets increase the policy and regulatory risks of investment. They act like an implicit but unknown cap on wholesale market prices.

Together, price caps and uncertainty over renewables policy have led to the growing problem, or at least the perception of the growing problem, of "missing money"—specifically where the margins during shortages ("scarcity rents") are too low to incentivise investment in peaking plants. These policies thus create the danger that the margin of capacity above peak demand is squeezed, and the risk of blackouts looms.

1.3. Finding the "Missing Money"

Ironically, governments have often reacted to the inefficiencies caused by one set of centralised intervention by adopting a further set of centralised interventions. When price caps threaten security of supply, policymakers have added financial incentives to offer generation capacity over and above those available from an energy-only market.

A number of Capacity Remuneration Mechanisms (CRMs) have recently been implemented or proposed in Europe, building on experience elsewhere. Figure 1 presents a taxonomy of such mechanisms, developed by the Agency for the Cooperation of Energy Regulators. It identifies five types of CRMs offering additional revenues for capacity:[5]

- **Strategic reserve:** In strategic reserve schemes, such as those in Sweden and Belgium and the one emerging in Germany, some generation capacity is selected and set aside to support security of supply in exceptional circumstances. An independent body determines the required amount of capacity, which is procured and set aside through a tender (typically year-ahead), with the costs socialised and borne by all network users.
- **Capacity obligations:** Capacity obligations are decentralised schemes, which oblige each large consumer and retail supplier of electricity to contract for generation capacity sufficient to cover its expected consumption or supply, respectively, plus a reserve margin determined by an independent authority. Those contracted to provide capacity must make it available in times of shortage, or face penalties. France has recently adopted such capacity obligations.

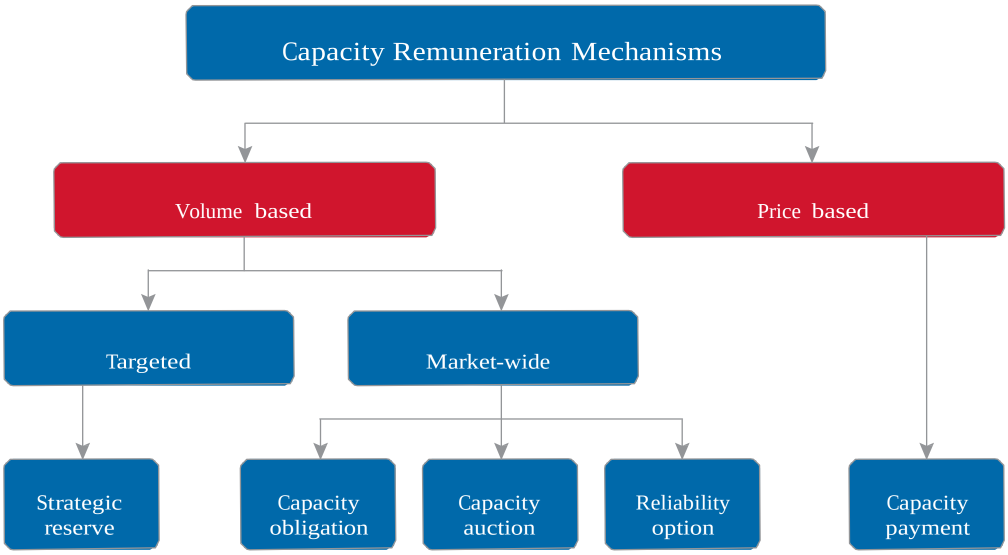
[4] Energy & Carbon (2015), Renewables and the missing money problem, April 2015.

[5] Agency for the Cooperation of Energy Regulators (2013) Capacity Remuneration Mechanisms and the Internal Market for Electricity, July 2013, p. 5.

- **Capacity auctions:** Some centralised schemes define the total need for capacity in advance of supply, and procure it through auctions for agreements that are backed up by penalties for non-delivery of capacity. Usually, the same auction price is paid to all successful bidders. Capacity auctions are carried out in the Pennsylvania, New Jersey, and Maryland (PJM) electricity markets in the US, and were recently adopted in Great Britain.
- **Reliability options:** Reliability options are capacity auctions or capacity obligations in that they can be allocated either by a centralised mechanism or by bilateral trading. The difference between reliability option schemes and other designs is that that they lack explicit penalties for non-delivery of capacity (in principle—in practice, they may be added later) and instead rely on the market price to incentivise investment. Generators have option contracts that oblige them to pay the difference between the wholesale market price and a reference price set by an independent body, whenever the former is higher than the latter. In return, the option provides the generator with a predictable income stream, but the difference payments incentivise it to be available at times of scarcity. If it is not supplying electricity at such times, it must pay out a large difference under the option whilst not receiving the potentially large revenue from the electricity market. Meanwhile, those options effectively cap the cost of electricity consumption, up to the volume of the options, since market prices that rise above the reference price are offset by difference payments received by demand-side holders of the options. Reliability option schemes are in place in Colombia and the New England region of the US, while Ireland is currently planning to introduce a reliability option programme from 2017.[6]
- **Capacity payments:** Under these schemes, an independent body sets a price per unit to be paid to generators (and/or consumers offering demand-side response) for capacity made available at times of system stress. The independent body determines the amount paid, with the quantity of supply determined by the actions of market participants. This is the prevailing system in Ireland's Single Electricity Market (SEM), where the SEM Committee determines the total revenues to be paid through the capacity payment, which is then allocated across the hours in the year and the generators who provide capacity in those hours.

[6] Proposal for Ireland: Utility Regulator (2014), Integrated Single Electricity Market - High Level Design for Ireland and Northern Ireland from 2016, Draft Decision Paper, SEM-14-045, June 2014; New England: Cramton, Peter (2006), New England's Forward Capacity Auction, Working Paper, University of Maryland; Colombia: Cramton, Peter and Steven Stoft (2007), Colombia Firm Energy Market, Proceedings of the Hawaii International Conference on System Sciences.

Figure 1
Taxonomy of CRMs



Note: Some price-based mechanisms can be targeted.

Source: Agency for the Cooperation of Energy Regulators (2013) Capacity Remuneration Mechanisms and the Internal Market for Electricity, July 2013, p. 5

The descriptions above refer simply to the remuneration of generation capacity. In fact, the rules vary from one CRM to another, with regard to which types of generation capacity are eligible for inclusion, whether the demand side of the market is also eligible to provide capacity (to reduce load), how eligibility to provide capacity is determined, how far in advance of needs the capacity is procured, how the costs are allocated, and how the system operator calls upon capacity with agreements.

Choices made in the design of capacity markets are critical to the success and efficiency of the mechanism. For instance, in order for the capacity agreements to cure the "missing money" problem, they must provide additional value to capacity. CRMs will only have a value if they include monitoring and enforcement mechanisms that ensure market participants with agreements face strong incentives to provide capacity (or strict penalties for not providing capacity) at times of system stress.[7]

Other design choices depend crucially on the local context. For instance, designers must decide early on whether the CRM sets prices and lets the quantity of capacity vary, or sets the quantity of capacity required and lets the price vary. In principle, either price-setting or quantity-setting could be equally efficient, and capacity mechanisms in the US have taken both approaches.[8]

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[7] NERA (2014a), p. 51.

[8] Weitzman ML (1974), "Prices vs quantities", Rev Econ Stud 41(4):683–691; the main result of this paper is that there is no a priori right strategy with regard to setting prices versus setting quantities, as the right strategy depends on the slopes as well as the uncertainty of supply and demand.

Policymakers can only make a rational choice based on a detailed understanding of the economic risks and incentives inherent in each mechanism, given their local market conditions.[9]

Even though price-based and quantity-based mechanisms can be equally efficient, debate in Europe has leant towards favouring quantity-based auction mechanisms over price-based capacity payments. In part, that tendency relies on confusion between the competitiveness of the allocation process and the competitiveness of its outcome. The appeal of capacity auctions lies in their perceived use of market mechanisms, with transparent and open competition between providers of capacity.[10] In comparison, capacity payments are seen as administrative systems. However, in practice, a well-designed capacity payment scheme will encourage generators to produce the competitive level of capacity, whereas capacity markets often operate within a tightly constrained regulatory environment that prevents efficient outcomes. Therefore, neither is any more or less "competitive" overall than the other.

Box 1
EU Thinking on Capacity Markets

Thinking on capacity mechanisms is evolving across the EU. In April 2015, the European Commission (EC) launched a state aid sector enquiry to ascertain whether they risk distorting competition on the EU's single market. The enquiry will initially seek information on a "representative sample" of EU states with capacity mechanisms in place or under consideration, namely Belgium, Croatia, Denmark, France, Germany, Ireland, Italy, Poland, Portugal, Spain, and Sweden.

The EC acknowledges that such mechanisms "may in some situations be justified". Its 2014 Guidelines on state aid for environmental protection and energy provided, for the first time, criteria against which their compatibility with state aid rules can be judged.[11]

These criteria include a requirement for member states to demonstrate such an intervention is necessary. Another is a requirement to show that the market design does not distort competition, for example by unduly favouring certain producers or types of technology, or by hindering the flow of electricity between member states.

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9 NERA (2010), Capacity Markets: Prices vs Quantities, November 2010.

10 In its Communication issued in November 2013, the Commission argued that "genuinely competitive bidding processes should become the default" to further minimise the necessary level of support, to make the costs of energy transparent, and to avoid "one tariff fits all support". Capacity auctions are expected to increase competition between technologies and responsiveness to market signals. In the accompanying guidance on public interventions, however, the Commission acknowledges that capacity markets may be subject to excessive pricing and subsequently lead authorities to impose price caps, which may preclude them from achieving security of supply more effectively than other interventions.

EC (2013), Delivering the internal electricity market and making the most of public intervention, Communication from the Commission, 2014/C 200/01, Brussels, 5 November 2013, p.10; EC Staff (2013), Generation Adequacy in the internal electricity market – guidance on public interventions, Commission Staff Working Document, SWD(2013) 438 final, Brussels, 5 November 2013, p. 14.

11 European Commission press release, State Aid: Commission launches sector enquiry into mechanisms to ensure electricity supplies. 29 April 2015. See http://europa.eu/rapid/press-release_ IP-15-4891_en.htm .

An important concern for the EU is that national capacity mechanisms are not put in place as substitutes for a more unified European power market. As Competition Commissioner Margrethe Vestager said when announcing the enquiry, "in some cases, it might be more efficient to invest in improving electricity grid connections between EU countries than to build new power stations".[12]

Before the release of the EC's 2014 Guidelines, the Agency for the Cooperation of Energy Regulators published a paper examining the impact of capacity mechanisms on the functioning of the EU's Internal Electricity Market. It warned of member states adopting "national and diverging approaches to security of supply with a lack of co-ordination among them". [13] It also argued that uncoordinated national capacity mechanisms posed the risk of both short- and long-term distortions to the functioning of the EU's electricity market. Short-term impacts include effects on power prices while, in the longer term, capacity mechanisms could lead to over-procurement of capacity, with consumers left bearing the additional costs.[14]

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[12] European Commission - Press release, *State Aid: Commission launches sector inquiry into mechanisms to ensure electricity supplies*, Brussels, 29 April 2015, IP/15/4891.

[13] ACER (2013), *Capacity Remuneration Mechanisms and the Internal Market for Electricity* of July 2013.

[14] Agency for the Cooperation of Energy Regulators (2013), p. 15.

2. The Design Process for the GB Capacity Market

The process that led to the creation of Great Britain's Capacity Market (GB Capacity Market) began in March 2010, with the publication by the Department of Energy and Climate Change (DECC) of the government's Energy Market Assessment.[15] That paper gave, as the starting point of government policy, three priorities for the reform of the electricity market in Great Britain,[16] namely to "effectively deliver secure supplies, the low-carbon investment needed in the long- term, and a fair deal for the consumer". In other words, to ensure security of supply, while meeting the UK's climate change goals at the least possible cost.

2.1. Initial Proposals Included Sharpening Cash-Out Prices

Much of the Energy Market Assessment paper focused on ensuring the right level of investment in low-carbon generation. However, the paper also recognised that: "All decarbonisation scenarios for the UK depend on large amounts of intermittent and/or inflexible generation, including wind generation and other low-carbon technologies. This means that the UK will require sufficient additional capacity to meet its energy needs at times when renewables are not able to deliver a consistent electricity supply".[17]

The paper discussed incentives to provide the "additional" (i.e., non-renewable) capacity needed to ensure security of supply. The paper concluded that the incentives provided by the then- current British electricity market design posed a risk: "the system may not give investors the right signals to invest in the extra capacity and other mechanisms needed to provide flexibility during the 2020s, when there is increased intermittent and inflexible generation".[18]

In March 2010, it was not inevitable that a capacity mechanism would be the final result of the review. The paper presented three possible "security of supply interventions" as part of a wider energy market reform package. They were:

- **Supporting better DSR and electricity storage** to help an electricity system with large volumes of intermittent generation balance more cost-effectively. DSR providers contract with customers to reduce their consumption of electricity at times of system stress. Measures to support DSR and electricity storage might include supporting the rollout of smart meters, which help consumers track and manage their use of electricity in real-time, and investment in R&D of storage technologies.[19]
- **The introduction of more effective price signals** in the existing electricity market, in line with proposals from Ofgem (the regulator of the electricity and downstream natural gas markets) to expose generators and suppliers to the full costs of balancing the system.

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15 HM Treasury and Department of Energy and Climate Change (2010), Energy Market Assessment, March 2010.

16 The electricity market in question serves (Great) Britain, i.e., England, Scotland, and Wales. Northern Ireland forms the other part of the United Kingdom, but operates within the Single Electricity Market for the island of Ireland.

17 HM Treasury (2010), p. 23.

18 HM Treasury (2010), p. 4.

19 HM Treasury (2010), p. 36-37.

Ofgem had expressed concerns over the rules for setting “cash-out prices”, which are the prices imposed on imbalances arising when market participants generate or consume more or less electricity than they have specified in agreements. Ofgem wrote in 2014 that these prices “are not creating the correct signals for the market to balance, and in particular are not correctly signalling the value of flexibility and peaking generation”.[20]

- **The introduction of capacity mechanisms** by placing obligations either on suppliers to demonstrate they were able to meet their expected demand plus a predetermined amount of spare capacity, or on the system operator, to maintain a predetermined capacity margin by issuing tenders for long-term capacity agreements.[21]

2.2. The Proposed Targeted Auction Mechanism

By the time it published its consultation document on electricity market reform in December 2010, the UK government had decided that a CRM would be required.

That paper set out the reasons that investment signals were proving inadequate to “overcome the additional uncertainty that arises as we deploy intermittent renewables and decarbonise”.[22]

DECC was concerned that peak electricity prices might not rise high enough to incentivise investment in new capacity, due to low levels of liquidity in the wholesale electricity market, uncertainty around policy on the low-carbon transformation, and the long investment cycles in generation capacity. It also cited problems with limits to the increased use of interconnectors with other EU energy markets, DSR, and storage.[23]

DECC argued at the time that Ofgem’s proposed cash-out reform would not sufficiently raise incentives to invest in new capacity without further intervention. The paper cited conclusions from Ofgem’s modelling that, in the absence of intervention, peak margins would fall from highs above 25% in 2011-12 to between 5% and 11% during the 2020s. According to DECC, an “economically optimal” capacity margin in Great Britain would be 8–12%, somewhat higher than Ofgem’s forecasts.[24] Ofgem’s analysis suggested that capacity margins would be improved by 1–2 percentage points if wholesale prices “were allowed to reflect market scarcity signals”,[25] but that might still leave the system short of capacity.

In response, DECC set out the main options for the design of the capacity market mechanism, expressing a preference for:

- A centralised system (i.e., an obligation on a single central body such as the system operator), rather than a decentralised system;

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20 Ofgem (2014) Electricity Balancing Significant Code Review – Final Policy Decision, 15 May 2014, p. II.

21 HM Treasury (2010), pp. 36-37.

22 DECC (2010), Electricity Market Reform: Consultation Document, December 2010, p. 19.

23 DECC (2010), p. 31-33.

24 DECC (2010), p. 30.

25 DECC (2010), p. 85.

- A quantity-based rather than price-based approach ; and
- A targeted approach offering payments to selected generators, rather than a "market-wide" system offering payments to all generators.[26]

2.3. The Initial Proposals Did Not Withstand Scrutiny

The outline design proved controversial and ultimately did not withstand public scrutiny. In its impact assessment at the time, the government argued that a market-wide mechanism is "a considerable intervention in the market", leading to significant risk of unintended consequences such as gaming. The government also raised concerns about providing windfall profits to some generators, and about "the risk that the 'right' type of flexible resource is not incentivised".[27]

Conversely, the government stated that a targeted mechanism is a "smaller intervention" with commensurately lower risk.

The impact assessment also suggested that investment in some forms of generation would continue to rely on peak power prices to generate an adequate return. This line of reasoning, the government acknowledged, relied upon the "effective functioning of the electricity market, based upon "moderate reforms", to ensure existing plant remained operational.[28]

These were dubious arguments. They exposed certain inconsistencies in the reasoning that underpinned the policy, as we argued at the time. First, assuming an effectively functioning market removes, by definition, any need for a capacity mechanism, which undermined DECC's case for intervention in the first place. Second, the government's assumptions about the failures of an energy-only market implied a need for the market-wide scheme, rather than the targeted one. Third, a targeted intervention is not necessarily a lesser intervention; intervening in part of a market does not leave the wider market undisturbed, and may even disturb it more than a coherent, market-wide scheme.[29]

After the government published its consultation document, NERA examined the arguments for creating a market-wide capacity payment mechanism in a report we produced for a major electricity company.[30] We noted that, in GB conditions, growing wind capacity creates a need for peaking capacity that can sustain output for long periods, rather than for the need for short-term flexible capacity implied by the DECC consultation document. All types of plants can provide such capacity, so we concluded that a market-wide capacity mechanism would give more appropriate incentives than a targeted one.

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26 DECC (2010), p. 98.

27 DECC (2010a), Electricity Market Reform - options for ensuring electricity security of supply and promoting investment in low-carbon generation, Impact Assessment, December 2010, p. 21.

28 DECC (2010a), paragraph 34.

29 NERA, (2011), Why the UK's Proposed Reform of Electricity Markets Needs More Rational Analysis, and Less Wishful Thinking, January 2011.

30 NERA (2011a), Electricity Market Reform: Assessment of a Capacity Payment Mechanism, March 2011.

We also noted that targeting support on selected generation capacity would simply depress market prices and discourage investment in other types of capacity. Introducing such a mechanism would cause centrally procured new capacity to replace existing capacity, with little or no increase in capacity margins or security of supply. Moreover, the imposition of a new system that removed scarcity rents would represent an expropriation of value from existing plants with sunk investment costs. Such a poorly justified government intervention might deter potential investors so much that security of supply actually declined.[31]

These issues, and other points of contention, were the subject of a consultation process on the entire Electricity Market Reform process, which ran from October 2013 until the end of the year.[32]

[31] NERA (2011a), p. 12.

[32] DECC (2013), Electricity Market Reform: Consultation on Proposals for Implementation, October 2013.

3. The Initial GB Capacity Market Design

Following the consultation process, DECC published its draft rules for the design of the GB Capacity Market in June 2014.[33] The Government's favoured design was market-wide, technology-neutral, organised across two descending clock auctions for each year of delivery and contained a variety of measures for controlling bidding behaviour and mitigating market power. The December 2014 inaugural auction largely implemented the government's draft design, with some tweaks to the specific rules and in order to comply with the conditions of state aid approval.

3.1. Market-Wide and Technology-Neutral

The government listened to the criticisms of its favoured targeted mechanism, and decided to introduce a market-wide capacity market that was technology-neutral—open to most forms of capacity, both existing and planned, including DSR. Exceptions apply initially to interconnected capacity (i.e., capacity supplied over the links to mainland Europe or the Republic of Ireland), capacity that receives support from low-carbon support schemes (such as the Renewables Obligation, the Feed-in Tariff scheme, or Contracts-for-Difference), or capacity with long-term contracts under the Short Term Operating Reserve scheme.[34] Units with less than 2 MW of capacity are also excluded, unless aggregated with others.

3.2. Capacity Procured through Two Annual Auctions

The rules specify that the system operator, National Grid, runs two annual auctions: a "T-4" auction four years ahead of the delivery period, which is intended to source the majority of necessary capacity, and a "T-1" auction the year prior to delivery, to source any remaining capacity (i.e., T-1 is intended to be a balancing auction for any residual requirement). The Secretary of State for Energy and Climate Change is charged with setting the level of capacity required in each auction.

Ahead of each auction, DECC publishes a demand curve based on a recommendation from National Grid and the government's favoured security standard of three hours of lost load in expectation.[35] This demand curve, as shown in Figure 2, sets out the government's willingness to pay for capacity. It incorporates existing capacity, and makes assumptions about the prices at which additional capacity and/or DSR will come forward. This sloping curve gives the UK government some flexibility on the amount of capacity to be bought each year, depending on its cost.[36]

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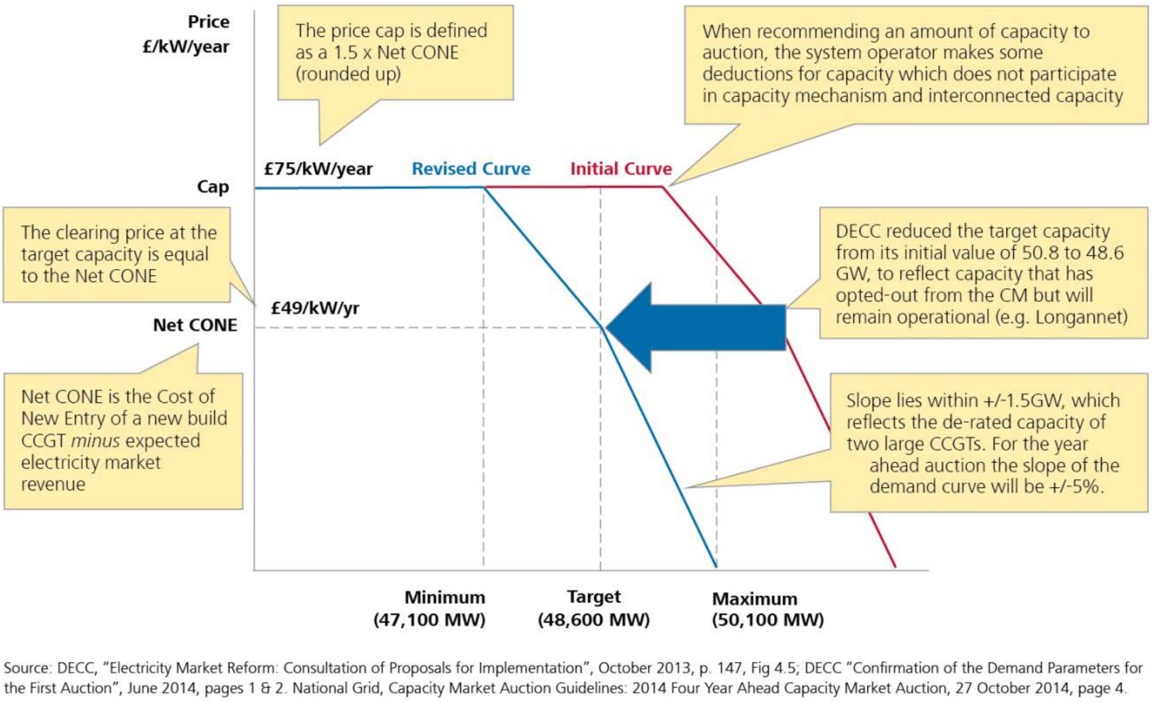
33 DECC (2014c), Draft Capacity Market Rules 2014, June 2014.

34 DECC (2014a), Electricity Market Reform – Capacity Market: Final Impact Assessment, 04 September 2014, p. 20.

35 National Grid (2014), Report to Secretary of State on Amendments to the Demand Curve, October 2014; DECC (2013), Consultation on the draft Electricity Market Reform Delivery Plan - Annex C: Reliability Standard Technology, July 2013, para. 17.

36 DECC (2014d), Implementing Electricity Market Reform – Finalised Policy Positions for Implementation of EMR, June 2014, paragraph 308.

Figure 2
The Government Specifies the Demand Curve in Advance of the Auction Demand Curve for 2018-19 CM at T-4



Source: DECC, "Electricity Market Reform: Consultation of Proposals for Implementation", October 2013, p. 147, Fig 4.5; DECC "Confirmation of the Demand Parameters for the First Auction", June 2014, pages 1 & 2. National Grid, Capacity Market Auction Guidelines: 2014 Four Year Ahead Capacity Market Auction, 27 October 2014, page 4

The auctions use the descending clock method and pay a single clearing price, whereby all successful suppliers receive the last-accepted bid (see Box 2, The Auction Design).

Box 2
The Auction Design

The specifics of auction design can have major implications for bidder behaviour and the ultimate outcome of the process.

Auctions in the GB Capacity Market take the form of "descending clocks". Bidders submit an "exit bid"—the level at which they are no longer prepared to provide capacity. The price offered by the System Operator drops in £5/kW increments, until the total capacity offered by generators falls to match the demand curve (see Figure 2). At this point, all the successful bidders will, in the delivery year, be paid the clearing price for the capacity offered.

DECC justified this approach by arguing that descending clock auctions should lead to the lowest price to consumers, with participants bidding in their true costs.[37] It chose pay-as-

[37] DECC (2014a), p. 22.

clear as opposed to pay-as-bid (where participants are paid according to their bid), DECC said, to avoid "strategic bidding" as suppliers seek to second-guess the market's marginal price. Similarly, DECC argued that a descending clock format would improve price competition compared with a sealed bid auction by enabling market participants to learn about the market value of capacity as the auction evolves.[38]

Notwithstanding DECC's belief in open-cry auctions that allow market participants to learn from the auction format, market participants may be limited in the extent to which they can learn and adapt their bidding strategy during the auction. DECC's rules aimed at market power mitigation require bidders to submit their planned and costs-based bids in advance to the auctioneer if they intend to bid above £25/kW.[39]

The system operator will run two auctions: a T-4 auction four years before each delivery year, and a T-1 auction one year prior. DECC explained its decision to introduce two auctions by reference to the challenges in assessing the need for capacity four years in the future, against relying solely on an auction one year ahead that would not give sufficient time to allow as-yet unbuilt capacity to participate. Furthermore, DECC says, a T-4 auction provides a mechanism for coordinating which investors will build any additional capacity: by signalling, through successful bidding, who has won capacity payments, it avoids the need for investors to second guess whether other investors are planning to build competing capacity.[40]

It is not clear such signalling is necessary. In an electricity market as large as the UK's, no individual investment decision is likely to push the market into over-supply, or leave it dramatically undersupplied.

3.3. Mandatory Pre-Qualification, Voluntary Participation

All eligible and existing generation units are required to pre-qualify for the auction, but participation in the auctions themselves is voluntary. Participants who opt out of the auction may choose to tell the system operator that they intend to remain operational, or that they intend to close. This allows the system operator to adjust the amount of capacity sought in the auction.[41] In calculating the contribution of opted in and opted out plants, the system operator applies a de-rating factor according to the technology they use, to reach a more accurate figure for the amount of capacity they are likely to provide. Those factors are based on the average availability of each existing unit type over the previous seven winter periods.[42,43]

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[38] DECC (2014a), pp. 40-43.

[39] DECC (2014c), Rule 4.8.

[40] DECC (2014a), p. 45-46.

[41] DECC (2104d), pp. 95-96.

[42] . DECC (2014e), Capacity Market Rules 2014, August 2014, Rule 2.3.

[43] For each generating technology class, the de-rating factor is calculated using a weighted mean average of the average availabilities (calculated according to Capacity Market Rule 1.3.5 (a) (i)) of all registered balancing mechanism units in that class over the preceding seven winter periods. For DSR CMUs, the de-rating factor is a mean average of declared availabilities over the preceding three winter periods, divided by contracted volumes.

Figure 3
De-Rating Factors for the 2014 GB Capacity Market Auction

Technology Class	De-Rating Factor
Oil-fired Steam Generators	82.10%
OCGT	93.61%
Nuclear	81.39%
Hydro	83.61%
Storage	97.38%
CCGT	88.00%
CHP and auto-generation	90.00%
Coal/biomass	87.64%
DSR	89.70%

Source: National Grid, "Capacity Market Auction Guidelines", June 2014, page 5.

3.4. Agreements, Delivery and Penalties

The market rules divide market participants into three groups: those eligible for capacity agreements over one year, up to three years, or up to15 years. The one-year agreements are open to units involving capital expenditure of less than £125/kW, namely DSR and existing generating plants not planning major refurbishment. Three-year agreements are open to units expecting to see capital expenditure of between £125/kW and £250/kW (i.e., existing generating plants undergoing major refurbishment). Fifteen-year agreements are available for units planning to spend more than £250/kW.[44] Generators eligible for multi-year deals may select any number of years up to their maximum entitlement. Pursuant to the EU Commission's State Aid decision, the Capacity Market Rules were amended essentially to restrict eligibility for 15-year agreements to new-builds,[45] as was intended but not explicitly stated in the initial version according to DECC.[46]

In return for capacity agreements, all providers will be expected to deliver energy (or, in the case of DSR, reduced demand) in periods of system stress during the delivery year, which runs from 1 October to 30 September. Failing to provide capacity during a system stress event incurs an hourly penalty equal to 1/24th of the auction clearing price. Monthly penalties are capped at 200% of monthly capacity revenues, while the annual penalty is capped at 100% of annual capacity revenues.[47] As is discussed below, these penalties are less onerous than those initially proposed by DECC.

44 National Grid (2014a), Capacity Market Auction Guidelines – 2014 Four year ahead Capacity Market Auction, August 2014, p. 4.

45 Ofgem (2015), Consolidated version of the Capacity Market Rules 19 June 2015, June 2015, Rule 8.3.6B.

46 DECC (2014f), Electricity Market Reform: Consultation on proposed amendments to the Capacity Market Rules 2014 and explanation of some immediate amendments to the Capacity Market Rules 2014, August 2014.

47 DECC (2014d), paragraphs 401-403.

3.5. Price Caps, Price Takers and Price Makers

New build plants and DSR are allowed to submit any bid up to a price cap, and are deemed to be "price makers". For the initial auctions, the price cap was set at £75/kW per year, or roughly 1.5 times the annual net cost of a new entrant (net CONE)—calculated by DECC for a new-build combined cycle gas turbine plant (CCGT) as £49/kW, equal to the total cost of a new entrant CCGT less its expected net revenues from the electricity market and ancillary services.[48]

Existing plants without significant refurbishment costs are deemed to be "price takers", whose bids are capped at £25/kW. They still receive the market-clearing price, but they cannot withdraw from the auction unless the price offered drops below this level.

Existing generating Capacity Market Units (CMUs) are price-takers by default, but may apply to become price-makers when they require a clearing price above the Price-Taker threshold of £25/kW in order to stay in operation in the Delivery Year. The auction rules recognise that some existing plants need to earn a high price to help finance essential maintenance (e.g., if the plants are old). Directors of companies wishing to become price-makers need to sign and submit a Price-Maker Certificate to Ofgem, which states that their "estimated net going forward costs with respect to the Relevant CMU (being the Company's total revenue requirement with respect to the Relevant CMU less risk-adjusted market value from sales of energy and ancillary services with respect to the Relevant CMU) exceed the Price-Taker Threshold".[49] The statements in this certificate need to be supported by a Price-Maker Memorandum,[50] but there are no specific requirements regarding the content of the memorandum.[51]

3.6. Cost of the Scheme

Ultimately, consumers will finance the costs of capacity for which the system operator has concluded agreements. They will be allocated the costs based on their share of peak demand (that is, demand between 4:00 pm and 7:00 pm on winter weekdays). Any penalties paid by plants will be passed back to consumers as a reduction in their costs.

The government expects the cost of capacity payments to be offset by reductions in the wholesale energy price.[52] As a result, in its Impact Assessment, DECC estimated that the Capacity Market would lead to a net increase in the average annual domestic electricity bill of only £2 over the period 2016 to 2030 (in 2012 prices)—equivalent to a 0.3% increase. While gross capacity payments are forecast to cost consumers an average of £14/year over

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[48] DECC (2014d), paragraph 314.

[49] DECC (2014e), Rule 4.8 and Exhibit B.

[50] DECC (2014e), Rule 1.2.

[51] The Capacity Market Rules merely define the Price-Maker- Memorandum to include evidence of "the reasons for that decision [to apply to become a price-maker], including any information and analysis which the board or the officers consider key to the decision".

[52] DECC (2014b), Electricity Market Reform: Capacity Market – Consultation on Proposals for Implementation: Government Response, June 2014, pp.107, 114.

the period, much of this increase will be offset by a reduction of wholesale prices that DECC ascribes to the existence of the Capacity Market. DECC expects the greater volume of capacity available to have a dampening effect on market prices. Overall, DECC's best estimate of the effect of introducing the Capacity Market is a net benefit with a present value of £350 million.[53]

3.7. Efforts to Prevent Gaming

One of the most important concerns for DECC in designing the Capacity Market was to guard against profiteering by participants. According to DECC, "[o]ne of the principal risks identified … is that of gaming",[54] because "[c]apacity markets are significant interventions in the market, adding complexity to the market and so creating potential for unintended consequences and for market participants to exploit arrangements to be able to earn undue profits".[55]

In its impact assessment, DECC argues that two factors combine to provide particular opportunity for generators to game the market. These are the inelasticity of demand for capacity (administratively determined by DECC based on the unwillingness or inability of consumers to respond to rising prices), and the low cost for most existing plants to remain open during the delivery period. DECC argues that these two factors mean the auction-clearing price could vary significantly, depending on whether or not new-build sets the market price in any given year. DECC fears that participants with sizeable generating portfolios have an incentive to withhold some of their capacity, forcing the price to be set by new-build, thereby earning excess returns from their capacity that remains in the auction.[56,57]

To manage this risk, all generating capacity is required to pre-qualify with the system operator. Any capacity that does not wish to participate in the auction must register as "permanently non-operational", "temporarily non-operational", or "operational, opted-out". Plants claiming to be non-operational may not bid in the subsequent T-1 auction for the same delivery year (or, in some cases, for subsequent delivery years).[58] Plants claiming to be operational, but "opted-out", reserve the right to participate in the subsequent T-1 auction and auction in future years. However, the system operator reduced the overall volume of capacity to be procured in the 2014 T-4 auction by the same amount,[59] as described further below ("Incentives for regulators to game the market").[60]

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[53] DECC (2014a), pp. 2 and 7.

[54] DECC (2014a), p. 32.

[55] DECC (2014a), p. 32.

[56] DECC's analysis appears to be based on the understanding that new-build plants would submit exit prices in excess of existing plants and at constant levels. In practice, exit bids amongst new and existing plants are likely to vary. For instance, Trafford, a new-build CCGT, obtained a 15-year agreement at £19.40 after other large new-build plants had exited the auction.

[57] DECC (2014a), p. 32.

[58] DECC (2014e), Rule 3.11.2.

[59] Except where such opted-out capacity had been taken into account previously.

[60] DECC (2014d), pp. 95-96; National Grid (2014), p. 4.

The rules surrounding generation capacity that is non-operational or that opts out of the auction are intended to prevent generators from shifting the supply curve to the left and increasing prices opportunistically, but the methods are different. In the case of plants claiming to be non-operational, the rules impose an implicit penalty (forgone future capacity revenues) on any such plants that later remain in operation. In the case of plants claiming to be operational, the rules remove the incentive to withdraw capacity from the auction in the first place by ensuring that opting out and remaining operational has no effect on the balance of supply and demand, and hence on prices, in the auction (although this approach also risks the system operator procuring less capacity than is really needed.

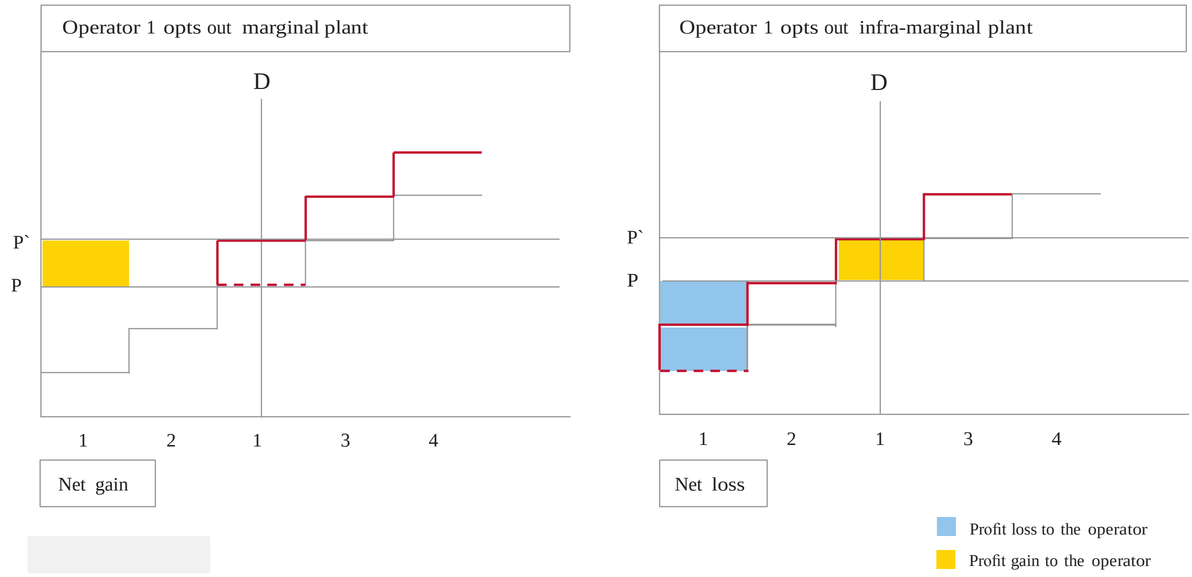
In addition to controlling behaviour prior to the auction, the rules set limits on behaviour within the auction itself, since price takers cannot submit bids in excess of £25/kW. DECC's modelling suggests that 80% of existing plants would have costs below this threshold. This market power mitigation mechanism is therefore intended to stop portfolio generators from withdrawing the 80% of total generation capacity that would otherwise be awarded agreements. In practice, it is unclear how significant this restriction on bidding behaviour has been and will be in the future— portfolio operators would be more likely to opt marginal plants out of the auction in the hope of earning marginally higher spreads on their lowest-cost units, as illustrated in Figure 4. In this example, Portfolio Operator 1 achieves a net gain from opting out his marginal plant, but suffers a net loss when opting out his infra-marginal plant, as the latter has a higher spread and is hence more profitable. In general, opting out marginal plants, as opposed to infra-marginal plants, is a dominant strategy for portfolio operators.

The auction design recognises that some existing plants will have costs above that threshold—if, for example, they are approaching the end of their life and have high maintenance costs. In such cases, existing plants can apply in writing to submit a higher bid price, as long as they provide a justification authorised by the company's board and presented to the regulator. If any plant withdraws from the auction, thus foregoing any capacity payment, but continues to operate in the delivery year, it risks investigation by Ofgem. Any written justification submitted earlier can subsequently be used as evidence in these investigations.[61]

Finally, use of a sloping demand curve gives flexibility to procure less capacity if the price is high, reducing opportunities for market participants to push up prices.

[61] DECC (2014d), paragraph 380.

Figure 4
Price Taker Rules Prevent Portfolio Operators from Pursuing Suboptimal Gaming Strategies



Source: NERA analysis

3.8. The State Aid Review

The GB Capacity Market proposals required approval from the European Commission under EU State Aid rules. That approval was given in July 2014,[62] but with one important caveat: the European Commission ruled that the market needed to be open to capacity from other EU states, via the interconnectors that link the British, Irish, and continental European electricity grids.

In its initial design, the UK government had pointed to a number of practical difficulties in allowing overseas capacity to participate in the auction. It identified four high-level problems:

- Verifying the physical capacity of plants outside Great Britain and its delivery of energy in periods of system stress;
- Assessing the appropriate de-rating of interconnected plants, given transmission constraints between them and the British market;
- Avoiding overpayments where plants in other jurisdictions may already benefit from local support schemes; and

[62] European Commission (2014), State aid SA 35980 (2014/N-2) – United Kingdom Electricity market_reform– Capacity market.

- Imposing penalties if an overseas plant had delivered power in its home market, but the interconnector had not delivered power to the GB market.[63]

In response to the State Aid decision, the UK agreed to allow interconnected capacity to participate in the Capacity Market auctions from 2015. DECC affirmed its intention to find a solution whereby capacity procured from overseas sources would physically deliver electricity to the British grid at times of system stress, and would face equivalent penalties for non-delivery to those faced by capacity in Great Britain. The decision also stated that: “The solution must be compatible with the EU Target Model and Third Energy Package requirements, and maximise compatibility with the internal energy market”.[64]

As a result, interconnected capacity will be permitted to enter the next T-4 auction, in December 2015, covering the 2019-20 financial year.[65] It will also be permitted to participate in the T-1 auctions, the first of which is due in 2017. Interconnectors will participate on a case-by- case basis, with the level of capacity that each interconnector can offer de-rated according to DECC’s estimate of its availability at times of system stress.[66] The Equivalent Firm Interconnector Capacity (EFIC) serves as the de-rating factor for interconnector CMUs. Under normal conditions, this is the greater of an historical and a forecasted de-rating factor determined by the Secretary of State on an annual basis.[67,68]

The State Aid review and the subsequent changes to the design of the Capacity Market illustrate an important characteristic of these types of regulatory intervention—namely their vulnerability to regulatory intervention at any stage in their lives. The UK’s reaction to the State Aid ruling is unlikely to be the last amendment to the Capacity Market.

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63 DECC (2014a), pp. 57-58.

64 European Commission (2014), p. 6.

65 DECC (2015), The Capacity Market (Amendment) Rules 2015, June 2015.

66 DECC (2015), Schedule 3A (Amendment 16).

67 DECC (2015a), Capacity Market supplementary design proposals and Transitional Arrangements and Proposed amendments to the Capacity Market Rules 2014 and explanation of some immediate amendments to the Capacity Market Rules 2014, January 2015.

68 For the historical factor, the starting point is a seven-year average of the portion of highest-demand periods where there was a positive price-differential between Great Britain and the interconnected country. Where transmission data is available, only the subset of positive-differential periods where transmissions took place will be considered. Otherwise, the ratio will be adjusted downward based on technical availability, ramp rates, and transmission losses. For the forecasted de-rating factor, a stochastic model is used by the Delivery Body/National Grid to generate a set of de-rating factors which, together with technical expert advice, will be the basis for the determination by the Secretary of State.

4. The First GB Auction

Having received State Aid approval for the scheme, the UK government was cleared to embark upon the first T-4 auction, scheduled for December 2014. The auction took place in an atmosphere of considerable uncertainty about the outcome—and, indeed, the auction clearing price was considerably adrift of most forecasts.

4.1. DECC's Assumptions Ahead of the Auction

The starting point for the T-4 auction was the decision by the Secretary of State on the volume of capacity needed. That volume is based upon an "enduring reliability standard": a Loss of Load Expectation (LOLE) of three hours per year.[69] LOLE represents the number of hours each year, on average, that demand will exceed supply. Based on analysis by National Grid, DECC set the target level of capacity at 53,300 MW which, given the three-hour LOLE standard, implies reliability of 99.97%.

That target level excludes capacity that the system operator expects to be available, but not to participate in the auction—including, in the first auction at least, interconnected capacity. The figure also excludes operational capacity that has "opted out" of the auction, at the level at which National Grid expects it to be available during each period. So, for the first delivery year of 2018-19, Secretary of State Ed Davey announced on 27 October 2014 a target of 48,600 MW of capacity for T-4, and 2,500 MW for T-1, giving an aggregate target of 51,100 MW (less than the preliminary target by 2,200 MW, to take opted-out capacity into account).

In its impact assessment, published a few months before the first auction, DECC set out the government's expectations for prices in the Capacity Market (see Figure 5). Its starting point is that a new-build CCGT plant must recover its annual cost, or revenue requirement, net of its profits from the electricity market and other services (net CONE). DECC's estimate of net CONE is around £49/kW, which is based upon estimates of the capital costs of new-build capacity assuming a 7.5% hurdle rate and a 25-year payback period.[70]

Capacity prices would diverge from this level if additional CCGT capacity is not needed in any particular year. In those years, the price would be set by the future expected costs of existing plants, which are relatively low because their construction costs are already sunk, or by plants or DSR with lower entry costs. DECC also noted that capacity prices would also be reduced by the revenues that plants earn for supplying ancillary services, such as payments for mitigating local transmission constraints, or for providing highly flexible generation that were not accounted for in the calculation of net CONE. "There is significant uncertainty around these estimates",[71] it added. Finally, DECC assumed that constraints on construction mean it is only possible to build 6 GW of open-cycled gas turbine (OCGT) and CCGT power

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69 DECC (2014a), p. 20.

70 Electricity generation cost model. 2013 update of non-renewable technologies. April 2013. Prepared by Parsons Brinckerhoff for the Department of Energy and Climate Change. PIMS Number: 3512649A [NB from European Commission (2014) p10].

71 DECC (2014a), p. 24.

plants in any given year, and that the more such plants are built the more their cost tends to rise.[72]

Before the first auction, DECC's modelling suggested that the Capacity Market would clear around £42/kW for capacity delivered in 2018-19, before falling over the next two years and stabilising between £29/kW and £37/kW from around 2022. DECC assumed that the market price would be slightly lower than net CONE because of the ancillary service payments some plants receive.[73]

Figure 5
Prices in the Capacity Market, £/kW (2012 prices)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capacity Prices	42	30	18	35	29	37	36	33	35	36	34	32

Source: DECC (2014a) page 28.

4.2. NERA's Pre-Auction Modelling

In our pre-auction modelling, conducted just prior to the first T-4 auction, we examined three scenarios for the bidding behaviour of generators in the T-4 auction, defined in terms of their "net going forward costs" (NGFC).[74] Figure 6 illustrates the concept of NGFC for a particular plant that expects to reach the end of its operational life at time T, and with a particular set of cost and revenue expectations.

The red line represents the plant's ongoing costs, including operating and maintenance costs but excluding sunk capital costs (which should be irrelevant to its forward-looking decision-making). The dark green line represents the revenues that the plant anticipates earning in the energy-only market. Following the auction in December 2014, and the absence of a capacity contract for the first delivery year, this particular plant expects to incur losses until the end of delivery period 2018-19 (equal to the sum of areas A and B). Over this period, its revenues from the energy market are lower than its ongoing costs. In our illustrative example, energy market revenues begin to rise after 2018-19 as the market supply and demand balance tightens.

After the 2018-19 delivery period, the plant anticipates receiving capacity market revenues in addition to the price it receives for energy. The light green line represents the sum of the plant's anticipated energy market revenues and its anticipated capacity payments in future auctions for the delivery years after 2018-19.

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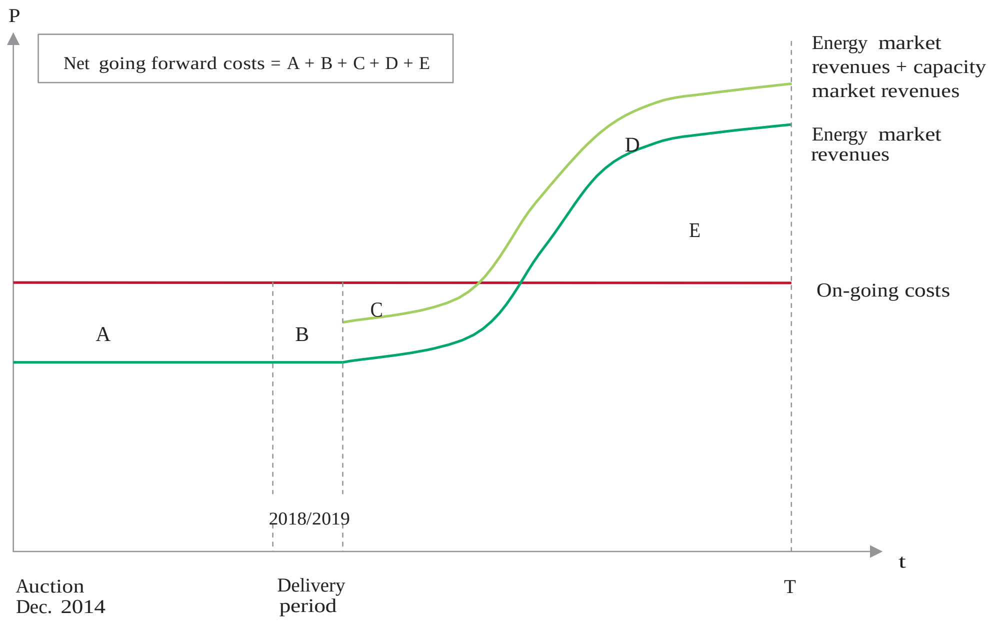
72 DECC (2014a), pp. 28-29.

73 DECC (2014a), p. 28.

74 The modelling platform we relied on was the Aurora model marketed by EPIS Inc., which we calibrated to Great Britain conditions.

The NGFC of a plant is the difference between its anticipated future costs and revenues over its life. In our illustrative example, NGFC is equal to the sum of the areas A, B, C, D, and E.

Figure 6
Bidder Valuations Depend on Market Participants' 'Net Going Forward Costs'



Source: NERA

The calculation of bidding prices based on separate forecasts of NGFCs for each plant on the system over the remainder of its economic life is computationally complex because of the dynamic structure of the problem. For example, NGFCs for the 2018-19 auction depend on expectations of prices in future auctions. We therefore modelled three simplified scenarios for the treatment of NGFC, focused on strategies for bidding in interim NGFC, defined as the NGFC incurred prior to the 2018-19 delivery year (equal to area A in Figure 6):[75]

1. *Immediate recovery:* Plants bid their full interim losses in the 2018-19 T-4 auction. This assumption is equivalent to assuming market participants expect to break even from 2018-19 onwards (i.e., plants bid in their full NGFC but areas C, D, and E sum to zero and therefore NGFC is equal to areas A+B). In this scenario, the auction cleared at the price cap in the first round and the auction failed to procure the target level of capacity in the first auction round.
2. *Three-year recovery:* Market participants amortise their interim losses over three years.[76] This scenario led to the market clearing somewhere around the £65/kW mark, in between DECC's forecast of £42/kW and the price cap of £75/kW.

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75 Similar bidding scenarios were published in advance of the auction in: NERA (2014b), The Potential Impact of Demand Side Response on Customer Bills, August 2014, p. 33f.

76 We amortised these costs over three years, allowing for the cost of capital.

3. *Written-off:* Market participants write-off their interim losses. This assumption is equivalent to assuming market participants expect higher profits after 2018-19 such that their interim NGFC will be balanced by operating profitably after 2019. In Figure 6, this strategy is equivalent to bidding NGFC assuming that areas A, C, D, and E sum to zero, and therefore NGFC is equal to area B. In this scenario, the market cleared at around £24/kW, according to our modelling.

It is unclear from the published materials how DECC handled the treatment of NGFC in its modelling.

4.3. The Main Outcomes

The first GB Capacity Market auction took place over a three-day period ending on 18 December 2014. In this auction, the government procured 49.26 GW of capacity for the period 2018-19 at a clearing price of £19.40/kW. The total cost to consumers was £0.96 billion, in 2012 prices.[77]

The government—perhaps unsurprisingly—hailed the auction as a success. Secretary of State Ed Davey declared that the auction was “fantastic news for bill-payers and businesses. We are guaranteeing security at the lowest cost for consumers”.[78]

Indeed, the clearing price was substantially below that forecast by DECC, and was marginally lower than that modelled in our third scenario. Participation in the auction was well in excess of the volumes required to meet the government’s capacity target, with almost 65,000 MW of capacity taking part. The relatively low price allowed for the procurement of around 660 MW above the targeted capacity of 48,600 MW.

The other key outcomes of the auction were as follows:

- **The auction attracted major new-build commitments.** The auction stimulated interest from investors in many new projects, with 11,250 MW of new-build capacity bidding into the auction. Of that, 2,600 MW was awarded Capacity Agreements by National Grid. One large CCGT, Trafford Power Station, accounts for 1,650 MW of this new-build capacity.
- **Embedded generation made up a significant portion of new-build with agreements.** The remaining 965 MW of new-build capacity is made up of small, embedded generation, a large proportion of which has been set up by independent developers. This implies that their NGFC are significantly lower than the majority of transmission-connected new-build OCGT and CCGT plants. Such embedded units often receive payments or benefit from cost reductions intended to reflect the idea that they help to reduce grid constraints and make the distribution system cheaper to run. In practice, it is not clear that embedded generation does perform these two roles. However, these benefits allow them to bid lower prices in the Capacity Market.

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77 DECC (2015b), The first ever Capacity Market auction official results have been released today, Press release, 2 January 2015.

78 DECC (2015b).

- **Coal-fired plants were less successful than gas-fired plants.** The first auction did not, as feared by some environmental lobby groups, offer a hidden subsidy and preferential treatment to coal-fired plants that otherwise would have been forced to close.[79] One-third of the existing coal-fired plants participating in the auction failed to be awarded a Capacity Agreement, compared with just 13% of the cleaner CCGT plants.
- **Demand-side response disappointed.** Demand-side response did not fare well, however, especially in comparison with its performance in capacity markets in the US, where DSR often wins a large percentage of the available payments. In the first auction, around 1,200 MW participated, but more than 70% of it failed to be awarded a Capacity Agreement. See Box 3, Why DSR Disappointed, for analysis of possible reasons.

Box 3
Why DSR Disappointed

Just 174 MW of demand-side response successfully bid into the Capacity Market auction—a fraction of National Grid's estimate of potential for the T-1 auction of 2,500 MW, representing just 0.34% of the capacity that received a Capacity Agreement.[80] In US capacity markets, such as the one for the Pennsylvania, New Jersey, and Maryland (PJM) electricity market, DSR is often a major source of capacity. In the upcoming PJM delivery year, DSR won 9% of available capacity payments.[81] DSR's performance in the GB auction seems poor by comparison.

It is possible that the majority of potential DSR products in GB were simply too expensive to win capacity payments. In practice, their failure to secure many Capacity Agreements may also reflect the treatment of DSR under the capacity market rules, which discouraged participation in the T-4 auction for two reasons:

- DSR that wins capacity payments is excluded from a key alternative subsidy payment. The government has put in place so-called "Transitional Arrangements" to ensure security of electricity supply ahead of the 2018-19 Capacity Market delivery period. Two transitional arrangement auctions are to be held, in 2015 and 2016. Eligibility in these auctions is limited to DSR that has not been awarded capacity payments. Accordingly, to participate in the T-4 auction, DSR providers were required to forgo three years of potential capacity revenues (from two years of Transitional Arrangement and from the T-1 auction) in exchange for just one year of capacity revenue from the T-4 auction. Generators were not eligible for, and therefore did not have to forgo, those alternative payments. Neither did generators have to forgo any other payments, such as revenue for providing National Grid with Short-Term Operating Reserve capacity or Fast Reserve products.
- DSR can only access the shortest of the three capacity payment agreement lengths. As noted above, of the three agreement lengths offered by the Capacity Market, DSR is only

79 See for example, E3G, Keeping Coal Alive and Kicking: Hidden Subsidies and Preferential Treatment in the UK Capacity Market: Briefing Paper, July 2014.

80 National Grid, (2015), Final Auction Results, T-4 Capacity Market Auction 2014, January 2015.

81 PJM (2012), "2015/2016 RPM Base Residual Auction Results", p. 19.

eligible to receive one-year agreements. This regime contrasts with arrangements in other jurisdictions, such as New England, where new resources (generators or DSR) are all eligible for multi-year agreements.

The likely outcome is that the consumer faces higher costs than would otherwise have been the case. First, if DSR is a cheaper source than at least some existing or planned capacity, it would have reduced the price paid by the UK government in the T-4 auction. Second, to the extent that DSR is discouraged from participating in the T-4 auction in favour of the T-1 auction, its price-lowering effect, if any, is reduced by a factor of 20 because the T-4 auction procures approximately 20 times as much capacity at the T-1 auction.[82]

Before the auction, we were asked to examine how the rules governing the participation of DSR in the capacity auction might increase the costs borne by consumers. We quantified the effects of some plausible "what if" scenarios, testing different levels of participation by DSR, up to the proportion of total demand met by DSR in the PJM capacity market. We found an impact on costs of up to £359 million in a single year, depending on participants' bidding strategies and the volume of DSR which came forward, which is equivalent to more than one-third of the total cost of the 2018-19 capacity market.[83]

82 NERA (2014b), p. 3.

83 NERA (2014b), Appendix B.

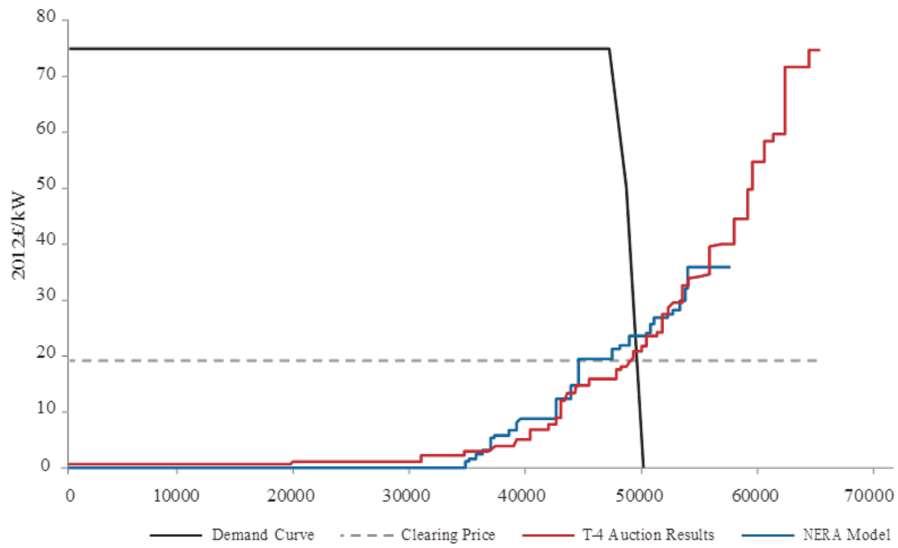
5. Interpreting the Auction Results

The UK government was quick to celebrate the low price for capacity in the first T-4 auction. It was able to argue that social welfare was well served by market forces, and that the auction mechanism flushed out least-cost providers. Generators certainly bid prices lower than DECC had anticipated. However, there are competing, and less charitable, explanations for the low prices that emerged than the force of competitive markets.

5.1. Generators Appear to Have Written-Off Interim Losses

DECC forecast that capacity prices in the first auction would be £42/kW. Our own analysis suggested that if bidders tried to recover all of their interim losses in the first capacity auction, the capacity market would clear at the price cap of £75/kW and, even if they tried to recover these interim losses over three years, the market would clear at £65/kW. A number of factors may explain why the price in the first auction was so much lower than these estimates.

Figure 7
Supply Curve for 2018-19 T-4 Capacity Market Auction – NERA Modelling vs Auction Results



Source: NERA Analysis; National Grid 19 December 2014, Final Auction Results: T-4 Capacity Market Auction 2014, p. 4

The auction may have elicited competitive bids from generators who were optimistic about the future evolution of prices:

- Generators may anticipate higher energy profits up to and during the 2018-19 period than is reflected in our modelling, which implies lower interim losses.
- Generators may anticipate higher revenues from the capacity and/or energy markets post-2019 that offset some or all of the interim losses.

A comparison of the supply curve of bids published by National Grid and our own modelled supply curve for the interim losses "written-off" scenario shows a close match, as shown in

Figure 7, thus providing a strong indication that one or both of these factors was at work. Without further analysis, it is not possible to conclude whether these expectations were rational or subject to a winner's curse.

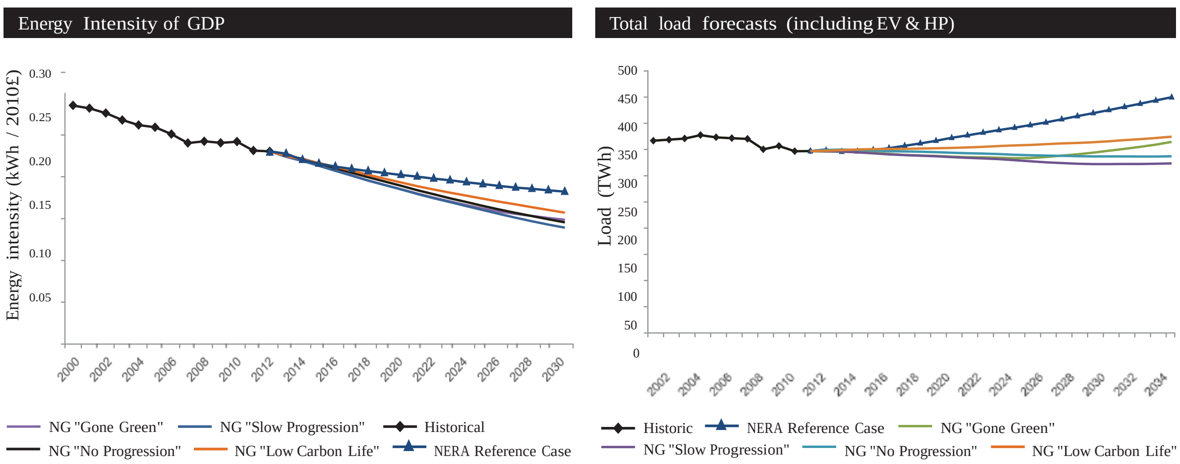
5.2. Incentives for the Regulators to Game the Market

Governments often assume that private investors are the principal source of market distortions. Indeed, as discussed, the UK government took considerable efforts when designing the Capacity Market to make gaming as difficult as possible. However, the design of the Capacity Market offers the potential for regulatory gaming, to the detriment of market participants and ultimately consumers, whose bills are driven higher by the impact of regulatory risk on the industry's cost of capital. In addition to the general threat of a market investigation, the auction rules offer scope for specific forms of regulatory discretion, for instance in setting the demand curve and in the treatment of plants opting out of the auctions, as explained below.

5.2.1. Demand Assumptions

National Grid considered a range of forecasts of end-user electricity demand in developing the target capacity for the auction, but underpinning all these forecasts were strong assumptions about energy efficiency improvements and the link between electricity demand growth and GDP. As a result, the range of forecasts considered by National Grid was extremely narrow. In all but one of its cases, National Grid forecast that total demand will be below 2013 levels throughout the period up to 2030, as illustrated in Figure 8. However, it is far from clear that the electricity intensity of GDP will decline as sharply as National Grid assumes. As can be seen from Figure 8, electricity intensity dropped sharply pre-2008, a period when GDP growth was dominated by growth in the low-energy intensity financial sector, but has since levelled off. Even a moderate reduction in the assumed rate of decline of the electricity intensity of GDP would result in significantly higher demand than forecast by National Grid for the 2018-19 delivery year, as shown in Figure 8, and it is curious that National Grid did not consider such scenarios.

Figure 8
National Grid's Demand Forecasts



Source: NERA analysis of various sources

5.2.2. Capacity credit allocated to renewables

The demand curve used in the auction is for required eligible capacity, and hence it factors in an assumption of the contribution to security of supply from non-eligible capacity such as renewables (known as the Equivalent Firm Capacity, or EFC).[84] However, National Grid—and, indeed, Ofgem—seem to make different assumptions about the EFC of renewables, in particular wind capacity, depending on the context. In its assessment of capacity requirements underpinning the Capacity Market,[85] National Grid assumed that wind's EFC was 23% to 27% of its installed capacity, according to our estimates; in its annual Electricity Capacity Assessment Report, Ofgem estimated the EFC of wind to be between 15% and 26% of total wind capacity until 2019;[86] and in the development of the new WACM2 transmission charging scheme,[87] National Grid and Ofgem assumed that the EFC of wind is 0%.

5.2.3. Treatment of operational opt-outs

National Grid's assumptions about likely supply during 2018-19 reduced the volume of capacity to be procured via the T-4 auction. In the mandatory pre-qualification process, the Capacity Market rules allow generating capacity that will be operational during the relevant delivery year to opt-out of the auction. A generator might take this path if, for example, it anticipated higher prices for capacity in the T-1 auction than in the T-4.

The Regulations give discretion to the Secretary of State, who is advised by National Grid, to adjust the demand curve in response to these opt-outs, but they do not state a specific formula.[88] DECC stated in its policy positions that the amount auctioned, as represented by the demand curve, will be reduced to avoid gaming.[89] After pre-qualification, National Grid assumed that all opted-out units would be operational during the delivery year, at a capacity de-rated by the same de-rating factor as plants that participated in the auction. In other words, National Grid assumed that a plant registering an operational opt-out was just as likely to be available during a system stress event as a plant awarded a capacity agreement, even though an opted-out plant has no commitment and faces a lower incentive to keep operating. A more realistic assumption would have de-rated its capacity to a greater degree, as DECC suggested in its policy positions.[90]

The credibility of National Grid's chosen de-rating factors for operational opted-out plants was tested within months. In August 2015, Scottish Power announced that it will close its 2.4

84 The EFC of wind is defined by National Grid as "the level of 100% reliable (firm) plant that could replace the wind generation and contribute the same to security of supply".

85 National Grid (June 2014), Electricity Capacity Report.

86 Ofgem (30 June 2014): Electricity Capacity Assessment Report, Table 10.

87 Ofgem (25 July 2014), Project TransmiT: Decision on proposals to change the electricity transmission charging methodology.

88 The Electricity Capacity Regulations 2014, Statutory Instrument No. 2043, July 2014, Regulations 13 and 23.

89 DECC (2014d), pp. 95-96.

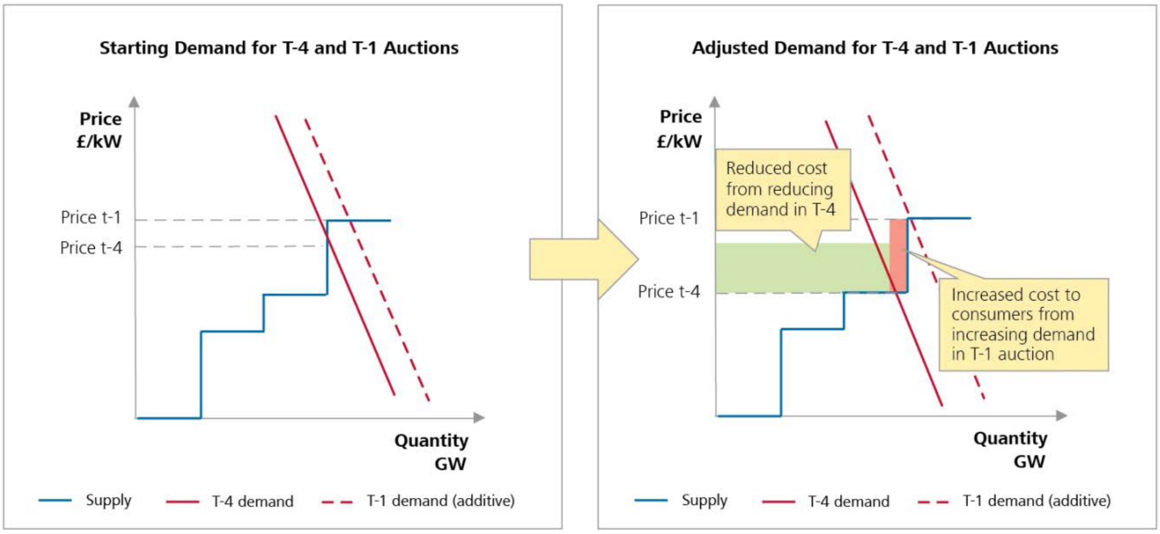
90 DECC (2014d), pp. 95-96.

GW Longannet coal-fired power plant in Fife in March 2016, after it failed to win an agreement from National Grid for supporting voltage on the transmission system.[91] As Longannet was an operational opt-out, this closure, if it takes place as planned, is likely to mean that more capacity will need to be sourced in the T-1 auction than was anticipated, with the prospect of high prices and the auction failing to clear. This example illustrates how plants that opts out from the auction are less likely than other plants to be available in the future, and deserves to be de-rated to a greater extent.

5.2.4. Implications

The impact of the choices outlined above is conspicuously symmetrical—they all have the effect of reducing demand for capacity (i.e., shifting the demand curve to the left) in the first T-4 auction, and thus potentially biasing down the price below the efficient level needed to meet the government's avowed security of supply target. In principle, to the extent that market participants anticipate this bias, however, it will be arbitraged away: bidders will move their supply to the T-1 auction in anticipation of higher demand later, leading to higher T-4 prices, up until the point where T-4 and T-1 prices equilibrate at an efficient market clearing price. In practice, however, arbitrage between the T-1 and T-4 auctions is restricted for two reasons. First, the T-4 auction rules restrict the opportunities to withdraw capacity (e.g., pre-qualified price-takers cannot drop out until the price drops to the price-taker threshold). Second, market participants can only get one-year agreements in T-1, whereas they may get multi-year agreements via the T-4. Marginal plants that require longer agreements may therefore not be able to switch from T-4 to T-1. As a result, the T-4 price can only be depressed by understating T-4 demand, illustrated in Figure 9.

Figure 9
Effect of Reducing T-4 Demand in Exchange for Higher T-1 Demand



Source: NERA

91 Scottish Power (2015), Longannet Power Station To Close In March 2016, Press Release, 18 August 2015.

Source: NERA

5.3. Penalties in Name Only

There is a further explanation for the low prices in the Capacity Market: the penalties associated with failing to deliver do not reflect the underlying value of capacity during scarcity conditions. DECC initially proposed to apply punitive penalties. Generators failing to supply capacity at times of system stress would not only lose out on the revenue from selling power in the market, but they would also face uncapped penalties linked to VoLL, potentially up to £16,000/MWh (as estimated by the government).

DECC's proposed penalty regime might therefore have resulted in a generator facing penalties that exceeded its revenue from Capacity Agreements. After consultation with stakeholders, DECC became convinced that the proposed penalties were excessive and would have raised costs for consumers, arguing: "There is an inherent balance to be achieved between a penalty mechanism which does not give 'free money' to unreliable plant, yet which enables debt to be raised on the back of Capacity Market revenues".[92] The outcome has been a penalty regime that includes a variety of caps on the penalties faced by market participants. At worst, generators participating in the Capacity Market and operational in the delivery year can only ever lose their capacity payments (and their energy market revenues).

In principle, if CMUs with capacity agreements cease operations and terminate their Transmission Entry Capacity (TEC) agreement, they must pay additional termination fees of £5/ kW or £25/kW, depending on the reason for termination.[93] In practice, some operators may choose to keep their TEC agreements open in order to avoid these penalties, particularly those with low or negative transmission charges. The Capacity Agreements therefore represent something of a one-way bet for generators, and will not command high prices.

In addition to the rules for existing plant, the capacity market arrangements require new plant to reach project milestones to avoid triggering termination. Eighteen months after the auction takes place, Capacity Providers must demonstrate that ten per cent of project capital expenditure has been incurred or that they have the necessary financial resources and contracts in place for commissioning.[94] However, six months after the first auction, the future of the largest new plant to win an agreement under the capacity market, Trafford Power, was in doubt. Operator Carlton Power said that it was struggling to obtain financial backing and may fail to meet the required delivery date.[95]

DECC might consider that, by driving down the cost of procuring capacity, it has achieved its stated objective and delivered value for money for the taxpayer. However, if generators face

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[92] DECC (2014a) p. 60.

[93] The Electricity Capacity Regulations 2014, Statutory Instrument No. 2043, July 2014, Regulation 32; DECC (2014e), Rule 6.

[94] DECC (2014c), *Draft Capacity Market Rules 2014*, June 2014, rule 6.6.

[95] *The Telegraph*, "Blow to UK energy plans as new gas plant in doubt", 12 October 2015. http://www.telegraph.co.uk/news/earth/energy/11925444/UK-energy-crisis-Trafford-gas-plant-in-doubt.html

little penalty for failing to deliver capacity, they may choose not to turn up in 2018. In that case, the mechanism will fail (albeit cheaply) to achieve its stated objectives.

6. Lessons from the GB Capacity Market

It is still early days for the Capacity Market. The true test of the market is more than three years away—only in the 2018-19 delivery period will we find out if the capacity with agreements is available during stress events, and the target security standard is achieved. But we can draw some lessons from the first auction, and we can offer some predictions based on the design of the market and a comparison with capacity mechanisms elsewhere.

Many policymakers remain persuaded that capacity markets offer an efficient means of ensuring adequate capacity within electricity systems. They often acknowledge that they will succeed only if they address risks created by other regulatory interventions. However, they seem less aware of the risks created by regulatory interventions in the capacity markets themselves.

6.1. Capacity Markets are Subject to Regulatory Change

Ideally, interventions such as the GB Capacity Market would see policymakers and regulators step in to correct the market failure in question, and then step back to allow market participants to operate within the new framework. The reality is rarely that straightforward. Further regulatory interventions are almost inevitable, making it difficult for bidders to plan effectively, and leading to increased costs from the system.

The experience of the US, where capacity markets have been in place since the late 1990s, is instructive. Over that period, most of these capacity markets have been refined or even totally redesigned a number of times.[96] Few of these markets have reached a steady state, with a range of reviews and reforms underway as illustrated in Figure 10.

Even before the first auction, the rules of the GB Capacity Market were subject to amendment. The State Aid decision by the European Commission required a change in the rules to allow participation by interconnected capacity from Ireland and Europe.

DECC is running an Electricity Demand Reduction pilot to investigate whether projects that deliver lasting energy savings (such as replacing old bulbs with LEDs) should be permitted to participate in Capacity Market auctions.[97] And the DSR has taken its case to the European Courts to address what it sees as unfair discrimination against its participation within the current rules.[98]

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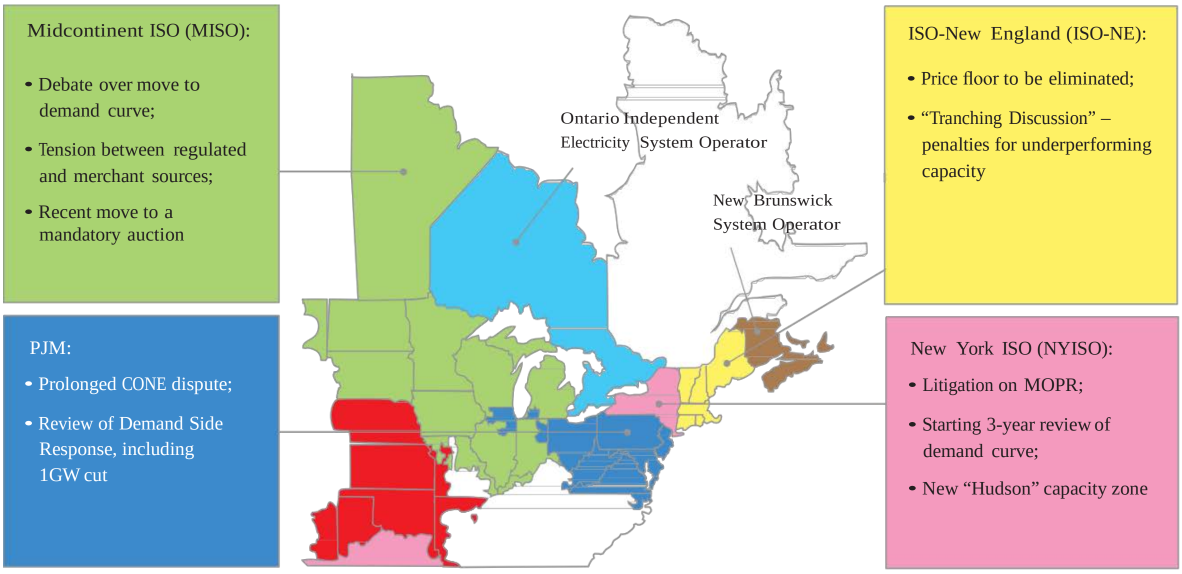
[96] Spees, Newell and Pfeifenberger (2013), Capacity Markets – Lessons Learned from the First Decade, Economics of Energy & Environmental Policy, MONTH 2013, p. 9.

[97] See www.gov.uk/electricity-demand-reduction-pilot.

[98] Tempus Energy, UK Energy Policy challenged in European Court for Needlessly Driving up Bills, Press Release, 4 December 2014.

Figure 10
Recent Debates in Northeast US Capacity Markets



Source: NERA Analysis and Spees, et al. (2013), Capacity Markets – Lessons Learned from the First Decade, Economics of Energy and Environmental Policy, page 25.

The department is also changing the rules governing price duration curves. The Capacity Market Rules make provision for the application of these curves, which aim to make agreements of different lengths comparable by accounting for the trade-off between price and length faced by the government when selecting capacity.[99] DECC consulted on the formula for the price duration equivalence curve from September to November 2014. The specific formula that DECC advocated would have capped prices for 15-year contracts at £35.12 in the first auction.[100] In the consultation process, generators argued that this methodology relies on assumptions about market prices for which there is no evidence, suffers from a lack of external validity, ignores capacity shocks and benefits of new capacity, and may deter investment in the latter if DECC's prices are too low.[101] Following the consultation process, DECC suspended the application of price duration equivalence curves for at least one further year, and is currently developing a new method for managing the trade-off between purchasing agreements of different lengths.

Participants in the GB Capacity Market might also take fright at the legal nature of the Capacity Agreements into which auction winners enter. Other arrangements between government and electricity market participants, such as the Contracts For Difference with renewable generators and new-build nuclear plants, are structured as private contracts in order to provide a "bankable" asset for financing purposes. The Capacity Agreements have

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99 DECC (2014h), Electricity Market Reform - Consultation on Capacity Market supplementary design proposals and Transitional Arrangements, September 2014, Chapter 5.

100 DECC (2014h), Annex B - Price Duration Curves Methodology.

101 DECC (2015b), Chapter 4, p.24.

no such legal status, being defined only in statute. The UK government may not have expected to act in a manner as arbitrary or unpredictable as some of its peers in mainland Europe; governments from Spain to the Czech Republic have torn up renewable energy subsidies, imposing losses on operators and investors. However, in order to ensure efficient investment, the government must convince investors that it will not behave in this manner, which is made much more difficult by the government's recent actions.[102] There are elements of the Capacity Agreements that are subject to regulatory discretion; a different legal structure would have accorded greater protection to market participants and may have increased investor confidence and ultimately provided more cost-effective security of supply.

6.2. Capacity Markets are Vulnerable to Regulatory Capture

On the other hand, market participants have been able to influence the design of the Capacity Market in ways that have arguably made it less efficient and therefore potentially less effective. Specifically, by influencing the penalty regime, generators have contributed to the creation of a market that places a low value on the commodity involved because there is little sanction for failing to deliver it, particularly for the marginal plant that is key to achieving security of supply.

Generators argued that the original penalty provisions would have made it impossible to raise finance against the capacity payments, as the imposition of those penalties could push individual plants into bankruptcy. However, the outcome appears to be capacity payments that are equally unbankable, as they are not high enough to cover the true net cost of new entrants.

6.3. Conclusion

Despite the drawbacks inherent in capacity mechanisms in general, and capacity markets in particular, authorities in Europe, North America, and further afield are contemplating the introduction of more such mechanisms to address real or perceived shortcomings in liberalised energy markets. The British experience to date illustrates the difficulty of designing capacity markets that harness market forces as intended without introducing the risk of arbitrary and unpredictable regulatory interventions.

To serve consumers' needs, any capacity mechanism must reimburse participants' costs of providing an efficient level of capacity and of ensuring security of supply. While it is important to ensure affordability for consumers, interventions aimed at driving down capacity payments risk undermining the ultimate goal of the policy.

Policymakers should seek to adopt mechanisms that are as formulaic as possible, and as free as possible from the risk of subsequent regulatory interventions. That means adopting a

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[102] Government has announced that onshore wind subsidies will be abandoned in 2016, causing losses for projects that are currently awaiting planning permission and cannot make a profit without the subsidy: The Guardian (2015), "Tories to end onshore windfarm subsidies in 2016", http://www.theguardian. com/environment/2015/jun/18/tories-end-onshore-windfarm- subsidies-2016, June 2015; "Government also attempted to cut subsidies for solar panels on homes, retroactively, and was overturned by the Supreme Court", The Guardian (2012), "UK government loses solar feed-in tariff bid", http://www.theguardian. com/environment/2012/mar/23/uk-government-solar-feed-in-tariff, March 2012.

rational economic design at the outset. Any regulatory uncertainty adds to participants' costs, which are then passed on to the consumer, and raises the risk of the mechanism failing to achieve its goal.

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