The Impact of Capacity Market Auctions on Wholesale Electricity Prices

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ABSTRACT

The objective of this analysis is to shed light on the impact—on electricity prices and net costs borne by the consumer—of the introduction of the Capacity Market. The analysis uses the 'surprise' announcement of the introduction of a Capacity Market Early Auction to assess its impact on wholesale prices using the 'difference-in-differences' (*did*) method. Although we cannot exclude entirely the possibility of other drivers, our results suggest that the announcement of introduction of the Early Auction may have reduced the spread between peak and base prices by £0.84/MWh. This may be consistent with a reduction in wholesale revenues of about half the total value of the Capacity Market of £380 million. Our research is subject to a number of assumptions and accompanying caveats which we spell out.

Keywords: Capacity Markets, Wholesale prices, Missing Money, Scarcity Pricing

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1. INTRODUCTION AND BACKGROUND

In 2014, government runs the first of a number of Capacity Market auctions for delivery from 2018/19 onwards

Prior to the introduction of the Capacity Market, secure supplies were entrusted to wholesale markets (providing adequate capacity) in conjunction with National Grid's deployment of balancing tools (managing the challenge of continuously balancing supply and demand).[1]

In 2013, government identified a risk to future supply adequacy.[2] In particular, government was concerned that at times of scarcity, wholesale prices may be too low to sufficiently reward generators that could provide power, and this 'missing money'[3] or even the perception of it may reduce planned investment in the capacity required to cover peak demand.

1. Over 2014–17, these were complemented by additional balancing tools: the Supplementary Balancing Reserve (SBR) and Demand Side Balancing Reserve (DSBR).
2. This built on analysis and evidence presented in Project Discovery, Ofgem's (2010) study of the adequacy of GB arrangements for delivering secure and sustainable electricity (and gas) supplies https://www.ofgem.gov.uk/ofgem-publications/40354/projectdiscoveryfebcondocfinalpdf
3. see Capacity Market Fundamentals by Cramton et al., 2013 for a discussion of 'missing money'.

This paper builds on original analysis conducted by the authors in Ofgem and published in October 2017: https://www.ofgem.gov.uk/ofgem-publications/124340.

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To address this risk, government announced in 2013 its commitment to introduce Capacity Market auctions delivering from 2018/19, with auctions held four years[4] in advance, to pay generators that make capacity available during these years. These payments provide an additional revenue stream for generators who continue to be able to sell power in the wholesale market. Three major four-year-ahead auctions have been held so far for delivery years in 2018–19 to 2020–21 costing around £1 billion each (see Table 1).

The first indication from government of the possibility of a Capacity Market for 2017/18 was on 1 March 2016, when government consulted on its proposal.[5] The government confirmed its intention in the summer. The auction was held in February 2017, around 9 months ahead of delivery. 54.43GW cleared at a price of £6.95/KW, determining payments of around £380 million.

Table 1: Major Capacity Market auctions

Delivery year	2017–18	2018–19	2019–20	2020–21
Main auction date—years before delivery	1 year	4 years	4 years	4 years
Price (£/KW per year)	7	19	18	23
Capacity (GW)	54	49	46	52
Total cost (£m, nominal)	378	956	834	1,180

Source: EMR Delivery Body

Importance of efficient interaction between Capacity Market and wholesale market

The rationale presented in 2016 for introduction of the Early Auction in 2017/18 was to address market failures and other drivers[6] in causing a lack of investment in traditional generation facilities. An Early Auction was identified as necessary *to ensure sufficient existing capacity and provide incentives for new-build capacity* and thereby enhance security of supply for winter 17/18. The proposal was consulted on against a back-drop (peaking in intensity in February 2016) of rumours and announcements of impending plant closures, which were reflected in scenarios (notably significantly enhanced closures) in DECC's analysis.[7]

A crucial component of ensuring a Capacity Market that functions in the interests of the consumer is its efficient interaction with the wholesale market. In practice, Capacity Market payments may be greater than the amount of 'missing money' in the wholesale market.[8] But the additional capacity procured in the Capacity Market should also enhance supply and thereby reduce wholesale prices (expectations of the supply shift should similarly lower forward[9] wholesale prices). In theory, the net injection of revenues should equal the missing money.

DECC's 2016 impact assessment for the Early Auction modelled an expected reduction in wholesale costs (£1.5 bn) equal to roughly half the expected cost of the capacity market payments

4. Auctions are also held one year before each delivery period. Transitional Capacity Auctions have also been held to help support 'demand side response' and small scale participation.

5. This draws on conversations with policy colleagues working in the Department of Energy and Climate Change (DECC) at the time of the announcement, and who indicated that the department did not give any indication to the market prior to 1 March 2016.

6. The effect of reductions of commodity prices in reducing profitability of coal plant in particular.

7. See for instance https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/521302/CM_Impact_Assessment.pdf.

8. Because the market expects Capacity Market introduction to reduce wholesale prices and peak energy rents.

9. 'Forward prices' refer to the price at which the wholesale market traded forward—days, weeks, months and years in advance—commitments to provide a volume of energy, and include peak load products (energy to be delivered during 7am–7pm on weekdays) and base load products (every hour of the week).

(£3.2 bn).[10] However, there is uncertainty on the extent to which the wholesale market will respond to Capacity Market introduction. Academics and other stakeholders[11] have identified this as an important area of research—Newbery (2016) for instance argues that wholesale costs may not fully compensate for these payments.

The size of the sums involved combined with the uncertainty over how and whether practice will play out according to theory emphasise the importance of research such as ours in shedding light in this area.

The academic literature contains many papers focusing on the rationale and design of capacity mechanisms. Cramton and Stoft (2006), Joskow (2007), and Bushnell et al. (2017) analyse the economic properties. Fabra (2018) provides a formal model, and Newbery (2016) analyses some key policy aspects and market distortions that could be exarcebated by capacity auctions.

We are aware of one attempt to evaluate empirically these interventions (Scouflaire, 2018). Our paper assesses the impact of the announcement proposing introduction of the Early Auction on wholesale prices, and estimates the accompanying wholesale revenue impact. It takes advantage of the unique opportunity to study 'forward prices' for winter 2017/18 both before and after the announcement of the introduction of a Capacity Market for that winter, an opportunity not available for other auctions which were announced long in advance of formation of forward prices. It draws on theory that suggests that introducing a Capacity Market should reduce wholesale prices by enhancing expectations of supply and thereby lower expectations of scarcity and market power (controlling for other factors), and that this price effect should be more pronounced in peak prices than in base prices (explained later).

Our analysis therefore examines how the spread between peak and base prices changes between the pre and post announcement periods, using base prices as a 'control' group against which to test the effect of the announcement on peak prices (the 'treatment' group). The possibility of a price effect on 1st March builds on an assumption that the Early Auction was unexpected and therefore not already 'priced in'. This assumption, which draws on our discussions with colleagues in DECC and is consistent with trade press reports[12], we test later. Our study differs from that of Scouflaire (2018), in that it focuses on one rather than many interventions, and that the short lead-in time for the early auction suggests certain potential impacts such as mix changes and increase in baseload capacities may be relatively constrained compared to auctions with greater lead-in times.

The rest of the paper is structured as follows

- Section 2 outlines theory
- Section 3 outlines empirical method, data and final model
- Section 4 presents results and tests
- Section 5 discusses possible interpretations, and outlines assumptions and caveats
- Section 6 presents conclusions and outlines opportunities for further research

10. This is for the 'announced closures' scenario (table 8) in DECC's impact assessment 2016 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/521302/CM_Impact_Assessment.pdf. Note that in the out-turn the auction cleared at a price (see Table 1) much lower than envisaged in modelled scenarios, and so payments for the Early Auction were significantly less.

11. See also final reports on National Grid's Electricity Capacity Reports by the Panel of Technical Experts advising the Department for Business, Energy and Industrial Strategy (BEIS) on Capacity Market procurement. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/625885/PTE_Report_2017.pdf.

12. For instance, ICIS Heren daily electricity markets report (2 May 2017) states "…the government announced unexpectedly last year that the capacity market would be brought forward a year earlier than planned…". Similarly industry responses to the DECC consultation conveyed an element of surprise, for instance icoss state: "the effect of this will be to increase supplier Capacity Mechanism charges unexpectedly with a significant increase now expected a year earlier in 2017".

2. THEORY AND METHOD

Introduction

Theory suggests that expectations of scarcity prompt higher prices, that this increase is mostly reflected in peak (rather than off-peak, or baseload) prices, and that capacity markets should dampen expectations of scarcity. Since this is based on future expectations, we mainly focus on the impact on forward rather than day ahead prices.[13]

A key paper that offers a promising method for identifying policy impacts such as the announced introduction of a Capacity Market is "Economic impact of enforcement of competition policies on the functioning of EU energy markets" published by the European Commission (2016). This paper seeks to identify the impact of EU competition policy enforcement in driving stronger competition in European gas and electricity markets and therefore contributing to lower prices, higher investment and improved productivity. It evaluates empirically the price effects of two individual competition policy enforcement cases using the *did* approach.

Of particular note is the case study on the Commission's case against E.ON (2008) for its alleged abuse of dominant position in the German wholesale electricity market. This study examines the impact of the Commission's decision on wholesale electricity prices, using daily data of peak and off-peak prices from the European Energy Exchange (EEX). The results show that the Commission's decision, by affecting supply and competition in the EEX, led to a reduction in wholesale electricity prices in Germany. This case study is particularly pertinent because it applies a method to identify the effect of withdrawing capacity from the market on wholesale prices, a method which can similarly be applied to identify the impact of adding capacity,[14] which we spell out later.

Scarcity and expected scarcity mean higher prices

Among other important variables such as gas and coal prices, scarcity—and expectations of scarcity—should also influence prices (particularly in the face of constraints to storing energy). This is because greater scarcity, which reflects a reduction in the margin between capacity and demand, implies a higher risk of market power, with accompanying higher prices. This may allow prices to be very sensitive to information on scarcity and capacity margins, and for spot prices to move much higher than the long-term equilibrium price. Expectations of capacity margins can also influence more long-term ('forward') prices so, other things equal, heightened expectations of scarcity should translate into higher forward prices.[15]

Peak prices reflect scarcity to a much greater extent than off-peak and base prices

Challenges in the storage of electricity contribute to the wholesale price difference between demand during peak hours and off-peak and baseload hours. Products that serve peak hours (peak load) are higher than off-peak and baseload not only because they employ their inputs less efficiently, but also because they are targeted at moments when demand is higher and pushes against

13. Much of the literature on formation of wholesale prices examines the relationship between forwards and futures prices with spot prices to understand the nature of ex ante premia. See Bunn & Chen (2013).

14. In particular it draws from the detailed papers underpinning the EC analysis which are Böckers & Szücs (2017) and Argentesi et al. (2017).

15. Bunn notes "a reduction in the margin indicates relative scarcity and one would expect that this leads to a higher propensity for shocks to induce greater price volatility and spikes. Given an adaptive adjustment by market participants, a perceived decreasing margin in the spot market may cause expected spot prices and therefore forward prices … to increase."

the limits of available capacity, and it is for this reason that scarcity value—and the ability to express market power—is more likely to kick in.[16]

The Capacity Market announcement should dampen expectations of scarcity and lower prices

Expectations of scarcity should be influenced by expectations of supply and demand, which in turn may be affected by regulatory interventions that drive a revision of expectations of supply or demand. In particular, the announcement of a Capacity Market, itself driven by concerns of insufficient supply, should serve to dampen expectations of scarcity by prompting traders to expect more capacity. Given the transmission mechanism outlined between scarcity and prices, it follows that the announcement of the introduction of the Capacity Market should serve to reduce prices.

Peak prices should fall more materially than base prices

Similarly, theory suggests that peak prices—which reflect scarcity to a greater extent than base prices—should fall more materially than base prices. This is because the supply schedule is much steeper in the peak period. Any impact on base load prices should reflect the effect on the portion of base load prices that correspond to peak hours.[17] Empirical analysis provides evidence supporting this theory,[18] showing more material impacts of changes in margin (and other related variables such as skewness) on peak prices than baseload.

Figure 1 illustrates these points. It is strikingly similar to Figure 5.3 of the European Commission's (2016), which illustrates how our work builds on that of Argentesi et al. (2017). In particular it shows peak load prices are higher than off-peak load (and by extension are also higher than base load), that the announcement of a Capacity Market serves to enhance (expectations of) capacity with the effect of dampening prices, and that the announcement has a bigger impact on peak prices than off-peak (and therefore base) prices.

3. DATA AND EMPIRICAL MODEL

Overview

The primary focus of analysis is on whether peak prices fell following the Capacity Market announcement. We use *did* econometric analysis using the base-load price as a control group to test whether the announcement had a statistically significant impact on peak load prices, our treatment group.

Our approach is justified as long as off-peak demand can be used as an effective control for peak and we can assume a highly convex supply curve.[19]

DiD analysis allows for an assessment of the impact of the announcement by looking for a statistically significant change in the average price difference between the treatment group (peak) and the control group (base) after the announcement. This double differencing removes the time invariant individual effects (of treatment and control group) and the common time effects that might otherwise confound identification of the effect of the announcement. We use the announcement of

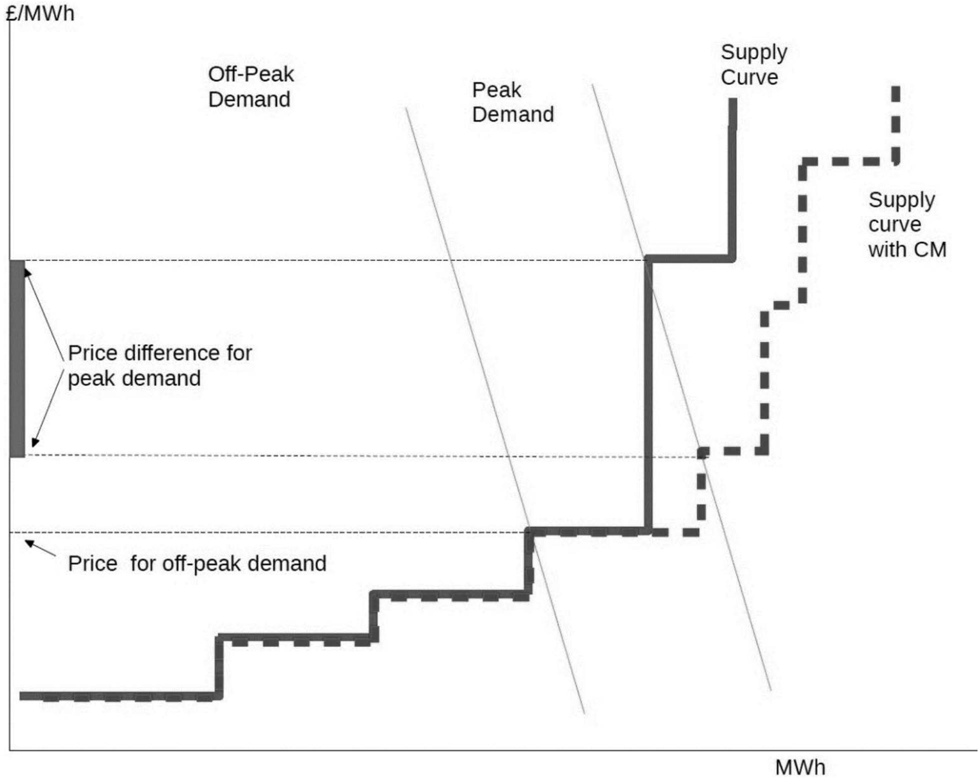
16. Theory is supported here by GB analysis which suggests that variables associated with scarcity expectations (such as greater volatility and skewness) have distinct effects with respect to peak and off-peak (and by extension, base load) trading. See 'Bunn & Chen (2013).

17. This builds on our assumption that there are no effects on off-peak price. We discuss implications of relaxing this assumption later.

18. Forward premia, Bunn et al. (2012).

19. These two assumptions are discussed in the European Commission's (2016) paper.

Figure 1: Demand (peak and off-peak) and supply (with and without a Capacity Market)



the Capacity Market proposal on 1 March 2016 as the cut-off point between the two time periods. In sum, therefore, we have introduced the following definitions:

- treatment group: peak forward prices
- control group: base forward prices
- pre announcement period: period before 1 March 2016
- post announcement period: period after (and including) 1 March 2016

Hypothesis

Our hypothesis is that the difference between our treatment and control groups—peak prices and base prices—will diminish following the announcement, controlling for other factors.

Controlling for other factors

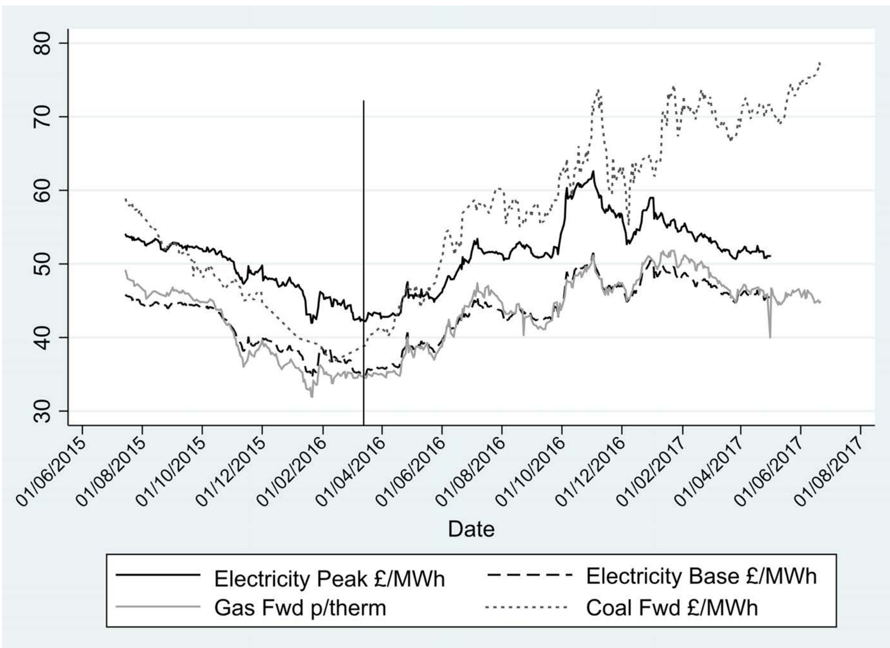
Without controlling for exogenous factors that may have different effects on the spread between groups between periods, we may suffer from omitted variable bias—where the *did* coefficient picks up the effect of these missing variables. For example, the effect of an unexpected statement decommissioning a large peak plant could be attributed to the announcement if not controlled for.

In order to identify possible important variables, we reviewed the literature and consulted with stakeholders including National Grid's trading team and BEIS. We collected data on the following variables:

- forward prices (peak and base) from the ICIS Power Index as well as from Bloomberg[20]
- gas and coal forward prices (GBP) for winter 2017–18 from ICIS
- data on French forward peak prices for winter 2017/18 (in GBP), to control for expectations of interconnectors flows of energy, from Bloomberg
- data on GDP expectations from the Office of National Statistics (ONS)
- carbon prices from Aurora (eos.Auroraer.com)

Figure 2 shows key variables: forward peak and base load prices as well as gas and coal prices. The upward movement of coal prices in the post-announcement period is striking. A quick eye-balling of the data shows it is not possible visually to identify a change in the difference between peak and base prices from the Capacity Market announcement (marked by vertical line).

Figure 2: Forward energy prices for winter 2017/18



We did not manage to obtain forward-looking data for expectations of a number of factors such as CCGT (combined cycle gas turbine) margin, capacities, renewables penetration, long-term weather forecasts, energy efficiency and Operation and Maintenance (O&M) costs.

In order to overcome the absence of forward looking data we included backward looking data, on the grounds that traders could be influenced by such 'behavioural factors', particularly where there is an absence of forward looking variables for them to consider. Therefore, in absence of data on expectations of CCGT margin we use contemporaneous data from Aurora.[21] Similarly, we opted to control for weather changes using the average of the last two weeks.[22] We also collected

20. We compared ICIS data to Bloomberg but found no large differences. We decided to use ICIS as it uses information from bids and offers which allows for a larger and more complete dataset.

21. This variable takes a number from 0 to 1, where for instance it takes the number one if CCGT (gas) is the marginal plant for the entire month, and 0.5 if CCGT (gas) is marginal for half the month. For all months in our dataset, CCGT and coal are the only plants at the margin.

22. Data was sourced from National Grid.

monthly capacity data (by technology,[23] including wind) from Aurora,[24] and monthly solar photovoltaic installation data from BEIS,[25] which we use in later tests.

We dropped some possible controls. In particular:

- both GDP forecast and carbon prices are produced relatively infrequently (monthly or quarterly frequency) and show little variation,
- we could not collect data on expectations of energy efficiency and O&M cost.

We consider it unlikely however that there was much variation in expectation of these drivers in the period in question, and posit their exclusion has limited impact on the key outcome.

Our data covered daily observations from the period 15 July 2015 to 1 May 2017. We imputed data using a mean average approach,[26] notably for CCGT margins data, available on a monthly basis, as well as some minimal imputation for missing dates of forward power prices.[27] The final data set employed is presented in Table 2.

Table 2: Final data set

Data	Daily data from 1 May 2015 to 1 May 2017
Peak power price (£/MWh)	ICIS power daily data
Base power price (£/MWh)	ICIS power daily data
Gas Forward price (p/therm)	Bloomberg
Coal Forward price (£/metric ton)	Bloomberg
Average Temperature of last two weeks (C°)	National Grid, supplementary reports
GDP Forecast (%)	MPC Forecasts of Annual GDP Growth based on Bank estimates of past Growth
CCGT Margin (%)	National Grid
France peak price (index)	Bloomberg
Capacities (MW)	Aurora
Renewable capacity (solar pv) (MW)	BEIS data

Model

Our *did* specification is as follows:

$$\begin{aligned} p_{it} = {} & \alpha + \beta_1 Treat_i + \beta_2 Post_t + \beta_3 \left(Treat_i \times Post_t\right) + \beta_4 \left(Treat_i \times GasDemeaned_t\right) \\ & + \beta_5 (Post_t \times GasDemeaned_t) + \beta_6 \left(Treat_i \times Post_t \times GasDemeaned_t\right) + \beta_7 Maturity_t \\ & + \beta_8 Maturity_t^2 + \beta_9 CCGTMargin_t + \beta_{10} CoalForward_t + \beta_{11} FrenchForward_t + \varepsilon_{it} \end{aligned} \quad (1)$$

where p_{it} is the daily forward price for winter 2017–18 for group i, for both peak and base load price.

There are two types of regression variables. One set controls for treatment groups and time periods. The other controls for factors that may shift the supply or demand curves of wholesale energy.

The first set of (three) variables is the *did* part of our regression and includes *Treat* and *Post* dummy variables. The *Treat* variable takes the value one if it is Peak and zero if it is Base; *Post* is a dummy variable taking value zero before 1 March 2016 and one after; and ($Treat_i \times Post_t$) is the key interaction variable representing the *did* estimator, which captures the effect of the announcement. Specifically, it looks for a change in the average difference between peak and base prices between the two time periods.

23. These are technologies connected to the transmission system and cover CCGT, Gas CHP-CCGT, Oil, Nuclear, Pumped Storage, OCGT, Coal, Wind (Onshore), Biomass, Wind (Offshore) and Hydro.

24. Aurora Eos.

25. Solar Photovoltaics Deployment in the UK, BEIS, August 2017.

26. Basing estimates of missing data on the average of the data points either side of the missing data.

27. This related to weekend data, and should affect both time periods—before and after the announcement—equally.

Our fourth, fifth and sixth variables control for the effect of gas prices. Gas generators are typically at the margin in GB. Gas prices are therefore important in setting prices. As gas price changes could have different effects for peak and baseload (and indeed off-peak)—off-peakers and baseload plant may use this input more efficiently than peakers—we control for possible asymmetric impacts of gas on peak and baseload with a triple differences model[28] using the gas demeaned forward.[29] The terms $\beta_4\left(Treat_i \times GasDemeaned_t\right)$ and $\beta_5(Post_t \times GasDemeaned_t)$ control for possible asymmetric effects of gas forward prices both on control versus treatments groups and on pre and post intervention groups. The triple difference interaction variable $\beta_6\left(Treat_i \times Post_t \times GasDemeaned_t\right)$ captures the effect of any change in the average price of gas on the difference between peak and base prices between the two time periods, thereby ensuring the *did* interaction variable of interest $\beta_3\left(Treat_i \times Post_t\right)$ is unaffected. Our model thereby advances the method developed by Argentesi et al. (2017) in its employment of triple differencing to control for potential asymmetric effects of a key explanatory variable.

On the demand controls we included a linear trend (*Maturity*) to control for changes in the risk premium as the contract gets closer to the delivery date and a quadratic term ($Maturity^2$).[30] We also tried to control for weather (using average of last two weeks temperature)[31] but dropped this from the specification owing to doubts over its reliability as a control for future expectations and the fact that its omission had no significant impact in the *did* coefficient.

CCGTMargin is the proportion of gas as a marginal fuel. *CoalForward* is our coal forward prices for the same period of winter 2017–18. *FrenchForward* is our index of French electricity forward peak prices. All these variables are expressed in GB pounds and should substantially capture exchange rate effects.[32]

We recognise the possibility of issues arising from endogeneity between the gas forward variable and the forward prices we are trying to explain, in that GB gas prices may not only drive but may also be affected by GB forward power prices. We consider however that double differencing and the large number of demand and supply drivers we include should mitigate endogeniety problems. We also note the extremely high historic correlations with international gas prices (typically above 90%) should limit materiality of the issue.[33]

4. RESULTS AND TESTS

The first specification of the *did* model follows ordinary least squares (OLS). Results are presented in Column (1) in Table 3 (we return to other columns later). Coefficients significant above the 99% confidence level are marked with ***, 95% with **, and 90% with *. Errors are reported below in parentheses. All variables in this model are statistically significant. All models use Newey West method to correct standard errors.[34]

28. We follow recommendations from Wooldridge (2007)
29. Gas demeaning is used to control for cross-sectional bias.
30. As the risk premium in forward prices may be non-linear.
31. We used average daily temperatures for the day, one week and three weeks before, which all showed similar results. We also tried the average of the past year weather but this long-term average shows little variation and could not be used in our estimation.
32. Controlling for exchange rates may be important given dramatic swings over 2016.
33. See for instance Figure 27 in https://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/10/NG-79.pdf.
34. Auto-correlation is of particular concern in DiD analysis. See for instance Bertrand, M, Duflo, E, and Mullainathan, S (2004) 'How Much Should we Trust Differences-in-Differences Estimates' Quarterly Journal of Economics. In order to address violation of assumption of no auto-correlation and homoscedasticity in distribution of the error term we estimate Newey-West standard errors, assuming a maximum lag order of autocorrelation of seven days. In choosing the precise lag order

The *Post* variable is a time dummy for pre and post intervention periods, which takes the value zero before 1 March 2016 and one after. It shows that, on average, prices were about £3.40/MWh more expensive before the announcement. The *Peak* variable takes the value one for peak price (our treatment group) and 0 for base price (the control). It shows that base load prices for winter 2017–18 have been on average about £8.50/MWh cheaper than peak prices.

The key coefficient *did* indicates the impact on the price difference of the intervention after controlling for other exogenous factors. The *did* coefficient is £0.84/MWh, and is statistically significant at the 99% level. *This suggests that the announcement of the Capacity Market lowers the peak–base differential by £0.84/MWh.* The sign of the coefficients are as expected and of a reasonable magnitude.

Significant variables in this model were prices of gas, coal and French power, as well as maturity effects, all of which show expected signs. Our triple difference coefficient *didgas* is statistically significant, and its coefficient suggests its absence in model specification could lead us to under-estimate the effect of the Capacity Market on the peak-base difference by around £0.19/MWh.

In order to test the validity of the results in regression (1), Table 3, we carried out a series of placebo tests. These allow us to check the significance of the *did* coefficient changes when we move the date of intervention arbitrarily. Thus, instead of setting the intervention date on the 1st of March, we set it 150 days before this date, and record the coefficient and its statistical significance. We then move the date forward by one day at a time, until 150 days after. We thereby record the *did* coefficient and its statistical significance for 300 alternative days.

Our hypothesis is that the statistical significance should pick up around the intervention date and become insignificant rapidly after. This is because after the intervention date, we assume that markets would have understood the impact of the announcement and wholesale prices going forward would already contain the effect of the capacity market. On the other hand, under our hypothesis, this test may produce statistically significant results, at least initially, as we move the simulated announcement date earlier (moving the vertical bar in figure 4 to the left). For example, if the true effect happens on the 1st of March, and we move our *did* dummy to the 1st of February, we will include in the intervention group 28 days with no effect. This will decrease the average impact picked up by the DiD coefficient, but still pick up the effect from the 1st of March onwards, and the coefficient may yet be statistically significant.

Figure 3 plots the *did* coefficient (solid line below) and its statistical significance in (solid line above). The latter indicates statistical significance, which achieves the 95% (99%) level when equal to or less than 0.05 (0.01) in the vertical axis. The *did* coefficient increases (absolutely) slightly ahead of the intervention of 1st of March. The significance of these coefficients also improves after this date.

In the absence of a formal test, we have drawn in Figure 3 (with dashed lines) a simulation of a result that we would consider to have been most supportive of our hypothesis. Although the actual results of our test are consistent with our hypothesis, the test leaves open the possibility the driver could have occurred earlier than the announcement of the 1st of March. We therefore do not rule out the possibility that some other change in expectations—possibly attributable to another

between one and seven days, we tested for the order of the lag using the autocorrelogram and partial autocorrelograms of peak price and base prices. Our result strongly suggested a lag of order 1 for peak prices. Discussions with colleagues also supported the view that information in the market would be internalised very rapidly because of the speed in which information is shared and updated. We consider it reasonable to assume that the day before yesterday may not have a future influence in price. We find applying the Newey-West method to correct standard errors yields the same results with the same coefficients.

Table 3: Regression results

VARIABLES	(1) DiD	(2) Test A: 30 days removed	(3) Test B: 90 days removed	(4) Test C: short-term
Post	–3.41***	–3.51***	–4.09***	–1.68***
	(0.26)	(0.36)	(0.56)	(0.25)
peak	8.48***	8.57***	8.69***	8.18***
	(0.19)	(0.20)	(0.21)	(0.28)
did	**–0.84*****	**–0.90*****	**–0.95*****	**–1.21*****
	(0.27)	(0.29)	(0.30)	(0.32)
peakgas	0.12***	0.12***	0.24***	–0.001
	(0.04)	(0.04)	(0.04)	(0.04)
postgas	0.013	0.01	0.02	0.11
	(0.04)	(0.04)	(0.04)	(0.24)
didgas	–0.19**	–0.20**	–0.36***	–0.13
	(0.08)	(0.09)	(0.10)	(0.24)
Maturity	0.05***	0.05***	0.06***	–2.19***
	(0.00)	(0.00)	(0.00)	(0.44)
Maturity^2	-5.29^{e-05}***	$-5.59e^{-05}$***	-5.64^{e-05}***	0.002***
	($3.56e^{-06}$)	(4.08^{e-06})	(4.95^{e-06})	(0.00)
Coal Fwd	0.50***	0.52***	0.50***	0.00
	(0.02)	(0.02)	(0.03)	(0.10)
CCGT Margin	0.96*	1.29**	0.83	–31.13***
	(0.50)	(0.53)	(0.59)	(6.39)
France Base	0.01***	0.01***	0.01***	–0.01**
	(0.00)	(0.00)	(0.00)	(0.00)
Constant	–9.07***	–11.87***	–10.40***	595.3***
	(2.24)	(2.47)	(2.85)	(114.6)
R-squared	0.91	0.89	0.82	.86
Observations	1,314	1,194	1,072	372

Notes: Standard errors are in parentheses. *** p<0.01, ** p<0.05, * p<0.1.. Test A: drops 30 days of data—15 days either side of the 1st of March 2016. Test B: drops 90 days of data—45 days either side of the 1st March 2016. Test C estimates impact using only data three months before the 1st of March and 6 months after.

variable we do not control for, perhaps linked with information on closures during January–March 2016—is driving the change in price differential. We return to this later.

In order to assess the possibility that our *did* coefficient is linked to a driver other than the announcement, we have explored what happened in the market in more detail and carried out additional tests. In particular, tests focus on the possibility that other factors—announcements or events—could drive our results. Table 4 lists announcements or events that may be of relevance.

Table 4 suggests a number of potential drivers of an effect may be ruled out, and that the only remaining other plausible drivers of an effect link to plant closure rumours and announcements and TEC (Transmission Entry Capacity) register publications.

Columns (2), (3) and (4) of Table 3 show results of a series of robustness tests to explore whether our results are driven by other unexpected announcements or events. These tests simulate alternative dates of such events or announcements.

Not having found any significant event in the period under study, other than the announcement of the capacity auction, we turn our attention to explore the role of rumours and speculation. Tests A and B in column (2) and (3) explore the extent to which results may be attributable to the

Figure 3: Repeated placebo tests (DiD coefficient is the lower solid black line)

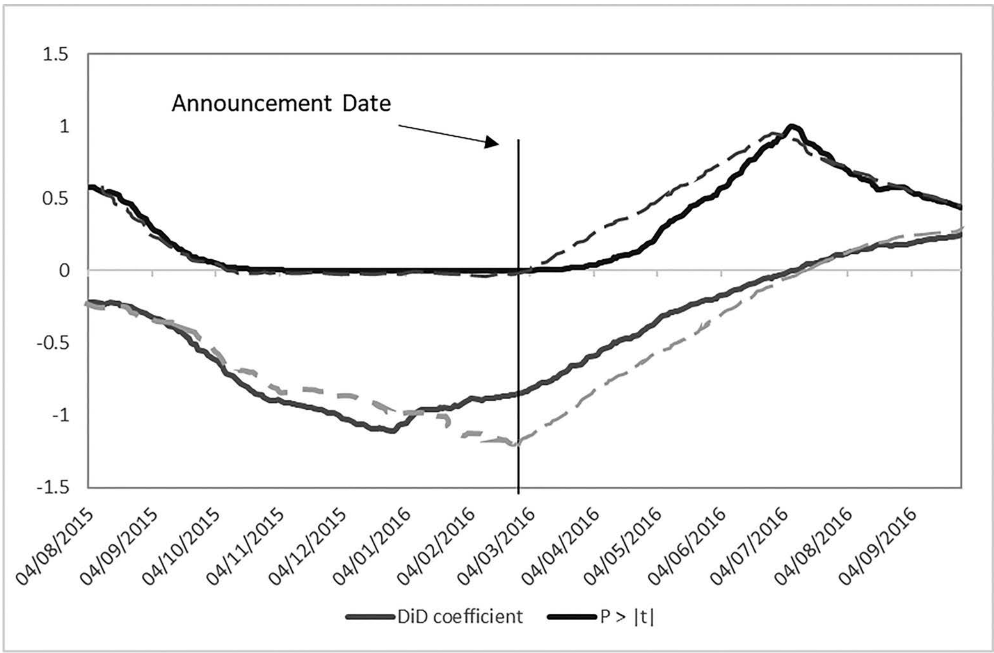


Table 4: Announcements and events that might affect winter 2017/18 peak—base price differential

announcements/events	when	expected effect, if any	potential to affect winter 2017/18	main tests we conduct
National Grid's NISM (notice of insufficient margin)	4 November 2015	(+)		restricting time period to exclude announcement
Coal phase out announcement	18 November 2015	(+)	somewhat—though phase-out focuses on 2025	restricting time period to exclude announcement
Plant closure rumours and announcements (uncertainty could drive irrational behaviours and unreliable observed prices upon which to base analysis)	peaking around February 2016	(+)		removing data four weeks either side of announcement; pushing simulated structural break forwards
National Grid's NISM	9 May 2016	(+)		pushing simulated structural break backwards four weeks
Transmission Entry Capacity (TEC) register publications (2016)	February: 22, 29 (published 1 March), and March: 7, 14, 31	(+ or -)		difficult to test for TEC registers
Embedded benefits reform (addressing payments that certain generators may receive)	on-going	(-)	limited—market unlikely to expect direct effects as early as winter 2017/18	unnecessary: theoretical effects are contrary in direction to those of CM introduction (hence likely to give conservative estimates); impact unlikely to be directly felt for winter 2017/18; no clear single date market became aware of likely change in arrangements

effect of possible speculative influences and over- or under-reactions by the market to the announcement or rumours in advance of the announcement. Test A removes data a fortnight either side of the 1st March announcement, and test B removes a month and a half either side of the announcement. Neither of these tests suggests doubt on the statistical significance at the 99% level of the finding of an effect. These tests suggest slightly larger effects of about £0.90/MWh and £0.95/MWh.

Test C in column (4) shows results of a 'short-term' test that restricts the dataset to three months before and after the announcement. This short-term result is statistically significant, and the impact is also somewhat bigger at –£1.20/MWh. These results suggest that we can rule out events or announcements more than three months either side of the Capacity Market announcement as driving our results.

There is a trade-off between a longer dataset, which presents a more fulsome picture, and a shorter dataset, which is less likely to reflect events we have not controlled for. On balance, we chose to employ the £0.84/MWh effect as our central estimate. This not only allows for greater confidence, but as it incorporates the period after the volume to procure was revealed in July 2016 and after the auction itself concluded in February 2017, it captures to some extent the effect of further revision of expectations as information from the auction is internalised.

Finally, we conducted further tests to explore for an effect on prices of first, DECC's announcement of the volume to procure (53.8GW) on 6th July 2016 and second, identification of the capacity payment price (£6.95/KW/yr) in early February 2017 following completion of the auction. While these announcements were not unexpected, the results (volume, price) could have been. Our tests suggest that the absolute price effect adjusts quite significantly as further information on volume and price is revealed to the market, meaning our overall estimate of £0.84/MWh likely masks significant variation of impact in the post-intervention period.[35]

5. INTERPRETATION AND CAVEATS

Identifying the driver of the effect

The model captures an effect during the period within two weeks either side of 1 March 2016, the statistical significance of which is robust to a host of alternative specifications. This suggests the existence of an effect, driven by one of the following

- the Capacity Market announcement on 1 March
- publication of TEC registers (linked with closures)

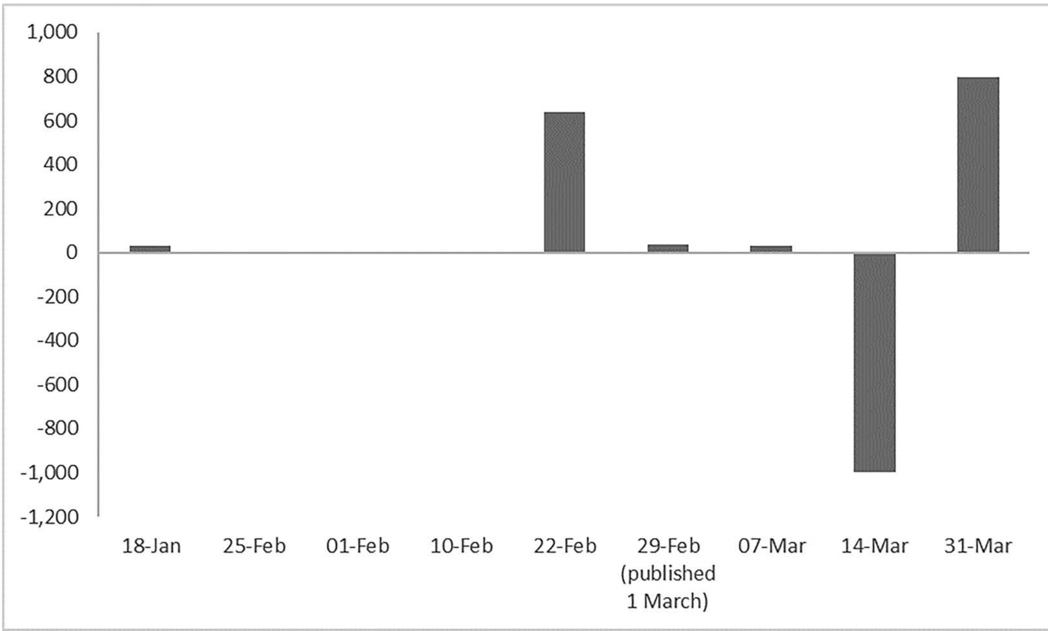
At first sight, the TEC register published on 1 March shows an increment of over 500MW of capacity compared with the previous register on 22 February. This change was attributable to an offshore windfarm. However, as the connected figure disappears in the subsequent registers it looks an unlikely driver of a long term effect. Figure 4 shows TEC changes that might affect winter 2017/18 prices below (removing suspect data from the TEC publication of 1 March 2016, since we are looking for an effect that was sustained).[36]

Quite eye-catching is the jump on 22 February—relatively close to the 1 March Capacity Market announcement date. If the 22 February TEC publication shifted expectations of the supply curve (and was therefore unexpected), then it could in theory contribute to the reduction we find in

35. Note the caveat that these tests may violate the key assumption of common trends between treatment and control underpinning the difference in difference method, and that we have not conducted further checks on these sub-sample tests.

36. Data sourced from National Grid website (https://www.nationalgrideso.com/connections/registers-reports-and-guidance) and with assistance of NG trading team.

Figure 4: Changes in TEC (total MW), with potential effects before end of winter 17/18 (1 January 2018)



the difference between peak and base prices. Figure 4 shows however that even more significant changes were afoot in the publication of the 14 March and 31 March registers. Our Test A suggests however that the 31 March publication is not associated with a change in expectations that drove a change in prices. And the 14 March publication is associated with a *reduction* in capacity, which ought to enhance expectations of peak prices, other things equal.

This leaves us with the possibility that the 22 February publication drove a sustained effect on prices. We consider this unlikely, not least as the change is relatively small compared with others, which are themselves not found to have had an effect. However, the possibility remains that the contents of the other releases were in line with expectations and therefore already priced in by the market, while the 22 February release contents could have been a surprise. In discussion with National Grid's trading team however, they did not identify any clear 'surprises' to the market in the contents of the 22 February TEC release.

The changes are substantially driven by two plant: one acquiring 376MW TEC commencing April 2017, and another renewing 260MW TEC. The larger of the two should not have been surprising since their plans were public.[37] We therefore cautiously consider that our results are more likely to be driven by the Capacity Market announcement—with the possibility that the market anticipated it somewhat—but note this as an avenue for potential further research.

Estimating the absolute effect on wholesale revenues

In order to provide a central estimate of the absolute reduction in both peak load and base load prices we make a simplifying assumption that scarcity value is reflected in prices in proportion to the relative number of hours of the two products. As the base load product covers all 7 days of

37. http://www.telegraph.co.uk/news/earth/energy/coal/12027606/Coal-plant-gets-green-light-to-burn-American-wood-pellets.html

the week and the peak load product covers a total of 2.5 days per week (7am to 7pm on weekdays), we expect the impact on peak load prices of a given reduction in expected scarcity to be 2.8 times[38] that of the impact on base load prices. This translates to an absolute reduction of £1.30/MWh in peak load prices, and £0.47/MWh (which we report rounded up to £0.50/MWh) in base load prices.

The product of base and peak load energy volumes and the appropriate price changes may give a sense of the potential absolute impact on wholesale revenues. In total, this suggests an estimate of around £170m.[39] However, this method does not capture the relationship between price and demand volume, in that highest prices tend to occur when demand volumes are highest. For this reason, it most likely understates the impact, and the £170m estimate may be considered a lower bound. Discussions with National Grid's trading team yielded a model that estimates an impact of around £210m.[40] We consider the evidence base plausibly suggests a wholesale revenue effect of *around £170m–£210m*, and probably towards the higher end of the range. This suggests an estimate of about half the value of the Capacity Market (which paid generators £380m) may offer a conservative estimate.

The value of the analysis

The analysis provides ex post evidence of the transfer of value from wholesale market to Capacity Market, an interaction set out in DECC Capacity Market ex ante impact assessments. In particular, it suggests theory does to some extent materialise in practice—perhaps half the value of £380m Early Auction capacity payments are transferred from the wholesale market.[41] It suggests that policy-makers may exercise caution in the extent to which their appraisals 'bank' this transfer effect. The analysis may also be of relevance to other jurisdictions such as Germany as they consider and appraise introduction of mechanisms to ensure capacity adequacy.

Second, it advances the method developed by Argentesi et al. (2017) by employing triple differences to control for confounding factors, specifically the potential asymmetric effects of the key gas price explanatory variable on control and treatment groups.

And third, our caveated estimate of the net payment of 'about half of the £380m' may assist in shedding light on the extent of 'missing moneys'—an indicator of energy security—in a counterfactual world in 2017/18 had the Government not intervened. This can be contextualised with wholesale revenues of around £10–15bn.

Assumptions and caveats

Apparent in this stylised interpretation is a host of assumptions with associated caveats.

38. 7 divided by 2.5 equals 2.8.

39. About 271 TWh of energy was consumed (transmission system) in 2016/17. Roughly 19GW of this was baseload, which runs all the time, equivalent to about 164 TWh of energy over the year. For a £0.84 /MWh price differential, this gives an impact of £0.47/MWh on base, and an absolute reduction in base revenues over a year of around £77m. The impact on off-peak is assumed to be negligible. Peak load energy on top of base load can be estimated at 70 TWh, which multiplied by a price effect of around £1.30/MWh amounts to over £91m. This gives a total of £167m (we report a rounded up figure of £170m). The equivalent effect for our sensitivity dropping 30 days either side of the announcement on 1st March (£0.90/MWh price difference) is £180m.

40. See Annex of Ofgem's previous working paper at: https://www.ofgem.gov.uk/system/files/docs/2017/10/final_version_-_technical_appendix.pdf.

41. The DECC impact assessment for the Early Auction modelled a wholesale cost saving roughly half the cost of CM agreements ('announced closure' scenario). In absolute terms, the Ministry modelled a reduction in wholesale costs of at least £1.5bn ('announced' closure and 'further closure' scenario), along with CM payments of about £3.2bn. See table 8 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/521302/CM_Impact_Assessment.pdf.

- First, the assumption of perfect arbitrage (eg between summer and winter products, or between forward and spot markets) is unlikely to hold. Analysis by Bunn et al. (2013) for instance suggest the existence of a premium on forward prices with sophisticated drivers, cautioning against assuming perfect arbitrage over time. To some extent our maturity controls may address this.
- Second, the volumes of trades driving this result are small in comparison with total energy to be delivered, particularly at the start of the dataset, suggesting further caution in market-wide extrapolation of the results.
- Third, the assumption that the market was expecting an energy-only market in advance of the Early Auction announcement may differ materially from reality. Had the market already expected with some probability the introduction of a Capacity Market, then our analysis would tend to under-estimate the effect of its introduction on wholesale prices—and over-estimate the potential scale of missing moneys. On the other hand, the market might instead have expected SBR extension (noting SBR had been extended for the previous year). The higher the expectation of SBR extension (holding other factors equal), the higher should be expectations of scarcity, wholesale forward prices (and the spread between peak and base) and wholesale revenues. The wholesale price effects of expectations of SBR extension and Capacity Market introduction are therefore opposites. Given uncertainty, a central assumption that any SBR and CM expectations cancel each other out may however be a reasonable central case assumption to employ, with caveats.
- Fourth, the analysis assumes no important variables or events have been omitted that could impact the spread between peak and base load differently between the two periods. However, publication of National Grid's TEC register coincided with the CM announcement, and so it is not possible to disentangle the two.
- Fifth, the analysis assumes no effect on off-peak prices, which we consider reasonable, both in light of theory and on grounds it should give conservative results. To give a sense of sensitivity of results to this assumption, however, should off-peak prices fall by (a purely illustrative) £0.25/MWh, then this would suggest an additional reduction in wholesale revenues of around £50m[42].

More generally, it should be noted that analysis only applies to winter 2017/18. For instance the Early Auction differs from other auctions in that it was held very close to delivery, with many participants already holding agreements for later delivery years. Options open to generators for the Early Auction therefore may have been limited to 'stay open', 're-open' or 'close'. Auctions held further in advance of delivery have the additional option of 'build'. For this and other reasons, the estimates cannot be readily extrapolated to other Capacity Market auctions and delivery years.

6. CONCLUSIONS AND FURTHER RESEARCH

Results suggest that the announcement of introduction of the Early Auction may have reduced the spread between peak and base prices by £0.84/MWh. While the analysis does not dismiss the possibility of another driver of this effect occurring during January-March 2016, we consider

42. For a given peak-base differential, and illustrative volumes (TWh) of baseload, peak and off-peak at roughly 164, 70 and 37, a first-order estimate of an off-peak effect of £0.25/MWh is (37 * £0.25) = £10m for off-peak; and peak plus base effect is (4.5/7) * (70 + 164) * £0.25 = £37m. Total effect £47m (or around £50m).

the Early Auction capacity market the most plausible explanation. The analysis might suggest the market may have anticipated this announcement.

The finding of an effect is robust to our alternative specifications. Further tests suggest some variability of the magnitude of the price impact over time. The price effect may equate to an estimated reduction in forward prices of around £1.30/MWh for peak load and £0.50/MWh for base load. Different methods for converting the price reduction into associated reductions in wholesale revenues suggest an effect of around £170m and £210m, and probably towards the higher end of this range. This suggests the net injection of money for generators resulting from introduction of the Early Auction—which pays generators £380m—could be around half of this capacity payment. In theory this additional payment purchases a higher level of energy security.

The analysis adds value in three respects. First, it provides ex post evidence of the transfer of value from wholesale market to Capacity Market, an interaction set out in DECC[43] Capacity Market ex ante impact assessments. In particular, it suggests theory does to some extent materialise in practice—perhaps half the value of capacity payments are transferred from the wholesale market—but that policy-makers may exercise caution in 'banking' the transfer effect. The analysis may be of relevance to other jurisdictions such as Germany as they consider and appraise introduction of mechanisms to ensure capacity adequacy. We are not aware of any other similar ex post analysis conducted in this field. Second, it advances the method developed by Argentesi et al.,[44] by employing triple differences to control for confounding factors—the potential asymmetric effects of a key explanatory variable on control and treatment groups. And third, our caveated estimate of the net payment of 'about half of the £380m' may assist in shedding light on the extent of 'missing moneys'—an indicator of energy security—in 2017/18 absent Government intervention, which can be contextualised with wholesale revenues of around £10–15bn.

This analysis offers many opportunities for further research.

- Further research may shed light on interactions with other opportunities for deriving value, such as from National Grid's ancillary services and embedded revenues, which this analysis did not consider. It could be explored whether a similar natural experiment could be constructed to assess this interaction—however this may be constrained by an absence of price data (National Grid does not hold its auctions for provision of ancillary services a year and a half or more in advance of delivery).
- Running the model for other announcements may suggest further improvements to the method.
- Analysis of the impact of previous publications of the TEC register may give a sense of its historical impact on wholesale prices, better to understand the materiality of the risk that the analysis is picking up the effect of TEC register publications rather than the Capacity Market announcement, noting coincidental dates of publication and announcement.
- While previous analyses[45] of forward prices find an absence of behavioural influences on GB prices further along the curve (month-ahead prices), further tests to control for

43. DECC, the Department for Energy & Climate Change was merged into BEIS, the Department for Energy & Industrial Strategy, in 2016.

44. Argentesi, E., Banal-Estanol, A., Seldeslachts, J. & Andrews, M., 2017, '*A retrospective evaluation of the GDF/Suez merger: Effects on gas hub prices*', Discussion Paper, DIW Berlin. Available from: https://www.diw.de/documents/publikationen/73/diw_01.c.558434.de/dp1664.pdf.

45. Bunn & Chen (2013) analyse GB electricity day ahead premia to consider the importance of a number of elements in price formation including behavioural aspects (adaptive behaviour to lagged variables), fundamentals (such as demand, fuel

such behavioural variables may nevertheless be useful in testing the validity of our results. The fact that some of our behavioural variables (such as recent temperatures) are statistically significant suggests further scope for exploration.

- Further research could explore market expectations in advance of the Capacity Market of scenarios including energy market, Capacity Market and SBR, better to interpret results.
- Analysis could further explore the effect of changes in distributed capacities.

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prices, and reserve margin) and risk aversion to spot market volatility and skewness (the authors call these statistical risk). Their analysis of GB prices further along the curve (month-ahead prices, including both peak and base) finds an absence of substantial impacts on premia of behavioural influences, in terms of adaptation to lagged dependent variables. The authors note a striking comparison with factors influencing day-ahead price formation, which they find to be linked with behavioural variables (in particular day ahead prices). The role of non-fundamental drivers of price chimes with research from elsewhere. Analysis of Australian prices for example suggests futures prices cannot be considered as an unbiased estimator of the future spot price and expectations of fundamentals, but are influenced by historical spot price behaviour, see Handika & Trück (2012).

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