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Keywords Carbon pricing, fuel mix, wind, marginal displacement factors, unit commitment model, econometrics

JEL Classification H23, L94, Q48, Q54

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1 Introduction

Energy policy aims to reduce emissions at least long-run cost while ensuring reliability. Policies to support wind or solar PV, improve efficiency, or shift peak demand need to be assessed on the cost of the emissions reduced. Ofgem (2018) in its *State of the market 2018* is a good example, comparing the cost effectiveness of various UK energy policies. Long-run cost reductions may require higher costs today to drive down future costs by innovation, demonstration and deployment. The EU *Renewables Directive* (2009/28/EC)[1] aims at these longer-term goals, as does *Mission Innovation* (Newbery, 2018). This paper shows how to estimate CO_2 reductions in electricity from specific policies, ignoring these longer run benefits. It argues that policies have both short and long-run impacts. Both need to be estimated and combined to measure carbon savings. The paper shows how to measure these savings.

We demonstrate this by looking at the CO_2 displaced by wind in Britain as the price of carbon varies. The UK Government introduced a Carbon Price Floor from 2013. This takes the form of a carbon tax (the Carbon Price Support, CPS) on fuels used to generate electricity. The CPS is added to the EU Allowance (EUA) price to give the total extra cost of the carbon content of fossil fuels. By 2015 this was sufficiently high to dramatically impact the fuel mix in generation, as shown in Figure 1. The share of coal fell from 41% in 2013 to 6% in 2018. Great Britain[2] therefore offers an excellent test-bed for the impact of a carbon tax (the CPS) as the fuel mix is likely to affect the carbon displaced by wind. Wind is hard to forecast with much accuracy day-ahead when the time comes to decide which types of generation to commit and run. As wind varies from moment to moment, the carbon displaced will depend on the plant operating, and which types of plant can adjust up or down at least cost. We study this short-run impact econometrically to find the main drivers of the short-run displacement achieved.

Policies are chosen for their long-run impact. Governments set targets for the future share of renewable electricity and 2050 carbon budgets. These policies will affect the future fuel mix, and hence the plant available to be dispatched day to day. We determine this long-run impact with an hourly unit commitment dispatch model of the GB system in 2015. We use that to examine the effect of increasing wind capacity by varying amounts up to 25%. Long run has the conventional meaning that it is a period over which wind capacity can change, in contrast to the short run in which the vagaries of wind can only be accommodated by the plant already committed and capable of responding. We study the impact of the CPS as it was in 2015. We also look at two counterfactuals. The first is no CPS, but just the EUA price, as it might have been without the policy intervention. The second looks to the CPS in the middle of 2018, when the EU Emissions Trading System was reformed, which raised the GB total carbon

[1] See http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0028:EN:NOT.

[2] Northern Ireland was exempt from the CPS as it forms part of the Single Electricity Market with Ireland, who declined to adopt a Carbon Price Floor.

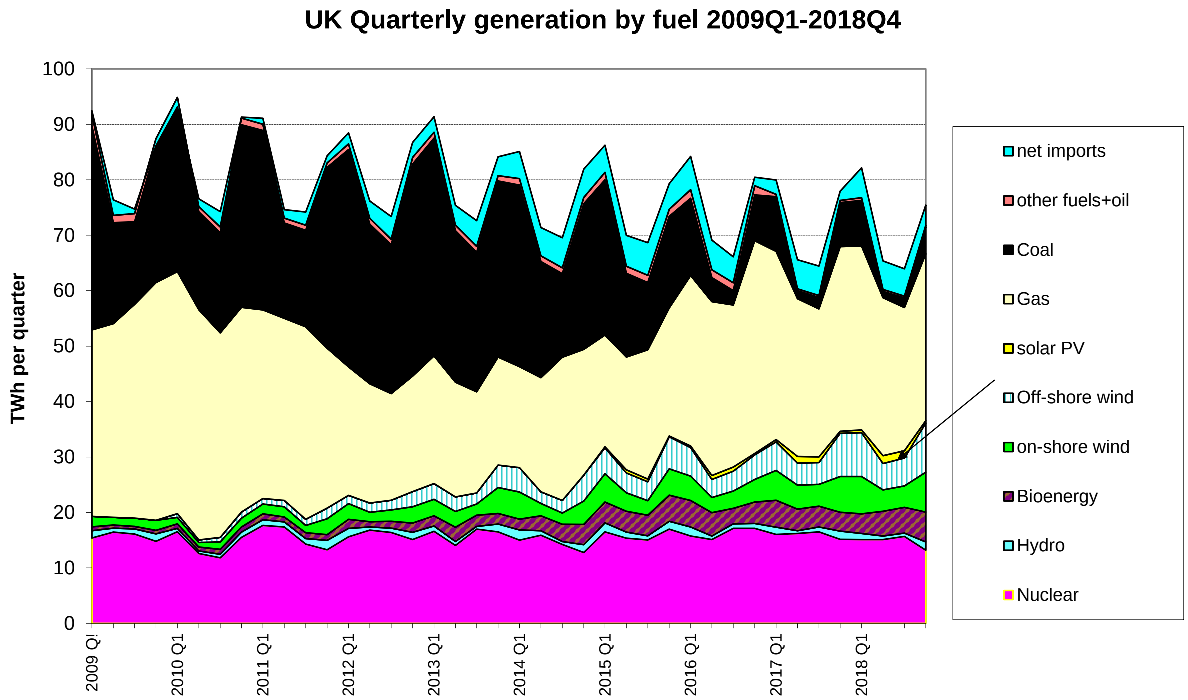


Figure 1: GB generation per quarter by fuel type (legends order the same as fillcolours)

Source: Elexon Portal at https://www.elexonportal.co.uk/news/latest

price substantially above its 2015 level.

This paper argues that policies to reduce emissions require an analysis of both the short-run and long-run impacts. Increased wind capacity raises the expected amount of wind generation, which can be estimated using a deterministic unit commitment model. Such models assume efficient plant commitment (including the reserves needed for balancing and reliability). After plant has been committed, realised wind and demand will likely differ from forecast. Plant already committed will need to change output to accommodate outcomes. These responses are better captured by a short-run econometric model that also reflects actual behaviour in a liberalised market that may differ for various reasons from an efficient centrally dispatched system.

The Marginal Displacement Factor (MDF) measures the tonnes of CO_2 reduced by an extra 1 MWh of wind in that hour. The MDF depends on the plant mix of the system (coal and efficient gas in our case) as well as fuel and carbon prices. The MDF of renewables will therefore vary over countries and time. The MDF is useful for determining the extra support to offer low-carbon technologies if the market price of carbon is below its social cost. It can be (and is) used to measure the cost-effectiveness of policy interventions that displace fossil fuel.

The econometric estimates also give the short-run Marginal Emission Factor (SR-MEF) of demand — the change in emissions resulting from a change in demand of 1 MWh in that half hour (tonnes CO_2/MWh). This can be used to estimate the impact of carbon prices on wholesale prices and hence on trade over interconnectors to France. For future interconnectors, both the short- and long-run impacts are needed.

The next section briefly reviews related literature before describing the British Carbon Price Floor and developments in the EU Emissions Trading System, their impact on GB carbon prices over time and the evolution of GB fuel costs. Section 4 summarises the merit order effect and its dependence on total fuel costs to motivate the dependence of the MDF of wind on relative fuel costs. Section 5 sets out the econometric analysis to derive the SR-MDF of wind. Section 6 explains the model used to measure the LR-MDF. Section 7 contrasts the SR and LR-MDFs and discusses their use in policy analysis. Section 8 measures the impact of the CPS, allowing us to quantify the impact of trade with France. Section 9 concludes.

2 Literature review

We have only found one *ex post* econometric analysis (Staffell, 2017) of the performance of the GB CPS - even though Britain's CPS has been in place for over five years. Staffell's paper has the broader aim of explaining why CO_2 emissions fell by 46% in the three years to June 2016, whereas our aim is to focus more narrowly on estimating the MDF for wind, and to explore the underlying mechanism driving changes in the MDF. The econometric methodology also allows us to identify the marginal plant setting the price in the day-ahead auction for interconnector use, so we can construct counterfactuals of the wholesale price without the CPS and the impact on interconnector flows, explored in greater depth in another paper (Guo et al., 2019).

Our SR-MDF estimates pick up from the period that Thomson et al. (2017) studied econometrically (2009-2014). They find that in 2010, a period of intermediate coal costs, the MDF was 0.61 tCO_2/MWh. Counterintuitively, this fell to 0.48 tCO_2/MWh in 2014 (when the CPS was introduced, although at a low level) when coal became more expensive. We aim to better understand these changes in the MDF, which Thomson et al. (2017) note might be due to the "unusual operation of the system in 2012-14". We confirm Thomson's findings and show the reason for the apparently counter-intuitive findings.

Most studies make "instantaneous" CO_2 emissions as the dependent variable in regressions (Wheatley, 2013; Thomson et al., 2017; Kaffine et al., 2013; Novan, 2015; Callaway et al., 2018). Instead we use half-hourly coal and gas generation as dependent variables and develop non-linear econometric models to estimate the marginal fuel (coal and gas MWh) displacement per MWh of wind and its dependence on the fuel cost difference. Staffell (2017) and Cullen

(2013) also uses coal and gas generation as dependent variables but study the impact in more parsimonious linear forms. With this we can estimate the MDF of wind. The conventional approach has the advantage that it gives the estimated MDFs directly. Our indirect estimate of the MDFs has two advantages. First, it explains the underlying mechanisms that drive the dynamics of the MDF. Second, it allows us to study the counterfactual in which the CFP is not implemented or carbon prices are set at a higher level. This would be difficult without knowing the underlying mechanisms.

The CPS raises the variable cost for coal plants more substantially than CCGTs, potentially changing the merit order of electricity generation. Fuel price shocks may have similar impacts. Cullen and Mansur (2017), Fell and Kaffine (2018), and Brehm (2019) study the impact of fuel price shocks on various aspects of electricity sector operation, including emission savings. Cullen and Mansur (2017) find that carbon prices are preferable when gas prices are low. Fell and Kaffine (2018) and Brehm (2019) find that low gas prices have the advantage on reducing emissions by displacing coal.

3 The British Carbon Price Floor

The Carbon Price Floor (CPF) was announced in the 2011 Budget to come into effect in April 2013. The CPF was intended to bring the price of carbon in fuels used in the GB electricity supply industry up to £(2011)30/tCO_2 by 2020 and £(2011)70/tCO_2 by 2030 (the dashed line at current prices in Figure 2), sufficient to make mature zero-carbon generation competitive against fossil fuels. The CPF is administered by adding the Carbon Price Support (CPS, a carbon tax added to the EUA price) on fuels used to generate electricity. The CPS was set at £4.94/tCO_2 in September, 2010. By April 2013, the EUA price had fallen to just under £4/tCO_2 so the effective price was far below the desired level (the dashed line in Figure 2). The CPS was raised in 2014 to £9.55/tCO_2 and again in 2015 to £18.08/tCO_2, to bring the price back to the desired CPF trajectory. In 2011, the UK Government hoped that other EU countries would be attracted by this fiscally appealing solution to the politically intractable problem of ETS reform. Other EU Member States declined to follow (until recently when the Dutch Government announced plans for a CPF).

Faced with a potentially large mismatch between the cost of generating electricity in Britain and on the Continent, the Chancellor froze the CPS at £18/tCO_2 from 2016-17 through 2020-21.[3] Figure 2 shows the increasing divergence between the EU and GB CO_2 prices. In November 2017 the EU finally agreed to reform the ETS, introducing a Market Stability Reserve that allows surplus EUAs to be cancelled (Newbery et al., 2018). In response the EUA price rapidly increased, and with it, the GB carbon price moved above the original CPF trajectory (Figure

[3] See http://researchbriefings.files.parliament.uk/documents/SN05927/SN05927.pdf.

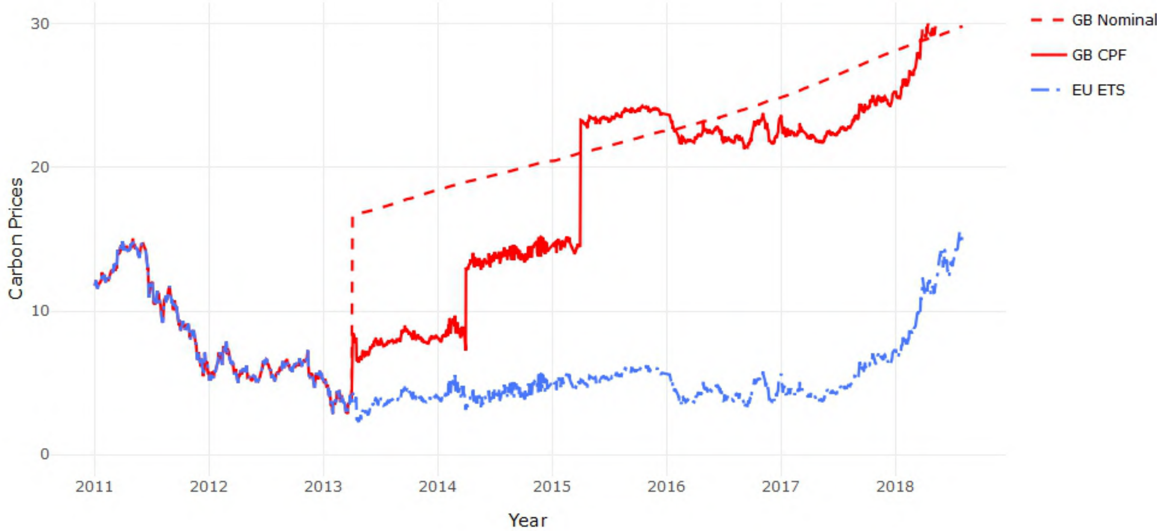


Figure 2: Evolution of the European Allowance (EUA) price and CPF, £/tCO_2

Source: https://www.investing.com/commodities/carbon-emissions

2).

The impact of this considerable increase in the fossil fuel cost has been dramatic. Figure 3 shows the variable fuel costs from 2012-18, with and without the CPS. The CPS gradually increased the cost of coal, but it was not until April 2015, when the CPS was almost doubled, that the variable coal cost rose above the variable cost of more efficient CCGTs. Figure 1 shows the massive switch from coal to gas, with renewables also rapidly taking share and further lowering carbon intensity.

The rest of this paper quantifies the impact of the CPS on the carbon savings from wind, which, as Figure 1 shows, has been increasing rapidly.[4] To do this we need to estimate both the short-run (SR) and long-run (LR) Marginal Displacement Factors (MDFs). The short-run impacts are studied econometrically over a period of varying fuel and CPS prices and varying plant mix and wind capacity. The hourly variations in output hold wind capacity constant, providing statistically highly significant estimates of the short-run impact of wind. We use an hourly unit commitment dispatch model of British electricity (described in detail in Chyong et al., 2019) to compute the long-run impact of the CPS. Wind capacity is increased by 25%, leaving the plant mix and fuel prices constant, and varying the level of the CPS. We expect the short-run MDF (SR-MDF) to differ from the long-run MDF (LR-MDF), as the SR-MDF

[4]The same approach could in principle be applied to carbon savings from solar PV or smart charging of battery electric vehicles, but the necessary data are not currently readily available.

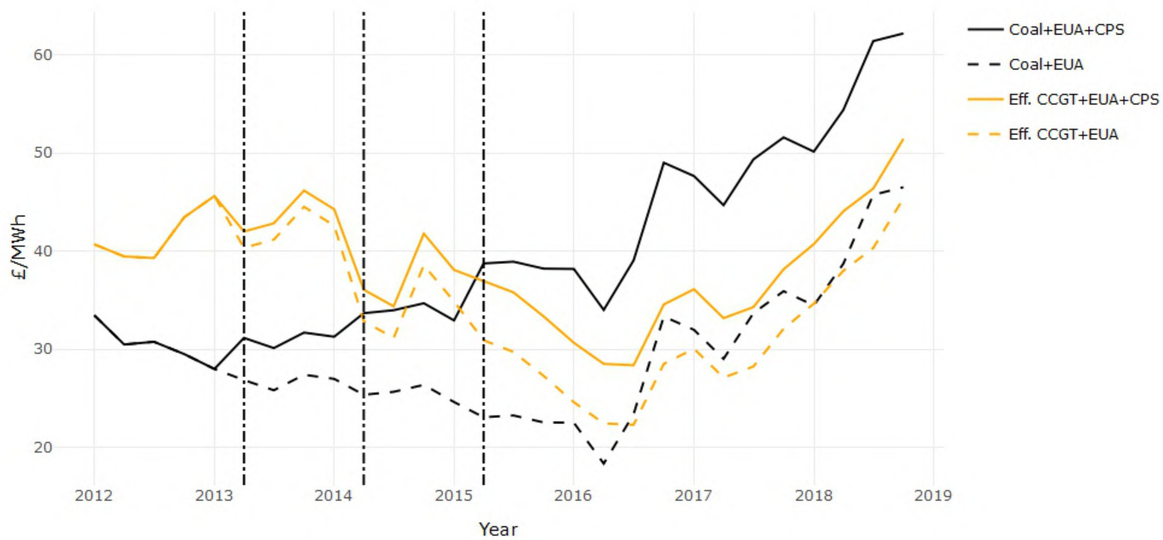


Figure 3: Electricity generation cost by fuels for generators

Source: BEIS *Quarterly Energy Prices* at https://www.gov.uk/government/statistical-data-sets/prices-of-fuels-purchased-by-major-power-producers

estimates the impact of variable (imperfectly predicted) wind on generation given the *existing* wind capacity. The way we have estimated the LR-MDF considers a deterministic world of known demand over the plant commitment horizon in which the known increase in wind capacity leads to an accurately forecast wind output. Plant is then efficiently scheduled to meet accurately predicted residual demand. The two estimates may differ for various reasons as we discuss below, and both estimates are needed to inform policy.

Table 1 gives the thermal efficiency of coal as 35.6% with emissions 0.871 tCO_2/MWh_e,[5] and the emission factors for the most efficient CCGTs in 2015 as 0.333 tCO_2/MWh_e, although the range is wide and includes less efficient older and oldest (and largely unused) CCGTs. Thus coal has more than twice the carbon intensity of gas. At a CPS of £18/tCO_2, the marginal cost of coal-fired generation is increased by £15.7/MWh_e and efficient CCGTs by £6/MWh_e, reducing the relative cost of gas by nearly £10/MWh_e, compared to the average baseload price from 2011-13 of £47/MWh_e.

The impact of the CPS can be clearly seen in the coal cost in Figure 3, although it is not until Q2 2015 when the coal cost exceeded efficient CCGT costs. Before then, the dark green spread (the average wholesale prices *less* the coal cost including the EUA *plus* CPS) was £7.7/MWh_e while the clean spark spread (average wholesale prices *less* the cost of CCGT including carbon

[5]See https://www.statista.com/statistics/548964/thermal-efficiency-coal-fired-stations-uk/. Subscript $_e$ indicates per unit of *e*lectricity output.

Table 1: Characteristics of GB Fuel Types

	Fuel Price £/MWh$_{th}$	Capacity GW	Efficiency GCV	CO_2 t/MWh$_e$
Coal	£6.57	17.1	35.6%	0.871
CCGT new	£15.87	14.2	55.1%	0.333
CCGT older	£15.87	5.2	52%	0.352
CCGT oldest	£15.87	7.6	36%	0.511

Note: GCV is Gross Calorific Value (Higher Heat Value), subscripts $_{th}$ refer to thermal content, $_e$ electric output. Efficiencies are often quoted for the more impressive Lower Heat Value. For gas the LHV is 90% of the HHV, downgrading the 61.2% nominal efficiency to 55.1% HHV. The oldest CCGTs are often running inefficiently part-loaded or in open-cycle mode for fast balancing response.

cost) was £3/MWh$_e$, making coal the preferred base-load and gas mid-merit. From November 2015 to June 2017 the dark green spread fell to $-$£1.8/MWh (a loss if running at full capacity all the time, but higher priced hours would still give a positive spread), while the average clean spark spread rose to £8.9/MWh, shifting gas from mid-merit to base load, and coal to mid-merit or peaking load. Figure 1 shows the impact on the fuel mix of generation.

Coal has normally been the major swing fuel in winter months, and indeed on a cold winter day (09:30 February 27 2018) CCGTs were producing 19.4 GW but coal was producing 11.1 GW, its maximum.[6] On a calm sunny summer day (15:40 August 3, 2018), CCGTs were producing 17.8 GW, coal only 0.5 GW, wind down to 1.1 GW and solar up at 4.8 GW. Clearly the CPS has had a major impact on the GB fuel mix, while the CPS will have increased marginal fossil generation costs and hence the wholesale price with consequential impacts on the volume and even direction of trade over interconnectors with neighbouring countries lacking a CPF, (notably,the high-priced island of Ireland).

4 The Merit Order Impact of Carbon Pricing

Renewables (wind, solar PV, run-of-river hydro) and nuclear power have zero variable carbon emissions and low variable costs, so if available, they will displace more expensive fossil generation. The merit order for conventional (dispatchable) plant ranks plant in increasing variable cost, with residual demand (total demand less renewable generation) determining the marginal

[6]Real time data are available from http://gridwatch.co.uk/; the installed capacity for coal was 11.1 GW in 2017, (instead of the value of 17.1 GW in 2015 in Table 1,) see https://transparency.entsoe.eu/. One reason for the significant reduction in coal capacity is because the Large Combustion Plant Directive persuades generators to close coal-fired capacity in the years leading up to 2016.

conventional plant displaced by renewables. Exactly which fossil generation will be displaced depends on their position in the merit order but also on which are able to adjust their output. The static merit order impact of renewables *capacity* in displacing fossil plant is well-understood (Clò et al., 2015; Cludius et al., 2014; Deane et al., 2017; Green & Vasilakos, 2012; Ketterer, 2014). The impact of variations in renewable *output* needs attention to plant dynamics.

Figure 4 shows the Q2 2016 merit order of GB nuclear, coal and CCGT plant (excluding biomass, CHP, pumped storage, interconnectors and renewables) with either just the EUA or with the added CPS at £18/tCO_2. At EUA carbon prices coal is cheaper than all CCGTs. With the CPS, efficient CCGTs displace coal, but that is still cheaper than the less efficient CCGTs, some of which are potentially operating as balancing units in open-cycle mode.

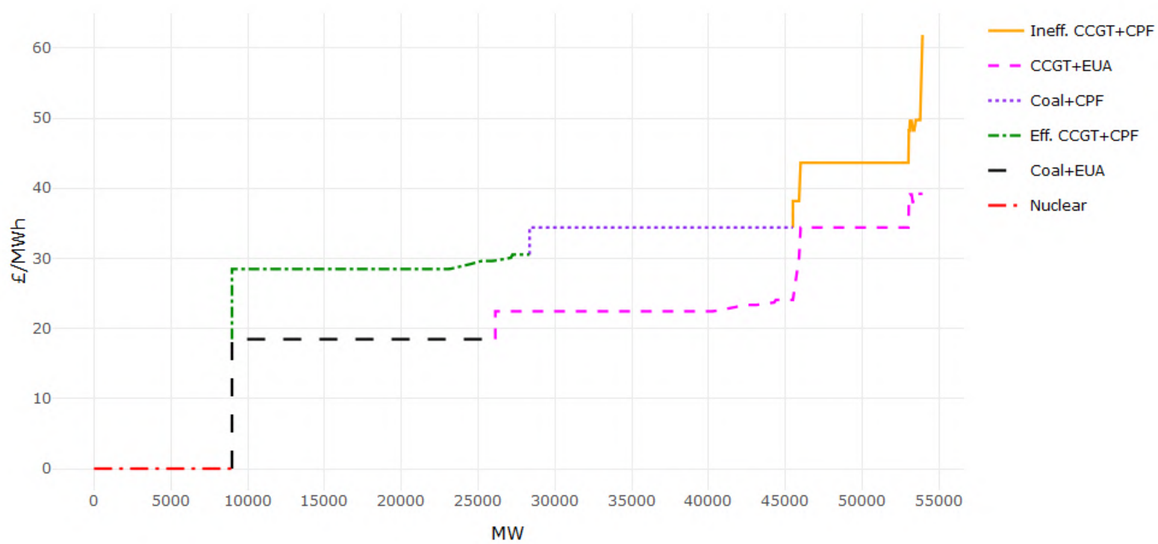
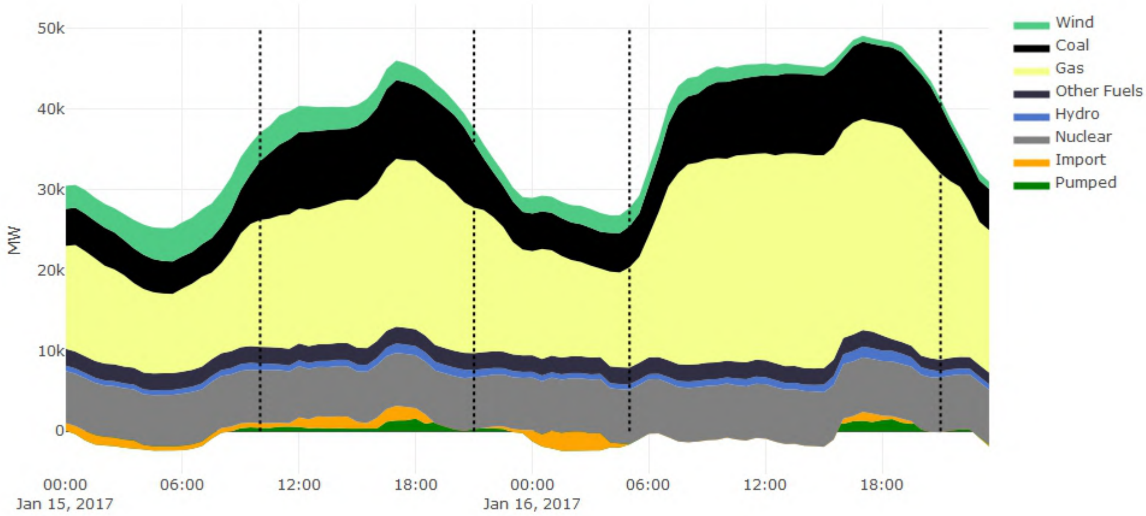


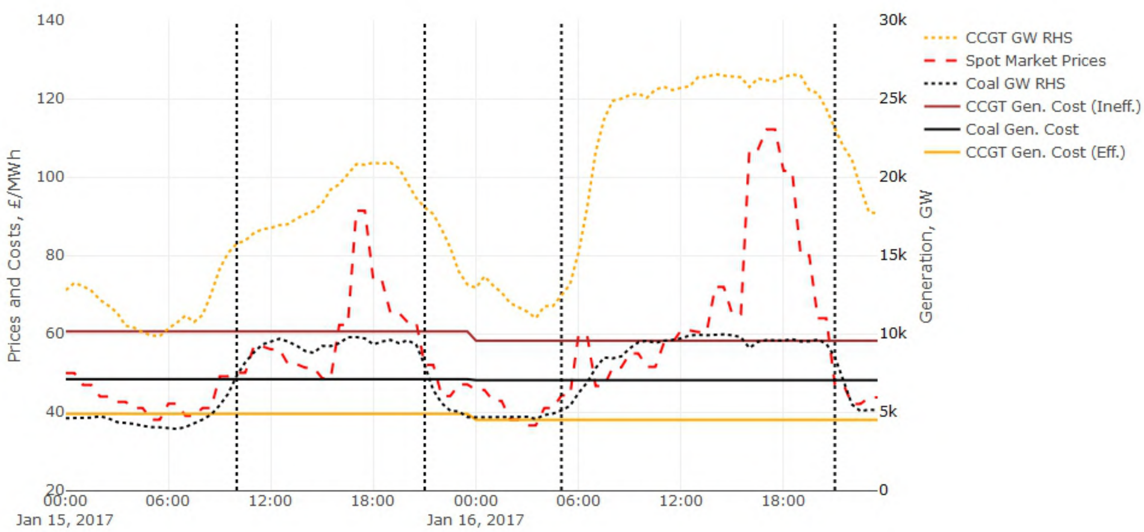
Figure 4: Merit order for conventional generation plant, Q2 2016

Figure 5a shows the half-hourly generation by fuel types in two consecutive days in January 2017. Exports are shown as negative imports and pumped storage either is a negative generation (when pumping) or positive. The negative amount is subtracted from the stable nuclear output, so that when nuclear is apparently negative that implies that pumping is demanding power. The horizontal lines in the lower part show the marginal costs of generating with gas in high efficiency (55.1%) CCGTs, including carbon at £18/tCO_2, the middle one is coal (35.6% efficiency) and the higher one is the least efficient CCGT (36% efficiency), not much higher than the peaking open cycle gas turbines (OCGTs) shown in the upper tail of the merit order in Figure 4.

Figure 5b plots the generation costs for coal and efficient CCGTs, the spot market prices, and coal and gas generation for the two days. The vertical lines in Figure 5 show where coal changes from having a negative dark green spread to positive or *vice versa* (where the spot



(a) Half-hourly output (legends order the same as fillcolours)



(b) Half-hourly spot market prices and generation costs

Figure 5: Generation, prices and costs by half-hour, 15-16 Jan 2017

Source: Elexon Portal

market prices intersect with the coal cost). Coal plant is costly to restart, so if needed later in the day will run at minimum load, and start to ramp up in time to deliver when demand and prices rise. Wind varies considerably over this 48 hour period (between 6.7 GW and 4.3 GW) but this variation is dwarfed by the variation in demand (from 25-49 GW). As a consequence, coal and gas generation follow load and any adjustment in response to wind variations are swamped by load variations. However, while load is reasonably predictable, wind is less predictable and likely to rely more on the balancing market, for which flexible plant is at a premium (as noted by Thompson et al., 2017).

5 Econometric Analysis

The short-run marginal displacement factor (SR-MDF) measures the marginal CO_2 savings of wind *with the existing capacity of wind* using data from 2012 to 2017. This covers the period before the implementation of the CPS (pre Q2 2013), the period when it was implemented and raised twice (Q2 2013 - Q2 2016) and when it is fixed at £18/tCO_2 (post Q2 2016). Figure 3 shows the generation costs for coal and gas during the period with and without the CPS, where we observe a switch of merit order from Q2 2015, when the CPS reached its highest level. Thomson et al. (2017) estimate the SR-MDF from 2009 to 2014. Our data overlaps their period, allowing us to assess the credibility of our work. Our method allows us to better understand the underlying mechanism driving changes in the SR-MDF. We then study the counterfactual SR-MDF without the CPS.

5.1 The short-run impact of wind

The conventional approach to estimate the SR-MDF (Hawkes, 2010; Thomson et al., 2017; Staffell, 2017) uses the following model:

$$\Delta E_t = a\Delta D_t + b\Delta W_t + c_t + u_t, \tag{1}$$

where ΔE_t is the half-hourly first difference of the system CO_2 emissions (tCO_2), and ΔD_t (MWh) and ΔW_t (MWh) are the first differences of electricity demand and wind output respectively. Coefficient a is the marginal emission factor (MEF) (tCO_2/MWh) of demand and $-b$ is the SR-MDF (tCO_2/MWh) of wind. c_t is other system effects which can be half-hourly specific, and u_t is an unobserved error term.[7]

By definition,

$$\Delta E_t = e_C\Delta C_t + e_G\Delta G_t + e_O\Delta O_t, \tag{2}$$

where C_t, G_t and O_t are electricity generated from *C*oal-fired stations, *G*as (CCGTs) and *O*ther energy sources; e_C, e_G and e_O are the CO_2 emission intensities for coal, gas (efficient CCGTs)

[7]Most relative research uses data at unit-level, such that the compositional effects across heterogeneous units, as well as operational effects, on emission factors are properly captured. Our paper shows that using a much cruder dataset we are able to obtain results that are qualitatively in line with other research that uses unit-level data.

and other fuel sources. O_t consists of energy sources which are negligible (open-cycle gas turbines and oil), must-runs (combined heat and power and biomass), and imports, which do not count as GB sources of emissions.[8] Therefore, $e_O \Delta O_t$ is close to zero because either $e_O = 0$ (for imports) or $\Delta O_t \approx 0$ (for the must-run and negligible energy sources).

Pumped Storage (PS) charges off-peak using mostly fossil generation and is then available to generate during high price hours, and more importantly, to provide fast reserve (available within 1 minute) when needed. If wind output falls (or more specifically, if residual demand increases), then replacement supply is needed. The five-minute output data reveals that PS ramps up more rapidly than other generation, but that over the following 25 minutes gas (and to some extent coal) can replace the PS, reducing its average effect over that half-hour. Given that PS required earlier fossil generation there is an obvious question of its carbon content. The position taken here is that PS will provide arbitrage, balancing and ancillary services to the extent of its capacity, regardless of wind output, which will primarily affect the value and timing of these services. The carbon content of the water released by PS when delivering these services depends on when PS charged (invariably off-peak) and hence will not vary with the subsequent day's wind output. For that reason although PS output will respond to changes in wind, its effective MDF is zero.

Substituting ΔE_t in (1) by (2) suggests to run the following regressions:

$$\Delta C_t = \alpha_0 + \alpha_1 \Delta W_t + \alpha_2 \Delta D_t + \boldsymbol{\theta' X_t} + \varepsilon_t, \tag{i}$$

$$\Delta G_t = \beta_0 + \beta_1 \Delta W_t + \beta_2 \Delta D_t + \boldsymbol{\delta' X_t} + \mu_t, \tag{ii}$$

where $\boldsymbol{X_t}$ is a vector that consists of hourly (or half-hourly) dummy variables. Having first differences (instead of levels) means that we do not need to worry about non-stationary processes.[9]

Consequently, we have:

$$e_C \alpha_2 + e_G \beta_2 \approx a = \text{MEF},$$

$$-(e_C \alpha_1 + e_G \beta_1) \approx -b = \text{SR-MDF}.$$

The SR-MDF is therefore estimated indirectly from regressions (i) and (ii) instead of (1). This indirect approach enjoys the following advantages. First, it identifies the underlying drivers of the dynamics of the SR-MDF (i.e. the shares of coal and gas displaced by wind). Second, the non-linear version of (i) and (ii) discussed below allows us to study the counterfactual in

[8] Nuclear, solar, wind, run-of-river hydro are not included in (2) because none of them generates GHG.

[9] One may also argue that the error terms between (i) and (ii) are negatively correlated because if one unit is unavailable to meet a given level of demand, another unit might take over. Therefore, a more efficient Seemingly Unrelated Regression (SUR) might be preferred. However, when the covariates between the two regressions are exactly identical, the SUR estimates turn out to be equivalent to the equation-by-equation OLS (Takeshi, 1995, p.197). This also applies to the non-linear regressions introduced in the next sub-section.

which the CPS is not implemented. Staffell (2017) uses a similar linear approach, looking at the specific fuel types that are displaced by wind (and solar). Staffell's finding that only fossil plant and imports adjust their output to wind changes supports out analysis of the two-step estimation of the SR-MDF using regression (i) and (ii) and their non-linear versions. As wind supply depends on wind speed, ΔW_t can be treated as exogenous. As the half-hourly domestic demand for electricity is inelastic to prices (Clò et al., 2015), ΔD_t is also treated as exogenous.

The slope coefficients α_1 and β_1 are the marginal *fuel* displacement of wind, measuring the changes in coal and gas generation caused by a change in wind output, conditional on the change in demand and time dummies. We would expect both $\hat{\alpha}_1$ and $\hat{\beta}_1$ to be negative, and $|\hat{\alpha}_1 + \hat{\beta}_1|$ to be close to but smaller than 1 — in addition to coal and CCGT plants, a small but significant proportion of changes in wind can also be compensated by imports and pumped storage. The coefficients α_2 and β_2 measure the response of coal and gas generation to demand changes. We would expect both $\hat{\alpha}_2$ and $\hat{\beta}_2$ to be positive and $|\hat{\alpha}_2 + \hat{\beta}_2|$ to be less than 1 because a proportion of changes in demand can also come from other sources.

The magnitudes of α_1 and β_1 depend on total energy demand (hence the time of the day) as well as the actual merit order between coal and gas, which is determined by $PD_t \equiv P_t^C - P_t^{G^e}$, the difference in variable energy generation costs between coal (P_t^C) and efficient CCGT plants ($P_t^{G^e}$) (hereafter the cost differential).[10,11] Each day is separated into two periods: off-peak (23:00-07:00) and peak (07:00-23:00) based on Economy 7 meters[12] as well as Figure 4 and 5, which suggest that the base-load plant is sufficient for energy demand during (most of the) off-peak hours and the mid-merit plant is the marginal fuel for most of peak hours.[13,14] We further split the two sub-samples based on PD_t, and denote the periods when $PD_t < 0$ as COAL-BASE and the periods when $PD_t \geq 0$ as GAS-BASE depending on which fuel is expected to run on base load, and run regressions (i) and (ii) on each sub-sample. (Details of the data sources and summary statistics are given in the Appendix A.3.) The results are shown in Appendix Table A.1.

[10]Because inefficient CCGT plants only count for a small proportion of energy supply and only supply energy in very cold winter days, we only consider the generation cost differential between coal and efficient CCGT plants, for which we use the short-hand gas.

[11]We use daily gas prices, smoothed quarterly coal prices, and daily EU ETS prices to calculate the daily generation costs, and hence the cost differential. Details are shown in the Appendix A.3. Therefore, the coal and CCGT plants generation costs are invariant within days.

[12]The definition on peak and off-peak is from https://customerservices.npower.com/app/answers/detail/a_id/179/~/what-are-the-economy-7-peak-and-off-peak-periods%3F based on London, Eastern and East Midlands. The results are not sensitive to changing the peak period to 08:00-23:00 or 07:00-22:00.

[13]In Figure 4, the boundary between base load and mid-merit load in GB should be slightly above 30GW, after taking CHP, biomass, and renewables into consideration.

[14]This is (at least) true for the period of studying, 2012-2017, when solar PV generation does not sufficiently reduce the demand from thermal plants, which is on average lower than 1 GW. With significant solar, one can separate the data base on the residual demand instead of time of the day, but that will complicate interpretation and the post-estimate counterfactual application.

5.2 The role of generation cost differentials between coal and gas

Appendix Table A.1 shows that the impacts of ΔW_t and ΔD_t on ΔC_t and ΔG_t depend on the cost differential (PD_t), especially for off-peak periods. During off-peak periods, a negative PD_t will boost the partial effect of ΔW_t and ΔD_t on ΔC_t. During peak periods a negative PD_t will diminish the impact of ΔD_t on ΔC_t, although the magnitude is small relative to off-peak periods. The same is true for the impact of ΔW_t and ΔD_t on ΔG_t, but in the opposite direction.[15] We conclude that the partial effects of ΔW_t and ΔD_t on ΔC_t and ΔC_t depend on PD_t, and assume the dependency is non-linear, suggesting the following regressions:

$$\Delta C_t = \alpha_0 + f(PD_t) \cdot \Delta W_t + k(PD_t) \cdot \Delta D_t + \boldsymbol{\theta' X_t} + \varepsilon_t, \tag{iii}$$

$$\Delta G_t = \beta_0 + g(PD_t) \cdot \Delta W_t + l(PD_t) \cdot \Delta D_t + \boldsymbol{\delta' X_t} + \mu_t, \tag{iv}$$

where $f(PD_t)$, $k(PD_t)$, $g(PD_t)$, and $l(PD_t)$ are non-linear polynomial functions of PD_t. The Bayesian Information Criterion (BIC) suggests a fourth degree polynomial. For example,

$$f(PD_t) = \alpha_{1,0} + \alpha_{1,1} PD_t + \alpha_{1,2} PD_t^2 + \alpha_{1,3} PD_t^3 + \alpha_{1,4} PD_t^4.$$

Regressions (iii) and (iv) are more robust because they are an improvement on the previous linear regressions, and non-linear relationships make more sense of the varying sensitivity of the merit order to the cost differential.[16]

From the the results shown in Appendix Table A.1, we would expect the *magnitudes* of $f(PD_t)$ and $k(PD_t)$ during off-peak periods to be decreasing with PD_t, meaning that as the coal generation cost increases relative to gas, coal will be less sensitive to changes in wind and total demand in off-peak periods, as it is moved away from base load. Furthermore, PD_t is expected to have its highest influence on the partial effects when PD_t is close to zero, the tipping point that determines the base-load fuel. Therefore we expect the slopes of $\hat{f}(PD_t)$, $\hat{k}(PD_t)$, $\hat{g}(PD_t)$, and $\hat{l}(PD_t)$ to be the highest at around $PD_t = 0$. For the same reason, the *magnitudes* of $g(PD_t)$ and $l(PD_t)$ during off-peak periods are expected to be increasing with PD_t, with the highest slopes at $PD_t = 0$.

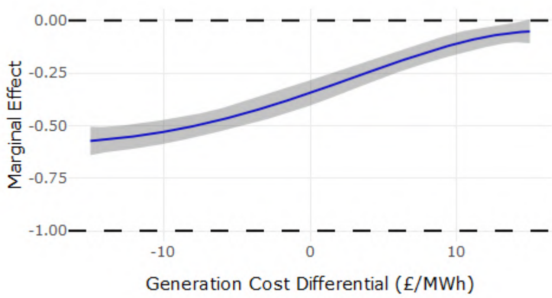
In peak periods, we expect PD_t to have negligible impact on $\hat{f}(PD_t)$, $\hat{g}(PD_t)$, $\hat{k}(PD_t)$ and $\hat{l}(PD_t)$ as gas provides flexible response regardless of the cost difference.

The detailed estimation results are shown in the Appendix A.1. The non-linear partial effects of ΔW_t on ΔC_t and ΔG_t (i.e. $\widehat{\partial \Delta C_t / \partial} \Delta W_t$ and $\widehat{\partial \Delta G_t / \partial} \Delta W_t$) and the corresponding 99%

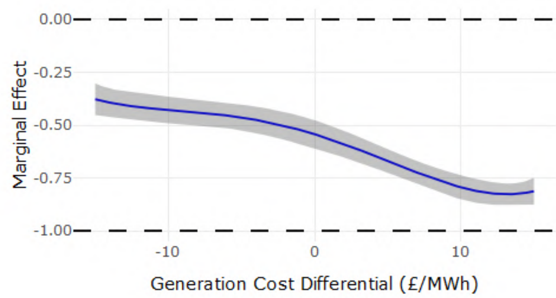
[15]We find no evidence of an asymmetric partial effect when wind rises and falls ($\Delta W_t > 0$ *v.s.* $\Delta W_t \leq 0$), and when the demand on fossil generation increases and declines ($\Delta C_t + \Delta G_t > 0$ *v.s.* $\Delta C_t + \Delta G_t \leq 0$). We also find that running regressions separately for weekdays and weekends does not change the story. Details are in Appendix A.1.

[16]The test for the joint significance of the polynomial terms are all statistically significant at the 0.1% level. For example, in $f(PD_t)$, the null hypothesis is $\alpha_{1,1} = \alpha_{1,2} = \alpha_{1,3} = \alpha_{1,4} = 0$.

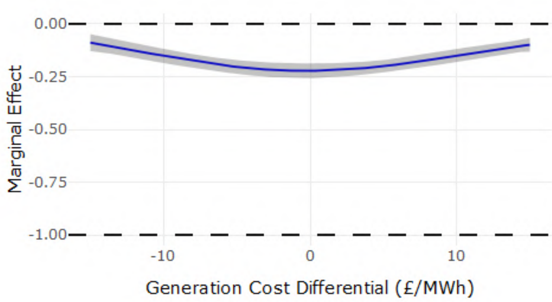
(a) partial effects of ΔW_t on ΔC_t, off-peak



(b) partial effects of ΔW_t on ΔG_t, off-peak



(c) partial effects of ΔW_t on ΔC_t, peak



(d) partial effects of ΔW_t on ΔG_t, peak

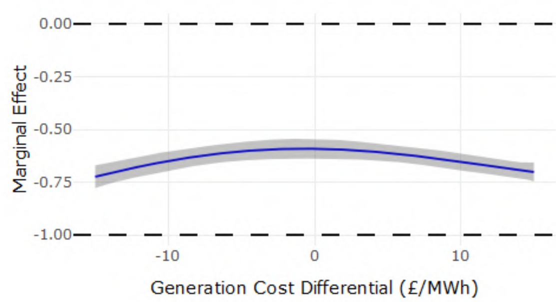


Figure 6: The estimated partial effects of ΔW_t on ΔC_t and ΔG_t, regressions (iii) and (iv)

confidence intervals are plotted in Figure 6, with the x-axis representing the cost differential PD_t and y-axis representing marginal effects. Overall, the partial effects are negative, and $|\widehat{\partial \Delta C_t / \partial \Delta W_t} + \widehat{\partial \Delta G_t / \partial \Delta W_t}|$ is close to but smaller than 1 for any given PD_t within the range considered.

Figures 6a and 6b show off-peak relationships. The slopes of the curves reflect the impact of PD_t on switching the merit order: the steeper the slope, the stronger the impact. The shapes follow our earlier expectations — upward (downward) sloping with the steepest slopes near $PD_t = 0$, and with decreasing slopes as PD_t moves away from zero, meaning that PD_t has little impact on the marginal fuel displaced by wind when the cost difference becomes large.

Thus in 2013 when $PD_t^{2013} = -£13.5$, a 1 MW change in wind supply *in off-peak periods* on average leads to a -0.56 MW change in coal generation and a -0.40 MW change in gas generation. In 2017 when $PD_t^{2017} = £13.5$, a 1 MW change in wind supply would on average result in a -0.06 MW change in coal generation and a -0.83 MW change in gas generation.

Figures 6c and 6d plot the peak relationships. The curvatures for the partial effects are more moderate than those in Figures 6a and 6b. This suggests that gas is always more responsive

(a) partial effects of ΔD_t on ΔC_t, off-peak
(b) partial effects of ΔD_t on ΔG_t, off-peak
(c) partial effects of ΔD_t on ΔC_t, peak
(d) partial effects of ΔD_t on ΔG_t, peak

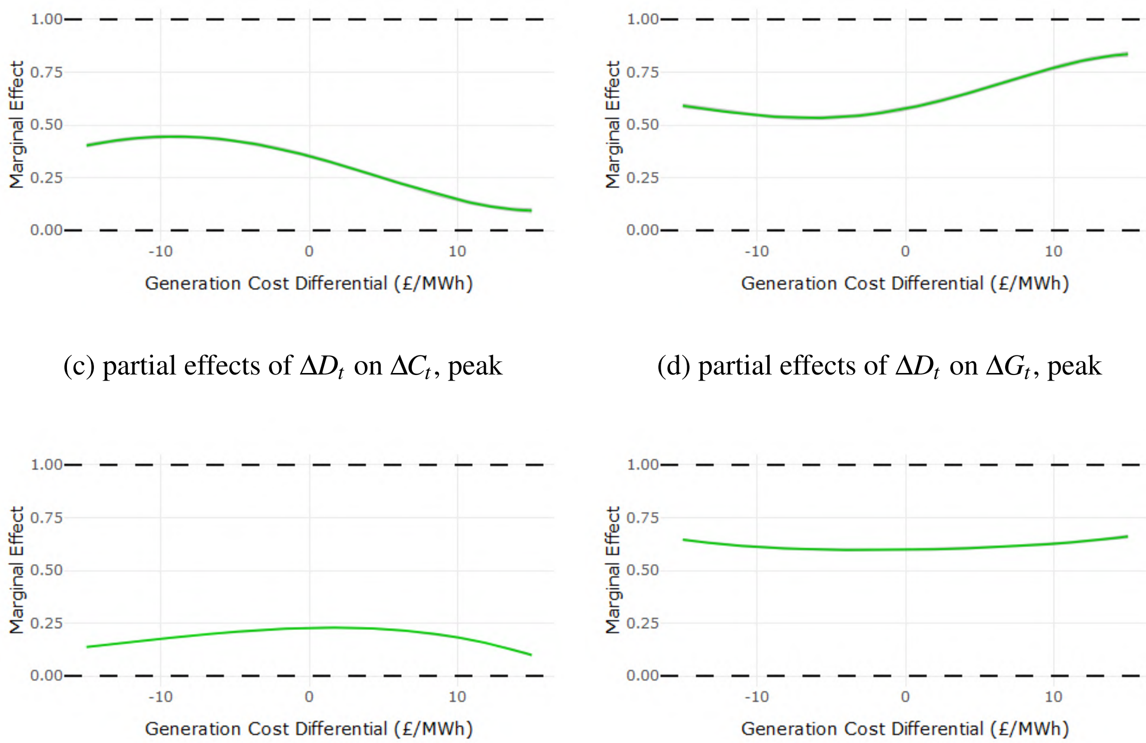


Figure 7: The estimated partial effects of ΔD_t on ΔC_t and ΔG_t, regressions (iii) and (iv)

to wind variations during peak periods due to its flexibility. At the margin, 1 MW of wind displaces 0.09-0.22 MW of coal and 0.59-0.72 MW of gas.

Figures 7 shows the partial effects of ΔD_t on ΔC_t and ΔG_t (i.e. $\widehat{\partial \Delta C_t / \partial \Delta D_t}$ and $\widehat{\partial \Delta G_t / \partial \Delta D_t}$). Again, Figures 7a and 7b plot the off-peak partial effects, and 7c and 7d plot the peak partial effects. All partial effects are always positive, and $\widehat{\partial \Delta C_t / \partial \Delta D_t} + \widehat{\partial \Delta G_t / \partial \Delta D_t}$ is also close to but smaller than 1 for any given PD_t within the interval of study.

The curvatures for the off-peak partial effects meet our initial expectations — downward sloping for coal and upward sloping for gas. As the generation cost for coal becomes higher (i.e. PD_t increases), gas becomes more sensitive to demand changes during off-peak periods. Thus when $PD_t^{2013} = -£13.5$, for 1 MW change in the energy demand, coal on average contributes 0.42 MW and gas on average 0.58 MW. When $PD_t^{2017} = £13.5$, 1 MW increase in demand would on average increase coal generation by only 0.10 MW and gas generation by 0.82 MW.

As with wind changes, in peak periods the marginal effects of demand changes do not vary much with PD_t. At the margin, 10%-23% of demand change is met by coal and 59%-66% by gas.

Besides the different signs, the impact of changes in wind is similar to the impact of changes in demand. Off-peak, the base load fuel is at the margin and respond to wind/demand changes. In peak hours, flexible CCGTs always provide the response. The difference between the partial effects of wind and demand is explained by the difference in predictability of wind and demand. As demand is more predictable, less flexible coal plant can be suitably scheduled ahead of time. Table 3 compares the two responses.

5.3 Short-run Marginal Displacement Factor of Wind

In addition to wind displacing coal and gas, it can also influence other flexible power sources, especially pumped storage and imports, which explains why $|\hat{f}(\tilde{P}_t)+\hat{g}(\tilde{P}_t)|<1$ and $|\hat{k}(\tilde{P}_t)+\hat{l}(\tilde{P}_t)|<1$. However, imports do not count as GB emissions, and for reasons given earlier wind does not affect carbon emissions from pumped storage. We can therefore confine attention to impacts on coal and gas for estimating the marginal CO_2 displacement factor of wind.

The estimation results from Figure 6 and 7 allow us to calculate the marginal CO_2 displacement of wind since 2012. For each half hour, given the generation cost differential, first calculate the partial effects of ΔW_t on ΔC_t and ΔG_t. Then multiply the estimated partial effects by the emission coefficients of coal and efficient CCGTs respectively to obtain the SR-MDF.[17] The calculation is done separately for peak and off-peak and then combined to give the final result. Figure 8 plots the quarterly average SR-MDF of wind, where the dotted curve represents the marginal cost differential between coal and gas (PD_t), which is to be read from the right-hand y-axis.

Figure 8 shows that the SR-MDF of wind in off-peak periods is decreasing during the period, with no strong trend for peak periods. The reason is straight-forward from Figure 6 and 7. When coal is cheaper and on base-load (before Q2 2015), coal responds more to wind changes during off-peak periods. Since coal has a higher emission intensity than gas, the marginal CO_2 displacement of wind is higher when coal is the marginal fuel during these off-peak hours before Q2 2015. In peak hours demand is more variable, prices are higher, so CCGTs are in-merit and better able in respond quickly to variations in wind, so the cost differential has little impact on the peak SR-MDF of wind. The solid curve is the average SR-MDF after combining peak and off-peak periods, which is also in general negatively correlated with the generation cost differential (PD_t). The negative relationship is mainly driven by the dynamics of the SR-MDF during off-peak periods. In addition, the gradual phase-out of coal-fired power plant over this period also plays a non-trivial role on the decline of the SR-MDF.

The CPS almost doubled after Q2 2015, causing efficient CCGTs to provide base-load power, displacing coal. Since then, wind primarily displaces gas in both peak and off-peak

[17] We use the emission factor of 0.871 tCO_2/MWh for coal-fired power plants, and a weighted average of 0.337 tCO_2/MWh for efficient CCGTs.

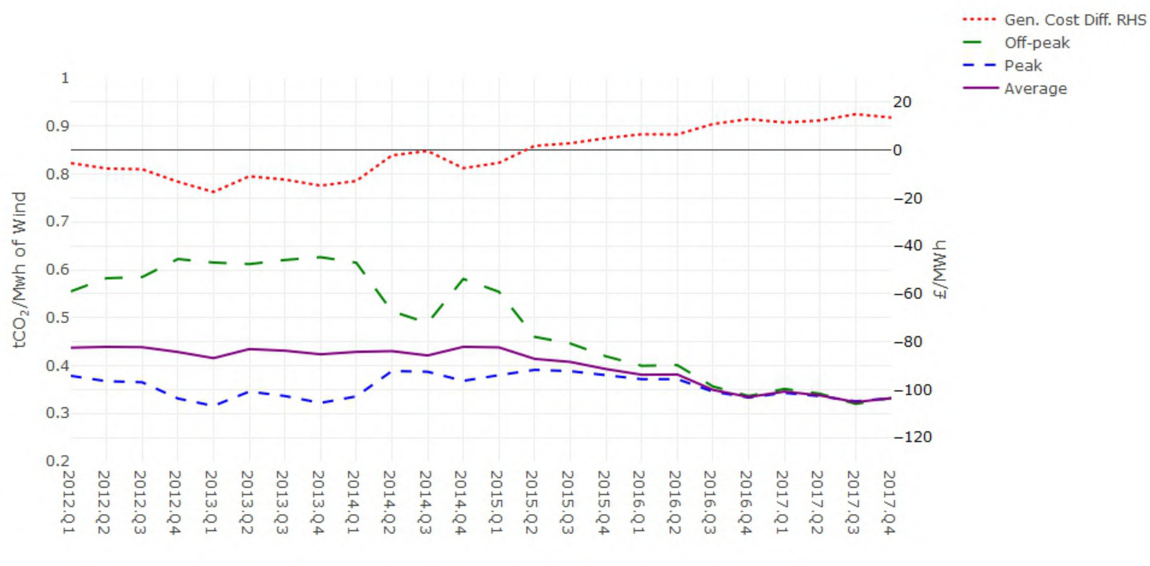


Figure 8: The short-run marginal displacement factors of wind

periods causing the SR-MDF for off-peak periods to fall. Thus from Q1 2012 to Q2 2015, a 1 MWh short-run increase in wind supply would on average reduce CO_2 emissions by 0.43 tonnes; while from Q2 2015 to Q4 2017, it would on average only reduce CO_2 emissions by 0.36 tonnes.

The period 2012-2017 slightly overlaps with that studied (2009-2014) by Thomson et al. (2017). Figure 9 shows a comparison of the results. We also used the best readily available data to replicate Thomson et al.'s results and extend their estimates to 2016 (the detailed numbers are shown in Appendix Table A.5 together with details for the replication).[18]

Despite using a rather cruder (but more accessible) data set, the replicated results on the SR-MDF are very close to those from Thomson et al. (2017), especially for the years between 2010-2013. On the other hand, our estimates from non-linear regressions are overall smaller than those from Thomson et al. (2017) and the replicated results, because we are using completely different emission factors[19] as well as different estimation methods. Despite that, the pattern for the dynamics of our estimated SR-MDF overlaps with the replicated results except for 2012, perhaps because we treat imports as overseas CO_2 emission and exclude their contribution.[20] Our results can be more intuitively explained by the merit-order effect given the

[18]We use the five-minute average generation by fuel type data from the Elexon portal (https://www.elexonportal.co.uk/article/view/216?cachebust=p3a16b2n35) which is only available up to Q1 2017.

[19]Thomson et al. (2017) use well-to-tank net calorific values (NCV) and as a result, the average emission factors for coal (with 35.6% efficiency) and efficient gas (with an average of 54.5% efficiency) are, respectively 1.12 tCO_2eq/MWh and 0.416 tCO_2eq/MWh, much higher than the carbon emission coefficients found by other studies. See https://www.parliament.uk/documents/post/postpn_383-carbon-footprint-electricity-generation.pdf.

[20]It would be possible, but challenging, to determine the marginal plant and hence emissions from the

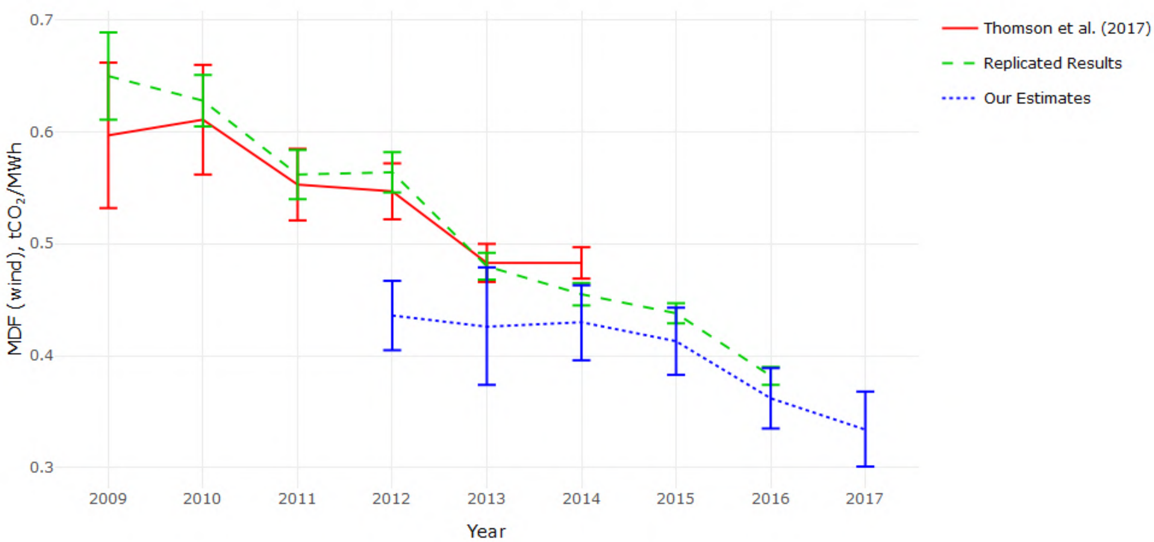


Figure 9: Comparisons on the patterns of annual MDFs, tCO_2(eq)/MWh

fuel cost movements shown in Figure 3. Although the CPS was introduced on 1 April 2013, efficient CCGTs did not become base load until Q2 2015. Without a switch in the merit order there is no reason for any drastic change in the SR-MDF in 2013.

Table 2: Marginal Generation Costs by Fuels

	Marginal Cost £/MWh_e			
	no CO_2	zero CPS	base CPS	high CPS
Coal	£18.46	£23.68	£39.36	£50.68
CCGT new	£28.80	£30.80	£36.79	£41.12
CCGT older	£30.52	£32.63	£38.97	£43.54
CCGT oldest	£44.08	£47.15	£56.35	£62.99
Carbon Cost £/tCO_2		£6.00	£24.00	£37.00

To compare the SR-MDF with the LR-MDF to be discussed in the next section, we estimate the SR-MDFs under three difference carbon price scenarios — no CPS (full carbon price £6/tCO_2), base CPS (full carbon price £24/tCO_2), and high CPS (full carbon price £37/tCO_2). We choose these three particular carbon prices because the average EUA price for 2015 is around £6/tCO_2,[21] then the zero and base CPS cases simulate the 2015 fuel mix with and with-

transmission-constrained Continental electricity market.

[21] The exact 2015 average was £5.85/tCO_2.

out the CPS. £37/tCO_2 corresponds to the high 2018 EUA price induced by the *Market Stability Reserve*. Table 2 gives the electricity generation cost by fuels under the three proposed scenarios, based on the fuel price and plant efficiencies given in Table 1.

Table 3: SR-MDF for the Three Carbon Price Scenarios

	Carbon Costs		
	£6/tCO_2	£24/tCO_2	£37/tCO_2
	Cost Differentials		
	£-6.98/MWh	£2.70/MWh	£9.70/MWh
$-\partial\Delta C/\partial\Delta W$	0.29	0.24	0.15
$-\partial\Delta G/\partial\Delta W$	0.56	0.60	0.69
SR-MDF	0.44	0.41	0.36
$\partial\Delta C/\partial\Delta D$	0.28	0.26	0.18
$\partial\Delta G/\partial\Delta D$	0.58	0.60	0.67
MEF	0.44	0.43	0.38

Notes: $-\partial\Delta C/\partial\Delta W$ is the coal Displacement Factor (DF, the decrease in Coal output for 1 MWh of Wind), $-\partial\Delta G/\partial\Delta W$ is the gas DF and SR-MDF = $-\partial\Delta CO_2/\partial\Delta W$ is the displacement of CO_2 in tCO_2/MWh of extra wind.

The SR-MDF and MEF under the three carbon price scenarios are given in Table 3, where the partial effects are averaged over peak and off-peak periods. As the carbon price increases, both $-\partial\Delta C/\partial\Delta W$ and $\partial\Delta C/\partial\Delta D$ declines, and both $-\partial\Delta G/\partial\Delta W$ and $\partial\Delta G/\partial\Delta D$ increases. This is driven by the merit-order switch during off-peak periods. The CPS forces gas (instead of coal) to respond to wind (and demand) changes during off-peak periods. During peak periods flexible gas always provides the main response to wind (and demand) changes. As coal has a much higher emission factor, both SR-MDF and MEF decline with carbon prices.

5.4 The SR-MDF without the CPS

By treating fuel prices as exogenous, we can calculate the marginal effects of ΔW_t on ΔC_t and ΔG_t without the CPS by adjusting the generation cost differential (PD_t) in the regressions (iii) and (iv). We then multiply the marginal effects by the corresponding emission factors to derive the SR-MDF without the CPS. The patterns are shown in Figure 10.

Without the CPS, the SR-MDF would stay relatively high, so the average SR-MDF in 2015 would be 0.44 tCO_2/MWh instead of 0.41 tCO_2/MWh, or 7% higher, while in 2017 it would be 0.40 tCO_2/MWh instead of 0.33 tCO_2/MWh, or 21% higher. The explanation is that without

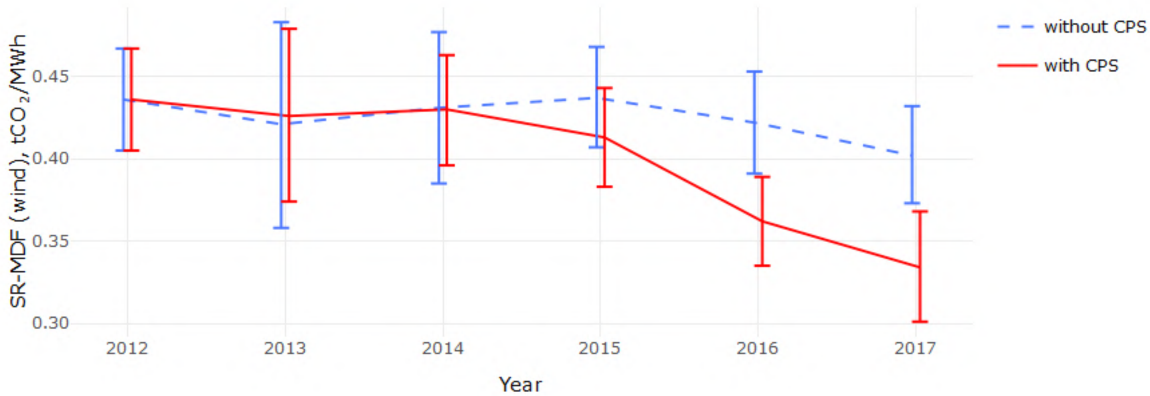


Figure 10: SR-MDF with and without the CPS

the CPS, both coal and gas costs would be lower, but the generation cost from coal would be much lower. Coal would continue on base load, being the marginal off-peak fuel until late 2017, when the gas and EUA prices increase and coal becomes mid-merit even without the CPS. This explains why the SR-MDF stays high until late 2017. During this period, without the CPS, wind displaces more CO_2, although the CPS shifts supply from coal to gas, reducing overall emissions.

6 Modelling the Long-run Carbon Savings from Wind

The long-run carbon savings from additional wind capacity is studied using a simulation model to determine dispatch with and without a significant increase in wind capacity. Deane et al. (2015) do this for EU scenarios in 2030 and 2050, using Plexos to minimize total costs over a year. They assume inelastic time varying demand, and take account of pumped storage and "operational and technical constraints" (presumably transmission capacities, ramping, minimum load and other plant characteristics). Ofgem (2018) in its *State of the market 2018* uses the LCP EnVision model to simulate not just dispatch but also investment and retirements from 2010-2017 to simulate counterfactuals with and without some or all of the policy interventions, including the CPS. Ofgem is interested in the increase in wholesale electricity costs and the policy costs, but ignores any longer-run benefits (learning spill-overs inducing climate change mitigation elsewhere).

We use our simple hourly unit commitment model of the 2015 GB power system (Chyong et al., 2019) to examine the impacts of varying wind capacity on fuel mix and hence CO_2 emissions, for three carbon prices and two levels of wind capacity. In contrast to Ofgem (2018) we do not attempt to model plant entry and exit, although the plant we simulate in 2015 is the plant listed as then present and consistent with our central carbon price (Ofgem, 2018, Figure A3, p9). Thus we can examine the impact of additional wind capacity on future carbon savings. All cases take the plant available in 2015, but hold demand and all outputs other than coal, gas, and pumped storage at their 2015 values.[22] The reference case takes the actual wind output in each hour of 2015 (an average wind year), and holds fuel and carbon prices constant across the year, so that variations in fuel prices and trade do not confound the variations of interest. The assumed fuel and the three carbon costs (EUA price plus CPS) are shown in Table 1, with the installed capacities, efficiencies and carbon intensities of key generation units.

The simulation determines an optimal hourly dispatch with predictable future demand and outputs of wind over the period of optimization. The simulations are re-run with 25% more wind in each hour (i.e. with 25%[23] more installed capacity at each location) to see how much coal and gas output is displaced in each hour and the resulting carbon savings, which in turn depend on the carbon price. Pumped storage (PS) is endogenous but only in arbitrage mode. Its more valuable use is in short-term balancing but that cannot be handled in a deterministic model. The hourly resolution inevitably conceals short-run variations (the actual output data are given in 5-minute periods), and so should be thought of as the predictable component of plant commitment. We compare and contrast the long-run and short-run analyses in section 7.

An improved but more complicated analysis would determine the plant mix including reserves for balancing as uncertainties in demand and wind are resolved, and then re-optimize dispatch in real time with actual demand and wind, limiting plant to those available, and subject to their various operating constraints (ramp rates, minimum load, etc.). Even this would fall short of describing market outcomes, as plant owners will typically set prices as a mark-up on their variable costs, by different amounts depending on their competitive position and their need to remain on the system. Interconnector flows and pumped storage will depend on market prices, not the system marginal cost. Modelling market prices at an hourly resolution is an enterprise with to date limited success, hence the need to interpret simulation results with care. Our deterministic modelling reduces the need for more flexible plant, probably increasing the role of coal in adjusting to changes, and understates total system costs.

As a cautionary remark, Table 4 shows that the fuel price differences in the 2015 CPS case are small (£2.7/MWh) compared to differences in variable O&M costs, so that the effective operating costs of coal and gas are almost identical. That makes the optimal dispatch very sensitive to minimum down times and minimum stable generation. Small changes in these parameters lead to surprisingly large changes in $\Delta C/\Delta W$, and so should be treated with a degree of caution. When fuel price differences are sufficiently large the results are more robust to

[22] From Elexon Portal at https://www.elexonportal.co.uk/news/latest.

[23] The 2015 average wind generation is 3.7 GW. The 25% increase raises average wind generation to 4.6 GW, compared to the 2017 average wind generation of 5.1 GW. The increase is small in magnitude, and therefore is treated as a marginal increase. We also ran a 5% and 10% increase of wind, confirming that the LR-MDF is consistent with varying wind changes.

changes in the technical parameters. GB coal stations have expected a very limited remaining life since the CPF was introduced, and have therefore likely reduced maintenance and moved outside the operating ranges that would be desirable for long and trouble-free operation, so taking industry standards for these parameters may not describe recent operating conditions. One of the advantages of our simple unit commitment model is that it can throw light on such sensitivities and thus indicate their robustness.

Table 4 gives the summary results that can be directly compared with the short-run results in Table 3. The first column shows that without the CPS and just the EUA of £6/tCO_2, the change (Δ) in wind output over the year of 8.11 TWh leads to a fall in CO_2 of 4.17 million tonnes, so the saving per MWh of wind, the LR-MDF (shown as $-\Delta CO_2/\Delta W$) is 0.51 tCO_2/MWh. The SR-MDF is shown immediately below and is lower as the less predictable short-run response relies more on gas, while the long-run predictable change in wind allows more coal to be scheduled to adjust.

With the CPS at its actual value of £18/tCO_2, the CO_2 price is £24/tCO_2, and the LR-MDF is 0.60 tCO_2/MWh, again higher than the SR-MDF and for similar reasons. The fact that the LR-MDF increases with the CPS while the SR-MDF falls is discussed in more detail below, but primarily reflects the very close variable costs of coal and gas (when variable O&M costs are included, making the MDF very sensitive to technical parameters such as ramp rates and minimum stable generation (MSG). A small increase in the MSG of coal considerable lowers the LR-MDF.

As with the SR-MDF, there is a slight fall in the LR-MDF moving to a CO_2 price of £37/tCO_2. The impact of the increased wind capacity decreases base-load coal by 2.77 TWh at zero CPS, with the larger share of adjustment made by mid-merit gas which falls by 5.26 TWh, giving $-\Delta G/\Delta W = 0.65$. At the actual CPS wind now displaces more coal (by 3.95 TWh) and less gas (by 4.07 TWh). As a result, $-\Delta C/\Delta W$ raises and $-\Delta G/\Delta W$ falls ($-\Delta C/\Delta W = 0.49$; $-\Delta G/\Delta W = 0.50$). At the high CO_2 price, less coal runs on average so the change in coal is slightly less than in the central case and gas slightly more, with $-\Delta C/\Delta W = 0.44$ and $-\Delta G/\Delta W = 0.56$. Summarising, the LR-MDF of wind raises from 0.51 (tCO_2/MWh) at zero CPS, to 0.60 with a CPS of £18/tCO_2, then it slightly falls to 0.57 at the highest carbon price as coal is squeezed out of the system.

The last three lines of Table 4 give the estimated average impact of raising the carbon price P_c by £1/tCO_2 on the output of coal, gas and CO_2.[24] The CPS switches the merit order, so that on average a £1/tCO_2 increase in the CPS (from zero CPS to £18/tCO_2) significantly lowers coal generation by 4.62 TWh/year, displaced by gas. Since gas plants emit less CO_2, the CPS saves 2.47 million tCO_2/year. Increasing the total CO_2 price further to £37/tCO_2 has a much

[24] Calculated by differencing the outputs at £6/tCO_2 and £24/tCO_2 and dividing by the £18/tCO_2 (=24-6) to give the first set of values (in the £24/tCO_2 column) and similarly differencing the outputs at £37/tCO_2 and £24/tCO_2 to give the final column.

Table 4: Displacement Factors for the Three Carbon Price Scenarios, 2015 Generation Mix

	Carbon Costs					
	£6/tCO_2		£24/tCO_2		£37/tCO_2	
	Cost Differentials					
	£-6.98/MWh		£2.7/MWh		£9.7/MWh	
	TWh	ΔCO_2	TWh	ΔCO_2	TWh	ΔCO_2
ΔC	-2.77	-2.41	-3.95	-3.44	-3.55	-3.09
ΔG	-5.26	-1.76	-4.07	-1.39	-4.50	-1.54
ΔW	8.11	-4.17	8.11	-4.83	8.11	-4.64
$-\Delta C/\Delta W$	0.34		0.49		0.44	
$-\Delta G/\Delta W$	0.65		0.50		0.56	
LR-MDF	0.51		0.60		0.57	
(SR-MDF)	(0.44)		(0.41)		(0.36)	
$\Delta C/\Delta P_c$ TWh/£			-4.62		-0.24	
$\Delta G/\Delta P_c$ TWh/£			4.62		0.25	
$\Delta CO_2/\Delta P_c$ Mt/£				-2.47		-0.12

Notes: $-\Delta C/\Delta W$ is the coal Displacement Factor (DF, the decrease in Coal output for 1 MWh of Wind), $-\Delta G/\Delta W$ is the gas DF and SR-MDF = $-\Delta CO_2/\Delta W$ is the displacement of CO_2 in tCO_2/MWh of extra wind. $\Delta X/\Delta P_c$ is the change in output of X (coal, gas or CO_2) for a £1 increase in the CO_2 price going from £6-24/tCO_2 or from £24-37/tCO_2, measured at the base level of wind.

moderate impact on the fuel mix and emissions — a £1/tCO_2 increase in the CO_2 price results in 0.24 TWh decline in coal generation (displaced by gas) and 0.12 million tCO_2 reduction. This is because increasing the carbon cost from £24/tCO_2 to £37/tCO_2 does not change the merit order.

We also calculate the capacity factor (CF)[25] as well as the coefficient of variation (CV) for the reference wind cases, summarised in Table 5. In the zero CPS case coal has a CF of 83% and a coefficient of variation (CV) of output of 25%, while gas has a CF of 22% (CV 91%), consistent with coal on base load and gas providing mid-merit variable output. As gas is displaced by the extra wind, its carbon benefit is low.

The situation changes considerably with the CPS at £18/tCO_2. Coal output is lower and more variable (CF falls to 18% and CV rises to 118%), while gas CF rises to 70% (CV 29%),

[25]This is given by the average output relative to the maximum observed output, which is below the nominal capacity. This seems a more relevant measure for CCGTs, where there is a large tail of less efficient plant that would otherwise give a very low CF for gas as a whole.

Table 5: Capacity Factors (CF) and Coefficients of Variation (CV), 2015 Base Wind

	Carbon Costs					
	£6/tCO_2		£24/tCO_2		£37/tCO_2	
	CF	CV	CF	CV	CF	CV
Coal	83%	25%	18%	118%	16%	129%
CCGT	22%	91%	70%	29%	72%	29%

consistent with gas on base load with coal displaced by the extra wind, raising its carbon benefit. This case is very similar to the high carbon cost (£37/tCO_2) case, because both cases share the same merit order.

PS is endogenous in the simulations and will be driven by peak and off-peak variable cost differences, which will vary between different wind capacity scenarios. However, it is important to remember that actual PS is partly driven by arbitrage, which is driven by wholesale price differences that likely differ from variable cost differences. The main revenue earner for pumped storage is providing balancing and ancillary services, which are not modelled. To test for robustness, we re-run all simulations with half the effective PS capacity, and reassuringly, the results were close.

As PS has a round trip efficiency of about 75%, if more storage is required, then losses will lead to more MWh of fossil generation, so the sum of the output changes of coal, gas and wind will not necessarily sum to zero. However, variations in pumped storage do not lead to changes in emissions, as we assume that all pumped storage will be used over the course of the day, when prices are higher than off-peak, either in arbitrage or balancing mode, regardless of the actual wind output.

As an additional test for the robustness of the wind scenarios, the model was re-run with 10% and 5% more wind capacity, and these confirm that the DFs are within 0.01 of those at 25% extra capacity.

6.1 The variation of LR-MDFs with Residual Demand

Figure 11 graphs a rolling average of the various displacement factors against residual demand.[26] The graph shows the displacement of coal output ($-\Delta C/\Delta W$), gas output ($-\Delta G/\Delta W$), pumped storage output ($-\Delta PS/\Delta W$), and the implied carbon saving, the LR-MDF ($-\Delta CO_2/\Delta W$,

[26]The graphs are constructed by first ranking the simulated hourly generation by residual demand, averaging the MW of coal, gas, pumped storage and wind over 672 ranked non-consecutive hours, and then calculating the ratios of interest based on the averaged outputs. This smooths out unimportant fluctuations caused mainly by pumped storage which differs for the same hours but with different levels of wind capacity. Residual demand is averaged over the same number of hours (672).

tCO_2/MWh) as a function of residual demand (taken as the sum of coal, gas and pumped storage) for the 2015 power system, the actual 2015 CPS, and reference wind case. It also shows the deviation of the average wind over these hours compared to the annual average. We expect a low residual demand to represent off-peak and high RD to represent peak hours.

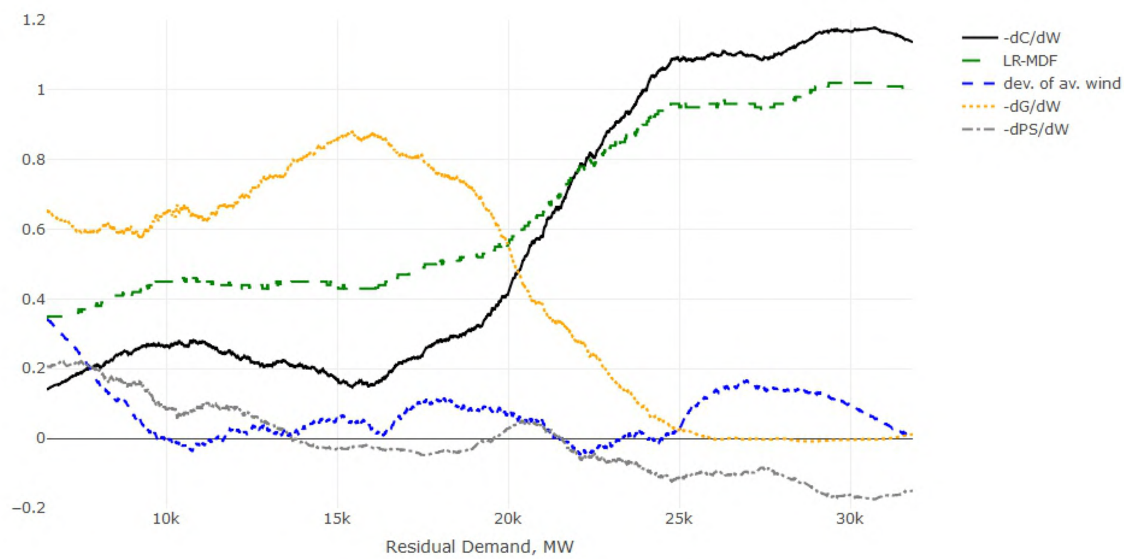


Figure 11: Displacement Factors v.s. Residual Demand, £24/tCO_2

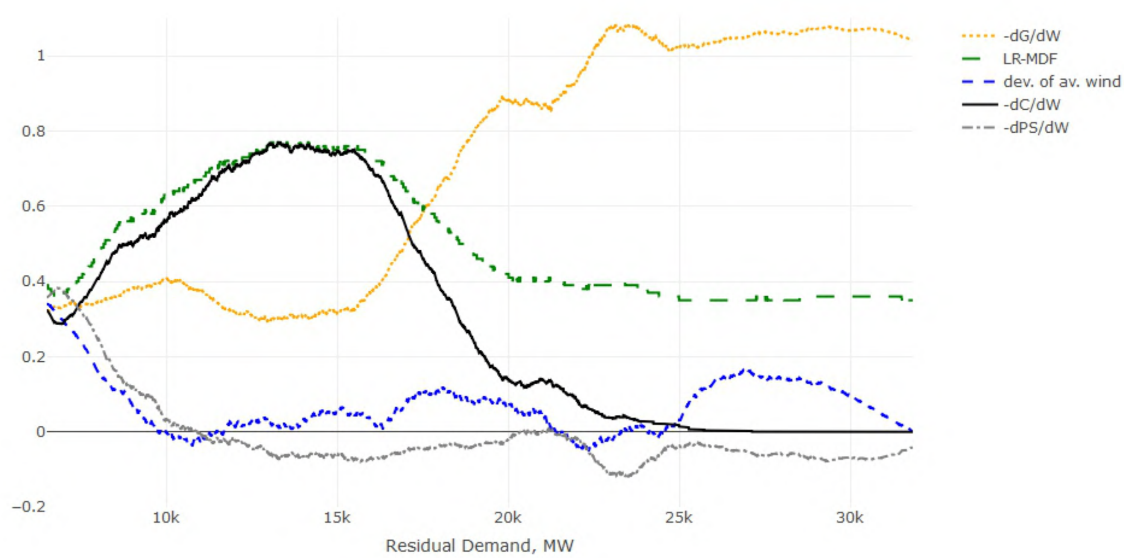


Figure 12: Displacement Factors v.s. Residual Demand, £6/tCO_2

When the total CO_2 price is £24/tCO_2, coal is mid-merit and gas is base load. When residual demand is low, wind displaces mostly gas as coal is running at minimum stable levels, but at higher residual demand when prices are high enough to make coal profitable, coal can respond flexibly ($-\Delta C/\Delta W$ rises to above unity) while gas is base load and hardly varying ($-\Delta G/\Delta W$ approaches zero). Coal (and CO_2) displacements move in counterpoint with gas, as $-\Delta C/\Delta W - \Delta G/\Delta W - \Delta PS/\Delta W = 1$, and averaged over many hours $\Delta PS/\Delta W$ is small, as the graph show. Thus the LR-MDF for wind is smaller at low levels of residual demand (RD), and higher at high RD. As a result the LR-MDF is larger than for the zero CPS case discussed below.

Figure 12 repeats this for the case with no CPS (just the EUA £6/tCO_2). This time coal does not respond at all at high residual demand when it is at base load, but does respond more strongly than gas at low RD, so the LR-MDF is high at low RD (off-peak) and lower for higher RD (peak periods) leading to a lower average LR-MDF.

Finally, at the very high carbon prices seen towards the end of 2018 (£37/tCO_2), the patterns are extremely similar to the actual 2015 CPS case in Figure 11, and are plotted in Appendix Table A.1.

7 Comparing the LR and SR carbon savings

The LR-MDF measures the impact of more wind capacity on the merit order under different carbon prices. More wind turbines lower the residual demand, edging out the most expensive fuel plants. When the variable cost for coal plant is higher than gas, a large increase in wind capacity would likely force the closure of some coal stations, until the wholesale price rises enough to make the remaining stations sufficiently profitable. As plant exit is not included, the LR model may over-estimate the maximum output that coal can supply, which may affect the LR-MDF at higher carbon prices, possibly reducing them as coal becomes a smaller share of the plant capacity. When the coal plants are entirely phased-out, building more wind turbines is likely to displace less efficient CCGTs.

In the short-run (the period in which plants are committed to deliver in future hours) the carbon savings will be affected by the types of plant that respond to the volatile hour-to-hour wind changes (some are predictable day-ahead and intraday while some are not). Which plant can increase or decrease output sufficiently rapidly will depend on its flexibility and the cost of ramping up and down, and this may not be the plant where the residual demand meets the static merit order. When coal plants are entirely phased out, CCGTs are likely to be the only fossil plant that responds to wind changes, while electricity storage and cross-border trading may play more important roles on avoiding excess wind curtailment and providing more reliable balancing and ancillary services.

Tables 3 and 4 give the SR and LR impacts of wind. The difference between LR- and SR-

MDFs is mainly the difference between *volatility* (and equal chance of an increase and decrease in wind output) and *certainty* of an increase in wind from installing more wind capacity. In the long-run, wind supply is driven by wind capacity, and building more wind turbines would certainly increase wind output, phasing out the more expensive fossil plants. In the short-run, wind output solely depends on wind speed. Forecast errors and varying (residual) demand require more flexible plant rather than the cheaper scheduled plant to respond to the wind changes.

The LR-MDF rises (from 0.51 to 0.60 or by 18% for 2015 data) as the total carbon price rises from £6/tCO_2 to £24/tCO_2. This is because the CPS moves coal from base-load to mid-merit where raising wind capacity is expected to displace coal rather than gas. In the deterministic model, coal can be scheduled to vary in response to future predicted wind variations and so plays a larger role than in the short-run econometric estimates, leading to a higher (and in this case an increase in the) MDF.

The econometric analysis shows that flexible CCGTs always respond to wind changes during peak periods; while for off-peak periods, the cheaper fuel responds to wind changes (the more costly fuel is likely at minimum load). We infer that either coal is profitable in peak hours, in which case it runs at maximum output (able to respond only to increases in wind) or unprofitable, in which case it is running at minimum load, only able to respond to falls in wind. In 2015 the variable costs of coal and gas are fairly close, so both are possible configurations. The CPS made coal more expensive than gas, shifting the marginal fuel for off-peak periods from coal to gas. As a result, the SR-MDF without CPS is higher than the SR-MDF with the CPS. Precisely, the CPS in 2015 lowered the SR-MDF from 0.44 to 0.41 (all tCO_2/MWh) or by 7%.

The relevant policy issue is whether increasing wind capacity reduces emissions, and the answer will be primarily driven by the LR-MDF. However, it is also worth noticing that the actual operation of the electricity system in real time requires flexible responses coming from possibly different plant than the apparently marginal plant suggested by the static merit order. If the increase in wind penetration has on average raised wind generation by 1 GW, then the amount of CO_2 displaced by the 1 GW of wind will depend on the LR-MDF. If the increase in wind penetration makes wind more volatile and increases the (half-hourly) changes of wind supply by an average of 0.1 GW, then the SR-MDF will explain the impact of that 0.1 GW of wind changes on CO_2 emissiona. When CCGTs becomes the only type of fossil plants in the market following the phase-out of coal plants, the LR- and SR-MDF converge as only gas is left to respond to long-run and short-run changes in wind supply.

8 Estimating the impact of the CPF on wholesale prices

The marginal emission factor (MEF), a in (1), gives the marginal emissions from changes in demand, so if the carbon price P_c changes, so will the cost of emissions from marginal plants, C_{C}:

$$\Delta C_{\mathrm{C}} = \mathrm{MEF} \cdot \Delta P_c \approx [e_C k(\tilde{P}_t) + e_G l(\tilde{P}_t)] \cdot \Delta P_c \tag{3}$$

from nonlinear regressions (iii) and (iv).

The wholesale price is not necessarily equal to the variable cost of the marginal plant setting the price (not least because in a single price auction like EUPHEMIA plant needs to cover its start-up costs and may add a margin to cover fixed costs). Nevertheless, small changes in the variable cost of the marginal plant, ΔC_c, should translate into corresponding changes in the clearing price in the EU day-ahead auction platform EUPHEMIA that sets the price for interconnector trade.[27] With that in mind, Figure 13 shows the evolution over time in current £/MWh of the marginal cost of the CPS, ΔC_{CPS}, and hence allows us to predict the change in the prices that drive interconnector trade.

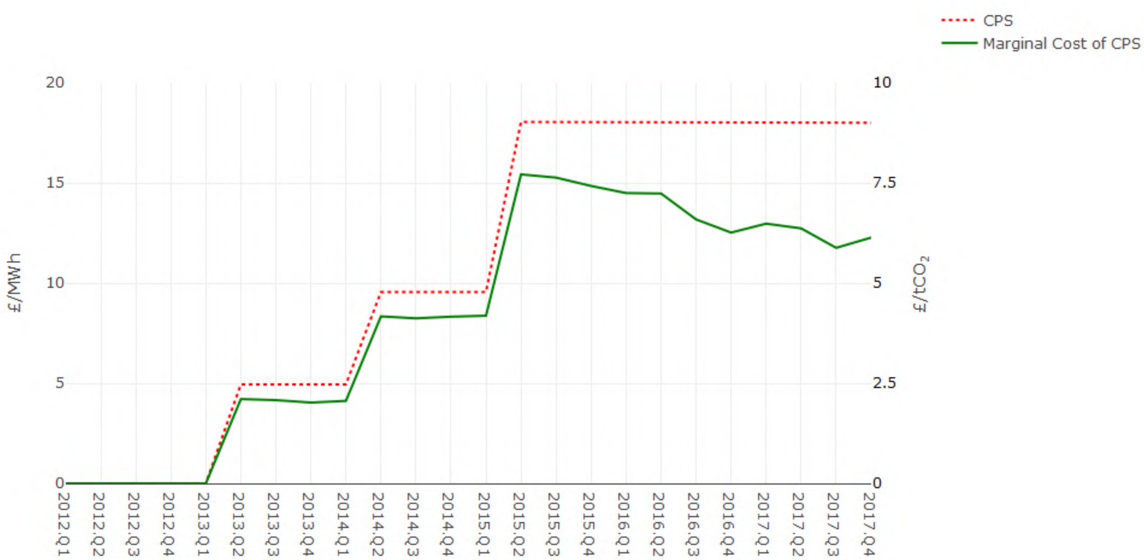


Figure 13: Marginal Cost of CPS on the Cost of Emission

As an example, we can ask what is the possible impact on trade with France over IFA in 2016 with and without the CPS. This is complicated by the fact that recorded trade is mainly determined by the day-ahead market, but can be subsequently changed by trades on the intraday and balancing markets, while our model only predicts price change from the day-ahead clearing

[27] This assumes 100% cost pass-through, which is often rejected in oligopolistic markets, but the GB electricity market is considered workably competitive, and so this is a defensible assumption.

price. The second complication is that the volume of the IFA flow can have further impacts on the spot market prices (SMPs) on both sides. Without the CPS the GB SMP will be lower. If from the (normal) position of importing the sign of the price difference between GB and France ($P_t^\Delta \equiv P_t^{\mathrm{GB}} - P_t^{\mathrm{FR}}$) changes, and with it the direction of the IFA flow, GB demand will increase. That will partly offset the fall in GB prices. Reduced imports or increased exports will drive the prices back towards equality, until the export capacity is fully used and GB prices are below French prices. (French prices will also fall somewhat as they reduce exports, but as France is connected to a much larger European market this effect will normally be considerable smaller.) The price change induced by each GW of extra exports (reduced imports) can be estimated from the price duration schedule. Newbery et al. (2016) using earlier data found this to be roughly €1/MWh/GW over the middle section of the schedule. Using just 2016 GB price data and ignoring scarcity prices above €100/MWh a linear estimate is closer to €1.25/MWh/GW, or €5/MWh for a complete change of direction of 4GW. If the French price impact is smaller (somewhat arbitrarily taken as €0.75/MWh/GW) then the total impact would be €2/MWh/GW.

To estimate the impact of removing the CPS, we first compute the notional price difference (P_t^Δ) assuming no trade over IFA, so that when GB would have imported P_t^Δ will now be higher (by up to €4/MWh depending on volumes[28]) and when GB would have exported P_t^Δ will now be lower. This gives the price difference (P_t^Δ) without the IFA shown as the dotted duration schedule curve in Figure 14. This schedule is adjusted down by the marginal cost of the CPS to the dashed schedule again assuming no trade. Finally, IFA trade is opened with the corresponding further price adjustment to give the predicted counterfactual price differences with IFA but no CPS. Notice there is now a flat section of price equality at $P_t^\Delta = 0$.

The results are a significant change in 2016 net imports over IFA from 10.9 TWh with the CPS to 5.6 TWh without the CPS, so that 5.3 TWh of net imports are because of the GB CPS. In 2016, GB is importing at the full available IFA capacity (nominally 2,000MW but can be lower due to maintenance) 72% of the time, and exporting the full capacity 10% of the time; while without the CPS, it is estimated that the number would be reduced to 55% for import, and 28% for export but at a lower price. As France owns half of IFA, the CPS profited their share of IFA by roughly €38 million in 2016 (while UK consumers paid more, National Grid profited from its share of IFA, and the Government received extra CPS revenue).[29] These estimates are somewhat rough and ready, but give a reasonable estimate of the impact of the CPS on one interconnector. For a fuller study see Guo et al. (2019).

[28] using the actual capacity from Nord Pool given at https://www.nordpoolspot.com/Market-data1/GB/Capacities/UK/Hourly/?view=table.

[29] This is estimated from half the difference in trade revenue with and without the CPS.

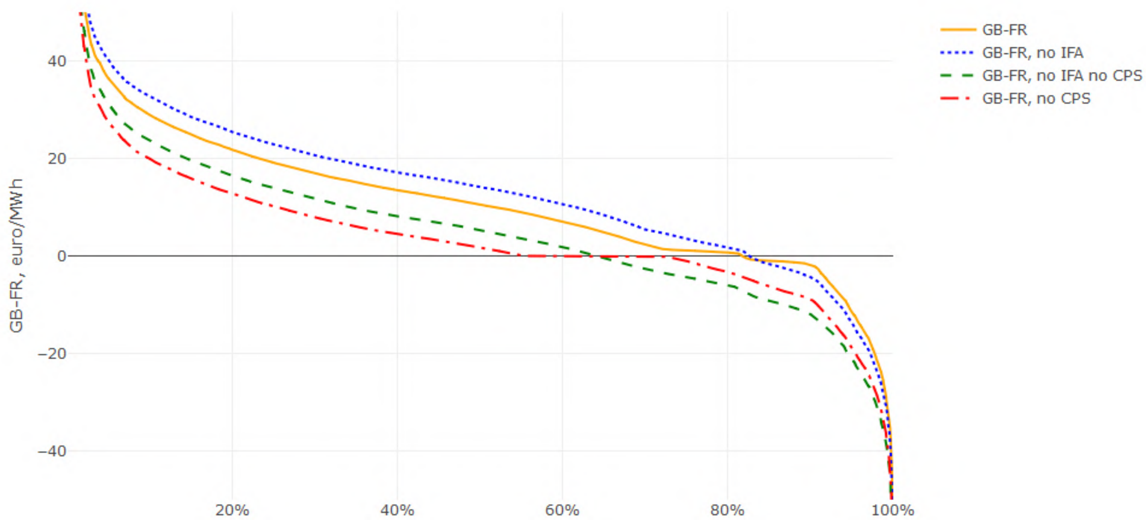


Figure 14: Actual and Counterfactual Loss-adjusted Price Differences

9 Conclusion

This paper has investigated the effect of the Carbon Price Support (CPS) on the carbon saving from wind by examining the impact of wind on the more carbon-intensive coal and less carbon-intensive CCGT outputs. The evolution of the fuel mix from 2010-17 strongly suggests that gas has displaced coal, and that wind has displaced both, but as the clean spark and dark spreads have varied substantially over this period with varying fuel and carbon prices, a more detailed examination was undertaken to tease out the various effects. The unit commitment simulation model explores the effect of different total carbon prices on the carbon savings from a significant increase (25%) in installed wind capacity, holding fuel prices constant. At 2015 gas and coal prices, the CPS at an additional £18/tCO_2 on an EUA price of £6/tCO_2 switches coal from base-load to mid-merit, so now coal rather than gas is displaced by extra wind capacity, *increasing* the carbon benefits of wind investment modestly. At higher total carbon prices, coal output decreases and moves more to peak hours, resulting in a smaller carbon savings from wind investment. This increase is, however, sensitive to technical parameters that are hard to identify in ageing coal plant, and could easily be reversed to a fall in the LR-MDF with the CPS.

The short-run impact of half-hourly varying wind on the fuel mix and emissions was explored econometrically. Variations in fuel and carbon prices as well as wind capacity and final demand over a longer time period (2012-2017) identify the drivers of the Marginal Displacement Factor (MDF) of wind quite precisely. The econometric study suggests that the short-run MDF depends on demand (i.e. which fuel type is running at the margin), the merit order, and the flexibility of fossil plants. Specifically, when demand is low (off-peak), base-load plant responds more strongly to short-run wind changes. However, when demand is high and so is its variability, more flexible CCGTs are better able to respond. Hence CCGTs are the marginal fuel during peak hours (07:00-23:00) regardless of the merit order, while coal would only be the marginal fuel during off-peak hours (23:00-07:00) when coal provides the base load. The CPS switches the merit order moving coal to mid-merit fuel, but the more flexible CCGTs become the marginal fuel for the entire day, *lowering* the MDF slightly.

We argue that following an increase in wind capacity, the LR-MDF explains the impact of increasing wind penetration on CO_2 emission, while the SR-MDF explains the impact of increasing wind volatility (i.e. half-hourly wind changes) on CO_2 emission.

Both the simulation and the econometrics confirm that the impact of wind depends quite sensitively on the state of the system — which plant are running and whether they are constrained by minimum loads, capacity, or ramping limits, which in turn depend on the time period over which wind varies. The fuel mix depends on fuel and carbon prices and the levels of residual demand. Different countries have very different plant mixes, and so the carbon benefits of additional renewables capacity will also vary, while over time, fuel and carbon prices as well as the plant mix will also vary. This paper shows how the emissions benefits can be measured for a given plant mix and set of fuel and carbon prices, implying that country level detailed modelling will be needed to understand their impacts.

The same econometric model can be used to estimate the price change caused by adding the CPS and that in turn can be used to estimate the impact on flows over interconnectors. In 2016 we estimate that the impact of the CPS was to transfer an extra €38 million to RTE, the owner of half of the France-England interconnector, IFA.

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A Appendices

A.1 The linear SR-MDF econometric model

Table A.1: Estimation results from linear regressions (i) and (ii)

(a) Off-peak period (23:00-07:00)

	ΔC_t		ΔG_t	
	COAL-BASE	GAS-BASE	COAL-BASE	GAS-BASE
(Intercept)	-5.19	-11.11^{*}	18.01^{*}	17.23^{*}
	(8.87)	(5.51)	(8.38)	(8.24)
ΔW_t	-0.52^{***}	-0.15^{***}	-0.41^{***}	-0.75^{***}
	(0.02)	(0.01)	(0.02)	(0.01)
ΔD_t	0.42^{***}	0.20^{***}	0.55^{***}	0.74^{***}
	(0.00)	(0.00)	(0.00)	(0.00)
Time Dummies	YES	YES	YES	YES
R^2	0.66	0.51	0.79	0.87
Obs.	17441	17062	17441	17062

(b) Peak period (07:00-23:00)

	ΔC_t		ΔG_t	
	COAL-BASE	GAS-BASE	COAL-BASE	GAS-BASE
(Intercept)	251.22^{***}	-130.50^{***}	-115.21^{***}	180.63^{***}
	(9.83)	(8.28)	(12.53)	(11.68)
ΔW_t	-0.15^{***}	-0.15^{***}	-0.66^{***}	-0.65^{***}
	(0.01)	(0.01)	(0.01)	(0.01)
ΔD_t	0.14^{***}	0.21^{***}	0.64^{***}	0.61^{***}
	(0.00)	(0.00)	(0.00)	(0.00)
Time Dummies	YES	YES	YES	YES
R^2	0.49	0.50	0.85	0.84
Obs.	34830	34072	34830	34072

$^{***}p < 0.001$, $^{**}p < 0.01$, $^{*}p < 0.05$

The table shows that all estimates for the coefficients of ΔW_t and ΔD_t are statistically significant at the 0.1% level, and their signs follow our initial intuition. Specifically, during off-peak periods it is normally the base-load plant that responds to changes in wind supply and/or electricity demand. Table A.1a shows that when coal is the base load, coal responds more strongly

Table A.2: Estimate asymmetric partial effects, Off-peak (23:00-07:00)

	ΔC_t		ΔG_t	
	COAL-BASE	GAS-BASE	COAL-BASE	GAS-BASE
		When wind rises, $\Delta W_t > 0$		
ΔW_t	-0.57^{***}	-0.16^{***}	-0.39^{***}	-0.76^{***}
	(0.04)	(0.02)	(0.04)	(0.03)
ΔD_t	0.42^{***}	0.19^{***}	0.56^{***}	0.75^{***}
	(0.01)	(0.00)	(0.01)	(0.01)
		When wind falls, $\Delta W_t \leq 0$		
ΔW_t	-0.46^{***}	-0.17^{***}	-0.49^{***}	-0.73^{***}
	(0.04)	(0.02)	(0.04)	(0.03)
ΔD_t	0.42^{***}	0.21^{***}	0.53^{***}	0.73^{***}
	(0.01)	(0.00)	(0.01)	(0.01)
		When fossil generation increases $\Delta C_t + \Delta G_t > 0$		
ΔW_t	-0.41^{***}	-0.16^{***}	-0.35^{***}	-0.55^{***}
	(0.04)	(0.02)	(0.03)	(0.02)
ΔD_t	0.33^{***}	0.21^{***}	0.61^{***}	0.69^{***}
	(0.01)	(0.00)	(0.01)	(0.01)
		When fossil generation increases $\Delta C_t + \Delta G_t \leq 0$		
ΔW_t	-0.43^{***}	-0.12^{***}	-0.49^{***}	-0.75^{***}
	(0.02)	(0.01)	(0.02)	(0.02)
ΔD_t	0.40^{***}	0.17^{***}	0.48^{***}	0.69^{***}
	(0.01)	(0.01)	(0.01)	(0.01)
		Weekdays		
ΔW_t	-0.54^{***}	-0.17^{***}	-0.43^{***}	-0.90^{***}
	(0.03)	(0.01)	(0.02)	(0.02)
ΔD_t	0.44^{***}	0.20^{***}	0.40^{***}	0.62^{***}
	(0.01)	(0.00)	(0.01)	(0.01)
		Weekends		
ΔW_t	-0.51^{***}	-0.13^{***}	-0.52^{***}	-0.77^{***}
	(0.03)	(0.02)	(0.03)	(0.02)
ΔD_t	0.48^{***}	0.17^{***}	0.40^{***}	0.72^{***}
	(0.01)	(0.01)	(0.01)	(0.01)

Table A.3: Estimate asymmetric partial effects, Peak (07:00-23:00)

	ΔC_t		ΔG_t	
	COAL-BASE	GAS-BASE	COAL-BASE	GAS-BASE
	When wind rises, $\Delta W_t > 0$			
ΔW_t	-0.15^{***}	-0.15^{***}	-0.67^{***}	-0.69^{***}
	(0.02)	(0.01)	(0.03)	(0.02)
ΔD_t	0.14^{***}	0.21^{***}	0.63^{***}	0.60^{***}
	(0.00)	(0.00)	(0.00)	(0.00)
	When wind falls, $\Delta W_t \leq 0$			
ΔW_t	-0.12^{***}	-0.14^{***}	-0.64^{***}	-0.61^{***}
	(0.02)	(0.02)	(0.03)	(0.02)
ΔD_t	0.14^{***}	0.21^{***}	0.65^{***}	0.62^{***}
	(0.00)	(0.00)	(0.00)	(0.00)
	When fossil generation increases $\Delta C_t + \Delta G_t > 0$			
ΔW_t	-0.12^{***}	-0.12^{***}	-0.55^{***}	-0.55^{***}
	(0.02)	(0.01)	(0.02)	(0.01)
ΔD_t	0.15^{***}	0.16^{***}	0.54^{***}	0.54^{***}
	(0.00)	(0.00)	(0.00)	(0.00)
	When fossil generation increases $\Delta C_t + \Delta G_t \leq 0$			
ΔW_t	-0.14^{***}	-0.15^{***}	-0.58^{***}	-0.56^{***}
	(0.02)	(0.01)	(0.02)	(0.01)
ΔD_t	0.10^{***}	0.25^{***}	0.69^{***}	0.56^{***}
	(0.00)	(0.00)	(0.01)	(0.00)
	Weekdays			
ΔW_t	-0.01	-0.19^{***}	-0.81^{***}	-0.68^{***}
	(0.01)	(0.01)	(0.02)	(0.01)
ΔD_t	0.29^{***}	0.21^{***}	0.48^{***}	0.55^{***}
	(0.00)	(0.00)	(0.00)	(0.00)
	Weekends			
ΔW_t	-0.09^{***}	-0.15^{***}	-0.73^{***}	-0.70^{***}
	(0.02)	(0.01)	(0.02)	(0.02)
ΔD_t	0.21^{***}	0.19^{***}	0.54^{***}	0.57^{***}
	(0.00)	(0.00)	(0.00)	(0.00)

Table A.4: Estimation results from non-linear regressions (iii) and (iv)

	Off-peak (23:00-07:00)		Peak (07:00-23:00)	
	ΔC_t	ΔD_t	ΔC_t	ΔD_t
(Intercept)	-2.57	11.27	59.08^{***}	38.57^{***}
	(5.22)	(5.76)	(6.48)	(8.72)
ΔW_t	-0.34^{***}	-0.54^{***}	-0.22^{***}	-0.59^{***}
	(0.02)	(0.03)	(0.01)	(0.02)
ΔD_t	0.35^{***}	0.58^{***}	0.23^{***}	0.60^{***}
	(0.00)	(0.00)	(0.00)	(0.00)
$\Delta W_t \times PD_t$	$2.39 \times 10^{-2***}$	$-2.13 \times 10^{-2***}$	0.05×10^{-2}	-0.09×10^{-2}
	(0.27×10^{-2})	(0.29×10^{-2})	(0.16×10^{-2})	(0.21×10^{-2})
$\Delta W_t \times PD_t^2$	3.26×10^{-4}	$-10.47 \times 10^{-4*}$	$8.30 \times 10^{-4***}$	$6.47 \times 10^{-4*}$
	(4.12×10^{-4})	(4.55×10^{-4})	(2.41×10^{-4})	(3.24×10^{-4})
$\Delta W_t \times PD_t^3$	$-2.91 \times 10^{-5*}$	$3.04 \times 10^{-5*}$	-0.36×10^{-5}	0.74×10^{-5}
	(1.37×10^{-5})	(1.51×10^{-5})	(0.79×10^{-5})	(1.07×10^{-5})
$\Delta W_t \times PD_t^4$	-0.82×10^{-6}	$3.62 \times 10^{-6*}$	-1.15×10^{-6}	0.48×10^{-6}
	(1.48×10^{-6})	(1.63×10^{-6})	(0.86×10^{-6})	(1.15×10^{-6})
$\Delta D_t \times PD_t$	$-1.86 \times 10^{-2***}$	$1.38 \times 10^{-2***}$	$0.16 \times 10^{-2***}$	$0.10 \times 10^{-2***}$
	(0.03×10^{-2})	(0.04×10^{-2})	(0.02×10^{-2})	(0.03×10^{-2})
$\Delta D_t \times PD_t^2$	$-6.65 \times 10^{-4***}$	$9.84 \times 10^{-4***}$	$-4.80 \times 10^{-4***}$	$1.81 \times 10^{-4***}$
	(0.50×10^{-4})	(0.55×10^{-4})	(0.30×10^{-4})	(0.40×10^{-4})
$\Delta D_t \times PD_t^3$	$3.71 \times 10^{-5***}$	$-2.50 \times 10^{-5***}$	$-1.30 \times 10^{-5***}$	-0.21×10^{-5}
	(0.19×10^{-5})	(0.21×10^{-5})	(0.11×10^{-5})	(0.15×10^{-5})
$\Delta D_t \times PD_t^4$	$0.90 \times 10^{-6***}$	$-1.68 \times 10^{-6***}$	-0.03×10^{-6}	$0.30 \times 10^{-6*}$
	(0.18×10^{-6})	(0.20×10^{-6})	(0.11×10^{-6})	(0.14×10^{-6})
R^2	0.64	0.84	0.48	0.84
Num. obs.	34503	34503	68902	68902

$^{***}p < 0.001$, $^{**}p < 0.01$, $^{*}p < 0.05$

to wind and demand changes — if ΔW_t increases by 1 MW, ΔC_t would on average drop by 0.52 MW while ΔG_t would on average only drop by 0.41 MW. This changes when PD_t becomes positive — a 1 MW increase in ΔW_t will only reduce ΔC_t by 0.15 MW, much less than the 0.75 MW reduction in ΔG_t. The story is similar for the impact of ΔD_t on ΔC_t and ΔG_t when coal supplies the base load, where a 1 MW increase in ΔD_t would increase ΔC_t by 0.42 MW and ΔG_t by 0.55 MW. However, when gas supplies the base load, a 1 MW increase in ΔD_t would only increase ΔC_t by 0.20 MW while increasing ΔG_t by 0.74 MW.

From Table A.1b, the magnitude of changes in the coefficients of ΔW_t for peak periods for coal is negligible. Gas has always been dominant in responding to wind changes during peak periods — a 1 MW increase in ΔW_t is on average accompanied by 0.66 MW fall in ΔG_t when coal is the base load, and by 0.65 MW otherwise. This might be because demand is both high and more variable during peak periods; therefore flexible gas plants are better able to adjust to wind variations. In off-peak periods when coal provides the base load, CCGTs are likely to run at their minimum stable output and hence have limited ability to respond to an increase in wind supply.[30]

In addition, we also use the linear regressions to study the asymmetric partial effects when wind rises *v.s* falls, when the demand on fossil generation increases *v.s* declines, and weekdays *v.s* weekends. To do this, we run the regressions conditional on the sign of ΔW_t and $\Delta C_t + \Delta G_t$, and on the day of week. The results are shown in Figure A.2 and A.3. We find the results robust to these factors.

The non-linear regression results are shown in Table A.4.

A.2 Replicating Thomson et al. (2017)

We use the five-minute average generation by fuel data from the Elexon Portal[31] for the year 2009-2016. The replication process can be summarized as follows:

1. Use the same fuel intensity values for coal (0.39988kg CO_2/kWh$_{th}$) and gas (0.22674kg CO_2/kWh$_{th}$)[32] as Thomson et al. (2017), and the average thermal efficiency of 36% and 55% respectively for coal and gas plants, to calculate the emission factors for coal (1.111kg CO_2/kWh) and gas (0.412kg CO_2/kWh).[33]

2. We use the same emission factors for other generation types as Thomson et al. (2017), and extend their Table 2 to 2016. However, although the emission factors for overseas electricity can be found at the IEA website,[34] it is expensive, hence we use the overseas emission factors for 2014 to proxy the overseas emission factors for 2015 and 2016.

3. Now that we have the emission factors for all fuel types, we can calculate CO_2 emissions for each five-minute interval. As in Thomson et al. (2017), we set negative imports to zero. However, for reasons given above, we ignore pumped storage.

[30] In spite of the negligible change in the coefficients of ΔW_t, the direction of changes in the coefficients of ΔD_t still suggests that as coal becomes more expensive (from COAL-BASE to GAS-BASE), coal shifts to mid-merit. Specifically, during peak periods, a 1 MW change in energy demand is on average accompanied by 0.14 MW change in coal generation when coal is the base load but by 0.21 MW otherwise.

[31] See https://www.elexonportal.co.uk/article/view/216?cachebust=72iua05a54.

[32] NCV *plus* well-to-tank NCV.

[33] Thomson et al. (2017) argue that the thermal efficiency of a generating unit should be varying with the relative load (i.e. actual load relative to its full capacity), while we are unable to obtain the data for generating units, hence we used the average efficiency.

[34] http://data.iea.org//payment/products/115-co2-emissions-from-fuel-combustion-2018-edition-coming-soon.aspx

4. The five-minute changes in wind output (ΔP_w), total system supply (ΔP_s) and total system emissions (ΔC) are calculated as the difference between successive values.

5. After removing outliers, we run the following regression for each year:

$$\Delta C = k_0 + k_1 \Delta P_s + k_2 \Delta P_w + \boldsymbol{h'X_t} + \varepsilon,$$

where k_1 is the marginal emission factor (MEF) and k_2 is the marginal displacement factor (MDF).

The results are shown in Table A.5 and Figure 9. The numbers following "±" are standard errors multiplied by 1.96.

Table A.5: Comparisons of annual MDFs, tCO_2(eq)/MWh

	MDF (wind)		
Year	Our Estimates	Replicated Results	Thomson et al.
2009		0.650 ± 0.039	0.597 ± 0.065
2010		0.628 ± 0.023	0.611 ± 0.049
2011		0.562 ± 0.022	0.553 ± 0.032
2012	0.436 ± 0.031	0.564 ± 0.018	0.547 ± 0.025
2013	0.426 ± 0.063	0.480 ± 0.012	0.487 ± 0.017
2014	0.430 ± 0.046	0.455 ± 0.010	0.483 ± 0.014
2015	0.413 ± 0.030	0.438 ± 0.009	
2016	0.362 ± 0.031	0.382 ± 0.008	
2017	0.334 ± 0.029		

A.3 Data Appendix

The values for the Carbon Price Support (CPS) are published by the Government (HoC, 2018). The carbon content of natural gas is well-defined at 0.1839 tCO_2/MWh_{th}, and the carbon intensity for coal is 0.310 tCO_2/MWh_{th} from DECC's *Greenhouse gas reporting - Conversion factors*. Table A.6 gives the carbon prices used.

The quarterly prices of fuels into power stations are published by BEIS (previously by DECC) as Table 3.2.1 and give gas and coal prices per kWh_{th}. Both include delivery and other costs from the spot prices (NBP for gas, various for coal but often ARA west Europe prices). The margin from NBP to power station can be estimated from the quarterly averages and that margin added to the day-ahead NBP price to give the opportunity cost of burning gas (which might otherwise be traded spot) but coal is more illiquid once delivered and stocked at the power station. It is less likely to be marked to market each day although the Bloomberg coal futures price will give an indication of restocking costs and hence the current value of coal

Table A.6: CPS rates in fiscal years beginning

	01/04/2013	01/04/2014	01/04/2015	01/04/2016
gas /MWh_{th}	£0.91	£1.75	£3.34	£3.31
coal /MWh_{th}	£1.59	£2.95	£5.65	£5.57
CPS £/tCO2	£4.95	£9.52	£18.16	£18.00

Source: https://www.envantage.co.uk/carbon-management/climate-change-levy-agreement/climate-change-levy-rates.html

(again including the margin to power station).

Generation Costs by Fuels

The gas price is less constant than the coal price as coal is more illiquid and storable, while the fuel prices published by BEIS only varies quarterly. It is fine to use quarterly prices but prices at higher frequency would provide more variation hence less variance on the estimates. Therefore, the daily spot natural gas futures price is downloaded from the InterContinental Exchange (www.theice.com), which is equivalent to the NBP gas price; we then average the daily spot price by years and quarters, and take difference between the BEIS quarterly prices and the quarterly averaged spot prices to calculate the delivery and other costs for each quarter of each year; finally, we top up the daily spot price by the delivery and other costs and obtain the daily gas price, which includes delivery and other costs. The daily coal price is obtained by smoothing the BEIS quarterly coal price to avoid sudden rises and falls at the border of two consecutive quarters.

The average thermal efficiency for coal-fired power plants is fixed at 35.6%, and the *weighted* average thermal efficiency for efficient CCGTs is fixed at 54.5% (ranging from 51.4% to 55.1% for efficient CCGTs). Given this, the carbon emission factor for coal is

$$0.31(\mathrm{tCO_2/MWh}_{th}) \div 0.356 = 0.871(\mathrm{tCO_2/MWh}_e),$$

and for efficient CCGTs is

$$0.1839(\mathrm{tCO_2/MWh}_{th}) \div 0.545 = 0.337(\mathrm{tCO_2/MWh}_e).$$

Then the generation costs for coal and efficient gas are respectively calculated using the formula:

$$\text{Generation Cost} = \text{Fuel Price} \div \text{Thermal Efficiency} + (\text{CPS} + \text{EUA}) \times \text{Emission Factor}.$$

Generation by Fuel Types Data

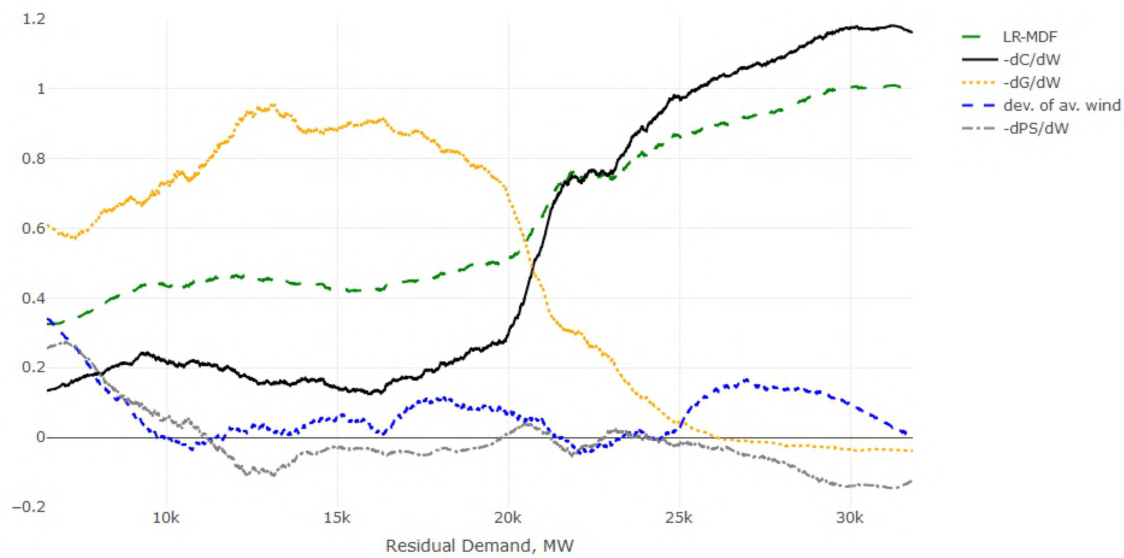

Figure A.1: Displacement Factors v.s. Residual Demand, £37/tCO_2

The data for half-hourly generation by fuel type were downloaded from the Elexon Portal.[35] Although there is no missing data, for each year there are some (half-)hours with misrecorded data. Specifically, whenever the CCGT generation is lower than 1000MW, we treat it as mis-recording and replace it by "NA"; we also remove the data where the half-hourly change in total electricity supply is above 3000MW — this ensures the removal of outliers even though this sacrifices a very small proportion of the "normal" data.

EUA Price Data

The EUA prices are downloaded from investing.com[36] and are converted to GBP using the exchange rate from the same website.[37]

A.4 Figure Appendix

Figure A.1 graphs a rolling average (over 672 non-consecutive hours ranked by residual demand) of the displacement of coal output ($-\Delta C/\Delta W$), gas output ($-\Delta G/\Delta W$), pumped storage output ($-\Delta PS/\Delta W$), and the implied carbon saving, the LR-MDF ($-\Delta CO_2/\Delta W$, tCO_2/MWh) as a function of residual demand (here the summation of coal, gas and pumped storage) for the 2015 constant fuel prices and the carbon cost seen towards the end of 2018 (£37/tCO_2). It also shows the deviation of the average wind over these hours compared to the annual average.

[35] https://www.elexonportal.co.uk/article/view/7324?cachebust=zvf6ghgjwi
[36] https://www.investing.com/commodities/carbon-emissions
[37] https://www.investing.com/currencies/eur-gbp