The Impact of Auctioning in the EU ETS: Are Utilities Still Profiting?

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REFORMING THE EU ETS: WHAT TO DO ABOUT WINDFALL PROFITS?

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In the run up to the end of the second phase of the European Emission Trading Scheme (EU ETS) in 2012 an intense political discussion was devoted to how CO_2 emission certificates are allocated. Considering that allocations to power generation plants account for ca. 50% of the certificates in the EU ETS, the power sector was prominently scrunitzed (Trotignon & Delbosc 2008). One central issue concerned whether or not the operating allocation method based by large on grandfathering in emitters by assigning them emission allowances free of charge (based on historical emissions) had enabled compliant power companies to generate large carbon rents or so-called windfall profits[1] (Veith et al. 2009; Matthes 2008). Pahle et al. (2011) provides evidence for Germany that the presence of windfall profits led to an increase in emission-intensive coal investments. Further research establishes correlations between movements in carbon prices and end-user prices, highlighting incidences of cost-pass through in the power market. Estimates on pass-through rates have ranged from 50-100% while more recent studies have ascertained rates of up to and beyond 100% (Sijm et al. 2008; Lise et al. 2010; Fell et al. 2015). Keppler and Cruciani (2010) estimate carbon rents in the power sector in Phase 1 of the EU ETS to have totalled more than EUR 19 billion.

In a move to assuage these concerns, for the third phase of the EU ETS (2013-2020) a dramatic shift towards an exclusively auction based system for allowances allocated to the power sector was instituted. Carbon certificates are now required to be purchased by power producers in accordance with the polluter pays principle[2] (Woerdman et al. 2009). The reform aims to negate the windfall profits being earned by producers in the power sector by forcing power producers to assume material costs (out-of pocket costs) for the allocated permits. The measure, however, has prompted fears among utilities and power companies with carbon intensive generation fleets that their business operations are being put at risk by the carbon costs incurred.

Against this backdrop, we address the question as to exactly what kind of welfare impacts increasing carbon prices under an auctioning regime have on electricity producers and how the welfare gains or losses are distributed among the countries part of the EU ETS. Futhermore, we investigate whether the carbon intensity of the generation fleet or the generation structure itself in the respective country has a greater impact on producer surplus.

FRAMING THE DEBATE AROUND WINDFALL PROFITS IN THE EU ETS

While the justification for windfall profits has been scrutinized, economic theory holds that cost pass-through occurs as a result of the opportunity costs that carbon allowances represent (Verbruggen 2008). The basic concept behind the notion of windfall profits is illustrated in figure 1. The opportunity costs represented by carbon allowances (grey column) are factored into the variable production costs of the respective power generator. As is apparent from the stylised diagramm, depending on the carbon intensity of the particular technology in the electricity mix, the carbon markup can vary greatly. Under market efficiency conditions, price equals the marginal costs (of the price-setting technology) and no profit is realized independent from the carbon price. However, carbon rents to lower-emission, infra-marginal technologies accrue due to the difference between the market price and their respective marginal costs (Keppler & Cruciani

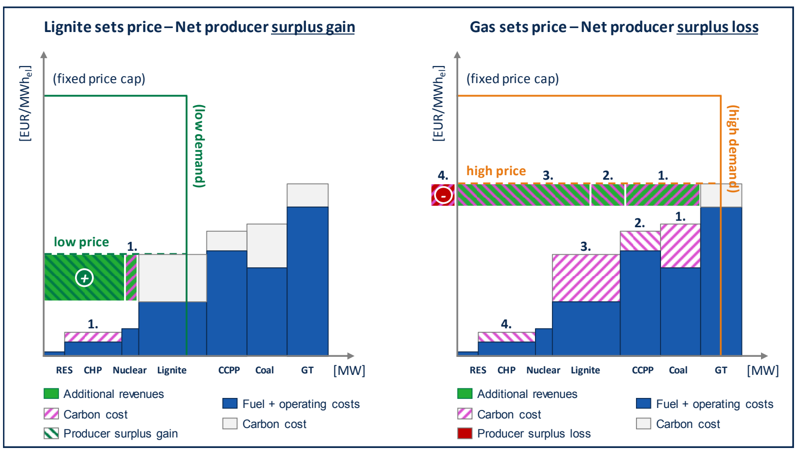

Figure 1: Impact of the price setting technologies on carbon rents

2010). Hence, the carbon price as well as the emission factor of both technologies have a strong impact on the producers´ profits. This is especially true if carbon price increases induce a fuel switch that leads to a more carbon intensive price-setting technology (Pettersson et al. 2012). In addition, the demand structure of the market plays an important role in determining which technology clears the market during the course of the year (see fig. 1).

Utilizing a fundamental model of the European electricity market (ELTRAMOD)[3] and developing two basic scenario sets based on 2014 data, we perform a model-based analysis of the electricity market assuming perfect competition and a cost-pass through rate of 100%. We benchmarked and backtested the model with historical data from 2014. The model can explain power prices very well based on fundamental data with an MAE of approx.. 4 €/MWh. The reference case (REF) is based on the data of 2014, while we analyse the impact of changing two parameters: the carbon price and the gas price. We vary the carbon price by two (2xCO_2) and fivefold (5xCO_2). Furthermore, we define a so-called high gas price scenario (HGas), where we increase the gas price by a factor of two. We also vary the carbon price in the high gas price scenario by a factor of two (HGas_2xCO_2) and five (HGas_5xCO_2) and analyse the impact of changing carbon prices. The model results for the respective carbon scenario are then compared to the corresponding high or low gas price reference case.

DO UTILITIES PROFIT FROM HIGHER CO_2 PRICES DESPITE AUCTIONING

The overall model results follow the intuive assumption of an inverse relationship between the price level of emission allowances and the absolute volume of CO_2 emissions from the power plants in the modelled countries. Futhermore, in all high gas price scenarios (HGas_REF, HGas_2xCO_2, HGas_5xCO_2) the emissions are higher than in the reference case. This is to be expected since a higher gas price undercuts the carbon intensity-specific advantage the fuel enjoys over, e.g., coal-fired generation. As figure 2 shows, the gradient between the first set of scenarios (REF, 2xCO_2, 5xCO_2) and the second set of scenarios with higher gas prices (HGas_2xCO_2, HGas_5xCO_2) is also steeper due to the fact that at a low gas price the incidence of fuel switching is much higher than when the gas price is twice as high.

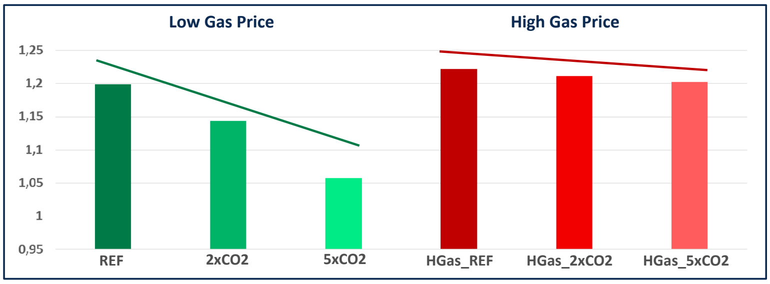

Figure 2: Absolute volume of CO_2 emissions (Bill. Metric Tonnes) in low and high gas price scenarios

Furthermore, as expected the electricity mix in the various countries analysed shows a general shift away from more carbon intensive generation units, e.g. lignite coal, in the higher CO_2 price scenarios towards more low-emission sources, e.g., natural gas. In sum, due to the 100% pass-through rate assumed, higher carbon and gas costs imputed in the respective scenarios generate larger system costs (meaning higher costs to meet the consumer's inelastic demand[4]) which in turn are reflected in net welfare losses.

As to the first question posed, the scenarios with higher CO_2 prices (2xCO_2 and 5xCO_2) show that contrary to the intuitive assumption, relative to the reference case gains in producer surplus do accrue to electric utilities part of the EU ETS. Higher carbon prices induce higher power prices. In the case where CO_2 intensive power plants are dispatched as the market clearing generation technology, the market price is respectively higher, creating a higher carbon rent for infra-marginal technologies in the merit order. For countries such as France with a low carbon fleet (nuclear), the margin between the new market price and the prevaling variable cost structure is greater, yielding a larger carbon rent and in turn a higher producer surplus. A similar trend is also detected for countries with a generation structure dominated by carbon intensive power plants. For example, in Poland where a large coal-fired capacity is installed, the carbon intensive fleet functions as the price-setting technology increasing the relative carbon rents for infra-marginal generators[5].

While this is the case for almost all countries analysed, Italy stands out as the only electricity market where a drop in the relative producer surplus is observed in the reference cases. This result provides interesting insight into our subsequent question, namely, what impact the country´s respective generation structure has on carbon rents. Power capacity in Italy is dominanted by gas-fired plants, which as noted have a much lower emission factor and are thus are less sensitive to carbon price increases. The model results indicate that natural gas maintains its price-setting status throughout the year in the scenarios with the low gas price. This results in a relatively small carbon mark-up on the market price that is not large enough to offset the increase in the variable costs of the carbon intensive infra-marginal technologies. The outcome is a net relative decrease in prodcer surplus.

Increasing the gas price by twofold in the model delivers some interesting insights: In Italy, the increase in the gas price does not affect the technology´s price-setting status. Once again, a relative net drop in producer surplus is observed. In Great Britain, however, diverging from the prior set of scenarios (Ref, 2xCO_2 and 5xCO_2) where a higher carbon price results in a fuel switch where gas is displaced by coal-fired generation as the price-setting technology and induces a relative increase in rents for infra-marginal producers, in the high gas price scenario this does not occur. This results in a situation that is similar to the one in Italy, where gas prevails as the market clearing technology and carbon intensive plants cannot recover their carbon costs resulting in relative drops in producer surplus. This implies that in markets where gas-fired generation capacity is the prevailing technology, the carbon intensity of the fleet is secondary to the structure itself.

SUMMARY

The analysis clearly shows that countries with a carbon intensive generation fleet that function as the price-setting technology in the power market profit from increses in carbon prices. Thus, auctioning off carbon allowances does not have a net negative effect on electricity producers (with CO_2 intensive technologies) per se. Of course, depending on the specific nature of the producer´s generation portfolio, differences in the scale of profits resulting from higher CO_2 prices are to be expected. For instance, utilities with a portfolio dominanted by nuclear power are better equipped to profit as those with more carbon intensive fleets.

However, in the case that the generation structure is dominated by low-emission producers, e.g. gas-fired plants, so that the fuel constitutes the price-setting technology in the merit order, the carbon mark-up earned is not large enough to outweigh the losses incurred by carbon intensive infra-marginal plants. This proved to be the case for Italy in both scenario sets and Great Britain in the high gas price scenario.

It is worth noting that the analysis is conducted with a bottom-up model based on 2014 data and thus does not reflect intertemporal changes in a country´s power supply structure. Nevertheless, the results highlight that contrary to much of the focus being given to the carbon intensity of the respective generation fleet, its underlying structure can have the ultimate bearing on the effect of the EU ETS on power producer´s bottom line. Summarising, it can be concluded that contrary to intuitive notions, nearly all utilities in Europe would profit from higher CO_2 prices in the current market situation and not only utilities with a (nearly) CO_2 free portfolio. Thereby, the shape of the merit order curve and the price setting technologies during the whole year are of crucial importance.

Footnotes

[1] Windfall profit is defined as the additional carbon rent accruing to plant operators under a carbon trading regime. Operating under free allocation, a direct windfall profit is earned by both the price-setting and the infra-marginal technologies in the merit order if opportunity costs are priced into their bidding price. Under an auction-based allocation, an indirect windfall profit accrues ceteris paribus to infra-marginal plants in the merit order whereas the rent for the price-setting technology is negated.

[2] Polluters are responsible for paying for the damage incurred by the natural environment.

[3] ELTRAMOD is a bottom-up electricity market model covering the electricity markets of the EU-27 states, Norway, Switzerland and the Balkan region (excludes Cyprus and Malta). Further model features and results from previous applications can be found in e.g. Gunkel et al. (2012).

[4] The assumption of an inelastic demand curve can be critically discussed, however several paper show a fully inelastic electricity demand in the short-term and still a very inelastic demand also in the long term. See e.g. (Dahl & Erdogan 1994) and (Wietschel et al. 1997)

[5] Due to model-specific restricitions, in Poland a large number of CHP plants function as must-run technologies, whereby operate on a cost-free basis. This, of course, exaggerates the respective windfall profit effect.

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