Eyes on the Price: Which Power Generation Technologies Set the Market Price?

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ABSTRACT

Upon discussion of price setting on electricity wholesale markets, many refer to the so-called merit order model. Conventional belief holds that during most hours of the year, coal- or natural gas-fired power plants set the price on European markets. In this context, this paper analyses price setting on European power markets. We use a fundamental electricity market model of interconnected bidding zones to determine hourly price-setting technologies for 2020. We find a price-setting pattern that is more complex and nuanced than the conventional belief suggests: across all researched countries, coal- and natural gas-fired power plants set the price for only 40 per cent of all hours. On some markets, the price setting is characterised by a high level of interconnectivity—as illustrated by the example of the Netherlands. During some 75 per cent of hours, foreign power plants set the price on the Dutch market.

Keywords: Price Setting, Electricity Markets, Merit Order, Generation Technologies

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1. INTRODUCTION

Wholesale power markets follow the principle of short-run electricity markets where the market clearing price is determined by the intersection of supply and demand at any given hour. In theory, the resulting hourly day-ahead market price is equal to the marginal costs of the last (marginal) unit in the merit order necessary to satisfy the demand. Given that this marginal unit sets the price for all power generation units operating during that particular hour, one can refer to this as "price setting".

It is frequently stated that in many European markets, gas- and/or coal-fired power plants are usually the marginal price-setting units (Finon 2013, 133–34; Geiger 2011; Genoese et al. 2015; Keles et al. 2020; Panos, Densing, and Schmedders 2017; Pietroni 2017). Geiger, for instance, notes with respect to the German power market that "the price setting unit is often either a gas or a coal plant" (Geiger 2011). Also concerning the German market, Genoese and Egenhofer conclude that "it is safe to assume that gas was the price-setting technology in most hours" when analysing the comparably high prices of 2008 (Genoese et al. 2015, 177). Keles et al. note on the Italian market that gas-fired power plants are mostly price setting there with a subsequent influence on the Swiss market (Keles et al. 2020). Researching the British market,

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Roques et. al. state that "gas-fired plants were often the marginal price-setting plants in the British electricity market" (Roques et. al. 2008). But is it safe to assume this? Is it still valid at present? And on what basis is this conventional wisdom accepted?

There are well founded reasons for this general idea. First, one can point towards the nature of European power plant portfolios with significant coal- and gas-fired generation capacities and their marginal pricing. Second, it should be noted that causal relationships between coal and/or gas prices and wholesale power prices have indeed been observed and documented (Emery and Liu 2002; Ferkingstad, Løland, and Wilhelmsen 2011; Mohammadi 2009; Moutinho, Vieira, and Carrizo Moreira 2011; Roques, Newbery, and Nuttall 2008). Beyond this research on the relationship between fuel and wholesale electricity prices, there is to our knowledge no academic literature that looks in detail into the actual price setting on European markets and the extent to which coal- and gas-fired power plants are indeed commonly price-setting. One very recent research by Germeshausen and Wölfing (2020) focusses on the price setting of lignite-fired power plants in the German-Austrian market in a two year period from 2015-2017. The authors find that in the researched time period lignite fired-power plants were setting the price for more than 3-7 but less than 15 per cent of the time and call for more research on price-setting technologies.

This paper aims to fill this gap and investigate price setting on European power wholesale markets using a fundamental electricity market model. From the hourly calculations of European power markets, one can derive the marginal price-setting technology for any given hour. Taking a whole year as a timeframe, it is possible to analyse how the hours of a year are structured and what share different generation technologies take in providing the marginal price-setting units. The core objective is to broaden knowledge of price setting on European power markets, and obtain a more nuanced picture of what technologies set market prices. Given that the European power market is integrated and significant cross-border flows are occurring, the analysis is not limited to one country but looks at 20 integrated European power markets[1]. This will help to understand interdependencies and in what ways larger markets dominate price setting elsewhere.

To this end, the paper first discusses the general approach to price setting on European power markets and the existing literature and research. This is followed by a description of the applied methodology with regards to the employed model. Afterwards, the results are presented, analysed and discussed. First in the light of price setting across borders, second with respect to the different price-setting technologies sorted into in three price level.

2. PRICE SETTING GENERAL APPROACH

As aforementioned, conventional belief holds that gas- and/or coal-fired power plants are the price-setting marginal units in different European countries for most hours of the year. This seems reasonable given the substantial capacities of gas- and/or coal-fired generation capacities in many countries and their marginal pricing. The marginal costs of coal- and gas-fired power plants fall within the commonly observed range of wholesale power prices. Other generation technologies such as nuclear power or renewable energy sources are characterised either by very low marginal costs or, in the case of peak generation units like oil or diesel generators, by very high marginal costs. Therefore, unless wholesale electricity prices are at any given mo-

1. The twenty modelled countries are: Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Hungary, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland and the United Kingdom.

ment extraordinary high or low, one can assume that these technologies do not provide the marginal price-setting units.

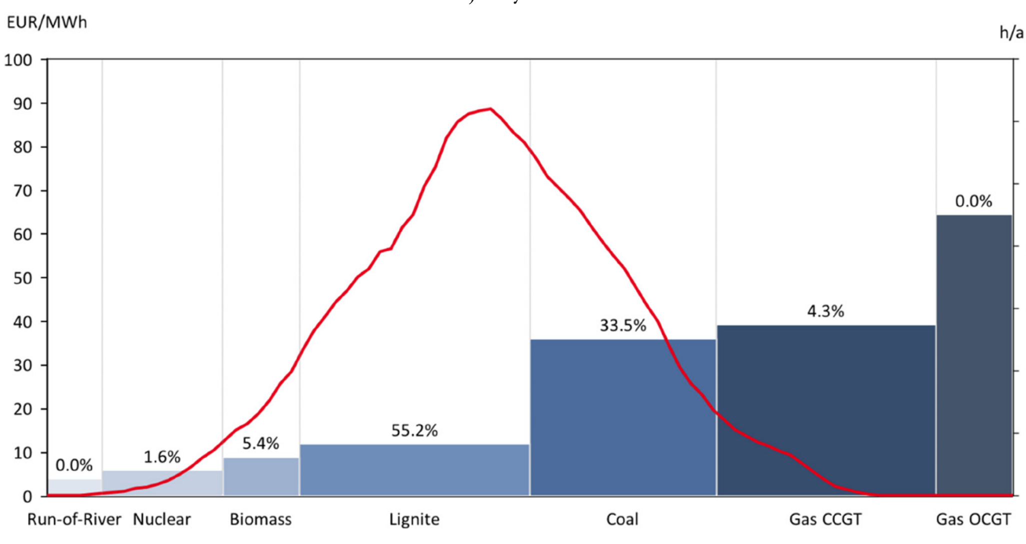
It should be noted at this point that European wholesale power prices have experienced a significant drop within the last several years, and that the number of hours in a year with very low prices increased significantly (Everts, Huber, and Blume-Werry 2016; Hirth 2018)[2]. It therefore seems plausible that during those low-priced hours, inflexible low-marginal cost generation technologies such as lignite, nuclear power or must-run technologies are indeed providing the last marginal unit on the merit order to meet the load—and are thus price-setting.

One should mention that wholesale electricity markets have also seen an increase in negative prices in recent years. This phenomenon has been linked with the deployment of (subsidised) low marginal cost technologies, first and foremost wind and PV. At times a combination of low demand, high penetration of renewable energy sources (with priority dispatch) and inflexibilities of conventional generation may cause prices to turn negative (Aust and Horsch 2020; Botterud and Auer 2020; Valitov 2019).

A look at the merit order can help to take further the idea of substantial coal- and gas-fired power plant capacities and their marginal pricing. Figure 1 displays an approximated example of a merit order in Germany. The line shows the German residual load of the year 2017 in 1,000 Megawatt (MW) brackets. The residual load is commonly defined as the difference between actual power demand and the non-dispatchable stochastic power generation of photovoltaics and wind turbines (Schill 2014). Other generation technologies (in this case predominantly thermal ones) are therefore those covering the residual load. The distribution of the residual load over the merit order curve shows which generation technology should, in theory, set the price at a given residual load. Following this principle, lignite and hard coal

FIGURE 1

Approximated 2017 German merit-order and residual load (as probability density function).* At 100 per cent power plant availability, lignite- and coal-fired power plants seem to set the price for the majority of hours.



* Marginal costs are based on authors´ estimations. Residual load and capacity data from Bundesnetzagentur | SMARD.de (Bundesnetzagentur 2018).

2. For a discussion on the causes of the price drop see Everts et al. (2016) and Hirth (2018).

power plants should be the price-setting units during most hours of the year, whilst gas-fired power plants alongside biomass and nuclear power plants take a smaller share.

One should note at this point that the unavailability of power plants—for instance due to revisions, maintenance and naturally occurring lower capacity factors of run-of-river and biomass power plants—are disregarded in this visualisation. Taking these factors into account would shift the merit order curve to the left and increase the hours in a year during which gas-fired power plants should provide the marginal units. In addition to the unavailability of power plants, this merit order and residual load-based view of the price setting concept also disregards cross-border flows, i.e. electricity imports and exports. These drawbacks demonstrate why this approach is not the most accurate way of looking at the concept of marginal units and price-setting technologies, but it can help to understand where the conventional belief or usual narrative might originate from.

Numerous scholars have researched price dynamics between gas or coal prices and wholesale electricity prices in different countries. Emery and Liu analyse the relationship between electricity futures prices and gas futures prices and find that they are co-integrated (Emery and Liu 2002). Mohammadi finds a stable long-run relation between real prices for power and coal and insignificant long-run relations between power and gas prices (Mohammadi 2009). Ferkingstad et al. research the interplay of different fuel and electricity prices in the Nordic and German markets and find a strong connection between gas and electricity prices yet no significant connection between electricity and coal prices (Ferkingstad, Løland, and Wilhelmsen 2011). Moutinho et al. observe inter alia a positive correlation between gas and electricity prices on the Spanish market (Moutinho, Vieira, and Carrizo Moreira 2011). Botterud and Auer (2020) analyse correlations between natural gas and different wholesale electricity prices in Europe and the United States. They find a relationship that shows less correlation after 2010 in Europe and a more consistent impact of natural gas prices on wholesale electricity prices in the United States which indicates that gas-fired power plants may be a more dominant price-setting technology in the United States than in Europe (Botterud and Auer 2020). Roques et al. analyse the correlation between electricity and gas prices in Britain with respect to portfolio optimisation for generators and calls for further research in the area, especially in regard to effects of carbon emission allowances on the marginal technology in the market (Roques, Newbery, and Nuttall 2008).

Even though the findings of scholars differ with different methodologies and research focuses, it can be noted that causal relationships between gas and/or coal prices and wholesale electricity prices exist, depending on the researched countries, time frames, applied methodologies and so forth.

In terms of price setting, reservoirs or storage plants, as well as pumped-hydro storage plants, serve a special role. Reservoirs and hydro-storage plants have effectively very low marginal costs and are, however, often the marginal unit to satisfy demand. Given that those plants have only a limited amount of water that can be discharged within a year, the usage hours are optimised to serve the highest priced hours. Economists mention that the opportunity costs of releasing water are equal to the expected future value of electricity produced when referring to this non-marginal costs-based dispatch (Faria and Fleten 2011; Pikk and Viiding 2013). With regards to hydro-storage plants or pumped-hydro storage plants, the term "price setting" can thus be misleading since shadow prices—reflecting the marginal costs of additional alternative (thermal) power plants—are used for the dispatch. The shadow prices thereby relate to the costs of a thermal reference power plant, and historic monthly water levels of reservoirs are used for modelling the dispatch of reservoirs and pumped-hydro power plants.

3. METHODOLOGY

3.1 Model

The techno-economic model Green-X[3] is used to model the European power market. It can be described as a numerical dispatch and investment optimisation model of twenty interconnected European countries and power systems. In economic terms it is a partial equilibrium model of wholesale electricity markets, focussing on the supply side.

The actual modelling can be described as a three-level process. In a first step, endogenous and exogenous capacity additions and deductions are determined. To this end, the model includes an up-to-date power plants database of all major (>10MW capacity) power plants in the geographical scope of the model. This includes plants under construction, planned constructions and decommissioning plants. The economics of power plants such as the efficiency are either based on available data or estimated based on the specific generation technology, construction date and other available data. Smaller plants and non-hydro renewables are included in the form of clusters. For the assessment of economic viability and incomes of power plants in this step, the long-term marginal costs are key whereas the short-term marginal costs are decisive for the dispatch (second step). For the assessment of economic viability, the model takes -next to incomes from the sport market- also incomes from support schemes, capacity remuneration mechanisms or balancing services into account.

The second step computes the hourly power plant dispatch based on the determined power plant portfolio under given constrains. Those include interconnector capacities, power plant availability and power demand. A marginal cost based merit order curve determines marginal power plants for every hour and country-specific wholesale electricity prices.

The third and final step calculates final market prices and considers the economic viability of new power plants. To this end, the model also estimates incomes from ancillary services based on information on historic ancillary services payments and expenditure published by TSOs.

Power generation is modelled with a high level of detail of power generation technologies. Those include hard coal fired power plants, lignite fired power plants, nuclear power plants, open cycle gas turbines, combined cycle gas turbines, oil fired power plants, mixed-fuel power plants, waste incarnation plants, different biomass plants, biogas plants, geothermal power plants run-of-river hydro power plants, hydro storage plants, pumped-hydro plants, battery storage, photovoltaics, concentrated solar power, tidal energy as well as wind onshore and wind offshore. For further differentiation there are a number of sub-categories.

Dispatchable plants generate electricity whenever prices are greater than their variable costs. Existing plants are regarded as sunk investments and decommissioned when they cannot cover their costs. The model regards some combined heat and power generation as must-run generation. That means a share of co-generation power plants are operational even if prices are below their marginal costs. The total amount of heat output from combined heat and power plants is exogenous given and fixed but investments and divestment is possible.

3. Green-X is a fundamental power model covering the 27 Member States of the European Union (EU) and selected EU neighbouring countries. It allows for the investigation of future deployments in the power and renewable sector including accompanying costs and benefits. It enables the derivation of a detailed quantitative assessment of renewable electricity sources deployed in a real-world policy context on a national and European level for the power, heat and transport sectors. It has been successfully applied for the European Commission within several tenders and research projects to assess the feasibility of '20% renewable electricity sources by 2020' and for assessments of its developments beyond that time horizon. In addition, Green-X can be used for a detailed quantitative assessment of the hourly market prices of the European power markets (Everts, Huber, and Blume-Werry 2016; Huber 2004).

Given the total cost minimisation approach, the model calculates cross-border trade endogenously. It is limited by net transfer capacities (NTCs) which are given exogenously. Here, the capacities are determined based on the Ten Year Network Development Plan (TYNDP) by ENTSO-E. Within countries it is assumed that there are no network constrains (copperplate).

The Green-X model is deterministic and thus does not model uncertainty regarding future price or demand developments. Demand is given exogenously and is assumed to be price inelastic.

One aspect many power market models struggle picturing accurately is hydro reservoir modelling. The dispatch of hydro storage is -unlike other generation technologies- not marginal cost based. Hydro reservoirs have effectively very low marginal costs, yet only a limited amount of water that can be discharged every year. One can note that the opportunity costs of releasing water are equal to the expected future value of electricity produced. The Green-X model uses shadow prices reflecting the marginal costs of additional (thermal) power plants to model the dispatch. In a final step, the shadow prices are adjusted manually within a slope until the dispatch reflects historic monthly water levels of hydro reservoirs.

The Green-X model is back-tested regularly to compare the model output to historic market data. This is done for calibration purposes in order to replicate the power market accurately in modelling. Features of the power market such as hourly to yearly average prices, price spreads, peak and off-peak spreads, capacities, generation mixes, carbon emissions and interconnector flows can be replicated adequately. It should, however, be noted that no model can give an absolute accurate replication of power markets due to the complex nature of interconnected power markets with dynamic developments and market actors behaviour. This analysis of price-setting technologies on power markets is thus no observation of real markets but on imperfect simulations of those markets.

The model was calibrated in a way to most accurately represent the current European power market and replicate hourly day ahead prices on the power exchanges. The year 2020 was chosen as a reference year. This near future horizon allows for using actual future market prices for most primary energy sources that were taken from the Intercontinental Exchange (ICE) at the time of the modelling (Spring 2018).

To model yearly power demand, historic GDP and power consumption data of different providers are used for an accurate calibration. The influence of energy policies on power consumption such as increases and reductions in demand through the deployment of electric vehicles or energy saving measures is taken into account, yet due to the short time horizon in question this influence is rather limited. For the modelling of the hourly demand, the model uses historic load profiles, whereby changes in consumption behaviour are considered.

4. MODELLING RESULTS

4.1 Price setting across borders

It is a key question of how the modelling results compare with the conventional belief. A first observation is that, with respect to the marginal price-setting units, the modelling results indicate a higher level of interconnectivity than one might assume. Large countries tend to dominate the price setting—presumably simply due to the large number of power plants and their differentiated marginal costs. Small countries such as Luxembourg only provide the price-setting marginal units for few hours a year and are to a great extent influenced by their neighbouring countries. Relative size, i.e. the size in relation to neighbours, and the level of interconnectedness in relation to its own generation also matter in this context. Hence, electricity markets and wholesale power prices of comparably small and well-interconnected countries are significantly influenced by the energy policies of their larger neighbours. Indeed, modelling results show that in terms of price setting, foreign energy policies can have a larger influence on a given state's electricity market than domestic policies.[4]

FIGURE 2

Price-setting technologies Netherlands 2020 in hours per year. Price setting in the Netherlands shows a substantial foreign influence.

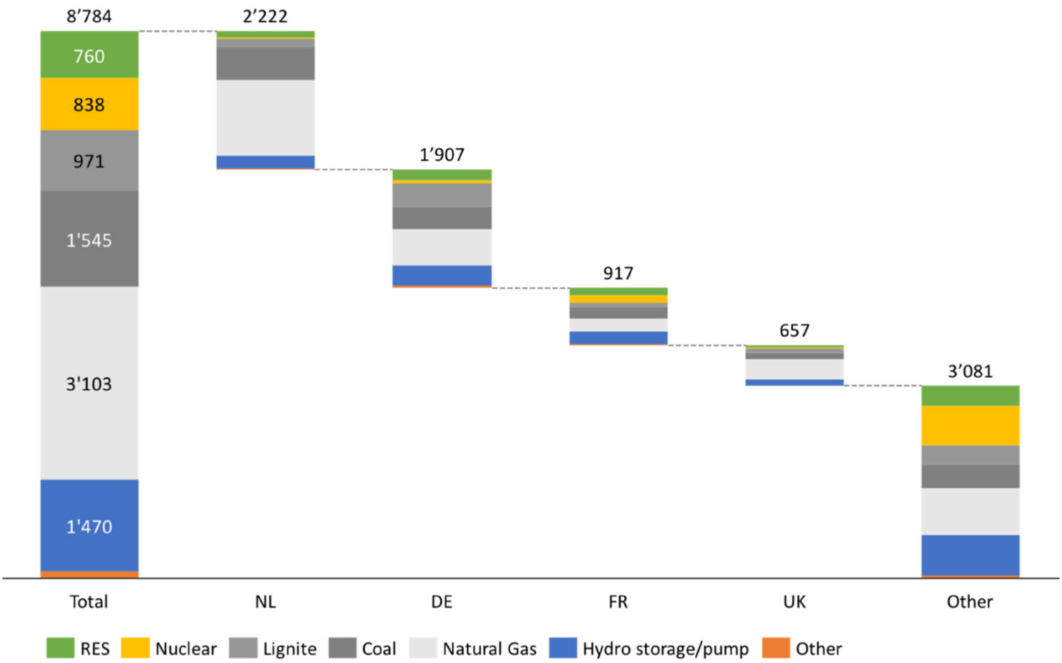


Figure 2 shows the structure of the price-setting units in the Netherlands for the year 2020. The bar on the left illustrates the amount of hours different technologies provide the price-setting units. The other bars show the countries where those price-setting units are located (Netherlands, Germany, France, Great Britain and other countries combined). Gas-fired power plants represent the most dominant price-setting technology and for most hours of the year, foreign power plants set the price in the Netherlands. One can therefore surmise that foreign markets and thus foreign energy policies influence the Dutch power market considerably.

A closer look at the German price setting (figure 3) reveals that this is not merely a Dutch or small-state phenomenon given that the German market represents the largest European market.

Other more isolated markets such as Great Britain are only marginally influenced by cross-border flows due to rather limited net transfer capacities. The Spanish and Portuguese markets on the Iberian Peninsula are also barely affected by outside markets in terms of price setting (see figure 4).

4. Examples for those energy policies are carbon price floors and capacity remuneration mechanisms. See Bucksteeg et al. (2019) for a detailed discussion on the impact of independent national capacity remuneration mechanisms on free riding effects and adverse allocation of generation capacity.

FIGURE 3
Price-setting technologies Germany 2020 in hours per year. Price setting in Germany is heavily linked with foreign markets despite the considerable size of the domestic market.

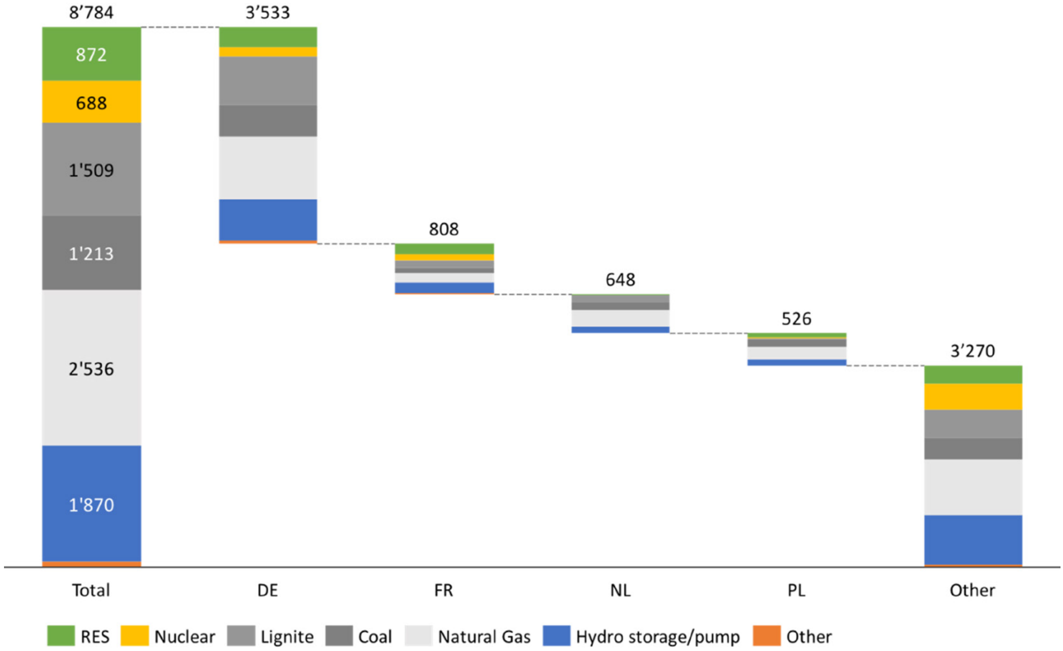
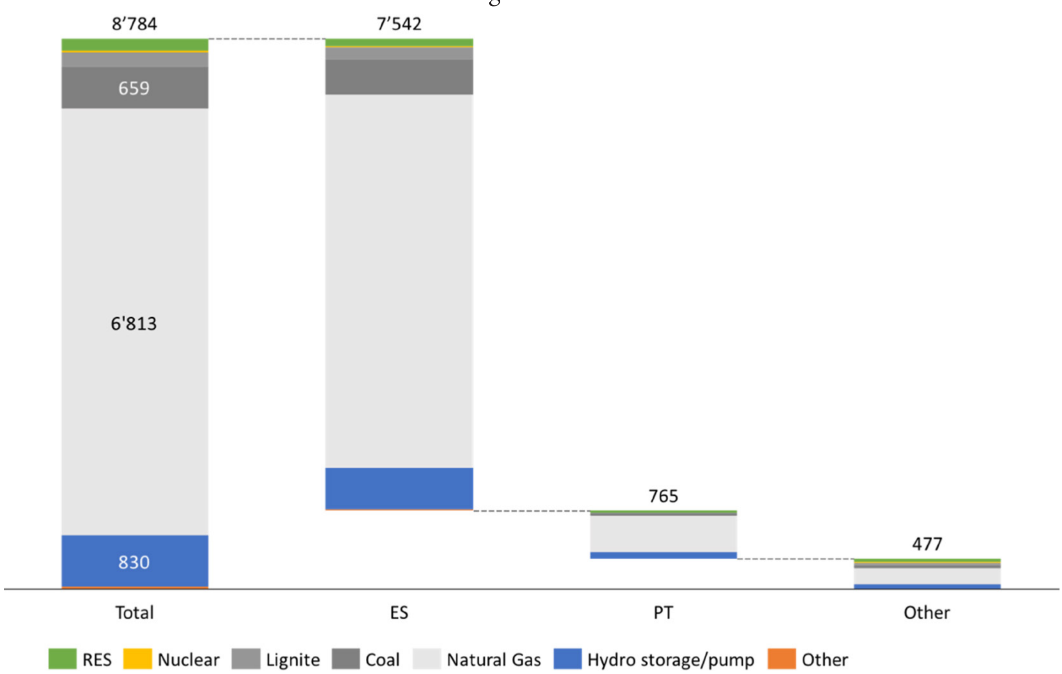


FIGURE 4
Price-setting technologies Spain 2020 in hours per year. Price setting in Spain shows little foreign influence.



As a general observation, the number of total hours power plants from a given country are price setting is highest in that given country, i.e. plants from country X do not provide as many price-setting hours in any other country as they do in country X.

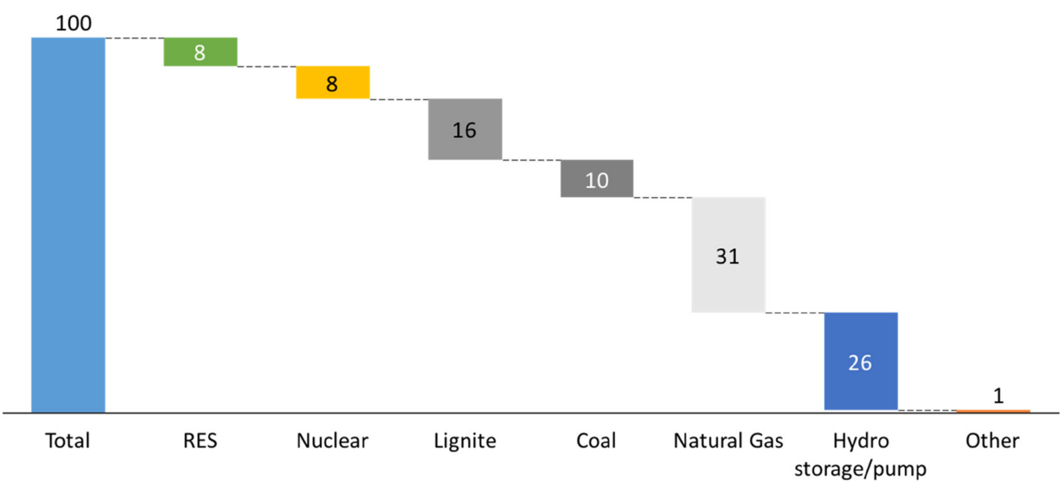
4.2 Price-setting technologies

Looking at the technologies that provide the marginal price-setting units, one can confirm aforementioned presumptions. For the large majority (>90%) of total hours in all countries, reservoirs, pumped-hydro, nuclear, gas-, coal- and lignite-fired power plants provide the marginal price-setting units. Other technologies such as stochastic renewables or other fossil plants play an almost negligible role in terms of price setting. This seems plausible given the very low marginal cost of renewable energies and their subsequent position at the starting point of the merit order. During most hours, further power plants are necessary to satisfy the demand, yet considering EU targets this may change with the deployment of more renewable electricity sources.

Altogether, the modelling results show that gas-fired power plants provide the price-setting units for almost a third of the total hours and thus for more hours than any other generation technology. Coal- and lignite-fired power plants follow, and together provide the price-setting units for over a quarter of the total hours (whereby lignite-fired power plants take a larger share than coal-fired ones). A notable point is that reservoirs and pumped-hydro power plants are also price setting for another quarter of the total hours. Nuclear power plants set the price for just below 10 percent of the hours, a share similar to that of renewables, including run-of-river power plants (see figure 5).

FIGURE 5

Price-setting technologies of all researched countries 2020 in per cent.



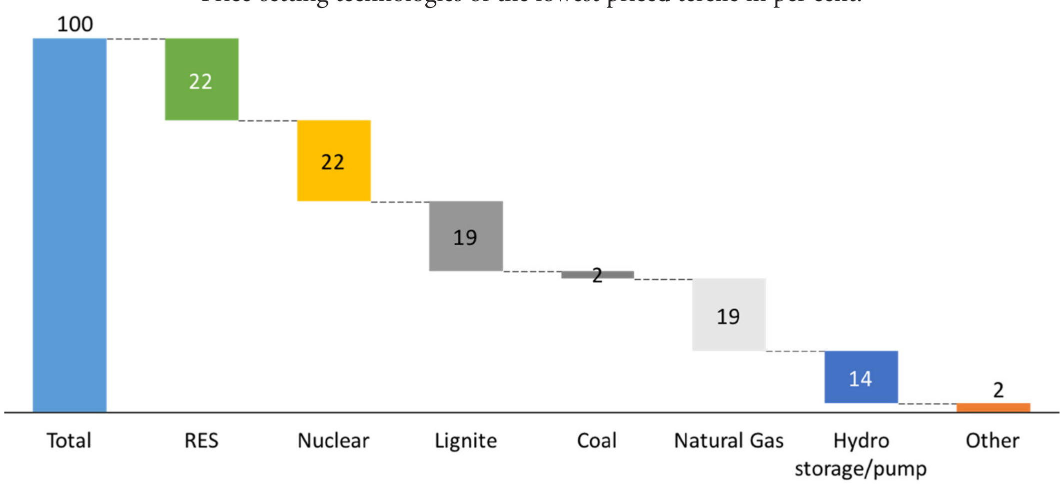
On an individual country basis, the picture of price-setting technologies can look very different depending on countries"—and surrounding, connected countries"—generation portfolios. Here one can observe some expected outcomes. The price setting in Poland, for instance, is dominated by lignite- and coal-fired power plants whereas in Great Britain, Italy and on the Iberian Peninsula, gas-fired power plants provide the price-setting units for the most hours. Similarly, Norwegian reservoirs as well as Finnish and Swedish nuclear power plants share the price-setting hours in the three states, which generally have a similar picture in terms of the price-setting units. This can be seen as an indicator of similar production parks, a high level of interconnectivity, or indeed a combination of both.

4.3 High vs low priced hours

In order to evaluate the modelling results further, one can divide the hours in a year into different groups. Therefore, the 8,784 hours of the year 2020 were divided into the highest, medium and lowest priced hours per country. This exercise can help to confirm common assumptions on low and high marginal cost technologies setting prices during low and high-priced hours respectively. It also provides further context on the origins on different price levels in different countries stemming from different generation portfolios.

FIGURE 6

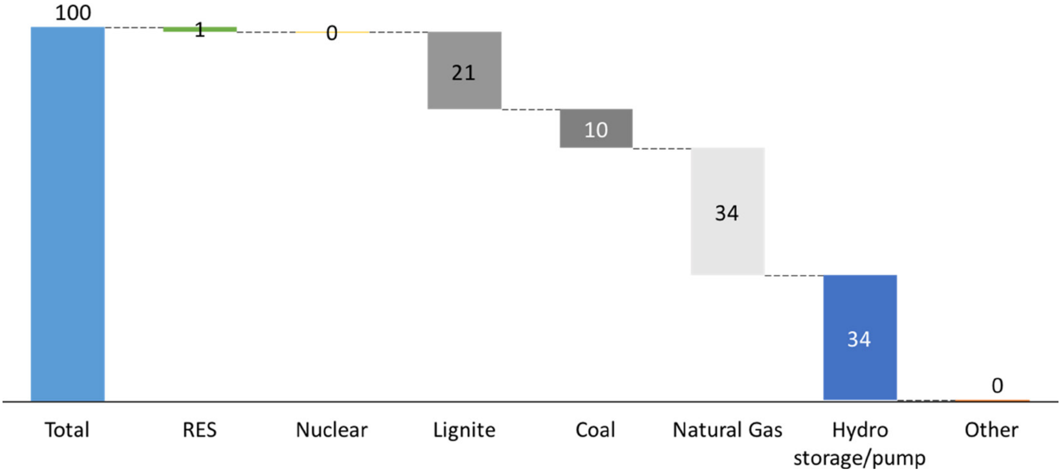
Price-setting technologies of the lowest priced tercile in per cent.



The price setting of the lowest priced tercile is as one might expect; characterised by low marginal cost technologies. Hence, nuclear is the technology that sets the price for most hours in the lowest priced tercile with almost a quarter of the total hours. Indeed, the hours during which very low marginal cost technologies such as nuclear, stochastic renewables and run-of-river power plants set the price are almost exclusively found in the lowest priced third of the total hours. Of interest here is the observation that coal-fired power plants provide almost no price-setting units in this low-price segment. In contrast, lignite-fired power plants set the price for a fifth of the hours in this segment. It may come as a surprise that, according to the results of the model, gas-fired power plants also provide the price-setting units for a fifth of the hours in the lowest priced third. In fact, gas-fired power plants are price-setting in lowest priced tercile throughout all modelled countries[5]. For most countries, this share only comprises a small percentage of the hours, but they dominate the price setting in this price segment on the British, Spanish, Portuguese and, to a lesser extent, the Italian market. It should be noted at this point that those four markets also comprise the markets with the highest overall price-level by quite a margin. This is the consequence of price-setting gas-fired power plants.

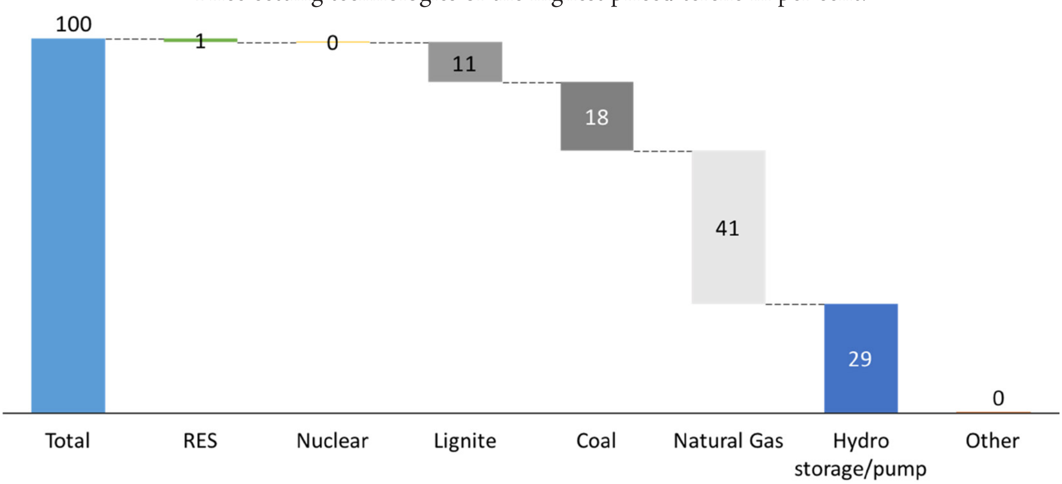
5. In countries with little or no gas-fired generation capacity, foreign gas-fired power plants provide the price setting units during those hours.

FIGURE 7
Price-setting technologies of the medium priced tercile in per cent.



The picture of price-setting technologies changes significantly in the medium-priced segment (figure 7). Renewable energies and nuclear power plants are no longer a relevant factor in terms of providing price-setting units. Gas-fired power plants, reservoirs & pumped-hydro plants as well as lignite- and coal-fired power plants each provide the price-setting units for about third of the hours. Again, the share of lignite-fired power plants is higher than that of coal-fired plants, and gas-fired units dominate the price setting on the British, Spanish, Portuguese and Italian market. Among Sweden, Finland and Norway it is Norwegian reservoirs that are setting the price for the great majority of hours.

FIGURE 8
Price-setting technologies of the highest priced tercile in per cent.



In the highest priced tercile, the share of gas-fired power plants as price-setting units increases further to two fifths of the hours, whilst the share of lignite-fired power plants is lower than in the other price segments (figure 8). Only in Eastern Europe does the latter technology remain a relevant price-setting technology. Coal-fired power plants provide the price-setting units for one fifth of the hours. As a further point of interest, the share of reservoirs as price-setting units is slightly lower compared with the medium priced segment. It seems striking that their share as price-setting units in Sweden, Finland and Norway is lower than in the medium priced tercile. Furthermore, for some hours in the highest price segment—albeit very few—there are lignite- and coal-fired power plants providing the price-setting units in the three countries, despite those technologies not playing a role there in the price setting in the medium and lowest priced thirds.

A look into prices reveals that Norway, Sweden and Finland represent the three countries with the lowest general price level and that prices during most hours, even in the highest priced segment, are not significantly above the marginal cost level of coal-fired power plants.

With respect to the price setting in the Nordic countries, analysts mention the relevance of German off-peak pricing for Nordic wholesale electricity prices (Loreck et al. 2013, 27–33; Mollestad 2016). The modelling results do not convey a significant relevance of German off-peak generation units as price-setting power plants in the Nordics. However, German off-peak generation may still be relevant in this context, even if it is not providing the price-setting units directly. During most hours in the Nordics, Norwegian reservoirs set the price as per the modelling results. However, the marginal costs of these reservoirs are not the decisive factor. Shadow prices used for the optimisation reflect the marginal costs of the next dispatchable power plant in the merit order, which in this case can be German coal- or lignite-fired power plants, once those in Finland and Denmark are exhausted. Hence, German off-peak generation may still have an influence on the price setting in the Nordic countries, without providing the actual price-setting units for a significant number of hours.

4.4 Conventional belief vs modelling results

Subsequently, there is the question of how the modelling results compare with the aforementioned conventional belief.

First, the modelling results indicate that gas-, lignite- and coal-fired power plants are indeed setting the price during most hours of year. This dominance is, however, not as clear as conventional belief might suggest. Whilst gas-, lignite- and coal-fired power plants provide the marginal price-setting units for most hours, their share lies below two thirds (see figure 5). Reservoirs and pumped-hydro power plants provide the marginal unit for approximately a quarter of the hours of a year, predominantly in the medium- and high-priced segments. Nuclear power plants and renewable electricity sources—first and foremost run-of-river hydro power plants—also provide price-setting units, primarily during low-priced hours. Generally, the results reflect the merit order of a given country, but according to the results of the model, the level of interconnectivity in terms of price setting can be high (see figure 2).

Altogether, the modelling results indicate that the price setting in Europe can be more complex than conventional belief might suggest. It is not incorrect to argue that coal-fired power plants set the price in times of low demand and gas-fired power plants when demand is high, but this can potentially disregard the heterogeneity of European power systems and the interconnectivity of markets.

5. CONCLUSION

The conventional belief holds that in many European countries, coal- and/or gas-fired power plants provide the marginal price-setting units for most hours of the year. The modelling results confirm that in the countries researched, coal-, lignite- and gas-fired power plants are indeed price-setting for most hours of the year. Their dominance is, however, not as clear cut as the conventional belief might suggest. The analysis with a fundamental electricity market model has shown that during hours of low demand, nuclear power plants and renewables are providing price-setting units for a considerable number of hours alongside lignite- and gas-fired power plants. Throughout all price segments yet especially during mid- to high-priced hours, reservoirs and pumped-hydro power stations play a substantial role in the price setting process. However, one should keep in mind that their marginal pricing does not reflect the marginal costs, as shadow prices or water values—reflecting the marginal costs of an additional alternative (thermal) power plants—are used for the dispatch (see above). In the highest priced segment, gas-fired power plants provide the price-setting units for the largest share of hours.

Large countries tend to have a strong influence on the price setting in smaller neighbouring countries, as long as there are sizeable interconnector capacities. More generally, one can observe a high level of interconnectivity between the countries researched. Policies such as carbon price floors or capacity remuneration mechanisms that are often implemented on a national rather than a European level therefore have effects across borders, affecting amongst other things the price setting and with it price levels. This may lead to market distortions not limited to the implementing country.

The price-setting technologies per country vary significantly depending on the generation portfolio of a given country and the connected surrounding countries. In Southern Europe (Italy, Portugal and Spain) and Great Britain, gas-fired power plants dominate the price setting, whilst lignite- and coal-fired power plants tend to do so in Eastern Europe. Hydro-storage and pumped-hydro plants provide the price-setting units during most hours in Northern Europe. The most balanced picture with respect to the price-setting technologies is to be found in central Europe and the price setting ergo reflects the general generation portfolio. These insights on the price-setting technologies on European power markets can help policymakers to come up with appropriate measures to foster an envisaged fuel switch away from coal or lignite towards natural gas as the price-setting technology. To this end, a clearer understanding of the extent to which different technologies are indeed price setting is critical.

Altogether, the analysis contributes to fill the identified gap in the literature. It shows that price-setting patterns are more complex and nuanced than the conventional belief suggests, and that power generation technologies other than coal- and gas-fired power plants provide the marginal price-setting units more often than one may assume. In this light, further research can help to establish a more detailed view on the price setting on European power markets. Other researchers could study price-setting patterns with their models and explore what effects different demand periods or policies may have and how this may change as the decarbonisation of the power sector progresses and more renewable energy sources are deployed.

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