Structure and Performance of Six European Wholesale Electricity Markets in 2003, 2004 and 2005

Part IV

Presented to DG Comp 26th February 2007

Prepared by London Economics in association with Global Energy Decisions

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10 Cross-country Comparison

This chapter presents a comparison and summary of results across the countries studied, namely Belgium (BE), Germany (DE), Spain (ES), France (FR), the Netherlands (NL), and Great Britain (GB). The purpose is to facilitate comparisons across countries for certain key elements. More details and sensitivities are available in the other more detailed chapters.

This study of the very difficult problem of relating electricity market structure to market outcomes (and uncovering evidence of either competitive or un-competitive market outcomes) involves the use of a detailed methodology. Our approach was therefore several-fold.

First, we investigated the more traditional structural measures of market concentration (those based on market shares) such as the concentration ratio and the Hirfindahl-Hirschmann index (HHI). Since market conditions in electricity markets can change so significantly, hour-to-hour, season-to-season, year-to-year, we estimated these measures on an hourly basis over the period 2003 to 2005. These measures are based on measures of capacity and generation. Clearly one can see the potential for considerable change in the hourly generation figures of each market but by taking account outages, deratings and in some cases long-term contracts and reserve commitments to system balancing, one can further see the possibility for hourly changes in capacity thus validating the approach. A number of sensitivities were also included to estimate the impacts of interconnectors, long term contracts, and reserve commitments on these measures.

We next undertook to estimate electricity-specific measures of market structure, this was done specifically by using the residual supply index (RSI) and the pivotal supplier indicator (PSI). These measures are designed to deal more effectively with the changing nature of electricity markets, and are calculated hourly. Threshold values (% of hours in the year) have been suggested in the literature as indicators of when non-competitive market outcomes are likely to be a significant problem.

The next element of the analysis was the calculation of market outcome measures. The standard economic measures of the competitiveness of market outcomes calculated as part of this study were the Lerner Index (LI) and Price-Cost Mark-Ups (PCMU). The calculation of these measures involves the estimation of the marginal cost of energy on the electricity grid for each hour of the 2003-05 sample period. This was done using GED's Prosym™ market despatch simulation model, with detailed inputs on unit characteristics, fuel prices and unit outages (both full and partial).

The final element of our analysis was to relate the estimates of the market outcome measures to the electricity-specific market structure indicator, the RSI. This was done using econometric regression (statistical) analysis. The econometric approach is useful and necessary since many random factors (weather, temperatures, outages) and more economically benign factors (scarcity) can combine to raise prices and margins. Such an approach will also capture the effects of the regulatory regime in each country, although this is not explicitly controlled for in the analysis. These factors may have little to do with market power, and so thus must be controlled for. Controlling for random and deterministic variables was thus done via the econometric approach.

It is noteworthy, before going further, to highlight the scale and extent of our analysis, as well as the degree that we believe we have advanced the debate and state of knowledge of the electricity sector in the EU's major markets. The study involved data collection and analysis on a scale that, to our knowledge, is unprecedented in the electricity-economics field globally. The study involved the hourly observation, simulation, and relating to price outcomes of output and marginal cost, and market structure for most every unit in every hour (8,760 hours/year and 8,784 in 2004) for three years ((8,760x3)+24=26,304) for six countries (x6=157,824). With countries having between 100 to over 250 units, and over 25 variables either collected or estimated, the study involved the collection of about 500m data points and manipulation and analysis of close to 1billion data points, and resulting in an approximate total of 75GB of data inputs and outputs. Further, while previous studies have looked at price cost margins in selected markets in the USA, (e.g, Borenstein *et. al*, 2002) and also related the RSI to price cost margins (Sheffrin 2002), no study to our knowledge has a comprehensively related market structure measures and market outcome measures. Previous studies either focused on a single country, a limited period, or did not account for as many factors. Further, with the general regression framework developed, we were able to control for a number of additional factors. Thus, our multivariate regression results can be seen as groundbreaking.

Finally, the results of our extensive analysis achieve a number of important points; but one should be plainly aware that our analysis is still not without limitations. Ultimately, our analysis supports the original two points of the first phase of the sectoral inquiry; namely, that the current market structure in the EU electricity markets (the six markets studied) in a significant number of hours is likely to be conducive to anticompetitive behaviour. And secondly, that price outcomes on the EU wholesale electricity markets may have been less keen contested, than they otherwise would have been, had the markets been structured more competitively. The general caveat of the analysis is that factors that we have been unable to control for may have caused the appearance of market power, and that the existence of market power is not necessarily evidence of its abuse.

10.1 Summary of *CR(n)* and HHI

The first part of our analysis calculated concentration ratios and HHIs on an hourly basis. The market shares, which form the basis of these market structure indicators, were calculated based on both capacity and generation bases. These measures varied hourly based on changes in availability brought about by factors such as outages and seasonal deratings. For the generation-based market shares the amount of electricity that was actually generated by the units of each company's portfolio of generation assets was taken as the basis for the calculations. The amount of capacity that was deemed to be in-merit (economical), based on the data returned by the companies, was also used as an alternative basis for calculating market shares.

Table 10.1 presents the average values of the traditional measure of market concentration for each country, over the three year period. These figures are calculated using the hourly market shares of companies based on Available Installed Capacity.

Table 10.1: Average HHI values based on Available Installed Capacity, (2003-2005)

Country	*CR(n)*[1]	HHI
BE Belgium	90.7%	8,307
DE Germany	54.1%	1,914
ES Spain	71.4%	2,790
FR France	92.6%	8,592
NL Netherlands	57.7%	2,332
GB Great Britain	32.6%	1,068

Source: LE

[1] The number of companies for the *CR(n)* calculation is different in the case of two of the countries. In both Belgium and France the concentration ratio is based on the top company in the market CR(1), while in The remaining four countries, Germany, Spain, Great Britain and the Netherlands, it is based on the top two companies in the market calculated on an hourly basis. This is because the CR(1) measure for the largest company in France and Belgium already raised the degree of concentration to a very high level.

From the table above, one can see that both France and Belgium are much more highly concentrated than any of the other four. Indeed, their *CR(n)* and HHI figures are near the maximums of 100% and 10,000 (respectively). It is clear that the qualitative conclusion of highly concentrated will not be sensitive to changes in assumptions or bases for interconnection allocation[2]. Other countries (DE, ES, and NL) are considered to be concentrated, while Great Britain is borderline unconcentrated/moderately concentrated[3].

In addition to the tables comparing across countries on the available capacity basis, it is useful to compare the distribution of HHI across countries for just a few cases studies. We choose to compare Great Britain and Spain, because they showed considerable differences in the distribution of their HHIs across time and across the basis for market share (we present available capacity and total generation).

The first figure below shows the distribution of the HHI in Great Britain based on available capacity. The distribution shows a rather tight distribution around the mean, median and mode. The range is about 200. There is little variation, and the range of HHI values are all near, or just at or above, the threshold of 1,000 which is the arbitrary borderline between unconcentrated and moderately concentrated. However, no significant number of values appear near or above 1,800, the threshold indicative of a concentrated market.

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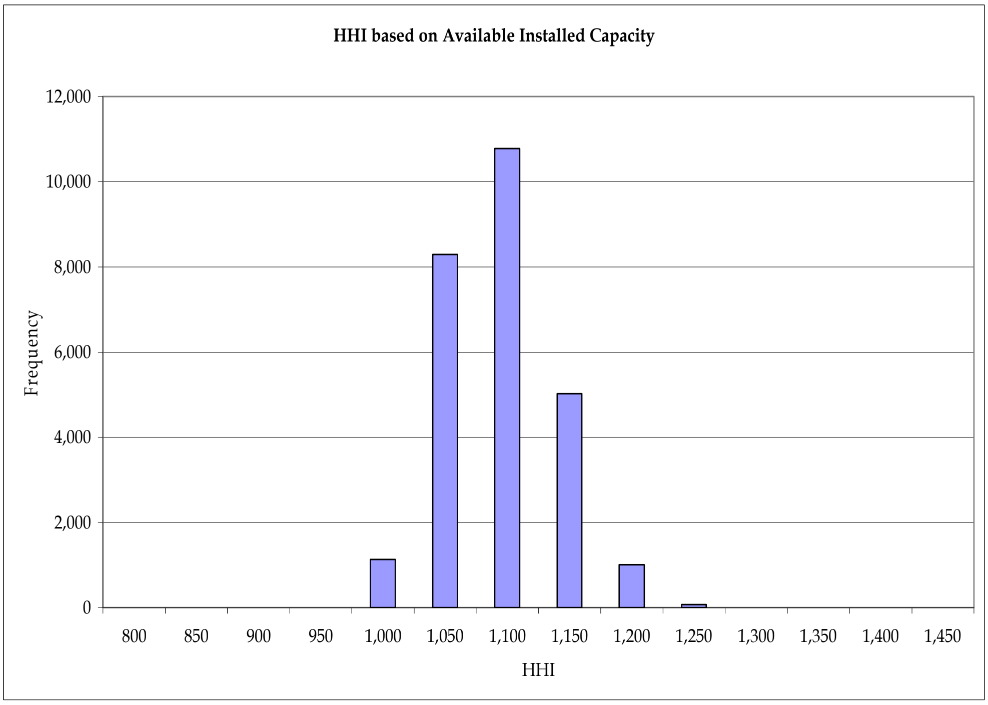
2 Many sensitivities were carried out, but in general, the qualitative conclusions were not sensitive to the changes in assumptions about market definition and how market shares were formed, with the main exception being the impact of interconnection in NL. For more detail on these sensitivities and the results one should see the country specific chapters.

3 The calculated HHI figures are assessed vis-à-vis the thresholds for concentration set out by a number of competition authorities, including DG Competition, that identify markets with a HHI below 1,000 not to be concentrated, between 1,000 and 1,800 to be moderately concentrated, and above 1,800 to be concentrated. It is important to point out that these thresholds are not the result of rigorous economic analysis but have developed over time as a generally accepted benchmark. These thresholds are therefore not steadfast rules and are adapted in particular situations to accommodate special market conditions.

Figure 10.1: Great Britain – Histogram of HHI Values based on Available Installed Capacity (2003-2005)



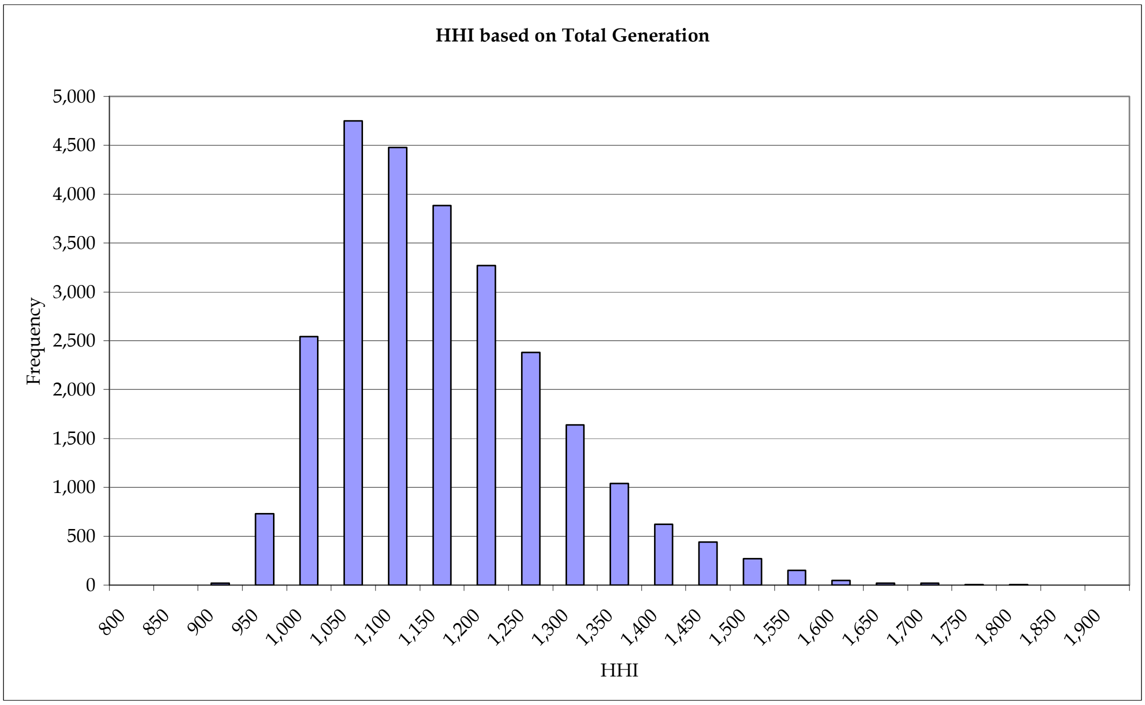
Source: LE

The next figure below shows the distribution based on total generation in the British electricity market. Now, one can see considerably more variation in the HHI. This is what one would expect, as generation will vary much more greatly as the various plants ramp up and down through the day to meet demand. The shape of the distribution is still regular[4], but skewed right[5] (high values to the right are more possible relative to the mean). An important factor is that the range of values in the total generation basis is higher. In addition, the value falls to the unconcentrated level, but also stretches close to the concentrated level (1,800). This indicates that in some hours, the British market might be concentrated enough to pose market power problems. However, note the previous discussion in the methodology chapter of the report within which we discuss the role of tightness of the market, the supply and demand balance, as a more fundamental determinant of market outcomes in electricity markets, than measures focussed on the market shares of companies in total generation. If the market is not tight, then even a concentrated structure based on total generation might yield competitive outcomes; conversely, a tight market with unconcentrated structure could yield less than competitive outcomes. Note also that "how many hours" the market is tight, is also an important question.

[4] It only has a single mode, or most likely value. This is characterised by a single peak.

[5] The mean will be to the right of the median of a skewed right distribution.

Figure 10.2: Great Britain – Histogram of HHI Values based on Total Generation (2003-2005)

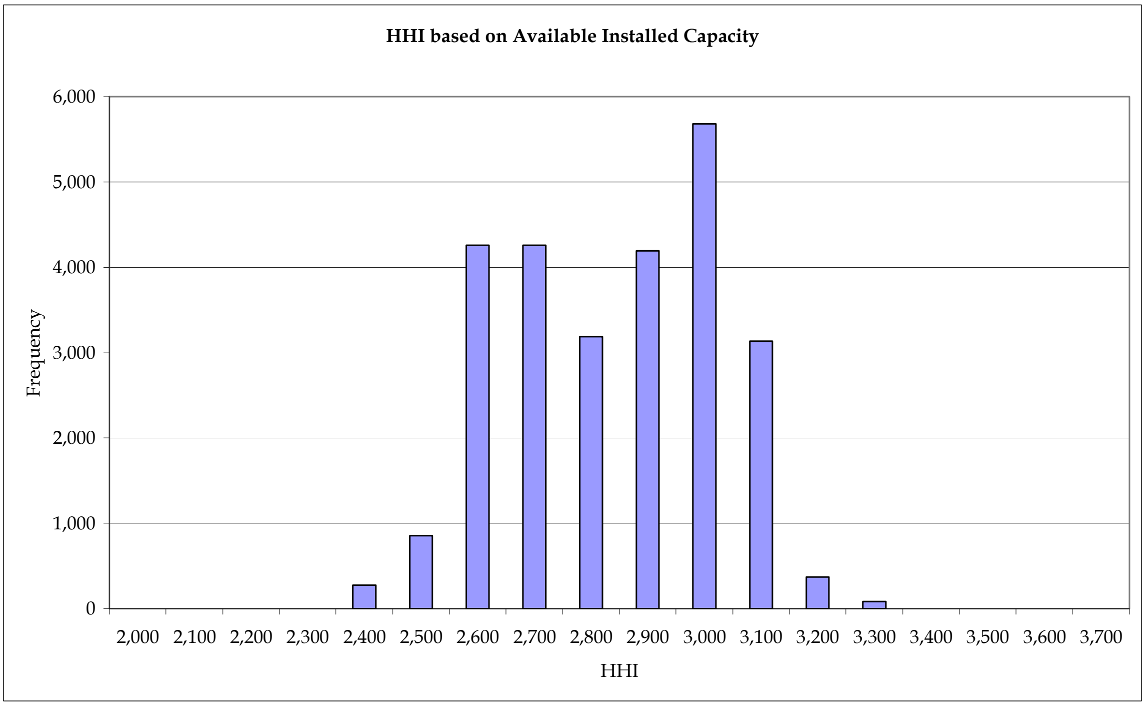


Source: LE

It is useful to compare the above figures with another country to see the variation in these measures across countries. Spain is chosen as an interesting comparator[6]. The figure based on available capacity, Figure 10.3, shows quite a different spread and shape from that observed in the British market. There are two peaks or modes to the distribution, and the range of value is quite a bit larger: almost 1000 (vis-à-vis approximately 200 in Great Britain). The maximum HHI based on total generation in Spain is approximately 3,300.

[6] Additional figures are available in each of the country specific chapters.

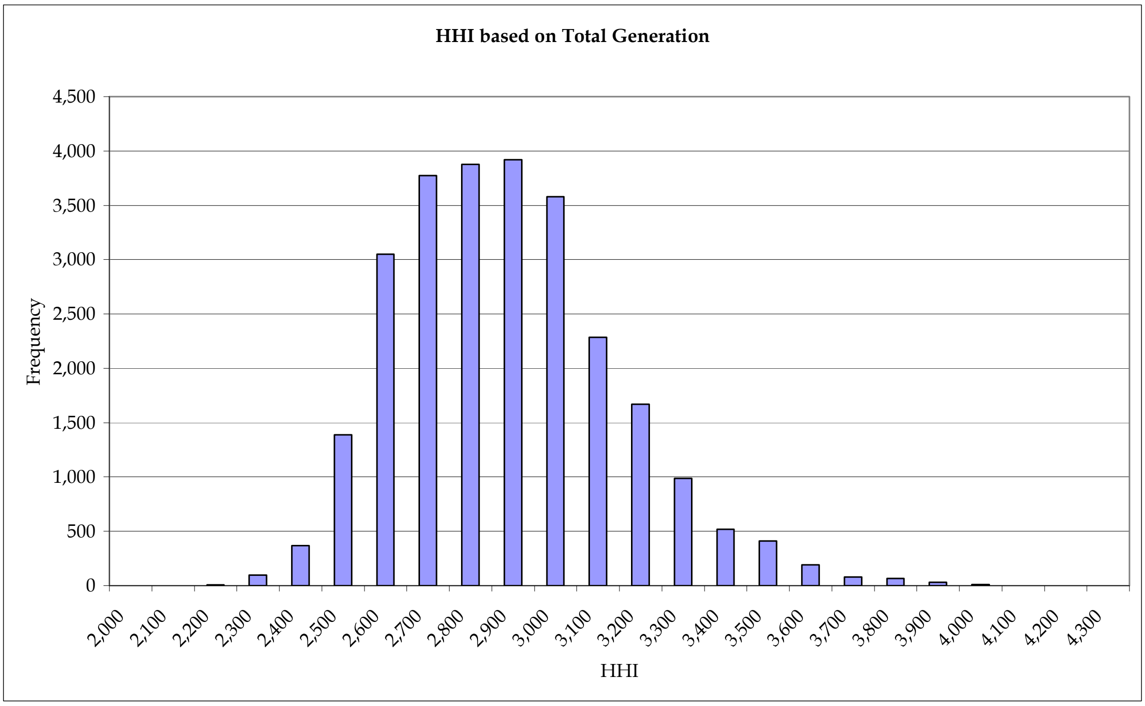
Figure 10.3: Spain – Histogram of HHI Values based on Available Installed Capacity (2003-2005)



Source: LE

Interestingly, the distribution of HHI based on total generation in Spain shows a much more regular bell-shape, with a single peak. However, note that some very high values are possible as the maximum is about 4,000. The minimum is now about 2,300. Thus, in some small number of hours, the Spanish electricity market is indeed very concentrated. However, for competition market structural analysis, the difference between the available capacity basis and the total generation basis in the Spanish market HHI is not qualitatively important; for some significant percentage of hours, the market is highly concentrated.

Figure 10.4 Spain – Histogram of HHI Values based on Total Generation (2003-2005)



Source: LE

10.2 Market Outcome Measures

The next step in our analysis for each country was to calculate market outcome measures. Two methods have been adopted for calculating these measures: the Lerner index (LI) and the price-cost mark-up (PCMU). The former is calculated as: (P-MC)/P, while the latter is calculated as: (P-MC)/MC (where P=price and MC=marginal cost).

Both LI and PCMU measures were calculated for each of the countries contained in the study. Table 10.2 presents a cross country comparison of the PCMU values for a selection of the countries[7].

Table 10.2: Price-Cost Mark-Up, (2003-2005)				
Period	**2003-05**	**2003**	**2004**	**2005**
Including carbon cost based on weighted averages of GED SMC & Exchange prices				
Germany	27%	59%	22%	15%
Spain	21%	26%	5%	28%
Netherlands	6%	33%	-2%	-5%
Great Britain	11%	NA	4%	13%
Excluding carbon cost based on weighted averages of GED SMC & Exchange prices				
Germany	51%	59%	22%	72%
Spain	35%	26%	5%	66%
Netherlands	14%	33%	-2%	13%
Great Britain	31%	NA	4%	42%
Source: LE				

[7] Price-Cost Mark-Ups were calculated for both Belgium and France but are not included in this table. In the case of Belgium, hourly power exchange prices were not available for the period of the study, resulting in the use of an Electrabel Price Index for traded electricity which provided daily values that there applied to the relevant hours. This calculation was largely for indicative purposes, and also to illustrate the impact of carbon emissions pricing against some basis. Our judgement, however, was not to compare BE with other countries in this table since the numbers would not be directly comparable. In the case of France, the issue was a problem with the data returned as part of DG Competition's Sector Inquiry that subsequently led to difficulties in determining the availability of nuclear units which appeared to capable of serving demand in a substantially greater number of hours in the simulated market despatch, than they did in reality. Time did not permit further investigation of this issue.

The cross-country comparison shows a variety of market outcomes[8] across countries and time. On average, of the countries in the table, the highest mark-ups are found in Germany. The lowest margins are in Great Britain and the Netherlands (11% and 6%, respectively). Germany and Spain have margins on average of approximately 27% and 21%, respectively. It is useful to note that the rank order of countries' margins does vary over time. For example, the Netherlands appears to have the second highest margins in 2003, but the lowest margins in 2004 and 2005[9]. Interestingly, all countries in the table had their lowest margins in 2004.

Overall, these results are broadly consistent with those one might a priori expect to find given the concentration measures, HHI and *CR(n)*, observed in each market. Recall the HHI figures were 1,914 (DE), 2,790 (ES), 2,332 (NL), and 1,068 (GB), however one should be somewhat cautious in drawing definitive conclusions on the relationship between margins and concentration using broad average figures.

The impact of the introduction of the pricing of carbon via the EU ETS and the estimation of the additional marginal cost this imposed on generation companies and utilities can be seen by comparing the top panel with the lower panel of the table (assuming the full marginal cost of carbon is included in the marginal cost calculation). We emphasize that the top panel of the table "with Carbon" means that the full marginal economic cost of carbon is included in the marginal cost estimates. This was estimated by calculating the emissions from the marginal plant from the despatch modelling and pricing those emissions using the market price. From the comparison of the table (top panel to bottom panel), it appears that the amount of added cost that is economically fully justified by marginal cost pricing according to our modelling varies across country.

[8] Although expressed explicitly in Table 10.2, it is important for one to realise that the margins are the margins of the weighted-average of the price and cost, with the weights being formed by the share in total annual load in each hour.

[9] One can find further discussion of this in the Netherlands chapter of the report.

While the introduction of carbon pricing (via EU ETS) may have been responsible for a substantial rise in the price of power (along with recent fuel price rises), it is perhaps natural to ask the question whether margins also increased in this recent historical context. Given all countries are expected to face broadly qualitative similar impact from the carbon pricing regime[10], it is useful to compare across countries the estimated maximum possible impact, on the basis of a purely economic dispatch, of fully pricing in the cost of CO_2 in each country.

[10] The EU Emissions Trading Scheme EU ETS came into effect in 2005. It is not clear how large the 'efficient' pass on of carbon cost should be. A standard economic 'cap-and-trade' scheme is a means of achieving a least cost solution to the problem of abating emissions. Achieving the decentralised least cost solution would require that participants price in the cost of the emissions according to the market price. Under a standard scheme the true economic cost of carbon would be reflected in the value (price) of an allowance—thus since firms could sell allowances, the opportunity cost of not selling them (e.g., emitting C02) would cause utilities to make efficient decisions with regard to how much to abate and emit. However, it is possible that the firms view the allowances as impacting their future allowance awards—in which case firms might not price/cost the allowances at true economic (opportunity) cost. We therefore are circumspect as to how allowances should be priced, but by including carbon in our marginal cost estimates, we avoid the possibility of overestimating the margin due to carbon.

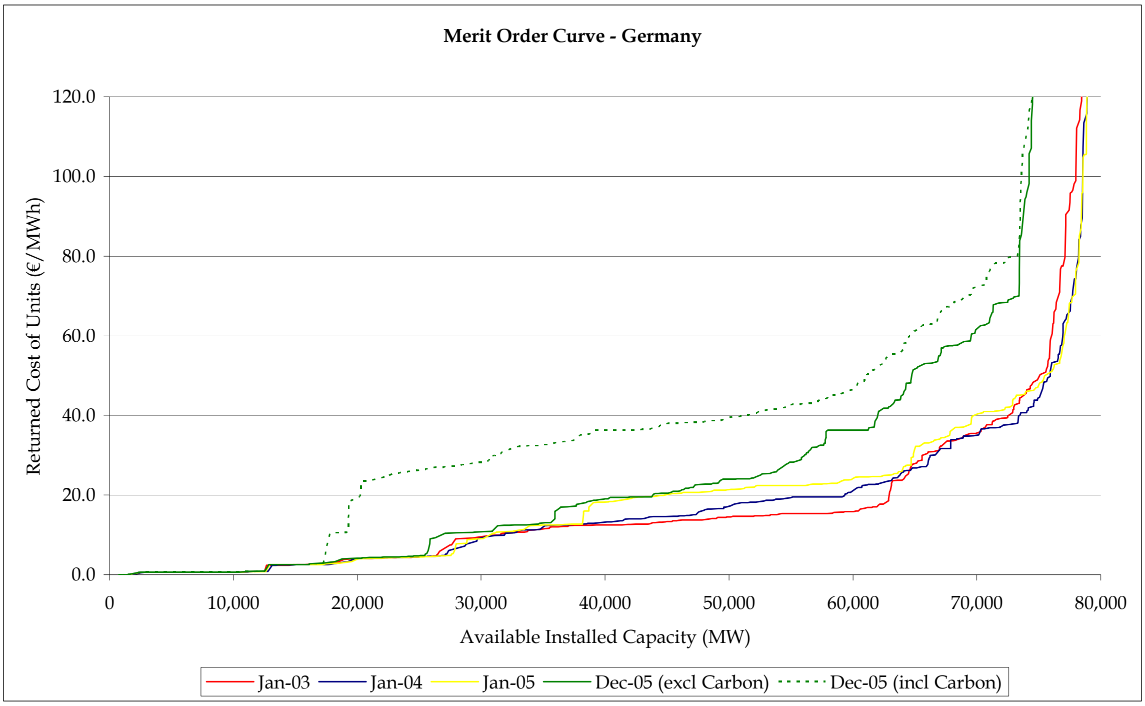
10.3 Breakdown of power price including margin, fuel cost and carbon

The discussion in the immediately preceding section dealt with the calculated market outcome measures, LI and PCMU in each of the relevant markets in the study. We now turn to results of deconstructing the average exchange price in each country into its constituent parts. The load weighted average exchange price, used in the LI and PCMU measures is broken-down into three separate parts; the marginal cost of generation, the mark-up and the full economic cost of carbon.

While decomposing all these factors would be quite difficult, it is useful to consider a graphical depiction of the changes in the marginal cost over time to illustrate how the supply curve changes with respect to various elements (plant additions, fuel price changes, etc.). We present in this chapter two graphical depictions for individual countries as case studies: Germany and Spain. This also shows the relative importance of some particular technologies such as hydro, nuclear, and coal.

Figure 10.5 shows the merit curve for Germany. The curve shows a significant evolution through time. The solid green line in 2005 has risen substantially over the other curves, showing the sharp rise in liquid petroleum and gas prices above all. The evidence of where the coal technology is, and how important it is in Germany, is illustrated by the shift in the green curve to the hashed green curve, showing the rise in price when including the cost of carbon. The lowest part of the curve has no emissions, and so is renewables and nuclear; coal comes in next, then gas and grades of fuel oil. Coal is the most intensive CO_2 technology, so it is evident where this is on the curve (where the green curve shifts up a lot—at about 15-20,000 MW capacity—Germany has about 40,000MW installed capacity of coal).

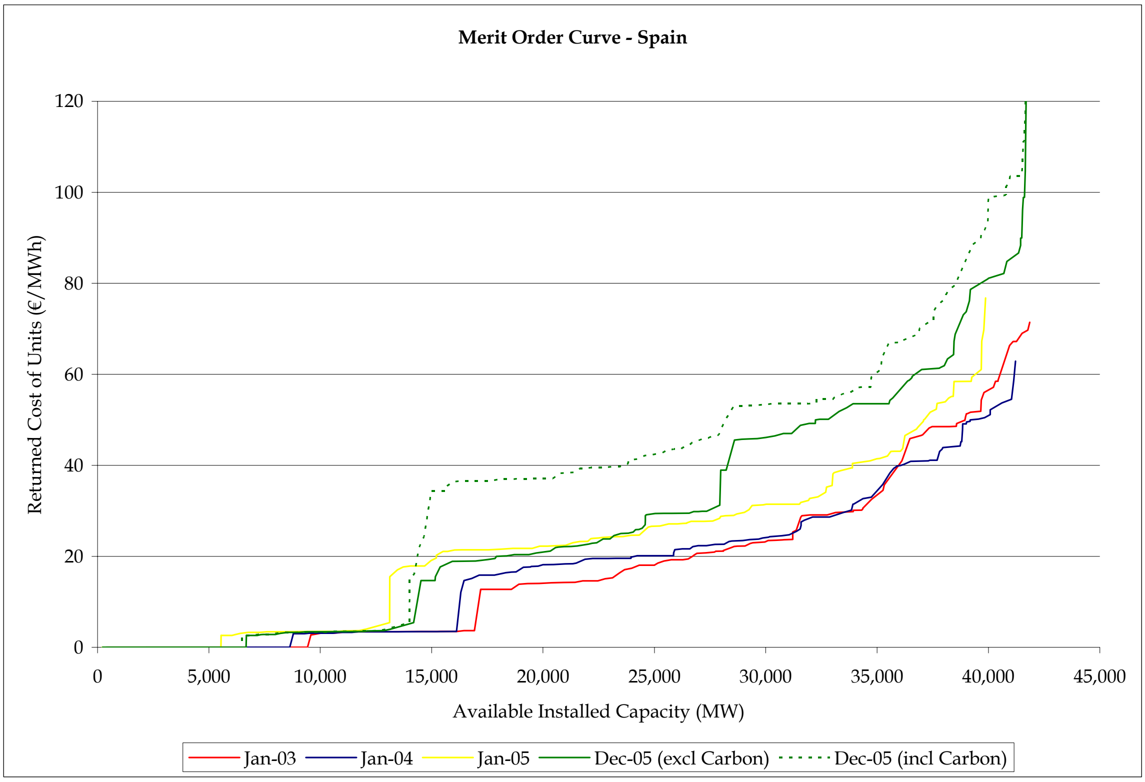
Figure 10.5: Merit curve Germany



Source: LE

As a comparison, we consider the Spanish merit curve, depicted in Figure 10.6. The curve indicates there is a higher percentage of total capacity in renewables (hydro in this case), relative to the market. This can be seen at the zero marginal cost area of the curve. Then, the very low (below €10/MWh) marginal cost capacity is the nuclear. Reductions in the availability of capacity over time have shifted the curve left. Fuel price increases, especially in the price of gas, are evident from about 25,000MW to 40,000MW. Here the shift to the yellow and then the green lines show gas and oil price increases. Coal prices have barely increased, and this is consistent with domestic coal arrangements that are in place pertaining to the Spanish electricity market. Conversely, the impact on mid-merit capacity of EU ETS is starkly evident, when comparing the solid and hashed green curves. The shift in the curve is most evident for CO_2 intensive technology.

Figure 10.6: Merit curve Spain



Source: LE

It is useful to compare the breakdown of prices on average across countries into marginal cost, cost of carbon under EU ETS, and margin. Table 10.3 gives the full details for all six countries. While we previously omitted results from France and Belgium, we present them here, with the same caveats, because the impacts of fuel and carbon can be considered while keeping the caveats on margins and prices in mind.

Table 10.3: Contribution to Power Price (€/MWh)			
Country	**2003**	**2004**	**2005**
BE Belgium			
Sys Modelled MC	€ 29.75	€ 31.70	€ 50.40
Carbon	€ 0.00	€ 0.00	€ 10.11
Mark-Up	€ 11.31	-€ 0.70	-€ 10.23
Total	€ 41.06	€ 31.00	€ 50.28
BE INDEX Price	€ 41.06	€ 31.00	€ 50.28
DE Germany			
Sys Modelled MC	€ 19.46	€ 24.27	€ 28.17
Carbon	€ 0.00	€ 0.00	€ 13.86
Mark-Up	€ 11.42	€ 5.36	€ 6.39
Total	€ 30.88	€ 29.63	€ 48.42
EEX Price	€ 30.88	€ 29.63	€ 48.42
ES Spain			
Sys Modelled MC	€ 23.95	€ 27.51	€ 33.65
Carbon	€ 0.00	€ 0.00	€ 10.12
Mark-Up	€ 6.29	€ 1.39	€ 12.20
Total	€ 30.24	€ 28.89	€ 55.97
OMEL Price	€ 30.24	€ 28.89	€ 55.97
FR France			
Sys Modelled MC	€ 11.09	€ 12.92	€ 15.63
Carbon	€ 0.00	€ 0.00	€ 3.65
Mark-Up	€ 18.96	€ 15.98	€ 28.85
Total	€ 30.05	€ 28.90	€ 48.13
POWERNEXT Price	€ 30.05	€ 28.90	€ 48.13
NL Netherlands			
Sys Modelled MC	€ 36.26	€ 34.64	€ 50.50
Carbon	€ 0.00	€ 0.00	€ 9.52
Mark-Up	€ 11.99	-€ 0.63	-€ 3.09
Total	€ 48.24	€ 34.01	€ 56.93
APX Price	€ 48.24	€ 34.01	€ 56.93
GB Great Britain[11]			
Sys Modelled MC	-	€ 33.33	€ 39.06
Carbon	-	€ 0.00	€ 10.00
Mark-Up	-	€ 1.25	€ 6.35
Total	-	€ 34.58	€ 55.41
UKPX Price	-	€ 34.58	€ 55.41
Note: all of the above values represent load weighted averages of the observed prices and costs.			
Source: LE			

[11] Hourly price exchange data is only available from the UKPX from July 2004.

Across all countries one can see there is a significant increase in the load weighted average system marginal cost over time. Importantly, one should recognise that the increases in marginal cost are likely due to a number of factors. These include fuel prices, capacity additions/subtractions, net exports, and the thermal efficiency of plant on the system. Although reported separately in this table, the impact of carbon in 2005 has also contributed to these increases.

In terms of cost, the marginal impact of carbon depends on how much carbon intensive technology (as well as its thermal efficiency) was on the margin in each hour in any particular market. Therefore, the impact of carbon on France's estimated marginal cost is low (weighted average €3.65/MWh), at least as estimated. This is because our estimates were essentially showing that nuclear (interacting with storage hydro)[12] and to a smaller extent gas were setting the marginal cost in France, the majority of the time. The carbon intensity of all of the above except gas is zero. Conversely, for countries such as Great Britain and Germany, coal and oil are the marginal plant in many hours, and these are carbon intensive technologies (and likely, the marginal plants will have lower than average thermal efficiency). In these cases, the marginal impact of carbon in 2005 is substantial—Germany having the highest cost of carbon at €13.86/MWh. Some countries, such as the Netherlands, show an average negative margin in 2005.

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[12] Mechanically speaking, the pumped storage can't set the price in that it is shaving load, and then the marginal thermal unit sets the price. However, with nuclear and large amounts of storage and pumped storage hydro, nuclear can set the price in many hours (but due to the interacting with the hydro).

In spite of the fact that utilities obtained their emissions allowances for free, one would expect[13] them to price in carbon costs fully, unless they believed doing so would lead to reduced carbon allowances in future rounds. However, we take no particular view on what utilities *should* in fact do with their carbon allowances. By assuming they are priced in, we essentially take the most conservative approach to finding high margins (the CO_2 amounts reported in this report correspond to the maximum possible impact of ETS if generators fully factor in the price of their CO_2 certificates in a competitive environment). One should be aware that the weights applied to computed the weighted averages in this table are similarly the weights applied throughout the report, based on the share of the load in each hour to the total annual load.

The detailed modelling gives the exact contribution and interaction between despatch and technology and fuel prices. Nonetheless, it is useful to compare technology intensity across markets which will give a broad indication of where the carbon intensive technologies are. Table 10.4 presents a comparison of average total installed capacity, by technology, of the units contained in the modelling analysis of each country.

Table 10.4: Country Comparison of Total Installed Capacity (MW) of Modelled Units, by Technology

Country	Gas	Coal	Nuclear	Pump Storage	Other	Total
BE	4,962	1,931	3,953	1,300	999	13,145
DE	14,851	41,158	21,007	6,173	4,920	89,373
ES	13,796	11,358	7,609	2,634	10,491	45,887
FR	1,873	8,003	63,620	4,464	17,964	95,924
GB	26,175	28,997	12,517	1,045	19,578	88,312
NL	9,564	4,333	453	-	1,947	16,298

Source: LE

[13] We say this from an economic perspective. Apparently recent news reports suggest that German competition Authorities believe that pricing in the full cost of carbon is evidence of abuse of a dominant position. We only note that via the design of EU ETS, it was fully intended that companies price in the opportunity or economic cost of carbon.

10.4 Contribution to fixed cost

In addition to estimating the market outcome measures, we also estimated the total value of the contribution to fixed cost likely to result from the optimal dispatch of each system. This value is equal to the quantity of each unit producing times the difference between the modelled system marginal cost (competitive price) and the average marginal[14] fuel cost returned, based on the data provided by the companies in response to DG Competition's data request as part of the Sector Inquiry. The estimated figures do not include the value of CO_2 allowance certificates, distributed at zero cost to generation companies and utilities is 2005. The sum over each company's units in every hour is then the annual total. These figures are found in Table 10.5, for the top 4 companies in each of the selected countries[15]. We note that all of the top four companies in the largest markets (DE, ES, and GB) and the largest (by this measure) company in the NL would have earned (had they traded all their power at the competitive price estimate) contributions to their fixed costs in excess of a billion euro over the three-year period. The smaller companies in the Netherlands each would have earned approximately €500m.

[14] The term average marginal cost indicates the per MWh produced fuel cost in each hour of the plant.

[15] The contribution to fixed cost calculation was not undertaken for France and Belgium, for previously reasons previously explained.

Table 10.5: Contribution to Fixed Costs (€'000)					
Company	**Company ID**	**2003**	**2004**	**2005**	**Total**
DE Germany					
C10	1338-S-DE	1,818,142.0	2,521,370.0	2,782,871.0	*7,122,383.0*
C02	0436-S-DE	1,761,631.0	2,094,008.0	3,084,305.0	*6,939,944.0*
C17	1681-S-DE	784,310.1	1,078,262.0	1,227,499.0	*3,090,071.1*
C03	0569-S-DE	635,197.4	817,859.9	1,358,937.0	*2,811,994.3*
ES Spain					
C01	0577-S-ES	853,472.1	1,029,273.0	1,394,689.0	*3,277,434.1*
C04	0875-S-ES	387,150.9	580,013.1	671,181.4	*1,638,345.4*
C05	1646-S-ES	110,710.3	183,125.7	351,760.2	*645,596.2*
C03	0850-S-ES	135,484.0	121,964.2	126,943.5	*384,391.7*
NL Netherlands					
C05	0712-S-NL	375,394.9	251,917.0	633,023.8	1,260,335.7
C03	0511-S-NL	256,825.5	211,884.0	142,804.9	611,514.4
C06	1193-S-NL	223,846.0	166,949.7	286,358.6	677,154.3
C02	0439-S-NL	210,725.3	149,863.3	79,092.7	439,681.3
GB Great Britain					
C04	0242-S-GB	1,706,199.0	1,808,226.0	2,995,477.0	*6,509,902.0*
C09	0453-S-GB	606,512.1	643,986.9	685,716.3	*1,936,215.3*
C05	0244-S-GB	422,153.5	448,385.1	732,872.3	*1,603,410.9*
C17	1387-S-GB	326,060.2	451,280.3	375,499.3	*1,152,839.8*
Source: LE					

The usefulness of this analysis shows a variety of factors. First, it shows that the model estimated competitive prices are not generally so low that companies would not earn an operating profit. The margins estimated could apply to a variety of costs, including investment costs and start-costs, fixed O&M, etc. In general, the figures indicate substantial sums that could be applied to investment, but without more detailed analysis we cannot say with certainty whether firms would have an incentive to invest in new generation plant. Second, (since exchange prices are higher in general) it shows that the exchange prices and the marginal cost estimates are in a reasonable range in terms of the economic realities of plant. Finally, the figures show the extent of portfolio impacts in the electricity generation industry. The contribution to fixed cost estimates below accrue to the largest companies because they own plant that can generate at a marginal cost that is substantially below the marginal cost of the last plant to generate electricity on the system (which will set the price in the simulated competitive market).

It is difficult, however, to say with any great precision how big these contributions to fixed cost are relative to the true economic total cost of capital for utilities in these countries. There will be added differences still, when one considers the differences between accounting (book values) and economic values[16]. Further, while we consider the figures indicative, one cannot say at what level sufficient incentive to invest exists, without a significant amount of additional detailed analysis. Moreover, any such study of investment incentives would have to be done on a more micro level (e.g., is a particular plant likely to be economic in the system given forecasts of load, prices, etc). Finally, a whole host of factors will influence the size of fixed costs, which are not merely the economic amortisation of the purchase price of the physical capital asset.

[16] In other words, for example, firms may have fully depreciated assets that are still economical. Thus the book value might be zero while the economic value may remain high (a hydro plant would be a good example—as these often have long asset lives).

We note, however, that since our purpose is mainly as a model check, we did perform some calculations merely to give an indicative feel for the size of the fixed costs relative to our estimated contributions to fixed cost. To do this, we constructed a generic new build station investment cost appraisal and amortisation. This situation considers the cost per MW for new build, so existing build that was built years ago at lower per MW investment cost, or that has been depreciated substantially would need lower payments per annum. To do the new build estimate, we considered a rough estimate of the per MW per year cost of a new 400MW CCGT. The figures are from CER and are figures based on judgement and industry sources. We took the life of the plant to be 15 years, and the weighted average cost of capital to be 6.5%. We then took the investment cost of the plant for greenfield new build to be €250m[17]. The investment cost included all connection, financing and financial close, legal, and construction costs. We considered the scrape value of the site to be €15m. These figures are based on the recent CER best new entrant paper, and are in line with LE's recent professional experience. We repeated the process with a selected 400MW generic coal project from recent USA DOE data, and converted to Euro using current exchange rates[18]. We then amortised the investment cost over the life of the plant, and divided by the MW capacity (400) to get a figure per MW per year.

To create a comparable figure, we summed over companies and years and then divided the total contribution to fixed cost figure by 3 to get the average annual figure. We then divided by the average total installed capacity of each market. Thus we have a per MW per year contribution to fixed cost figure.

[17] As a public source check, the cost of Greenfield CCGT is estimated by CER in its 2006 Best New Entrant pricing example. See http://www.cer.ie/cerdocs/cer05088.pdf. They used a WACC of 6-7% with 70% gearing, a 15 year lifespan and a €259m investment cost. €196m was the estimated cost of the EPC contract. We used 250m as the costs of construction and land in Ireland are likely at the top of the range in the EU.

[18] See http://www.netl.doe.gov/coal/refshelf/ncp.pdf, and www.x-rates.com. There were a range of values on the data table available, but the modal figures seemed to indicate an investment cost of $US 1 million per MW. We took the Colorado tri-state Generation and Transmission Project as indicative.

From Table 10.6, one can see that even taking the generic new build (which we argue should be at the upper end of the investment cost scale as it is possible that a number of units are already completely amortised for a number of companies in each country), for most markets the contribution to fixed cost is in excess of the new build figure on a per MW per year basis. Only Spain is somewhat below this, with about €50,000 being contributed per unit capacity, versus about €60,000-€68,000 for the generic new build. However, this is potentially not an issue given the relatively large quantity of hydro capacity in Spain and the likelihood that a substantial proportion of this may already be fully amortised, although it retains a significant economic value. Also, companies in Spain have already previously received substantial contributions to stranded costs as a result of the transition to the pool system, payments that ended in 2005. These two factors will likely combine to reduce the need for companies in Spain to generate revenues sufficient to contribute to fixed costs vis-à-vis other markets in the study. This country specific aspect along with the more general reality that substantial proportions of the capacity portfolio of the countries is already partially or fully amortised, combine to reduce to the need of companies to meet our high threshold of amortising new build capacity and indicate that the competitive prices are in the range of those consistent with amortising fixed costs[19]. However, in relation to the figures, it is difficult to interpret them with greater precision.

[19] Interestingly, the story told by the figures above is consistent with recent evidence. For example, Spain had estimated considerable stranded costs in their conversion to a liberalised market. The figures estimated above are consistent with this. In addition, evidently companies had varying incentives to keep the Spanish pool price low or high based on payments they received from the stranded costs pool. For an interesting discussion see "The Spanish Electricity Industry: Plus ça change …", Claude Crampes and Natalia Fabra , CEPR Working paper, 2004.

Table 10.6: Comparison contribution to fixed cost and generic new build	
	€/MW/Year
Generic CCGT 400MW	67,980
Generic Coal 1000MW	61,911
	2003-05 Average
Germany	76,942
Netherlands	73,119
Spain	50,220
Great Britain	109,102
Source:	

Finally it is useful to note that in terms of economics and competition, the mere existence of such operating revenues (or the cost and pricing structure that would generate them) is not necessarily indicative of any particular market failure. Indeed, it is the ability to earn a margin by investing in the latest efficient plant that is expected to provide the incentive to invest for utilities.

10.5 RSI and PSI

Our analysis also included estimating the residual supply index (RSI) and the pivotal supplier indicator (PSI) for each country and for the biggest two to four firms in each country. These indicators are electricity-specific indicators used to give a richer measure of market structure in electricity markets than standard concentration measures.

Results can be found for the PSI in Table 10.9. From the table we see that some companies are pivotal on a very high percentage of hours. Interestingly, some company's degree of pivotalness has increased over time, for example, company 0436-S-DE in Germany increased from 10.6% to 31.1% from 2003 to 2005. A similar increase can be seen in Spain for company 0577-S-ES. Great Britain shows no company is pivotal in a significant number of hours[20].

[20] FERC Guidelines suggest that if a company is found to be pivotal in excess of 20% of hours in the period under assessment, then the resulting market outcome is not likely to be indicative of a competitive market outcome. This threshold is not the result of rigorous economic analysis but rather of reasoned assessment of the measures performance in a number of markets and as such it is applied in throughout this report as a guiding principle rather than a steadfast threshold.

Table 10.7: PSI threshold test results					
		PSI Result			
Country	**Company**	**2003-2005**	**2003**	**2004**	**2005**
BE	**0513-S-BE**	26,304	8,760	8,784	8,760
	% hrs = 1	*100.0%*	*100.0%*	*100.0%*	*100.0%*
	1469-S-BE	0	0	0	0
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.0%*
DE	**0436-S-DE**	3,037	927	965	1,145
	% hrs = 1	*11.5%*	*10.6%*	*11.0%*	*31.1%*
	0569-S-DE	0	0	0	0
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.0%*
	1338-S-DE	13,091	3,918	4,749	4,424
	% hrs = 1	*49.8%*	*44.7%*	*54.1%*	*50.5%*
	1681-S-DE	2	0	0	2
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.0%*
ES	**0577-S-ES**	5,219	1,033	1,919	2,267
	% hrs = 1	*19.8%*	*11.8%*	*21.8%*	*25.9%*
	0850-S-ES	0	0	0	0
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.0%*
	0875-S-ES	6,759	1,990	2,422	2,347
	% hrs = 1	*25.7%*	*22.7%*	*27.6%*	*26.8%*
	1646-S-ES	7	0	0	7
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.1%*
FR	**0340-S-FR**	0	0	0	0
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.0%*
	0472-S-FR	26,304	8,760	8,784	8,760
	% hrs = 1	*100.0%*	*100.0%*	*100.0%*	*100.0%*
	1449-S-FR	0	0	0	0
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.0%*
GB	**0232-S-GB**	0	0	0	0
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.0%*
	0453-S-GB	0	0	0	0
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.0%*
	1340-S-GB	0	0	0	1
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.0%*
	1477-S-GB	0	0	0	6
	% hrs = 1	*0.0%*	*0.0%*	*0.0%*	*0.1%*
NL	**1193-S-NL**	1,305	389	567	349
	% hrs = 1	*5.0%*	*4.4%*	*6.5%*	*4.0%*
	0712-S-NL	8,232	2,914	2,608	2,710
	% hrs = 1	*31.3%*	*33.3%*	*29.7%*	*30.9%*

Table 10.7: PSI threshold test results					
		PSI Result			
Country	**Company**	**2003-2005**	**2003**	**2004**	**2005**
NL	**0511-S-NL**	3,805	1,657	1,313	835
	% hrs = 1	*14.5%*	*18.9%%*	*14.9%*	*9.5%*
	0439-S-NL	24	24	0	0
	% hrs = 1	*0.1%*	*0.3%*	*0.0%*	*0.0%*
Source: LE					

The RSI is a generalised form of the PSI. The PSI is based on an absolute calculation of pivotalness and as such returns a binary variable (1,0) to indicate whether the specific company was pivotal in that hour. The RSI calculates the indispensability of a specific company relative to the load in the particular hour and thus provides for a continuous measure of market power. Therefore with the RSI one not only determines whether a company is indispensable in a given hour but also one can assess the degree to which the market is relying on this company's available capacity to meet the load, the basis of the company's market power.

A threshold test is similarly applied to assist in the interpretation of the results on calculated RSI values. If in any market a company is found to be below the 110% (1.1) threshold in more than 5% of hours, the resulting market outcome cannot be considered to be a competitive outcome[21]. The summary results across countries of the specified threshold test for the RSI are contained in Table 10.8.

[21] This threshold test, similar to the one applied in relation to the PSI, was developed based on knowledge of market performance and was not the result of rigorous economic study. It nevertheless acts as a guiding principle in our interpretation of results but should not be considered to be a steadfast rule.

Table 10.8: RSI threshold test results		
Country	**Company**	**03-05 % line**
BE Belgium	0513-S-BE	100.0%
	1469-S-BE	5.0%
DE Germany	0436-S-DE	47.7%
	0569-S-DE	4.6%
	1338-S-DE	77.1%
	1681-S-DE	3.8%
ES Spain	0577-S-ES	41.1%
	0850-S-ES	0.0%
	0875-S-ES	49.2%
	1646-S-ES	0.6%
FR France	0340-S-FR	0.5%
	0472-S-FR	100.0%
	1449-S-FR	0.0%
NL Netherlands	0439-S-NL	3.5%
	0511-S-NL	32.8%
	0712-S-NL	44.6%
	1193-S-NL	22.7%
GB Great Britain	0242-S-GB	1.2%
	0453-S-GB	1.7%
	1340-S-GB	1.2%
	1477-S-GB	2.3%
Source: LE		

The result of comparing the RSI measures across countries show a significant contrast. In the most concentrated countries, the presence of certain suppliers is indispensable to meeting load in up to 100% of hours. In other countries, such as Great Britain, the number of hours is less than 5% for any of the large companies.

A number of sensitivity scenarios were calculated in relation to each of the countries, including scenarios to estimate the potential impact of existing interconnector links on the market structure in each country[22]. Overall the assessment found that interconnectors did not have the potential to affect the results already found in relation to France, Belgium and Great Britain. However, in particular cases interconnectors are found to impact considerable on the results presented above. In Spain, there is a noticeable impact but the observed effect gets potentially larger as one looks at the Netherlands and finally the German market, where the difference in results are most stark.

[22] One should refer to the specific country chapters to see the full compliment of sensitivity cases calculated in relation to each country, as well as the basis for these scenarios. As is explained in more detail both in the methodology chapter and in the individual country chapters, assumptions had to be made about the apportionment of interconnector capacity in each market due the absence of company specific data on interconnector capacity reservations and utilisation.

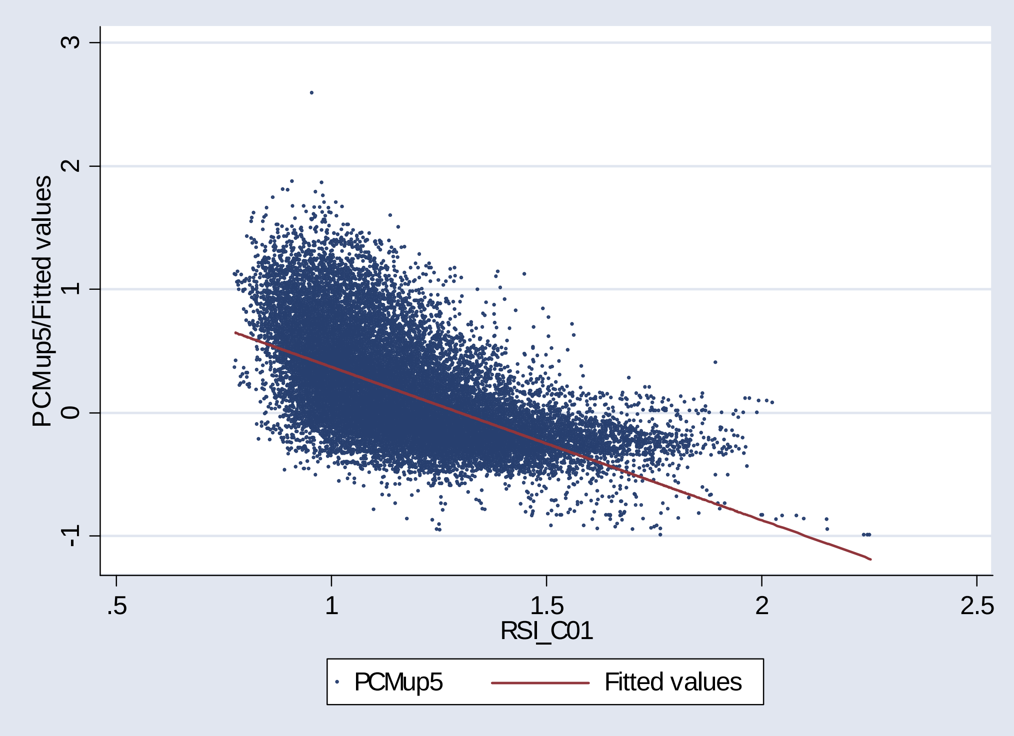
10.6 Single variable regression analysis

In order to investigate the relationship between the market outcome/market performance measures and the structural indicators previously discussed, we undertook a detailed regression analysis with the objective of testing this link and in the presence of such a link, uncovering the nature of the relationship. There are of course many factors that influence price and margin, including scarcity, that may not be market power related, so a model that is able to control for such factors would prove extremely interesting and would contribute substantially to a relative dearth of literature and analysis of this issue. For this reason, we undertook regression analysis of PCMU and LI on RSI. RSI is a continuous measure so it is the only candidate for regression analysis[23]. We start this analysis with simple regression analysis—we regress the price cost mark up on the RSI of the biggest companies in each market.

A graphical representation of the estimated regression line resulting from a simple (univariate) regression of PCMU on the RSI relative to company 0577-S-ES in Spain is presented in Figure 10.7.

[23] Previously studies have attempted to econometrically investigate the relationship between PCMU and HHI but this has largely not been successful. See; Williams, E. & R. Rosen, 1999; "A Better Approach to Market Analysis", mimeo, Tellus Institute, Boston, July 1999.

Figure 10.7: Fitted values regression PCMU on RSI – Spain

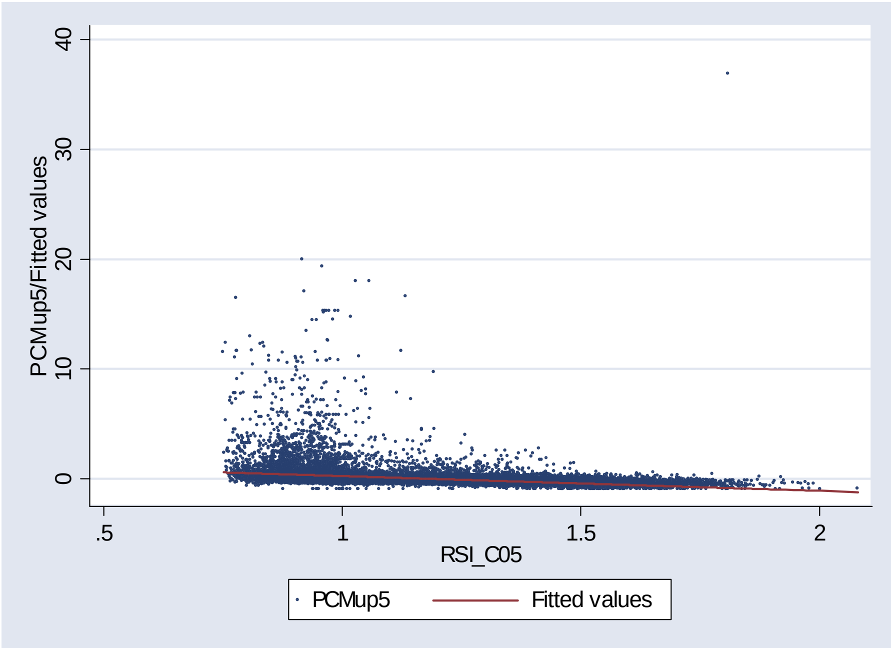


Source: LE

Some discussion of the figure is warranted. The figure shows the fitted line and the scatter of points. There are apparently some features not captured in the simple univariate linear regression model. For example, there seems to be a possible quadratic effect, with observations more likely to be above the fitted line at the extreme values of the observed RSI. We investigated this and found that the goodness-of-fit of the estimated regression equation was only marginally improved by the adoption of such an approach. A variety of regression specifications have been estimated on relation to each country, the details of which can be found in the specific country chapters. One should note that the purpose of this simple regression analysis was mainly to confirm the link between RSI and margins empirically, this is confirmed irrespective of the model functional form chosen.

It is useful to compare this previous result with at least one other country. The estimated regression line resulting from the simple regression of PCMU on the RSI relative to company 0712-S-NL in the Netherlands is presented in Figure 10.8.

Figure 10.8: Fitted values regression PCMU on RSI – the Netherlands



Source: LE

The linear relationship between PCMU and RSI seems much closer to reality in the Netherlands than in Spain. There is some tendency towards large values that are above the line for low values of RSI, but on the whole the vast majority of points are clustered evenly around the line. The fitted line appears to be a reasonable representation of the observations.

While we presented just two graphs of the estimated regression lines of the simple regression results, the regressions were carried out for each large company for whom reliable margin data and RSI data were estimated[24]. The cross-country results are presented in the table below for the regressions of PCMU on RSI.

[24] Regression analysis was not undertaken in the case of France and Belgium for reasons previously outlined. Further discussion of this is contained in the specific country chapters.

Table 10.9: Comparison across company and country—simple regression PCMU on RSI					
Company-Country	Variable Name	Coefficient	Std. Err.	t	R-squared & Prob>F
0577-S-ES	RSI	-1.242	0.010	-120.0	35.6%
0577-S-ES	_constant	1.613	0.012	130.6	0.0%
0875-S-ES	RSI	-1.385	0.012	-118.5	35.1%
0875-S-ES	_constant	1.718	0.013	128.4	0.0%
0242-S-GB	RSI	-0.85	0.015	-57.8	20.3%
0242-S-GB	_constant	1.32	0.022	59.6	0.0%
0453-S-GB	RSI	-0.90	0.015	-58.8	20.8%
0453-S-GB	_constant	1.35	0.022	60.5	0.0%
1340-S-GB	RSI	-0.87	0.015	-58.4	20.6%
1340-S-GB	_constant	1.33	0.022	60.2	0.0%
1477-S-GB	RSI	-0.87	0.015	-56.4	19.5%
1477-S-GB	_constant	1.29	0.022	58.1	0.0%
0436-S-DE	RSI	-2.36	0.034	-69.1	15.4%
0436-S-DE	_constant	2.93	0.039	75.0	0.0%
0569-S-DE	RSI	-2.00	0.030	-66.7	14.5%
0569-S-DE	_constant	2.82	0.039	72.6	0.0%
1338-S-DE	RSI	-2.43	0.042	-57.5	11.2%
1338-S-DE	_constant	2.73	0.043	62.8	0.0%
1681-S-DE	RSI	-1.92	0.029	-67.0	14.6%
1681-S-DE	_constant	2.75	0.038	73.1	0.0%
0511-S-NL	RSI	-1.22	0.021	-57.2	11.1%
0511-S-NL	_constant	1.55	0.028	55.5	0.0%
0712-S-NL	RSI	-1.35	0.024	-56.2	10.7%
0712-S-NL	_constant	1.58	0.029	54.6	0.0%
Source: LE					

The results from the table above are the marginal impacts of RSI on the price cost mark up, absent of the *ceteris paribus* caveat. This is due to the fact that no other factors or regressors are included in the regression model. Thus, in this model, only random error is controlled for. The RSI value is equal to one (100%) when a large supplier is technically pivotal, when the residual supply in the market is equal to the load in that hour. So a coefficient estimate of -1 would mean that essentially a 1% change in the RSI would lead to a 1% change in the price-cost mark up. The expected sign is negative, since more capacity means the market is less tight, and thus the RSI will rise, and margins would then be expected to fall. The t-values indicate that all estimated coefficients are statistically significant for each company in each country. The R-squared values range from about 11% to 35%, which is a reasonable fit for this type[25] of regression. There is a near 0% chance that the regressions are merely by chance given the models' specifications and the further regression analysis undertaken in each of the country chapters.

We also note that, while there were some sensitivities to RSI estimated, we did not feel it would be necessary to carry out the regressions using alternative RSI measures under the various sensitivity estimates. This was for a variety of reasons. First, the randomness or error that is introduced from a sensitivity (or alternative scenario) is modelled implicitly in the error term. If the model is not capturing the full reality (without the sensitivity) then that simply shows up as error; but the regression results using the standard RSI are already highly significant. Second, the impact of using the sensitivity cases for things such as interconnectors especially is likely to be low. In the more competition (atomistic allocation) scenario, for example, the shares of the biggest companies do not change, so this should not have a big impact (especially when controlling for scarcity). Secondly, for the alternative case (allocation to the largest player based on market shares), this would only tend to make the existing largest companies 'more pivotal' and so would tend to accentuate the results.

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[25] These regressions are referred to as univariate regressions, meaning they include only one explanatory variable along with a constant to explain the variation in the dependent variable (PCMU). To further develop the explanatory power of this regression one could, for example, include as an independent variable a lag of the dependent variables, or by including a full range of dummy variables, one for each hour (1-24), season (winter, spring, summer fall), day of the week, as is subsequently discussed.

10.7Multiple variable regression analysis

While the single variable models are important first steps in the development of our modelling, they are not likely to be the best models. This is because a number of factors may also be driving price cost margins, and these are not effectively controlled for in the univariate analysis. The addition of further explanatory variables enables the model to estimate the impact of the RSI on margins while controlling for the potential impact of the newly included variables.

Therefore, to develop our models and our general understanding further, we built and tested additional regression models. We tested the sensitivity of the models to violations in the classical linear regression assumptions and tested the results across a variety of specifications. Dummy variables were included for peak and off peak periods, as well as to capture seasonal and annual effects, thus allowing for shifts in the intercept of the estimated regression line. The slope of the estimated regression line was also allowed to vary through the inclusion of what amount to slope dummy variables for peak and off-peak periods. Summary results for just one of these models estimated for the top two companies in each of four countries (DE, ES, NL, and GB) can be found in Table 10.10[26]. As a reference for these results one can find the specific company references in Table 10.11.

[26] Additional regressions and model output details can be found in the country chapters.

Table 10.10: Multivariate Regression Analysis

(Dependent variable; price cost mark-up)

Explanatory variable name	DE	ES	GB	NL
RSI_C01	-0.42	-2.11*	-3.21*	-2.26*
RSI_C02	2.21*	-2.28*	-2.27*	-2.35*
RSI_C01_C02	-0.02	1.72*	1.54*	2.25*
Scar	-2.16*	-0.73*	-0.32**	-1.87*
C0_gas	0.00*	0.00*	0.00*	0.00*
C0_coal	0.00***	0.00*	0.00*	0.00*
d2004	-0.25*	-0.27*	-0.09*	-0.18*
d2005	-0.37*	-0.08*	-	-0.25*
dpeak	0.22*	0.08*	-0.02**	0.04*
dsummer	0.11*	0.01***	0.11*	0.02***
dwinter	-0.12*	-0.08*	-0.22*	-0.20*
dwkday	-0.03*	-0.07*	-0.19*	-0.21*
_cons	-0.65	3.58*	5.14*	3.70*
R-squared	*26.2%*	*51.2%*	*29.8%*	*16.4%*

Note: *=significant at 1% level; **= significant at 5% level; ***= significant at 10% level
Source: LE

Table 10.11: Company reference for comparison of multivariate regression results

Company	DE	ES	GB	NL
RSI_C01	0436-S-DE	0577-S-ES	0242-S-GB	0511-S-NL
RSI_C02	1338-S-DE	0875-S-ES	1477-S-GB	0712-S-NL

Source: LE

The figures presented in the table above are the coefficient estimates for one particular model with multiple regressors included, and compared across all countries. This model included dummy variables to control for year, peak, summer-winter, and weekdays. It also included the two RSI figures of the largest companies, and scarcity (see the country chapters and the methodology chapter for definitions of the variable and the methodology). An interaction term is also included, as are measures of behaviour that are potentially consistent with withholding behaviour[27], summarised as the difference between actual and modelled generation.

The coefficients' statistical significance is based on robust[28] standard error estimates. As indicated by the asterix (*), almost all of the coefficients are statistically significant. The expected sign of (-) is found for all the significant[29] coefficients on the RSI variables and scarcity (save company 1338-S-DE in Germany[30]). The scarcity variable has varying degrees of impact across countries, suggesting that the impact of the scarcity of generation is larger for some countries. However, the general size (magnitude) of the RSI variables is interestingly similar across countries, save Germany. One difference about Germany that may cause these results is that a large amount of long-term contracts exist for some companies in Germany. While one explanation might be that the nature of the contracts gives certain companies less ability or incentives to influence prices, not much can be concluded about this with certainty at this time without further investigation.

[27] In essence these are measures of all the reasons for which modelled generation and actual generation differ. For this reason, we do not necessarily interpret them as any indicator of market power use or abuse. Conversely, however, we exploit this fact by including them in the regressions. Thus, the regressions can be interpreted as having controlled for possibly benign reasons that some particular generation technology differed from the modelled approach in reality.

[28] These are error terms that allow deviations from the standard normal iid assumptions for the error terms. Thus the test statistics on the coefficients are 'robust' to violations in the classical linear assumptions such as the presence of heteroskedasticity. To correct for heteroskedasticity, we use Huber-White sandwich estimator of variance in place of the traditional calculation to ensure our standard errors are robust.

[29] One does not normally interpret the sign of statistically insignificant coefficient estimates.

[30] See the Germany chapter of the report for a further discussion of this result.

The other variables and dummy variables are significant and of the expected signs in general. The summer variable increases margins, while the winter variable decreases. This is noteworthy that this is an increase in margins, not prices. Further, these variables control for unobserved factors correlated with the dummy variables (e.g., winter-not winter, summer-not summer). It is therefore not possible to interpret whether these impacts are due to market power or not.

Finally, a few words about the additional variables. First, the interaction term is of a positive sign and significant across countries. This result indicates that the degree to which a particular firm can manipulate the market outcome through the exercise of market power is enhanced the more the company's closest competitor is similarly indispensable to serving load[31]. The "withholding" variables may also be potentially difficult to interpret. Withholding here is merely the difference between actual and modelled generation and aggregated across companies by technology. It is therefore not a company-specific measure. Further, as noted elsewhere, it cannot be said with certainty why actual and modelled generation differ, and some may be merely due to multiple optima or nearly optimal despatch patterns (i.e., it is possibly equally efficient to have a number of different despatches). However, the usefulness of these variables is that they are thus controlled for the in the regressions.

[31] This result can be found algebraically by taking the partial derivative of the fully specified regression equation with respect to the RSI of either company.

10.8 Conclusions to the summary chapter

This chapter has given an overview and summary of the report. The summary chapter set out broad comparisons of the cross-country results for our key indicators and outcome measures. In general, some important differences emerge in some of the results, while the results are broadly similar in other cases.

The concentration of the markets was measured by traditional (*CR(n)* and HHI) and more innovative measures (RSI and PSI) of market structure designed specifically for electricity markets. Concentration, in general as measured by traditional concentration measures, shows marked differences across countries, but little variation over time or by method within countries. Some markets, such as Great Britain, are borderline unconcentrated; others such as Spain, Germany and the Netherlands are moderately to highly concentrated, while France and Belgium are highly concentrated. Our results were, in general, not sensitive to a variety of factors and sensitivities, such as the allocation of the interconnector. In most cases, our qualitative conclusions were not sensitive to changes in assumptions. There were notable exceptions, such as the allocation of interconnection for the Netherlands (who controls what shares over the interconnector will likely change the overall picture of whether the Netherlands is a concentrated or unconcentrated market).

Results from the RSI threshold test show that broadly similar outcomes occur, but the magnitudes change. The most concentrated markets fail the RSI threshold test in a very large percentage of hours, with respect to the largest companies (e.g., 100% in France and Belgium). On the other hand, only a small number of hours show RSI failing the threshold test in some markets such as GB. Spain, the Netherlands and Germany have two companies with significant market position between about 20% and 50% of the time.

Comparing the market outcome measure and the actual breakdown of costs also shows interesting differences. Countries with lower costs seem to have higher margins for example, but no broad consensus correlation can be observed. A similar lack of consensus can be had when comparing the concentrations and the margins. Great Britain had low margins, while the Netherlands had the lowest margins; but Great Britain is less concentrated than the Netherlands. There are also important differences in margins across time. It is difficult to interpret these results, so the additional analysis of margins using RSI regressions is both necessary and warranted. Issues in relation to the availability of French nuclear plant created challenges in modelling the marginal cost in France, and the lack of a good hourly price for Belgium meant that estimates of margins in these countries should be considered less reliable than in the other four. They are only presented in the breakdown for the benefit of showing the impacts of carbon. In addition, further analysis such as regressions and fixed cost contribution was not carried out for these countries.

Of considerable further interest is the breakdown of the power exchange price into the constituent components; cost, mark-up and the cost of CO_2 emissions since the introduction of the ETS. We cannot fully interpret whether companies have passed on the full cost of carbon or whether they have "raised" margins in response to carbon. It is perhaps that companies do not pass on the full cost since they have received allowances for free. We further do not take a stance on what should have been done. We have included the full cost of carbon in our comparisons, as this is the maximum amount a competitive market would have passed on the cost of carbon. Thus we take the most conservative approach. What we can conclude from our results is that seemingly differential factors have occurred across countries, and the size of the marginal impact varies across countries with the introduction of EU ETS, while the total marginal cost of carbon as estimated also changes.

We also compared estimates of the contribution to fixed costs. This section indicated that had the largest companies traded at the marginal cost estimates, (theoretically the perfectly competitive price), they would have earned billions of euro towards their investment costs. This assessment was a broad check on the overall level of the marginal costs estimated by the modelling of each market. Comparisons of the per MW value of these contributions showed that, even for a generic 'new plant', the contributions estimated would have covered the annual amortised payments for the new plant in DE, GB, and NL. In Spain the per MW values were slightly lower, but we note that many plant in Spain would not be new and have lower fixed costs.

Finally, we estimated regression models for four countries using a variety of explanatory factors and specifications. The regression results included the estimation of the impact of RSI on margins and estimates including a variety of explanatory variables. The results showed that the RSI, a continuous measure of how pivotal an individual large supplier is, significantly explains margins in all markets. This result is apparently robust to controlling for a number of factors, including model specification, changes in the assumptions of the statistical model, and inclusion of other explanatory factors such as scarcity, year, seasonality, and the modelled differences between actual and modelled generation of coal and gas. The results are consistent with the hypothesis that pivotalness gives firms market power in electricity markets, but does not necessarily prove it.

11 Conclusions

This chapter gives conclusions to the report. It first reviews the country-by-country conclusions and then gives some overall conclusions to the report.

11.1 Belgium

We start our discussion of country-specific conclusions (alphabetically) with Belgium. Belgium remains one of the more concentrated markets of the six we studied. By traditional concentration measures, Belgium's market concentration is high by any standards. Much debate in electricity market research has centred around whether some threshold for the HHI was sufficient to relate market concentration to market power, but no serious arguments have been made that concentrations about 80% for CR(1) or CR(2), or HHI above 2,500 would be conducive to competitive market outcomes.

By these measures, Belgium's HHI was between 7,694 (mean value over the sample period based on available capacity) and 8,843 (mean based on total generation). CR(1) was 86.4% and 93.7%.

There are variations in the concentration measures based on a number of factors. First, hourly measures were calculated. Variation and changes in availability (e.g., forced and planned outage, summer deratings, etc) impact the concentration measured in the market as measured by capacity. We also calculated the standard concentration measures based on generation. Here, changes in the share of total generation or in merit capacity can potentially cause the standard concentration measures to vary.

The sensitivity of these conclusions was qualitatively not large to changes in the assumptions and factors such as allocation of the interconnectors. By various means, the CR(1) ranged from 75.5% to 94.3% and HHI ranged from 5,332 to 8,932. All well above standard thresholds of 30% and 1,800[32].

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[32] There is no clear threshold accepted by all. As discussed previously, 1800 might be too stringent a threshold if there is excess capacity, and too high a threshold if the market is tight. This said, the general information from the website of the DG Competition defines HHI<1000 to be unconcentrated, 1000<HHI<1800 moderately concentrated, and HHI>1800 highly concentrated. The US Federal Energy Regulator (FERC) and anti-trust authorities use similar guidelines.

RSI and PSI were calculated as measures of market structure that are more finely tuned to electricity markets than traditional measures. The proposed threshold test is failed for Belgium 100% of the time.

Price outcomes in terms of price cost margins were estimated for Belgium. Price cost margins were calculated using the Platts and Electrabel's BPI prices. Belgium does not have an obvious wholesale hourly spot price over the sample time period 2003-05[33]. Of the available prices, the BPI is for a limited quantity[34] and does not represent any kind of supply and demand matching via price. Further evidence on the relationships between the BPI and scarcity also suggest that BPI is not well correlated with scarcity as required. Platts is a daily 'assessment' price (a survey of over-the-counter and possibly other trades) and as such is also not an hourly series of price values. Therefore, the price cost margin estimates for Belgium should be interpreted with caution as they are based on representative prices in the majority of hours.

The various measures of margins using these limited price data showed marked variations with significant margins in some years and negative margins in others. For example with LI in 2003 at 27% using the BPI (38% for the PCMU), but zero using Platts prices in the same year. The margins over BPI were negative using either LI or PCMU in 2005. The negative results in 2005 may be explained by a lack of CO_2 allowances being fully priced in. These results should be interpreted with much care since they are prices for a set quantity sold and supplied (by the largest operator) (BPI) and over the counter assessment prices (Platts)[35]. Our conclusion on Belgium prices and margins is then that the results are indicative but, due to data constraints, merit further investigation or interpretation along the methods used in our report, perhaps once a longer time-series of BELPEX data are available.

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[33] The Belgian Power Exchange (BELPEX) is an hourly day-ahead spot market but only has been trading since late November 2006.

[34] The BPI is not an appropriate price for measurement of margins because it does not result from the interactions of supply and demand. The main operator sets BOTH the price AND the quantity; therefore, the informational content of the price cannot be relied upon. The chapter on BE has additional discussion.

[35] The Platts prices in addition may reflect other additions to margins (such as forward or over the counter premia) that should not necessarily be associated with market power.

Due to the lack of available and comparable price data, we did not estimate regression models for Belgium. We note that with the concentration measures as currently stand, qualitative conclusions that Belgium's market structure is unlikely to be conducive to competitive outcomes remain the same.

11.2 France

The French market was in general found to be highly concentrated, regardless of what measure was used.

Market structure as measured by traditional concentration measures HHI and CR(1) consistently returned a result indicative of a highly concentrated market, regardless of approach taken to calculate such measures.

In terms of our sensitivity analysis, this had little impact on the qualitative conclusion that the market is highly concentrated on the basis of the results for the traditional concentration measures.

While in general there are variations in the concentration measures based on a number of factors, such as outages and availability over time, the results on concentration are not sensitive to these in France.

The electricity-specific measures of market structure confirmed the qualitative conclusions of the HHI and CR(1) for France. In general, the largest company's RSIs failed the proposed screening test with RSI<110% in greater than 5% of hours. Similar results were found for the PSI in France, with the PSI finding a single company was pivotal in 100% of hours.

Price-cost margins in France were higher than in other markets. However, price cost margin outcomes in France come with a strong note of caution. France's reliance on nuclear capacity coupled with hydro give it a very low estimated marginal cost in many hours. Study of the apparent differences between the modelled output of nuclear and its actual output led us to be cautious about the results due to what appears to be an over-estimation of the availability of nuclear capacity in France. We believe this to be likely a data issue on the reported capacity of nuclear plant versus their actual running. We cannot tell with any great certainty whether this difference is due to some kind of exercise of market power or rather some rationale that is benign and a function of how French nuclear plants are operated. Nevertheless even if one could correct for this, the load profile in the French market indicates that nuclear capacity would remain setting the price in a large number of hours in the market. It is important to further note that the large quantity of electricity exported, on average, by France was accounted for[36]. The overall leads one to further consider the ability of firms to amortise fixed costs in a market where infra-marginal rents are not apparent due to the flat nature of the merit curve. Although a calculation of the contribution to fixed cost was not undertaken, due to potentially difficulties in interpretation as a result of the absence of data about how much the fixed costs of French nuclear units represent and how much of these costs are really amortised, this issue means that similarly no real conclusions can be reached in relation to the market outcome measures. A caveat applies in relation to these figures, not because they are not correct but because given the current data one cannot discern whether market characteristics or market behaviour are determining the results. With these cautions in mind, however, France had some of the highest margins of any country studied.

[36] This was handled in each country by modelling demand as the sum of total generation reported on an historical basis. To the extend that generation for export existed, then, it was modelled as demand.

Relating the RSI to the market outcomes via regression analysis for France was not done. However, the extremely high market concentration in France indicates that France is not near any recognised of borderline or threshold in terms of a market structure that might be competitive, due to the unique nature of electricity markets[37]. Therefore, the regression analysis to a certain extent is not needed to determine the true nature of the market structure in France[38].

The breakdown of power prices into cost estimates plus margin, and the inclusion of carbon revealed that a significant portion (approximately 22% or €3.75) of recent price rises in France can be attributed to carbon cost inclusion due to the introduction of the EU ETS. The impact of carbon on the French market is estimated to be lower than in markets such as Great Britain or Germany, which is as expected given the amount of non-carbon intensive technology employed (nuclear and pumped storage/storage hydro). From a purely economics perspective, in spite of the fact that utilities obtained their emissions allowances for free, one would expect them to price in carbon costs fully, unless they believed doing so would lead to reduced carbon allowances in future rounds. However, we take no particular view on what utilities should in fact do with their carbon allowances. By assuming they are priced in, we essentially take the most conservative approach to finding high margins (i.e., the amounts reported are the maximum possible impact of the ETS if generators fully factor in the price of CO_2 certificates in a competitive environment). One caveat that should be added here is that the estimate of the overall cost of carbon is based in the results of the modelling of the system. Therefore, any difficulties that arise in relation to the availability of nuclear capacity and its impact on the simulated competitive system marginal cost, similarly arise in relation to the estimate of the cost of carbon.

Our conclusions on France are that the French market is highly concentrated and this conclusion is not depending on the measures taken or the allocation of the interconnectors.

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[37] Recall from the methodology chapter that electricity markets might behave competitively a la Bertrand even if concentration is high, if capacity is high relative to demand. In the case of France, however, this is not likely to be the case.

[38] That is not to say it would not have been useful for other purposes. It could be used to indicate how 'well' certain operators were behaving. But in general this was not the goal of this report as it was not intended as a specific inquiry into specific operator's behaviour.

11.3 Germany

The German market was in general found to be concentrated. German concentration measures were somewhat sensitive to variations in allocations of interconnection and also due to a high level of contracted generation. Whether this level of concentration is conducive to competition is an open question, but our analysis suggests, at least in some significant number of hours, that poor market outcomes are possible.

Market structure as measured by traditional concentration measures HHI and CR(2) ranged from moderately concentrated to highly concentrated.

Based on available installed capacity, the HHI for Germany was found to be 1,914 on average through the sample period, and the CR(2) was found to be 54% and ranged from a high of 2,158 to a minimum 1,734 over the sample period[39]. Allocating the interconnectors led to a range from 1,160 to 2,603 for HHI and 42.1% to 64.3% for CR(2). We note that threshold values such as 1,800 for the HHI and 33% for *CR(n)* are somewhat arbitrary.

[39] There are variations in the standard concentration measures based on a number of factors. First, hourly measures were calculated. Variation and changes in availability (e.g., forced and planned outage, summer deratings, etc) impact the concentration measured in the market as measured by capacity. We also calculated the standard concentration measures based on generation. Here, changes in the share of total generation or in merit generation would cause the standard concentration measures to vary.

In terms of our sensitivity analysis, Germany might be considered to range from moderately concentrated to highly concentrated, depending on whether the basis for market shares is generation or capacity, whether one accounts for the potential role of long-term contracts, and also depending on whether interconnection is allocated to large companies already holding capacity in the country, or whether interconnection capacity is allocated to competitors. Variations in availability or in merit capacity over time also impacts on the concentration measures. The range of mean HHI under these for the measures excluding the interconnector was 1,914 to 2,145, while, as seen above, the HHI based on available installed capacity goes up to 2,603 in our 'added to the biggest player' scenario, and as low as 1,160 in the 'atomistic' scenario (mean values). We note, however, that these variations varied over time and interconnection allocation measure. Even in the atomistic interconnector case the market would still be considered to be moderately concentrated. Across the variety of cases, a significant number of hours are likely to range from concentrated to highly concentrated.

The electricity-specific measures of market structure in general confirmed the qualitative conclusions of the HHI and CR(2) for Germany. However, there is more contrast between the two types of indicator with Germany than in some other countries. The RSI and PSI pointed more towards possible poor market structure. In general, the largest two companies' RSIs failed the proposed screening test with RSI<110% in greater than 5% of hours. Similar results were found for the PSI in Germany, with the PSI finding a single company was pivotal in between 49.8% of hours. This percentage of hours of pivotal-ness is well in excess of any screen for possible market power problems. Thus the electricity specific market structure measures point towards a market structure that is likely to exhibit non competitive outcomes.

Price-cost margins in Germany were significant and higher than Great Britain or Spain, with an average price cost margin over the full sample period of 35.2% for the LI and price-cost mark-up (51%), and 54.4% for the price cost mark-up over Platts.[40]

[40] Based on Platts assessment price.

Relating the RSI to the price cost margins via regression analysis for Germany showed similar results as to other countries (ES, GB, and NL), with some exceptions. The RSI is a significant explanatory variable for the margins estimated in Germany. The inclusion of additional variables such as scarcity did not change this conclusion, nor did the inclusion of more than one RSI variable. Statistical significance was in general robust to a number of changes in the assumptions, including changing specifications, dummy variables for peak and off peak, and violations of the classical linear regression assumptions. The regression results for Germany did show some differences to the other countries. Inclusion of the scarcity variable caused some of the RSI variables to lose their statistical significance, and in at least one regression the scarcity variable changed sign.

Contributions to fixed cost estimates showed substantial sums would have been earned at the competitive price (marginal cost) estimates. This indicated that marginal cost estimates for the German market were not so low than many generators would not earn significant margins towards their fixed costs. Comparison of the German contributions to fix cost vis-à-vis a generic new entrant showed sufficient contributions to cover the annual amortisation payments of a new entrant. This was done merely as a modelling check and to give an idea of how large the fixed cost contributions were. We were not able to further validate the size of the contribution to fixed cost[41]. However, one should note that for existing market participants, a substantial proportion of their portfolio is likely to be partially or fully amortised thus reducing the need to cover such costs. Furthermore, in the vast majority of hours the EEX price exceeded the competitive market price, thus allowing for potentially greater contributions to fixed and other costs.

[41] Doing so would have required estimates of the book value, depreciation, and age and technology profile of plant.

The breakdown of power prices into cost estimates plus margin, and the inclusion of carbon revealed that a significant portion of recent price rises in Germany can be attributed to carbon cost inclusion due to the introduction of the EU ETS. In spite of the fact that utilities obtained their emissions allowances for free, one would expect[42] them to price in carbon costs fully, unless they believed doing so would lead to reduced carbon allowances in future rounds. However, we take no particular view on what utilities *should* in fact do with their carbon allowances. By assuming they are priced in, we essentially take the most conservative approach to finding high margins (i.e., the amounts reported are the maximum possible impact of the ETS if generators fully factor in the price of CO_2 certificates in a competitive environment).

Estimates of withholding were significant in the regression analysis in Germany. We do not interpret this specifically as estimates of economic withholding as a means of the use of market power, but rather included withholding in the regression as a measure of either economic withholding or other reasons why the modelled despatch may have deviated from the actual despatch. These impacts were statistically significant in some cases on the regressions of margins on RSI, but were small relative to the RSIs and scarcity, and also did not tend to make other variables such as the RSI insignificant.

The regressions of margins on RSI are important (in that they provide added information for a more borderline cases and relate market outcomes to market structure). Whether Germany in fact is moderately concentrated or highly concentrated, price cost margins (LI and PCMU) were significantly related to market structure via the regressions. This latter finding could indicate that market power use or market imperfections exist/have existed. Of course, alternatively, it is always possible that the regression models as specified are unable to distinguish between this explanation and some alternative unknown, but more benign, rationale.

[42] We say this from an economic perspective. Apparently recent news reports suggest that German competition Authorities believe that pricing in the full cost of carbon is evidence of abuse of a dominant position. We only note that the via design of EU ETS, it was fully intended that companies price in the opportunity or economic cost of carbon.

11.4 The Netherlands

The wholesale electricity market in the Netherlands was in general found to be concentrated, but perhaps more than in other countries the traditional concentration measures showed the most variation among the countries, time and within particular scenarios such as allocation of the interconnectors. Whether this level of concentration is conducive to competition is an open question, but our analysis suggests, at least in some significant number of hours, that poor market outcomes are possible.

Based on available capacity, the HHI for the Netherlands was found to be 2,153 on average through the sample period, and the CR(2) was found to be 54.5%[43]. Measuring concentration by available installed capacity and allocating the interconnectors led to a range from 938 to 3,835 for HHI and 34.4% to 77.4% for CR(2). We note that threshold values such as 1,800 for the HHI and 33% for *CR(n)* are somewhat arbitrary.

The Netherlands was somewhat unique in terms of our sensitivity analysis. Due to a high level of interconnectivity, in general, the Netherlands might be considered borderline unconcentrated to highly concentrated, depending on whether interconnection is allocated to large companies already holding capacity in the country, or whether interconnection capacity is allocated to competitors. Sensitivity analysis regarding the allocation of interconnectors to market shares, basing market shares on generation or in merit capacity, as well as the attribution of long-term contracts did have some impacts on the concentration measures. The range of HHI under these measures was 1,239 to 3,304, on average. Variations in time matter less than interconnection, but also cause some changes in the estimated concentration measures.

[43] There are variations in the concentration measures based on a number of factors. First, hourly measures were calculated. Variation and changes in availability (e.g., forced and planned outage, summer deratings, etc) impact the concentration measured in the market as measured by capacity. We also calculated the standard concentration measures based on generation. Here, changes in the share of total generation or in merit generation would cause the standard concentration measures to vary.

We also note that interconnection policy between the Netherlands is one of the more advanced and transparent in the EU, with open auctions to allocate interconnection capacity, use-it-or-lose-it rules, limits on any one company obtaining an excess share of capacity, among other things. In spite of all this, there is some evidence that the Netherlands does not function as a market fully integrated with Germany (see EC DG Comp second report on the electricity sector 2006), but investigating the details of this were beyond the scope of this report.

The electricity-specific measures of market structure to a certain extent confirmed the qualitative conclusions of the HHI and CR(2) for the Netherlands. Some hours show market structure that is conducive to non-competitive outcomes. In general, the largest two companies' RSIs failed the proposed screening test with RSI>110% in less than 5% of hours. Similar results were found for the PSI in the Netherlands, with the PSI finding a single company was pivotal in between 31.3% of hours.

Price cost margins in the Netherlands were lower than in Great Britain, but lower still than in Germany, with an average price cost margin over the full 2003-05 sample period of 13.7% for the LI (APX), 14.4% for the price-cost mark-up based on the APX, and 15.9% for the price cost mark-up (PCMU) based on Platts prices.[44] There were significant variations in the margins over time, for example with the PCMU weighted average of 33.1%, -1.8%, and 12.7% for 2003, 2004, and 2005[45] respectively.

Relating the RSI to the price cost margins via regression analysis for the Netherlands showed similar results as to other countries (GB, DE, ES). The RSI is a significant explanatory variable for the margins estimated in the Netherlands. The inclusion of additional variables such as scarcity did not change this conclusion, nor did the inclusion of more than one RSI variable. Statistical significance was in general robust to a number of changes in the assumptions, including changing specifications, dummy variables for peak and off peak, and violations of the classical linear regression assumptions.

[44] Excluding the impact of carbon in 2005.

[45] Excluding the estimated cost of carbon from 2005.

Contributions to fixed cost estimates showed that marginal cost estimates for the Dutch market were not so low that the marginal cost estimates would not have earned operators substantial sums. Comparison of the Dutch contributions to fix cost vis-à-vis a generic new entrant showed sufficient contributions to cover the annual amortization payment of a new entrant. This was done merely as a modelling check and to give an idea of how large the fixed cost contributions were. We do not interpret whether the sum would have been sufficient to cover fixed capital costs in the market[46]. However, one should note that for existing market participants, a substantial proportion of their portfolio is likely to be partially or fully amortised thus reducing the need to cover such costs. Furthermore, in the vast majority of hours the APX price exceeded the competitive market price, thus allowing for potentially greater contributions to fixed and other costs.

The breakdown of power prices into cost estimates plus margin, and the inclusion of carbon revealed that a significant portion of recent price changes in the Netherlands can be attributed to carbon cost inclusion due to the introduction of the EU ETS. This is in spite of apparent negative margins. Our estimates were that, on average, the cost of carbon added €9.52 to the APX price. Whether operators were willing to allow negative margins due to receiving ETS allowance for free cannot be fully determined from our analysis. In spite of the fact that utilities obtained their emissions allowances for free, one would expect them to price in carbon costs fully, unless they believed doing so would lead to reduced carbon allowances in future rounds. However, we take no particular view on what utilities should in fact do with their carbon allowances. By assuming they are priced in, we essentially take the most conservative approach to finding high margins (i.e., the amounts reported are the maximum possible impact of the ETS if generators fully factor in the price of CO_2 certificates in a competitive environment).

[46] Doing so would have required estimates of the book value, depreciation, and age and technology profile of plant.

Estimates of withholding were calculated for the Netherlands. Withholding was defined as the difference between actual and modelled generation. These results should be interpreted with a large amount of caution because we cannot be sure how much the deviations between modelled generation and actual generation are due to market power related causes. Nonetheless these variables were included in some of the multiple regression equations and were statistically significant in the Netherlands. We do not interpret this specifically as estimates of economic withholding as a means of the use of market power, but rather included withholding in the regression as a measure of either economic withholding or other reasons why the modelled despatch may have deviated from the actual despatch. Thus the deviations between modelled and actual generation were controlled for in this way. These impacts were significant in some cases on the regressions of margins on RSI, but were small relative to the RSIs and scarcity, and also did not tend to make other variables such as the RSI insignificant.

Our final conclusions on the Netherlands are that the Dutch market appears concentrated but may achieve moderately concentrated status in a significant number of hours, dependent on the role of the interconnector in the market. In some hours, though, the market is likely to be relatively highly concentrated. The Netherlands also had some very low margins in a number of off-peak hours. This is not too surprising, given the amount of CHP and other must-run plant that may need to avoid shutting down at night in the Netherlands.

In such borderline cases, the regressions of margins on RSI become more important (in that they provide added information for a more borderline case). Whether the Netherlands in fact is concentrated or not, price cost margins (LI and PCMU) were significantly related to market structure via the regressions. This latter finding could indicate that market power use or market imperfections exist/have existed. Of course, alternatively, it is always possible that the regression models as specified are unable to distinguish between this explanation and some alternative unknown, but more benign, rationale.

11.5 Spain

The Spanish electricity market was in general found to be concentrated. Whether this level of concentration is conducive to competition is an open question, but our analysis suggests, at least in some significant number of hours, that poor market outcomes are possible.

Market structure as measured by traditional concentration measures HHI and CR(2), based on available capacity, the HHI for Spain was found to be 2,813 on average through the sample period, and the CR(2) was found to be 71.8%[47]. Allocating the interconnectors led to a range from 1,945 to 2,293 for HHI and 59.6% to 65.1% for CR(2), all of which are in excess of the threshold values of 1,800 and 33% for the HHI and CR(2) measure respectively. We note that these threshold values are somewhat arbitrary.

Sensitivity analysis regarding the allocation of interconnectors to market shares, basing market shares on generation or in merit capacity, and the attribution of long-term contracts did have some impacts on the concentration measures, but not so much so as to alter the qualitative conclusions. The range of HHI went from 2,790 based on available installed capacity to 2,896 based on in merit capacity. We also note that the level of physical interconnection from Spain to France and from Spain the Portugal is very low.

The electricity-specific measures of market structure confirmed the qualitative conclusions of the HHI and CR(2) for Spain. In general, the largest two companies' RSIs failed the proposed screening test with RSI<110% in more than 5% of hours. Similar results were found for the PSI in Spain, with the PSI finding a single company to be pivotal in 25.7% of hours over the three year sample period.

[47] Spain was somewhat sensitive to the hourly variations in standard concentration measures. There are variations in the concentration measures based on a number of factors. First, hourly measures were calculated. Variation and changes in availability (e.g., forced and planned outage, summer deratings, etc) impact the concentration measured in the market as measured by capacity. We also calculated the standard concentration measures based on generation. Here, changes in the share of total generation or in merit generation would cause the standard concentration measures to vary.

Price cost margins in Spain were higher than in Great Britain, but lower than in France and Germany, with an average price cost margins over the 2003-05 sample period of 13.9% for the LI, 20.8% for the price-cost mark-up (PCMU) using the OMEL prices and 16.1% for the price cost mark-up based on Platts prices. The margin showed some variation across time, similar to other countries. For example, the PCMU was 26.2%, 5.0%, and 27.9%, for 2003, 2004, and 2005 respectively (OMEL prices).

Relating the RSI to the price cost margins via regression analysis for Spain showed similar results as to other countries. The RSI is a significant explanatory variable for the margins estimated in Spain. The inclusion of additional variables such as scarcity did not change this conclusion, nor did the inclusion of more than one RSI variable. Statistical significance was in general robust to a number of changes in the assumptions, including changing specifications, dummy variables for peak and off peak, and violations of the classical linear regression assumptions.

Contributions to fixed cost estimates showed that marginal cost estimates for the Spanish market were not so low than many generators would not earn significant margins towards their fixed costs, if they traded at a price equal to the marginal cost resulting from the optimal dispatch modelling, a scenario equivalent to perfect competition. These calculations were done as a validation of the competitive price/marginal cost estimates. Comparison of the Spanish contributions to fix cost vis-à-vis a generic new entrant showed contributions insufficient to cover the annual amortization payment of a new entrant. We note, however, that this new entrant scenario is a high hurdle (due to many plant being partially or fully amortised) in terms of validation of the fixed cost contribution estimates, and our goal was not to study investment incentives in detail in each market. This was done merely as a modelling check and to give an idea of how large the fixed cost contributions were. The OMEL price is above the modelled marginal cost in the majority of hours thus indicating further benefits if traded at this price.

The breakdown of power prices into cost estimates plus margin, and the inclusion of carbon revealed that a significant portion of recent price rises in Spain can be attributed to carbon cost inclusion due to the introduction of the EU ETS. In spite of the fact that utilities obtained their emissions allowances for free, one would expect them to price in carbon costs fully, unless they believed doing so would lead to reduced carbon allowances in future rounds. However, we take no particular view on what utilities should in fact do with their carbon allowances. By assuming they are priced in, we essentially take the most conservative approach to finding high margins (i.e., the amounts reported are the maximum possible impact of the ETS if generators fully factor in the price of CO_2 certificates in a competitive environment).

Estimates of withholding were significant in Spain. We do not interpret this specifically as estimates of economic withholding as a means of the use of market power, but rather included withholding in the regression as a measure of either economic withholding or other reasons why the modelled despatch may have deviated from the actual despatch. These impacts were significant in some cases on the regressions of margins on RSI, but were small relative to the RSIs and scarcity, and also did not tend to make other variables such as the RSI insignificant.

Our final conclusions on Spain are that the Spanish market appears to be concentrated by both traditional and new electricity-specific market structure measures. We note that the existence of large hydro and nuclear resources in Spain likely mean that for such a level of concentration, the market structure could either provide anticompetitive opportunities or provide rather competitive outcomes. Hydro availability likely plays a large role. The relating of structure to outcome via the RSI regressions becomes all the more crucial as an empirical test. The results of this analysis, however, showed that price is a significant function of market structure and pivotalness.

Price cost margins (LI and PCMU) were significantly related to market structure via the regression on RSI. This latter finding could either indicate that more subtle forms of market power use or market imperfections exist/have existed or, alternatively, that the models as specified are unable to distinguish between this explanation and some alternative unknown, but more benign, rationale.

11.6 Great Britain

Finally, the market in Great Britain was in general found to range from borderline unconcentrated to moderately concentrated. Of all of the countries studied, the market structure in Great Britain can be seen to be the only one largely conducive to competitive outcomes.

Based on available capacity, the HHI for Great Britain was found to be 1,072 on average through the sample period, and the CR(2) was found to be 31.2%. Allocating the interconnectors led to a range from 1,004 to 1,189 for HHI and 31.6% to 36.8% for CR(2)[48].

We note that threshold values such as 1,800 for the HHI and 33% for *CR(n)* are somewhat arbitrary.

The electricity-specific measures of market structure confirmed the qualitative conclusions of the HHI and CR(2) for Great Britain. In general, the largest companies' RSIs passed the proposed screening test with RSI>110% more than 95% of hours. Similar results were found for the PSI in Great Britain, with PSI finding no single company was pivotal often in more than 7 hours out of a total of 26,304.

Price cost margins in Great Britain were lower than in other countries, with an average price cost margin over the full sample period of 21.5%for the LI and 27.5%, and 30.7% price-cost mark-up (using UKPX prices 2004-05) and for the price cost mark-up using Platts prices.[49] There was some variation over time with 2004 showing some low margins relative to 2005, with PCMU respectively at 3.8% and 41.9% (UKPX data).

[48] There are variations in the concentration measures based on a number of factors. First, hourly measures were calculated. Variation and changes in availability (e.g., forced and planned outage, summer deratings, etc) impact the concentration measured in the market as measured by capacity. We also calculated the standard concentration measures based on generation. Here, changes in the share of total generation or in merit generation would cause the standard concentration measures to vary.

[49] Based on Platts assessment price 2003-05. UKPX prices were not available for the full period.

Relating the RSI to the price cost margins via regression analysis for Great Britain showed similar results as to other countries. The inclusion of additional variables such as scarcity did not change this conclusion, nor did the inclusion of more than one RSI variable. Statistical significance was in general robust to a number of changes in the assumptions, although in our more detailed models (Regression Analysis - Part 3) more variables became insignificant when including more than one company's RSI as a regressor. Including other variables, changing specifications, dummy variables for peak and off peak, and violations of the classical linear regression assumptions, in general did not change the results.

Contributions to fixed cost estimates showed that marginal cost estimates for the market in Great Britain were not so low than many generators would not earn significant margins towards their fixed costs, if they traded at the UKPX price. Comparison of the contributions to fix cost in Great Britain vis-à-vis a generic new entrant showed sufficient contributions to cover the annual amortization payment of a new entrant. This was done merely as a modelling check and to give an idea of how large the fixed cost contributions were. However, one should note that for existing market participants, a substantial proportion of their portfolio is likely to be partially or fully amortised thus reducing the need to cover such costs. Furthermore, in the vast majority of hours the UKPX price exceeded the competitive market price, thus allowing for potentially greater contributions to fixed and other costs.

The breakdown of power prices into cost estimates plus margin, and the inclusion of carbon revealed that a significant portion of recent price rises in Great Britain can be attributed to carbon cost inclusion due to the introduction of the EU ETS. In spite of the fact that utilities obtained their emissions allowances for free, one would expect them to price in carbon costs fully, unless they believed doing so would lead to reduced carbon allowances in future rounds. However, we take no particular view on what utilities should in fact do with their carbon allowances. By assuming they are priced in, we essentially take the most conservative approach to finding high margins (i.e., the amounts reported are the maximum possible impact of the ETS if generators fully factor in the price of CO_2 certificates in a competitive environment).

Estimates of withholding were significant in Great Britain. We do not interpret this specifically as estimates of economic withholding as a means of the use of market power, but rather included withholding in the regression as a measure of either economic withholding or other reasons why the modelled despatch may have deviated from the actual despatch. These impacts were significant in some cases on the regressions of margins on RSI, but were small relative to the RSIs and scarcity, and also did not tend to make other variables such as the RSI insignificant.

Our final conclusions on Great Britain are that the market seems evidently unconcentrated by both traditional and new electricity-specific market structure measures. In spite of its unconcentrated structure, price cost margins (LI and PCMU) were significantly related to market structure. This latter finding could either indicate that more subtle forms of market power use or market imperfections exist/have existed or, alternatively, that the models as specified are unable to distinguish between this explanation and some alternative unknown, but more benign, rationale.

11.7 Overall summary and conclusions

This report has been an in depth study into the structure and functioning of the EU electricity wholesale markets using six countries as case studies (BE, DE, ES, FR, NL and GB). In general, where possible, the same methodology was applied to each country. Uncertainties surrounding the data on availability and capacity of nuclear plant in France and lack of hourly market price data in Belgium prevented us from carrying out some elements of the analysis (e.g., regressions) on these countries.

Our methodology followed from the structure-conduct-performance paradigm. We studied the market structure in a number of ways as well as the market performance (outcomes measures such as price-cost margins).

The methodology of the study had several parts. First, traditional concentration/market structure measures were estimated for each country. Next, more finely tuned market structure indicators such as the RSI and PSI were estimated. Market outcome measures such as the Lerner index (LI) and the price cost mark-up (PCMU) were also estimated. These used observed spot price data and marginal cost estimates. The marginal cost estimation was based on despatch simulation modelling, using state-of-the-art models and the best data available, both public and private. Similar approaches have been used in a multitude of studies in the EU, North America, and elsewhere. In addition, we were able to compare results to actual running costs, and also break down recent power price changes into estimates of marginal cost, and the marginal cost of carbon emissions under EU ETS.

There were a number of important elements of our study that could be considered groundbreaking. First, we were able to rely on and compare actual reported data from the utilities with our modelled data and public data. To our knowledge, this is groundbreaking in that it is the first study in Europe to be based on data reported by companies that compares this with market data, as well as comparing outcomes across time and country. Data on plant details including thermal efficiencies, must run status, capacity, constraints, technical operational characteristics of plants, energy, reserves, etc, was all provided by the generation companies and utilities. Further data on actual running and output was provided, and this enabled us to compare actual output with modelled output, and also to control for this in our regressions.

The relating of RSI measures to price cost margins is the second and more innovative element of the study. First, statistical analysis (linear regressions) relating RSI to price cost margins have, to our knowledge, not been done before on such a scale and over such a time period (four countries for three years each). Further, the RSI indicators for the biggest companies seemed to be robust to changes in the specifications in general, across time and space. Finally, we included a number of additional explanatory factors, including scarcity, 'withholding', peak-off peak slope and intercept dummy variables, etc, in our RSI regressions, something to our knowledge not done before.

Comparing the results across countries showed some marked differences and other similarities.

The concentration of the markets was measured by traditional (*CR(n)* and HHI) and more innovative measures (RSI and PSI) of market structure. Concentration, in general as measured by traditional concentration measures, shows marked differences across countries, but in general little variation over time or by means of calculating market share within countries. Some markets, such as Great Britain, are borderline unconcentrated; others such as Germany, Spain and the Netherlands are best described as moderately concentrated to highly concentrated, while France and Belgium are very highly concentrated. Our results were, in general, not sensitive to a variety of factors and sensitivities, such as the allocation of the interconnector. There were notable exceptions, such as the allocation of interconnection for the Netherlands (who controls what shares over the interconnector will likely change the overall picture of whether the Netherlands is a concentrated or unconcentrated market).

Results from the RSI threshold test show that broadly similar outcomes occur vis-à-vis the traditional concentration measures. The most concentrated markets failed the RSI threshold test in a large percentage of hours, with respect to the largest companies (e.g., 100% in France and Belgium). On the other hand, only a small number of hours show RSI failing the threshold test in some markets such as Great Britain. Spain, the Netherlands and Germany have at least one company with significant market presence between about 20 and 50% of the time, but other companies passed the threshold test. So our conclusion is that the RSI and PSI show more clear indications of market structures that may be conducive to market power use for certain companies at certain hours (i.e., for given supply and demand outcomes).

Comparing price cost margins and the actual breakdown of costs also shows interesting differences. Countries with lower costs seem to have higher margins for example. France had the highest estimated margins (although data difficulties led us to caveat this result). Great Britain had low margins, while the Netherlands had the lowest margins. It is difficult to interpret these results and they should not be read too precisely. While the average prices cost margins across country seem broadly correlated with concentration, other factors are evident. These conclusions give the rationale to carry the analysis of price cost margins further via the regressions on RSI and other explanatory variables. We also note again that the finding of negative margins is not uncommon in these types of studies.

More interesting still is the breakdown of the power exchange price into components including carbon. We cannot fully interpret whether companies have passed on the full cost of carbon or whether they have "raised" margins in response to carbon. We note that for EU ETS, from an economic perspective, to achieve a least cost solution to reducing carbon emissions to a given level, companies *should* pass on the marginal cost of carbon (with the price of a unit of carbon being determined by market trading of EU ETS allowances.) However, from a competition or overall policy perspective, we are circumspect as to what the true nature of EU ETS pricing should be. It is also perhaps possible that companies do not pass on the full cost since they have received allowances for free. Our analysis merely took a conservative approach in that we included the cost of carbon in our marginal cost estimates (the amounts reported are the maximum possible impact of the ETS if generators fully factor in the price of CO_2 certificates in a competitive environment and thus we cannot be underestimating the cost due to carbon). What we can conclude from our results is that seemingly differential factors have occurred across countries, and the size of the margin changes across countries with the introduction of EU ETS, while the total marginal cost of carbon as estimated also changes.

We also compared estimates of the contribution to fixed costs. This was done primarily as a test of our modelled marginal cost estimates. The results indicated that had the largest companies traded at the marginal costs or estimated competitive prices, they would have still earned billions of Euro in operating profits towards their investment costs. In other words, the marginal costs estimated as competitive prices are not inconsistent with an incentive to invest. In this sense, we are also secure that it is less likely that the marginal cost estimates are "too low" and not representative of the true marginal value of power on the system (plus a margin that is 'perhaps' more than is economically justified by cost and scarcity alone). This was done merely as a model check, and not as a detailed investigation into investment incentives.

Finally, we compared simple and multiple regression results across countries. The regression results included both simple regression of PCMU on RSI measures and multiple regression results. The results showed that the RSI, a continuous measure of how pivotal an individual large supplier is, significantly explains margins in all markets. This result is apparently robust to controlling for a number of factors, including scarcity, year, seasonality, modelled differences between actual and modelled generation of coal and gas, and an interaction term designed to capture the nature of competition among the largest companies in each of the markets.

It is useful to consider the results on the whole and ask/answer the question of how much can be said with about the interpretation of these results and with what degree of certainty. The standard concentration measures are well known to be of limited use in predicting the degree of market power in electricity generation markets. At the same time, our analysis has reduced much of the uncertainty surrounding their usefulness. We have shown that in many cases these measures are less sensitive to the assumptions than might have been alleged previously. No doubt, though, this conclusion may not be static as changes in the levels of interconnection, possibilities of further congestion, and other factors change over time.

We believe our most interesting results are the regression results. These indicate that price-cost margins are significantly explained by the RSI of the largest companies, even when many other factors are controlled for. Thus, the impact of RSI of the largest company is seen as independent of other factors such as seasonality, peak-off-peak, scarcity, and even other suppliers RSI.

Admittedly, the results of our measures, models, and regression outputs should come with the general caveat of any such analysis; i.e., that we cannot be 100% certain that some unmeasured factor or element is driving the results. While this caveat would exist for any such analysis, we believe we have controlled for as many factors as was feasible within the time and resources of the project, limitations of the data etc. We have throughout the project tried to make conservative assumptions with regards to finding market power where there is none. In general as well, the regression results do not particularly prove *causality* either. In other words, the regressions show that RSI tends to go down (less capacity of one supplier available relative to demand) when price cost margins tend to go up. One cannot say for sure that this is due to market power.

Nonetheless we do conclude that we have furthered the state of knowledge of how electricity markets work. The relationships found between RSI and PCMU are clearly not likely due to sampling error and are not likely a result of violations in the assumptions of the linear regression model. Thus, our results show that margins are related to market structure on a very micro and dynamic level. This suggests that market structure plays a significant role in determining price, and that as a result prices in the EU markets studied are not as keen as they might have been, had market structures with less pivotal suppliers existed.

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