Quantifying the "merit-order" effect in European electricity markets

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Executive summary

The increase in renewable energy sources has contributed to containing and even lowering electricity wholesale prices in many markets (although not necessarily retail prices) by causing a shift in the merit order curve and substituting part of the generation of conventional thermal plants, which have higher marginal production costs. This merit order effect along with priority dispatch can affect revenues of conventional power plants, especially in Member States experiencing rapid deployment of variable renewables. In some Member States, this raises the question of how to ensure adequate investment signals on generation guaranteeing capacity and balancing power at the lowest possible cost.

This Rapid Response Energy Brief quantifies the merit order effect in 2030 and 2050 in European electricity wholesale markets by comparing electricity systems in a Reference and Mitigation Scenario for both years. Scenario results show for the Scenario modelled that the reduction in wholesale electricity price between scenarios is on average €1.6/MWh and €4.2/MWh for 2030 and 2050 respectively. A simplified approach is also used to assess the impact of Demand Response on system costs.

Introduction

The electricity production from renewable energy sources (RES) has increased in most European member states over the past 10-15 years. The investment incentive for RES is mainly driven by policy support measures such as feed-in tariffs, which guarantee a fixed price per unit of renewable electricity generated, while other generators must sell their electricity in a spot market. However, the influence of RES on electricity spot market prices is growing with the increasing share of renewable electricity deployed. This is due to the how spot prices are determined as a function of supply and demand. The supply curve, the so called merit order, is derived by ordering the supplier bids according to ascending marginal cost. The intersection of the demand curve with the merit-order defines the market clearing price i.e. the electricity spot market price. The feed-in of renewable energy sources with low or near zero marginal cost results in a shift to a right of the merit-order.

This shift moves the intersection of the demand curve and the merit order to a lower marginal price level and thus the electricity price on the spot market is reduced (see Figure 1). This reduction in price is called merit-order effect.

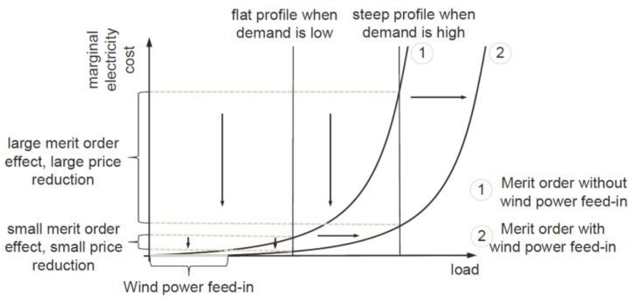

Figure 1: Right shift of the merit order and the supply curve particularly due to wind power feed-in. source: (Keles et al 2013).

The INSIGHT_E project is funded by the European Commission under the 7th Framework Program for Research and Technological Development (2007-2013).

This RREB provides a brief review of ex-post analyses carried out on the merit order effect and then looks ahead to 2030 and 2050, carrying out an ex ante analysis of the merit order effect of the energy scenarios EU 2030 Climate and Energy Policy Framework[1]. Note that it is not the objective of this RREB to undertake a qualitative analysis of the technical appropriateness of the portfolios or results from the 2030 EU Policy Framework. Results will specifically focus on the merit order effect.

Review of ex post analyses of the merit order effect

There is a significant amount of analysis of the merit order effect, the bulk of which are referred to in (Azofra et al., 2014) and (Ray 2010). These studies can in general be categorised as model based or statistical based studies.

We present here a statistical analysis of the merit-order effect using the example of wind power in Germany. The merit-order effect can be shown by analysing historical market prices from the European Electricity Exchange (EEX). According to (Keles et al 2013), linear regression of market prices and wind power feed-in points to an average price reduction of €1.47/MWh for every additional GW of wind power. This average effect cannot explain extreme price events. "*Thus, the correlation of electricity price and wind power feed-in might depend on point of time and is presumably nonlinear*" according to (Keles et al 2013). To further analyse the price reduction effect the current power plant mix as well as the demand situation are taken into account. Therefore an hourly record of electricity price, wind power feed-in and demand (load) is formed and sorted ascending by the load. With a linear regression the price change αL as a function of the load can be shown in Figure 2. The negative values indicate that the wind power feed-in leads to lower electricity prices. Furthermore, it can be obtained that the price reduction effect highly depends on the load situation and can be significantly higher than the average reduction of 1.47 €/MWh (see Figure 2). This is in line with the findings of (Hirth 2013). (Hirth 2013) further shows that this price reduction also affects the market value of variable renewables and is also dependent on the penetration of renewable energies. The market value of wind power falls from 110 % of the average power price to 50-80 % with an increase of wind power penetration from zero to 30% of total electricity production (Hirth 2013).

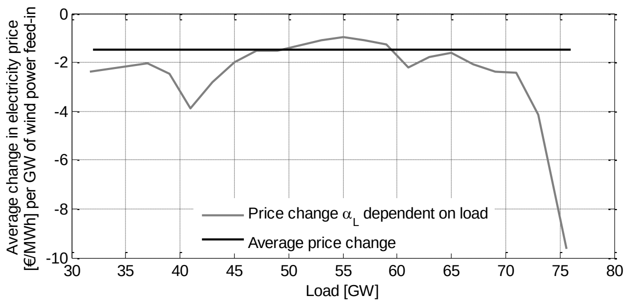

Figure 2: Average change of the deseasonalized electricity price per GW wind power depending on load interval (Keles et al 2013).

A further comparison of price reductions in the German merit order curve is shown in Figure 3. There are four significant changes in the curve according to (Keles et al 2013). These changes can in general be linked to technology switches in the merit order. In area 'I', a local peak is evident, representing the change from lignite to coal fired power plants. The price reduction effect increases when lignite fired power plants are the price setting units instead of coal. A similar peak can be obtained in area 'III' where a switch from coal to gas fired power plants occurs in the merit order, although the price reduction effect in area 'I' is higher than in area 'III'. The occurrence of negative prices is high in this area because plant operators try to avoid shut-down and ramp-up costs and accept negative electricity prices to stay online. Other restrictions like reserve requirements and, in the case of gas fired power plants, heat delivery, cause plant operators to be online which can lead to an excess electricity supply and thus to negative prices. Area IV represents the peak load power plants (oil or gas fired) which are the most expensive power plants due to their low efficiency and high fuel costs. In this area the price reduction effect is very high, if their utilisation is avoided.

[1] http://ec.europa.eu/clima/policies/2030/index_en.htm

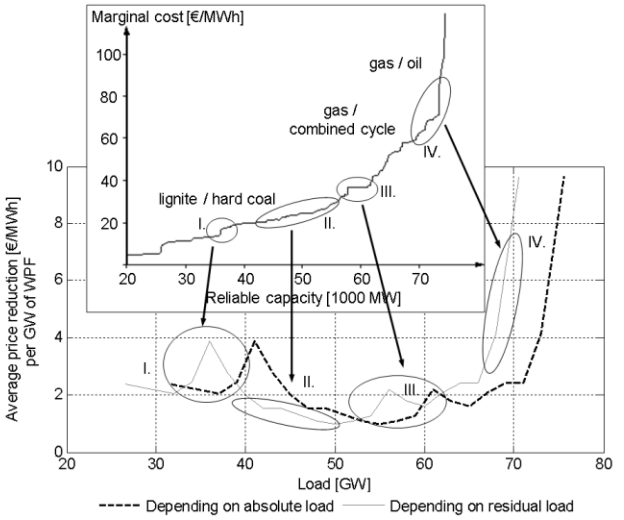

Figure 3: Price reduction per GW wind power feed-in depending on the load level and the German merit-order curve (Keles et al 2013).

The merit order effect outlined here is dependent on the German market design. However, other market designs would lead to a similar merit order effect according to (Keles et al 2013).

Traditionally, electricity demand does not respond to price levels changes that occur on spot or balancing markets. The traditional perspective of *"generation follows the demand"* is however expected to change in a situation where the demand responds to electricity price levels and consumers are able to benefit financially from shifting consumption.

Demand response (DR) *is regarded as the modification of electricity consumption in response to price of electricity generation and state of the electricity system reliability* (DOE, 2006). The communication of price levels to electricity consumers could lead to an electricity system where increasingly the *"demand follows generation"*. Within Europe, there are some standing arrangements to involve energy intensive industrial customers in DR. This is mostly done through critical peak pricing or time of use pricing and some system operators make use of large avoided loads as part of their system balancing services (Torriti, Hassan, & Leach, 2010). However, this is still not applied in many European countries; DR is only commercially active as a flexibility resource in France, Ireland, the United Kingdom, Belgium, Switzerland and Finland (SEDC, 2014). Countries with large penetration of RES such as Germany currently use demand flexibility to maintain system-wide reliability (Koliou, Eid, Chaves-Ávila, & Hakvoort, 2014).

Demand response could reduce the required capacity of peaking electricity units, could increase load factors of existing generation units and furthermore can have positive effects on electricity network capacity utilization. Furthermore, demand response could be used to provide balancing capacity to complement the variability of renewable sources.

Demand response is anticipated to play a role in Europe in order to reach the 2020 targets and beyond. In particular, the Energy Efficiency Directive (EED), art. 15, explicitly urges EU national regulatory authorities to encourage demand-side resources, including demand response, "to participate alongside supply in wholesale and retail markets", and also to provide balancing and ancillary services to network operators in a non-discriminatory manner (EC, 2012). The European Commission states that the potential in Europe for DR in electricity markets is believed to be high but is currently still underutilized (EC, 2013) due to the concentration on industrial users primarily. Residential users are in the future also expected to become involved in demand response provision but still some technical, regulatory and economic barriers exist (SEDC, 2014). In this RREB the impact of DR on total system costs is quantified at an EU wide level in 2030 and 2050.

Ex-Ante Analysis of Merit Order Effect - Methodology

Looking ahead, we analyse the merit order effect in two distinct power plant portfolios in each of two specific years (2030 and 2050) using a power systems modelling model based approach. These portfolios are developed based on scenario analysis results carried out with the PRIMES model that were used to inform the EU 2030 Framework for climate and energy policies. The first scenario is a Reference Scenario and the second scenario is a Mitigation Scenario. The merit order in this analysis is defined as the difference in price between the two scenarios. A brief description of the scenarios is provided here.

The Reference Scenario is the EU Reference Scenario[2] 2013 which explores the consequences of current trends including full implementation of policies adopted by late spring 2012. The Reference scenario has been developed through modelling with PRIMES, GAINS and other related models and benefited from the comments of Member States experts. The Reference scenario provides an energy system pathway up to 2050 affected by already agreed policies. The Mitigation Scenario by contrast, also provides an energy system pathway up to 2050 but in this case achieves GHG

[2] ec.europa.eu/smart-regulation/.../ia...2014/swd_2014_0015_en.pdf

reductions of 40% and 80% in 2030 and 2050 respectively, met through economy wide equalisation of carbon prices. Aggregate portfolio capacities in each Member State for the Reference Scenario for 2030 and 2050 are shown in Figure 4 and Figure 5 respectively. Installed capacities of variable renewable generation for each Member State for 2030 and 2050 is shown in the Annex.

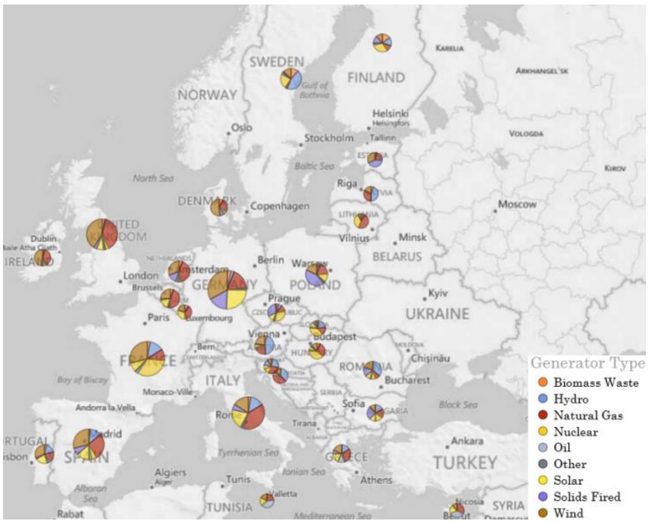

Figure 4: 2030 Reference Scenario Capacities

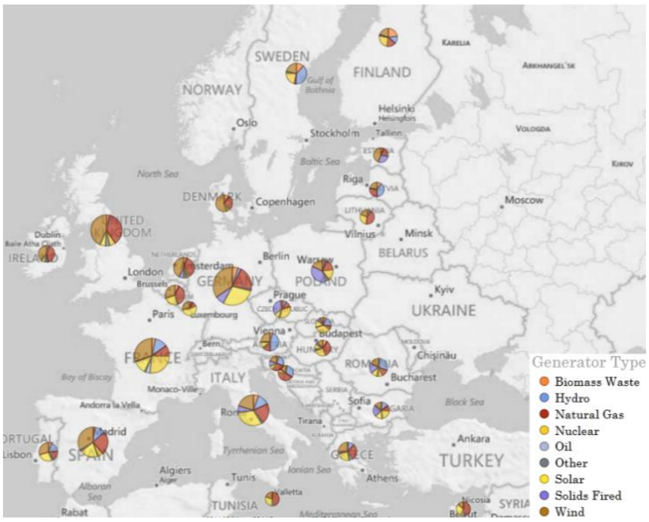

Figure 5: 2050 Reference Scenario Capacities

Model Description

This RREB employs a model based technique to investigate the electricity price difference between the reference and mitigation scenario. The software used to model the electricity market is the PLEXOS Integrated Energy Model. PLEXOS is a modelling tool used for electricity and gas market modelling and planning. In this analysis, the focus is on the merit order effect and the modelling is limited to the electricity system, i.e. gas infrastructure and delivery is ignored in these simulations. Within the electricity sector, the model optimises thermal and renewable generation and pumped storage subject to operational and technical constraints at hourly resolution. The objective function is to minimise total costs over the year across the full system. This includes operational costs, consisting of fuel costs and carbon costs; start-up costs consisting of a fuel offtake at start-up of a unit and a fixed unit start-up cost. Model equations can be found at (Deane et al., 2014) and (Energy Exemplar). In these simulations a perfect market is assumed across the EU (i.e. no market power or bidding behaviour and power plant bid their short run marginal cost.) A power plant portfolio is constructed for each Member State for each scenario (Reference and Mitigation) and each year (2030 and 2050). In all, approximately 2,220 individual thermal power plants are included in the model. Power plant capacities, efficiencies and fuel types are based on outputs from the PRIMES model. The model seeks to minimise the overall generation cost across the EU to meet demand subject to generator technical characteristics. The resulting market price is defined as the marginal price at MS level (note that this is often called the *shadow price* of electricity) and does not include any extra revenues from potential balancing, reserve or capacity markets or costs such as grid infrastructure cost, capital costs or taxes. These additional revenues or costs are not considered in this study.

To determine the impact of increased levels of variable renewable generation, annual carbon prices (equivalent to ETS price) are set at €40/tonne CO_2 in 2030 and €100/tonne CO_2 in 2050 for both scenarios. In the Reference Scenario, electricity demand rises 12% between 2010 and 2030, increasing further through 2050 (+32% on 2010). Driving forces for this include greater penetration of appliances following economic growth, which mitigate the effects of eco-design standards on new products, increasing use of heat pumps and electro-mobility. The share of electricity in final energy consumption rises from 21% in 2010 to reach 24% in 2030 and 28% in 2050. In the year 2030, the demand for electricity at EU28 level is 5% lower in the Mitigation Scenario than in the Reference Scenario whereas in 2050 demand for electricity is 16% higher in the Mitigation Scenario, due to further electrification of transport and heat.

Interconnection between Member States is modelled as net transfer capacities and no interregional transmission is considered. The electricity network expansion is aligned with the latest 10 Year Development Plan from ENTSO-E, without making any judgement on the likelihood of certain projects materialising. Fuel prices are also consistent across scenarios for each year and are shown in the Table 1.

Table 1: Fuel prices used in study[1]

Fuel prices	2030	2050
Oil (in €2010 per boe)	93	110
Gas (in €2010 per boe)	65	63
Coal (in €2010 per boe)	24	31

Results for 2030

Results for the year 2030 for each Member State are show in Figure 6 in terms of the absolute reduction in annual wholesale electricity price in the Mitigation scenario relative to the Reference scenario. The absolute annual values are provided in the Annex. Results are driven by differences between the Reference and Mitigation Scenario portfolios and also by differences in demand. It can be seen the reduction in market price in the majority of central European Member States is relatively benign at less than €1.5/MWh with an overall average of €1.6/MWh. The greatest impact is seen in the UK and Ireland. In the UK two elements are driving a strong reduction in wholesale price between the Reference and Mitigation Scenario. Firstly the demand in the Mitigation Scenario is approximately 5% lower than the Reference Scenario. Secondly there is a strong increase in installed renewable capacity with almost a third of the EU total offshore wind capacity installed in the UK. This has a strong seasonal impact and tends to reduce prices in the winter months when wind speeds are high and demand is also highest. This reduces the need for higher marginal cost generators to meet peak demand. Similarly Ireland sees a strong reduction in price between the two scenarios and this is primarily driven by an increase in onshore wind capacity. Across the EU there is a general trend in the increase on variable renewable generation in the Mitigation Scenario and the drop in Market prices. In contrast to the UK, Italy sees a large increase in PV and this has a big impact on wholesale electricity prices in summer months with negligible differences in prices in winter. Results for The Netherlands show a 4% drop in wholesale market price between the Reference and Mitigation Scenario driven in part by a drop in demand of almost 9% and an increases in both onshore and offshore wind energy. In the Baltic region, an increase in Biomass Waste fired generation capacity in Latvia and Lithuania coupled with an increase in onshore wind capacity in Estonia contribute to average price reductions of 3-4%.

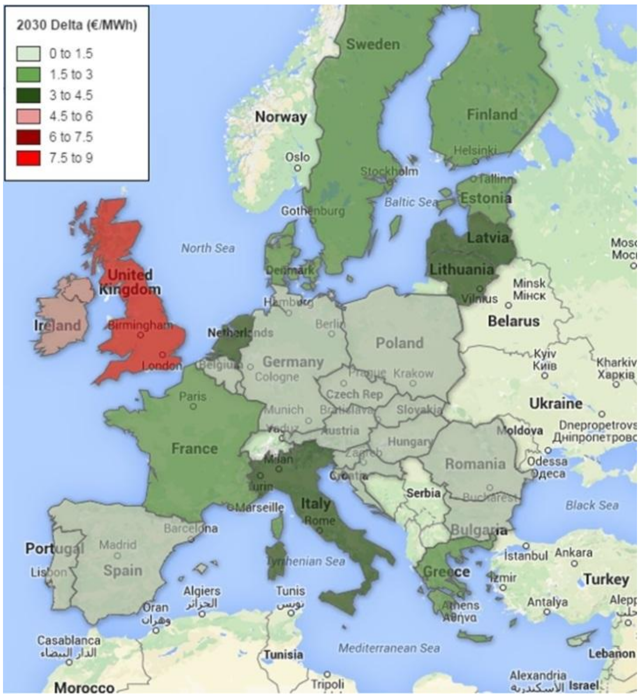

Figure 6: Reduction in price (€/MWh) between Reference and Mitigation Scenario for 2030

On the Iberian Peninsula, both Spain and Portugal have already high levels of renewables in the Reference Scenario. Demand drops by approximately 6% in both Member States for the Mitigation Scenario. In the Mitigation Scenario Portugal has a reduced installed capacity of wind and solar energy and both Member States experience only a minor reduction in prices. France is the Member States with the largest absolute reduction in demand. France also sees a strong increase in biomass waste capacity and associated generation in the mitigation scenario.

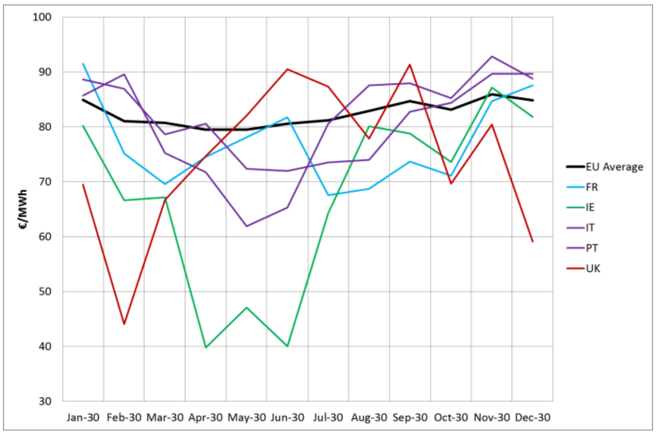

Figure 7: Monthly 2030 prices for select Member States for Mitigation Scenario. EU average is also shown in black.

Turning to price volatility, a number of Member States exhibit strong variations in monthly prices as shown in Figure 7. In particular, Ireland and the UK show strong fluctuations in monthly prices which is primarily driven by high levels of variable renewables. These two Member States also have levels of curtailment of variable renewables [7% and 1% respectively], it should be noted that operational constraints which currently limit the instantaneous penetration of variable renewables (as highlighted in HET 2 on wind energy curtailment) are not considered in this modelling exercise. Inclusion of these limits would increase curtailment in this region.

The large growth in renewable capacity, changes in demand and differences in power plant portfolio between the scenarios impact on the utilisation of thermal power plant in 2030. Natural gas fired plant are particularly affected. The EU wide average cost of generation for natural gas in 2030 is approximately €72/MWh, compared with €41/MWh for coal. The Mitigation Scenario has higher ambition in terms of emissions reduction and has approximately 8% less installed natural gas capacity. In the Reference Scenario these plants are operating at a 25% capacity factor EU wide compared with 18% in the Mitigation Scenario. Greece experiences the largest reduction in % terms for capacity factor (48% to 27%) with natural gas generation being replaced by onshore wind and other renewables. Germany too sees a significant reduction in natural gas generation with annual capacity factors reducing from 48% to 35%.

Results for 2050

For the year 2050 the Mitigation Scenario sees an increase in variables renewable installed capacity (wind and solar) from 45% in the Reference Scenario to 52% in the Mitigation Scenario. The 2050 portfolios also see significant emissions captured with CCS (Carbon Capture and Storage) particularly in Poland and Italy. In contrast to 2030 where there was an overall reduction in electricity demand, 2050 sees a 16% increase in demand in the Mitigation Scenario over the Reference Scenario with a number of Member States having more than a 25% increase in demand in the Mitigation Scenario.

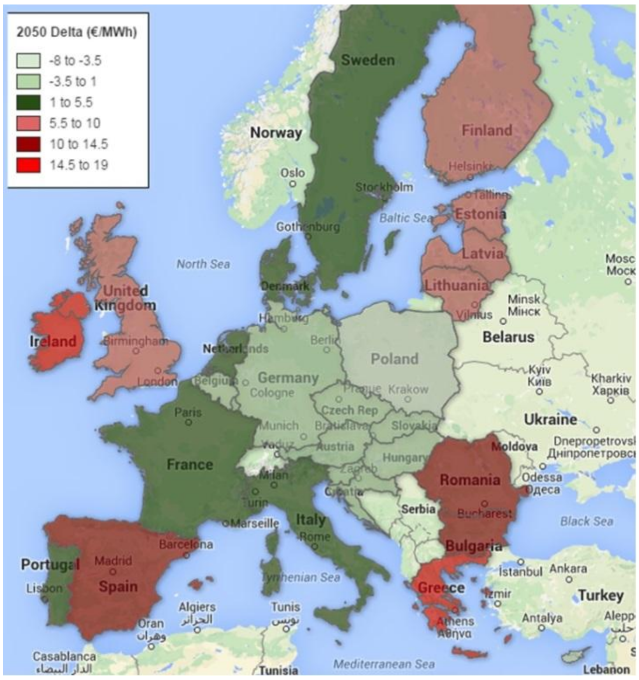

Figure 8: Variation in price (€/MWh) between Reference and Mitigation Scenario for 2050

At an EU wide level there is an overall reduction in average wholesale prices of approximately €4.2/MWh. A number of Member States see an increase in prices between the Reference and Mitigation Scenario. Poland experiences an increase in average price; this is caused by an overall reduction in installed capacity coupled with an increase in demand. Belgium also sees higher prices in the Mitigation Scenario. In Belgium demand increases by 22% while overall installed capacity grows by 12% with a significant portion of this growth in non-firm variable renewables. This requires greater imports and also gas fired generation within the country to increase its output and leads to overall higher wholesale prices. A number of Member States experience strong reduction in wholesale prices. Greece sees a modest increase in demand but a large relative increase in variable renewables and hydro installed capacity. This has a particular pronounced impact especially in summer months when solar generation is high. Elsewhere across the EU, the increase in installed capacity of variable renewable generation has strong implication for wholesale prices however addition of low carbon plant such as nuclear also has important implications. Romania has increased installed capacity of nuclear in the Mitigation Scenario and coupled with increase in variable renewable generation contributes to a strong reduction in price.

It is important to remember also that the carbon price for the Mitigation Scenario is held at €100/t. In the EU Impact Assessment Document the Carbon price in the Mitigation Scenario is estimated at €264/t. This carbon price would lead to significantly higher prices in the Mitigation Scenario for all Member States.

Impact of demand response

Demand response can have a significant impact on the merit order. In this study the main type of demand response that is considered is load shifting, meaning that the electricity demand has been shifted from peaking moments to off-peaking moments in time. To examine the impact of Demand Response (DR) simulations were undertaken for the Reference Scenarios where 10% and 15% of each Member State peak demand was made available for demand response in 2030 and in 2050 respectively. Replacing this peak demand in off-peak moments leaves the electricity demand equal for each year. Demand response consequently reduces the need for expensive peaking plants to operate and decreases the marginal price while it increases load factors of the baseload units. Demand Response units are modelled as virtual pumped storage units with 100% efficiency. The optimiser's objective function is to minimise total system costs whereas a customer using DR will aim to reduce their overall electricity bill. This is a relatively simple method to simulate demand response and will not reflect full system benefits as it does not directly include a price response component (which is important with high levels of variable renewable generation) but provides a useful starting point in gauging its impact from a system wide perspective.

From an EU wide perspective, the introduction of DR in 2030 reduces total system generations costs (i.e. variable cost of generation and start-up costs of generators) by €2.0bn or approximately €0.5/MWh. For the year 2050 the impact is slightly bigger at a total reduction in system costs of €2.8bn or approximately €0.6/MWh. Impacts are not shown at individual MS level as the simplified technique used here is appropriate for assessing the reduction in system costs but not for assessing the impact on prices.

Comments and discussions

This Rapid Response Energy Brief quantifies the merit order effect in 2030 and 2050 in European electricity wholesale markets by comparing a Reference and Mitigation Scenario for both years. It is important to note that these estimates do not reflect the total costs of electricity as they exclude subsidies and other costs. It has been shown that for the scenarios examined that the inclusion of variable renewables can put downward pressure on wholesale electricity prices with the greatest impacts seen in Member States with high levels of variable renewable penetration. While the inclusion of variable renewables has a primary impact, the study also highlights the impact of demand for electricity and portfolio changes on wholesale market prices. These changes and impacts differ for each Member State but pronounced impacts are seen in Member States where these conditions are met. It is also interesting to note that in general the merit order effect as analysed here is lower in Member States with higher number of Interconnection points, particular in central Europe while peripheral Member States have a more pronounced impact. Increased interconnection has not been analysed in this report but would make an interesting future study.

While a detailed economic analysis of the impact of wholesale prices on generator revenues is beyond the scope of this analysis, some points can be taken from the current analysis. Within the power sector in Europe today, current market prices are not sufficient to cover the fixed costs of all plants operating on the system, a situation that is expected to become more critical in particular due to the current overcapacity induced by the economic slowdown in recent years and the penetration of renewables, which predominantly have fixed costs. The low capacity factors for natural gas fired plant, particularly in 2030, suggest that natural gas fired plant may still struggle to achieve sufficient financial remuneration in an energy only market in some Member States.

Like all modelling exercises the results in this study have to be interpreted in the context of modelling assumptions which have important implications for the understanding of results. Firstly it is important to bear in mind that only one set of deterministic scenarios have been examined and results are therefore representative for these inputs. One year of wind and solar profiles have been examined and therefore inter-annual variations in generation output have not been captured. Equally one set of maintenance and forced outages for thermal plant have been used and not sensitivity to results to these outages presented. More specifically the modelling technique used in this exercise employs perfect foresight, whereby the model has full knowledge of all input variables such as demand and variable renewable generation output. It is well understood that power systems with high penetration levels of variable renewable electricity will be more challenging to operate in absence of perfect foresight. Finally the modelling assumptions assume a perfect market where Member States can easily transport power throughout the EU network.

For further reading or information, please visit www.insightenergy.org

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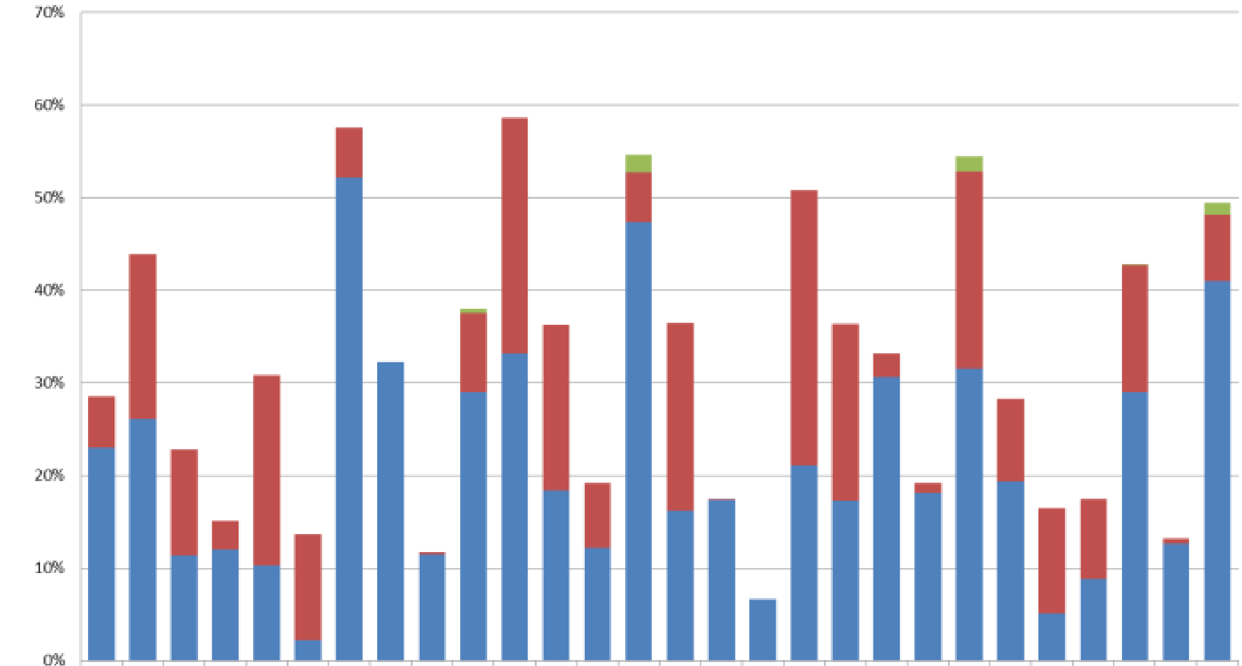
Annex



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%Solar	6%	18%	11%	3%	21%	11%	5%	0%	0%	9%	25%	18%	7%	5%	20%	0%	0%	30%	19%	3%	1%	21%	9%	11%	9%	14%	1%	7%
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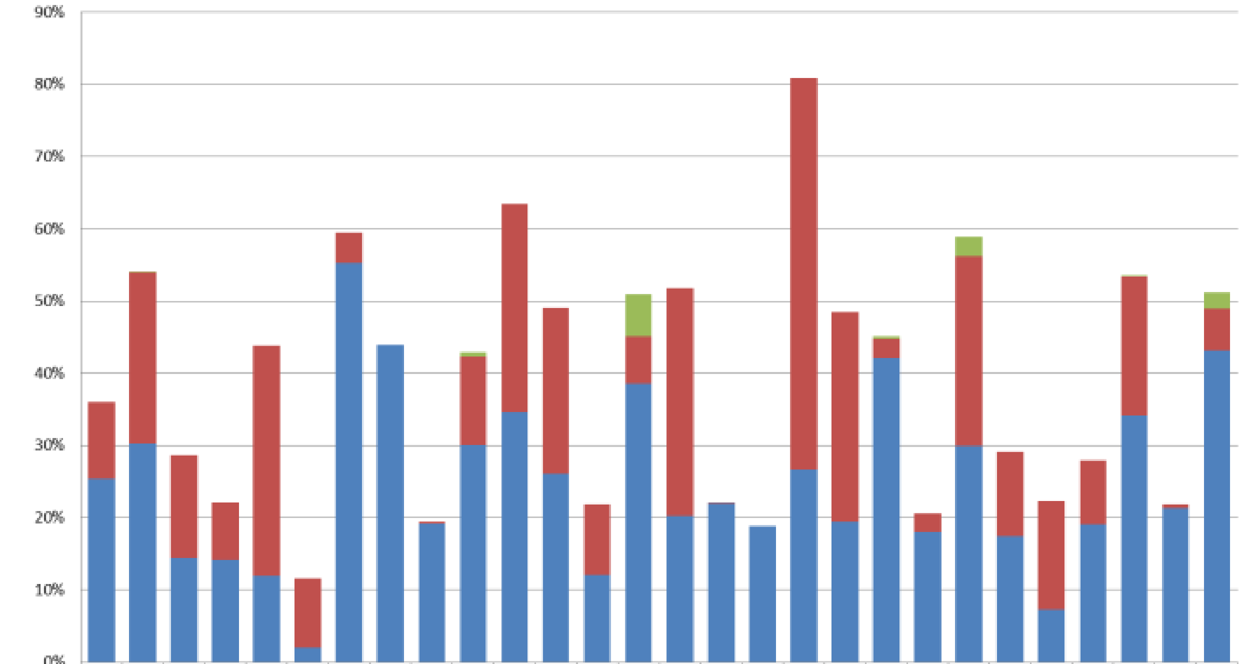
Figure 3: Variable Renewable Capacities by Member State for 2030



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%Wind	25%	30%	14%	14%	12%	2%	55%	44%	19%	30%	35%	26%	12%	39%	20%	22%	19%	27%	19%	42%	18%	30%	17%	7%	19%	34%	21%	43%

Figure 4: Variable Renewable Capacities by Member State for 2050

Table 2: Annual average prices-time weighted (€/MWh), average price received (€/MWh) and associated annual generation (GWh) by variable renewable technology for 2030 Reference and Mitigation Scenario by Member State.

		2030 Reference Scenario			2030 Mitigation Scenario		
MS	**Technology**	**Reference Price (€/MWh)**	**Average Price Received (€/MWh)**	**Annual Generation (GWh)**	**Mitigation Price (€/MWh)**	**Average Price Received (€/MWh)**	**Annual Generation (GWh)**
AT	Solar-AT	86.3	82.0	1484	85.4	81.3	1472
AT	Wind Offshore-AT	86.3	0.0	0	85.4	0.0	0
AT	Wind Onshore-AT	86.3	82.7	13620	85.4	81.9	13840
BE	Solar-BE	84.9	82.5	4877	84.9	83.1	4884
BE	Wind Offshore-BE	84.9	83.2	6490	84.9	83.4	8275
BE	Wind Onshore-BE	84.9	83.2	10799	84.9	83.4	11614
BG	Solar-BG	82.7	78.7	2054	82.7	79.7	2565
BG	Wind Offshore-BG	82.7	0.0	0	82.7	78.5	162
BG	Wind Onshore-BG	82.7	80.0	2631	82.7	78.5	4481
HR	Solar-HR	87.0	85.7	215	86.9	86.4	293
HR	Wind Offshore-HR	87.0	85.9	425	86.9	86.8	425
HR	Wind Onshore-HR	87.0	85.9	999	86.9	86.8	1307
CY	Solar-CY	88.9	57.1	918	87.0	75.6	967
CY	Wind Offshore-CY	88.9	63.5	2	87.0	83.8	43
CY	Wind Onshore-CY	88.9	73.0	740	87.0	86.0	1002
CZ	Solar-CZ	84.4	83.2	2438	84.2	83.8	2439
CZ	Wind Offshore-CZ	84.4	0.0	0	84.2	0.0	0
CZ	Wind Onshore-CZ	84.4	83.8	653	84.2	84.8	653
DK	Solar-DK	82.9	79.4	654	80.5	77.7	448

DK	Wind Offshore-DK	82.9	76.0	7275	80.5	71.9	8101
DK	Wind Onshore-DK	82.9	76.0	11843	80.5	72.0	13083
EE	Solar-EE	81.6	0.0	0	79.3	0.0	0
EE	Wind Offshore-EE	81.6	80.4	301	79.3	77.7	286
EE	Wind Onshore-EE	81.6	80.4	2357	79.3	77.7	3192
FI	Solar-FI	80.4	80.9	55	78.9	78.3	57
FI	Wind Offshore-FI	80.4	78.6	3018	78.9	76.4	3018
FI	Wind Onshore-FI	80.4	78.6	3834	78.9	76.4	3729
FR	Solar-FR	78.9	72.8	14081	76.2	71.5	14424
FR	Wind Offshore-FR	78.9	69.7	46067	76.2	67.3	47852
FR	Wind Onshore-FR	78.9	69.7	81743	76.2	67.3	83672
DE	Solar-DE	82.7	70.7	50224	82.5	73.2	50809
DE	Wind Offshore-DE	82.7	79.6	46063	82.5	79.3	46065
DE	Wind Onshore-DE	82.7	79.8	113960	82.5	79.5	122334
GR	Solar-GR	88.3	79.1	5541	85.6	76.7	6041
GR	Wind Offshore-GR	88.3	85.6	400	85.6	81.1	541
GR	Wind Onshore-GR	88.3	85.6	9551	85.6	81.2	15719
HU	Solar-HU	89.3	88.0	810	88.9	88.5	448
HU	Wind Offshore-HU	89.3	0.0	0	88.9	0.0	0
HU	Wind Onshore-HU	89.3	88.0	2224	88.9	88.6	2294
IE	Solar-IE	73.1	67.9	587	67.3	61.1	683
IE	Wind Offshore-IE	73.1	49.8	737	67.3	34.7	771
IE	Wind Onshore-IE	73.1	51.2	16569	67.3	38.0	18198
IT	Solar-IT	85.1	70.4	39135	80.8	57.5	51312

IT	Wind Offshore-IT	85.1	78.8	3256	80.8	70.3	4203
IT	Wind Onshore-IT	85.1	78.9	42160	80.8	71.3	44736
LT	Solar-LT	84.8	0.0	0	81.0	0.0	0
LT	Wind Offshore-LT	84.8	82.1	1	81.0	77.7	1
LT	Wind Onshore-LT	84.8	82.1	400	81.0	77.7	403
LV	Solar-LV	84.0	85.9	1	80.9	81.9	1
LV	Wind Offshore-LV	84.0	80.7	536	80.9	76.4	536
LV	Wind Onshore-LV	84.0	80.7	1018	80.9	76.4	1193
LU	Solar-LU	86.6	84.0	386	86.3	82.7	629
LU	Wind Offshore-LU	86.6	0.0	0	86.3	0.0	0
LU	Wind Onshore-LU	86.6	83.6	467	86.3	82.7	652
MT	Wind Offshore-MT	85.0	70.7	187	85.0	93.1	204
MT	Wind Onshore-MT	85.0	75.4	190	85.0	94.4	216
NL	Wind Offshore-NL	86.3	83.5	13774	83.1	77.9	20227
NL	Wind Onshore-NL	86.3	83.5	21341	83.1	77.9	27209
PL	Wind Offshore-PL	84.4	83.5	1078	83.9	84.1	2355
PL	Wind Onshore-PL	84.4	83.5	15430	83.9	84.1	16348
PT	Wind Offshore-PT	81.1	64.2	252	80.7	64.7	252
PT	Wind Onshore-PT	81.1	65.0	21402	80.7	65.4	20420
RO	Wind Offshore-RO	84.0	81.2	7	83.8	80.5	7
RO	Wind Onshore-RO	84.0	81.2	8013	83.8	80.5	8520

SK	Wind Offshore-SK	87.0	0.0	0	86.6	0.0	0
SK	Wind Onshore-SK	87.0	86.1	904	86.6	87.0	1320
SI	Wind Offshore-SI	87.2	0.0	0	86.8	0.0	0
SI	Wind Onshore-SI	87.2	86.2	650	86.8	86.6	323
ES	Solar-ES	84.4	72.1	24759	84.2	76.4	25967
ES	Wind Offshore-ES	84.4	77.9	100	84.2	78.6	100
ES	Wind Onshore-ES	84.4	77.9	88936	84.2	78.7	95151
SE	Wind Offshore-SE	82.3	78.7	1895	80.2	75.4	1907
SE	Wind Onshore-SE	82.3	78.7	10989	80.2	75.4	11600
UK	Wind Offshore-UK	84.2	76.9	74302	75.9	54.8	94838
UK	Wind Onshore-UK	84.2	77.0	78887	75.9	56.0	82820

Table 3: Annual average prices-time weighted (€/MWh), verage price received (€/MWh) and associated annual generation (GWh) by variable renewable technology for 2050 Reference and Mitigation Scenario by Member State.

		2050 Reference Scenario			2050 Mitigation Scenario		
MS	**Technology**	**Reference Price (€/MWh)**	**Average Price Received (€/MWh)**	**Annual Generation (GWh)**	**Mitigation Price (€/MWh)**	**Average Price Received (€/MWh)**	**Annual Generation (GWh)**
AT	Solar-AT	99.1	90.9	3026	99.4	85.9	4733
AT	Wind Offshore-AT	99.1	0.0	0	99.4	0.0	0
AT	Wind Onshore-AT	99.1	93.2	15852	99.4	92.2	21062
BE	Solar-BE	94.9	88.4	9128	98.0	88.8	10767
BE	Wind Offshore-BE	94.9	90.6	12931	98.0	92.7	17671
BE	Wind Onshore-BE	94.9	90.6	15755	98.0	92.7	17392
BG	Solar-BG	62.9	50.9	3134	50.2	35.0	4219
BG	Wind Offshore-BG	62.9	0.0	0	50.2	30.0	161
BG	Wind Onshore-BG	62.9	51.3	4087	50.2	29.8	6365
HR	Solar-HR	98.5	97.1	713	101.4	96.1	1498
HR	Wind Offshore-HR	98.5	97.5	828	101.4	96.5	1984
HR	Wind Onshore-HR	98.5	97.5	1326	101.4	96.5	3468
CY	Solar-CY	97.4	74.2	1546	84.6	42.3	1993
CY	Wind Offshore-CY	97.4	103.9	1	84.6	95.3	187
CY	Wind Onshore-CY	97.4	97.7	1014	84.6	87.8	1442
CZ	Solar-CZ	91.8	90.4	2583	92.0	89.4	3588
CZ	Wind Offshore-CZ	91.8	0.0	0	92.0	0.0	0
CZ	Wind Onshore-CZ	91.8	91.5	789	92.0	89.5	2337
DK	Solar-DK	83.5	78.2	650	81.4	73.4	444

DK	Wind Offshore-DK	83.5	59.0	7862	81.4	51.0	8589
DK	Wind Onshore-DK	83.5	58.8	18383	81.4	50.9	19932
EE	Solar-EE	81.0	0.0	0	75.2	0.0	0
EE	Wind Offshore-EE	81.0	76.7	749	75.2	67.7	973
EE	Wind Onshore-EE	81.0	76.7	4601	75.2	67.7	6175
FI	Solar-FI	77.1	73.1	64	71.2	65.7	67
FI	Wind Offshore-FI	77.1	66.8	3527	71.2	57.7	3527
FI	Wind Onshore-FI	77.1	66.8	11098	71.2	57.7	14057
FR	Solar-FR	89.5	79.5	25443	86.4	69.2	32772
FR	Wind Offshore-FR	89.5	76.4	64063	86.4	75.8	65848
FR	Wind Onshore-FR	89.5	76.4	102780	86.4	75.8	116095
DE	Solar-DE	93.9	77.1	69966	96.0	77.7	73642
DE	Wind Offshore-DE	93.9	89.9	51198	96.0	91.5	51276
DE	Wind Onshore-DE	93.9	88.9	152688	96.0	90.5	195526
GR	Solar-GR	90.7	66.1	10251	73.1	24.6	13516
GR	Wind Offshore-GR	90.7	87.2	397	73.1	63.3	5085
GR	Wind Onshore-GR	90.7	83.7	19897	73.1	56.3	23389
HU	Solar-HU	100.8	98.9	1378	102.2	98.3	1701
HU	Wind Offshore-HU	100.8	0.0	0	102.2	0.0	0
HU	Wind Onshore-HU	100.8	99.2	2671	102.2	99.8	3868
IE	Solar-IE	79.7	74.8	974	64.7	83.2	598
IE	Wind Offshore-IE	79.7	55.1	2105	64.7	51.9	2873
IE	Wind Onshore-IE	79.7	52.5	17128	64.7	25.8	29350
IT	Solar-IT	90.3	63.3	67590	88.0	45.1	95710

IT	Wind Offshore-IT	90.3	78.9	8078	88.0	88.6	12493
IT	Wind Onshore-IT	90.3	77.4	53857	88.0	83.5	67121
LT	Solar-LT	84.7	0.0	0	77.9	0.0	0
LT	Wind Offshore-LT	84.7	67.5	142	77.9	56.5	142
LT	Wind Onshore-LT	84.7	67.5	1269	77.9	56.5	1561
LV	Solar-LV	83.2	84.9	1	76.8	77.1	1
LV	Wind Offshore-LV	83.2	66.3	988	76.8	55.5	1100
LV	Wind Onshore-LV	83.2	66.3	1250	76.8	55.5	2233
LU	Solar-LU	97.9	89.6	906	100.0	87.5	1677
LU	Wind Offshore-LU	97.9	0.0	0	100.0	0.0	0
LU	Wind Onshore-LU	97.9	90.6	772	100.0	91.5	1579
MT	Wind Offshore-MT	88.5	88.0	298	83.1	85.6	311
MT	Wind Onshore-MT	88.5	89.5	206	83.1	85.6	311
NL	Wind Offshore-NL	96.1	88.7	24180	93.2	79.1	35120
NL	Wind Onshore-NL	96.1	88.7	31521	93.2	79.1	41797
PL	Wind Offshore-PL	87.8	81.7	3095	93.1	86.0	6107
PL	Wind Onshore-PL	87.8	81.7	16433	93.1	86.0	18779
PT	Wind Offshore-PT	75.2	63.3	705	70.7	79.0	697
PT	Wind Onshore-PT	75.2	57.3	23544	70.7	71.2	24219
RO	Wind Offshore-RO	66.1	55.5	869	52.4	36.0	2690
RO	Wind Onshore-RO	66.1	55.5	8618	52.4	36.0	16278

SK	Wind Offshore-SK	94.3	0.0	0	94.8	0.0	0
SK	Wind Onshore-SK	94.3	91.9	1440	94.8	92.3	2379
SI	Wind Offshore-SI	100.0	0.0	0	101.4	0.0	0
SI	Wind Onshore-SI	100.0	98.7	1434	101.4	99.8	1420
ES	Solar-ES	90.9	76.2	39821	79.4	39.2	69993
ES	Wind Offshore-ES	90.9	85.6	288	79.4	93.4	269
ES	Wind Onshore-ES	90.9	83.0	120609	79.4	85.4	138497
SE	Wind Offshore-SE	79.2	60.5	3365	75.4	54.0	2337
SE	Wind Onshore-SE	79.2	60.5	22533	75.4	54.0	23708
UK	Wind Offshore-UK	81.9	64.0	99214	75.7	51.1	136970
UK	Wind Onshore-UK	81.9	63.9	103833	75.7	51.1	133886