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EUROPE'S ELECTRICITY MARKET DESIGN 2030 AND BEYOND

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List of Abbreviations

AT – Austria

BE – Belgium

CAPEX – capital expenditure

CCGT – combined-cycle gas turbine

CH - Switzerland

CP – capacity payments

DE – Germany

DK - Denmark

FR - France

FRSP – Fixed Reserve Scarcity Prices

GB – Great Britain

HHV – Higher Heating Value

IEA – International Energy Agency

IT – Italy

IT-N – Italy North

LCOE – Levelised Cost of Electricity

NL – The Netherlands

NO - Norway

NPS – New Policies Scenarios

OPEX – operating expenditure

ORDC – Operating Reserve Demand Curve

O&M – Operating and maintenance cost

RES – renewable energy supply. Broader term which also includes VRE as well as dispatchable renewables such as hydro, biomass, geothermal

ROI – return of investment

SE – Sweden

SEM – Single Electricity Market (in Ireland)

SO – system operator

VoLL – Value of Loss Load

VRE – variable renewable energy. Specifically refers to wind- and solar-based generation technologies

WEO – World Energy Outlook

Executive Summary

Europe has made significant progress in the creation of a single electricity market, since the first electricity directive of 1996. Subsequent directives have seen a shift from market-driven investment in fossil-fuel based power plants to significant investment in subsidised renewable electricity generation. By 2017, almost all new investment in electricity generation was in the form of subsidised renewables.

The European Union's climate targets for 2030 would imply a further step up in the share of renewables in electricity production (to 50% or more), without binding targets at the national level. Intermittent renewables (VRE – variable renewable energy) impose well-known challenges for the rest of the electricity supply industry, such as efficient matching of supply and demand. At a Europe-wide level, network investments will be needed to support both supply and demand matching of the whole European power grid, and could involve substantial increases in interconnection.

In the light of these developments, a number of key questions emerge:

A. **How well is the current market design working, as we continue with the roll out of renewables generation?**

B. **Following A, what limited adaptions to the current market design might be possible in the timeframe to 2025?**[1]

C. **In the context of A and B, will there be a tipping point in the current energy market, when the penetration of RES might be so high as to cause the need for a more radical market redesign to address the investment signal issue?**

One way to look at these questions is to understand the quantitative impact of higher penetration of VRE and possibly higher fossil fuel prices on wholesale power price in terms of its average and volatility. Will the wholesale power prices still be a reliable signal to guide investment decisions in the European power sector?

Our modelling results suggests that the so-called merit order effect of higher shares of VRE is very specific to local market context – for example, it is rather pronounced in Germany and less so in Britain, while in Italy higher fossil fuel prices will cancel out the merit order effect completely. That is, the interplay between fossil fuel prices and higher VRE depends on the existing conventional generation mix.

All in all, our modelling results show that doubling VRE capacity (relative to 2015) will result in a rather modest decrease in annual average power prices in key European power markets, while

[1] This report is motivated by the sort of electricity market that might be necessary by 2030, but recognises that this market will itself be decided in 2025, on the basis of the electricity market conditions that might have emerged by then. Hence the title of this paper, and its focus on 2025 modelling.

higher VRE penetration means higher volatility of these prices. However, all of these results do not suggest a breaking point in the existing power market design (yet).

Further, with higher VRE penetration the potential for overcapacity could be larger (although our modelling results show that the 2015 capacity mix is already in a state of overcapacity, to some extent). The potential exit of conventional generation in response to the merit order effect, thereby exacerbating their missing money problem, means that power prices could be higher on average (in response to tighter capacity margins).

For example, in a high fossil fuel and carbon price market condition, CAPEX for offshore wind would need to decrease by just 35% (on 2016 levels) for the technology to break even using energy-only wholesale power prices alone. This is the background to recent zero subsidy offshore wind auction results.

Our modelling results also show the importance of further interconnection between markets in Europe – though perhaps very expensive and/or difficult to achieve. This allows near complete convergence of power prices (both baseload and peak prices) and, more importantly, stabilises these prices (reducing volatility) and hence reduces potentially higher market risks due to more VRE. However, increased interconnection does not change the picture we paint on the 'financeability' of subsidy-free RES and fossil fuel investments via energy only markets by 2025.

Finally, our modelling results suggest that higher fossil fuel and carbon prices seem to help stabilise the economics of conventional generation (even with the large overcapacity under higher VRE). In some of our scenarios (higher fossil fuel prices), the existing CCGTs could be profitable (though rather marginally). High fossil fuel prices, coupled with higher carbon prices (north of Euro 50/tonne of carbon dioxide), means that power prices could serve as a longer term investment signal for conventional generators (new CCGTs might be profitable).

Our main conclusions and recommendations on our initial questions are as follows:

On question A, we would suggest that the available evidence and our own modelling shows that if wind and solar are to be self-financing by 2025 under the current European electricity market design, they would need to be operating in circumstances which combine much lower capital cost and/or much higher fossil fuel/carbon prices. In the absence of these favourable conditions for VRE, long term subsidy mechanisms in the form of auctions would need to continue in order to meet European renewable electricity targets.

However, we do find that wind, particularly offshore, is likely to suffer less from cannibalisation of its market than solar. This is because wind output is better able to capture the average annual wholesale price of electricity. A move away from feed-in-tariffs for wind and solar to market prices will also expose generators to increased price volatility, which would raise their investors' target rates of return. The question of the need for a fundamental market redesign to let the market guide generation investments in both renewables and conventional generation would seem to remain.

On question B, interventions to create capacity markets or sharpen ancillary services markets payments can help to address the problems of the current market design by creating the incentives for the optimal addition and retention of power plants in the system.

However, these mechanisms are problematic to design and investments supported by them will likely have higher costs of capital given the volatile and difficult to predict income streams that they give rise to. This is because ancillary services markets are subject to fundamentally different governance arrangements relative to energy markets, making them expensive to rely on as a source of long-run funding for generation investment.

On question C, we do not foresee a sharp tipping point in the current energy market. Instead we see a trend continuation in current generation ‘financeability’ problems, with only some partial mitigation should commodity prices rise, as expected by the IEA, or there be substantial improvements in interconnector capacity across Europe.

A sharp further drop in renewable electricity capital (and O&M) costs, closure of unprofitable fossil fuel power plants and/or rise in carbon prices would certainly help to drive the arrival of subsidy-free renewables within the existing electricity market design.

Will a radical market redesign be necessary? Given the willingness of member states to live with largely subsidised new electricity generation from the period beginning around 2005 to 2018, this seems unlikely.

Will market designs converge across Europe? The issue is whether different local circumstances will cause continuing, or indeed increasing, divergence in market arrangements. One could imagine Ireland, Iberia, the UK, Greece and Germany having significantly different market configurations by 2025 given the differences in their requirements to, and ability to absorb increased amounts of, VRE.

1. Introduction

Europe has made significant progress in the creation of a single electricity market. Successive electricity directives[2] in 1996, 2003 and 2009 have significantly shifted the electricity supply sector from dominance by national monopolies towards a European market dominated by competing pan-European companies whose business models have continued to change dramatically over the past few years.[3]

The electricity directives to date have incorporated a view of market reform which involved vertical separation of generation, transmission, distribution and retailing and the promotion of horizontal competition in generation and retailing. Sustained pressure from the European Commission, supported by national governments, has resulted in widespread separation of generation and retailing from electricity networks and a movement towards a competitive day-ahead wholesale market for electricity across most of Europe. Associated regulation of third-party access to interconnectors and non-discriminatory transmission and distribution charges have supported the promotion of competition at the wholesale and retail level.

One early result of the reforms was a reduction in government intervention in the generation investment decisions of companies. This led to widespread market entry and market-driven investment in fossil-fuel based power plants (making use of CCGT technology and the end of EU restrictions on the use of gas for power generation[4]). Over time, industrial and commercial retail tariffs have been almost completely deregulated in most European countries, while many residential customers have shifted to non-regulated tariffs. Wholesale and retail electricity prices moved in line with fossil fuel prices which were the dominant component of wholesale electricity costs.

However renewable energy directives in 2001 and 2009,[5] which complemented but also undermined the EU's climate change efforts, significantly influenced investment in electricity generation. While the 1990s and early 2000s could be unusually characterised by reliance on the market to finance new generation investment (see Helm, 2002; Pollitt, 2012), since 2002, there has been a significant rise in the share of renewable electricity (RES – renewable electricity supply) investment in Europe. This, combined with slow growth in electricity demand, has meant that by 2017 almost all new investment in electricity generation is in the form of subsidised renewables (IEA, 2018). Renewable subsidies usually specify both the quantity and type of new renewables investment and are entirely decided by national governments, not the decentralised actions of individual firms.

[2] Directives 96/92/EC, 03/54/EC and 09/72/EC.
[3] See Pollitt (2018) for a detailed review of progress in the single electricity market.
[4] Directive 75/404/EC on the restriction of the use of natural gas in power stations was revoked on 18 March 1991.
[5] Namely, the renewable electricity directive (2001/77/EC) and the renewable energy directive (2009/28/EC).

However, renewables subsidies (per MWh) have begun to shrink significantly and the EU's climate targets for 2030 now place emissions reductions at the forefront of action, with no new binding renewables targets at the national level[6]. Ambitious climate targets would imply a further step up in the share of renewables in electricity production (to perhaps 55%), which combined with nuclear power (estimated to still be 20% of production in 2030), will mean only a residual role for fossil fuels in electricity supply by 2030.[7]

Intermittent renewables impose further challenges for the rest of the electricity supply industry. They suggest the need for attention to the efficient matching of supply and demand in real time. This would seem to suggest a key role for both active demand side management, whereby demand is incentivised to adjust in real time to the available supply (up or down), and for large scale energy storage capable of supporting both supply and demand. In addition, network investments will be needed to support both supply and demand matching of the whole European power grid, and also increasingly highly distributed (small scale) renewable generation. This could involve substantial increases in interconnection to make better use of hydro storage resources in Norway, as well as to exploit negative co-variances in supply and demand across large distances in Europe. It could also involve the reinforcement of local distribution networks to facilitate electricity exports or to cope with higher load peaks from further electrification of transport and heating.

[6] See https://ec.europa.eu/clima/policies/strategies/2030_en for the EU's 2030 energy and climate targets.
[7] This is based the EU's own modelling. See Newbery et al. (2018) for a discussion of this calculation.

2. Objectives & timeliness

The EU's ambitious 2030 goals for decarbonisation, combined with the central role electricity might play in supporting electrification of transport as well as heating and industry, suggest that new thinking on market design for electricity is required. The EU has recognised this in the publication of a 'winter package' of suggested energy market reforms in November 2016. These efforts highlight many of the issues, but a workable solution (or set of solutions) and a long-run plan for European electricity has yet to fully take shape.

The emergence of a system heavily dependent on upfront capital investment in intermittent renewable generation, energy storage and reinforced networks suggests the need to consider a significant redesign of the current set of markets based around fossil fuel-based electricity. Marginal-cost-based electricity pricing may not be a good guide for long-run electricity investment; indeed, it no longer is in the Europe of today where almost all new investment in generation is aided by government support schemes. The emphasis in the 1996, 2003 and 2009 directives was on enhancing market driven generation investments across Europe via the development of integrated wholesale power markets across the continent. However, how can competition be maintained or enhanced given the potential for self-generation, competition between generation and network investment, customer provision of ancillary services (e.g. from home appliances and electric vehicles), and the advent of peer-to-peer trading of electricity?

On the other hand, these questions may be premature. It may be that we are some way from the market conditions that require a fundamental market redesign. This paper goes back to basics in electricity market design in the light of the new realities highlighted above.

While it is tempting to just discuss electricity market design in abstract, we instead discuss it in a near-future time frame, recognising the fundamental reality that it takes time to change electricity markets, especially at the level of the whole single electricity market. We are motivated by the sort of electricity market that might be necessary by 2030, but recognise that this market will itself be decided in 2025, on the basis of the electricity market conditions that might have emerged by then. Hence the title of this paper, and its focus on 2025 modelling.

3. Motivating questions to be addressed

A. ***How well is the current market design working, as we continue with the roll out of renewables generation?***

There has been a lot of evidence accumulating on this question. This looks at how renewable electricity supply (RES) is impacting on current electricity prices and the demand for ancillary services and interconnection. Falling wholesale prices and rising demand for ancillary services is not necessarily a sign of a problem in the current market design. It may be that this indicates that the market is working in a situation where fossil fuel prices are low[8], new technology is getting cheaper[9] and overall electricity demand continues to fall.[10] This question is largely addressed in sections 4 and 5.

B. ***Following A, what limited adaptions to the current market design might be possible in the timeframe to 2025?***

This discussion focuses on the potential for the development of more sophisticated ancillary services markets (e.g. for capacity, frequency and voltage support, within and across borders). A key issue is the need for coordination of the rules around those markets versus the idea that different countries should be allowed to pursue different approaches to the development of more sophisticated ancillary services from highly distributed energy resources.[11] This question is addressed by sections 5, 6 and 7.

C. ***In the context of A and B, will there be a tipping point in the current energy market, when the penetration of RES might be so high as to cause the need for a more radical market redesign to address the investment signal issue?***

Here we will model the possible evolution of wholesale electricity prices under different RES penetration scenarios. A key starting point is that market designs deliver technologies of choice: the current market design was built to support fossil fuel electricity generation with high marginal costs, not RES with high upfront capital costs. The idea here is that it is possible that a new market design will only be necessary when short term prices no longer provide efficient long run signals for capital investment. It is by no means clear whether this will be the case by the mid-2020s, as RES penetration may simply, correctly, incentivise interconnection between price zones and itself be supported by a recovery in wholesale gas / carbon prices. We will use market modelling of the European electricity system in 2025 to explore the potential for such wholesale price tipping points. This question is analysed in sections 6 and 7.

[8] The average German import price for natural gas was lower in absolute terms in 2017 than in 2005 (BP, 2018).
[9] See IRENA (2018).
[10] For the EU28, electricity consumption was at the same level in 2016 as in 2005 (See Eurostat data, NRG).
[11] For example, mandating the offering of dynamic retail tariffs to households.

4. The context: evolution of electricity markets and the role of rising renewables

Over the past decade the relationship between electricity demand and investment has evolved with the electricity sector becoming more capital-intensive due to incentives to invest in renewable energy supply (RES) and especially in variable renewable energy (VRE) technologies to both drive down their costs at the same time as meeting environmental targets. In 2017, the combined global capital investment in wind and solar PV stood at ca. $230 bn. This meant investment in wind and solar PV exceeded the investment in traditional power sector technologies such as distribution (ca. $220 bn) and transmission (ca. $80 bn) (IEA, 2018). By contrast, combined investment in conventional thermal generation technologies (coal, gas and oil, nuclear) stood at ca. $140 bn, which represents just 60% of investments in wind and solar PV. The majority of the growth in capital investment in all renewable technologies (wind, solar PV, hydropower, batteries and other renewables) was in developing countries such as China and India, in absolute terms; however, in terms of per capita investments, Europe is the second largest region with $117/capita, just behind the USA at $138/capita (with China at $72/capita).[12] Thus, the impact of rising renewables on the power sector has attracted considerable attention especially in Europe and the USA, with particular interest in such questions as market operations and the design of power markets to accommodate more VRE.

A distinctive feature of VRE is its near zero instantaneous marginal cost when it generates electricity. The impact of zero marginal cost on electricity prices is an example of a “merit-order” effect (detailed discussion of this effect is found in subsequent sections): more VRE on the system depresses average wholesale prices and load factors of conventional generators and hence their revenues (especially for baseload plants). Further, due to the nature of subsidies (e.g., feed-in-tariffs or FiTs) there is a corresponding economic incentive to generate electricity whenever wind/solar resources are available to get guaranteed revenue. This means that in some instances hourly electricity prices could be zero or even negative, reflecting the fact that FiTs are paid regardless of market prices or even the capability of the grid to absorb renewable generation. For example, the daily average wholesale price fell below zero in Germany on New Year's Day in 2018, and on this day prices in several national markets within the Central Western Europe (CWE) area[13] were reported to be experiencing negative prices is some trading hours. There were many trading periods in the CWE region when several markets encountered negative hourly prices. In total, the first quarter of 2018 has seen 70 hours of negative prices in Germany and 8 hours of negative prices in France and Belgium (see **Figure 1**), out of 2,160 total

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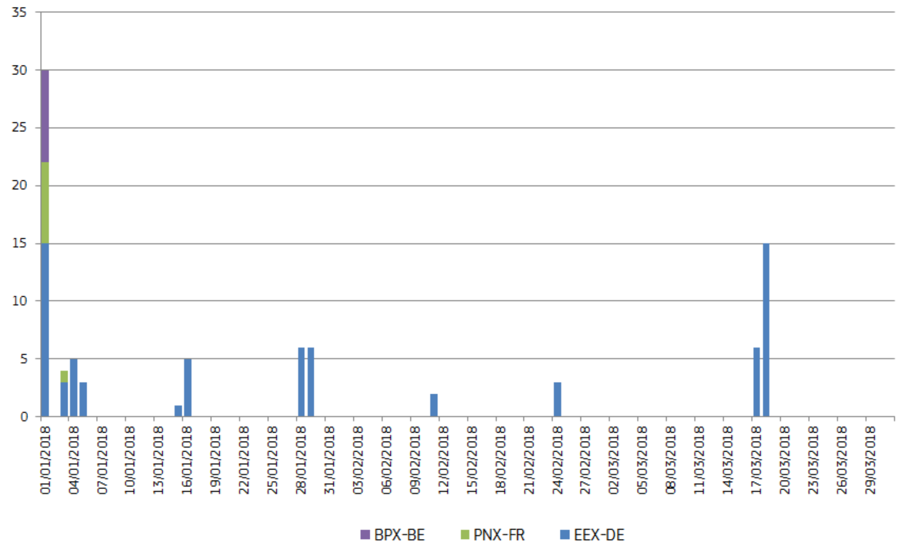
[12] Own calculations based on (IEA, 2018).

[13] CWE region consists of Austria, Belgium, France, Germany, the Netherlands and Switzerland.

hours. Markets in the Czech Republic and Denmark, which are also integrated with the German market, saw 25 and 32 hours of negative hourly prices respectively (DG ENERGY, 2018).

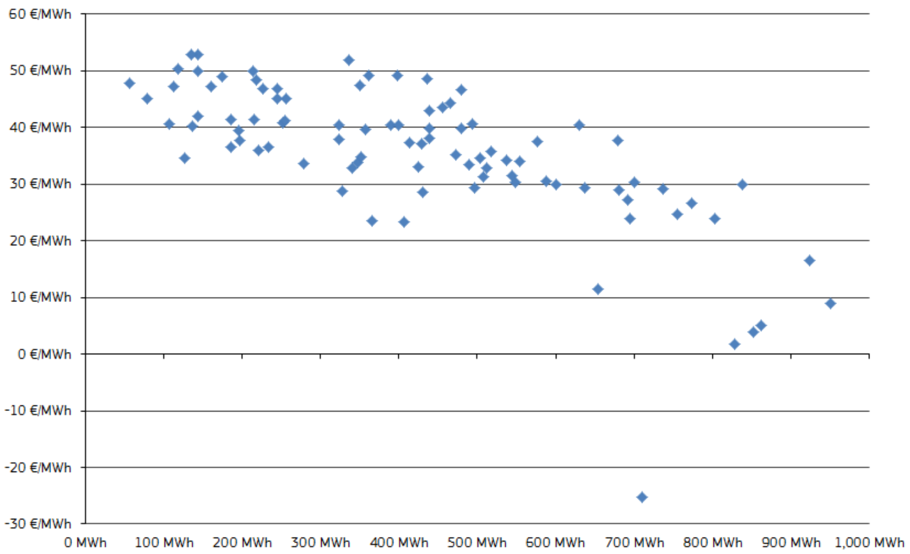
Figure 1: Number of negative hourly wholesale prices (Q1 2018)



Source: DG ENERGY (2018).

Indeed, market data for Germany suggest a clear negative correlation between wind and solar output and daily average wholesale prices (see **Figure 2**).

Figure 2: The impact of the variation of the amount of daily combined wind and solar generation on daily average wholesale prices in Germany (Q1 2018)



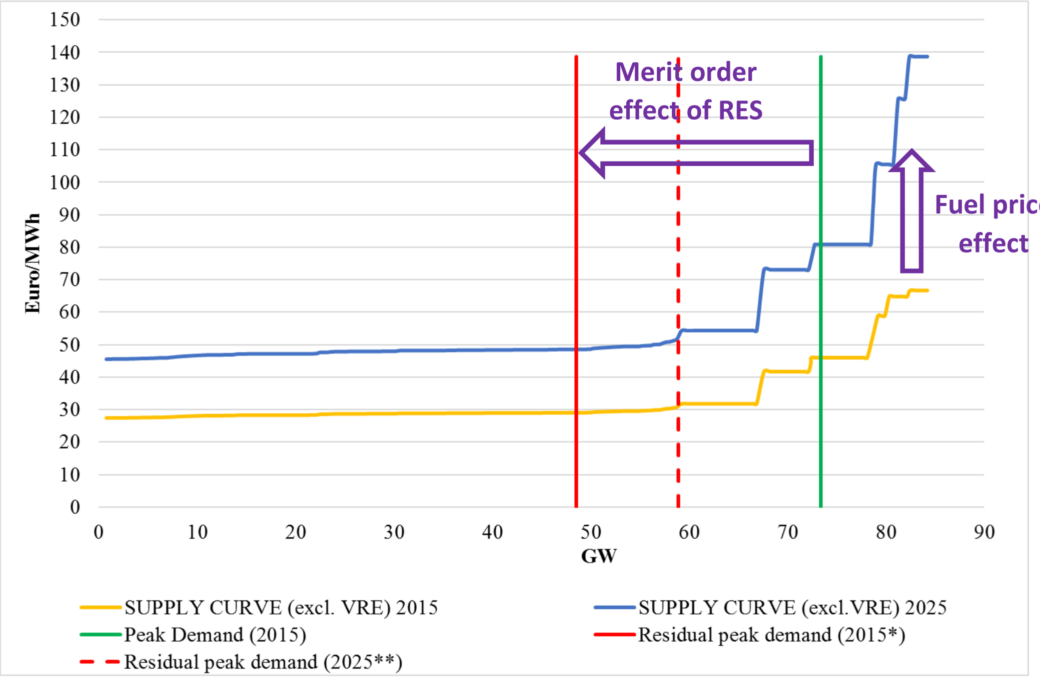
Source: DG ENERGY (2018).

This negative correlation does not pose a problem for fossil fuel generators if peak prices rise to maintain the average price they receive. However, this does not appear to be happening and thus the overall effect of extra VRE on wholesale electricity prices is to reduce the average prices due to displacing fossil fuel-based generation but also due to those negative prices. Nevertheless, fossil fuel generation and hence fossil fuel prices may still play a dominant role in setting wholesale prices when residual demand is being met by these conventional generation technologies.

It is easy to see both the merit-order effect of VRE and the impact of fossil fuel prices on wholesale price formation: **Figure 3** and **Figure 4** show both peak demand and the supply stack of conventional generation (coal, gas and crude oil/diesel) for actual 2015 fossil fuel prices as well as the supply curve based on an IEA 2025 projection of higher fossil fuel prices for Germany and Italy respectively. The IEA’s New Policies Scenario (NPS in IEA, 2018) suggest an increase of 61% for gas, 22% for coal and 102% for crude oil relative to the average annual prices of 2015 for Europe. The figures show the quantity of residual fossil fuel generation (illustrated demand net of RES) stacked in order of marginal cost. Looking left to right in **Figure 3**, we see gently rising marginal cost up until around 60 GW in Germany, until higher cost technologies begin to raise the marginal cost substantially over the range 60-75 GW. The figures show that the extent of the merit-order effect is specific to local market context – it depends on the conventional generation mix, peak demand and the magnitude of VRE generation.

In Germany the merit order effect displaces all gas and oil-fired generation in 2015 leaving coal, wind, solar, biomass and nuclear to be the dominant generation technologies in the market. If German nuclear generation is to be phased out by 2025 then one can see that the fossil-fuel prices and the merit order effect in Germany are of similar magnitude in 2025, assuming the same level of wind and solar penetration. On the contrary, the Italian case shows that because the peak (residual) demand is met predominantly by peaking generation technologies, the impact of the fossil fuel prices is much more pronounced relative to the merit order effect of VRE (smaller capacity level) than in Germany.

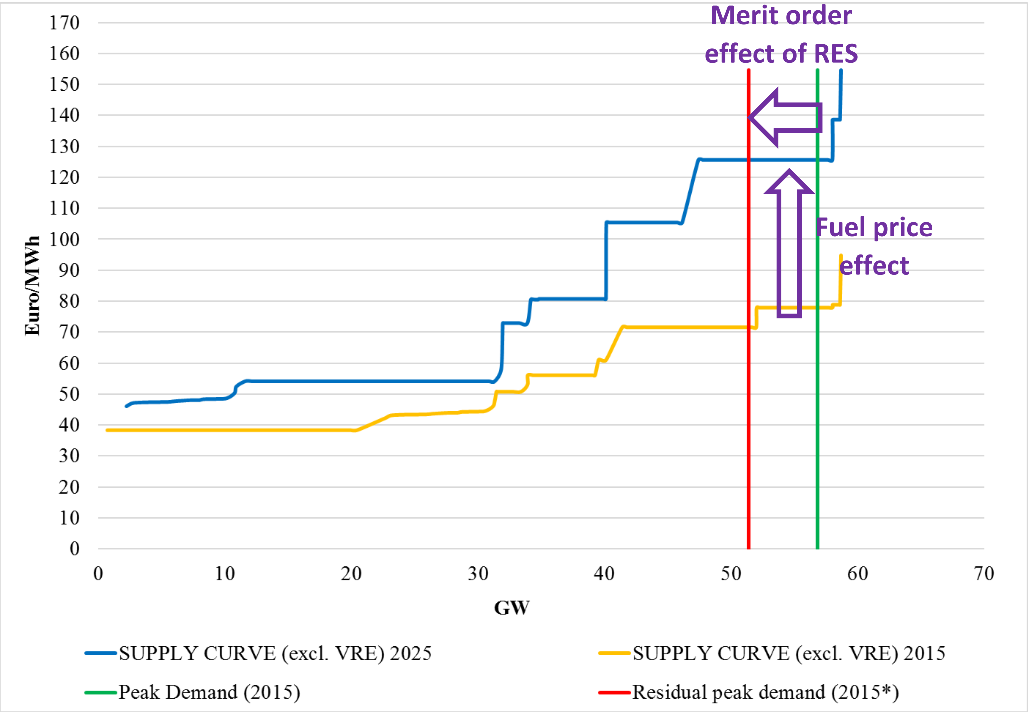
Figure 3: Merit order effect of VRE - Germany (2015 & 2025)



** Peak demand less 2015 wind, solar, nuclear, biomass;*

*** Peak demand less 2015 wind, solar and biomass.*

Figure 4: Merit order effect of VRE - Italy (2015 & 2025)



** Peak demand less 2015 wind, solar and biomass*

The question which arises is whether wholesale prices, in the presence of the merit order effect, are serving as a long-term investment signal in conventional generation technologies, such as a combined cycle gas turbine (CCGT), for example? Later on, we address the related issue of whether higher fossil fuel prices (if they were to occur), by raising electricity market prices, improve profitability for new fossil fuel generation.

Table 1 gives a simple example of the economics of investing in a CCGT plant based on actual power prices, gas and carbon prices in Germany from 2015 to present. First, one can see that average wholesale prices in that period covered between 71%-92% of a CCGT's short-run marginal cost. Secondly, there is no clear pattern between peak prices (their magnitude and instances) and implied running hours of the CCGT. While 2017 saw much higher peak prices (but also more hours of negative prices) relative to other years, the running hours are roughly the same as in other years. The exception is 2018 when gas and carbon prices rebounded to a high level, suggesting the importance of the fossil fuel price effect on the economics of the CCGT.

Table 1: Economics of investing in a CCGT plant in Germany: 2015-present

	2015	**2016**	**2017**	**2018***
MAX hourly prices, €/MWh(e)	99.77	104.96	163.52	98.19
MEAN hourly prices, €/MWh(e)	**31.82**	**28.98**	**34.19**	**41.73**
MIN hourly prices, €/MWh€	-79.94	-130.09	-83.06	-76.01
Instances of negative hourly prices	**98**	**98**	**149**	**110**
TTF average day-ahead gas price, €/MWh(th)	21.1	15.7	17.3	25.27
EU ETS price, €/tCO2	7.5	5	5.5	20.49
Short-run marginal cost (SRMC),€/MWh(e)	**44.90**	**34.24**	**37.32**	**56.76**
N hours prices > SRMC	1276	701	1404	2859
Implied capacity factor	15%	8%	16%	33%
Mean prices as % of SRMC of a CCGT	**71%**	**85%**	**92%**	**74%**
Inframarginal rent, € mn	**4**	**3**	**9**	**14**
Profit without CAPEX annuity, € mn	**(5.11)**	**(5.91)**	**0.36**	**4.90**
Profit with CAPEX annuity, € mn	**(45.20)**	**(46.00)**	**(39.73)**	**(35.19)**
CAPEX, €/kW	758	758	758	758
CAPEX annuity, € mn	40	40	40	40
Fixed OPEX, €/kW/yr	20	20	20	20
Discount rate	10%	10%	10%	10%
Thermal efficiency (HHV)	0.55	0.55	0.55	0.55
Variable OPEX, €/MWh(e)	3.99	3.99	3.99	3.99

Carbon intensity, kgCO2/kWh	0.33	0.33	0.33	0.33
Plant Capacity, 450MW	450	450	450	450
Plant Lifetime (years)	20	20	20	20

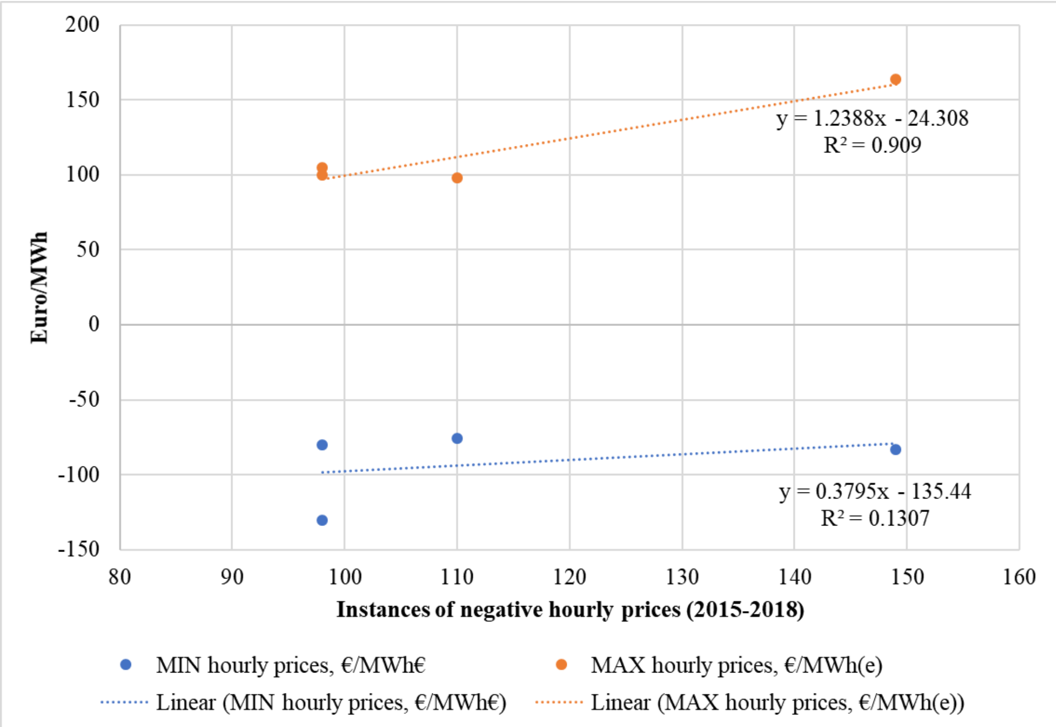
CAPEX = capital expenditure
OPEX = operating expenditure
* until 30 September 2018

Source: Own calculations.

Although it may seem that even with a low number of running hours, power prices could be high enough to generate inframarginal rent for our CCGT plant, this is not enough to cover even fixed OPEX of existing CCGTs and certainly not the fixed OPEX <u>and</u> the CAPEX of new CCGTs. This is a problem If CCGTs are required on the system for system adequacy reasons. Indeed, if this is the case, the "missing money" problem (discussed in detail below) does seem to be serious within the prevailing structure of costs and power price dynamics. This is a problem in terms of providing a signal to keep existing CCGTs running on the system, let alone in terms of enouraging new investment in them.

However, with the higher level of VRE penetration, the economics of the CCGT might improve (or at least not deteriorate) especially if this implies higher prices (peak hours). **Figure 5** shows the relationship between the number of hours with negative prices in 2015 to Sept-2018 (x-axis) and minimum and maximum prices in the same period (y-axis). One can also see from **Figure 5** that there is a clear linear relationship between instances of negative hourly prices (caused by VRE) and the level of peak power prices, but no straighforward relationship between the number of negative hourly prices and the level of those negative prices. This suggests a highly volatile market environment when VRE generation is high relative to hourly demand.

Figure 5: Relationship between frequency of negative prices and MIN/MAX prices: 2015-2018



As we noted earlier, the current market design had the effect of supporting conventional generation technologies from 1990 until around 2010 with lower relative capital costs and higher short-run cost than those of VRE, such as wind. VRE technologies are characterised by high fixed costs incurred up front and stable annual running costs which do not vary much with output. The instantaneous short run marginal cost of a MWh of electricity produced from intermittent renewables such as solar PV and onshore wind turbines is virtually zero.[14]

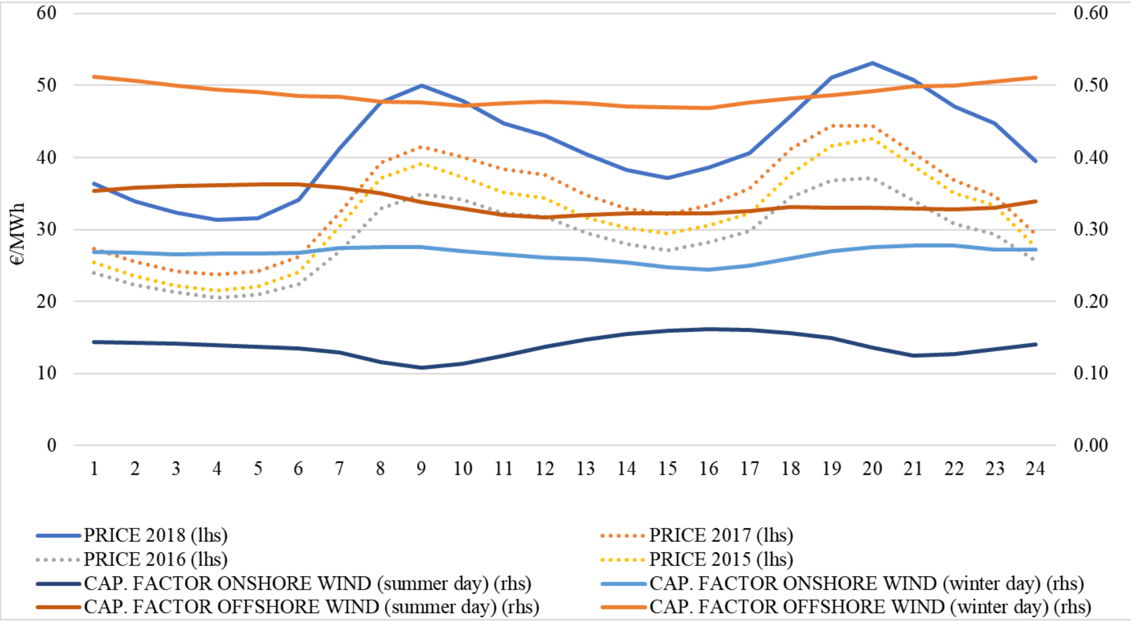
The fixed annual running costs can be quite significant however, especially for offshore wind. For example, the fixed operating and maintenance (O&M) costs for offshore wind in Europe are estimated between US$109-140/kW/year or $30-40/MWh at 40% load factor. In comparison, the costs for onshore wind (in Germany, for example) are US$66kW/year or $30/MWh at 25% load factor (IRENA, 2018). As for solar PV's O&M costs, these have not been thought to be a major challenge in their economics, but due to the fall in overall costs of solar PV modules the share of O&M costs has increased significantly in some markets (IRENA, 2018). O&M costs in Germany and the UK now account for 20-25% of the LCOE, or US$30-40/MWh (IRENA, 2018). In the U.S., utility-scale solar PV plants have O&M costs in the range of US$10-18/kW/year or up to $14/MWh at a 15% load factor (IRENA, 2018).

[14] This situation is not the same as those where electricity markets with high starting levels of hydro-electricity were 'successfully' liberalised (e.g. Norway, Chile and New Zealand). These systems have been characterised by high peak electricity prices due to hydro shortages, low initial amounts of fossil fuel capacity and public financing of the bulk of the renewable capacity.

VRE currently suffer from three market failures: the under-pricing of carbon (at way below the required level to incentivise optimal decarbonisation); the need to price the learning externality, where future VRE costs are reduced by each MW of VRE installed; and the failure of financial markets to properly price capital for long run investment (at way above its true cost to society).[15] Technically, the failure to price carbon is a regulatory failure rather than a failure of electricity market design per se. The argument for the existence of a learning benefit in subsidised roll out of renewables is strong as illustrated by Newbery (2017), notwithstanding the general rule that most subsidies are wasted[16]. These market failures are the reason governments have had to subsidise VRE across the world and will probably have to do so in Europe for several years yet, albeit at reducing levels. However rapid cost falls in solar and wind power suggest that a world where governments no longer have to subsidise renewables may be close at hand (see Newbery et al., 2018; Lang, 2018).

Thus, the prospect of wind and solar being self-financed through wholesale power prices, just like the conventional fossil fuel generation technologies, may be possible provided their costs fall sufficiently and/or wholesale prices (or the fossil fuel and carbon prices that may continue to drive them) are high enough to allow wind and solar PV to be feasible without subsidies. However, the effect of power price dynamics on potential revenues for wind and solar could be quite different, as **Figure 6** and **Figure 7** suggest.

Figure 6: Average power price profiles vs wind generation profiles across hours of day for Germany



[15] See Grubb et al. (2008) for a discussion.
[16] See Ades and Di Tella (1997).

Onshore and offshore wind have rather stable within-day capacity factors, meaning that the revenue stream is rather stable. In contrast, the revenue stream for solar PV is very seasonal due to shorter periods of daily PV generation in the winter and hence reduced revenue capture. In addition, peak PV output may coincide with peak daily demand and therefore depress peak prices (the so-called cannibalization effect).[17] Thus, average wholesale power prices might not be close to the prices that wind and solar actually receive if they were to be solely relying on wholesale markets to finance their investments.

Figure 7: Average power price profiles vs solar generation profiles across hours of day for Germany

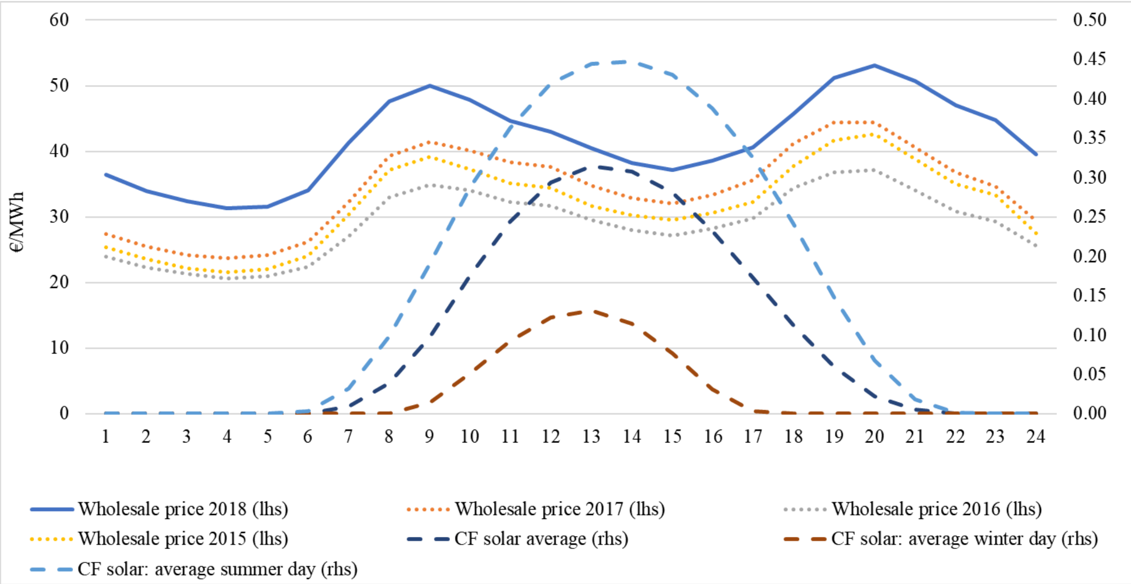
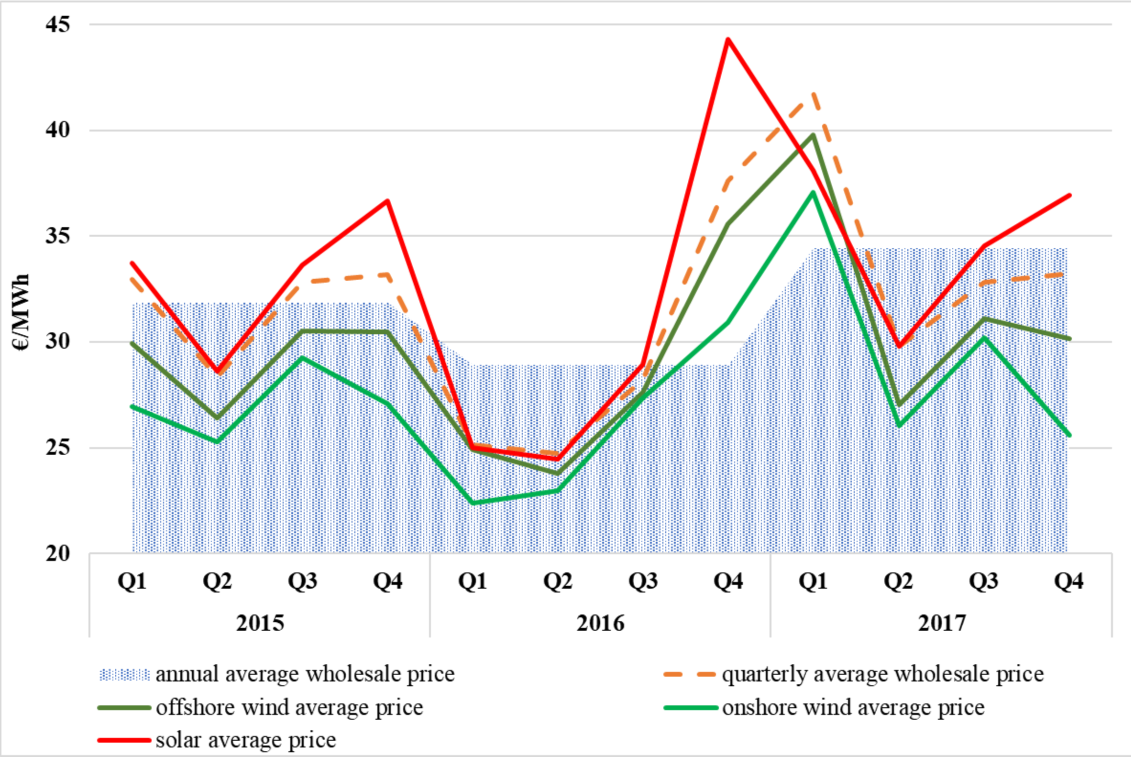


Figure 8 shows that in 2015 solar generation was able to capture higher than average power prices, despite the possibility of "cannibalization" but the capture prices are indeed seasonal. When solar PV generates the most (summer period, Q2) captured prices are lower than in other periods when solar PV generates less, for example during the winter period (Q4). On the contrary wind (both onshore and offshore) seemed to consistently capture prices below average annual price level, but the captured prices are less seasonal than the solar PV prices.

[17] Californian duck curve is illuminating in this regard: https://energyathaas.wordpress.com/2016/05/02/the-duck-has-landed/

Figure 8: 2015-17 average annual wholesale prices and average "captured" prices by wind and solar generation: Germany



All in all, a higher VRE penetration level poses challenges and uncertainties to the economics of both conventional generation technologies as well as for VRE itself. Further, the economics of wind and solar relying solely on wholesale power prices are different. While these differences may be systematic and reasonably predictable in terms of the average timing of output and revenue capture for VRE, solar, in particular, will capture less than the average yearly wholesale price. Fossil fuel prices as well as peak prices could all be important for long-term investment signals in the power sector, as the theory of power market design suggests. The next section reviews this theory.

5. Literature review

A very high penetration of VRE may pose challenges for the theory of electricity markets due to the variable and ‘zero marginal cost’ nature of VRE (following Rifkin, 2014). The question of whether the current market design can accommodate large shares of VRE without radical changes is at the heart of the current policy and academic debates. This question of the future of market design that addresses the policy trilemma – sustainability, security of supply and affordability – is important not only for electricity and climate policies but also has implications for competition policy. Market design is a function of which technologies it seeks to support and hence will be significantly determined by the wholesale prices it gives rise to, vis-à-vis the technologies it seeks to favour. In line with our motivating questions, our look at the literature focuses on the following question: ***will the short-term wholesale electricity prices be able to provide adequate long-run signals for capital investments in VRE?***

The rest of this section will summarise a selection of literature focusing on the relationship between a high level of VRE penetration and the current electricity market design. In particular, we focus on the classic ‘missing money’ (and missing markets) problem, that our example of the CCGT in Germany has highlighted above.

5.1. “Energy only”, capacity payments and variable (intermittent) renewable energy supply

In the prevailing electricity market design, spot prices are determined by the marginal cost of the most expensive operating power plant. These prices, however, are only enough to cover plants’ running (marginal) costs but not their capital costs. Stoft (2002) suggests that under peak load pricing all operating power plants may be able to cover their capacity costs, not only by inframarginal rents, but also by scarcity rents in a long-run equilibrium. Scarcity rents arise during peak hours when total available generation capacity is not enough to cover demand and prices rise above marginal costs. The price rise in this situation will only be limited by the marginal cost of demand side response or by the value of loss load (VoLL). In theory, such an electricity market design can operate and finance generation capacities and is referred to as an “energy only” market. Indeed, as Newbery (2016) noted, capacity adequacy could, in principle, be delivered by competitive energy-only markets. Newbery (2016) pointed out how security of supply – in the sense of insuring that supply and demand is instantaneously balanced - is supplied by the system operator (SO) through acquisition of a range of ancillary and balancing services, while adequacy – in the sense of having enough long-term capacity on the system - can be provided by a competitive “energy only” market. This is said to have been envisioned by the Target Electricity Model (TEM), part of the EU Third Package (Newbery, 2016).

However, in practice, the "energy only" market design faces many practical challenges even in the absence of VRE. First, most electricity consumers cannot respond to short-term wholesale price movements and selective curtailment of customers appears difficult. Thus, the market may not clear under a condition of scarcity, as demand is not elastic enough (Joskow and Tirole, 2007). Second, the social and political acceptability of scarcity prices may be low, and this is exacerbated by the fact that under stress conditions there is the possibility of the exertion of market power by incumbents. Hence, a true scarcity situation and exertion of market power (artificial withholding of generation capacity for scheduled maintenance, for example) is sometimes difficult to detect and distinguish. This leads to a root cause of the "missing money" problem: politicians and regulators tend to impose price caps in wholesale electricity markets (Hogan, 2005), implicitly or explicitly, to dampen price rises and limit the potential for market power abuse. Third, and as result of these considerations, wholesale prices are uncertain (e.g., due to potential price caps and other regulatory interventions) and hence investors are not able to recoup their capital costs through scarcity rents. In fact, as Neuhoff et al. (2016) noted, the "missing money" problem may exist even without explicit price caps as investors may *expect* that under stress and scarcity events, wholesale prices may be capped by regulators or by technical interventions by system operators.

Thus, Hogan (2005) proposed an improvement to the energy-only market design to address the lack of a market for reliability: to price scarce reserve at the opportunity cost of energy through a regulated operating reserve demand curve (ORDC). According to Hogan (2018) an ORDC will improve reliability because better scarcity pricing would contribute to long term resource adequacy – this will improve 'investability' in generation technologies. A large increase in prices under scarcity conditions provides better incentives at just the right time, when and where capacity would be especially needed (Hogan, 2018). It does suggest that, in effect, scarcity pricing may be relying on a few very high price hours every few years to finance peak capacity. The author also pointed to the fact that capacity markets (which contract for the availability of capacity a year or 4 years ahead) in themselves do not create the correct incentives to operate capacity or change load in response to short-run scarcity conditions (Hogan, 2018) and this can lead to lower security of supply. This may be because of the unwillingness of governments to expose participants in the capacity market to high enough penalties for non-delivery. This point highlights a general issue that there is no getting away from the need for very high prices (in the form of positive or negative payments) to incentivise actual delivery in real time when supply is scarce.

On the other hand, Joskow (2007) noted that price caps are rarely a binding constraint and that the missing money problem is often a result of other market imperfections. Joskow (2007) therefore concludes that a forward capacity market is needed to ensure resource adequacy. Indeed, Newbery (2016) noted that if markets were not subject to policy and regulatory interventions, then resource adequacy could be delivered by profit-motivated generation investment. But for this to be the case, Newbery (2016) suggested that investors should have confidence in receiving an adequate revenue stream from various markets – energy and ancillary services markets. Hence, if price caps are set below the VoLL, then ideally the revenue shortfall from the energy only market should be covered by payments for the provision of ancillary services such as flexibility, ramp-rates, frequency response, black start capability etc. Furthermore, generators might receive revenues which might be supported by spot wholesale prices being higher than marginal cost (due possibly to market power exertion) and the provision of additional services to the SO and/or provision of complimentary products such as heat (CHP). Hence, in practice, the "missing money" problem could be smaller, and its size is specific to the local market context. However, if these ancillary services are inadequately remunerated and poorly defined (e.g. by subjecting fossil fuel generators to low quality competition from electrical energy storage or demand response) then the possibility of missing money would still exist. Indeed, as Newell et al. (2012) noted, in practice, as is now well known, actual electricity markets often produce results where energy and ancillary services prices may not be sufficient to support new investment. Partly, this is because a new investment relying on volatile market revenue streams is risky and subject to cannibalisation by future investments (and new technologies – such as electrical energy storage - which themselves target some, but not all, ancillary services). However, this could be because – as we noted above - demand has been in decline and with growing renewables the price signal is, correctly, to reduce fossil fuel generation.

A worry remains that the dependence of new generation assets on multiple volatile sources of revenue in energy and ancillary services markets is likely to give rise to higher costs of capital for new investment and higher long run system costs than might be necessary under an alternative longer term financing arrangement[18]. Relative to wholesale energy markets, system operator run ancillary services markets can have low liquidity and be subject to fairly arbitrary changes which mitigates them being low cost ways of financing new generation investment.

So, beyond the missing money problem, as suggested by Newbery (2016), there is a "missing market" problem (Newbery, 1989). Newbery (2016) noted that even if the revenue is potentially adequate to cover capital costs but is not perceived to be so by generators and/or their financiers, then there is a "missing market" problem. Capacity markets, for instance, can be seen as the acceptable solution to this missing market problem for investors faced with political uncertainty (Newbery, 2018). The debate between energy-only markets with scarcity pricing, and energy-only and capacity payments to support resource adequacy, is rather an old one and pre-dates the emergence of VRE. In general, forcing money to be all energy or a combination of capacity and energy payments is not the issue in theory and thus the two fundamental market design options should not affect the 'financeability' of generation capacity. In practice, capacity adequacy must be maintained and a number of jurisdictions have chosen either the energy-only

[18] In the era of vertically integrated utilities, such investments could be financed at the regulated rate of return, implying much lower financing cost.

and scarcity pricing or energy-only and capacity payments of various forms (for further discussions on this subject see e.g., Hogan, 2018; Joskow, 2013; Cramton et al., 2013; Newbery, 2016; Neuhoff et al., 2016; Papavasiliou and Smeers, 2017).

There are signs that system operators are creating new ancillary services markets to competitively support the transition to high renewables penetration (see DotEcon, 2015). The island of Ireland provides a very interesting case study. Ireland is covered by its own Single Electricity Market (SEM), which is overseen by its two system operators, Eirgrid and SONI. The system is currently set up to handle up to 65% non-synchronous generation (mostly from onshore wind), and it has plans to increase this to 75%. As part of meeting this target, the SEM has implemented the DS3 (Delivering a Secure Sustainable Electricity System) programme which sets out to define and procure packages of ancillary services to support the grid. Under the programme[19] it has defined 14 ancillary service products, including a new frequency response product for delivery of frequency response within 0.15 seconds. In the first competitive auction to procure these new services, offerors will be required to submit a package bid for 5 ancillary services products (around frequency response and short term operating reserve), at a discount to maximum prices published by the system operators. This market will offer six year contracts and support battery technology. While Ireland is a small, isolated market within the European single electricity market with likely high demand for ancillary services, it is nonetheless a good example of how system operators can and do respond to the changing needs of their system.

A key issue for relying on ancillary services markets to supplement generator income is the fundamental difference in the governance arrangements and liquidity of ancillary services markets versus wholesale energy markets. Ancillary services markets are run by national system operators and are local to each system (as the Irish example illustrates). They are subject to the risk that they will be abolished or redesigned within quite short time frames. They operate under a wide range of pricing mechanisms, including mandatory provision, fixed prices, bilateral contracts and auctions[20]. The system operator in Great Britain recently (between 2016 and 2018) reduced the number of ancillary services products from 30 to 22. Ancillary services income is volatile and system operators are often under incentives to minimise total ancillary services expenditure, as part of their incentive regulation. Such regulation may not be optimal from the point of view of long run investment in electricity generation. By contrast, wholesale electrical energy markets are increasingly integrated across Europe and provide long price histories on which to base future price projections, and the market fundamentals which drive prices are straightforward to model (as demonstrated in subsequent sections).

A market for reserve capacity, in the form of short run operating reserve, an ORDC or a capacity market is a way to create an ancillary services market for capacity to be available on the electricity system. However, this is still subject to the governance criticism outlined above. The

[19] See Eirgrid (2018).
[20] See for example Greve et al. (2018) and Anaya and Pollitt (2018).

best mix of short run operating reserve markets, an ORDC or a capacity market depends on the governance and predictability of these different market mechanisms. Hogan's argument (2005, 2018) is that a short run ORDC renders a longer run capacity market obsolete. However, this is premised on the ORDC market itself being a predictable source of funding over a multi-year period, so as to render reliance on a longer-run capacity market (for capacity provision 1, 4 or 15 years ahead) unnecessary. The uncertain nature of ancillary services markets has already led to them attracting short-run payback investments (in demand response and diesel generators) at the expense of longer-run payback CCGT generation in the GB capacity market. This *may* be the right answer but it does demonstrate the nature of these markets.

The performance of capacity markets can be questioned[21]. A key issue is what exactly is the capacity market product that customers are paying for. An incomplete 15 year market for capacity pays some generators to provide capacity for 15 years. However, with less than full contracting for 15 years ahead – what exactly are customers really buying? Even in the case of one or four years ahead, when the system operator contracts for the whole of the predicted maximum demand capacity, will the group of capacity providers actually deliver during a capacity stress event? If the penalties for non-delivery are low, they may not. Indeed it is worse than this: generators may still withdraw capacity to push up the wholesale price and simply pay the non-delivery penalty on their withdrawn capacity. If the penalties are too high, then the cost of capital will be pushed up and there will be a bankruptcy risk. Meanwhile capacity markets have been subject to market manipulation, with governments seeking to contract with new generation to drive down prices in capacity markets or drive up capacity targets to increase clearing prices.[22] There have also been attempts to set floor and ceiling prices in capacity auctions which often bind, undermining the market price determination process. Capacity market participation rules are subject to challenge. We note that following a legal challenge from a demand side response provider, payments in the UK capacity market have recently been cancelled by a decision of the European General Court which ruled that the original approval process undertaken by the European Commission was inadequate.[23]

A fundamentally different approach would be to shift the focus of provision of adequate capacity away from the generators and on to retailers. Instead of worrying about generator incentives to provide adequate capacity to the system, the focus could be on the procurement of adequate capacity by retailers. In this set up, retailers would be exposed to the VoLL for all of their customers in the event of a failure to supply. This would be particularly relevant for smaller customers (i.e. residential and small business) who would need to be on default non-supply contracts which compensated them at their estimated VoLL. Larger customers could simply choose their own contractual level of financial compensation in the event of non-supply (trading

[21] Cramton and Stoft (2005).
[22] See Pollitt and Haney (2013).
[23] See Case T-793/14, http://curia.europa.eu/juris/celex.jsf?celex=62014TJ0793&lang1=en&type=TXT&ancre= Accessed 30 November 2018.

off lower prices for less non-supply compensation). A high level of VoLL exposure by retailers would encourage over-contracting of generating capacity by them. This approach has traditionally not been followed by regulators, partly out of fear of retailer free-riding as low quality-low price retailers on narrow margins might choose to run excessive bankruptcy risks given the existence of limited liability, relative to a system of positive incentives on generators to provide capacity. A related suggestion to this is that instead of capacity markets (see Bidwell, 2005), retailers should contract for reliability options with generators, where generators agree to provide reliability at fixed prices during stress events and effectively forego price spike revenues. This addresses the market manipulation problem which may arise in capacity markets.

The currently prevailing electricity market design has evolved naturally to support the operation of, and investment in, fossil fuel power generation technologies. The missing money problem has been limited to the issues of robustness of demand-side management (market clearing under scarcity conditions), the possibility of market power exertion at peak demand periods by conventional generators and resultant regulatory interventions in the form of price caps and/or technical interventions by system operators (SOs). However, with the rise of intermittent renewable electricity supply, the missing money problem may be exacerbated. VRE can be seen as completely price-inelastic negative demand (due to zero marginal cost) and thus it intensifies price volatility and demand fluctuations (see Cramton et al. 2013). This leaves fossil fuel generators even more exposed to volatile income streams in the energy market and in the market for ancillary services. Second, with the rise of VRE, the attractiveness of investments in conventional generation capacity reduces due to the “merit order” effect of VRE (see, e.g., Green and Vasilakos, 2010; Sensfuß et al., 2013; Ritz, 2016). This is because new fossil fuel investments no longer start off as base load investments with maximum load factors, as they did in the past. Furthermore, more VRE on the system depresses average wholesale prices and the load factors of conventional generators, and hence their revenues. This may be the ‘correct’ signal to send to new fossil fuel investment, but it does increase their ‘financeability’ challenge in conditions where they may be necessary for capacity adequacy.

Thus, the question of whether the current “energy only” market can provide adequate long-run price signals to guide investment decisions in generation capacity (both conventional and VRE) is becoming ever more important with the rise of VRE. Coincidentally, the rise of VRE creates a need for flexible reserve capacity to meet the unpredictable nature of VRE generation. And so, the discussion around “energy only” with better scarcity pricing (through ORDC, for example) has been renewed, but in the context of supporting higher VRE and in arguing that the existing energy-only market can – with appropriate ancillary service markets - accommodate a very large amount of zero-marginal cost VRE (Hogan, 2018).

In this paper, we focus on energy and ancillary services markets. De Vries and Verzijlbergh (2018) suggest that optimal ‘market design’ would co-optimise across energy, networks and environmental objectives. This would mean taking network investment decisions jointly with price determination in wholesale energy and ancillary service markets, and with due account of the pricing of all government objectives for decarbonisation and industrial policy towards energy. This sounds like a very difficult, and currently impossible, task in reality. Anaya and Pollitt (2018) discuss co-optimisation simply in the context of reactive power (voltage support) services, noting that it is important to jointly optimise across energy and ancillary services markets, and that some jurisdictions do this in the context of *some* ancillary services.

5.2. Quantitative analyses and modelling: impact of VRE on electricity systems

The merit order effect of VRE is well understood at both the theoretical and empirical level. We now discuss the empirical evidence on the size of the effect in European electricity markets.

Bublitz et al. (2017) provide a good summary of some empirical and modelling studies that estimated quantitatively the merit-order effect. The effect ranges from Euro -15/MWh to Euro -0.55/MWh depending on modelling assumptions, RES technology (wind, solar, biomass, etc.), location (Germany, Spain, Ireland) and methodology (simulation, time series analysis). Gianfreda et al. (2018) noted that while day-ahead prices are likely to decline as VRE production increases, the effects on balancing market prices (intra-day energy prices which reward adjustments near real time) are more ambiguous. They investigated the effect of VRE on the balancing market of the Northern Italian zone which is characterised by a high solar PV and hydro penetration. The authors found evidence of increasing balancing prices in particular market conditions, that could be a sign of strategic behaviour in real time markets (i.e. balancing markets) by conventional producers prone to the merit order effect in the day-ahead market. They also compared the obtained results with those in the German balancing market (where, on the contrary, balancing costs have decreased) and postulate that the different market designs may explain these results. As one can see from the above discussion, there is an acknowledgement in the academic literature that increasing levels of VRE have a negative impact on average wholesale prices, and thus may exacerbate the missing money problem outlined in the previous sub-section.

Modelling literature which compares analyses of energy-only markets with scarcity pricing (e.g. ORDC) and other market design options – such as energy-only and capacity payments – are rather limited. Levin and Botterund (2015) used mixed-integer programming (MIP) to determine optimal generator expansion decision and hourly unit commitment dispatch in a power system. The authors analysed the impact of increasing wind power capacity on the optimal generation mix and generator profitability. They focused on ERCOT and analysed three market policies that may support resource adequacy: Operating Reserve Demand Curves (ORDC), Fixed Reserve Scarcity Prices (FRSP) and fixed capacity payments (CP). They found that optimal expansion plans are comparable between the ORDC and FRSP implementations, while capacity payments may result in additional new capacity relative to capacity levels under the other two market design options (ORDC and FRSP), i.e. potentially excess capacity. As for price volatility, they

found that under the FRSP policy there are more frequent reserve scarcity events and hence price spikes, while prices under ORDC tend to be smoother. As one would expect, they found that under all policies, average energy prices decrease (and so do the revenues of base load plants) with increasing wind penetration. On the other hand, intermediate and peak load plants benefit from higher reserve prices and are less exposed to reduced energy prices. Thus, they concluded that an ORDC approach may be preferred to FRSP as it results in similar expansion and revenues with less extreme energy prices while a fixed CP leads to additional new flexible CCGT units, but lower profits for other technologies. However, unfortunately the impact on total system costs is not analysed.

Papavasiliou and Smeers (2017) analysed how ORDC could support flexible generation under increasing penetration of unpredictable, highly variable and non-controllable renewable supply. The authors tested the performance of the mechanism by developing a model of the Belgian electricity market. The model was validated against the historical outcomes of the market over a study period of 21 months. With the model analysis, they verified that based on the observed market outcomes of their study period, none of the existing combined cycle gas turbines of the Belgian market can cover their investment costs. However, if ORDC were to be introduced in the Belgian market then the resultant price adders that reflect the true value of scarce flexible capacity restores economic viability for most combined cycle gas turbines in the Belgian market. Therefore, according to Papavasiliou and Smeers (2017), ORDC fulfils its objective: flexible resources in the Belgian market that were not viable given historical energy and ancillary services prices in the retained 21-month period would have been viable if price adders correctly reflecting scarcity had been introduced. They concluded that it is important to have an efficient short-term market for sending the right signal on scarcity of capacity, which, in the argument of DG COMP, makes the capacity market redundant (Papavasiliou and Smeers 2017).

6. Methodology, research framework and scenarios

The objective of our modelling work is to quantitatively assess the impact of higher VRE on average annual wholesale prices and volatility of those prices in selected European power markets to look for tipping points in wholesale prices as VRE penetration increases. We also want to understand the impact of fossil fuel (and carbon) prices on wholesale power prices. In particular, we want to know if the anticipated increase in commodity prices which the IEA expects by 2025 (relative to 2015) would make investments in VRE 'subsidy-free'.

For this, we employ our own economic dispatch model and calibrate it to simulate the interconnected power markets of North Western Europe. The model simulates European power markets at hourly resolution and at plant level. Its objective is to minimise total costs (fuel and carbon costs and variable OPEX) of meeting hourly demand, while respecting many techno-economic constraints of power plants such as ramping constraints and N-1 system security constraint (operating/spinning reserve requirement). We assume completely inelastic demand curves, but we price country-specific VoLL in the model. Thus, as the supply margin reduces, possibly violating the N-1 security constraint and the system demand constraint, the wholesale prices would approach VoLL. The model also endogenously optimises the operations of pump storage units. Thus, it optimises only operational decisions – such as dispatch, pumping and discharge – and does not look at investment and divestment decisions explicitly. For this research, we have modelled coal, gas and oil-fired power stations, while assuming all other technologies to be exogenous. These other technologies are onshore and offshore wind, solar PV, biomass, hydro run-of-river, nuclear and other (e.g. geothermal) generation technologies. The model was calibrated to 2015 data to simulate SEM (in Ireland), Great Britain (GB), France (FR), Belgium (BE), the Netherlands (NL), Switzerland (CH), Germany (DE), Austria (AT), Italy (IT), Denmark (DK), Norway (NO) and Sweden (SE). Italy, Denmark, Norway and Sweden were subsequently divided into their respective bidding zones, as is currently the case. In total, 25 market bidding zones were modelled explicitly, considering their interconnection capacity. Hence, the model assumes full coupling of these market zones (**Table 2** and **Figure 9**).

Table 2: Market zones in the European power market model

AT	IT-Centre-North	GB	SE3	NO5
BE	IT-Centre-South	SEM	SE4	
DK1	IT-Centre-South	NL	NO1	
DK2	IT-North	CH	NO2	
DE	IT-Sardinia	SE1	NO3	
FR	IT-Sicily	SE2	NO4	

Figure 9: Existing market zones in Europe

Source: Ofgem (2014)

The following scenarios were modelled:

1. **Baseline** – assumes same level of wind (both onshore and offshore) and solar PV capacity as in 2015 but only commodity prices will increase as per IEA WEO (2018) New Policies Scenario (NPS). See **Figure 10**.
2. **Scenario A** – increase of 50% of wind (both onshore and offshore) and solar PV capacity relative to 2015 for all markets considered in the model. This is a near-term target (which has already been reached in some of the countries we consider here, such as GB).
3. **Scenario B1** – increase of 100% of wind (both onshore and offshore) and solar PV capacity relative to 2015 for all markets in the model (see **Figure 12**). This is chosen to be roughly in line with reaching 2030 targets.
4. **Scenario B2** – same as in Scenario B1 but we look into the question of whether the increase in VRE capacity (100% increase relative to 2015) would cause overcapacity in the power system and hence depressing of wholesale power prices. See Section 7.4 for a

detailed discussion of our methodology to address decommissioning of unprofitable plants.

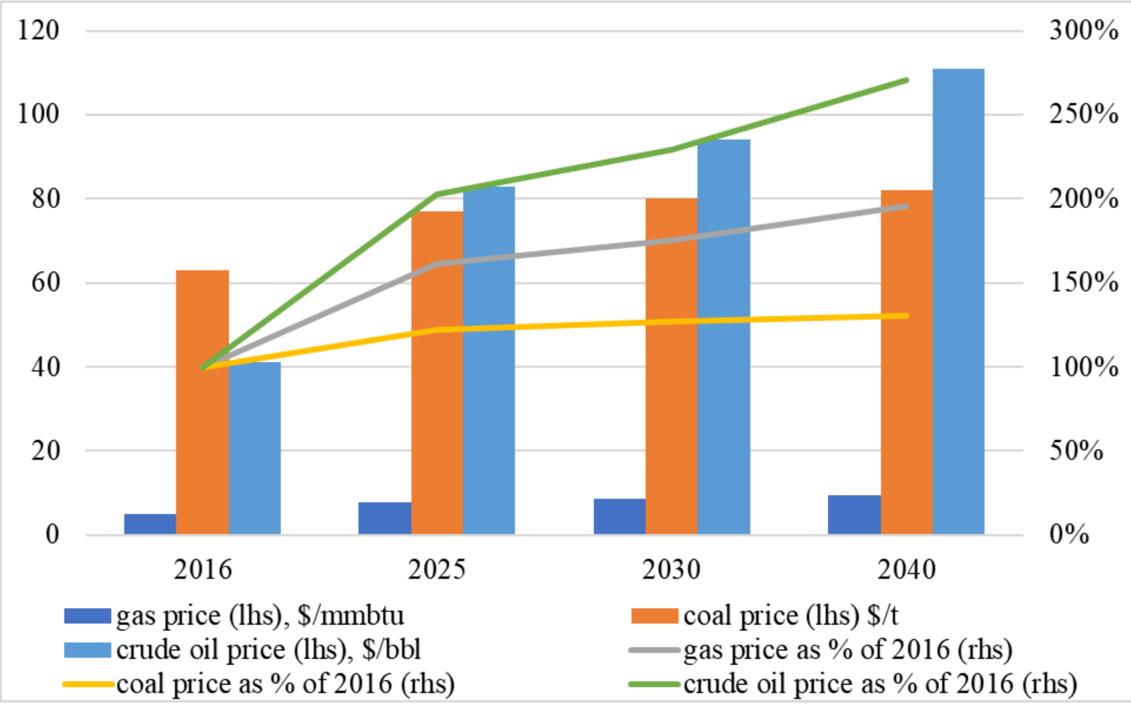
5. **Scenario C1** – as in scenario B1 but assumes higher fossil fuel prices than the projected prices for 2025. We "bring forward" the commodity prices projected by IEA (2018) under its NPS for 2040 to the year 2025, thus assuming a situation whereby commodity markets could become tighter sooner (see **Figure 10)**.
6. **Scenario C2** – as in scenario C1 but assumes higher carbon cost on top of higher fossil fuel prices. Thus, we examine the role of high carbon cost on economics of both VRE and conventional generation
7. **Scenario D** – as in scenario B1 but assumes "unlimited" interconnection capacity between all the market zones in the model.

Table 3: Input parameters and assumptions for modelled scenarios

<table>
<tr><th rowspan="2">Scenarios</th><th colspan="2">VRE capacity</th><th rowspan="2">Fossil fuel capacity</th><th rowspan="2">Interconnection capacity</th><th colspan="3">Fossil fuel prices</th><th rowspan="2">Carbon cost</th></tr>
<tr><th>wind</th><th>solar</th><th>Gas</th><th>Coal</th><th>Oil</th></tr>
<tr><td>Baseline</td><td colspan="2">2015</td><td>2015</td><td rowspan="6">2015</td><td>$7.9/mmbtu</td><td>$77/tonne</td><td>$83/bbl</td><td rowspan="5">€25/tCO2</td></tr>
<tr><td>A</td><td colspan="2">50% higher than baseline</td><td rowspan="2">as in baseline</td><td colspan="3" rowspan="3">as in baseline</td></tr>
<tr><td>B1</td><td colspan="2">100% higher than baseline</td></tr>
<tr><td>B2</td><td colspan="2" rowspan="4">as in B1</td><td>Partly decommissioned (see Section 7.4)</td></tr>
<tr><td>C1</td><td rowspan="3">as in baseline</td><td rowspan="2">$9.6/mmbtu</td><td rowspan="2">$82/tonne</td><td rowspan="2">$111/bbl</td></tr>
<tr><td>C2</td><td>€57/tCO2</td></tr>
<tr><td>D</td><td>unlimited</td><td colspan="4">as baseline</td></tr>
</table>

Source: fossil fuel prices are from IEA (2018).

Figure 10: IEA projected commodity prices for Europe (NPS scenario)

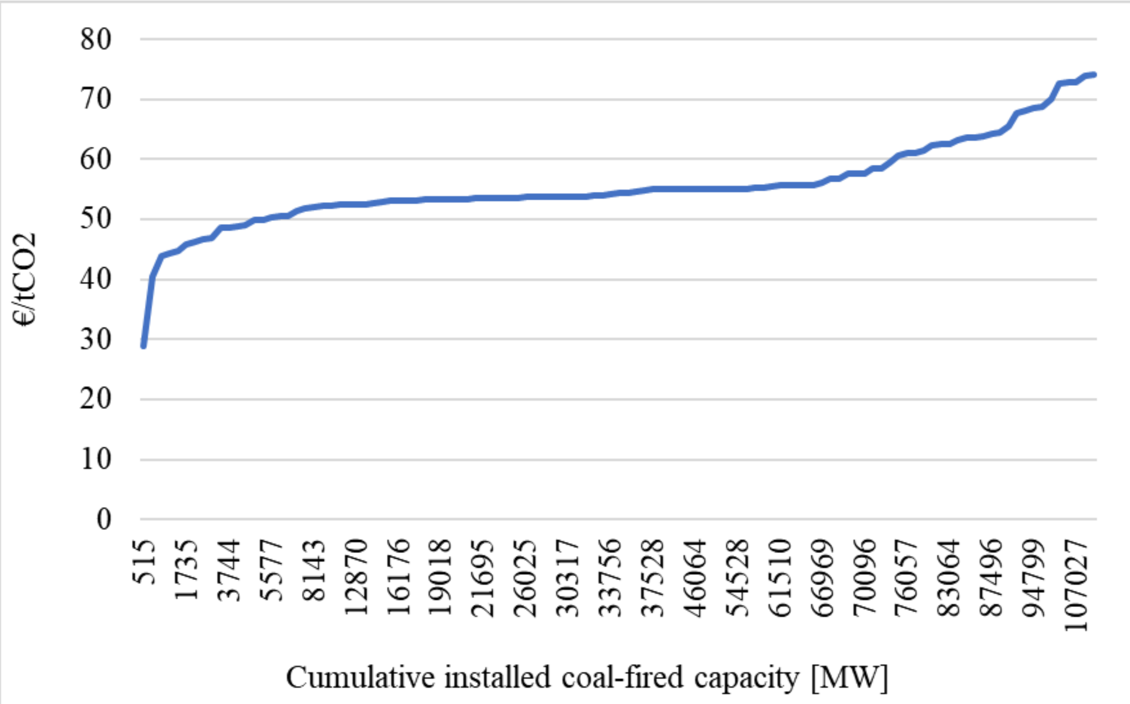


Source: IEA (2018).

Note that in some European markets (e.g. Germany) coal power plants may use bituminous coal or lignite coal; the coal price in Table 3 is for bituminous coal (IEA assumes coal's energy content of 6000 kcal/kg). For lignite, we assume a constant price (for all scenarios considered) of €16.5/tonne (with energy content of 2305 kcal/kg), which is an average price (and energy content) of lignite in Germany (Booz & Co, 2012).

One can also see from **Table 3** that price differential between coal and gas widens in favour of coal, and especially taking into account indigenously produced low cost lignite in Europe. One implication of this wider price differential is that it would require a relatively high carbon price to support phase-out of inefficient coal-fired generation. Figure 11 shows a lower bound CO_2 price curve depending on prices of coal and gas as well as their thermal efficiencies and carbon intensities. At this lower bound – or even below –, even the most inefficient coal-fired plant is preferred to any gas-fired unit. What this means is that, to at least phase-out inefficient coal-fired units, one needs to have a carbon price which is above the curve; and depending on how much coal-fired generation capacity one wants to phase out, the carbon price needs to be very high. So, for example, under scenario C2, where we assume a carbon price of Euro 57/tCO_2, we would expect to induce most efficient gas-fired plant to run ahead of all inefficient and most carbon-intensive coal-fired units. Potentially, at a price of Euro 57/tCO_2, the most efficient gas-fired units are preferred in the merit order to 70GW of coal-fired units. Moreover, at this price, we would expect the economics of new and most efficient gas-fired plants to become economically viable, and hence replace all old cold-fired units in Europe.

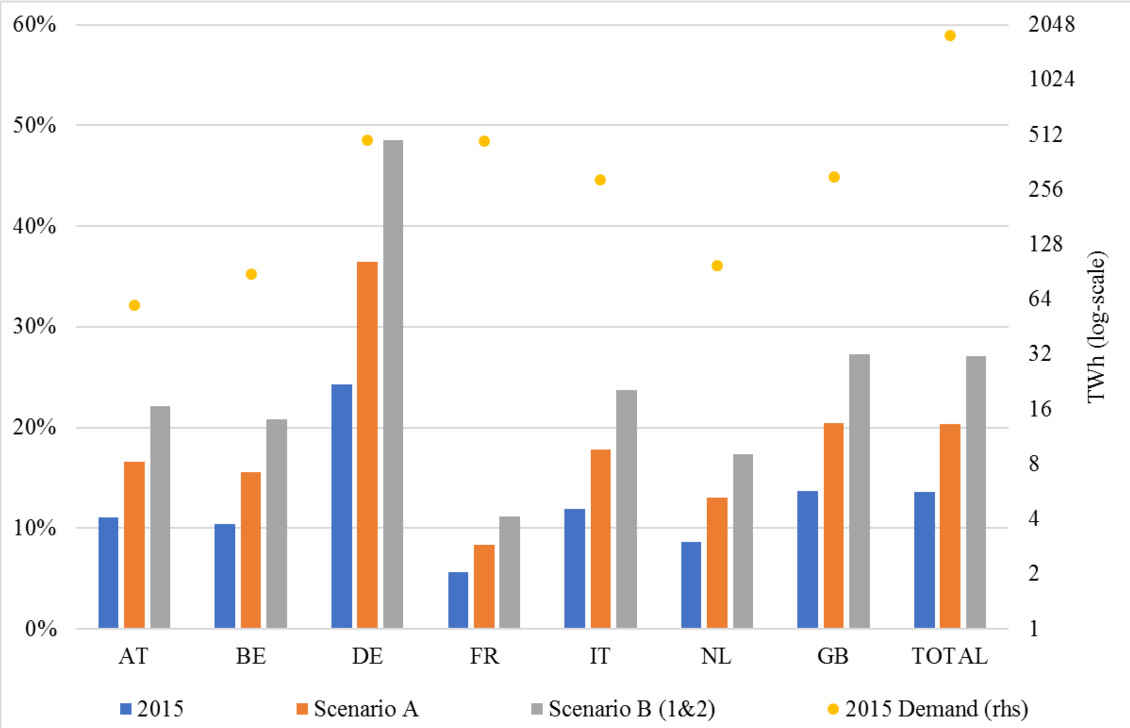
Figure 11: Lower bound of CO_2 price to support phase out the most inefficient coal-fired generation in Europe under prevailing fossil fuel price scenario C1



We should note that if wind and solar capacity increases by 50% relative to the 2015 level (Scenario A), then the expected share of total renewable generation (wind, solar, hydro and biomass) in total electricity demand of the 25 market zones considered in this model will be 31% while under Scenario B1 (an increase of 100% relative to 2015) the total renewable generation in demand will reach 38%.[24] For our modelling exercise, we assume hydro and biomass do not increase, but their share of electricity demand is 11% in 2015.

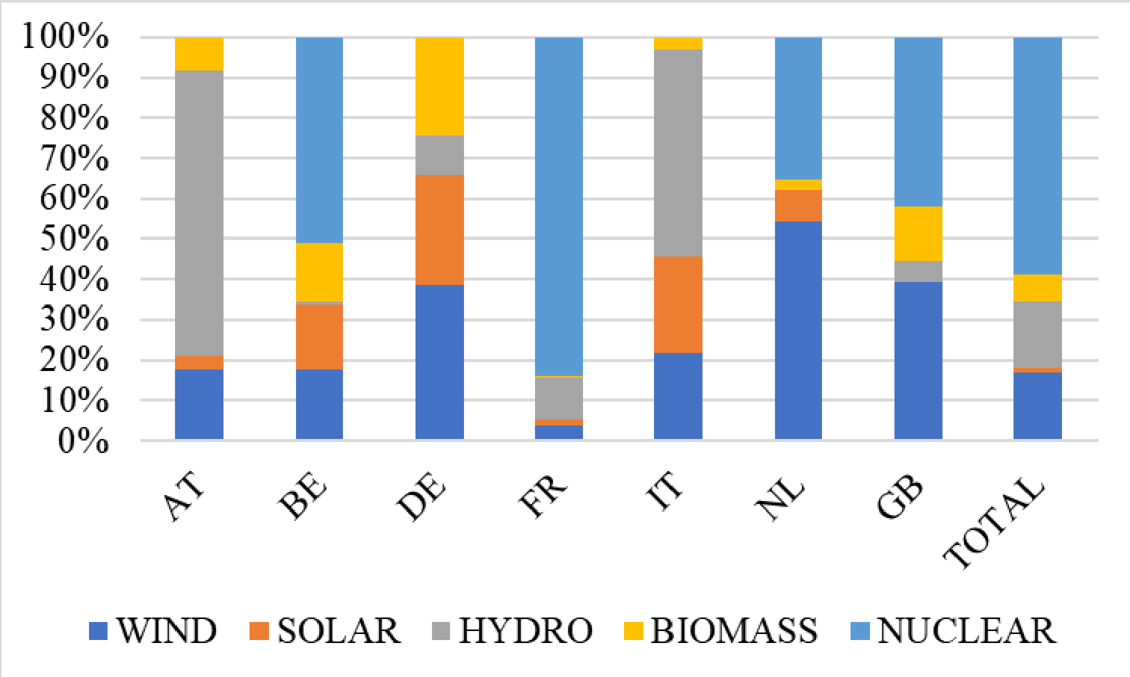
[24] A 38% share of RES in 2025 is short of the 55% that might be required by 2030, but substantial associated increases in biomass – dispatchable renewables – might also be expected.

Figure 12: Share of wind and solar generation in electricity demand for 2015 and two simulated scenarios (A and B1&2) for 2025



Thus, by comparing Scenario A and B1 with the Baseline scenario, we quantify the impact of additional VREs on annual average wholesale power prices (the merit order effect) and their volatilities. We would expect our modelling results to conform to the finding in the literature that more VRE in the power system will depress annual average power prices, and also may increase price volatility. That said, we would also anticipate that the expected increase in commodity prices, as outlined in IEA NPS scenario for Europe in 2025, may in fact negate this merit order effect as we have outlined in Section 4 *au-dessus*. Furthermore, interactions between the merit order effect and the fossil fuel price effect are very specific to the local market context, as these depend on the generation mix of each market (see **Figure 13**) as well as their interconnection level. Thus, estimating the two effects and their interactions is an empirical and modelling question.

Figure 13: Low carbon generation in selected countries in 2015 by generation technologies



Source: ENTSO-E

Furthermore, should our results suggest that investment in VRE in 2025 could still require subsidies (in the absence of further substantial cost reductions) because the expected increase in commodity prices are not high enough to offset the merit order effect of additional VRE, then the question would be: if commodity prices were to recover much faster than expected, would this mean VRE investment can be "subsidy free"? By comparing Scenario C1 with Scenario B1, we can answer this question. Moreover, if fossil fuel prices are not high enough (Scenario C1), then what is the impact of higher carbon cost on the economics of investments in VRE and conventional generation? To understand this question, we compare modelling results from Scenario C2 with those from Scenario C1 and B1.

We should note that an important issue to consider is: if such a large increase in VRE capacity (e.g. 100% increase relative to 2015 level in Scenario B1) may negatively impact the profitability of conventional generation (exacerbating their possible missing money problem, as discussed before), then they may divest these unprofitable assets. Thus, an optimal capacity expansion problem, given exogenous (large) increase in VRE, could mean substantially lower optimal conventional generation and effects on equilibrium wholesale prices. We examine this issue in our Scenario B2. Section 7.4 gives more details about our methodology for modelling divestment of conventional generation in response to an increase in VRE capacity.

Lastly, we also want to understand the role of further interconnection between our market zones in a high VRE (Scenario B1) electricity system – will a highly interconnected, pan-European electricity system bring further benefits in terms of stabilising wholesale prices (less volatility) as well as supporting the move towards “subsidy free” VRE investments? Comparing scenario D with B1 and C1 would answer this question.

7. Modelling Results

This section reports the main results from our modelling work (outlined in Section 6). We first present the results of the merit order effect in a 2025 electricity system for our covered markets (Section 7.1). We then present the results showing the potential impact of an increase in commodity (and carbon) prices in a high VRE world and whether the expected commodity price increase would allow subsidy free investments in VRE (Section 7.2). We then present the results of the role of further interconnection between market zones and how this may help integration of more VRE further (Section 7.3). In each case, what we are most concerned about is the dynamics of how increasing renewables impacts the wholesale prices. Since the model only looks at operational decisions (investment and divestment decisions are outside of the scope of the current model version), we have attempted to address the question of potential overcapacity as VRE capacity increases by 100% relative to the 2015 level (Scenario B1) in Section 7.4. Lastly, in Section 7.5 we bring all our modelling results to further analyse if and under what conditions/scenarios our projected power prices serve as a long-term investment signal for both conventional and VRE generation.

7.1. Impact of more VRE on European power markets

Our modelling results (see **Table 4** and **Appendix 1** for more detailed results) show that the magnitude of the merit order effect is different for the market considered.

Table 4: Modelling results – impact of higher VRE and merit order effect

		BE	**DE**	**FR**	**IT**	**IT-N***	**GB**
Baseline	**Price (Mean), Euro/MWh**	**50.12**	**49.68**	**51.67**	**50.68**	**51.16**	**50.07**
	coefficient variation	11%	9%	198%	9%	9%	9%
Scenario A	**Price (Mean), Euro/MWh**	**49.02**	**48.23**	**49.66**	**49.32**	**50.23**	**49.11**
	coefficient variation	12%	11%	166%	12%	10%	10%
Scenario B1	**Price (Mean), Euro/MWh**	**47.90**	**46.34**	**47.71**	**45.01**	**49.00**	**48.21**
	coefficient variation	13%	15%	174%	36%	13%	11%

** IT-N stands for Italy North region (a separate bidding zone in Italy) representing more than half of Italy's annual electricity demand.*

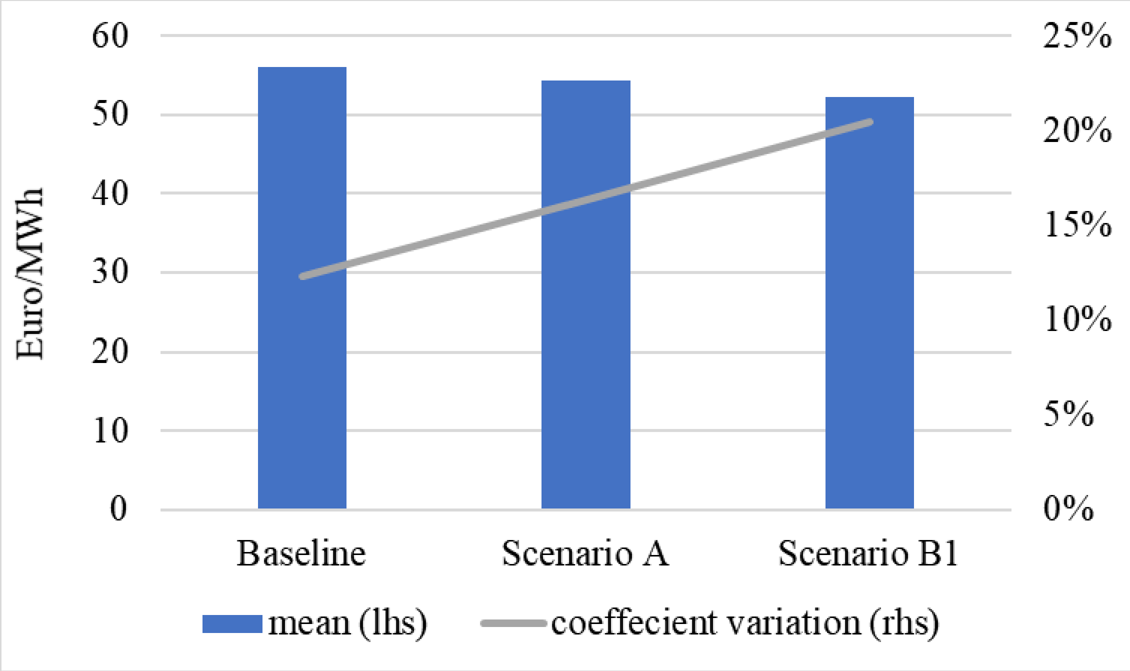
For the majority of the markets (Belgium, Germany, France and Great Britain), the effect of more VRE is rather modest – a reduction in the average annual wholesale price of between Euro 1.9-4/MWh when wind and solar capacity are doubled (Scenario B1 vs Baseline).

However, the effect is relatively more pronounced for Italy, on average. Doubling of wind and solar capacity in Italy would result in Euro 5.7/MWh reduction in average annual price (Scenario B1 vs Baseline). The primary reason for this is that we have applied a uniform increase in wind

and solar capacity (50% in Scenario A and 100% in Scenario B1 relative to Baseline, see **Figure 12**) for <u>all six main bidding zones in Italy</u> (see **Table 2**). As a result of our scenarios, in some of these bidding zones the share of RES will be very high relative to respective demand in those regions, meaning that power prices in those zones could be more volatile and could see more curtailments (more "0" price hours in 2025). Taking the weighted average of prices in those six bidding zones as an average price for the whole of Italy means that, even though those bidding zones are small, their impact on average price for the whole of Italy is 'visible'. We have also reported prices and volatilities for the Italy North (column "IT-N", see **Table 4**) bidding zone, which is the largest market zone in Italy (representing more than 50% of Italy's annual electricity consumption in 2015). One can see the merit order in that region is comparable to those obtained for other markets. Thus, for Italy, the merit order effect of VRE on annual wholesale prices is more ambiguous. For example, treating Italy as a single bidding zone may produce a comparable merit order effect to other markets (e.g. GB or BE), but that would ignore the effect of the increase in RES on balancing cost (e.g. either via increased re-dispatch cost due to internal constraints within the single IT zone, or else via increased transmission expansion cost).

As for the impact on price volatility, here, as one would expect, more VRE also means higher price volatility. Price volatility increases from 2 p.p. (Belgium and GB) to 27 p.p. (for Italy as a whole). It is worth noting that our modelling results suggest a very high volatility for the French wholesale power prices which could be an overestimation. The results show that in some hours (3 hours of the whole 2025 for Baseline and 2 hours for Scenario A and B1), there may not be enough capacity to meet the operating reserve requirement, which is assumed to be a function of N-1 but also of expected wind generation. In other words, those three hours of price spikes might induce investment in more generating capacity or more interconnections. However, if we were to exclude those three hours from the sample, then the merit order effect and the volatility of power prices in France would be similar to other markets in the analysis (see **Figure 14**).

Figure 14: Simulated power prices in France (excl. outliers)



7.2. Impact of higher commodity and carbon prices on European power markets

Our modelling results show that higher fossil fuel prices (Scenario C1) seem to have a rather modest impact on the average annual wholesale power prices (see **Table 5**). One can see that higher commodity prices do indeed increase average annual prices by around 5% (or ca. Euro 2.5/MWh) relative to the average annual prices in Scenario B1 (high wind and solar case). Italy seems to be an exception, again, as commodity prices have a higher impact on annual average prices there – the increase is ca. 8% (Euro 3.4/MWh) relative to Scenario B1. If one looks at the supply curve for Italy (see **Figure 4**), which is very steep in the relevant region (where peak demand will likely intersect with the supply curve), this suggests that the peaking plants could be inefficient gas and/or diesel generators. It is also worth noting that higher commodity prices cancel the merit order effect of higher VRE in Belgium and GB, as annual average prices in the high commodity price scenario are now back to the level of prices obtained in the baseline scenario. Moreover, the Italy North bidding zone has an average annual price exceeding the average price under the baseline scenario (Euro 52.91/MWh vs Euro 51.16/MWh) – fossil fuel price effect is more pronounced than the merit order effect of VRE in that bidding region. In Germany, France and Italy as a whole, average prices under high commodity prices are still below the average prices under the baseline, indicating a stronger merit order effect of VRE than the higher fossil fuel price effect there.

Table 5: Impact of higher commodity and carbon prices on annual average wholesale prices

		BE	DE	FR	IT	IT-N*	GB
Baseline	**Price (Mean), Euro/MWh**	**50.12**	**49.68**	**51.67**	**50.68**	**51.16**	**50.07**
	coefficient variation	11%	9%	198%	9%	9%	9%
Scenario B1	**Price (Mean), Euro/MWh**	**47.90**	**46.34**	**47.71**	**45.01**	**49.00**	**48.21**
	coefficient variation	13%	15%	174%	36%	13%	11%
Scenario C1	**Price (Mean), Euro/MWh**	**49.95**	**47.97**	**49.52**	**48.40**	**52.91**	**50.40**
	coefficient variation	15%	17%	167%	34%	16%	14%
Scenario C2	**Price (Mean), Euro/MWh**	**73.20**	**71.63**	**72.64**	**69.00**	**72.88**	**73.36**
	coefficient variation	6%	9%	114%	24%	7%	4%

** IT-N stands for Italy North region (a separate bidding zone in Italy) representing more than half of Italy's annual electricity demand*

It is interesting to compare results from higher carbon price scenario (Scenario C2 vs C1 and B1) in that the more than doubling the carbon price (Euro 25/tCO2 to Euro 57/tCO2) dramatically increases annual average wholesale power prices in all markets. On average, across all our markets, power prices increase by 52% relative to annual average price in Scenario B1, with Italy North seeing an increase of 49% and Germany of 55%. What is more interesting is that price volatility reduces remarkably. Volatilities in all markets considered under C2 are now even lower than volatilities in the baseline. A higher carbon price increases costs of fossil fuel generation for all conventional plants, with coal paying more than gas as emissions from gas are less than from coal. When VRE increases by 100% (scenario B1), this pushes residual demand to the region of the supply curve (see **Figure 4**), where most coal plants would set the wholesale power prices. Given lower coal (and carbon) prices, this results in average prices being lower for Scenario B1. Therefore, increasing the carbon price pushes up the curve and hence baseload prices are substantially higher in Scenario C2.

It is important to distinguish between wholesale power prices that a conventional generator (dispatchable plant) can get and the prices and revenues that a "subsidy-free" VRE (wind and solar) generator could get, solely based on wholesale prices. As we noted before (see Section 4, **Figure 6**), within a day, wind and solar capacity factors and price profiles will have different effects on captured prices for onshore, offshore and solar PV, due to their inherently different resource base. Solar generation seems to peak at a time when power prices could also peak; thereby creating the so-called "cannibalisation" effect (more solar PV means less revenue due to the depressing price effect at peak times when solar PV actually generates electricity). Wind resources and especially offshore wind is more reliable in this sense – within a day, capacity factors are rather stable. There may also be a strong seasonal effect as European power prices

(on average) are lower in the summer than in the winter, thus favouring wind and penalising solar relative to conventional plants.[25]

Table 6 shows our calculations based on our modelling results. It shows "captured" average annual prices for three VRE generation technologies – onshore wind, offshore wind and solar PV – taking Germany and Italy as an example (detailed calculations for other countries are in Appendix 1: Detailed Modelling Results, Table A. 2). Captured prices by a VRE technology are its total revenue over the course of the year (2025), from wholesale energy only prices divided by total generation over the same period. Thus, this captured price depends on hourly generation profiles and achieved capacity factors for onshore, offshore wind and solar PV.

Table 6: "Captured" prices by wind and solar in Germany and Italy under various scenarios (Euro/MWh)

	DE				IT		
	Onshore wind	Offshore wind	Solar PV	Average wholesale price	Onshore wind	Solar PV	Average wholesale price
Baseline	44.17	44.67	43.86	49.68	45.24	45.29	50.68
Scenario A	47.87	48.86	46.39	48.23	48.96	46.76	49.32
Scenario B1	45.48	47.39	42.59	46.34	43.19	33.43	45.01
Scenario C1	46.95	49.32	43.66	47.97	46.57	36.50	48.40
Scenario C2	70.76	72.67	67.64	71.63	67.13	57.39	69.00
Scenario D	46.91	47.19	44.35	47.40	47.31	44.72	47.44

The results suggest that offshore wind can consistently achieve prices above the average wholesale prices (but this is rather marginal). Onshore wind captured prices are quite close to the actual annual average prices whereas solar, as one would expect, achieves lower prices than the actual wholesale prices. What is striking, but perhaps not surprising (as we have seen from **Figure 6**), is that more wind and solar capacity means lower captured prices for solar PV: doubling of wind and solar capacity (Scenario B1) means a drop of ca. Euro 1.3/MWh from average captured prices by solar PV, whereas the captured power prices by wind (onshore and offshore) actually increased. Similarly, an increase in commodity prices (Scenario C1&2) helps wind generation, especially offshore, more than it helps solar PV.

7.3. The role of further interconnections in a high VRE Europe

Our modelling results underline the importance of developing further interconnection between European power markets (see **Table 7**) to enable more VRE. Scenario D assumes unlimited interconnection between the markets and hence the difference between scenarios B and D shows the impact of removing interconnection constraints on prices. Changes in peak

[25] See DG ENERGY (2018).

interconnection flows are shown in **Table 8** for Germany (see Appendix 1: Detailed Modelling Results, for detailed results of peak interconnection flows).

Table 7: Modelling results for Scenario D and B (MIN, MEAN, MAX prices are in Euro/MWh)

	Scenario B				
	mean	**min**	**Max**	**Std. dev.**	**Coef. Var.**
BE	47.90	23.56	320.56	6.11	13%
DE	46.34	-89.59	60.10	6.92	15%
FR	47.71	-130.09	5677.67	82.82	174%
IT	45.01	-92.77	72.67	16.25	36%
IT-N*	49.00	18.11	72.74	6.15	13%
B	48.21	35.00	60.10	5.19	11%
	Scenario D				
	mean	**min**	**max**	**Std. dev.**	**Coef. Var.**
BE	47.45	34.53	72.81	5.94	**13%**
DE	47.40	34.49	72.74	5.93	**13%**
FR	47.43	34.53	72.81	5.93	**13%**
IT	47.44	34.51	72.74	5.93	**13%**
IT-N*	47.47	34.56	72.88	5.94	**13%**
GB	47.46	34.53	72.74	5.93	**12%**

** IT-N stands for Italy North region (a separate bidding zone in Italy) representing more than half of Italy's annual electricity demand*

One can see that more interconnections stabilise wholesale prices: our results show complete convergence between key markets in Europe both in terms of price level (average, minimum and maximum levels) but also the price variations are reduced significantly. All in all, further interconnections may help reduce risks in financing both conventional and VRE technologies and hence could reduce financing cost further. However, it is interesting to note that increased interconnection does substantially change average prices.

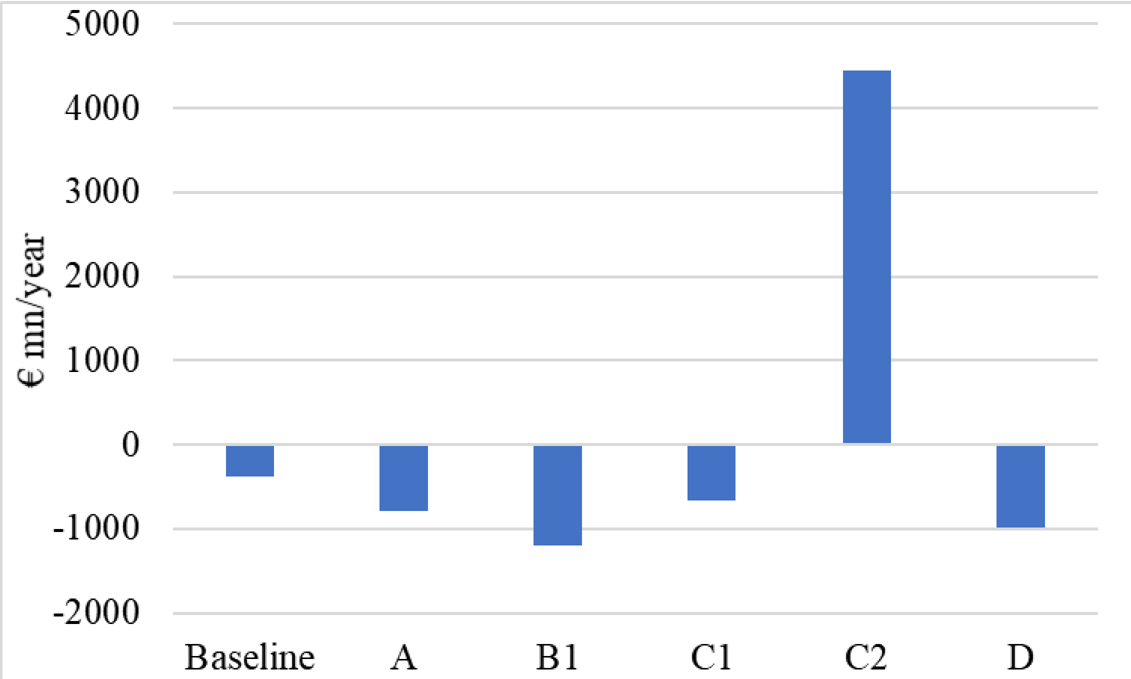
Table 8: Peak interconnection flows under Scenario B1 and D – Germany (GWh)

		SCENARIO				**SCENARIO**	
FROM	**TO**	**B1**	**D**	**FROM**	**TO**	**B1**	**D**
DE	AT	4.708	2155	AT	DE	1.950	1950
DE	BE	0.281	24	BE	DE	0.001	1
DE	DK1	1.986	1712	DK1	DE	1.600	1600
DE	DK2	0.600	600	DK2	DE	0.586	586
DE	FR	5.397	3482	FR	DE	4.569	8
DE	NL	5.134	2450	NL	DE	2.449	2449
DE	CH	5.352	5205	CH	DE	5.200	5200
DE	SE4	2.649	596	SE4	DE	0.619	595

7.4. Impact of more VRE on “missing money” of conventional plants and system’s overcapacity

As we discussed above, more VRE on the system depressess wholesale prices and affects running hours of dispatchable plants. **Figure 15** shows total profit of conventional plants in Germany under all scenarios. First, and as was confirmed by actual market data (see Table 1), even with the existing level of VRE (Baseline) and higher commodity prices (than 2015), total profit of all existing plants is negative – ca. € -373 mn/year. As we put more VRE on the system (Scenario A an B1), the size of the “missing money” problem increases – under Scenario B1 the total profit of all existing conventional plants that we model for Germany is ca. € -1197 mn/year. One can also see that higher fossil fuel prices (Scenario C1) indeed help to imrpove overall profitability, but this still remain largely negative.

Figure 15: The size of the "Missing Money" problem under various modelled scenarios – Germany



However, a higher carbon cost dramaticaly improves the profitability of conventional plants: total profit under this scenario (C2) is ca. + €4450 mn/year. Lastly, with unlimited interconnecion capacity, the economics of existing coventional plants improves, but rather marginally.

It is important to acknowledge that the merit order effect of more VRE cannot be examined in a static way. In equilibrium, if market participants anticipate an increase in VRE capacity (due to government support) then, depending on the capacity mix and interconnection between market regions, this increase will negatively impact the profitability of existing dispatchable plants. In turn, if this negative impact is substantial, then operators of these unprofitable plants could decide to close them, thus addressing the potential problem of overcapacity.

In our modelling, we look at this overcapacity problem in the following way:

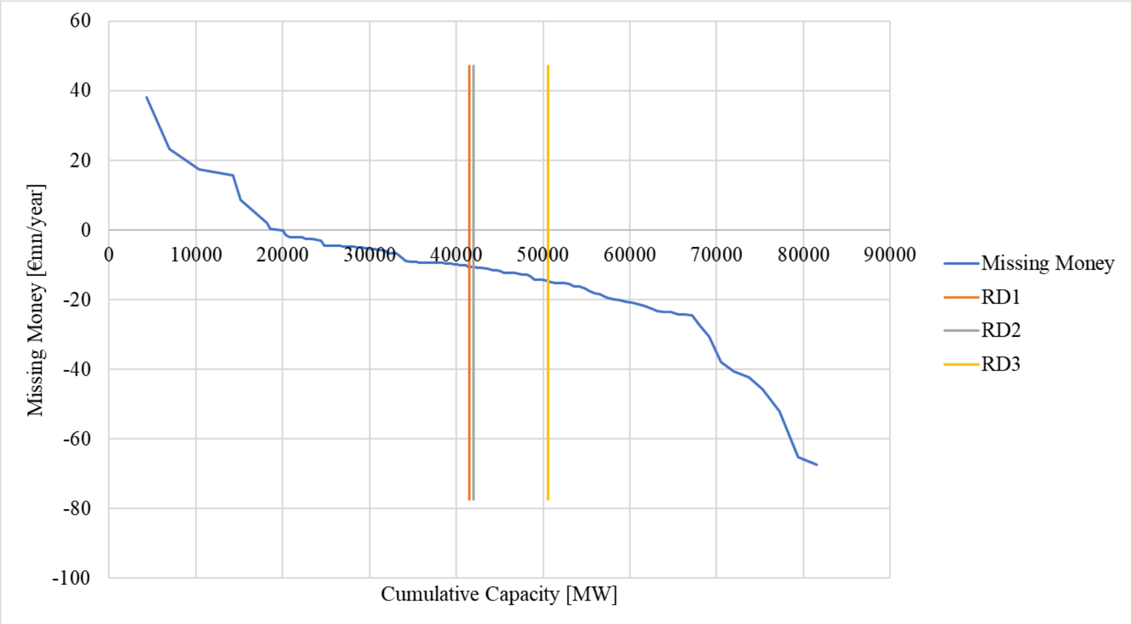
1. We first calculate operating profit[26] for each plant (that has at least been dispatched once in 2025) that we modelled.
2. Then, we rank all the plants according to their profitability with the most profitable one first to the least profitable last.
3. Based on this profitability ranking, we then calculate cumulative capacity.
4. Finally, we plot the residual demand curve for three peak demand hours, also taking into account operating reserve (spinning) requirement for those three hours.

Taking Germany and Scenario B1 as an example, the above methodology results in the following **Figure 16** which shows: (1) peak demand hour results in residual demand of 50.6 GWh (with N-1 operating reserve margin); (2) total conventional generation capacity is 81.6 GW; (3) the magnitude of the plant level missing money ranges from + Euro 38 mn/year (the most profitable plant) to – Euro 6 mn/year (the most unprofitable plant); (4) the cumulative profit of all 118 generators who were dispatched at least once in 2025 is: – Euro 1345 mn/year.

Thus, the "missing money" curve in **Figure 16** could be seen as the order of plant decommissioning. One should divest all plants that lie to the right of RD3, because they are unprofitable *and* do not contribute to system security (being understood here narrowly as meeting peak hour demand plus N-1 security margin). This will result in 31 GW of capacity (81.6 GW less 50.6 GW of peak hour demand) that should be divested (the size of overcapacity).

[26] The profit of a plant is defined here as wholesale price times generation less fuel and carbon costs as well as variable and fixed OPEX.

Figure 16: "Missing Money" of conventional plants and peak residual demand - Germany (Scenario B1)



Note: "RD1-3" = residual demand for three peak demand hours.

As one would expect, removing unprofitable and not required (from security of supply point of view) plants will impact the merit order and hence the equilibrium wholesale prices.

Figure 17 shows the supply curve with fossil fuel and carbon costs for Scenario B1 (see Table 3 for input assumptions) and the location of proposed decommissioned plants (based on the above methodology). The most unprofitable plants that we should expect to be divested are located in the lower flat part of the marginal cost curve. They are indeed in the region where peak demand occurs and hence, they also set prices. Removing these plants from the system will alter the cost curve (see **Figure 18**) – peak demand hours are now being met by higher cost plants and the peak hour prices could increase significantly compared to the system with overcapacity.

Figure 17: Supply curve of conventional plants and location of unprofitable/decommissioned plants - Germany (Scenario B1)

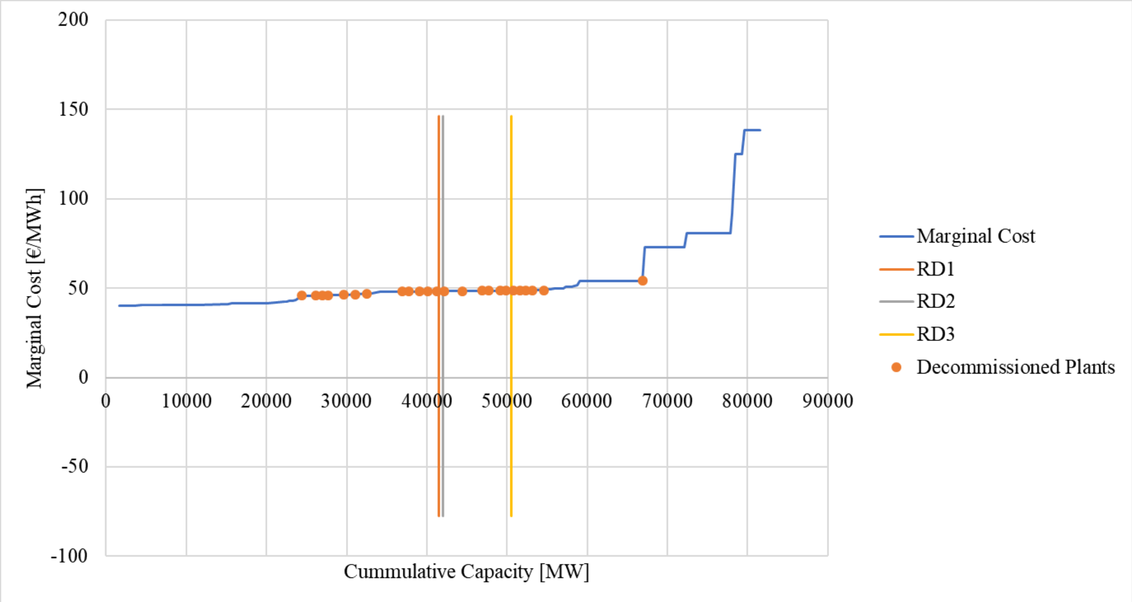
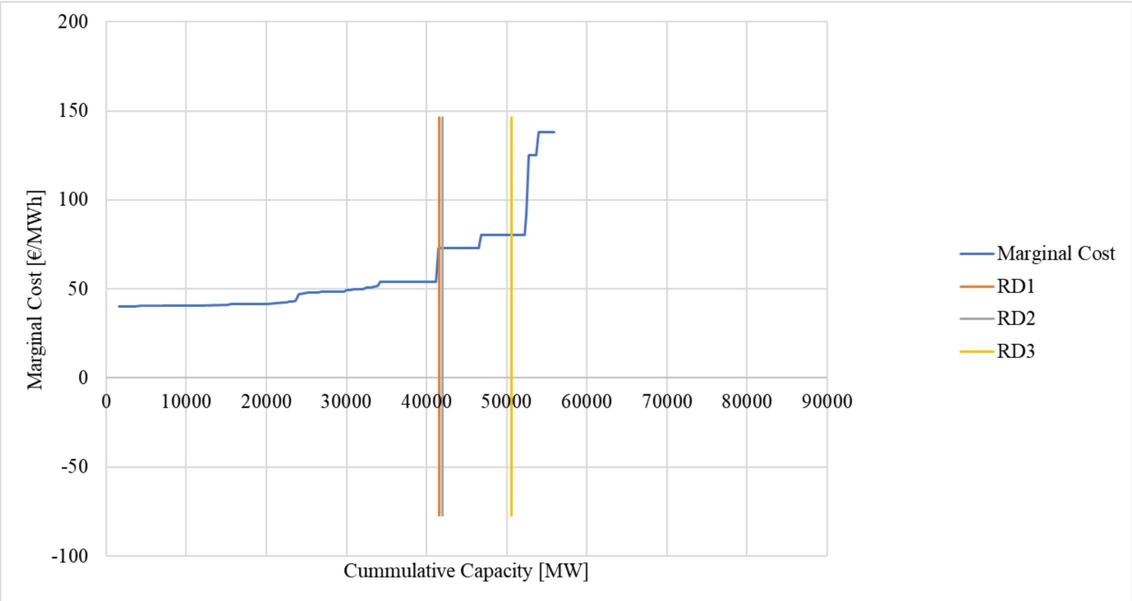


Figure 18: Supply curve of conventional plants after removing decommissioned plants - Germany (Scenario B1)



Repeating the above procedure but for all other markets for Scenario B1 results in 90.4 GW of conventional capacity being decommissioned, which is 43% of the total capacity of conventional power plants that we model.[27] Thus, with the list of those decommissioned plants, we re-ran our model for Scenario B1 (which we called Scenario B2). The results from this simulation run is reported in Table 9 (Scenario B2 highlighted in red). As we expected, removing unprofitable plants from the power system will shift respective merit orders and hence power prices – average annual prices are now amongst the highest in all scenarios considered (exception being very high fossil fuel and carbon price, Scenario C2). One can also see that with increased wholesale power prices due to much tighter capacity margins (we have divested all unprofitable plants such that the remaining capacity is just enough to cover peak demand and the required N-1 security margin), price volatilities have also increased substantially. In fact, volatilities are the highest in all our scenarios.

Table 9: Impact of decommissioning of unprofitable plants on wholesale prices

		BE	DE	FR	IT	IT-N*	GB
Baseline	**Price (Mean), Euro/MWh**	50.12	49.68	51.67	50.68	51.16	50.07
	coefficient variation	11%	9%	198%	9%	9%	9%
Scenario B1	**Price (Mean), Euro/MWh**	47.90	46.34	47.71	45.01	49.00	48.21
	coefficient variation	13%	15%	174%	36%	13%	11%
Scenario C1	**Price (Mean), Euro/MWh**	49.95	47.97	49.52	48.40	52.91	50.40
	coefficient variation	15%	17%	167%	34%	16%	14%
Scenario C2	**Price (Mean), Euro/MWh**	73.20	71.63	72.64	69.00	72.88	73.36
	coefficient variation	6%	9%	114%	24%	7%	4%
Scenario B2	**Price (Mean), Euro/MWh**	57.42	54.86	57.43	50.43	56.24	92.77
	coefficient variation	23%	26%	179%	33%	22%	281%

All in all, with our modelling exercise, we measured quantitatively: (1) the merit order effect of VRE on power prices, (2) the impact of fossil fuel prices on wholesale power prices, (3) the role and impact of a high carbon price on wholesale power prices, (4) the impact of further interconnection between main European market zones, and (5) the potential problem of overcapacity when VRE capacity is significantly increased (relative to 2015). It seems that carbon prices and overcapacity (or tighter supply/demand market condition) have the most influence on annual average power prices. By contrast, the other three factors (the merit order effect, fossil fuel prices and improved interconnections) have relatively modest impacts on average power prices. The next section outlines what this might mean for investments in conventional (dispatchable) generation and in VRE.

[27] Note that we only model coal, gas and oil-fired power generation while other technologies and their 2015 actual generation are assumed to be exogenous and constant in the model.

7.5. The economics of investing in conventional generation and VRE

In this section, we examine the impact of more VRE as well as higher commodity (and carbon) prices on the economics of a CCGT plant, and also on the economics of VRE technologies – onshore, offshore wind and solar PV. Again, we take Germany as an example (see **Table 10**) but our modelling results could be applied to other markets.

First, of all scenarios analysed, it is only under relatively high fossil fuel and carbon prices (Scenario C2) that investment in new CCGTs is feasible (profit of a CCGT after CAPEX is + €4.93 mn/year); operating existing CCGTs could also be profitable when fossil fuel rises higher relative to the baseline (Scenario C1) and when there is no overcapacity (Scenario B2). Under all other scenarios, neither investment in new CCGTs nor the operation of existing ones seems viable via participation in the energy market alone: profit taking into account fixed OPEX and/or CAPEX is negative.

Table 10: Economics of investing in a 450 MW CCGT plant in Germany: 2025 for all simulated scenarios

	SCENARIOS						
	BASELINE	**A**	**B1**	**B2**	**C1**	**C2**	**D**
MAX hourly prices, €/MWh(e)	71.66	62.01	60.10	268.57	63.07	91.39	72.74
MEAN hourly prices, €/MWh€	**44.22**	**48.23**	**46.34**	**54.86**	**47.97**	**71.63**	**47.40**
MIN hourly prices, €/MWh€	34.44	36.71	-89.59	-89.59	-89.59	-63.35	34.49
Instances of negative hourly prices	0	0	6	7	6	6	0
TTF day-ahead gas price, €/MWh(th)	20.49	20.49	20.49	20.49	20.49	20.49	20.49
EU ETS price, €/tCO2	22	22	22	22	22	51	22
Short-run marginal cost of a CCGT, €/MWh(e)	**48.54**	**48.54**	**48.54**	**48.54**	**48.54**	**58.13**	**48.54**
N hours prices > SRMC	47	4116	3653	6110	3847	8138	4037
Implied capacity factor	1%	47%	42%	70%	44%	93%	46%
Inframarginal rent, € mn/yr	0.1	8	7	34	11	54	8
Profit without CAPEX, € mn/yr	- 8.77	- 0.99	- 2.29	24.97	2.38	45.02	- 0.74
Profit with CAPEX, € mn/yr	- 48.86	- 41.08	- 42.38	- 15.12	- 37.71	4.93	- 40.83
CAPEX, €/kW	758	758	758	758	758	758	758

CAPEX annuity, € mn/yr	40	40	40	40	40	40	40
Fixed OPEX, €/kW/yr	20	20	20	20	20	20	20
Discount rate	10%	10%	10%	10%	10%	10%	10%
Thermal efficiency (HHV)	0.55	0.55	0.55	0.55	0.55	0.55	0.55
Variable opex, €/MWh(e)	3.99	3.99	3.99	3.99	3.99	3.99	3.99
Carbon intensity, kgCO2/kWh(e)	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Plant Capacity: 450MW	450	450	450	450	450	450	450
Plant economic lifetime, years	20	20	20	20	20	20	20

We can conclude that higher VRE penetration will likely reduce the incentive to invest in CCGTs. The power prices arising from all considered scenarios may no longer serve as a good long-run investment signal to bring new CCGT capacity on line, unless we have a very high fossil fuel and a high carbon price by 2025 (Scenario C2).

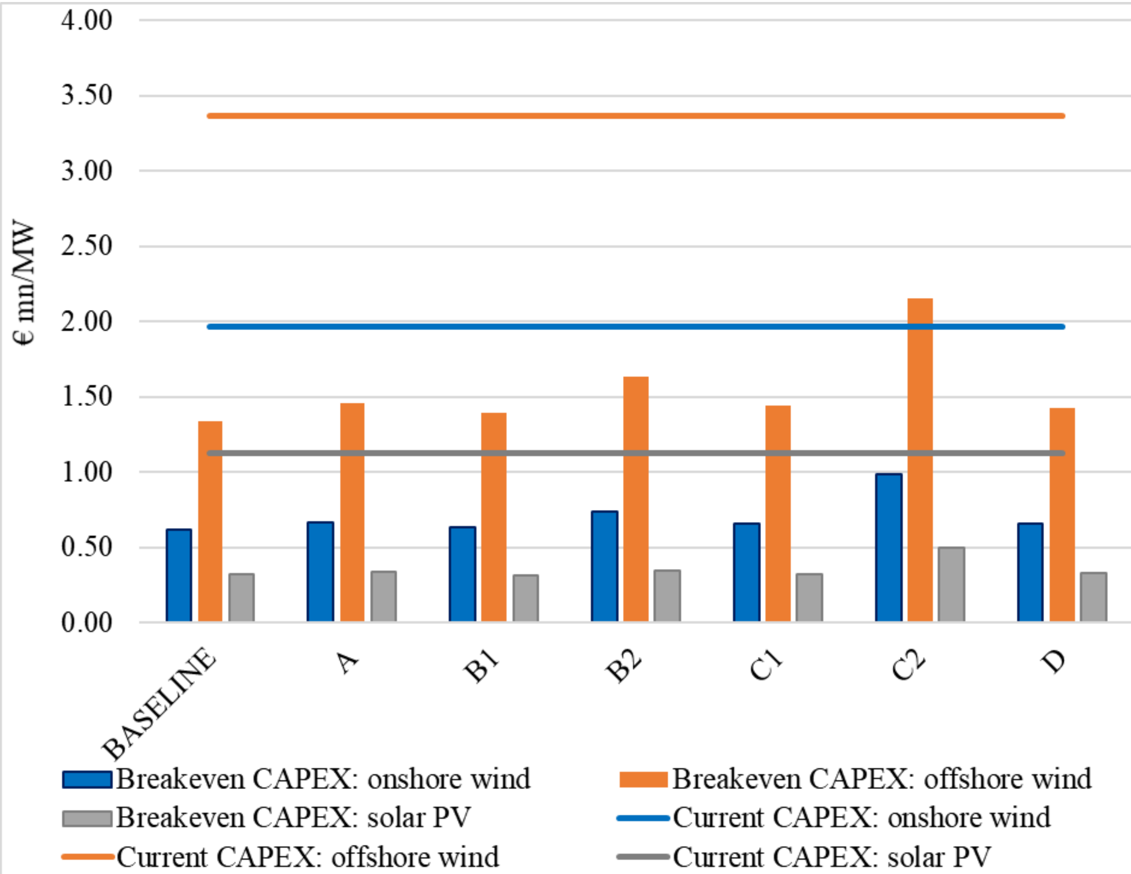
Finally, we look at the potential economics of "subsidy-free" wind and solar PV investment, taking Germany as an example. **Table A. *4*** in Appendix 1 shows profitability of wind (onshore and offshore) and solar PV, assuming these generation technologies would get revenue solely from wholesale energy-only prices. The table shows calculations assuming the current level of CAPEX for the three technologies and also shows our calculations of the breakeven CAPEX given prevailing wholesale power prices in different simulated scenarios. One can see that "subsidy-free" wind and solar PV investment would not be feasible in all our simulated scenarios at the assumed current (2016) CAPEX level (recent 'subsidy-free' auction results are for future delivery). As we would expect, those scenarios that have high average wholesale power prices would increase annual profit for VRE from energy-only prices. For example, in Scenario C2, which has the highest fossil fuel and carbon prices and hence high wholesale power prices (see Table 5), VRE achieves the highest revenue. But all in all, given the prevailing high CAPEX level in all scenarios analysed, profits are negative. Thus, **Figure 19** plots the required reduction in CAPEX for all three VRE technologies assuming a 10% return on investment (ROI) and a 20-year payback period. For onshore wind to be "subsidy-free", we would expect the CAPEX to fall by 50-70% from the existing (IEA, 2017) level by 2025, depending on the scenarios analysed and their input assumptions. For offshore, by 35-60%; for solar PV, by 56%-72%. For example, a high fossil fuel and carbon price market condition (Scenario C2) CAPEX for offshore wind would just need to go down by 35% for the technology to breakeven, using energy-only wholesale power prices alone. Recent offshore wind auction results suggest that this is possible, but challenging.

To put this required reduction in CAPEX in a historical context: according to IRENA (2018), onshore wind costs dropped by approximately 25%, or 561,000 Euros/MW between 2008 and

2017. Offshore wind costs have remained quite volatile, and peaked around 2016; while solar PV costs in Europe have dropped by 83% from 2010-2017, although this is not linear. There has been a linear drop of about 168,000 Euros/MW between 2015 and 2017.

We should point out that the presented calculations (in F**igure 19**) are rather simplistic in the sense that we have not taken into account such important aspects as technical degradation of wind turbines and fixed and variable OPEX, which we pointed out could be rather substantial, at least for wind technologies (see Section 4).[28] This means that our estimation of breakeven CAPEX reduction is a lower bound and, for example, taking into account fixed running OPEX would further deteriorate the "subsidy-free" economics of VRE investments.

Figure 19: Reduction in CAPEX needed to breakeven for "subsidy-free" VRE under all scenarios – Germany



All in all, the modelled scenarios (A-D) seem to suggest that it is far from clear that wind and solar PV could achieve "subsidy-free" investments by 2025: as a benchmark, the recent GB offshore wind CfD, which was deemed "subsidy free", cleared at £57.5/MWh or Euro 64.6/MWh. Further, both Germany and the Netherlands also received "zero-subsidy" bids to

[28] See Appendix 1, Table A. 4 for more details of the modelling assumptions.

build offshore wind projects (though in Germany, these projects did receive subsidised offshore transmission links and project development costs and they are not guaranteed to go ahead yet). Unlike in the UK, the “zero-subsidy” projects in Germany and the Netherlands are fully exposed to wholesale prices, meaning project developers might receive downside as well as upside from the wholesale market (in the UK CfD is essentially fixed price contract).[29] The average annual wholesale price in Germany in the year preceding the “zero-subsidy” bid was €34.2/MWh, while in the Netherlands it was €32.5/MWh. As noted before, the average wholesale electricity prices might not be a good indication of the actual captured prices. Thus, to make these investments subsidy free, CAPEX should fall further and quite significantly (depending on wind and solar penetration level by 2025) and/or other revenue streams should be captured (e.g. from participation in the balancing market) to close the missing money gap.

[29] See Lang (2018).

8. Conclusions

In closing, we emphasise that our modelling exercises are not intended to offer predictions of what the future electricity system will look like in 2025. They are merely intended to be a tool for helping us get a sense of the significance of the impact of certain changes in the electricity market (such as increased VRE, changes in fossil fuel prices and changes in the price of carbon). We acknowledge that any modelled scenarios cannot completely capture all of the issues which might be relevant for a major change in market design.

Our modelling results suggest that if wind and solar generation technologies are to rely on expected wholesale power market prices in the medium term (by 2025) to self-finance their investments, there needs to be a substantial decrease in the CAPEX of these technologies (on 2016) to enable genuine “subsidy-free” investments in VRE. There are encouraging signs from recent offshore wind auctions that this might happen by the early 2020s. Solely relying on commodity prices to support such investments might be feasible but remains very challenging, based on our modelling results, even if we take a rather bullish view that by 2025 commodity markets are going to be very tight (tripling of crude oil prices and doubling of natural gas prices by 2025, relative to 2016).

Our modelling results also show that wholesale power prices may no longer serve as a long-run investment signal for conventional generating capacity (CCGT, for example) in conditions where conventional generation will not be required to produce base-load electricity but will be required for system adequacy. Even at a very high level of commodity prices, our results show no clear prospects for new capacity addition. However, there could be an improvement in profitability of existing CCGTs under a high commodity price/high carbon price scenario. With further penetration of VRE, our results show the negative impact on profitability of CCGTs, exacerbating their missing money problem further.

Our modelling results also show the importance of further interconnection between markets in Europe – which may be very expensive/difficult to achieve – as this allows near complete convergence of power prices (both baseload and peak prices) and more importantly stabilises these prices (reducing volatility) and hence reduces potentially higher market risks due to more VRE. However, increased interconnection does not change the picture we paint on the ‘financeability’ of subsidy-free RES and fossil fuel investments via energy-only markets by 2025.

If there was to be sufficient closures of fossil fuel power plants, in response to low profitability, that would make a difference to market prices but would put more pressure on ancillary services markets to support adequate amounts of generation for system stability (including fossil fuel plants, assuming these were still very cost-effective providers of such stability). Many of the currently existing fossil fuel plants would still be required to provide adequacy and other services to the system in the presence of much higher penetration of intermittent renewables.

By contrast, a significant rise in carbon prices would significantly improve the ability of a low carbon electricity system to be self-financing. Raising carbon prices thus remains a good policy for promoting unsubsidised low carbon generation within the current market design.

We set out to address three interrelated questions with respect to the European wholesale electricity market design. These were:

A. *How well is the current market design working, as we continue with the roll out of renewables generation?*

B. *Following A, what limited adaptions to the current market design might be possible in the timeframe to 2025?*

C. *In the context of A and B, will there be a tipping point in the current energy market, when the penetration of RES might be so high as to cause the need for a more radical market redesign to address the investment signal issue?*

On A, we would suggest that the available evidence and our own modelling shows that, if wind and solar are to be self-financing by 2025 under the current European electricity market design, they would need to be operating in circumstances which combine much lower capital cost and/or much higher fossil fuel/carbon prices. In the absence of these favourable conditions for VRE, long term subsidy mechanisms in the form of auctions would need to continue in order to meet European renewable electricity targets. However, we do find that wind, particularly offshore, is likely to suffer less from the cannibalisation of its market than solar. This is because wind output is better able to capture the average annual wholesale price of electricity. A move away from feed-in-tariffs for wind and solar to market prices will also expose generators to increased price volatility, which would raise their investors' target rates of return. The question of the need for a fundamental market redesign to let the market guide generation investments in both renewables and conventional generation investment would seem to remain.

On B, interventions to create capacity markets or sharpen ancillary services markets payments can help address the problems of the current market design by creating the incentives for the optimal addition and retention of power plants to the system. However, these mechanisms are problematic to design, and investments supported by them will likely have higher costs of capital, given the volatile and difficult to predict income streams that they give rise to. This is because ancillary services markets are subject to fundamentally different governance arrangements relative to energy markets, making them expensive to rely on as a source of long-run funding for generation investment.

On C, we do not foresee a sharp tipping point in the current energy market. Instead, we see a trend continuation in current generation 'financeability' problems, with only some partial mitigation should commodity prices rise as expected by the IEA, or should there be substantial improvements in interconnector capacity across Europe. A sharp further drop in renewable electricity capital (and O&M) costs, closure of unprofitable fossil fuel power plants and/or rise in carbon prices would certainly help to drive the arrival of subsidy-free renewables within the existing electricity market design.

Will a radical market redesign be necessary? Given the willingness of Member States to live with largely subsidised new electricity generation from the period beginning around 2005 to 2018, this seems unlikely. However, the market design will need to evolve, with some significant changes in the market for ancillary services. Will these changes be radical? This is something of a matter of perspective. In Ireland or the UK, continued evolution of the market for ancillary services might not seem that radical by 2025. In other markets such as Germany, which has resisted splitting into more than one price zone within the existing wholesale market coupling arrangements, and has chosen to socialise the entire grid costs associated with the addition of distributed VRE, the introduction of more market based signals for ancillary services looks more radical.

Will market designs converge across Europe? This is an open question. We have seen a significant degree of convergence in electricity markets as a result of the single electricity market process since 1996. This was partly based on the implementation of a Target Electricity Model from around 2004. The issue is whether different local circumstances will cause continuing or indeed increasing divergence in market arrangements. This might be true for ancillary services in the presence of continuing limitations in the state of interconnection, national variations in carbon pricing and given that certain ancillary services do not travel well (e.g. reactive power) and remain local services, within sub-markets. One could imagine Ireland, Iberia, the UK, Greece and Germany having significantly different market configurations by 2025, given the differences in their requirements and ability to absorb increased amounts of VRE.

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Appendix 1: Detailed Modelling Results

Table A. 1: Average, min and max prices (in Euro/MWh) for the whole year (2025) as well as price volatility (standard deviation & coefficient variation)

		BE	DE	FR	IT	IT-N	GB
Baseline	**mean (lhs)**	50.1	49.7	51.7	50.7	51.2	50.1
	min (lhs)	38.7	38.7	38.7	38.1	38.8	38.7
	max	336.6	80.5	5682.6	80.4	80.5	80.4
	standard dev.	5.5	4.5	102.1	4.6	4.6	4.44
	coefficient variation	11%	9%	198%	9%	9%	9%
Scenario A	**mean**	49.0	48.2	49.7	49.3	50.2	49.1
	min	36.7	36.7	-57.4	-51.2	37.7	36.8
	max	336.6	62.0	5680.4	72.8	72.7	61.9
	standard dev.	5.8	5.1	82.6	5.9	5.2	4.8
	coefficient variation	**12%**	**11%**	**166%**	**12%**	**10%**	**10%**
Scenario B1	**mean**	47.90	46.34	47.71	45.01	49.00	48.21
	min	23.56	-89.59	-130.09	-92.77	18.11	35.00
	max	320.56	60.10	5677.67	72.67	72.74	60.10
	standard dev.	6.11	6.92	82.82	16.25	6.15	5.19
	coefficient variation	***13%***	***15%***	***174%***	***36%***	***13%***	***11%***
Scenario B2	**mean (lhs)**	57.42	54.86	57.43	50.43	56.24	92.77
	min (lhs)	19.19	-89.59	-49.58	-91.17	18.98	19.17
	max	316.43	268.57	5704.11	124.96	125.19	5447.03
	standard dev.	13.29	14.21	103.09	16.82	12.48	260.48
	coefficient variation	***23%***	***26%***	***179%***	***33%***	***22%***	***281%***
Scenario C1	**mean**	50.0	48.0	49.5	48.4	52.9	50.4
	min	13.3	-89.6	-130.1	-92.2	12.7	27.3
	max	345.6	63.1	5686.7	89.8	93.8	63.1
	standard dev.	7.6	7.9	82.8	16.4	8.5	6.8
	coefficient variation	***15%***	***17%***	***167%***	***34%***	***16%***	***14%***
Scenario C2	**mean**	73.2	71.6	72.6	69.0	72.9	73.4
	min	53.7	-63.4	-130.1	-84.7	53.8	53.7
	max	365.0	91.4	5710.6	107.8	101.2	91.5
	standard dev.	4.7	6.5	82.7	16.4	5.3	3.1
	coefficient variation	***6%***	***9%***	***114%***	***24%***	***7%***	***4%***
Scenario D	**mean**	47.45	47.40	47.43	47.44	47.47	47.46
	min	34.53	34.49	34.53	34.51	34.56	34.53
	max	72.81	72.74	72.81	72.74	72.88	72.74
	standard dev.	5.94	5.93	5.93	5.93	5.94	5.93
	coefficient variation	***13%***	***13%***	***13%***	***13%***	***13%***	***12%***

Table A. 2: Implied wholesale prices that wind and solar may receive in the "energy only" market in 2025 under various scenarios (in Euro/MWh)

		ONSHORE WIND				OFFSHORE WIND		SOLAR PV					Total Wind
		BE	DE	FR	IT	BE	DE	BE	DE	GB	FR	IT	GB
BASELINE	**annual average**	44.62	44.17	45.86	45.24	44.67	44.23	38.76	43.86	44.83	46.05	45.29	44.69
	Q1	45.08	44.74	45.03	45.57	45.28	44.93	43.54	45.55	47.27	46.13	46.42	45.45
	Q2	43.19	42.88	45.11	43.82	43.26	43.01	36.45	43.05	44.03	48.25	43.84	43.30
	Q3	43.46	43.12	46.39	45.25	43.59	43.23	39.29	43.46	44.37	43.52	45.54	43.48
	Q4	45.66	45.00	47.08	46.19	45.69	45.10	39.84	46.06	46.77	46.50	46.53	45.57
SCENARIO A	**annual average**	48.73	47.87	49.48	48.96	48.86	48.09	41.92	46.39	48.90	46.93	46.76	49.01
	Q1	48.73	48.26	48.59	49.24	49.02	48.54	46.04	47.86	50.63	48.50	47.79	49.38
	Q2	47.73	46.74	47.24	47.42	47.89	47.07	39.74	45.42	48.37	45.87	45.07	48.12
	Q3	48.00	47.25	50.85	49.21	48.19	47.49	42.71	46.33	48.53	46.14	47.67	48.25
	Q4	49.71	48.54	51.30	49.91	49.74	48.78	42.50	48.30	50.22	49.37	47.24	49.68
SCENARIO B1	**annual average**	47.17	45.48	47.39	43.19	47.39	45.98	40.44	42.59	47.65	42.93	33.43	47.77
	Q1	47.00	46.08	46.58	44.32	47.41	46.55	44.11	44.48	49.06	45.36	36.32	47.99
	Q2	46.17	44.33	44.81	35.86	46.49	44.82	38.37	41.39	47.15	41.59	21.98	47.06
	Q3	46.88	45.22	48.34	45.50	47.12	45.62	41.42	42.58	47.49	41.41	40.57	47.55
	Q4	48.06	45.76	49.67	47.12	48.09	46.52	40.56	44.61	48.58	46.62	39.43	48.18
SCENARIO B2	**annual average**	55.91	53.10	57.14	48.93	56.43	54.04	46.72	47.20	71.30	51.70	38.37	78.62
	Q1	55.99	55.90	58.76	51.48	57.64	57.90	55.50	55.98	71.03	60.03	43.39	87.31
	Q2	49.71	46.60	49.84	39.15	49.95	47.13	42.39	42.88	68.34	49.11	26.27	64.05
	Q3	52.01	48.80	53.24	49.05	52.21	49.40	46.55	45.38	75.11	45.51	43.87	70.24
	Q4	61.63	56.83	63.25	55.01	61.95	58.40	52.76	58.33	71.02	61.90	46.77	84.58
SCENARIO C1	**annual average**	49.06	46.95	49.14	46.57	49.32	47.53	43.67	43.66	49.28	44.34	36.50	49.82
	Q1	48.94	47.63	48.29	48.14	49.51	48.22	46.05	45.82	52.06	46.87	39.68	50.41
	Q2	47.61	45.45	46.13	38.18	47.95	46.00	39.30	42.29	48.46	42.75	25.05	48.62
	Q3	48.38	46.53	49.89	48.79	48.68	46.97	42.49	43.71	48.94	42.84	43.56	49.17
	Q4	50.39	47.45	51.90	51.04	50.39	48.33	41.96	45.81	50.42	48.45	42.36	50.42
SCENARIO C2	**annual average**	72.40	70.76	72.35	67.13	72.67	71.28	63.18	67.64	73.14	67.73	57.39	72.91
	Q1	72.12	71.51	71.83	68.04	72.54	71.99	67.86	70.63	73.68	71.30	60.03	72.96
	Q2	71.63	69.24	69.40	59.56	71.99	69.78	60.09	65.50	72.67	65.37	44.74	72.43
	Q3	72.58	70.43	72.99	69.60	72.68	70.82	65.05	67.76	73.29	66.00	65.39	73.08
	Q4	73.02	71.18	74.73	71.49	73.18	71.99	63.08	71.38	73.96	72.97	64.44	73.09

SCENARIO D	**annual average**	46.94	46.91	47.23	47.31	47.19	47.19	38.67	44.35	45.12	44.66	44.72	47.19
	Q1	46.96	47.30	47.60	47.89	47.42	47.62	42.94	46.18	46.73	46.69	46.82	47.53
	Q2	45.57	45.69	46.09	46.04	45.97	46.09	36.11	43.17	43.89	43.06	42.92	45.74
	Q3	46.76	46.57	46.99	46.95	46.96	46.90	39.78	44.36	45.33	44.42	44.37	46.85
	Q4	47.82	47.48	47.81	48.02	47.88	47.75	39.49	46.29	47.52	46.59	46.85	48.02

Table A. 3: Peak electricity flows (GWh) between markers: Scenario D (unlimited interconnection capacity) and Scenario B1 (existing interconnection capacity level)

FROM	TO	SCENARIO B1	SCENARIO D	FROM	TO	SCENARIO B1	SCENARIO D
AT	DE	1.950	1950	NL	DE	2.449	2449
AT	IT-N	0.340	206	NL	NO2	3.655	10
AT	CH	2.153	2153	NL	GB	1.103	1103
BE	DE	0.001	1	CH	AT	1.200	3
BE	FR	3.209	3209	CH	DE	5.200	5200
BE	NL	3.043	3043	CH	FR	2.927	2927
BE	GB	1.000	1000	CH	IT-N	5.147	3818
DK1	DK2	0.602	3	SE1	SE2	3.680	2388
DK1	DE	1.600	1600	SE1	NO4	1.602	677
DK1	SE3	1.300	692	SE2	SE1	2.068	2068
DK1	NO2	2.833	107	SE2	SE3	8.395	2249
DK2	DK1	0.600	14	SE2	NO3	1.395	553
DK2	DE	0.586	586	SE2	NO4	0.724	323
DK2	SE4	1.629	1482	SE3	DK1	0.692	692
DE	AT	4.708	2155	SE3	SE2	2.251	2251
DE	BE	0.281	24	SE3	SE4	5.425	906
DE	DK1	1.986	1712	SE3	NO1	3.650	2302
DE	DK2	0.600	600	SE4	DK2	1.483	1483
DE	FR	5.397	3482	SE4	DE	0.619	595
DE	NL	5.134	2450	SE4	SE3	1.279	906
DE	CH	5.352	5205	NO1	SE3	2.304	2304
DE	SE4	2.649	596	NO1	NO2	2.176	2176
FR	BE	3.795	3210	NO1	NO3	0.726	606
FR	DE	4.569	8	NO1	NO5	0.587	587
FR	IT-N	3.459	3459	NO2	DK1	1.533	550
FR	CH	3.769	3482	NO2	NL	0.707	707
FR	GB	4.000	961	NO2	NO1	5.786	2178
IT-CN	IT-CS	1.770	1770	NO2	NO5	2.182	563
IT-CN	IT-N	2.946	2946	NO2	GB	1.400	10
IT-CN	IT-SA	0.241	241	NO3	SE2	0.774	1
IT-CS	IT-CN	3.088	1771	NO3	NO1	0.607	607
IT-CS	IT-SA	0.413	413	NO3	NO4	0.223	223
IT-CS	IT-S	0.681	681	NO3	NO5	0.552	552
IT-N	AT	0.210	210	NO4	SE1	0.908	678
IT-N	FR	1.383	1383	NO4	SE2	0.388	388
IT-N	IT-CN	3.438	2948	NO4	NO3	2.154	223
IT-N	CH	3.820	3820	NO5	NO1	4.785	588
IT-SA	IT-CN	0.302	302	NO5	NO2	0.954	586
IT-SA	IT-CS	0.929	412	NO5	NO3	1.088	562

IT-SI	IT-S	1.036	1036	GB	BE	1.000	1000
IT-S	IT-CS	4.249	682	GB	FR	4.865	998
IT-S	IT-SI	1.036	1036	GB	SEM	1.000	1000
SEM	GB	1.000	999	GB	NL	1.092	1092
NL	BE	3.593	3041	GB	NO2	6.689	710

Table A. 4: Economics of investing in wind and solar PV in Germany: 2025 for all simulated scenarios

	SCENARIOS						
	BASELINE	**A**	**B1**	**B2**	**C1**	**C2**	**D**
ONSHORE WIND – GERMANY							
Revenue, € mn/yr	2923	4752	6020	7029	6215	9367	6210
Profit with current CAPEX, € mn/yr	-6385	-9209	-12595	-11586	-12401	-9248	-12406
Profit with breakeven CAPEX, € mn/yr	0	0	0	0	0	0	0
CAPEX (current), €/MW	1966292	1966292	1966292	1966292	1966292	1966292	1966292
Breakeven CAPEX, €/MW	**617532**	**669269**	**635893**	**742459**	**656428**	**989406**	**655894**
CAPEX (current) annuity, € mn/yr	9308	13962	18615	18615	18615	18615	18615
CAPEX (breakeven) annuity, € mn/yr	2923	4752	6020	7029	6215	9367	6210
Discount rate	10%	10%	10%	10%	10%	10%	10%
Total installed capacity, MW	40300	60450	80600	80600	80600	80600	80600
Plant lifetime, years	20	20	20	20	20	20	20
OFFSHORE WIND – GERMANY							
Revenue, € mn/yr	654	1067	1360	1599	1406	2109	1396
Profit with current CAPEX, € mn/yr	-992	-1403	-1933	-1695	-1887	-1185	-1898
Profit with breakeven CAPEX, € mn/yr	0	0	0	0	0	0	0
CAPEX (current), €/MW	3370787	3370787	3370787	3370787	3370787	3370787	3370787
Breakeven CAPEX, €/MW	**1339192**	**1456000**	**1392267**	**1636166**	**1438945**	**2158161**	**1428669**
CAPEX (current) annuity, € mn/yr	1647	2470	3293	3293	3293	3293	3293
CAPEX (breakeven) annuity, € mn/yr	654	1067	1360	1599	1406	2109	1396
Discount rate	10%	10%	10%	10%	10%	10%	10%
Total installed capacity, MW	4159	6239	8318	8318	8318	8318	8318
Plant lifetime, years	20	20	20	20	20	20	20
SOLAR PV – GERMANY							
Revenue, € mn/yr	1535	2436	2982	3305	3057	4737	3105
Profit with current CAPEX, € mn/yr	-3806	-5576	-7700	-7377	-7625	-5946	-7577

Profit with breakeven CAPEX, € mn/yr	0	0	0	0	0	0	0
CAPEX (current), €/MW	1123596	1123596	1123596	1123596	1123596	1123596	1123596
Breakeven CAPEX, €/MW	**323005**	**341652**	**313649**	**347661**	**321564**	**498205**	**326616**
CAPEX (current) annuity, € mn/yr	5341	8012	10682	10682	10682	10682	10682
CAPEX (breakeven) annuity, € mn/yr	1535	2436	2982	3305	3057	4737	3105
Discount rate	10%	10%	10%	10%	10%	10%	10%
Total installed capacity, MW	40470	60705	80940	80940	80940	80940	80940
Plant lifetime, years	20	20	20	20	20	20	20

Source: Current CAPEX for onshore, offshore and Solar PV were taken from IEA (2017).

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