



The challenges of intermittency in North West European power markets

THE IMPACTS WHEN WIND AND SOLAR DEPLOYMENT REACH THEIR TARGET LEVELS

Introduction

European energy policy continues to head firmly in the direction of dramatically lowering carbon emissions, despite the difficult economic climate in many countries. To this end various Directives are now being implemented throughout the EU to drive this transition in the different industry sectors.

Not surprisingly the power sector is at the centre of the change: it accounts for a major proportion of carbon emissions; several viable low-carbon options are available to replace fossil fuel fired power stations; and electrification of the heat and transport sectors could offer the longer term route to their eventual decarbonisation.

One of the main components of the EU's drive towards decarbonisation is the

Renewables Directive – in response to which many countries have recently published their individual National Renewable Energy Action Plans (NREAPs). Together, they show how much needs to be done to reach the 2020 targets outlined in the Directive.

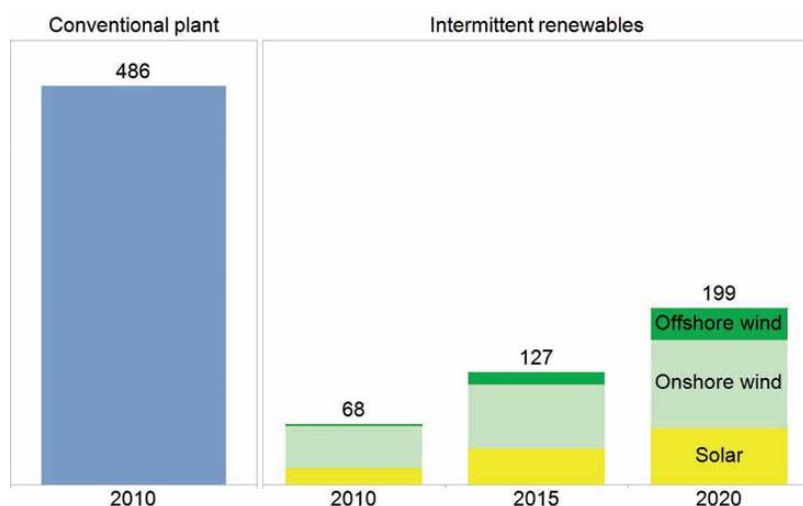
However, the drive to decarbonisation is not expected to stop at the 2020 levels. Many in the industry have suggested a continued trajectory towards complete decarbonisation by the middle of the century.

Conventional and renewable assets built now will earn their revenues in this environment, and investment decisions made today need to take account of the market impacts of an entirely new fleet of generation capacity.

Imagination and market analyses will also be tested by the inevitable consequences on both the grid networks and consumer demand – both legacies of a world dominated by firm thermal power generation.

In 2009, we carried out a groundbreaking analysis of the scale and nature of the transformation in the 'island' power markets of Ireland and the UK¹. This work suggested that installing wind generation to meet policy targets could utterly transform their economic character. That analysis – to an unprecedented level of detail, and supported by many key participants – quantified the financial risks and rewards facing investors in new and existing thermal generation as well as understanding of the complex requirements that demand-side flexibility will need to deliver to have a full role in these markets. Amongst the findings were that:

- wholesale prices are likely to become increasingly volatile;
- risk to investors in thermal plant could increase dramatically;
- operational regimes of power stations like gas-fired CCGTs will become erratic as well as their load factors reducing; and,
- the investment signals provided by the BETTA market design in Great Britain would become increasingly stretched.



Current and future installed capacity if NREAP targets in Northern Europe are met (GW)

¹ Impact of intermittency: how wind variability could change the shape of GB and Irish electricity markets, July 2009, Pöry.



Northern Europe

While the analysis of the UK and Irish markets suggested a remarkable change, it was not obvious that implementation of the NREAPs would produce the same outcomes on the Continent as in the UK and Ireland.

At first glance there are four good reasons why the impact may be much less on the continental power system:

- greater geographic spread, so the weather is more likely to average out;
- much more interconnection between countries, enabling power to be moved from place to place in response to local effects;
- potentially different patterns to the maritime weather experienced by the UK and Ireland (e.g. less wind); and finally
- clear potential of the Scandinavian and Alpine hydro systems to smooth out the renewables output.

Our projections of power markets involve consideration of future commodity prices, generation technology development, plant closures and new construction, interconnection, as well as interplay with the heat and transport sectors. While including all of these, the analysis for this report had to also have very detailed profiles for the deployment and operation of renewable generation and international grid developments.

We also wanted to understand the likely interaction with the gas markets (which would respond to the different running pattern for gas-fired power stations) and the

potential for electricity demand to become smarter (for example by responding to any spikes in electricity prices).

The diagram to the right shows the countries on which we chose to focus our analysis, selected to include the wind generation built in and around the North Sea with the interactions of large amounts of solar in Germany and the potential for balancing from the hydro systems in the Nordics and the Alps.

To carry out such analysis we extended the well-established Pöyry European gas and power market models to properly evaluate the ‘intermittency’ impacts, and comprehensively integrate the in-house Nordic hydro market model, which has a long history in its own right. Only by taking these steps and evaluating the markets at an hourly level of granularity were we able to achieve the rigour and precision required to draw firm conclusions.

The models we use to understand the interactions over these large electricity systems are leaders in their class, forecasting how all the power stations across Europe will run in the future taking into account the variability of wind, sunlight, cloud cover, precipitation and snowmelt, temperature and demand.

They also include important operational factors: the cost of start ups, no-load costs, the option value of water and the commercial interchanges of power across Europe. A typical scenario produces 5 million hourly prices and creates datasets of 20Gb.



Countries examined in the study

While aware that other commentators have claimed that European decarbonisation could be conceptually possible – if many more interconnectors are built and demand can be managed in a totally different way – we were much more interested in likely market outcomes.

As one of the leading advisers in Europe’s energy markets we aimed to continue our approach of delivering robust and detailed market analysis that is essential for investors, energy companies and policymakers.

We are grateful for the support of several companies in this work, in particular DONG Energy, EnBW, Statkraft and RWE. This work is entirely independent and the views expressed are not influenced by any views of the participating companies.

Focus of the study

Several questions needed to be answered to make the commercially orientated assessment we deemed necessary. In particular:

- What is the likely deployment of renewables, particularly wind and solar generation?
- What will the output of these renewables actually be? This question has some subsidiary points too: how 'variable' is the weather, and over what time horizons?
- How will the Nordic and Alpine hydro systems interact physically and commercially, with the markets and to what extent will their operation be affected by network constraints?
- What will the market prices be – what level and how volatile?
- How will operating regimes of thermal plant change?
- What are the commercial prospects for existing and new generating plant – how robust is their investment case?
- How robust are the findings, for example to different market structures, grid developments, renewables deployment and the development of flexible demand?

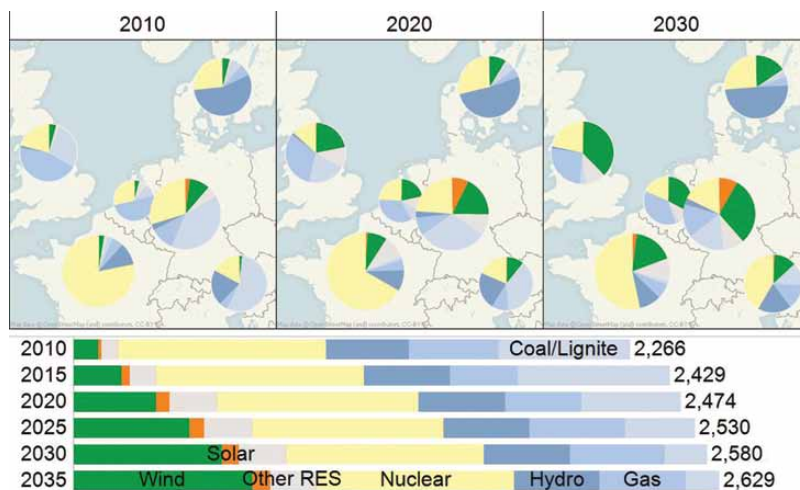
And finally

- What considerations should policymakers be factoring into their implementation plans?

Our starting point was to determine a deployment path for the generation, by type and location. The map below illustrates this progression over time.

In order to carry out the full analysis, the Pöyry team invested over 1,000 days and took almost a year to develop the necessary computational processes to realistically model such a complex and dynamic market.

This summary document can only give a flavour of the richness of the data and information that we can now draw on.



Generation split by the six major zones of the study and in aggregate for North Europe (TWh)

Findings

Our approach to investigating the impact of weather in the future with large amounts of weather dependent renewables (especially wind and solar) is to base our pricing and dispatch models on a sequence of recent historical years' weather data. Although there is no guarantee that the same weather patterns will reoccur, by taking seven years' data (and over 100 million demand, wind and solar records) we are able to evaluate the interaction of differing weather systems and capture accurately the correlation of wind, solar and demand patterns as they were.

Wind and solar output will be highly variable and will not 'average out'

A series of market scenarios developed in the course of the work gave realistic and quantitative views that are now available for industry players, financial institutions and policymakers.

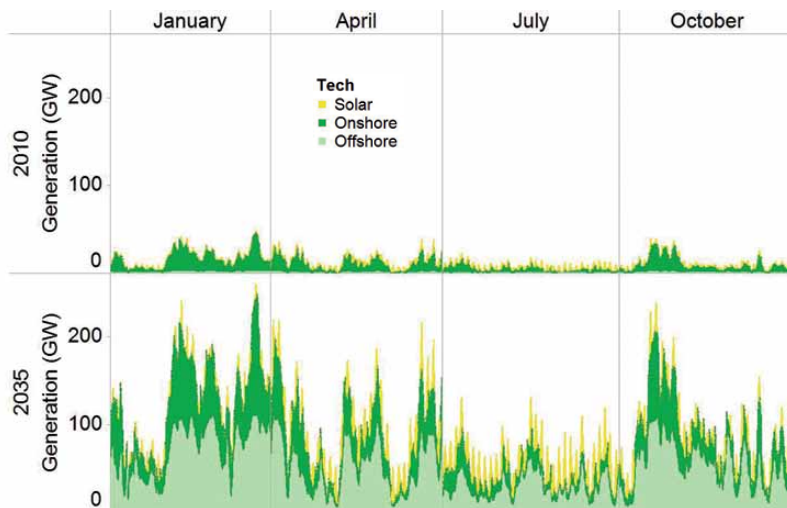
Our most significant findings are presented in the remainder of this section.

The chart below gives some indication of the dramatic changes in renewable output over the timespan of the study.

There is a stark contrast between the current output of intermittent renewables and what may be expected in 2030. This diagram highlights the high but unpredictable wind

generation in winter, and the greater solar output in the summer months.

It is the strong conclusion of this study that in Northern Europe the overall output of the renewable generation will be highly variable, and will not average out because of weather and geography.



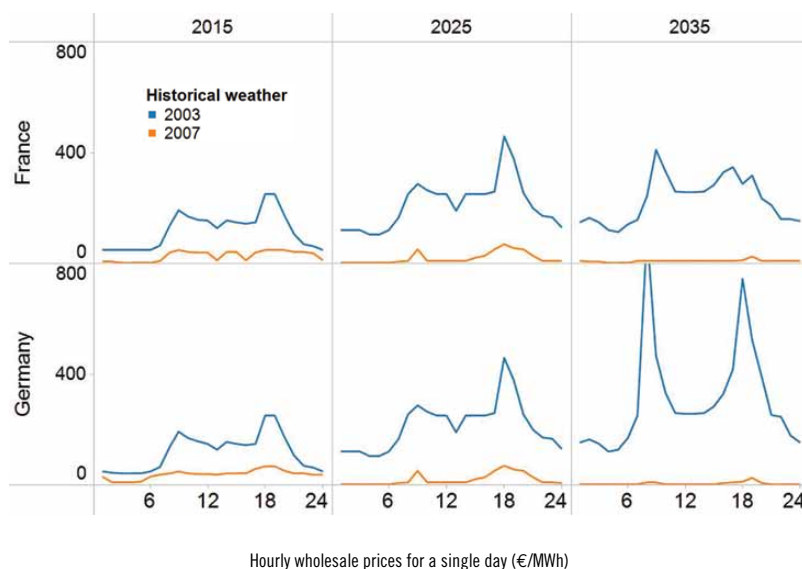
Aggregate hourly output across North Europe for four months (GWh)

Findings

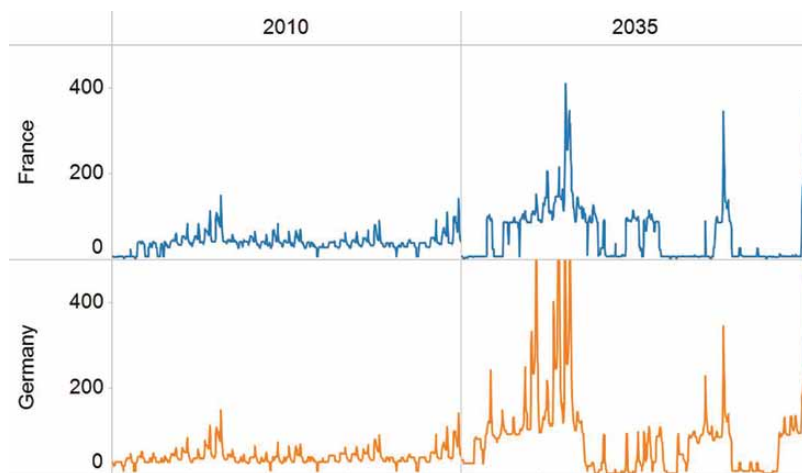
The impact of such variability is directly seen in wholesale market prices – the chart to the right shows the difference in these for one sample day, with the orange price track based on our windiest day’s weather, while the blue price track is the least windy day.

By 2030 wholesale market prices in some countries will have become highly volatile and driven by short term weather patterns

Inevitably, with prices increasingly driven by the weather, market price volatility increases, although not to the same degree in each country. Hourly price tracks for a typical month in France and Germany are shown on the right, and highlight the potential changes that may occur between 2010 and 2030. However, countries with large amounts of hydro – in particular the Nordics – are much less affected by increased price volatility.



Hourly wholesale prices for a single day (€/MWh)



Hourly wholesale prices for a month in France and Germany (€/MWh)

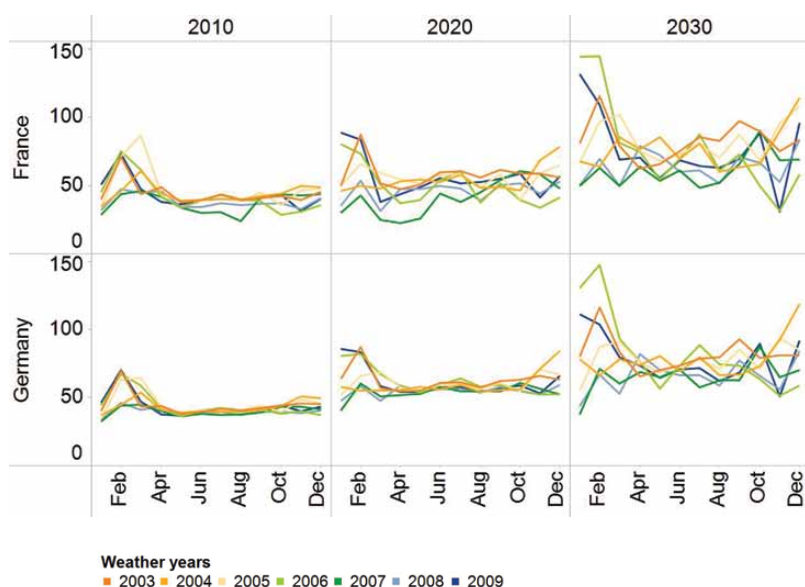
Findings

Along with increased volatility, prices will become more unpredictable, due to the very nature of weather systems. The chart below shows the evolution of monthly average prices in Germany and France over the years of the study, with different colour tracks for each historical year's weather. Prices in 2010 are only marginally affected by weather patterns, but by 2030, different weather patterns produce radically different market prices.

Wholesale prices will become far more 'peaky' than at present

Over time, the impact of the renewables will change the underlying character of the

market prices – with a marked shift towards fewer periods of far higher prices when renewables output is low, but also many more periods of very low market prices when there is a surplus of renewables and nuclear output. These two features have distinct drivers: the 'merit order effect' (lower system marginal price, some zero, or low price periods; and the 'scarcity effect' (price peaks, as fixed costs are recovered from a short period).



Monthly wholesale prices across different historical weather tracks in France and Germany (€/MWh)

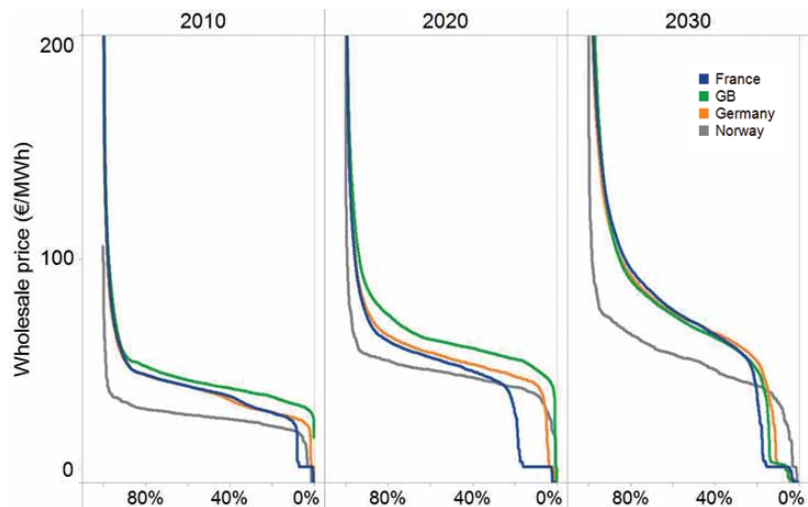
Findings

The price duration curves below show this evolution for a few sample countries – again, each country has its own pattern, with France developing this characteristic earlier than Germany; in the Norwegian market the hydro systems’ relative ability to arbitrage low price periods results in fewer low prices, but high prices can be still driven by other markets.

In directional terms both the wholesale and retail prices are likely to rise, but diverge between countries

effect’ continues to influence prices, this is overwhelmed by the cost of subsidising renewables (i.e. adding wind generation to

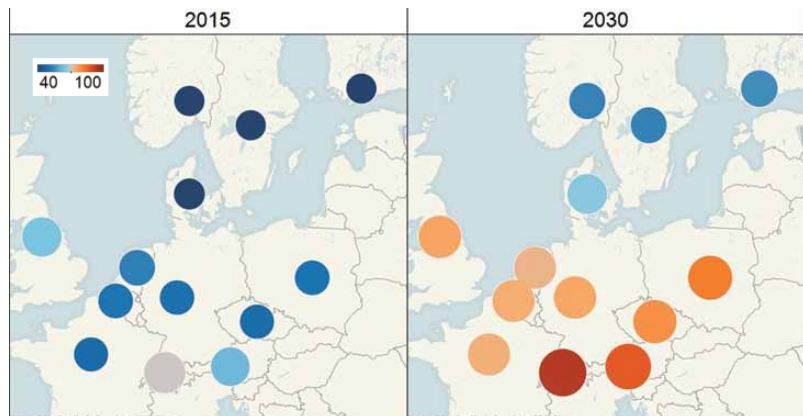
the market does reduce wholesale market prices but the cost of the subsidies still has to be borne by the market).



Price duration curves showing hourly prices stacked from highest to lowest (€/MWh)

Overall market prices in our scenarios rise significantly, but to different levels and in a different manner in each country, largely driven by generation costs. The chart to the right shows the overall change in market prices between 2015 and 2030.

However market prices are also likely to diverge between countries unless substantial interconnector reinforcement takes place. Also, although the ‘merit order



Annual average wholesale prices (€/MWh)

Findings

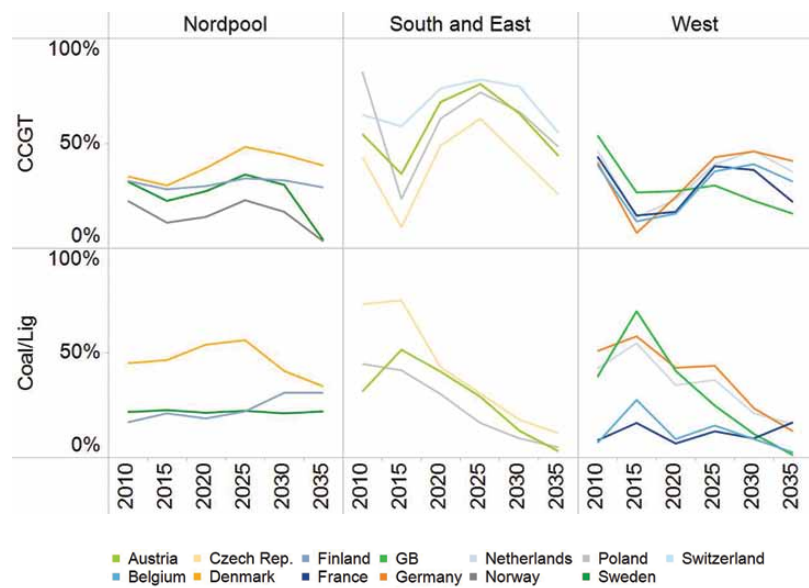
Thermal generation becomes 'intermittent' in its operation

Over time the operational position of all thermal plant in the market will be fundamentally altered: it will become increasingly marginal to the system and its operation far more uncertain, with starts being driven by the underlying weather, instead of responding to simple demand patterns.

In making this study useful for participants and investors in the European power markets we based our work on significant but realistic interconnector developments, recognising that the historical pace of building such infrastructure, particularly in this highly populated region, is slow.

Nevertheless, greatly expanded interconnection over an even wider geographic area has been vaunted by several commentators and NGOs as a key to decarbonisation. We were keen to

understand quantitatively the full role of interconnectors – both their capacity to mitigate the impact of intermittency as well as whether such projects would be attractive to investors.



Annual load factors of CCGT and coal/lignite plant in different countries

Findings

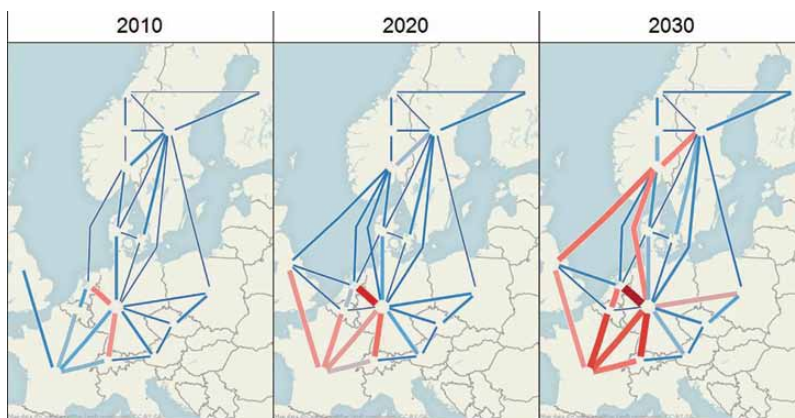
In particular we examined the sensitivity of the above findings to construction of an 'Offshore Grid' (as illustrated below) – increasing interconnection between those countries with North Sea coasts and expansion of grid reinforcement on the Continent.

While greater interconnection has some economic benefits, they are asymmetric and therefore there are significant barriers to their deployment

A summary report of this nature can only reveal a small part of the detail of the work carried out. However, a key finding was that the market price impact of increasing interconnection substantially (by almost 60GW in 2035) was very little in nearly all countries with the exception of Nordpool where prices actually rise significantly. Nordic prices rise because a rising proportion of the hydro output in this part of Europe is able to access higher prices elsewhere in other countries.

This heavy reinforcement of interconnection doesn't appear to offset the need for very much backup plant, however. This surprising observation comes from the fact that weather systems – in particular high pressure 'cold and calm' periods in winter – can extend for 1000 miles, so that periods of low wind generation are often correlated across Europe. Hence interconnection helps when it is windy in one country and still in another, but when it is calm across many countries together, interconnection is much less helpful.

Analysis carried out in this study suggests that interconnectors are not a complete solution, and that the benefits of interconnection are not evenly spread, either between countries, or between generators and customers. Consumers in one country could benefit, whilst those in another country lose out. Equally, generators in one country could see much higher returns at the expense of consumers.



Interconnection capacities assumed in each country

Findings

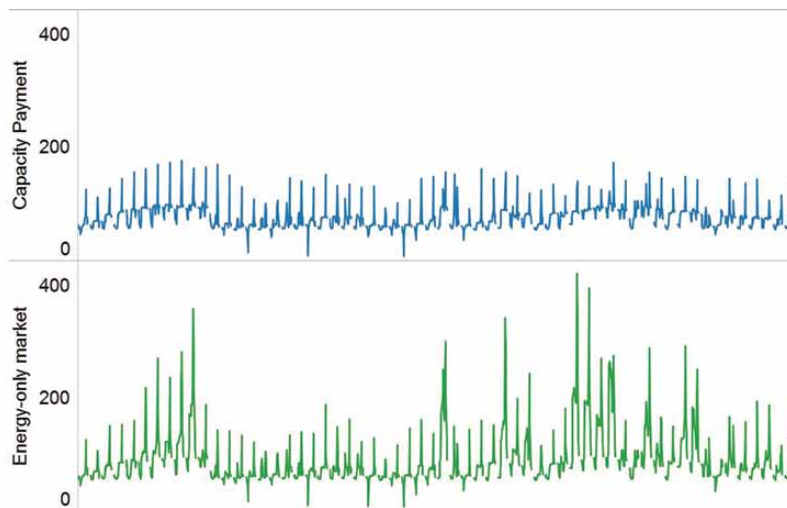
Inevitably the large amount of thermal capacity that essentially operates as a backup to the wind becomes more valuable for its capacity than its energy output. Already in many countries in Europe there are various ways in which such capacity is managed by the System Operator.

the relevance of capacity payments we wanted to model the impact of different mechanisms – one important feature described above that might be moderated is energy price volatility, as peaking plant would be guaranteed a certain level of return.

However, we found that from investors' and utilities' perspectives, the changes are mixed. The chart below illustrates how the level and volatility of market prices can change under one modelled capacity payment mechanism compared to our 'Targets Met' basecase.

Unless market designs change, the investment case for thermal plant is challenging – and this holds even for a significant shortfall against targets of renewables deployment

However, in the highly intermittent markets examined in this work, we examined the desirability of changes to wholesale market structure – for example those in which there are structural payments for capacity as well as energy. Given the already public debate about



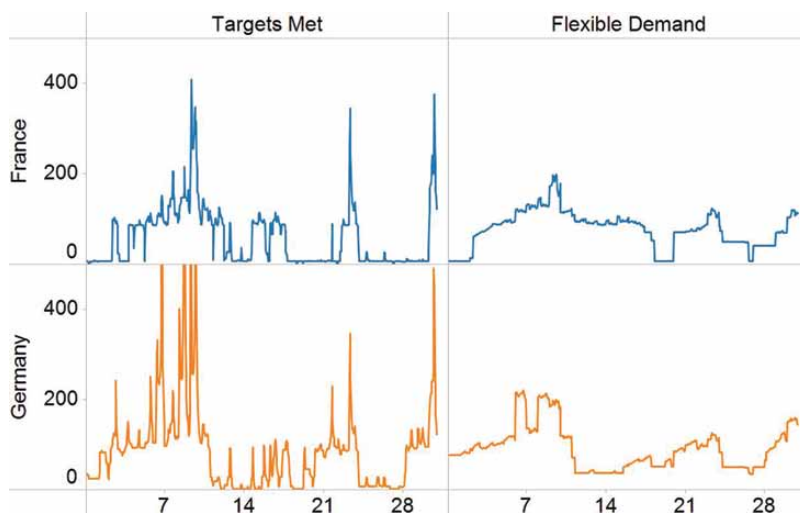
Hourly wholesale prices for January and February 2020 (€/MWh)



Findings

Any outlook of a future world with highly intermittent generation output and very high price spikes would not be complete without a detailed examination of the scope for the demand-side of power markets to become involved.

While demand-side response at the moment is largely the domain of large industrial customers, future technological developments could enable this to include a far greater range of residential electrical uses, as well as in the future including electrification of heat and transport systems (for example the use of more heat pumps for heating, and extensive use of electric vehicles).



Hourly prices for January and February

‘Flexible demand’ may be an important dynamic, but its role is complex

Flexible demand embraces many aspects – for example the speed of response, the timescales for being turned off, speed of deployment and likely behavioural characteristics. We have modelled many of these in great detail and have found

that in many ways ‘demand-side’ solutions are most suited to matching the needs of intermittency. The chart above illustrates one scenario we modelled for Germany, assuming an increase in flexible heating demand, some flexibility from non-heat sources (such as washing machines, tumble dryers etc.) and optimised charging of electric vehicles.

Overall we found that, while ‘demand-side’ involvement may be attractive, the wide range of likely deployment patterns and technological developments will further complicate investment decisions – and quite possibly slow deployment. Models that we have developed in the course of this work can evaluate this aspect of the intermittent electricity market in great detail.



Concluding remarks

Our aim in carrying out this study was to develop a sufficient understanding for investors and participants in the power markets of North Western Europe to take a view on the impact on their assets and investments.

The answer has turned out to be much more complicated than a simple 'Can the market deal with this?' or indeed 'Can we square the circle by building enough interconnection or changing demand pattern to match the intermittent generation'.

We have little doubt that investors will face major challenges developing appropriate

investment and divestment strategies to deal with this kind of future ahead. Thermal assets may be highly valuable if the market evolves in one direction, but also face the strong risk that they will be unprofitable for most of their lifetime.

Equally, the challenge for policy makers and regulators is to create suitable market structures without relying on the 'golden bullets' of more interconnection and demand side response while definitely making efforts to promote and develop both of these. In particular the European Target Model will need to encompass the value of capacity and 'flexibility'.

Unlike previous work that has concluded that theoretically demand can meet supply – usually by massive, and possibly unrealistic increases in interconnection and electrification – Pöyry can now draw on a deep understanding of the economic character of such markets, and take realistic views on the outlook for current and future investments and developments.

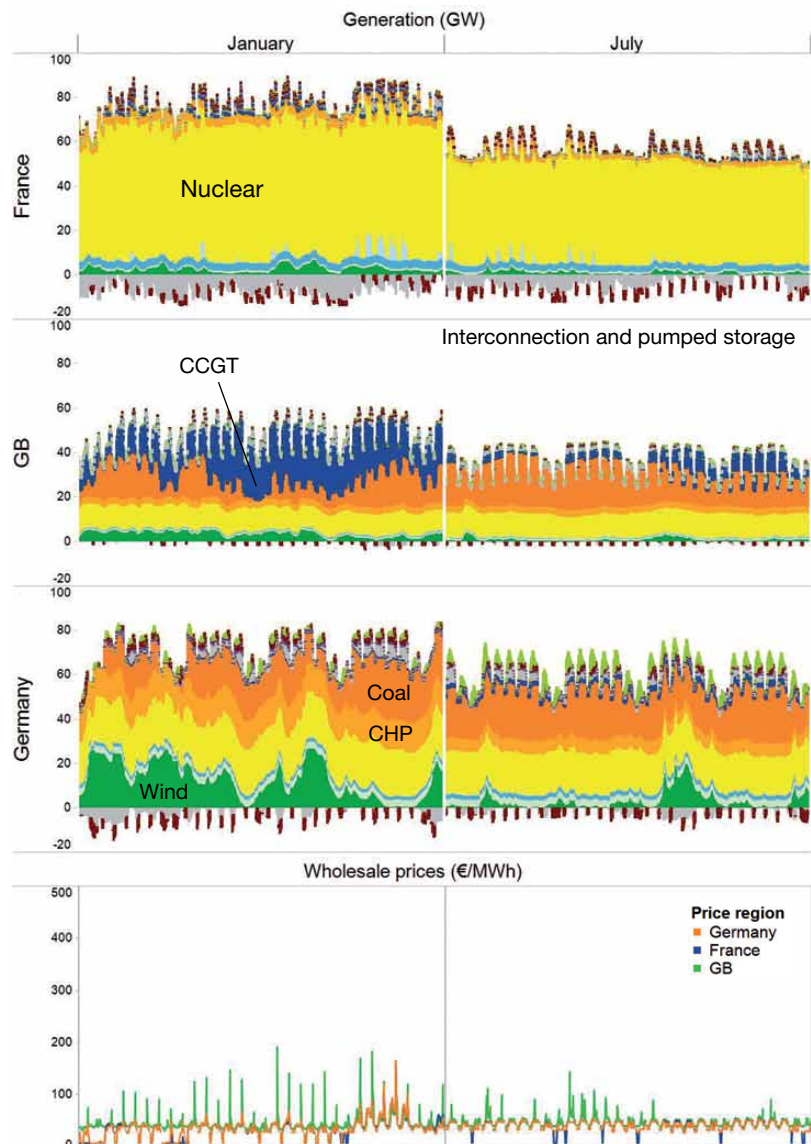
Pöyry looks forward to continuing its work with the energy industry in meeting the market challenges of decarbonisation.

The World in 2010

The current electricity market is one which is dominated by the daily pattern of demand, with more electricity demand during the day and less at night, along with higher demand during the week and lower demand at weekends.

In France, the generation fleet is mainly nuclear, which mostly runs at baseload. There is currently a small amount of wind generation and large exports to other countries. In GB, there is currently very little wind generation, with the system a balance of nuclear, coal and gas CCGTs. Coal and gas plant compete driven by the relative variable cost of generation. In Germany, the system is a balance of some wind generation, along with nuclear, coal and combined heat and power (CHP). In all countries the generation patterns are predictable.

Prices in all countries have low volatility, with higher prices in weekday peak hours, and on occasions, there are dips in prices overnight driven by low demand.



- Generation type**
- Solar
 - Pumped storage
 - Peaker
 - Interconnection
 - CCS CCGT
 - CCS Coal/Lig
 - CCGT
 - Coal/Lig
 - CHP
 - Nuclear
 - Reservoir hydro
 - ROR hydro
 - Other Renewables
 - Offshore wind
 - Onshore wind

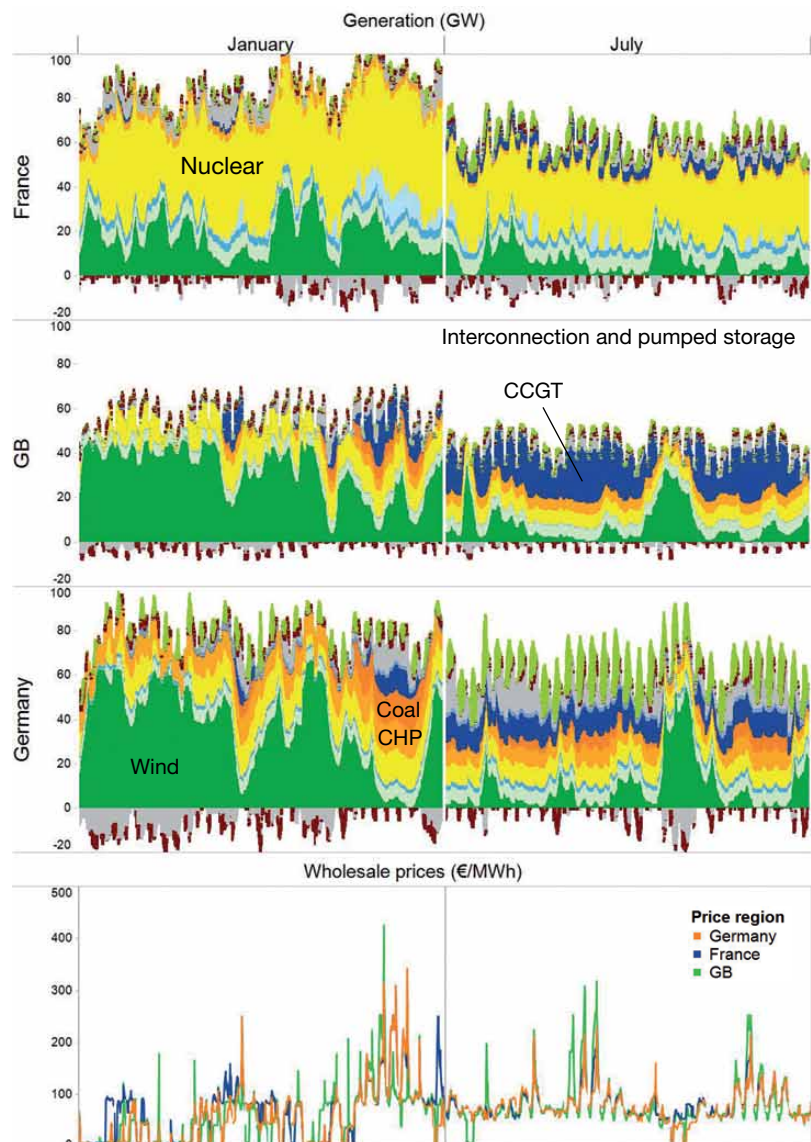
The World in 2030

By 2030, the electricity system will be transformed. In all countries, wind generation becomes a dominant factor, and the rest of the thermal system has to flex in response. The French system still has a lot of nuclear generation, and the balancing of the wind is achieved via a combination of flexing the nuclear plant along with imports and exports. In GB during the winter months, the thermal plant have much lower load factors than in 2010, and operate in response to wind generation. With the drop in wind speeds in the summer, the CCGTs run at much higher load factors.

There are also very significant swings in output – for example in Germany at the end of January where a period of 4 days of very low wind is followed by a ramp to 50GW of wind generation which drives most of the conventional plant off the system. During the summer months, the German system has large amounts of solar generation.

Prices in 2030 are much more extreme and unpredictable than at present. There are a large number of low or zero priced periods when there is significant wind generation, and when the wind dies, prices jump to high levels.

- Generation type**
- Solar
 - Pumped storage
 - Peaker
 - Interconnection
 - CCS Coal/Lig
 - CCGT
 - Coal/Lig
 - CHP
 - Nuclear
 - Reservoir hydro
 - ROR hydro
 - Other Renewables
 - Offshore wind
 - Onshore wind



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