Blowing in the wind – measuring and managing the costs of renewable generation in Europe

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Executive Summary

Over the course of the next decade the way in which Europe's demand for electricity is met will change fundamentally. Driven by a political will to meet ambitious targets for reductions in emissions of carbon dioxide and supported by generous subsidy schemes, electricity generation from renewable sources is expected to grow explosively between now and 2020. For example, commentators expect growth in the volume of renewables electricity generation capacity to be over 150% over the next decade and constitute 75% of all new generating capacity constructed over the period.

The vast proportion of this new renewables generation, some 90 GW, is likely to be wind generation which relative to today's thermal generation has output which is intermittent and unpredictable.

Frontier Economics and Consentec have been commissioned by Energibedriftenes Landsforening (EBL) to examine the implications of an increase in the prevalence of intermittent and unpredictable generation for Europe's electricity system and how it might be managed in an efficient manner. This report presents our findings.

Based on the historical operation of windfarms in Britain and Germany, it appears that, even at only one hour ahead of intended production, there is a significant degree of uncertainty regarding the level of output from wind generators. An implication of this is that Europe's system operators are likely to need to carry significantly more reserve to balance the peaks and troughs in wind production than has historically been the case. Given expectations of wind generation growth, it might be that additional reserve requirements would be in the order of 22GW to 27 GW. The cost of providing this reserve could be equivalent to an additional 20% of the capital cost of the wind generation itself.

There are many emerging technologies for this reserve provision. Over the horizon of the next decade, with the possible exception of improved demand side management, none of them appear likely to compete materially with those that are currently in use. This means that part loaded thermal plant and hydro plant are likely to be the main providers of reserve over the course of the next decade. In particular, repowered and refurbished hydro plant are efficient and clean relative to thermal alternatives. Therefore, their use could dramatically reduce the cost of the additional reserve provision.

However, as hydro resources are concentrated in certain regions of Europe it will be important that market arrangements for interconnectors allow reserve to be traded across borders. As we show, at the moment, current arrangements in Europe are not fully developed to allow this to occur. Failure to address this could further increase the already high cost of meeting Europe's emission targets.

This should therefore be an area of regulatory focus in the coming years.

1 Introduction

Across Europe the mix of technologies used to generate electricity is likely to change radically over the next decade. Driven by ambitious targets and generous subsidies, the extent to which power is generated from renewable sources seems likely to increase very materially between now and 2020. Given that most renewable generation is only likely ever to be an intermittent source of generation (wind and solar generation for example), this will have far reaching consequences for the way in which the electricity systems of Europe are managed. Most notably, it will require changes to the way in which existing conventional generation is used to manage this intermittency or, alternatively, the development of new technologies to manage the unpredictable peaks and troughs in production from renewable sources.

Given this expected fundamental change in the make up of Europe's generation park, Frontier Economics and Consentec have been commissioned by Energibedriftenes Landsforening (EBL) to examine the implications of an increase in the prevalence of intermittent generation and how it might be managed in an efficient manner. This report presents our findings.

In it we use regional projections to estimate the likely growth in renewables generation across Europe until 2020. As we note, a fundamental issue is that currently the energy produced by renewables generation is, over short periods of time, relatively unpredictable and subject to significant forecast error. A likely implication of this is that, compared to the current situation in which Europe's demand for electricity is met predominantly through relatively predictable thermal generation, there will be a significant increase in the demand for energy that can be delivered in short timescales. Typically known as balancing energy or reserve, this will be needed to "balance out" the peaks and troughs of intermittent renewables generation. We assess the likely volumes and costs of such balancing energy that might be required to manage the increased volume of intermittent generation.

We then go on to assess the possible technologies that might be available to meet this new demand. We note that it seems likely that the provision of reserve through increased interconnection will be an important component of the overall solution of managing increased volatility of electricity production. To that end we examine the extent to which the current arrangements for trading balancing energy between jurisdictions across interconnectors are likely to be suitable in the future given this increased demand for balancing services.

Our report is divided into seven further chapters

- in Chapter 2, we present the likely evolution of generation and transmission in Europe in the long term;

- in Chapter 3, we consider the implications for electricity system management of the likely growth in renewables generation and assess the extent of the intermittency and unpredictability of wind generation and the timescales over which such intermittency will manifest itself;

- in Chapter 4, we review the technological options available to manage the expected increase in the intermittency and unpredictability of generation in the future;

- in Chapter 5, we assess the likely costs of managing increased intermittency, given our analysis in the preceding chapters on the likely demands for balancing services and the possible technologies available to meet this demand; and

- in Chapter 6, we consider the role that interconnectors might play in managing intermittent generation;

- In Chapter 7, we provide our conclusions of this study.

2 The changing face of the European electricity system

In this chapter we describe the changes to Europe's power system that are likely to occur over the next decade or so, given the extensive policy initiatives now in place both at the EU and regional level. In turn, we examine:

- how Europe's generation fleet is likely to evolve between now and 2020;
- the extent of new transmission interconnection that could be constructed over the longer term; and
- given this new infrastructure, the implications for the European electricity system.

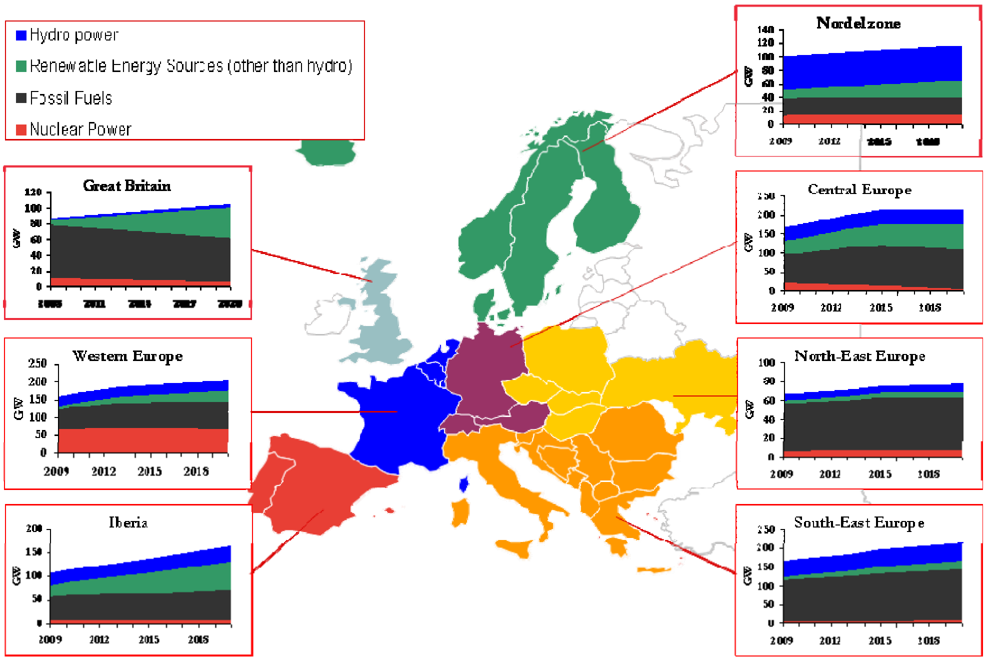
2.1 Europe's new power generators

In this section we examine the main types of generation technology currently used to meet the demand for electricity across Europe and then project forward how this might evolve over time on the basis of a number of official and published sources.

Figure 1 below illustrates one scenario for the evolution of generation capacity by technology type between now and 2020. For ease of exposition, we have divided generation technology into four main types:

- nuclear power generation;
- generation from fossil based fuels - principally coal, gas and oil fired generation;
- hydro generation, which includes run of river, reservoir storage and pumped storage; and
- non hydro based renewable generation – principally wind generation. However, it also includes photovoltaic generation and other forms of renewables generation such as tidal power and biomass.

Figure 1. Evolution of generation



Source: UCTE, NORDEL, and BERR for Great Britain

The data presented in Figure 1 above are from a variety of publicly available sources that varies by region:

- For continental Europe, we have used projections out to 2020 based on data published by Union for the Coordination of Transmission of Electricity (UCTE).
- For the Nordic region, we have used estimates out to 2012 published by NORDEL (the organisation for the Nordic system transmission operators), and have included trends forecast by Elektrizitäts-Gesellschaft Laufenburg (EGL) for the capacity evolution of Nordic generation by technology to 2020.
- For Great Britain, we have used projections from a report published for the Department for Business Enterprise and Regulatory Reform (BERR)[1] that

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[1] "Growth Scenarios for UK Renewables generation and implications for future developments and operation of electricity networks", Sinclair, Knight Mertz, June 2008.

estimated the likely evolution of generation by technology up to 2020 that would be consistent with the government's stated policy ambitions[2].

We emphasize from the outset that the data sources above present only one vision of the future. Clearly, it might be the case that renewables targets are not met (or indeed surpassed) or different technologies are adopted more widely and therefore the generation mix in 2020 might be very different by region to that presented here. There are clearly also uncertainties on the demand side – for example, whether energy efficiency measures will result in overall reductions in customer demand, or whether new sources of demand (e.g. for transport) will offset this. However, for the purposes of this report, we have not sought to independently ratify or challenge the forecasts presented here.

Nonetheless, while we would warn against drawing definitive conclusions on the basis of the data, it does seem that discernable trends can be drawn from Figure **1**:

- First, it is clear that there are some regions that are set to increase extensively their intended renewable generation as a share of the overall generation capacity. This includes Great Britain, the Iberian peninsula and Central Europe.
- Second, some regions, notably Western Europe (and principally France) appear set to continue to rely upon nuclear generation as their main source of generation. In other regions, notably Germany, nuclear generation is expected to decline by 2020[3] on account of previous policy decisions.
- Third, the Nordic regions will continue to use hydro generation as their main source of electricity generation. The Iberian peninsula and parts of continental Europe (notably Switzerland, France and Austria) will also continue to be extensive users of hydro generation.
- Fourth, up to the horizon of 2020 fossil fuels will continue to play the main role in the generation of electricity. This applies throughout Europe but is most notable in Eastern Europe[4].

Figure 2 below aggregates the data presented above for Western Europe[5]. It demonstrates that the aggregate installed generation capacity in Western Europe

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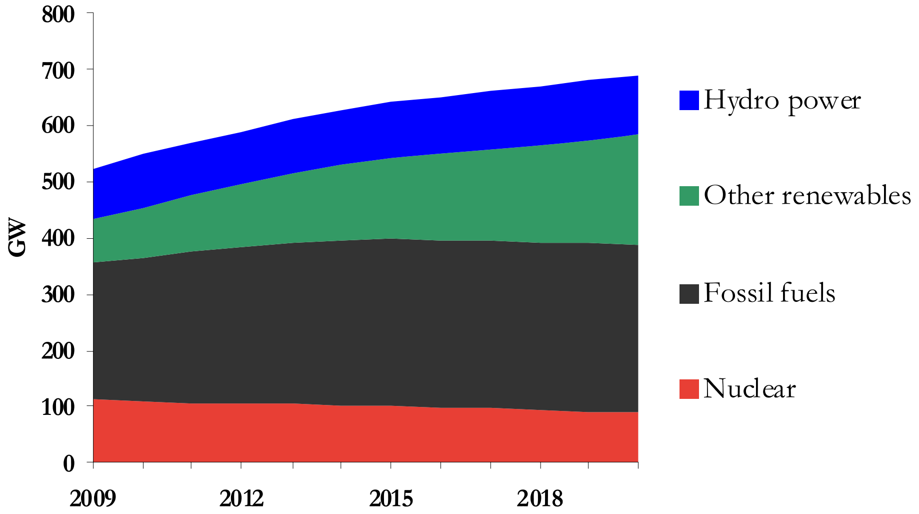
[2] UK projections are a slightly different in nature than the other predictions presented: they are based on targets being met rather than on predictions of what is reasonably expected.

[3] The significant lead time for new nuclear build means that there is no increase in nuclear capacity by 2020, with the exception of plants already under construction, even for those jurisdictions that have recently confirmed an interest in adopting greater levels of nuclear power (such as Great Britain).

[4] Some fossil fuel generation plants might adopt carbon capture and storage technologies in the future, but we have not factored this in to our 2020 projections.

is set to increase by over 30% in the course of the next decade – from 525 GW of installed capacity today to 690GW in 2020.

Figure 2. Evolution of generation mix in Western Europe 2009 – 2020



Source: UCTE and BERR

Figure 2 highlights the point that the growth of non hydro based renewables generation is likely to be the key driver of this overall growth in generation capacity. On the basis of the data that we have used, non hydro renewables generation is expected to increase by over 150% from today's current levels – from a current installed capacity of 76 GW to 195 GW by 2020. It therefore is likely to constitute approximately 75% of the overall increase in installed capacity over the course of the next decade.

As a result, non-hydro based renewables generation's share of total installed capacity in Western Europe is likely to double over the course of the decade – from 15% of today's capacity to nearly 30% of installed capacity by 2020.

We would reiterate at this point that the data presented here is only one possible vision of the future and we have not sought to test the robustness of the projections. However, the conclusion that renewables generation is likely to be the principal form of generation growth over the next decade seems consistent with the overall EC policy commitment to source 20% of energy consumption from renewables by 2020, which implies a higher proportion of renewable electricity generation by 2020.

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[5] Data presented here are aggregated for Spain, Portugal, France, Belgium, Netherlands, Germany, Switzerland, Austria and Great Britain.

Therefore, even if there is some doubt over the level of future renewables generation, it seems reasonable to conclude that there is going to be a significant increase in the level of installed capacity in non hydro renewables generation by 2020.

The data presented above for non-hydro renewables generations cover a wide range of renewable technologies, including onshore and offshore wind generation, photo voltaic generation and others such as wave and tidal generation and the use of biomass in thermal generation. While the exact splits in technologies will depend on the details of individual subsidy schemes and experience in the construction and use of new technologies[6], the consensus view is that the largest proportion of non-hydro renewables generation will be accounted for by wind generation. In the UCTE data presented above, it estimates that over 75% of what we have classified as non-hydro renewables generation will be wind generation. Similarly, in the UK wind generation is expected to account for 80% of renewables generation by 2020. Applying these two assumptions, the total increase in wind capacity in Western Europe by 2020 would be estimated at 94GW.

2.2 New transmission build

The dramatic changes in the make up of Europe's generation fleet by 2020 are likely to be accompanied by increases in cross-border transmission capacity. Figure 3 maps the planned interconnector capacity growth until 2015.

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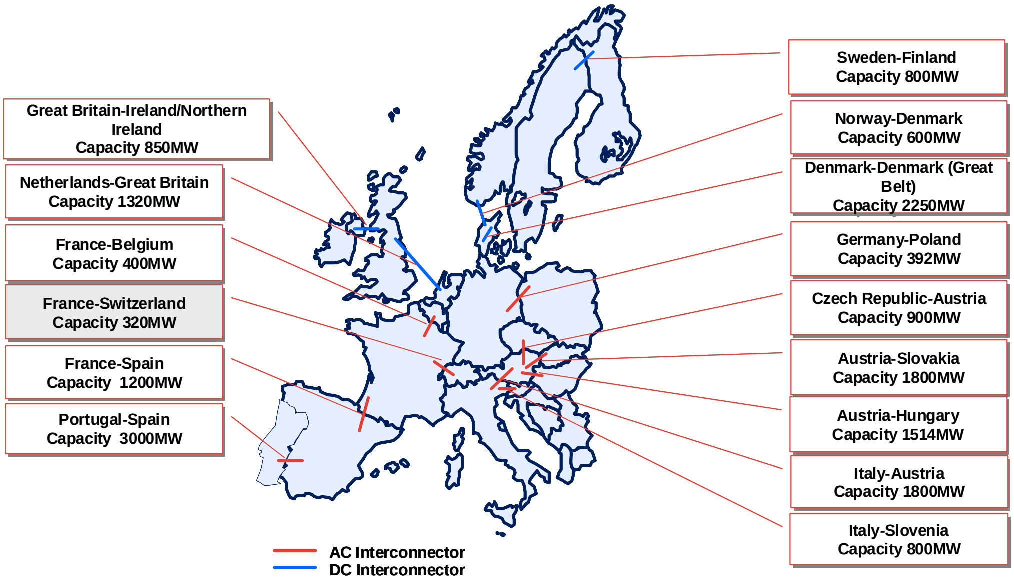
[6] For example, a combination of recent technical difficulties in the construction of offshore wind generation in parts of the Baltic Sea together with a recently introduced particularly generous subsidy scheme for photo-voltaic generation has led some commentators to suggest that, in Germany, solar technologies might be more prevalent in the future than previously thought.

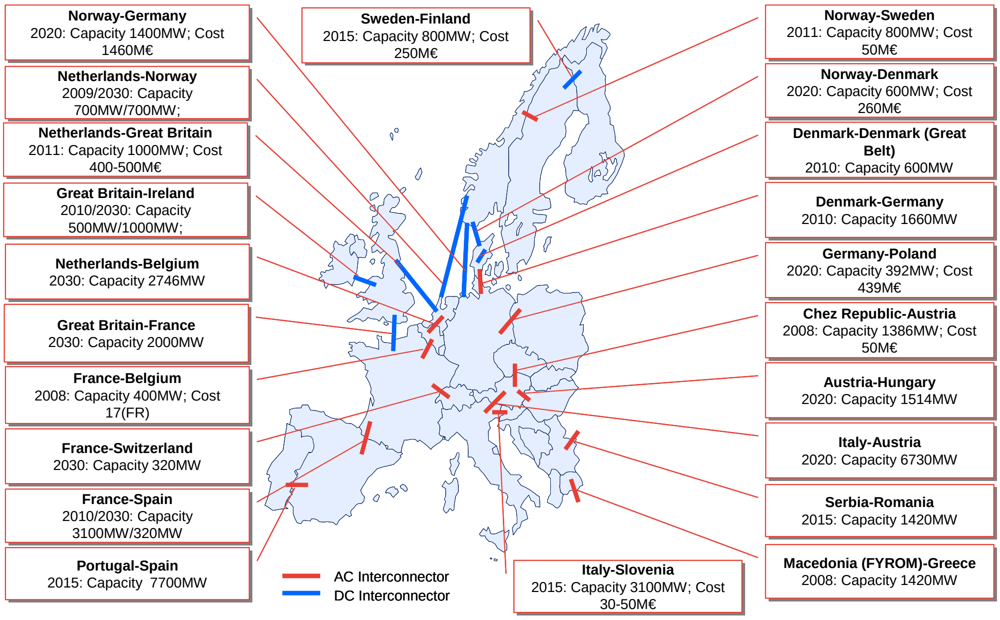
Figure 3. Expansions or interconnection capacity – planned or in construction



Source: Frontier based on UCTE reports

Figure 4 presents some estimates of the projected interconnector capacity growth to 2030 that might be required to accommodate new renewables targets.

Figure 4. Projections for interconnector capacity growth until 2030[7]



Source: Tradewind 2008

The overall impact of these capacity increases is illustrated below in Figure 5. According to these projections, up to an additional 40GW of interconnector capacity might be constructed between now and 2030. This implies an increase in the order of over 50% relative to today's current level of interconnection of over 70GW of interconnector capacity connecting EU member states.

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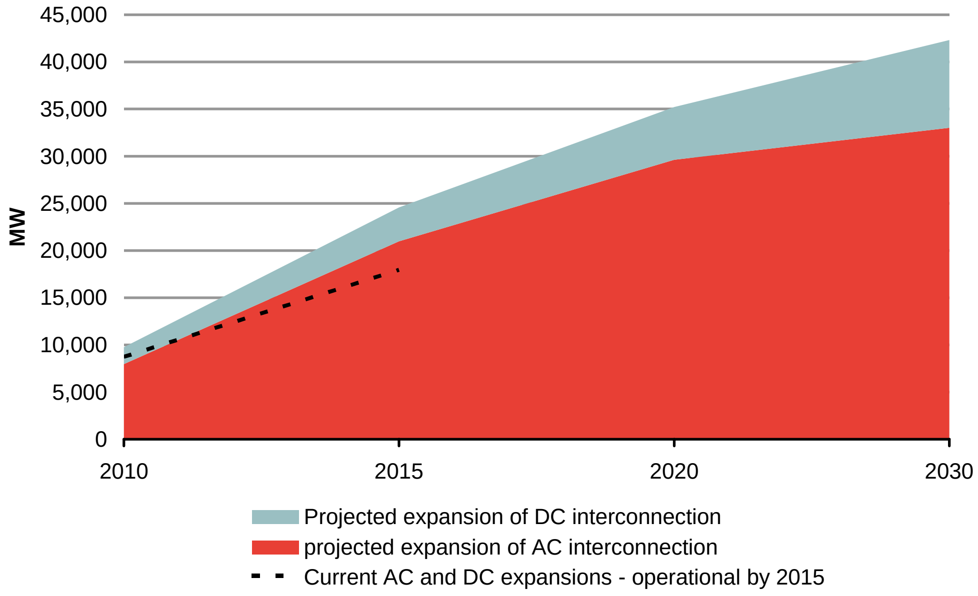
[7] This figure presents purely international interconnections

Figure 5. Volume of projected interconnector capacity expansion until 2030



Source: Frontier based on Tradewind projection

2.3 Implications

We have noted in this chapter that the next decade is likely to see a large increase in the overall level of wind generation. The most notable feature of this wind generation is that, by its vary nature, its output is intermittent and also difficult to predict as, obviously, it depends on wind speed at that location at any particular time. This intermittency and unpredictability is particularly marked when compared to the relatively predictable and stable output of the thermal generation that currently dominates the system.

A prerequisite for maintaining a secure electricity supply is that the demand and supply must (within certain narrow tolerances) equate on a second-by-second basis across the entirety of the system. Historically, this has meant that controllable thermal or hydro generation has been operated so as to fluctuate in line with variations in demand or other thermal generation availability that occur naturally over the course of any given day. Also, system operators and market participants have expended significant resources in improving techniques for forecasting the demand for electricity over the course of the day, as this allows them to optimise the use of electricity plant on the system to meet demand as efficiently as possible.

However, the rise of renewables generation with its inherent intermittency and unpredictability means that, everything else being equal, there will be greater uncertainty on how the demand-supply balance will be met. It will now not just be demand and unexpected thermal plant outages that are the cause of most uncertainty – rather an increasingly large proportion of the overall fleet of generators will themselves by intermittent and unpredictable in the level of output it generates[8]. This increasing uncertainty of the output of the generation park of the European system appears set to alter fundamentally the way in which the electricity systems and the electricity markets of Europe operate.

New transmission systems will facilitate the physical integration of the European markets. Consequently, flows between countries with a large share of intermittent capacity and countries with reserve capacity (such as hydro capacity) could be enhanced to mitigate the impact of intermittency.

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[8] At present, the expected reserve requirement is mostly upward, given that demand forecasts are unbiased and plant outages create the need for upward reserve. In the future, reserve requirements are expected to be more two-sided, and as a consequence, more reserve and different types of reserve will be needed.

3 Implications of increased intermittency and unpredictability of generation

As we have already noted, although there is still uncertainty over the exact magnitude, most commentators expect a significant increase in the level of renewables generation in Western Europe over the course of the next decade. As most of this is likely to be wind generation (both offshore and onshore), it seems incontrovertible that, if policy objectives are to be achieved, then an increasingly large proportion of Europe's new generation sources are likely to be able to generate only on an intermittent basis.

In this chapter we examine how this increase in intermittent and unpredictable generation will impact on the electricity markets of Europe. Currently, a major focus of electricity markets is ensuring that generators and consumers of electricity balance their projected consumption and generation volumes at the day ahead stage through normal market interaction. Indeed, in many jurisdictions there is a day ahead auction, typically in the morning of the day ahead, that allows market participants to balance their portfolios of generation and consumption for the following day.[9] However, even with the current generation portfolios in Europe there is a need to update contractual positions after the day ahead auction in light of fluctuations in expected generation and expected demand that arise as information as to the likely outturn of each is updated[10].

After the day ahead market, there are two main ways in which changes might occur:

- First, **through intraday markets**. These are markets that allow participants to refine their positions after the day ahead market closes but before real time. Sometimes, particularly across international borders, trades in these markets have to be sanctioned by the system operator (SO) so as to ensure that technical limits of the grid are not breached.

- **System operator actions**. At a point close to real time, known as gate closure, the market for participant-to-participant trading closes and the system operator ensures that the overall system demand and supply balance is maintained throughout the trading period. Its principal tools to do this are specialist balancing services, which are typically provided by part loaded

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[9] Most power market arrangements in Europe create incentives for parties to balance broadly their contractual and physical positions. This means that a change in a contractual position will tend to induce a physical change in generation or consumption plans and vice versa.

[10] Although not the focus of this report, the fact that wind generation can vary markedly on a day-to-day basis might place strain on other elements of the generation fleet, as it will have to cycle more frequently than it currently does to balance out the potential daily intermittency of wind generation.

thermal generators or hydro plant that can change output quickly in response to changes in demand or sudden shortfalls in generation such as an unexpected generation plant outage. Such services are usually procured by the system operator to deliver energy in a number of time scales ranging from almost immediately to within, say, 1 hour of being instructed.

Growth in intermittent and unpredictable generation as a proportion of the total generation capacity on the system clearly means that at the close of the day ahead market there will, relative to now, be greater uncertainty as to the likely levels of generation in forthcoming time periods (i.e. the periods of the next day). The question that we seek to answer in this chapter is whether market participants will be able to operate in the intraday markets to refine their positions as expectations of the volume of wind generation evolve over time or whether, instead, the system operator will need to rely on increased volumes of reserve to ensure that the demand-supply balance is maintained.

Therefore, in the remainder of this chapter we:

- first, draw on case study data to assess the extent to which wind generation is intermittent and the extent to which forecasts of output improve as the time before delivery lessens; and
- second, given this evidence, we go on to draw some conclusions about the likely impact for managing the system as a result of increased wind generation.

3.1 Assessing the intermittency and unpredictability of wind generation

We have drawn on evidence from Great Britain and from Germany to assess the extent to which, in practice, wind generation has proved to be difficult to forecast and over what timescales forecasts of output improve. We present the analysis for Great Britain and for Germany in turn.

3.1.1 Experiences from Great Britain

Like all electricity markets, the British market has a set of operational rules in place that govern the type and timings of information provision from generators to the system operator. Two such pieces of information that are relevant to this study are:

- Initial physical notifications (IPNs). At 11am at the day ahead stage each generator on the system communicates to the system operator (SO) its estimate of the output of each individual generation unit over the forthcoming electricity day[11].

- Final physical notifications (FPNs). One hour before the start of a half-hour delivery period, the generator is obliged to inform the system operator of the intended output of each of its units for the delivery period.

None of this information provided by the generators to the SO has any commercial relevance – rather it is simply operational data that generators must provide to the system operator on a per unit basis.[12] However, by comparing metered output of a generating unit against the relevant forecast from the IPN data and the FPN data it is possible to establish the extent to which, given current technology, wind forecast accuracy improves over time.

Figure 6 below shows the forecast accuracy for two wind farms. The left hand figure illustrates the forecast accuracy of a 90MW wind farm and the right hand figure the forecast accuracy of a 25 MW wind farm. Each distribution compares the actual metered output of the wind farm with the forecast of output as stated in the IPN data made at 11am the previous day[13]. The data goes from the commissioning date of each wind farm (mid-2005 for the left-hand figure and September 2007 for the right-hand figure)[14].

Given that the IPN forecast provides estimates over the entirety of the following day, it allows us to see the extent to which the forecast of output improves as the time prior to the period of delivery reduces. For example, one might expect that a forecast of wind generation made 13 hours ahead of the delivery period might, on average, tend to be more accurate than a forecast made 37 hours ahead of delivery.

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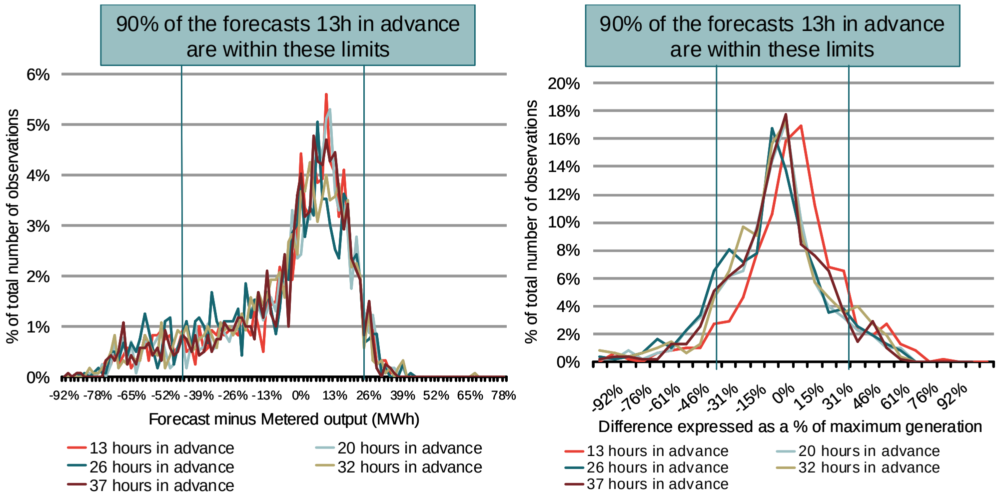
[11] This means that at 11am, the generator must forecast output for each of its units over a time window of between 13 hours ahead (i.e. output for the 12.00am to 12.30am balancing period) and 37½ hours ahead (i.e. the output for the 11.30pm to 12.00am balancing period at the end of the day).

[12] Generators have strong obligations to provide their best estimate of forthcoming production in their FPN submission contained within their generation licence and within the Grid Code.

[13] For the 90MW wind farm the distribution of forecast accuracy is made up of 1336 forecasts for each forecast time horizon and for the 25 MW wind farm we have 456 forecasts in each distribution.

[14] It may be the case that forecast accuracy has improved over time, particularly for the older wind farm.

Figure 6. Accuracy of forecasts made between 13 hours and 37 hours ahead of delivery for single wind farms



Source: Frontier

However, as Figure 6 shows, perhaps somewhat surprisingly, for the wind farms shown here there is no discernable improvement in the accuracy of forecast of output whether the forecast relates to production in 13 hours from the time of forecast or 37 hours ahead of real time[15].

Figure 7 below presents data for the same two wind farms as in Figure 6. In this case, it compares metered output for each balancing period to the forecast of output for that balancing made at the one hour ahead stage as stated in the FPN submission to the system operator.

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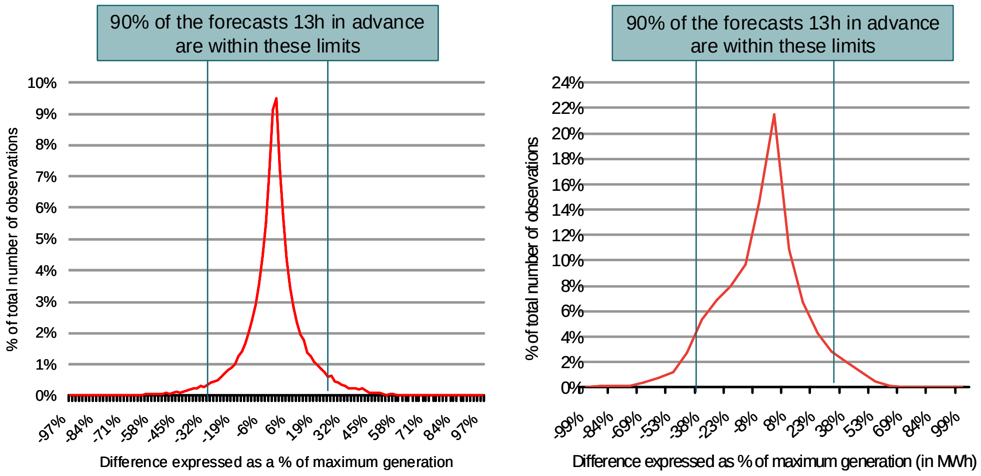
[15] It is also noticeable that there is an obvious bias towards over-forecasting generation for one of the wind farms. We are unsure of the reason for this and did not find it representative of other wind data we examined.

Figure 7. Accuracy of forecast of single wind farms one hour ahead of delivery[16]



Source: Frontier

Figure 7 indicates that, relative to the forecasts made at the 13 hour ahead stage and more distant forecasts, there is some improvement in forecast accuracy at the one hour ahead stage. For example, in the case of the 90 MW wind farm (on the left in the above figures) 90% of forecasts made 13 hours ahead of delivery are within 48MWh of actual output, but at the one hour ahead stage 90% of forecasts are within 30MWh of actual output. Although less significant, the same trend can also be discerned for the smaller wind farm presented on the right in Figure 6 and Figure 7 above.

Overall therefore it would seem that, while there is little improvement in forecast accuracy of wind generation in the period between 37 hours and 13 hours ahead of delivery, there is some improvement in the accuracy of the forecast made at the one hour ahead stage. However, it is worth noting that even at the one hour ahead stage there is still a relatively wide forecast error:

- for the left wind farm (90 MW): 25% of the time, the forecast error at T-1 is larger than half the average output of the station; and
- for the right wind farm (25 MW): 40% of the time, the forecast error at T-1 is larger than half the average output of the station.

We have also examined the extent to which there might be a portfolio effect across wind farms. For example, it might be the case that a deviation between forecast and metered output at one wind farm is offset by a deviation in the

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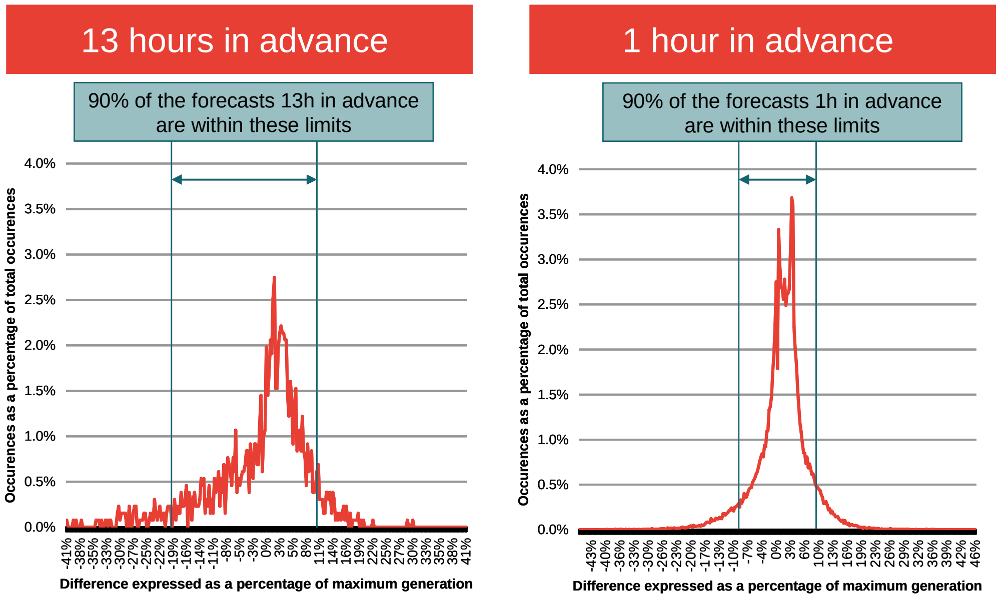
[16] The distribution of one hour ahead forecast error for the 90MW wind farm, pictured on the left hand side of Figure 7 the diagram, is made up of 52,617 forecasts and for the 25 MW wind farm, represented on the right hand side of the diagram, of 21,723 forecasts.

opposite direction in another wind farm. This would be beneficial in the sense that over and under forecasts of wind generation might tend to even out in any given period. To test this hypothesis, we repeated the analysis shown above for the aggregate of 11 wind farms in Great Britain. Our findings are shown below in Figure 8.

Figure 8. Analysis of forecast error for a portfolio of GB wind farms



Source: Frontier Economics

Compared to Figure 6 and to Figure 7, Figure 8 presents an improvement in the forecasts of the actual metered output from wind farms:

- 13 hours in advance, 90% of the forecast in the portfolio described by Figure 8 are between -19% and +11% of actual aggregated metered output, whereas it was between -48% and +29% of the 90 MW wind farm's actual aggregated metered output, and between -38% and +38% for the 25 MW wind farm; and
- 1 hour in advance the improvement is also important, with 90% of the aggregated forecast between -7% and +8% of actual aggregated metered output, compared to between +/-23% for the 90 MW wind farm (left) and between +/- 38% for the 25 MW wind farm (right).

Consequently, there is a non-negligible portfolio effect, which partly counterbalances the wind forecast error. However, the findings from this analysis of the portfolio of wind generators appear to confirm our findings from our single wind farm analysis. Namely that:

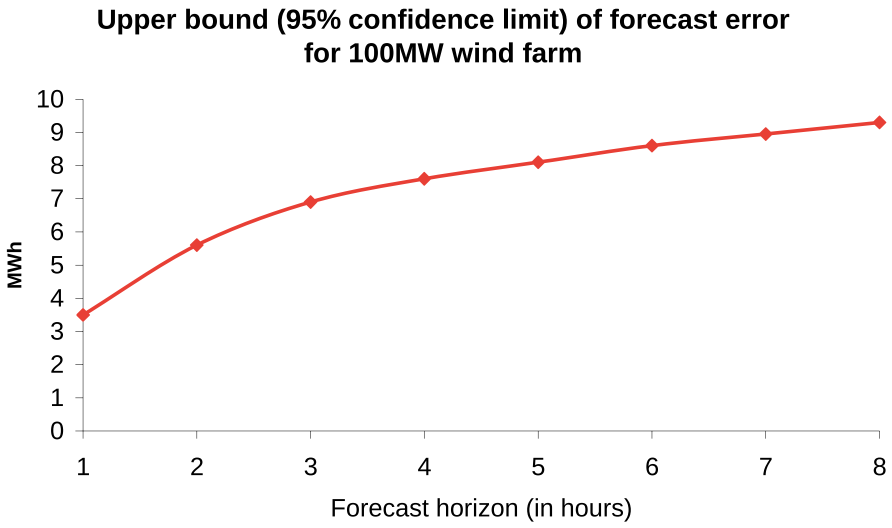
- there is some improvement in forecast accuracy between the 13 hours ahead forecast and the 1 hour ahead forecast; and
- even at the one hour ahead stage there is still a significant degree of forecast error.

It is also worth noting that this forecast error applies in both directions. For example, a wind farm might sell an amount into the day ahead market on the basis of its forecast at 11am of what it believes it will generate over the forthcoming day. However, following that sale, the production forecast might change so that either more or less generation from its wind turbines is expected. In this case, either the wind generator would have to sell more wind generation or buy back energy in the intraday markets. By contrast, thermal generator uncertainty tends to be one way, in that it is more likely to be the case that a thermal generator has only to buy power in the intraday markets on account of unexpected outages of its plant. Although not unheard of, it is less likely to be the case that a thermal generator is unexpectedly available and wishes to generate at short notice and therefore sell its output in the intraday markets.

3.1.2 Germany

We have also drawn upon similar data for the German system. Figure 9 below presents data from a study undertaken by ISET; a research institute at the University of Kassel, Germany, focused on the impacts of renewables generation and especially known for its developments of forecast methods for wind energy generation. This study examines achievable wind generation forecast accuracy for the German wind energy portfolio with a total peak power production capability of about 22 GW.

Figure 9. Forecast error for wind farms in Germany



Source: ISET

Figure 9 illustrates the 95% confidence limit for forecast errors and its dependency on the forecast horizon. The values are given as a relative percentage of the installed wind power (or, to make it easier to compare with the examples before) as the forecast error for the output of a stylized 100 MW wind farm.

The evidence shows that forecast quality improves as the forecast horizon is reduced. This improvement, however, is limited for forecast horizons of several hours and only becomes significant when the forecast horizon is reduced to a time period of less than 3 hours. Even with a forecast horizon of one hour, which is close to the typical gate closure of intraday markets, a material forecast error remains.

This is consistent with our findings for the British market when comparing forecasts made at the 13 hour ahead stage with those of the 1 hour ahead stage, although we note that the German research indicates that it may be possible to improve the accuracy of forecasting beyond that experienced in the British market.

Consequently, evidence from both the British and the German markets shows that the increase in intermittency implies some greater requirements for intraday trading and for balancing. We consider each in the next sections.

3.2 Increased requirements for intraday trading

The analysis in the preceding section appears to support two broad conclusions on the unpredictability of wind generation. These are that:

- First, there is some improvement in forecast accuracy as the time horizon of the forecast reduces. However, on the basis of the German analysis, it appears that a large proportion of this improvement is as the forecast horizon closes to within 2 hours of the start of the delivery period.

- Second, even at the one hour ahead stage, there is still considerable uncertainty as to the level of generation from wind farms. Our analysis of the portfolio of wind generators in Britain shows that even 1 hour ahead, the forecast error is higher than half the aggregated maximum output more than 5% of the time.

In the context of European electricity markets, it therefore seems reasonable to conclude that the expected significant increase in the prevalence of wind generation will mean that the certainty with which market participants and system operators can ascribe to a particular forecast of generation outturn will reduce relative to today's thermally dominated system.

As we have already suggested, this means that commercial outcomes in day ahead auctions, typically conducted at 11am or midday at the day ahead stage, will need to be refined as improved information about the likely outturn generation of wind farms becomes available. This is in contrast to now, where the relative reliability and predictability of thermal generation means that positions established at the day ahead stage are less likely to need refining on account of changes in expected generation output.

Overall, therefore, the increase in the prevalence of wind generation would suggest that there will be increased demand for trading closer to real time than is currently the case. This will allow wind generators to fine tune their positions after the day ahead auctions as forecasts of actual output improve[17]. As noted previously, there are already numerous examples of intraday traded markets in Europe, for example, Elbas in the Scandinavian region and more recently EEX has opened an intraday market in Germany.

However, liquidity in these intra day markets is relatively low. This, in part, is a function of demand – many market participants are clearly content with not trading out of unexpected imbalances, they do not need to trade because generator output from thermal plant is relatively certain, or they just balance within their own portfolio. Also, intraday trading across borders is still in its infancy and arrangements tend to vary significantly across countries.

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[17] In jurisdictions where wind generation receives a "feed in" tariff and faces no imbalance penalty the wind generator itself will have no incentive to trade closer to real time. However, this does not mean that the need to fine tune positions is reduced – rather it is passed to the agent responsible for trading wind output. In Germany, for example, this task is undertaken by the host TSO.

One conclusion, therefore, is that measures that can improve trading in intra-day markets will clearly be helpful in managing fluctuations in forecasts of expected output as the delivery period approaches.

A second conclusion, however, is that even at the hour ahead stage there is likely to be significant uncertainty regarding the output of wind generation over the next hour. This means that trading on the intraday market is not sufficient to counterbalance the effects of intermittency. Balancing by the TSO is necessary.

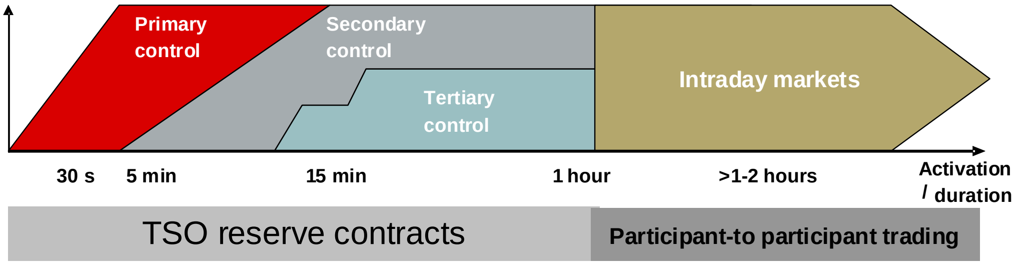
3.3 Increased requirements for balancing

At the hour ahead stage, the complexity of managing the electricity system in real time and ensuring that demand and supply balance on a second-by-second basis requires the system operator to take over the running of the system. The system operator can alter the intended running patterns of particular generators to ensure that the demand supply balance occurs in real time.

Typically the SO has a number of tools at its disposal to do this. In some systems there might be a balancing market (such as the British market) in which generators offer and bid to sell to or buy from the SO. In other markets, the SO might ensure system balance through the utilisation of reserve contracts bought at the day ahead stage or before (e.g. Germany). As already noted, reserve contracts are contracts between the system operator and generators and provide the system operator with the option (but not the obligation) of buying (or selling) additional power from (or to) a particular generating unit. This allows the SO to adjust that generator's output so as to maintain system integrity.

There are three broadly recognised types of reserve as illustrated below in Figure **10**.

Figure 10. Types of reserve used by system operator



Source: Frontier Economics

As Figure 10 indicates, the three types of reserve that are available are:

- **Primary reserve**, which is available to the system operator at between about 30 seconds and 15 minutes notice. It is used to manage short term perturbations in demand and supply, for example, to manage demand spikes or the forced outage of a generator. Primary reserve ensures that changes in system frequency due to such events are prevented and the system is stabilised at a certain frequency which is close to but not equal to the default frequency of 50 Hz. Primary reserve is activated on a decentralised basis, triggered by frequency deviations within the synchronous interconnected system.

- **Secondary reserve**, which is available to the system operator between 5 to 15 minutes. It is used on continental Europe first to bring back frequency to 50 Hz after deviations and second to ensure that balances of control areas are maintained at levels planned at the scheduling stage. Secondary reserve is activated automatically, and only in that control area where the cause of frequency or balance deviations can be found.

- **Tertiary or minute reserve**, which is available to the system operator within a time frame of 15 minutes to an hour. This is usually manually activated and used to manage longer term perturbations from expected levels of generation or demand and takes over from the utilisation of primary and mainly secondary reserve (so that those reserves can revert to standby for the next significant perturbation).

Clearly, given the expected increase in wind generation it will be the case that fluctuations in the net demand supply position are greater than in a system with only thermal (or more predictable) sources of generation. Everything else being equal therefore, having a greater proportion of wind generation on the system will mean that the system operator will require more reserve on the system than it would have held on a thermal or hydro dominated system, as the variability of generation will be greater.

The volume of primary reserve required to be held within the UCTE interconnected system is currently set to 3,000 MW. This is intended to cover the simultaneous failure of two of the largest generating units connected to that system (a nuclear power plant with a capacity of 1,500 MW is the largest single unit on the UCTE system). As long as there are no single wind farm or groups of wind farms with a total capacity of more than 1,500 MW connected to the system via a single line or transformer, which could go out of service spontaneously, it follows that the requirements for primary reserve will be unchanged with the introduction of more wind generation capacity.[18]

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[18] For some years it has been discussed whether voltage dips after a short circuit in the extra high voltage grid could cause wind farms with a total capacity of more than 3,000 MW to trip from the system (which would have required a re-dimensioning of primary reserve). As a consequence, the design of generators and, in particular, the required technical specifications regarding the so called

Regarding the question of whether secondary or tertiary reserve is needed to balance intermittency from renewable and, in particular, wind energy generation, different investigations[19] have shown that time periods during which generation from portfolios of wind farms significantly change are sufficiently long to activate tertiary reserve and do not require activation of secondary reserve. Therefore, changes in reserve demand as a result of additional wind generation, at least to a very large extent, only affect tertiary reserve (or, indeed, even slower reserve quality such as so-called hours or dedicated wind reserve, which is procured by different European TSOs).

In Chapter 6 we discuss the likely volumes of additional reserve that might be required. For the moment we assume that given the large predicted increase in wind generation there will be a commensurate large increase in the requirements for tertiary reserve. This can only be provided by plant that can respond quickly to requests to change production and in a controlled manner. Historically, this has been through either part loaded thermal plant, hydro plant or, in some cases, large demand side customers changing their consumption of electricity as requested.

The next question we seek to answer, therefore, is whether, given the increased requirements for increased volumes of plant that can quickly change its output levels, existing technologies are likely to continue to be the main providers of the flexibility required to manage intermittency of wind generation or whether new technologies might progress sufficiently to fill this role. We discuss this in the next chapter.

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fault-ride-through capability were changed to prevent this problem for new units connecting to the system.

[19] See, for example, G. Dany, Kraftwerksreserve in elektrischen Verbundsystemen mit hohem Windenergieanteil (reserve requirements in interconnected systems with high wind energy generation), PhD thesis, RWTH Aachen University, 2000.

4 Options for managing increased intermittency in generation

The previous chapters have identified that it is a commonly held view that there is likely to be a large increase in renewables generation over the course of the next decade. Most of this is likely to be wind generation which is intermittent and unpredictable in nature. As a result, therefore, it is likely that there will be a large increase in the requirements for flexible, controllable, generation to manage the unpredictability of wind generation. This flexible generation might trade in intraday markets to allow generators themselves to fine tune their positions or, more likely, be contracted by the system operator in the form of additional tertiary reserve.

In this chapter we examine what technologies might be used to provide this additional flexible generation that will necessarily accompany the increased volume of wind generation capacity installed on the system. We therefore examine in turn:

- the **range of possible technologies** that could be used to meet the demand for addition flexible, controllable generation;
- of these possible technologies those that are **most suitable for the provision of tertiary reserve**; and
- the **costs of reserve provision** for each of the reserve technologies.

4.1 The range of possible technologies

In this section we identify the possible technologies that might be used to provide the additional flexible generation that will be required to manage the greater volume of wind generation on the system. We have identified three broad categories of technology:

- generation technologies;
- storage technologies; and
- demand management.

We discuss each in turn.

4.1.1 Generation technologies as providers of reserve

There are a number of generation technologies that are currently used to provide flexible generation to the electricity market. These include:

- open cycle gas turbines, which have the ability to start and increase levels of production rapidly;
- part loaded thermal plant. Typically, most thermal plant cannot quickly start and then increase production rapidly. However, when it is operating within certain ranges of output (usually 50 – 80% of rated capacity) it is technically feasible for a plant to adjust output quickly within these ranges of output; and
- hydro plant. Reservoir storage plant can, subject to the energy limits of the water storage basin and environmental constraints on changes to discharge rates, quickly change output over the entirety of its rated capacity.

4.1.2 Electricity storage

The ability to store electricity is particularly useful in the context of wind generation as it might allow energy to be stored in periods of high wind and low demand for use at times when it is less windy but demand is high. More useful still would be a storage technology that could quickly and controllably release stored power on to the grid to manage unexpected shortfalls in generation.

There is a large range of storage technologies potentially available, some of which have been used for some time and some of which are still in development. We discuss the following three types of electricity storage technology in turn:

- mechanical storage;
- electrochemical storage; and
- electro magnetic storage.

Mechanical storage

There are three main types of mechanical storage technology:

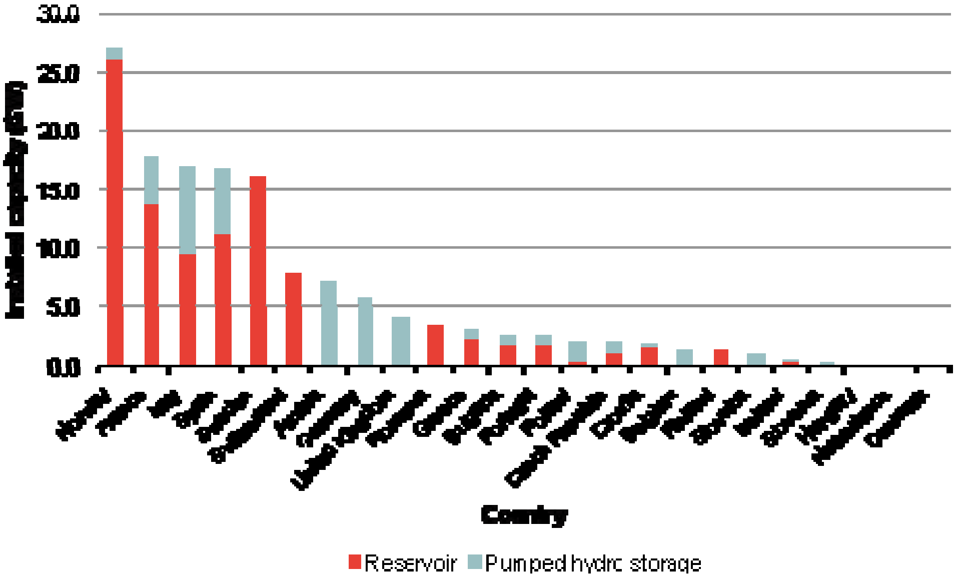
- pumped hydro storage;
- compressed air storage; and
- flywheels.

We briefly discuss each in turn.

Pumped hydro storage

Pumped hydro storage is a well established and mature technology, with a large number of plants in operation across the EU as Figure 11 indicates.

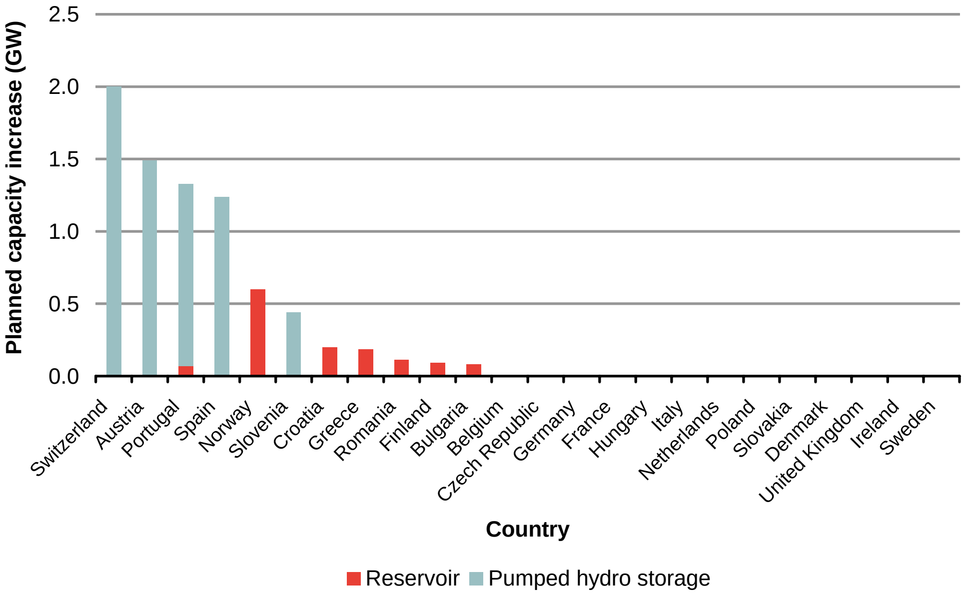
Figure 11. Installed pumped storage and hydro reservoir capacity in the Europe



Source: Frontier Economics based on UCTE, Platts and Nordel

Because pumped storage technologies are considered to have a very significant adverse impact on the environment and require suitable terrain, the potential for new pumped storage hydro plant is considered to be relatively low. There is, however, the possibility of retrofitting the turbines and pumps to existing hydro facilities to increase the generation and pumping capacity. Figure 12 below indicates that, despite the obvious benefits of pumped hydro storage, the announced quantity of new pumped storage plants and reservoirs in the EU is relatively low. However, in some jurisdictions – notably Norway, we understand that material capacity increases of pumped storage are possible through the refurbishment or repowering of existing reservoir plants.

Figure 12. Announced new pumped hydro and reservoir projects in the Europe



Source: Frontier Economics based on UCTE, Platts and Nordel

Compressed air storage

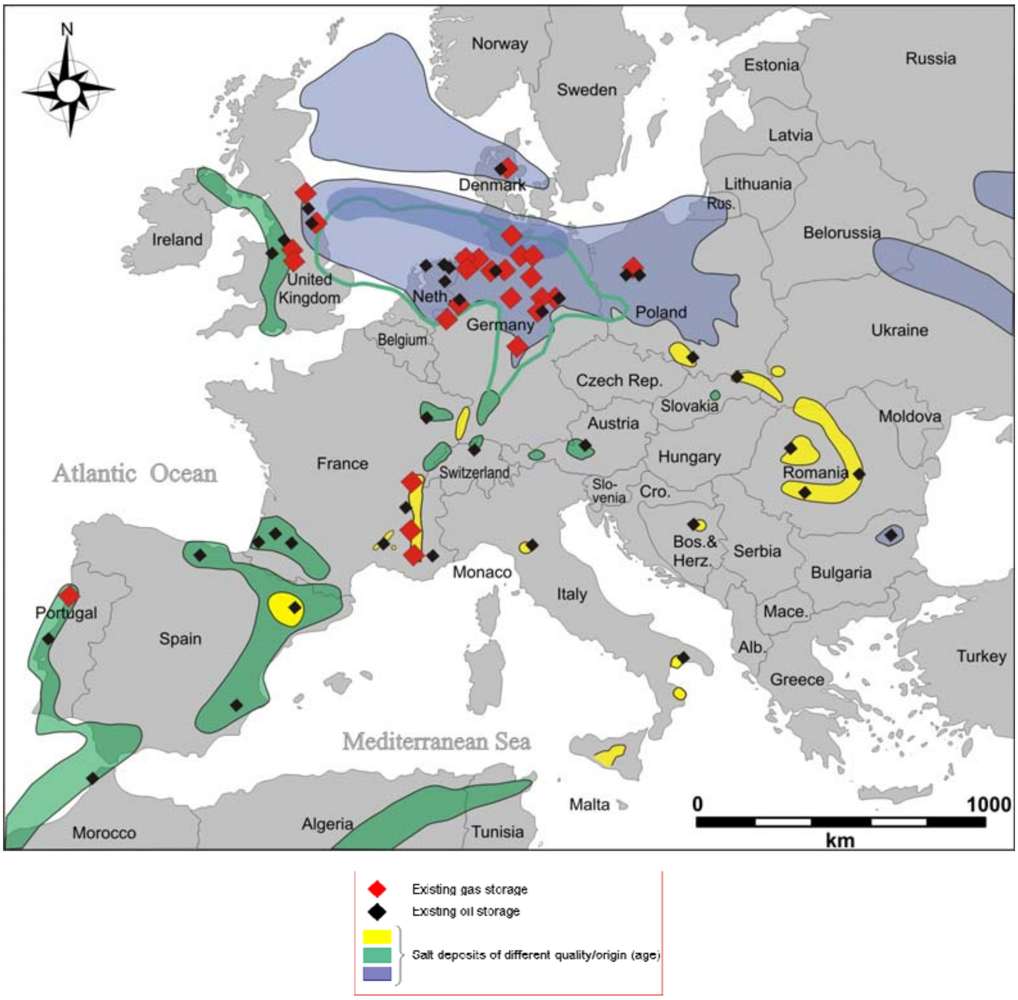
Compressed air energy storage (CAES) was first developed in the 19th century. However, there are only a few large storage applications in operation – in Germany, the USA and Japan. The technology relies on compressing air for release at a subsequent point in time. There are two main types of compressed air storage:

- Diabatic CAES is used in Germany and the US. It stocks the compressed air in caverns (salt caverns, depleted gas fields or aquifer areas). The heat from the compression process is lost. When energy is needed, gas turbines are used to reheat the compressed air.

- Adiabatic CAES stores both the compressed air and the heat resulting from the compression process. This heat is then reused when the compressed air is released. AA-CAES thus does not need gas turbines, and the process is more efficient than the traditional CAES.

It is generally agreed that the geology of Europe is relatively conducive to the use of CAES. Figure 13 below shows that suitable salt caverns are relatively plentiful, at least in northern Europe.

Figure 13. Salt structures and existing gas storage in Europe



Source: Gillhaus, Crotogino KBB

Flywheels

The idea of using flywheels as independent energy storage dates back to the 1960s. The energy is stored as kinetic energy in a rotor. It is released by the deceleration of the rotor's rotation. The liberated kinetic energy is then transformed into electricity. The discharge time of flywheels is generally very short, which makes them convenient for high power short term needs.

4.1.3 Electrochemical storage

Electrochemical storage can be divided into three broad types of technology – batteries, flow cells and hydrogen. We briefly discuss each in turn.

Batteries

There is a large range of battery technologies either in small scale use or currently in development. Some of the most relevant for this study include:

- **Lead acid batteries** are a relatively mature technology. It is a conventional rechargeable battery that consists of two electrodes that form a cell and has a relatively low "energy density" that means it is more appropriate for stationary applications. Their lifetime depends on the number of recharge and discharge cycles and on the extent of the discharge per cycle.

- **Sodium sulphur batteries** have been developed more recently than lead acid batteries. Like lead acid batteries, they are conventional batteries but operate at much higher temperatures, which means that they require an additional heat source to function. Typically they have a longer life time than lead acid batteries.

- **Nickel metal hydride batteries** have recently been used for smaller electronic applications (such as mobile telephones). Research to date has not allowed these batteries to be expanded to larger applications.

- **Lithium Ion** batteries are also currently used in small applications. They are increasingly commonly used in transport applications (e.g. cars) due to improvements in safety. Recent developments for lithium-ion batteries include a new processing technique allowing a tenfold increase in the speed of charging and discharging.

- **Nickel Cadmium** batteries are used in aircraft and electric vehicles. Test projects of this technology as a mechanism for stationary electricity storage have been launched in the US, but without good results to date.

Flow Cells

Flow cells are rechargeable batteries that use electrolytes stored in external tanks that flow through the battery which then return to the external tank. Three technologies that we consider in this study are:

- **Vanadium Redox** is the most promising of the fuel cell technologies – it is increasingly used in stationary applications (including in Japan and the USA) for wind generation storage and has a relatively high efficiency.

- **Zinc Bromine** is a significant competitor to vanadium redox. It has a relatively long life and is considered to be more easily scalable than other battery technologies. However, drawbacks include corrosive electrolytes leading to a higher potential for leakage.

- **Regenesys** is a brand of flow cell battery developed by RWE. The generic name is polysulfide bromide batteries. The technology was subsequently sold by RWE to VRB-ESS, one of the main developers of the vanadium redox battery, which has reduced further development in this area.

Hydrogen

There is a significant number of hydrogen storage options technically available, although most of these are at the development stage. The aim of power-to-power hydrogen technologies is to use electricity to produce hydrogen and to convert hydrogen into electricity, either using a fuel cell or a combustion turbine. A fuel cell works similarly to a battery, with fuel reacting with an oxidant thanks to an electrolyte - in the case of a hydrogen fuel cell, the reaction happens between hydrogen and oxygen.

4.1.4 Electromagnetic storage

Electromagnetic storage uses magnets to store an electric flow, typically within a small component. A key feature of this technology is that to date it has generally been used for short term power provision rather than long term energy provision. Two technologies that have been developed widely are:

- **Supercapacitors.** A capacitor uses an insulator (dielectric) to benefit from a voltage difference between two points of an electric circuit. The voltage difference creates an electric field in the dielectric, which then stores this energy. With the supercapacitors technology, the dielectric is extremely thin. The space created by the reduction of its width is used to increase the size of the conductors, resulting in much higher energy efficiency.

- **Super conducting magnetic energy storage (SMES)** stores energy within a magnetic field derived from a flow of current passing through a superconducting coil. This means that it has relatively high efficiency, particularly for smaller units.

4.1.5 Demand side management

The two current main goals of demand side management are consumption reduction and consumption smoothing, i.e. decrease of peak demand. Demand management could also be used to balance the effects of intermittency by incentivising end users to consume more or less depending on variations in production. Such a program would be equivalent to certain peak demand reduction programs currently being tested across the world, which are aimed at reducing demand for a certain number of consecutive hours during which peak production technologies would otherwise be required, or outages would occur. Most of those programs have been tested in the United States and in particular in

New York. Eirgrid also put in place a Winter Peak Demand Reduction Scheme in 2003, with good responses. The following table summarizes the characteristics of these various schemes.

Table 1. Peak demand reduction programs

Current programs	**Characteristics**	**Volumes**	**NPV of costs**[20]
Eirgrid's Winter Peak Demand Reduction Scheme	• Implemented in 2003 • Demand reduction during the peak winter hours from 5pm to 7pm • T.o.u system[21]	Volumes increased from 80 MW to 113 MW daily reduction from 2003 to 2007	503,310 €/MW
New York State Peak Load Management program (PLM)	• More than 80 firms participate • T.o.u. system[22]	62 MW contracted for peak demand reduction	291,662 €/MW
New York state Enabling Technologies Program (ETP).	• Dynamic scheme [23]	Demand reduction of 308 MW over three years	38,067 €/MW
New York state Peak Load Reduction Program (PLRP)	• Customers participate in programs such as load management, time of use or real time pricing[24]	Demand reduction of 360 MW over three years	279,509 €/MW
New York's Emergency demand reduction program	• Compensation for consumption reduction for two summer days • T.o.u system[25]	Reduction of 668 MW	184,471 €/MW

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[20] If each scheme was implemented over 30 years.

[21] Time-of-use system: Days and hours in which the scheme is implemented are set in advance, as well as rewards for consumption reduction. The consumer then decides the extent of his consumption reduction, and is rewarded based on observed metered consumption.

[22] Dynamic schemes are price/load response arrangements undertaken and handled by the electricity supplier, any third party service provider or eventually the customer himself. Such arrangements offer the possibility to aggregate switchable loads at customer level and, if adequate communication capacity is available, this option opens up for coordinated tailoring of the consumption. The ETP program offers compensation of $40/kw of reduced consumption on certain summer days

[23] Includes incentives to reduce energy consumption through investments in Energy information system, Communication infrastructure, or Transaction software

[24] Includes a collection of dynamic scheme and time-of-use offers to New York state industrials and utilities

[25] TSO asks curtailments from customers at a fixed price determined in advance. Customers who curtail are paid on a MWh saved basis

Source: Frontier Economics

All these schemes however currently only result in relatively low reductions in capacity or energy needs. Demand management at its current stage would not be able to mitigate the total impact of intermittency.

The development and spread of new technology at the household level means that there is the potential for significantly greater use of demand management in the future. The most promising of these technologies is batteries for electric cars. The grid could use electricity stored in these batteries while they charge overnight. Using Germany as a case study and assumptions on take up of electric cars and charging times it is possible to conceive of an additional 4GW of demand management capacity being available to the German TSOs on account of better demand management associated with electric car charging[26].

4.2 Technologies most suitable for the provision of tertiary reserve

As we noted previously, to be suitable for the provision of tertiary reserve, the technology should be able to respond to the request for an increase (or decrease) in production within a 15 minute time window. A second characteristic is that it should be able to generate for a sustained period (here we assume up to four hours) – this would provide sufficient time for more traditional thermal technologies to commence production to replace the output of the tertiary reserve.

We therefore filter the technologies described in the previous section on the basis of these two key criteria. We also apply two more qualitative criteria in our assessment of those technologies that might be able to provide reserve:

- if there is an obvious superior technology to others identified, on the basis of the current state of technology, we dismiss the inferior ones; and
- if there are likely to be siting limitations, we note this in our assessment.

We set out conclusions as to the potential technologies that are more likely to be used to provide tertiary reserve in Table 2 below. In the next subsection we estimate the likely costs of reserve provision from these various technologies.

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[26] We measure the scale of the potential impact of electric car batteries on the German grid by applying a simple calculation. We assume that by 2020, 10% of German households adopted electric cars and that on average 50% of them would charge overnight. The charging and discharging duration of an electric car connected to the grid is determined by the capacity of the plug. Currently, a plug for an electric car in Germany has a capacity of 2 kW. Assuming that there are 40 millions households in Germany by 2020, the total available capacity for the German grid by then would then be around 4GW.

Table 2. Assessment of possible technologies suitable for provision of tertiary reserve

Technology	Response time of less than 15 minutes	Duration greater than 4 hours	Technical or siting limits	Suitable for tertiary balancing services
Part- load thermal	✓	✓		✓
OCGT	✓	✓		✓
Hydro (reservoir)	✓	✓	Unlikely new sites would be utilised for reserve	✗
Refurbished hydro reservoir	✓	✓	Depends on nature of existing sites	✓
Demand side management	✓	✓		✓
Pumped storage hydro	✓	✓		✓
CAES	✓	✓		✓
AA CAES	✓	✓		✓
Flywheels	✓	✗		✗
Lead acid VRLA	✓	✓		✓
Sodium sulphur	✓	✓		✓
Nickel metal hydride	✓	✓	Currently surpassed by other technologies	✗
Lithium ion	✓	✓		✓
Nickel cadmium	✓	✓	Currently surpassed by other technologies	✗
Vanadium redox	✓	✓		✓
Zinc bromine	✓	✓		✓
Regenesys	✓	✓	Included in V-Redox	✗
Hydrogen fuel cells	✓	✓		✓
SMES	✓	✓	Not yet used for commercial tertiary reserve provision	✗
Supercapacitors	✓	✗		✗

Source: Frontier Economics

As Table 2 indicates, we conclude that it seems unlikely that new reservoir storage will be constructed to provide reserve. As we noted above, construction of new reservoir storage is likely to be significantly constrained in the future due to environmental concerns (and, as highlighted in Figure 12 there has only been a very small number of new reservoir hydro generation projects announced). By contrast refurbishment of reservoirs to allow pumped storage provides significantly more options for provision of tertiary reserve and given it is already operational is significantly less likely to be limited by environmental or site availability concerns.

4.3 Cost of reserve technologies

In this section we assess the potential cost of each of the technologies identified above as being potentially suitable for providing tertiary reserve from a technical and siting perspective.

We estimate the cost of providing reserve by collating capital and operating and maintenance costs and the estimates on the technical lifetime of each of the technologies identified above from publicly available sources. This provides us with the typical costs of construction and operation of the technologies that we have identified above as potentially suitable for reserve provision in the future.

To estimate the costs of reserve provision we assume that, over the long run, the revenue from the technology would need to cover its capital and operating costs otherwise it would not be developed. However, for many of the technologies identified above, there are two distinct sources of revenue:

- first, the revenue that a generation technology is likely to recover through normal energy market sales to other market participants; and
- second, the revenue that a particular technology might recover from sales of tertiary reserve to the system operator.

Therefore, where relevant, to calculate the costs of reserve provision we estimate not only the costs of the technology but also the likely revenue from normal energy market transactions. The difference between the two provides us with an estimate of the revenue that would need to be recovered through the provision of reserve to cover the costs of provision[27].

Table 3, below, sets out the assumptions we have used on the costs of different technologies that could be used to provide reserve.

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[27] For example, a part loaded combined cycle gas turbine (CCGT) plant has a significant capital cost but would be expected to also earn a significant revenue stream from the production and subsequent sale of electricity through normal markets. The cost of provision of reserve for this technology therefore, would be the difference between the capital and operating costs and the revenue stream from energy markets.

Table 3. Assumed costs of different technologies for the potential provision of reserve

Technology	Total Capital Cost (€/kW)	Fixed O&M (€/kW/yr)	Technical life of asset	Assumed efficency
Part loaded CCGT	480	27	30	55%
OCGT	390	7.5	30	37%
Refurbished hydro reservoir	400[28]	13	30	83%
Demand side management	845[29]	Included in capital cost	15	NA
Pumped hydro (new)	1940	13	30	83%
CAES	600	11	30	52% (including gas consumption)
CAES adiabatic	800	12	30	72%
Lead- acid batteries	1770	15	10	77%
Sodium sulphur	1,980	20	15	74%
V-Redox	2370	25	10	68%
Zinc bromine	2500	25	10	65%
Li-Ion (LiFePO4)	4170	25	10	86%
Fuel cells	4400	13	12	32%

Source: Sandia, EPRI, BERR

To derive some high level estimates of the costs of reserve provision, given the costs set out above in Table 3, we make assumptions about the revenue that each

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[28] Estimate based on indicative cost forecast of Tornstad power project in Norway

[29] Technically not a capital cost but adapted to be comparable with other cost data

technology would recover through "normal" energy market transactions (as opposed to the revenue earned from the provision of reserve).

The key assumptions we make are:

- For generation technologies we assume that:
    - OCGT plant produces electricity at only a few of the highest priced hours of the year; and
    - CCGT plant is part loaded and recovers the average 2008 spark spread depending on its load factor.
- For storage technologies we assume that each storage technology charges during the 6 lowest priced hours of the day and discharges during the six highest priced hours of the day.

A further critical assumption in deriving costs of reserve is the assumed load factor of the plant that will allow it to earn revenue in the standard electricity market. The key assumptions we make for load factors are:

- for CCGT, OCGT and pumped storage we use historic load factors as observed in the British market and reported by the market operator, Elexon[30];
- as an alternate CCGT case, we assume a lower load factor to take account for the risk that gas prices are higher than has historically been the case;
- as an alternate pumped storage case, we assume a higher load factor for pumped storage; and
- other storage technologies are assumed to run for an average of 1,000 hours per annum in the energy markets.

Our assumptions on load factors are set out in Table 4.

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[30] These are used by Elexon in its credit assessment protocols

Table 4. Assumed annual load factors for electricity generation

Technology	Assumed load factors
OCGT	1.28%
CCGT case 1	54%
CCGT case 2	40%
Refurbished hydro reservoir	15%
Pumped storage case1	1.28%
Pumped storage case 2	15%
CAES	15%
AA CAES	15%
Lead Acid VRLA	11%
Sodium sulphur	11%
Zinc-Bromine	11%
V-Redox	11%
Li-Ion	11%
Fuel cells	11%

Source: Elexon and Frontier Economics

On the basis of these load factors, we estimate the energy revenue that each technology would recover through standard energy transactions. We assume the difference between the annualised costs, as derived from the inputs set out in Table 3, and the annual revenue from the energy market sales, derived on the basis of the load factors assumed in Table 4, will be the revenue recovered though the sale of tertiary reserve to the system operator. Put another way, we assume that over the long run, the revenue from the provision of tertiary reserve and the revenue from the sale of energy in normal energy markets in aggregate exactly equates our assumed costs for each technology[31].

Demand management is treated differently. There is no capital cost for demand management, but only a variable cost per MW of peak demand reduced. In addition, there is no revenue to be made from demand management on the wholesale market. Thus, we use total costs per MW of implementing the Eirgrid

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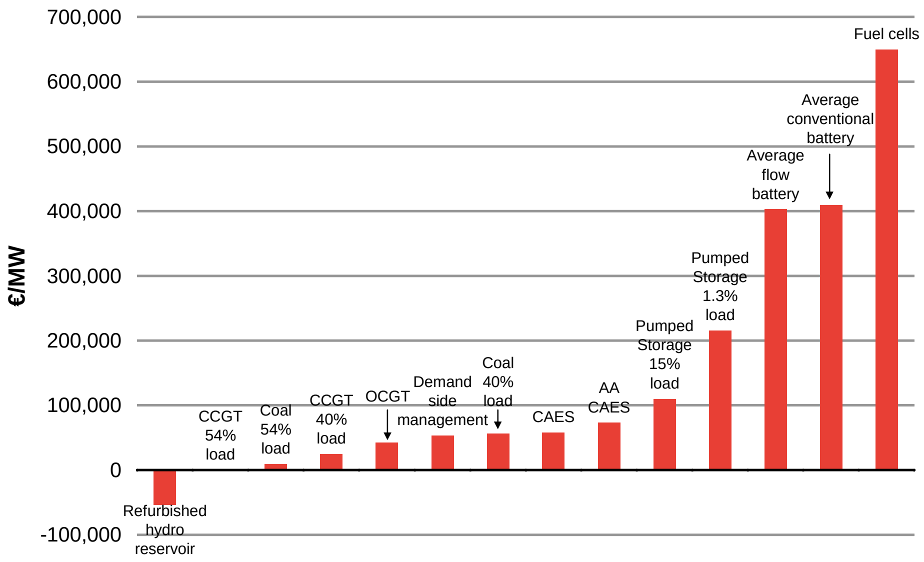
[31] It is worth noting at this point that part loading thermal plant clearly has an additional environmental cost. For example, average current CCGT plants emit 0.19tCO2/MWh produced. One MW of a CCGT plant part-loaded at 40% would generate 3504 MWh in a year and therefore emit 666 tCO2 emitted during that year.

Winter Peak Demand Reduction Scheme previously described, and compute the NPV of costs per MW of implementing the program over 30 years.

Figure 14 below sets out our estimates of the cost of providing reserve using the various technologies identified as possible providers of reserve in the future.

Figure 14. Estimates of per MW annual cost of provision of tertiary reserve through a variety of technologies



Source: Frontier Economics

Our estimates in Figure 14 do not, however, take into account possible changes in the cost of provision over time that might occur. For example, it seems reasonable to assume that, for some of the technologies identified, capital costs might fall over time because of technological improvements in production processes.

Therefore, we rerun the analysis described above, but make assumptions on the potential change in capital costs that might occur between now and 2020.

Table 5. Assumed changes in capital cost by 2020

Technology	Assumed change in capital costs by 2020	Rationale for change
Part loaded CCGT	No change	
OCGT	No change	
Refurbished hydro reservoir	No change	
Demand side management	-20%[32]	Reduced cost due to technological improvements and wider use of smart metering, e-cars, etc.
Pumped hydro (new)	-3%	Reduced availability of site but expected cost decrease over time
CAES	-11%	Improvements in technology plus less expensive use in new cavities
CAES adiabatic	-16%	Technology improvements supported by EU R&D
Lead- acid batteries VRLA	-46%	Improvements in lifetime and efficiencies should reduce overall per MW cost
Sodium sulphur	-40%	Technological improvement
V-Redox	-46%	Technological improvement
Zinc-Bromine	-20%	Technological improvement
Li-Ion	-30%	Recent technological discoveries suggest might be significant scope for cost reductions over time
Fuel cells	-49%	Technological improvement

Source: Frontier

Using the assumed reductions in capital costs set out in Table 5 above, Figure 15 below sets out revised estimates of the costs of provision of reserve of the different technologies.

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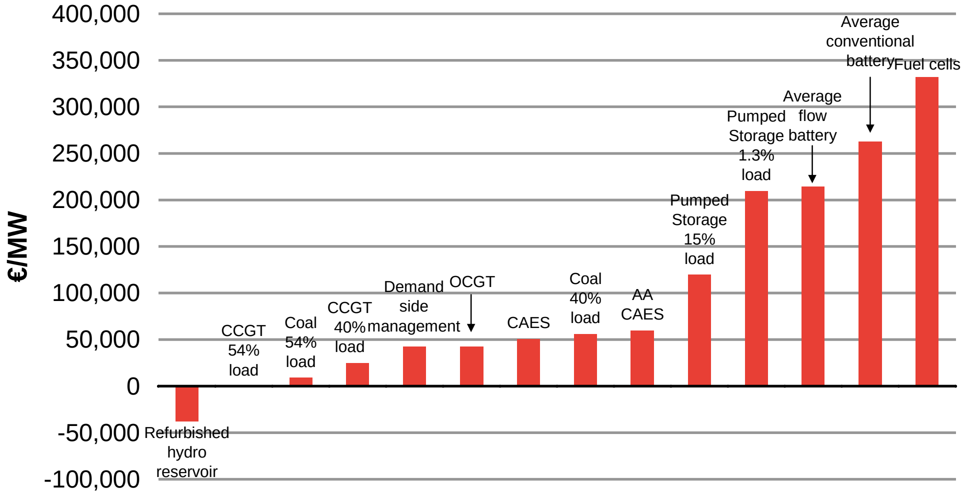
[32] Technically not a capital cost but adapted to be comparable with other cost data

Figure 15. Estimates of per MW annual costs of provision of tertiary reserve through a variety of technologies using assumptions on reductions in capital costs



Source: Frontier Economics

The estimates presented in Figure 14 and Figure 15 are broadly consistent with prices for reserve observed in some markets, which suggests that our bottom up approach to estimating the costs of reserve provisions is reasonably robust. For example, the estimated average price to be available to provide tertiary reserve in Germany is €5 per MW per hour, implying an overall cost of in Germany of €43,800 per MW of availability per annum. This would be broadly equivalent to our estimate of the cost of provision of a coal plant operating at a 45% load factor.

The main conclusions arising from the analysis presented in this section are:

- first, current technologies for the provision of reserve, namely part loaded thermal plant and open cycle gas turbines are likely to continue to be the main providers of reserve at least until the end of the next decade;
- second, where site conditions permits, the repowering of reservoir facilities would appear to present a viable economic alternative to the use of thermal solutions for reserve provision[33]; and

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[33] In Norway combined hydro/pumped hydro plants operate either on seasonal changing of operation mode (as the "Duge" power station) or short time (hours) changing of operation mode (the "Saurdal" power station). Building new combined hydro generation/pumping capacity in existing power stations would be cost effective, with around 400 Euro/KW for new capacity

- third, compressed air storage and conventional pumped storage seem, subject to siting availability, likely to be the other main sources of reserve provision.

However, there are three significant caveats to these conclusions:

- first, technological progress greater than we have allowed for in our calculations might mean that the costs of new technologies for reserve provision fall faster than we might anticipate. In particular, the current drive to use technology to manage better the demand for electricity might be more successful in the near term than we have allowed for.

- second, the costs of reserve provision for existing technologies might rise faster than we have allowed for here. There are two potential drivers in this regards:
  - input prices might rise significantly above current levels (either fuel or carbon costs); or
  - significantly lower load factors, on account of displacement in the merit order by new wind generation, means that existing conventional thermal plant will need to recover significantly more revenue through the provision of reserve services to remain commercially viable; and

- third, reliance on part-loaded thermal plant to provide reserve implicitly assumes that there will be sufficient CCGT available. Current gas-fired electricity capacity in UCTE is 111GW. It is forecast to increase to 165 GW by 2015 and 185 GW by 2020 in the zone (UCTE System Adequacy report).

(investment in the “Tonstad” power station was 3 bill. NOK for 1000 MW). Modifying or upgrading power stations like “Duge” to allow more flexible operation is another solution, and the cost for such upgrading is not fully elaborated at the time being

5 Economics of managing intermittency

In this report to date we have identified that if countries are going to meet their renewables targets there will be a very large increase in the volume of wind generation connected to the European system by 2020. Given its intermittency and unpredictability in output, this means that this growth in wind generation will need to be accompanied with a commensurate increase in the provision of flexible generation to maintain system security. We have also concluded that it appears unlikely that by 2020 there will be any new technology that makes the provision of such services cheaper than today – indeed if anything there is likely to be upwards pressure on the costs of provision.

Given these findings, in this chapter we now go on to estimate the likely volume of reserve that will be required to manage the increase in intermittency and assess the potential costs of provision.

5.1 Volume of tertiary reserve required

Assuming that all balancing requirements would be fulfilled by using tertiary reserve[34] we have estimated the relationship between the requirements for reserve to be held on the system and installed wind capacity. For this purpose we have used a probabilistic method for reserve dimensioning that is also used by different European TSOs and which we have recently applied in an application for German NRA Bundesnetzagentur as a cross-check of reserve requirements in Germany[35].

We have taken the German system, which has a peak load of 70-80 GW, a diversified park of power plants (with the largest units being about 1500 MW) and currently has about 22 GW of wind energy installed, as a basis for our analysis. For this system and typical rates of power plant failures, load forecast errors and wind energy forecast errors we estimate that the total demand for the sum of secondary and tertiary reserve to be approximately 7.5 GW positive and 6 GW negative reserve. Assuming that the relative level of forecast accuracy remains stable (i.e. the forecast error in relation to total wind capacity), reserve requirements for a wind capacity of 37 GW would be almost 12 GW (positive)

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[34] In reality, (limited) parts of these reserve requirements could be substituted by slower reserve qualities than tertiary reserve or by intra day trading. However, the total amount of traded volumes and additional tertiary reserves required will exceed the reserve requirement when only tertiary reserve is used, due to a loss of the portfolio effect with other sources of imbalances. Nevertheless, using slower reserve qualities or intra day trading could be sensible from an economic point of view, depending on price relationships.

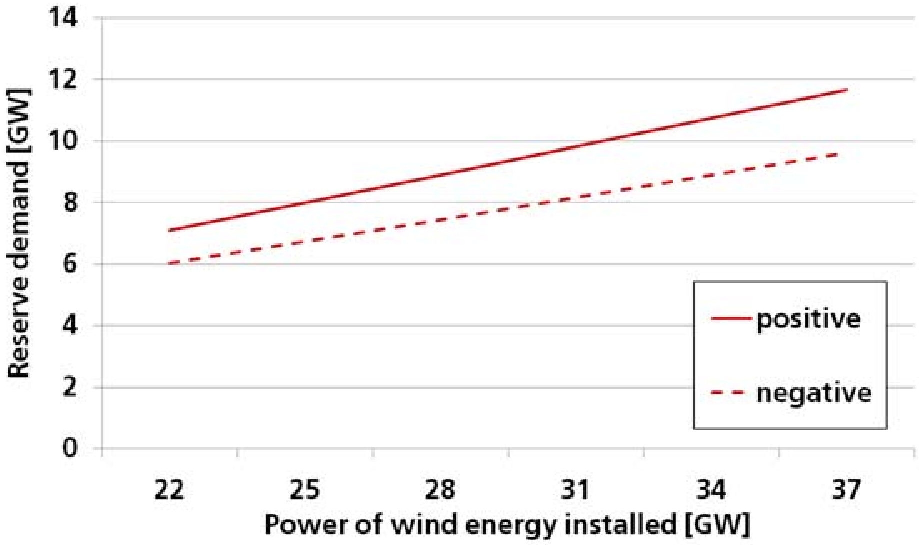
[35] See, for example, Maurer, C. et. al., Dimensioning of secondary and tertiary control reserve by probabilistic methods, European Transactions on Electrical Power, volume 19, number 4, pages 544--552, 2009.

and almost 10 GW (negative). In a system like the German one (but also others like Denmark, Spain and Portugal) with high wind energy penetration the relationship between increments of wind energy capacity and incremental reserve demand is more or less linear (here about 0.25 to 0.3 GW of additional reserve per GW of additional wind capacity).

These figures are dependent on the dimensioning method used – probabilistic methods are increasingly used by European TSOs, but are still far from common. Other dimensioning methods still used by many TSOs, which are based on the assumption that the total reserve demand should equal the size of the largest generation unit, have proven to be insufficient for systems with high penetration of intermittent generation.

Furthermore, our analysis indicates that systems with only low shares of intermittent generation show a less than linear relationship of reserve demand and installed wind capacity due to portfolio effects with other sources of forecast errors (especially load forecast error and plant failures).

Figure 16. Estimated relationship between installed capacity of wind generation on the system and requirements for tertiary reserve.



Source: Consentec

The future level of wind penetration is uncertain, and there will clearly be differences between the exact relationships between wind generation and reserve holding requirements in individual systems and geographies. However, in order to estimate at a high level the likely implications of wind penetration on the European system we have used this estimated relationship from the German system to derive a broad indication of potential reserve holding requirements across Europe.

In Chapter 2 we noted that on the basis of public projections for the evolution of generation, by 2020 there could be an additional 94 GW of installed wind generation connected to the electricity systems of Western Europe relative to today's level. Given the relationship illustrated above in Figure 16, a high level estimate of the additional implied tertiary reserve requirement might be an additional 27 GW (upwards) and 22 GW (downwards) of tertiary reserve[36].

5.2 Estimating the costs of additional tertiary reserve provision

Given the estimated volume of incremental reserve that could need to be provided to support the expected increase in wind generation in this subsection we evaluate the potential cost of its provision.

Currently, both Germany and Great Britain have markets for the provision of reserve. In Great Britain, generators participate in auctions conducted by the system operator offering to sell upward reserve. The auctions require the generators to specify an availability fee that it requires to compensate it for being able to provide reserve and a utilisation fee when the system operator actually draws on the reserve. The availability fee is specified on a £ per MW per hour of availability basis (with a commitment to be available for a pre-agreed number of hours in each, say, weekday, over a set period of, say, 1 year). The rate for the utilisation of the reserve is specified on a £ per MWh basis for delivered energy. Activation rates for reserve are around 0.7%.[37]

In Germany, reserve auctions for tertiary reserve take place on a daily basis. Offers are accepted on the basis of an offered availability fee (a price for delivered energy is not considered for acceptance of the offer and payment of the reserve contract)[38]. Activation rates for tertiary reserves are however low (below 5% typically) as system operators prefer to use automatically activated secondary reserve as long as their total reserve demand does not exceed the amount of available secondary reserve (which may happen, but only occasionally, for example, after power plant failures).

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[36] This compares to current tertiary reserves of 7GW in Germany and 700MW in Switzerland.

[37] Frontier calculation based on National Grid data.

[38] However, the cost of energy delivered is considered to derive the order in which contracted reserve providers are called off.

Table 6. Latest prices for provision of tertiary reserve in Great Britain and Germany

	Availability fee[39] €/ MW / hr	Utilisation fee € / MWh
Great Britain	€10.2/MW/h[40]	€266
Germany	€5/MW/hr[41]	€ 80-150[42]

Source: National Grid and www.regelleistung.net (German reserve market platform)

Assuming that the wind capacity increase in Western Europe by 2020 will be of 94 GW (as estimated in chapter 2), we can deduce from Figure 16 that the resulting reserve requirements should be in the range of 22 to 27 GW.

Based on this volume, we use two scenarios on the availability fees, based on GB and German prices presented in Table 6:

- our low scenario assumes an availability fee of 5 €/MW/hr; and
- our high scenario assumes an availability fee of 10.2 €/MW/hr.

We then use the German and British utilisation rates of the reserve capacity to produce a frequent use scenario (5%, as in Germany) and an infrequent use scenario (0.7% utilisation, as in GB). We use the corresponding utilisation fees presented in Table 6 (€266 for the infrequent use scenario and €115 for the frequent use scenario).

Based on these assumptions, our resulting estimate of the yearly cost of reserve corresponding to a 94GW wind capacity is in the order of €2.5bn – €3.0bn. This is equivalent to 20% of the capital cost that will be required to build 94 GW of additional wind farms by 2020[43].

It is true that these rough estimates are based on current costs for technologies used to provide these balancing services. Nevertheless, this is a good indicator that relying on these technologies, at least with their current cost structures,

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[39] For British figures we use a £ / € exchange rate of 1.26 (Bank of England 2008 average).

[40] 2008 average based on average accepted availability price (£MWh), STOR market information, National Grid.

[41] Prices vary significantly between 0€/MW/hour and 15€/MW/hour depending on the time of day and direction. Positive reserve is expensive in peak hours and negative reserve is expensive during weekend nights.

[42] Only for positive reserve. Negative reserve normally has a negative price, i.e. generator pays, of 5 - 10 €/MWh.

[43] Assuming a capital cost of wind of around 1,320 k€/MW, a discount rate of 10% and a lifetime of wind of 25 years.

would result in a very high total cost of wind, and consequently a large increase in the average cost of electricity. Using interconnectors would allow SOs to rely less on these reserve technologies. The next chapters present the potential use of interconnections to provide balancing services.

6 Using interconnectors to manage intermittency

As we have demonstrated in previous chapters the cost of providing the system services that will be necessary to manage the intermittency of renewables in the future is likely to be very large. On the basis of a relatively simplistic methodology, we have estimated that the costs could be in the order of €2.5 to €3.0bn. It seems likely therefore that the drive to increase the prevalence of renewables generation will be accompanied by a drive to reduce the costs of the reserve to manage the greater volume of intermittency. One obvious way in which this might be achieved is through an increase in the use of interconnection to provide balancing services.

Therefore, in this chapter, we analyse the potential value from, and current barriers to, the trade of system services across interconnections. To do so, we examine the market behaviour and current rules in place for trading across three interconnectors, namely:

- Norned (Norway-Netherlands) – a recently commissioned DC link of 700MW capacity;
- IFA (France-Great Britain) an older DC link with relatively well established trading rules and a capacity of 2000MW; and
- the French-German border, which comprises a number of AC links within the synchronous AC system of Western Europe with capacity that varies between 2400 and 4500 MW.

For each link, we observe historical flows across the interconnector and compare them to historical electricity price differentials for both day-ahead prices and also for imbalance prices. In this context we are assuming that the imbalance price is a proxy for the costs of reserve in each of the systems[44].

This provides us with an indication as to the extent to which the current rules in place for use of each of the interconnectors might be considered to operate efficiently.

Given our historical data series we then evaluate three alternative ways of using some of the capacity on the link, to assess the extent to which it might have been more valuable to have used the interconnector other than at the day-ahead stage.

To analyse the benefits from the alternative ways of using the capacity, we first examine the benefits of selling an incremental 1 MW of capacity in the day-ahead

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[44] Market rules in place in most jurisdictions tend to determine imbalance price with reference to the costs of balancing.

market. This is simply the rent in each hour as calculated as the absolute value of the day-ahead price differential between the two countries[45].

We then examine three alternative ways that this incremental MW of interconnector capacity could have been used, to assess whether it would have been more optimal to use the interconnector capacity in one of three possible ways. These are:

- First, by always reserving the interconnector capacity for use for trade in balancing services rather than for trade at the day ahead stage. In this case the rent captured would be the spread in imbalance prices (our proxy for the costs of balancing services) rather than the spread of day ahead prices.

- Second by assuming perfect foresight, and assessing whether it would be better to sell the 1 MW of incremental capacity in the day ahead market or retain the capacity to capture the spread between imbalance prices. In other words, for any hour the rent captured would always equal the maximum of the two possible rents that we have identified. The gain would be the positive difference between balancing price differential and day-ahead price differential in that given hour.

- Third, we examine the case of possibly overloading the cable. In this case, "baseline" capacity would be used in the day ahead market, thereby capturing the day ahead spread between the two markets. If there is a similar or greater spread in the same direction to be captured in the balancing market we assume that the cable is overloaded. Conversely if the spread reverses, we assume that the reversed spread is captured and the there is a reduction in the net flow across the interconnector (i.e. relative to the day ahead transaction there is a counter flow).

In relation to the third of these options – overloading – it is important to note that there may be additional costs imposed on the TSO or interconnector owner.

According to a German study[46], overloading of around 10% on 110 kV lines is feasible for 1 to 3 days without damage to the line (although overloading the line for three days instead of one requires a lower level of overloading). The results of this analysis are also valid for extra high voltage (EHV) cables and subsea cables – in spite of heat dissipation for the latter.

However, while 10% overloading may not impose additional costs on the cables, it may impose costs on the associated convertor stations. Indeed, due to their

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[45] For the purposes of simplicity, we ignore interconnector losses.

[46] H. Brakelmann, Netzverstärkungs-Trassen zur Übertragung von Windenergie: Freileitung oder Kabel, 2004.

high capital costs, AC/DC converters are designed for the maximum possible flow. Consequently, while possible, depending on the design, they may be unlikely to allow overloading. The cost of increasing the capacity of a converter, a prerequisite for overloading, would be as high as $285k per MW. Overloading may therefore require capital expenditure to be feasible. Our analysis of the potential benefits of alternative ways of using the interconnection capacity does not take capital expenditure into account.

Finally, for each interconnector we consider whether the current arrangements for the reservation and trading of interconnector capacity facilitate the required trade of balancing services on these interconnections.

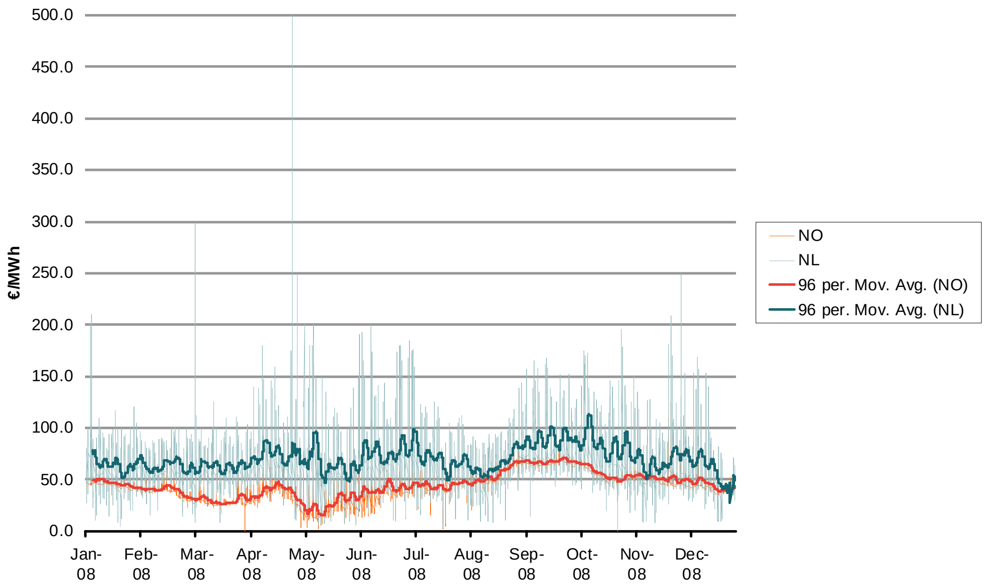
6.1 Norned

The Norway-Netherlands interconnection, Norned, was commissioned in April 2008. It has a capacity of 700 MW, and at 580km long is currently the world's longest underwater high voltage DC cable.

6.1.1 Activity on Norned

Figure 17 below shows that, although the trend in prices is similar in both markets, the day-ahead electricity prices in the Netherlands were on average €25 per MWh higher than in Norway. Day ahead electricity prices in the Netherlands were higher than Norwegian prices 88% of the time in 2008, with a maximum day-ahead price spread of greater than €450/MWh.

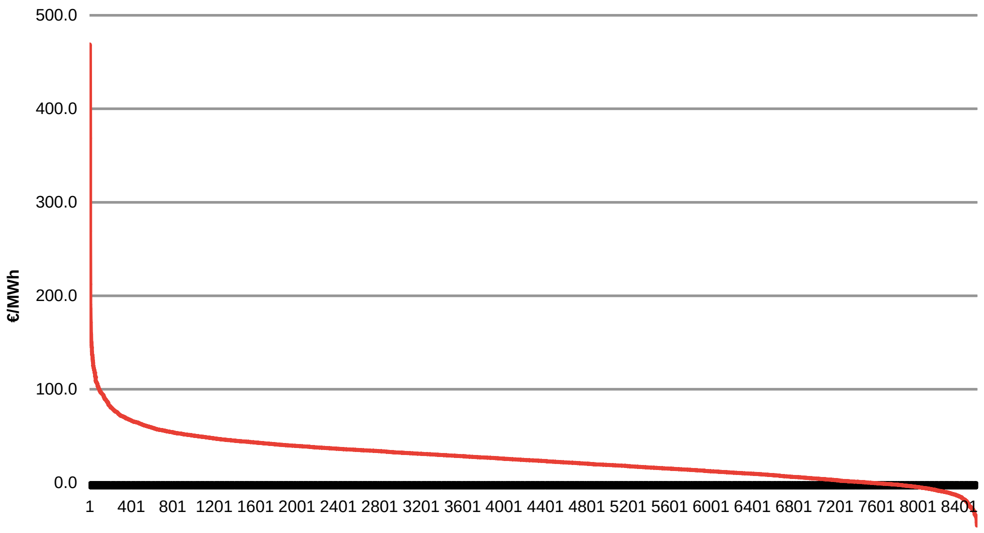
Figure 17. Norway and the Netherlands electricity day-ahead prices 2008



Source: Frontier based on Nordpool and Energate data

As Figure 17 shows it seems that the commissioning of Norned in April 2008 did not result in a reduction of the price differential despite the fact that the link between Norway and the Netherlands was at maximum capacity for 73% of the time it was operating in 2008. Subtracting the Norwegian day-ahead price from the Dutch one in each hour of 2008, and ordering the resulting price differentials from the greatest to the smallest, we obtain a day-ahead price spread duration curve between the Netherlands and Norway, presented in Figure 18.

Figure 18. Day-ahead price spread duration curve (NL-NO)



Source: Frontier based on Nordpool and Energate data

Day-ahead prices in the Netherlands are higher than in Norway 88% of the time, with an average differential of 25€/MWh.

Figure 19 below plots the relationship between price differential and interconnector flow. It demonstrates that there is a positive correlation between flows and price differentials, reflecting the rational behaviour of the market: when prices in the Netherlands were higher than prices in Norway (right hand side of the chart), the flow tends to be from Norway to the Netherlands (top of the chart), and vice versa on the (less frequent) occasions when prices were higher in Norway[47].

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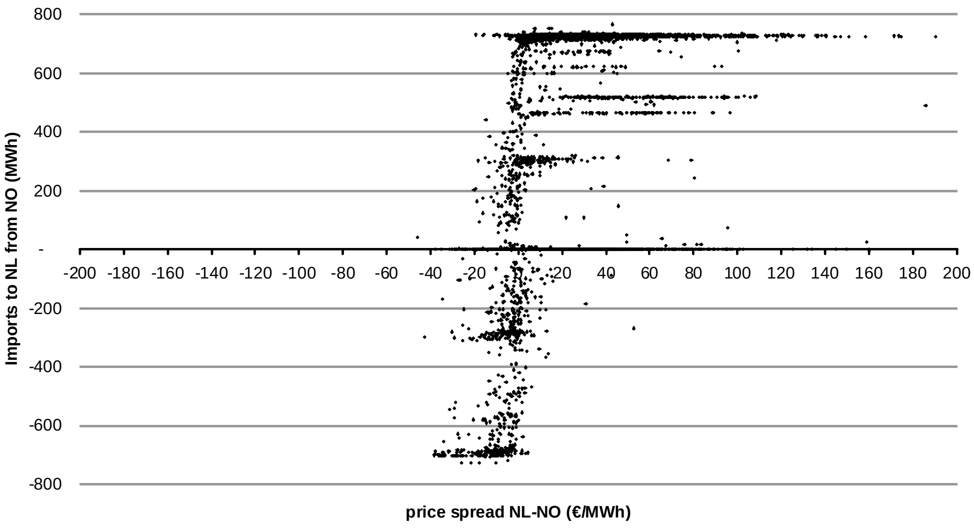
[47] We note that there are some obvious points when full flow was not apparent despite price differentials. We assume that this is due to constraints on the cable soon after commencement of operation rather than sub optimal behaviour of market players.

Figure 19. Scatter plot – flows from Norway to the Netherlands depending on day-ahead price difference (NL-NO)



Source: Frontier based on Energate and Nordpool data

To have a view on the costs of reserve provision, we have used the imbalance prices in each market as a proxy. We focused on upwards imbalance prices[48], which were similarly defined across our countries of observation. Figure 20 presents the upwards imbalance price spread duration curve between the Netherlands and Norway in 2008.

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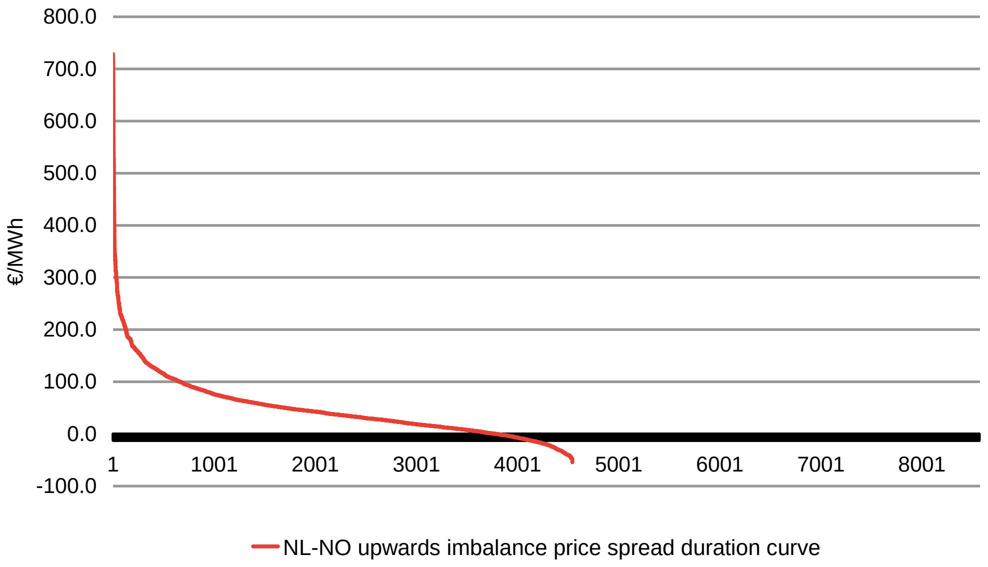
[48] As opposed to downwards imbalance prices.

Figure 20. Upwards imbalance price spread duration curve (NL-NO), 2008



Source: Frontier based on Nordpool and DTe data

Note: Less than 8760 hours of data are shown, as for a certain number of hours in 2008, either Nordpool or DTe do not provide imbalance price data

Imbalance price differences follow a similar pattern to the day-ahead price spread: imbalance prices in the Netherlands are higher than in Norway 83% of the time, with an average differential of 48€/MWh, much higher than the day-ahead price spread. Imbalance price differentials and day-ahead price differentials are of the same sign 83% of the time.

6.1.2 Alternative ways of using the capacity

Table 7 presents the benefits associated with using 1 MW of Norned capacity for each of the alternative ways previously described[49].

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[49] These are measures of the ex-post profits rather than an ex-ante assessment of the option value of reservation of capacity.

Table 7. Congestion rent from 1 MW of Norned capacity used under three alternative methods[50]

Capacity use	Estimation of the 2008 congestion rent	Comparion with day-ahead market revenue
Selling on the day-ahead market	236,085 €/MW per year	
Reserving capacity for the balancing market	225,452 €/MW per year	-11 k€/MW per year
Perfect foresight balancing/day ahead arbitrage	260,856 €/MW per year	+25 k€/MW per year
Overloading / counter flowing Norned	461,537 €/MW per year	+225 k€/MW per year[51]

Source: Frontier Economics

Table 7 shows that out of these three alternative ways of using 1 MW of the capacity of Norned, two are more profitable than selling on the day-ahead market.

6.1.3 Current arrangements

Trading on the day-ahead markets in the Netherlands and Norway using Norned is feasible. However, there is no arrangement yet between Norway and the Netherlands that would allow market players to capture the benefits of trading balancing products through Norned to exploit the value from the need to manage intermittency.

6.2 IFA

The IFA interconnection, un underwater DC link, has been in existence since 1961. Its current capacity is 2,000 MW.

6.2.1 Activity on IFA

The difference between French and British electricity day-ahead prices is much lower than that between the Dutch and Norwegian, as can be seen in Figure 21.

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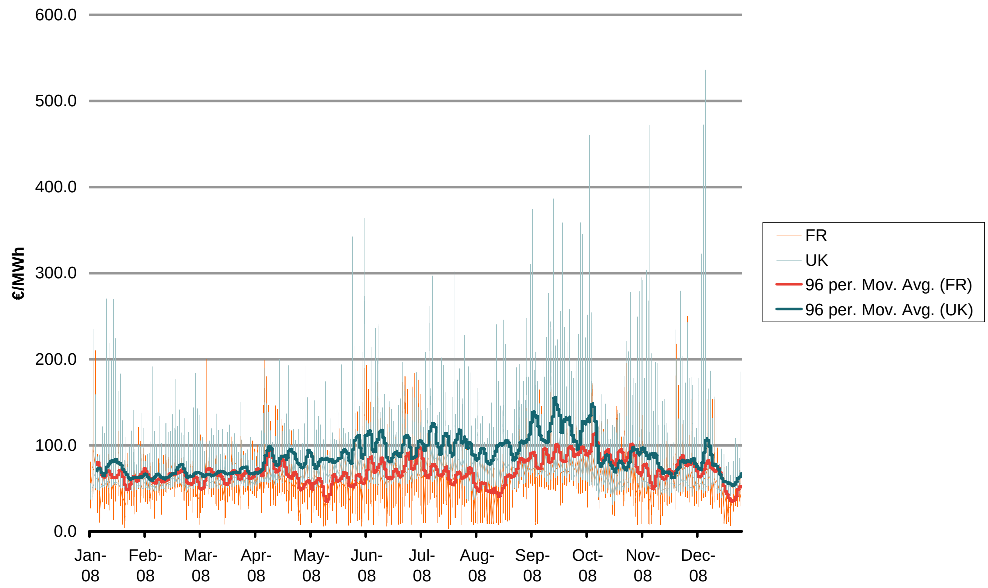
[50] Note that we have assumed that all prices remain constant

[51] This does not include the capital expenditures necessary for the AC/DC convertor station to be increased to allow overloading.

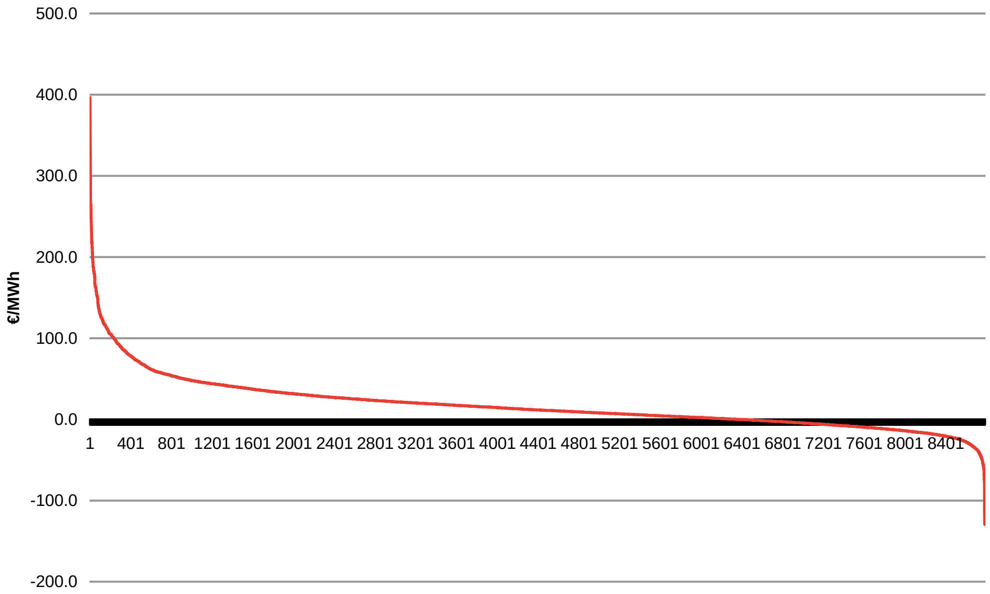
Figure 21. French and British electricity day-ahead prices 2008



Source: Powernext, Elexon

British day-ahead prices are higher than French prices 72% of the time, with an average difference of 17.6€/MWh in favour of the Britain. Figure 22 highlights this bias by ordering the 2008 hourly day-ahead price differences between Britain and France from the highest to the lowest.

Figure 22. Britain-France day-ahead price spread duration curve



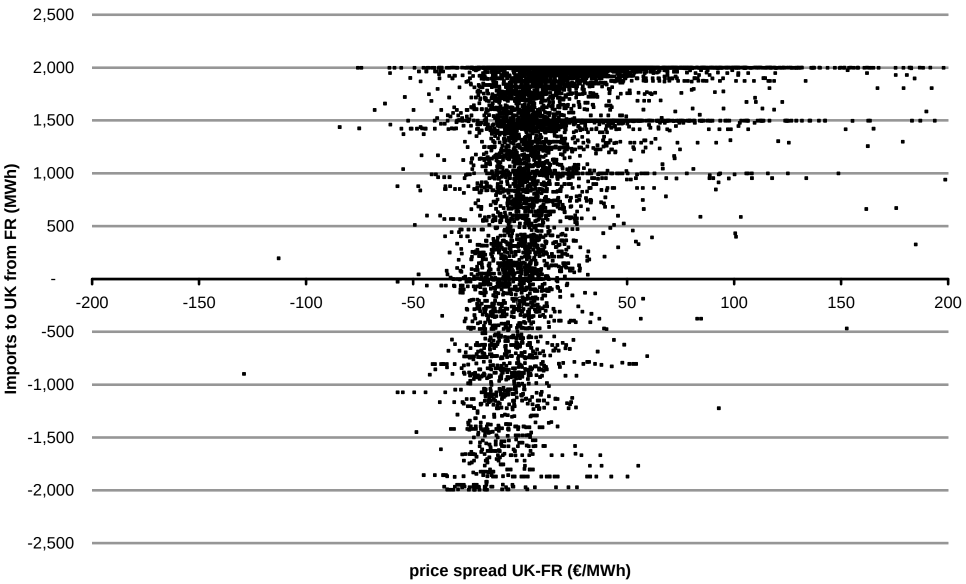
Source: Powernext, Elexon

Such a bias could explain why the IFA is used 87% of the time to export from France to Britain. Figure 23 presents the flows from France to Britain, depending on the day-ahead price difference. Theoretically, and as for the interconnection between Norway and Netherlands, a positive correlation should exist between the price differential and the direction of the flow: if prices are higher in Britain, rational sellers should be willing to sell to Britain, resulting in a flow in the direction of Britain. Surprisingly, Figure 23 does not show as strong a positive correlation as might be expected.

There are a range of possible explanations for this apparently perverse behaviour. For example:

- The market arrangements in place that govern access to the interconnector bring about suboptimal behaviours;
- The level of transaction costs might impact on use of the interconnector;
- Treatment of renewables generation in either jurisdiction might induce distortions in interconnector flows; and
- Differences in the structure of the market on either sides of the link may distort bidding and operating patterns with consequent impact on interconnector flows.

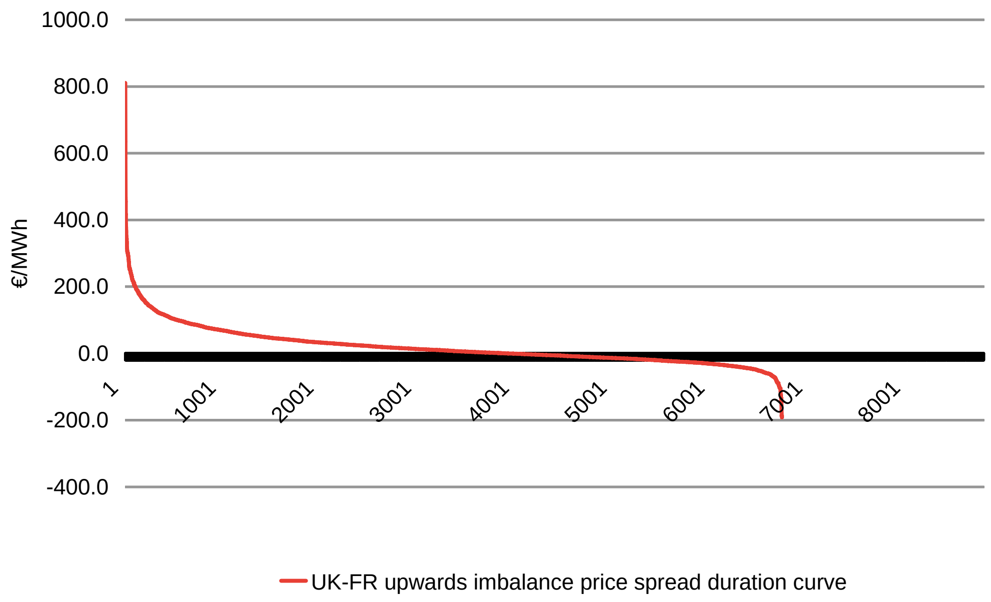
Figure 23. Scatter plot - Flows from France to Britain depending on day-ahead price difference (Britain-France)



Source: Frontier based on RTE, Powernext and Elexon

For Britain and France we again used upwards imbalance prices as a proxy for balancing prices. As illustrated in Figure 24, British imbalance prices were higher than the French imbalance prices during 58% of the year, with an average difference of 20€/MWh.

Figure 24. Upwards imbalance price spread duration curve (Britain-France), 2008



Source: Frontier based on RTE and Elexon

Note: Less than 8760 hours of data are shown, as for a certain number of hours in 2008, either RTE or Elexon do not provide imbalance price data

The imbalance price spread and the day-ahead price spread between Britain and France were of the same sign only 69% of the time.

6.2.2 Alternative ways of using capacity

Table 8 presents the additional revenues that could be derived from using 1 MW of the IFA interconnector in alternative ways[52].

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[52] These are measures of the ex-post profits rather than an ex-ante assessment of the option value of reserving

Table 8. Congestion rent from 1 MW of IFA capacity under three alternative methods[53]

Capacity use	Estimation of the 2008 congestion rent	Comparion with day-ahead market revenue
Selling on the day-ahead market	212,580 €/MW per year	
Reserving capacity for the balancing market	135,179 €/MW per year	-77 k€/MW per year
Perfect foresight balancing / day ahead arbitrage	222,857 €/MW per year	+10 k€/MW per year
Overloading / counter flowing IFA	347,760 €/MW per year	+135 k€/MW per year[54]

Source: Frontier Economics

The additional benefits of using the interconnection to exchange balancing products compared to the day-ahead market appear to be lower on IFA than on Norned. Nevertheless, two out of the three alternative ways of using the interconnector appear more profitable on the margin than arbitraging only on the day-ahead market.

6.2.3 Current arrangements

Trading through the IFA on the day-ahead market is well established. The main factors impacting the ability to trade on the intraday and balancing markets on the IFA is the timing of interconnector gate closures.

The IFA has six intraday gate closures throughout the day. This means that the IFA timeline is independent of both the timeline for the French and the British gate closures: the British system uses 48 rolling gates at t-1.0 hour every half hour; and the French electricity market has 24 gate closures at t-2 hours.

In relation to the national markets, three situations can then occur, impacting traders' behaviour on the IFA:

- neither of the French or British systems has gone through gate closure in relation to the hour considered; or

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[53] Note that we have assumed that all prices remain constant

[54] Again, this does not take into account the capital investment necessary on the convertor stations for overloading to be feasible

- one of them is closed; or
- both of them are closed.

At times when both national markets are open, the three systems (French, British and the IFA) allow intraday nomination. The unused capacity from the day ahead auction does not have Use-It-Or-Lose-It (UIOLI) conditions attached and can thus be used subsequently. Therefore, when the French market has closed but the British market remains open, the balancing mechanism is active in France, and participants from Great Britain could in theory bid into it providing they hold capacity for the interconnector.

However, the interaction of nominations and bidding process make the practicalities of this challenging: The IFA nomination arrangements require participants to provide a long notice period before changing their scheduled flows. This means that bids and offers on the French balancing market have to be accepted 3 to 4 hours in advance. Consequently, in reality such bids have little value.

Finally, when both system gates are closed, there are arrangements in place for exchanges between the system operators of Constraint Management and Balancing Power (CMBP). Backstop arrangements are also in place for emergency assistance[55].

As a result of these arrangements, beyond the French gate closure, it is only the system operators that trade over the IFA. Figure 25 presents the monthly SO-SO trades in 2008, and compares them against the spare capacity on IFA the same months. During 2008, IFA was only used at full capacity 50% of the time. Figure 25 clearly shows that SO-SO trades can be material in volume, but do not exhaust the spare capacity on IFA.

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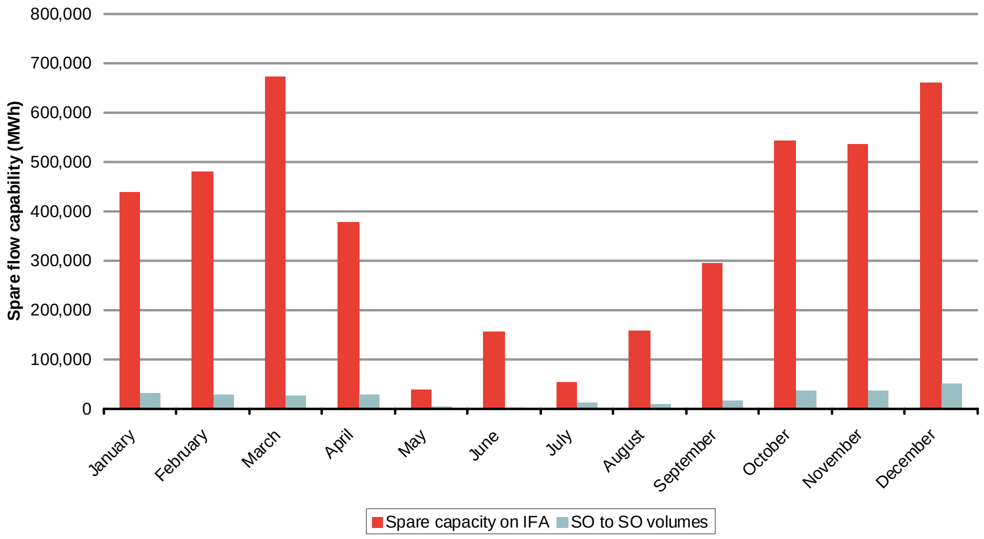
[55] However, balancing on the SO's own system is the priority and if critical conditions appear, it can withdraw its emergency assistance to the other system.

Figure 25. SO-SO trades on IFA compared to monthly spare capacity



Source: Frontier Economics based on RTE and National Grid

To understand the basis on which the system operators trade balancing, in Table 9 and Table 10 we compare:

- the bids and offers from RTE and National Grid on each other's balancing market on the different windows of a random day; and
- the actual final buy and sell balancing prices of the TSOs on their respective markets during the same day.

Table 9. Bids and offers from RTE and National Grid, 6-7 May 2009

Window	From RTE		From National Grid	
	Offer	Bid	Offer	Bid
2300-0500	72.99	0	91.51	0
0500-1000	80.42	0	225.51	25.16
1000-1300	84.46	3.72	241.22	34.73
1300-1600	69.29	0	222.55	37.94
1600-1900	72.98	0	238.09	36.52
1900-2300	76.96	0	228.59	32.28

Source: Frontier based on Elexon, RTE

Table 10. System Buy and System Sell prices in Britain and France, 6-7 May 2009

Period	SBP	SSP	SBP	SSP
2300-0500	31.92	18.88	23.31	16.35
0500-1000	36.84	23.51	37.20	26.76
1000-1300	49.83	47.46	68.15	43.85
1300-1600	46.05	39.69	36.02	25.37
1600-1900	35.60	31.74	32.82	22.94
1900-2300	38.24	27.86	41.12	30.71

Source: Frontier based on Elexon, RTE

The cell on the top left of Table 9 shows the price at which RTE was willing to sell its balancing electricity to National Grid during the first window of the day (€72.99/MWh). In the same cell in Table 10, we show the SBP for the same period, which represents the average price at which RTE actually bought the balancing power from its local generators (€31.92/MWh).

The difference between these two values implies that RTE was only ready to sell its balancing electricity to National Grid at a much higher price than it paid for it. This clearly limits potentially efficient trades. This behaviour is visible during all periods of this randomly selected day, and in both directions (i.e. the offers from National Grid shows the same characteristics).

There are clearly a number of reasons for this observed difference. Not least, that the system operators have to forecast in advance the volume and level of balancing offers which they will be provided by resources on their system and their level of "native" demand for such resources, before offering power to the other operator. Equally, there may be locational issues within national systems which limit the scope of efficient trades – the system buy and system sell prices shown above are national prices. Nevertheless, it may be that the system operators are not exploiting the full scope for balancing exchanges.

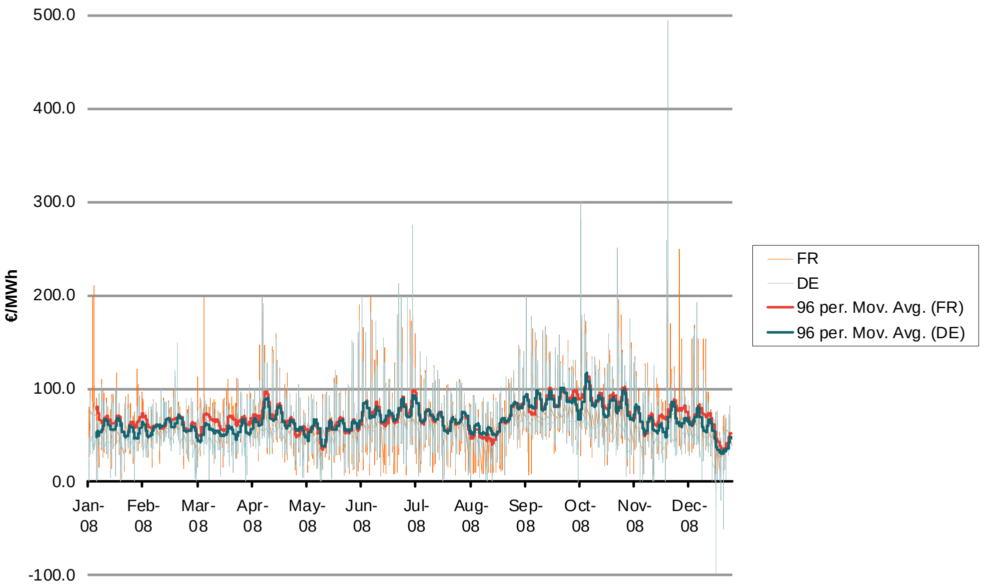
6.3 French-German interconnection

The French-German interconnection, a series of AC links, has a capacity of 4,500 MW from Germany to France and 2,400 MW from France to Germany.

6.3.1 Current activity

Unsurprisingly, French and German electricity prices are closely related, as illustrated in Figure 26. The day-ahead prices in France are higher than the German prices 62% of the time, and the average spread is only of 3.3 €/MWh. German prices exceeded French prices by up to 300 €/MWh during 2008, while French prices exceeded German ones by up to 150 €/MWh.

Figure 26. France and Germany electricity day-ahead prices 2008

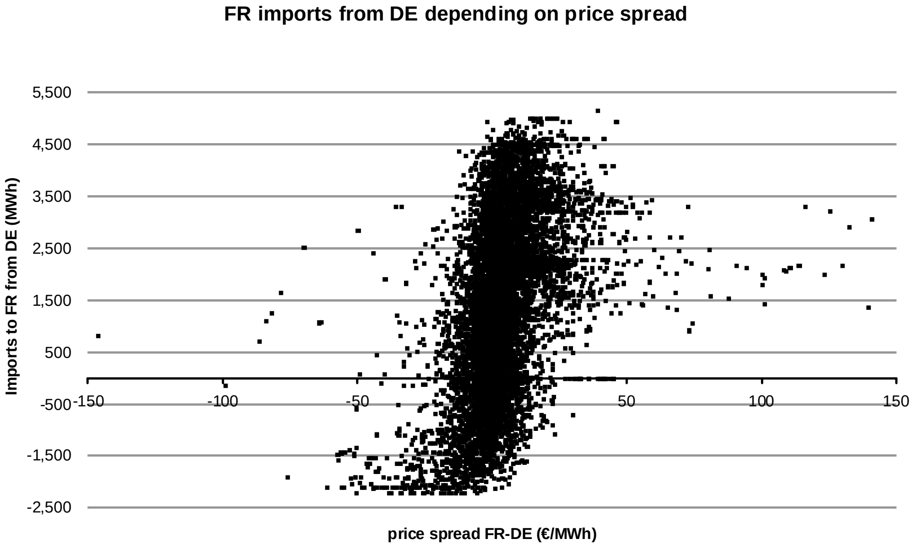


Source: Frontier based on Powernext and Energate data

The French-German interconnection was full during only 5% of 2008. The nominations of traders exhibits relatively rational behaviour, as shown in Figure 27: when prices are higher in Germany (left part of the chart), exports tend to go from France to Germany (lower part of the chart), and vice versa.

We note that with an AC interconnection there may be a difference between the physical inflows/outflows and the contractual transfers as a result of factors such as loop flow across the synchronous system.

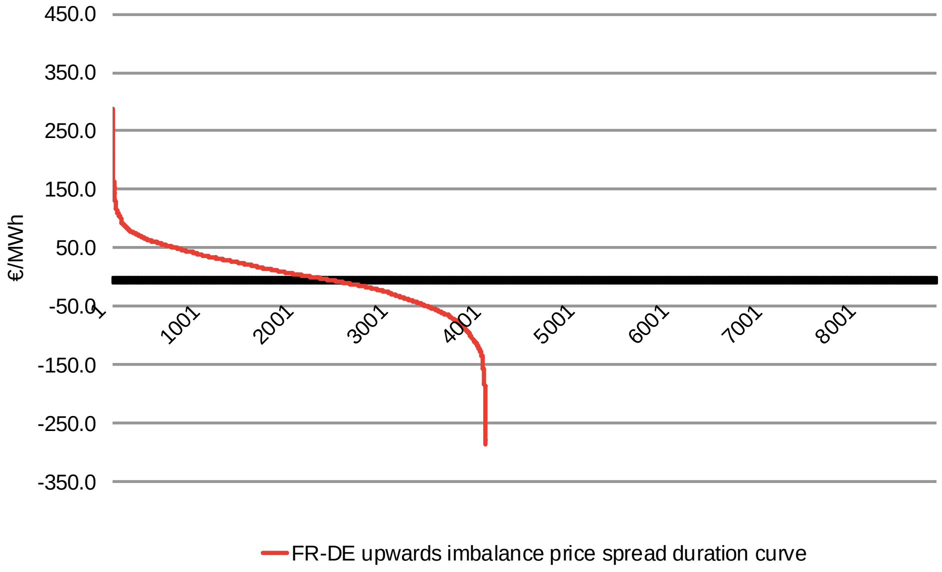
Figure 27. Scatter plot - flows from Germany to France depending on day-ahead price difference (France-Germany)



Source: Frontier based on RTE, Energate and Powernext data

In Figure 28 we present the imbalance spread duration curve between the two markets.

Figure 28. Upwards imbalance price spread duration curve (France-Germany), 2008



Source: Frontier based on RTE and RWE data

Note: Less than 8760 hours of data are shown, as for a certain number of hours in 2008, either RTE or RWE do not provide imbalance price data

The French-German case differs from our two other case studies in that the upwards imbalance price spread is actually lower than the day-ahead price spread. French upwards imbalance prices are higher than German ones during only 54% of the time, and the difference is only 1.3 €/MWh.

Given that the available imbalance price spread data at this border covers less than half of the year 2008, we have not computed the benefits of the alternative ways of using 1 MW of the interconnection capacity as we did for the two other case studies.

6.3.2 Current arrangements

Day-ahead trading is well established on the French-German border. The trading opportunities on the intraday and balancing markets depend in part (as for IFA) on gate closures. However, in the German system, the latest opportunity for participation in the tertiary reserve market is before even the day ahead market (the market for tertiary reserve currently closes at 10.00 on the day-ahead). This is clearly long before the French gate closure (and also significantly in advance of gate closure on the German system). Participation in this mechanism can therefore be considered separately.

While there is nothing commercially preventing French operators participating in the provision of tertiary reserve[56], none do so. It is true that tertiary reserve contracts are only rarely called upon in Germany, but prices for procured but not utilised tertiary reserve are high, so participation would make sense from an economic point of view.

One of the reasons that French operators do not participate in the German balancing market could be that 100% availability of resources over the contract period is required by the German TSO for the provision of these balancing services. For a French operator, this means 100% availability of the required interconnection capacity, which may be difficult for them to guarantee (e.g. this is not within their control).

Returning to the situation after the day ahead market, there are three further situations to consider:

- In the case when no gate is closed, intraday markets are operational both in France and in Germany. Intraday capacity arrangements are in place for daily capacity, even if they are different in both directions. Usage of these arrangements is yet relatively low, with 85 MW used out of 1,857 MW available for intraday utilisation in the France to Germany direction, and 88 MW out of 2,955 MW available in the other direction[57].

- In the case when the French gate is closed, German operators participate in the French balancing mechanism. German and Swiss operators were the only active foreign players on that market in 2007. Table 11 illustrates the amount of capacity exchanged through this process and compares it with the interconnection capacity.

- Finally, when both gates are closed, there is currently no SO to SO trading arrangement is in place.

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[56] Due to the automatic provision of secondary reserve, it is impossible for French operators to compete on that market.

[57] CRE 2008 report on the management and utilisation of French electricity interconnections (« gestion et l'utilisation des interconnexions électriques françaises »).

Table 11. Participation of German operators in the French balancing mechanism

Direction	2008	% of available capacity	2007	% of available capacity
Upward	13 MW	4%	12 MW	4%
Downward	30 MW	6%	9 MW	2.5%

Source: CRE

The French-German interconnector arrangements therefore offer more opportunities for shorter term trading than NorNed, but potentially fewer opportunities, at least for very short term trading, than on the IFA.

6.4 Summary

These three interconnections case studies highlight the variety of situations and agreements in Europe. Several barriers currently block the development of the cross-border provision of balancing services. These include:

- Inconsistencies between the timing of gate closure in each of the markets and other features of the market arrangements which make trading across interconnectors near real time difficult;
- TSOs may not be sufficiently incentivised to seek to procure large quantities of reserve outside of their own footprint; even if, on the face of it, such services appear cheaper;
- This is all the more likely if TSOs perceive that they might not be able to place sufficient reliance on reserve that is sourced outside of their own jurisdiction.

We have also demonstrated that monetary benefits can be derived from using a share of the interconnector's capacity for these uses.

7 Conclusions

There is expected to be a large increase in non-hydro renewables generation by 2020 (+75%), mostly driven by investments in wind capacity which represent 75% to 80% of the total non-hydro renewables capacity increase. The additional wind generation capacity in Western Europe by 2020 is estimated at approximately 94 GW under this one scenario.

Wind is intermittent and unpredictable and the addition of intermittent capacity could dramatically change European electricity markets. Growth in intermittent and unpredictable generation as a proportion of the total generation capacity on the system clearly means that at the close of the day ahead market there will, relative to now, be greater uncertainty as to the likely levels of generation in forthcoming time periods. The role of intraday markets and balancing services in managing this intermittency will therefore be crucial.

To have an idea of the extent of the change, we assessed the scale of intermittency and unpredictability of wind generation by analysing case studies in Britain and Germany. For Britain, we evaluated the accuracy of wind forecasts from individual wind farms, at different points in time prior to the actual time of production. We drew three conclusions:

- wind forecast accuracy does not dramatically improve between 37 hours ahead of the actual production and 13 hours ahead;
- wind forecasts are much closer to metered output when made one hour ahead of production; but nevertheless
- wind forecast error remains very large even one hour ahead of generation.

Considering these individual wind farms as a portfolio partially mitigates the scale of errors in wind forecasts. Despite this portfolio effect, the aggregated forecast error one hour ahead remains high. 5% of the time the error is greater than half of the average aggregated production. The results from German research are consistent with these findings.

Currently, even with the existing generation portfolios in Europe, there is a need to update planned physical generation after the day ahead market in light of fluctuations in expected generation and expected demand that arise as information as to the likely outturn of each is updated. Intraday markets and system operator actions are the two main ways in which change might occur.

Intraday markets allow participants to refine their position after the day-ahead market is closed but before real time. There are already numerous examples of intraday traded markets in Europe, for example, Elbas in the Scandinavian region and more recently Germany, and EEX in Germany. However, liquidity in these intra day markets is relatively low. This, in part, is a function of low demand for intra-day trading. Many market participants are clearly content with not trading out of unexpected imbalances, do not need to trade because generator output from thermal plant is relatively certain, or balance within their own portfolio. Also, intraday trading across borders is still in its infancy and arrangements tend to vary significantly across countries. Measures that can improve trading in intra-day markets will clearly be helpful in managing fluctuations in forecasts of expected output as the delivery period approaches.

Even at the hour ahead stage (which is the gate closure period in many European power markets) there is likely to be significant uncertainty regarding the output of wind generation over the next delivery hour. This means that trading on the intraday market is not sufficient to counterbalance the effects of wind intermittency. System operator actions will therefore be necessary since they are the only mechanism for managing imbalances when all participant-to-participant trading is closed. The system operator maintains the overall supply-demand balance, using balancing services, i.e. agreements with certain generators that can quickly provide output or withdraw output from the system at the SO's demand. Three types of balancing services can be provided:

- primary reserve, which is generally used to manage perturbations in the system such as frequency fluctuations;
- secondary reserve, which is also used to manage system frequency and is activated automatically; and
- tertiary reserve, which is manually activated and used to manage longer term perturbations.

Tertiary reserve is the most suitable for the provision of services to balance wind intermittency.

Historically, tertiary reserves have been provided either by part loaded thermal plant, hydro plant or, in some cases, large demand side customers changing their consumption of electricity as requested. Given the increased requirements for increased volumes of plant that can quickly change output levels, we analysed whether these existing technologies are likely to continue to be the main providers of the flexibility required to manage intermittency of wind generation or whether new technologies might progress sufficiently to fill this role.

Several storage technologies have the technical characteristics necessary to compete with generation technologies and demand management for the provision of balancing services:

  - mechanical storage technologies include mature technologies such as pumped hydro storage and compressed air storage, although new CAES applications have recently been developed;

- electrochemical storage technologies such as batteries (conventional and flow cells) and hydrogen fuel cells – this is a major area of development for transport and stationary applications; and
- electromagnetic storage technologies such as super capacitors and superconducting magnetic energy storage – however, the latter are more adapted to the provision of primary reserve than tertiary reserve.

From an analysis of the different costs of alternative technologies and their potential energy market revenue streams, we assessed the likely range of costs to provide reserve in the future. We concluded that traditional thermal generation technologies (OCGT and part-load thermal plants) or the repowering or refurbishment of existing hydro plants are likely to remain the most effective ways of providing additional balancing services before 2020. Of these traditional technologies, refurbished or repowered hydro plant appear to be the most economic given our assumptions, though it is clearly also the most constrained locationally.

Using a method applied by some European TSOs, we estimated that the likely volume of tertiary reserve required to manage the increase in generation intermittency resulting from an additional 94 GW of wind generation in Western Europe is in the range of 22 GW (for downwards reserve) to 27 GW (for upwards reserve).

The cost of this additional reserve requirement can be evaluated using current prices for reserve. Using case studies of current markets in Germany and Great Britain, we estimated the cost of providing the additional reserve requirement (capacity and utilisation) to be in the range of €2.5 billion to €3 billion. This would represent about 20% of the capital cost of the additional wind generation.

It seems likely therefore that the drive to increase the prevalence of renewables generation is likely to be accompanied by a drive to reduce the costs of the reserve to manage the greater volume of intermittency. Given the potential for refurbished or repowered hydro plants to provide balancing services, one obvious way in which this might be achieved is through an increase in the use of interconnection to provide balancing services.

We analysed the potential value from and current barriers to, the trade of system services across interconnections. To do so, we examined the market behaviour and current rules in place for trading across three interconnectors, namely:

- Norned (Norway-Netherlands, 700 MW);
- IFA (France-Great Britain, 2000 MW); and
- French-German border (2400 to 4500 MW).

Using historical data on day-ahead and imbalance price[58] differentials across the interconnectors we evaluated the profitability of using some of the capacity on the interconnectors for day-ahead trading in the energy market or for trade in balancing services. We note that for a range of reasons this approach only provides a rough estimate of the potential benefits.

We considered the revenue earned from using an incremental 1 MW of capacity in the day-ahead market compared to that of three alternative ways of using the incremental MW of interconnector capacity. These are:

- first, by always reserving the interconnector capacity for use for trade in balancing services rather that for trade at the day ahead stage;
- second, by assuming perfect foresight, and assessing on an hourly basis whether it would have been better to sell the 1 MW of incremental capacity in the day ahead market or reserve it to capture the spread between imbalance prices; and
- third, by examining the case of possibly overloading the cable.

We found that, based on our rough metrics, the second and third alternatives are more profitable than reserving capacity for use in the day ahead energy market.

In spite of the potential benefits that could be derived from using interconnector capacity to trade balancing services, there appears to be significant scope to optimise the current arrangements for cross-border provision of balancing services. There is no arrangement in place that would allow the market to capture the benefits of trading balancing products on Norned. On IFA and on the French-German interconnection, arrangements for trade on the intraday and balancing markets are more developed. However, in both cases there remain constraints to efficient trade.

Particularly in combination with the development of refurbished hydro generation capacity, using interconnections for the provision of balancing services would mitigate the impact of increased intermittency in generation and create additional value. A necessary condition however for the use of interconnection to this purpose is the development of efficient cross-border trading arrangements across time periods. This should therefore be an important area of regulatory focus in Europe over the coming years.

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[58] In this context we are assuming that the imbalance price is a proxy for the costs of reserve in each of the system

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