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The economic case for developing HVDC-based networks to maximise renewable energy utilisation across Europe: an advanced stochastic approach to determining the costs and benefits

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SUMMARY

This paper is concerned with the rationale for development of significantly enhanced transmission capacity on a continent scale, in this case in Europe. With a particular emphasis on the accommodation of wind power in the North Sea, it describes an assessment of the extent to which lack of transmission capacity at a European level will act as a constraint to realising Europe-wide targets for electricity from renewable sources in 2020. A plausible generation and demand scenario has been postulated and inter-area power flows studied in a number of network cases for the whole of Europe. The network cases are intended to provide insights into the drivers for different levels of transmission expansion and the different network configurations by which increased transfer capability might be delivered offshore. The analytical methods used take account of realistic time series of available generation including wind and hydro, model spatial correlations of wind and hydro power, minimum stable generation and on and off times, and regionally differentiated reserve requirements. Most particularly, by means of Monte Carlo simulation, the variability of power deficits and surpluses at different locations and flows between locations can be assessed. The analysis is achieved through use of the ANTARES tool developed by RTE. The main metrics used to compare the different scenarios are annual energy production from different types of generator, emissions of carbon dioxide, the total energy from renewables, and the volume of 'spilled' wind energy. The results suggest that new offshore network capacity to allow increased exchange of power between different countries will be important to realising the full potential of new wind power developments. This new network capacity not only allows local surpluses of wind power to be used elsewhere but also facilitates reserve power to be held remote from a particular area and so minimise the total holding of reserve and increase the utilisation of renewable energy. However, it has two further effects: depending on the exact location, it can permit onshore network constraints to be bypassed and, as is shown, it can allow cheap high carbon generation in remote areas to be used instead of lower carbon fossil fuelled plant in a local area. It may thus be concluded that not only are support for investment in very low carbon generation capacity such as wind and development of the transmission network important for reduction of carbon emissions associated with use of electricity, but so too is effective pricing of carbon emissions.

KEYWORDS: Transmission network planning; offshore grids; renewable energy.

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1 INTRODUCTION

Within Work Package 5 (WP5) of the European Union (EU) funded TWENTIES project [1], the authors have undertaken a study of the potential costs and benefits of investing in high voltage direct current (HVDC) networks in order to facilitate the utilisation of the renewable energy resources available in Europe, notably offshore wind in the North Sea and hydro power in Scandinavia.

Wind generation remains among the most cost-effective renewable sources of electricity but its successful development depends not only high average wind speeds but also effectively navigating planning procedures. In China and the US, for example, this leads to wind generation being developed in areas that are quite remote from the main demand centres [2][3]. The ensuing need for investment in additional transmission capacity is found also in Europe where the special representative of the European Commission responsible for power networks has pointed towards the importance of the power network in unlocking access to Europe's most promising renewable resources [4] to help the target of 20% of energy coming from renewables by 2020 [5], including offshore wind for which estimates of the amount of capacity that will be built range from 40GW in 2020 to 150GW in 2030 [6]. The additional network capacity to facilitate access to offshore wind resources will be particularly expensive and, as the penetration of renewable generation increases, the risk associated with intermittency also increases and may require a commensurate growth in the amount of spinning or standing reserve generation to be made available. However, enhancements of transmission capacity to allow export of power from areas with significant renewables can also contribute to security of supply by facilitating imports under calm conditions and allowing reserve to be shared over larger areas and exploiting diversity in the availability of power from different sources [7][8]. Moreover, as the transmission capacity required to connect ever larger offshore wind farms to shore increases and the connection distances lengthen substantially, it is likely that HVDC will replace high voltage alternating current (HVAC) as the principal means of connection and this offers the possibility of significant contributions to enhancement of grid stability by means of supplementary controls on voltage source converters (VSC) [9]. The need to minimise the capital cost of transmission, improve network branch utilisation and optimise network capacity in light of the diversity of outputs from different, spatially dispersed sources and the possibilities opened up by VSC have led to significant interest in multi-terminal HVDC networks [9]-[11]. Furthermore, given suitable control paradigms, groups of offshore wind farms might be used within areas of a meshed network as a 'virtual power plant'[2] (VPP) to offer ancillary services, gain additional sources of revenue for wind farms thus improving the overall economics of their development and reducing dependency on part-loaded fossil-fuelled plant. However, significant challenges exist in coordinating control of the various converters and managing interactions between protection schemes. These aspects are being investigated in other parts of TWENTIES WP5 which aims to prove such network elements as HVDC circuit breakers [12].

This paper concentrates on exposition of the rationale for development and utilisation of renewables on a coordinated, continent-wide basis and the necessity for expansion of transmission capacity, particularly offshore. While other studies have sought to quantify the economic benefits of such investment in Europe, e.g. [7][8][11] , it remains challenging to take account of all the influencing factors. For example, credible models of available power that take account of both spatial and temporal correlations have only recently been developed and these have not always been available to investigators at the same time as reasonable representations of hydro power and the way it might best be utilised. Meanwhile, the results of some studies have been based on relatively few different sets of operational conditions. In addition, early studies provided relatively little insight into the potential for meshed HVDC networks to complement the existing HVAC networks or did not seek to detail what the relative costs and benefits of such network developments might be. The study reported here aims to address a number of these issues and to provide some specific insights into the benefits of coordinated development of offshore HVDC networks in which particular branches can fulfil the functions both of bringing wind power back to shore and interconnecting different market regions.

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[2] By 'virtual power plant' is meant a collection of generation assets that are used together in a coordinated manner to act as a single power plant offering a variety of power generation services.

The study is not intended to be a full net present value analysis of the costs and benefits associated with constructing offshore wind farms and connecting them into the existing network. Consequently, the costs of constructing the wind farms or the revenues that might accrue to the operators of those wind farms or to the transmission network operators are not quantified. Instead, the interest of the study is to understand the benefits in terms of reduced fossil fuel generation and improved system performance that could be realised by connecting the currently proposed offshore wind generation into the existing system in different ways. Different network configurations will not only affect the extent to which the wind energy produced can be utilised without 'spillage' or curtailment but also where the energy is used and the impact it will have on the generation mix. Consequently, for each network configuration the total energy produced from each generation type is recorded together with the amount of spilled energy, energy not served and CO_2 emitted.

In the remainder of this paper, the characteristics of the modelling approach will be described and the initial findings presented together with some conclusions which may be drawn from the analyses. The paper will also describe a number of future areas for research.

2 MODELLING APPROACH

2.1 Generation and demand

Key to understanding the drivers for development of new interconnection capacity in Northern Europe and the benefits of coordinated development of one or more offshore grids is adequate modelling of the demand for electricity and how this interacts with the availability of generation and their respective relative costs of operation to determine what sources of electric power are dispatched. It has always been the case not only that demand at a particular time is somewhat uncertain (affected in the short-term largely by variations in weather) but also available generation. While particular thermal generating units might be out of service due to maintenance or forced outages, the availability of wind power is particularly uncertain due to variability of wind speeds. In turn, prudent utilisation of available hydro resources would take account of these uncertainties within the constraints imposed by water storage capacity, expected in-flows and maximum power output. However, a further constraint is imposed on the dispatch of generation to meet demand across a large area by the capacity of the network to transfer power within it. If the benefits of increased network capacity are to be fully understood, all these effects should be modelled.

The study reported here has used the ANTARES analysis tool [13][14] developed by the French system operator, RTE, which has also been used in production of the European 'Ten Year Network Development Plan' (TYNDP) on behalf of ENTSO-E, the European Network of Transmission System Operators of Electricity [15]. ANTARES makes use of detailed hourly wind speed, loads and key generator parameters such as capacity, forced outage rates and operating cost. However, in order that credible hourly time series of dispatches can be produced, it also makes use of generator minimum on and off times as well as main hydro characteristics such as typical monthly inflows within a unit commitment process based on heuristics and defined operating reserve requirements. The latter are defined at the level of an "ANTARES macro-node", the size of which may vary from a single substation to a whole country.

A particular feature of ANTARES, described in [16], is its capability to model multivariate stochastic processes such as wind speeds across a wide area. Although it is possible to input a set of locationally differentiated wind power time-series and use these deterministically, a built-in statistical analysis function, based on characterisation using various distributions (Beta for wind power, Weibull for wind speed), allows the underlying characteristics of a set of input data to be derived and a large number of randomly generated time series to be sampled from them. When the generated time-series are wind speeds, they are converted to wind power using given speed to power curves.

2.2 Network representation

One of the objectives in this study has been to understand the variability of power imbalances in different locations within a coherent representation of dispatches of power that takes into account inter-temporal constraints. This requires the simulation of a large number of years of operation in a

Monte Carlo approach, typically thousands of them if a loss of load probability is to be estimated with any degree of confidence. However, the priority here has been metrics of predominant system behaviour such as the total energy produced by different classes of generation and carbon emissions which, in a typical study, can be estimated with around 100 trials. Even so, to include a very detailed network model in such a simulation would be extremely computationally intensive. Moreover, in a study of future power balances and main flows between regions 10 or more years into the future there are so many uncertainties, not only in respect of the installed generation capacities and level of demand but particularly in respect of changes to detailed network parameters, that it makes little sense to dedicate the huge effort required to articulate those network changes that may be expected to have occurred in the interim at anything other than an approximate inter-area 'net transfer capability' (NTC) level. (To model much greater detail at the network level – at the very least, individual branches, positive phase sequence impedances and ratings – without due to regard to the uncertainties in background conditions in respect of generation capacity, operating costs and demand would give results that were more precise but more precisely wrong). Even then, with roughly 1200 different power stations or wind farms and 56 regions or putative offshore hub locations represented as single nodes with interconnections between them based on NTCs, a sequential simulation of each hour of operation in 100 different years takes about an hour on a typical office PC and yields a considerable amount of information that needs to be analysed.

As a consequence of the above, the approach taken has been to represent the European power system as a number of nodes each of which represents a single country having demand and generation capacity made up of individual generating units of different types. The operation of generation is modelled on a stochastic basis with a 1 hour time step. With network branches between nodes representing actual or proposed power flow paths, different study cases can be straightforwardly set up with different sets of NTCs on the various branches.

3 CASE STUDIES

A number of different cases have been modelled in order to explore the rationale for development of, in particular, offshore network capacity and quantified in terms of:

- annual CO_2 emissions;
- the annual energy production of different types of thermal generation;
- 'spilled energy', i.e. available low carbon energy that could not be utilised;
- unsupplied energy.

The primary driver – of reduction in carbon emissions – should clearly be articulated but this will be dependent on precisely which generation resources would be used under different circumstances. In addition, to meet the demand for electricity remains the fundamental requirement of power systems and quantification of the 'spill' or curtailment of renewable energy will be important in determining limits to their utilisation. Moreover, depending on the nature of trading arrangements and renewables incentives, restriction of output from wind farms can be very costly, e.g. in Great Britain (GB) in 2011 where, on occasion, the system has had to take balancing actions costing in excess of £500/MWh to reduce outputs at particular wind farms[17], and does little to increase public support for wind power.

The cases studied concern both different generation and demand scenarios and different levels of NTC between different regions. They are summarised below.

3.1 Generation capacity and demand scenarios

While the study has seen a number of different 2020 and 2030 scenarios developed for potential generation capacity and load across the European Economic Area (EEA), the results reported here concern only the central case for 2020 and one variant on it. Although described in terms of that year, the scenario, summarised in Table A.1 in the Appendix below, should not be regarded as a forecast of what will be developed by then. Rather, it is intended to provide a reasonable basis for assessment of what levels of power transfer across Europe might be necessary to enable the 2020 targets broadly to be met with further increases in renewable energy thereafter, and what benefits might accrue from development of new offshore network capacity, delivered in different structures.

The scenarios used in TWENTIES WP5 have been based on a number of other published scenarios such as those produced by Eurelectric [18] and the European Wind Energy Association (EWEA) [19] based on the European country 'Renewable Energy Action Plans' (REAPS) [20]. These all differ slightly from each other; from these starting points, the scenarios here have adopted the following conventions:

- no expansion of total fossil fuelled thermal generation capacity – implicit in this is that thermal plant which reaches the end of its economic life will be replaced by equivalent plant;
- nuclear closures are assumed to take place according to figures published by the World Nuclear Association [21] including the programme of nuclear generation closures in Germany which will see all nuclear plants there shut by 2022;
- aside from that already under construction in 2011, no new nuclear generation is assumed to be built by 2020;
- levels of additional wind generation are postulated which would permit achievement of targets for total renewable energy production, broadly based around EWEA statistics;
- solar to be consistent with projections from the European Photovoltaic Industry Association [22];
- the combined total of renewable resources and annual demand being broadly sufficient to meet the 2020 renewable energy target given an assumed capacity factor for onshore wind of 25%, for offshore wind of 35%, for hydro of 50% and solar of 15%, which in the scenario would give an overall renewables production of around 1300TWh[3].

The variant on the scenario detailed in Table A.1 is one in which no new offshore wind capacity is connected, i.e. the total for offshore wind is 2.5GW.

3.2 Determination of generation dispatch

In this study, historic hourly wind power time series, scaled up to future capacities, have been used for countries in which there is already a significant history of wind power performance and data accessible to the investigators, i.e. Germany, Spain, Italy, Portugal, Denmark (East and West), Austria, Switzerland, France, Belgium and the Netherlands. For other countries, wind power time series have been synthesised using statistical representations of wind based on 5 years of hourly 'backcast' data from Meteo France on a 50km grid and the same speed to power curves as used in TradeWind [23].

Within ANTARES, generation is dispatched on the following basis.

(a) For every day of each month, the monthly available hydro energy is broken into daily blocks, proportionally to the daily demand elevated at the power α, where α is an operational parameter heuristically fitted for every area of the system. For instance, if the value of α is very high then week-ends are allotted considerably less hydro energy than week-days.

(b) For every week of the year, an economic optimization is carried out with a time step of one hour, in which the overall generation cost (sum of 168 hourly values) is minimized while respecting minimum and maximum limits on the power output of each plant, as well as the interconnection capacity limits.

The costs used in determining the economic dispatch are set up to define a typical 'merit order' in respect of generating plant of different types in which, for example, subject to generator availability and network and the unit commitment constraints, wind and nuclear power are preferred to cheap lignite generation which, in turn, is preferred to coal and combined cycle gas turbines. That is, in view of the uncertainties of actual present day and future costs, the relative costs are regarded as being most important in determining the dispatch. Moreover, in understanding the scope for enhanced network capacity to facilitate the meeting of European renewables targets, a coordinated, Europe-wide dispatch was assumed. Based on costs given in [24], the merit order and the weighting given to different adjustments was determined based on the following costs: nuclear, €7/MWh; lignite, €15/MWh; coal, €27/MWh; CCGT €40/MWh; and oil €121/MWh. In addition, unsupplied energy was costed at

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[3] The National REAPS [20] suggest approximately 34% of all electricity demand must come from renewables if the 20% target for energy overall is to be met.

€25000/MWh, spilled energy at €100/MWh (reflecting a typical minimum bid price quoted by wind in the GB balancing mechanism [17]) and CO_2 at €21/tonne [25]. However, a sensitivity case for the merit order was also assessed in which CCGT is preferred to coal and lignite.

Further details on the dispatch of generation in ANTARES can be found in [13].

3.3 Network capacity cases

In respect of each of the generation/demand scenarios, a number of different network capacity cases were studied based on a common underlying structure described in section 2.2 above. This structure is shown in Figure 1. The different network cases addressed variations in three main respects with different levels of net transfer capacity (NTC):

1. the NTCs onshore within the three main regions of analysis: the continent of Europe, Scandinavia and the British Isles;
2. the NTCs between the three regions, i.e. offshore, and the broad configuration in which the offshore NTCs are delivered;
3. the way of connecting new offshore wind farms.

The latter two respects are interrelated in that one option for connection of a single offshore wind farm or a group of them whose outputs are collected together at a single hub is via a radial link back to a single shore, usually within the same territory as that from which the wind farm development originated. However, another is via some form of offshore grid, e.g. in the form of an 'H', offering two or more onshore entry points. As noted in section 1, it is reasonable to assume that the majority of the newer locations of offshore wind farms will be further out from shore than those that have been developed to date and will thus make use of HVDC voltage source converter technology; this, in turn, opens the possibility of DC grids and a choice of how much power to direct to which terminal. Moreover, onshore terminals may be within the same AC synchronous area or different ones. In the former case, there exists the possibility of using the offshore grid to transfer power from one part of the AC system to another and to bypass onshore constraints; in the latter, the DC grid may provide interconnection capacity between different AC systems. An example of a possible H-grid structure that has been modelled in this study is shown in Figure 2.

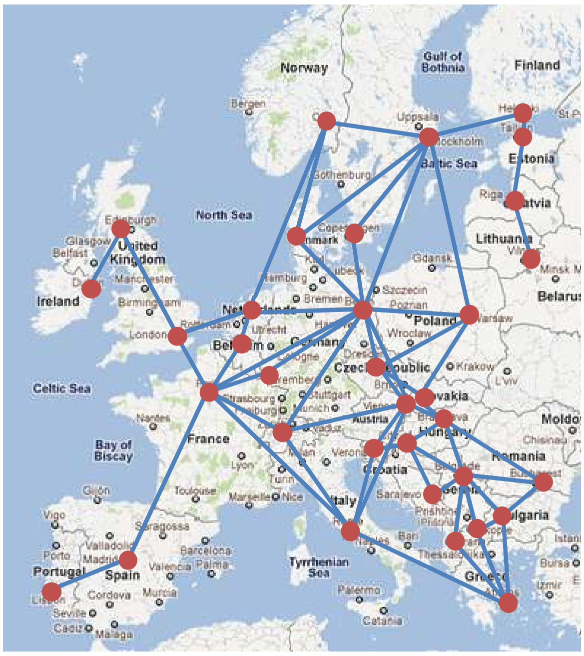

Figure 1: initial network structure

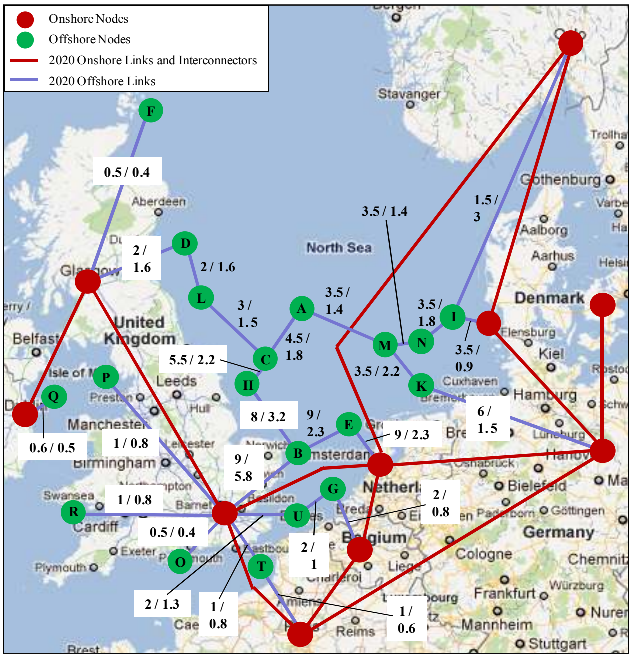

Figure 2: detail of the North Seas region showing offshore H-Grid

Instead of an H-grid, interconnection capacity may be provided by more conventional 'point-to-point' means with offshore wind farms connected radially. In the study, these are assumed to also be provided by HVDC (which need not be VSC) and the routes considered have been: Belgium – GB South; Germany – Norway; and Norway – GB North. In addition, the proposed 'embedded' HVDC link between GB North and GB South has been modelled.

It should be recalled that testing of the impact of changes to NTCs depends on running at least 100 'Monte Carlo-years' within ANTARES, which typically takes around an hour. Hence, the intention in studying a number of different levels of NTC, which includes the default case of present day NTCs as documented by ENTSO-E [26], was not to guarantee an optimal solution but rather to give a reasonable indication of what might be achieved within each structure in respect of the facilitation of low carbon generation. Nonetheless, some attempt at an outline cost-benefit analysis has been made.

4 RESULTS AND DISCUSSION

The main results for the particular background of installed generation capacity studied (section 3.1) and the default merit order are summarised in Table 1 in terms of annual energy production, spilled energy and CO_2 emissions. These are the expected values averaged over 100 'Monte Carlo years' simulated in ANTARES and may be compared with the total annual electricity consumption in the model of 3667TWh. Where production of energy from a particular type of generation is lower in one case than another, it will be a consequence of limited network capacity and the effect that has on power transfers and on the dispatch of generation to respect minimum on and off times, the need for locally scheduled reserve and limits on use of hydro resources.

Table 1: summary of results – annual expected values

All TWh except CO_2 in millions of tonnes	**Radial**	**Radial + new 3GW interconnectors**	**Radial + new 1GW interconnectors**	**H-Grid 1**	**H-Grid 2**
Connection of new offshore wind generation	Radial	Radial	Radial	Within H grid	Within H grid
New offshore NTC	None	3GW point-to-point	1GW point-to-point	H high	H low
Nuclear	868.0	876.0	871.5	875.3	872.3
Hydro	670.2	670.4	670.4	673.9	673.9
Lignite	313.6	317.3	315.2	314.7	313.0
Coal	688.9	700.6	693.0	697.7	700.2
Gas	346.8	325.8	338.7	326.1	334.5
Other dispatchable fossil fuelled generation	21.5	15.7	18.1	18.9	17.2
Wind generation	412.2	416.0	415.6	414.9	411.0
Total renewable generation	1203.4	1207.4	1207.0	1209.8	1205.9
Net pumped storage production	-10.5	-9.2	-10.2	-9.5	-9.8
Unsupplied energy	2.3	0.6	0.9	1.0	0.7
Net spilled energy	12.0	11.0	11.2	10.5	10.8
CO_2 emissions	1143.2	1145.1	1143.0	1142.2	1144.7

Note: 'total renewable generation' includes hydro, wind and solar (121TWh, not shown). There is a further 233.5TWh of non-dispatchable thermal generation (not shown) which includes approximately 159TWh of biomass, biogas and waste generation and which is not included in the total renewable generation figure. Existing interconnector NTCs between regions, added to by the introduction of new interconnectors, are 4.7GW between Continent and Scandinavia and 3GW between Continent and Isles.

Broadly speaking, the following observations can be made. However, in all cases, it must be noted that network constraints *within* a particular country have not been modelled.

- Wind: new offshore network capacity between regions can help to increase the expected annual production in Europe within the given background of installed capacity by up to 5.5TWh.
- Hydro: the H offshore grid helps facilitate an increase the expected annual production of around 3.5TWh relative to all other cases.
- Nuclear: new offshore network capacity can allow production to be increased by up to 8TWh.
- Lignite: some forms of new offshore NTC allow a small increase in production (around 3TWh) relative to other forms.
- Spilled energy: the variation among the different network cases studied is only 1.5TWh although the H-grid tends to minimise offshore spillage compared to other configurations. (Most of the increase was in GB and Denmark (West) due to network congestion).
- Unsupplied energy: as would be expected, this is worst with limited onshore NTC and no new offshore NTC. (The variation between offshore network cases is 2.3TWh). However, this figure

should be approached with caution in view of the relatively limited number of 'Monte Carlo years'. (See section 2 above for discussion on uses of ANTARES).
- CO_2 emissions: in the cases studied, there is little overall variation with different levels or forms of new offshore network capacity.

The initial H-grid capacities in GW for the links are denoted by the first number in the labels in Figure 2 (e.g. 3.5GW for link A to M) and have been selected taking into account the generation capacity of the nodes to which it is connected and allowing for some inter-area transfer. The lower capacities were derived in the following manner. ANTARES records the instances across all the 'Monte Carlo years' for which the capacity of each line is reached in the positive and negative directions and calculates the percentage congestion accordingly for each hour of the year; these data were used to estimate the frequency with which the link is congested over all hours of the year and all 'Monte Carlo years'. The link capacities were then reduced as a function of the level of congestion: the most congested links (congested >95% of the time) were not reduced at all while those links with moderate levels of congestion (>50% of the time) were subject to a 20% reduction and those that are least congested (<20%) were reduced by half. This process was repeated over 2 iterations[4] and the line capacities after the second iteration are denoted by the second number in the labels in Figure 2, e.g. 1.8GW for link A to M.

The H-grid with the highest branch capacities is the best for low CO_2 emissions and low spill of energy. Relative to the case with radial connection of new offshore wind and increases in inter-region NTC via point-to-point interconnectors, the H-grid reduces spill of energy from offshore wind farms, i.e. offshore wind is better utilised. The reduction in spilled offshore wind becomes progressively less apparent as the capacities of the H-Grid branches are reduced.

It is possible to see some of the effects on net transfers from some of the detailed results that ANTARES is able to produce. Some of these are shown in Table A.2 in the Appendix in which, for all the hours of the year in which the mean transfer (calculated for those same hours across the 100 'Monte Carlo years') is positive, the total energy transfer is quoted, and similar for the hours in which the mean transfer is negative. Table A.2 also shows, in parentheses, the number of hours concerned.

In addition to the cases shown in Tables 1 and A.2, some further cases were run in which

a) onshore network constraints were relaxed within each region, i.e. power transfers within a region were unrestricted by network considerations;
b) for cases in which new offshore wind generation capacity was connected radially to shore, the radial connection (assumed to collect the power from a number of wind farms) was rated at 80% of the total wind generation capacity.

In these additional cases, the following was found.

- Relaxation of onshore network constraints within regions would allow the total expected annual wind production to be increased by around 7TWh, nuclear power production to be increased by up to 35TWh and production from lignite power stations to be increased by as much as 74TWh. There is an associated rise in energy transfers from Continent to Isles and Scandinavia.
- CO_2 emissions: new offshore wind capacity saves around 45 million tonnes per annum compared with the case in which no new offshore wind capacity is built. Relaxation of onshore NTC constraints causes emissions to increase by 19 million tonnes. (While such a relaxation of constraints enables higher utilisation of nuclear power and, to a lesser extent, wind, it also facilitates use of lignite).
- As would be expected, a radial connection capacity equal to 80% of the capacity of the wind generation that is connected would increase the amount of offshore wind energy spilled and CO_2 emissions (1.9TWh and 1.3 million tonnes respectively).

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[4] In theory, multiple iterations would allow a more optimised network to be arrived at, not least when the length and cost of each branch is taken into account.

4.1 Variability of results

An important aspect of the results, and one which may significantly affect the investment proposition represented by each of the different configurations, is the variability of power flows in the course of a year of operation and between one year and another. For example, Figures 3 and 4 show, for each hour of the year and for each hour in a 3-day period respectively, the *expected* power flows (flows averaged across the 100 'Monte Carlo years' for the same hour) on the inter-regional boundary between Continent and Scandinavia in one of the radial + interconnector cases; Figure 3 reveals the strong seasonality while Figure 4 the diurnality present in the flows. However, it must be noted that these are the average values for the given hours over 100 'Monte Carlo years'; examination of the range of power flows in a given hour on a given link (say, Germany to Norway, 5pm on Wednesday 19 February in the H Grid 2 case) reveals that while the expected value is 1090MW, the range of possible values extends between 2000MW and -2000MW and the standard deviation is 1563MW.

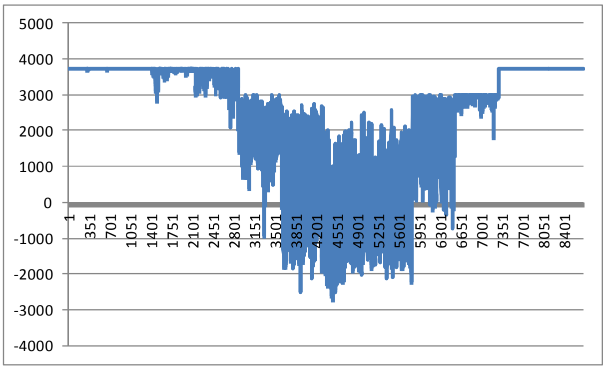

Figure 3: expected power flows between Continent and Scandinavia in each hour of the year

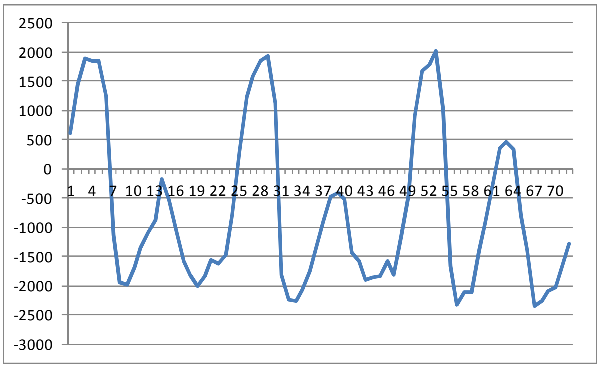

Figure 4: hourly power flows between Continent and Scandinavia over 3 days in summer

Significant variability with respect to generation production may also be observed when each 'Monte Carlo year' is examined individually. In the Radial case, for example, the standard deviation for nuclear production was 7.9TWh, for lignite was 5.4TWh, for coal was 8.6TWh, for gas was 6.5TWh and for available wind power was 7.9TWh.

4.2 Reversing the Merit Order

A final set of simulations was carried out in which the 'merit order' determining the preference for dispatch of different types of generation was changed. This was intended to reflect the possible effect of future high carbon prices and, theoretically, reduced gas prices such that CCGT and gas-fired combined heat and power plant are dispatched before coal and lignite. The results for comparison with those in the default merit order are shown in Table 2.

Table 2: summary of results – annual expected values for the merit order sensitivity case

All TWh except CO_2 in millions of tonnes	**Radial**	**Radial + new 1GW interconnectors**	**H-Grid 2**
Connection of new offshore wind generation	Radial	Radial	Within H grid
New offshore NTC	None	1GW point-to-point	H low
Nuclear	871.8	871.0	867.5
Hydro	674.0	670.4	670.3
Lignite	100.2	86.9	142.1
Coal	333.7	334.8	307.1
Gas	913.5	924.5	901.0
Other dispatchable fossil fuelled generation	17.1	18.0	21.4
Wind production	410.5	415.0	411.4
Total renewable generation	1205.5	1206.4	1202.7
Net pumped storage production	-10.2	-8.3	-11.3
Unsupplied energy	0.7	0.8	2.2
Net spilled energy	15.1	13.0	14.2
CO_2 emissions	799.1	790.1	821.1

As would be expected, lignite and coal based generation diminish significantly while gas generation increases. Carbon emissions reduce significantly (to a minimum of 790 million tonnes, i.e. by over

30%) suggesting that measures to change the merit order can have a very significant effect in the short-term. Wind generation changes very little as does hydro generation.

The effect of the changed merit order on transfers between regions is shown in Table A.2 in the Appendix. It shows that net transfers from Continent to Isles reduce significantly reflecting the increased use of (now cheaper) domestic gas generation in the British Isles. Similar is true for the Continent to Scandinavia boundary.

4.3 Cost-benefit analysis

Since this study does not consider the full investment costs associated with offshore wind development, only the comparative network investment and generation operational costs are considered. Marginal costs are attributed to each of the operational aspects as referenced in Section 3.2. These costs reflect one particular estimate of the current costs of generation; in light of the fact that considerable uncertainty attaches to these costs, no attempt has been made to predict future energy or CO_2 prices. The levelised annual cost of one network configuration is compared with another and in turn with annual operating costs of generation in the two cases plus cost of 'spilled' and unsupplied energy. This is an important distinction because this is not an attempt to say that an investment in the H-Grid configuration is justified on its own but rather that the additional costs (if any) that are incurred may be justified by a reduction in cost of generation or volumes of CO_2, spilled energy and unsupplied energy. Moreover, the comparison is deliberately made ex-post allowing the reader to apply prices to the different aspects according to their own expectations.

The capital costs attributable to the offshore portions of the different network configurations vary according to the length and capacity of the network branches, the number of onshore and offshore converter stations and the number of DC circuit breakers in the system. While considerable experience has been gained regarding point to point DC interconnectors, the costs of the type of network structure proposed here are much more speculative. The following assumptions have therefore been applied:

- 1 converter station per onshore and offshore node;
- 1 platform per offshore node except where DC breakers are required when 2 are assumed;
- DC breakers only present in H-grid cases, 2 per link, with the cost equal to a mid-size converter;
- 20% charge for civil works and commissioning (the figures in [27] do not include civil works);
- Discount Rate 10%;
- Lifetime 20 years.

The assumed unit costs have been based on [27] and are shown in Table A.3 in the Appendix.

The first two rows of Table 3 show the comparison of the resulting levelised annual cost of each of the configurations against the cost of the Radial case with DC breaker costs excluded and included. The 'Radial + new 1GW interconnectors' and 'Radial + new 3GW interconnectors' cases have, as expected, higher costs than the Radial case with additional annualised capital costs of between €242m and €865m. The costs of the H-grid meanwhile are heavily dependent on the costs of DC breakers; in the case where no DC breakers are included the H-grid would show additional costs of between €158m and €960m, depending on cost assumptions and line capacities, whereas if DC breakers are included additional annual costs of between €1981m and €4503m could be expected.

Table 3: estimated annualised cost differentials compared with Radial network case

€m	Radial	Radial + new 1GW interconnectors	Radial + new 3GW interconnectors	H-Grid 1	H-Grid 2
Capital Cost Differential Excl. DC Breakers	0	242 to 327	615 to 865	642 to 960	158 to 255
Capital Cost Differential Incl. DC Breakers	0	242 to 327	615 to 865	3545 to 4503	1981 to 2459
Operational Cost Differential (excl. unsupplied energy cost)	0	-700	-1235	-1128	-535
Operational Cost Differential (incl. unsupplied energy cost)	0	-35700	-43735	-33628	-40535

The second two rows present the annual operational cost savings or increases excluding and including the costs of unsupplied energy, the value of which is contested in the literature; besides, as has been noted above, this study was not oriented towards an estimate of energy not supplied which would require simulation of many more ‘Monte Carlo years’ than have been done.

All the configurations bring operational cost savings with respect to the Radial case as might be anticipated. Whether unsupplied energy costs are considered or not, the cost savings associated with the ‘Radial + new 1GW interconnectors’ and ‘Radial + new 3GW interconnectors’ outweigh the additional capital costs relative to the Radial case. In the case of the H-grid, the argument is less clear. If unsupplied energy costs are taken into account, the additional capital costs relative to the Radial case seem justified even if DC breakers are included in the equation. Where the unsupplied energy costs are ignored, the justification depends entirely on whether DC breaker costs are included; if these are ignored the case seems to be made but if they are included the capital costs far outweigh the operational cost savings. However, the comparison between an H-grid and Radial + point-to-point interconnectors is less clear cut and is likely to depend on the reliability benefits that would arise from a grid structure, even without DC breakers so long as onshore loss of infeed limits are respected.

In addition to increasing utilisation of renewables, offshore network capacity can do two further things: depending on the exact location, allow onshore network constraints to be bypassed; and permit cheap high carbon generation in remote areas to be used instead of lower carbon fossil fuelled plant in a local area. Depending on how carbon is priced and the effect of that in determining a Europe-wide merit order, an example of this is displacement of a significant number of hours of running of combined cycle gas turbine plant in Western Europe by lignite plant in the east. It may thus be concluded that not only are support for investment in very low carbon generation capacity such as wind and development of the transmission network important for reduction of carbon emissions associated with use of electricity, but so too is effective pricing of carbon emissions. This is confirmed by the results from the reverse merit order analysis which shows a significant reduction in carbon emissions which result from the switch to gas from lignite and coal.

5 FURTHER WORK

The precise level of benefit of new offshore power transfer capacity is uncertain and, even for a particular background of installed generation capacity, varies significantly due, in particular, to the varying weather (affecting, in particular, the available wind and hydro power), uncertainty in the merit order and uncertainty in demand for electricity. Moreover, in the study reported here, the available time and human resource have permitted only a very high level assessment of costs to be done. This suggests that, while the benefits of at least some increased inter-area transfer capability are quite clear and notwithstanding the findings of comparable studies such as OffshoreGrid [11] and ISLES [28], further, more detailed analysis is required to determine if it should be delivered by means of one or more multi-terminal offshore grids or if dedicated point-to-point interconnections should be preferred alongside straightforward connections of wind farms to shore.

Given that for a credible 2020 background such as that described in section 3.1, the volumes of wind energy involved are not huge relative to the overall demand for electricity, it is the intention of the project team to go on to study some possible 2030 backgrounds to flesh out the case for long-term investment in offshore network capacity more fully.

The results will be sensitive to a number of considerations, among them: the maximum power capability of single voltage source converter stations and HVDC cables; the costs of converters and of cables; the costs of offshore platforms; the precise design of an offshore network and what that entails for the number of platforms required and the need for DC breakers, and how much they, in turn, may be expected to cost. In practice, a mix of radial connections, point-to-point and grid solutions is likely to be developed, not least because of the modularity of the VSC technology and what is likely to be the incremental nature of investment. However, what should also not be overlooked is that, whatever investment there is in offshore network capacity, the onshore network would generally also need to be upgraded to be able to bring power from the coast to the main demand centres.

All else being broadly equal, a significant advantage for an offshore grid solution (as distinct from one with radial connections of wind farms and simple point-to-point interconnectors) should lie in its increased reliability. That is, an offshore grid structure with multiple export paths for power from any particular wind farm reduces the risk associated with loss of any one network branch. However, the effect of short circuit faults on any location of the offshore grid must be taken into account. If no DC breakers are provided, faults must be cleared from the AC side at each terminal of the DC grid. This implies loss of all generation on that grid, not just that behind the faulted branch. However, such a loss may be only for a short time – as noted in the ISLES project [28], once the fault has been cleared, the offshore grid may be reconfigured by opening and closing of disconnectors and re-energised, though the acceptability of such an approach would depend on the initial 'loss of infeed' at each terminal and its effect on the onshore grid there, and on the time taken to re-start the healthy offshore grid. Moreover, there are different options for the design of the converters at each terminal which serve to change the required performance and size of DC breakers (and hence size and cost of offshore platforms), though these different converter designs also imply different sizes and costs.

Progress is being made on the design and realisation of the relevant HVDC technologies and the strategies for control of a multi-terminal DC grid, not least in TWENTIES. In time, it will be possible to estimate the costs of different grid design options with some confidence. However, the reliability performance of the grid should still be evaluated, as further work within TWENTIES will do.

Alongside the technical factors affecting offshore grids and the costs of equipment, other influences on a preferred design of new offshore power transfer capability include the regulatory treatment of network branches that serve both to take wind power to shore within a particular TSO area and to interconnect two TSO areas, and the preference, driven by considerations of planning rights, for fewer rather than more onshore landing sites and offshore cable routes. In addition, fundamental questions remain to be answered fully in respect of wider grid stability in the presence of large amounts of wind generation and how to deal with those periods, sometimes lasting a number of days, in which little or no power is available from wind farms across a quite large area.

6 CONCLUSIONS

This paper has reported a detailed analysis that has been carried out using Monte Carlo analysis to investigate the rationale for development of significantly enhanced transmission capacity in Europe. With a particular emphasis on the accommodation of wind power in the North Sea, it provides an assessment of the extent to which lack of transmission capacity at a European level will act as a constraint to realising Europe-wide targets for electricity from renewable sources in 2020. A plausible generation and demand scenario has been postulated and inter-area power flows studied in a number of network cases for the whole of Europe, with particular reference to different offshore network structures in the North Sea.

The main metrics used to compare the different scenarios have been annual energy production from different types of generator, emissions of carbon dioxide, the total energy from renewables, and the volume of 'spilled' wind energy. The results suggest that new offshore network capacity to allow increased exchange of power between different countries will be important to realising the full potential of new wind power developments. This new network capacity not only allows local surpluses of wind power to be used elsewhere but also facilitates reserve power to be held remote from a particular area and so minimise the total holding of reserve and increase the utilisation of renewable energy. However, it might also allow cheap high carbon generation in remote areas to be used instead of lower carbon fossil fuelled plant in a local area. It may thus be concluded that not only are support for investment in very low carbon generation capacity such as wind and development of the transmission network important for reduction of carbon emissions associated with use of electricity, but so too is effective pricing of carbon emissions.

A number of areas for future research have been highlighted, notably efforts to assess the benefits in terms of system reliability that are represented by the different network structures proposed, examination of alternative future generation backgrounds in 2020 and 2030 and a more detailed analysis of the capital costs

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APPENDIX

Table A.1: generation capacity and electricity demand in the 2020 scenario

	Continental Europe	British Isles	Scandinavia	**Total**
Coal (GW)	101.2	29.8	9.6	**140.6**
Lignite (GW)	52.5	0.3	1.2	**54.0**
CCGT (GW)	119.0	30.9	4.8	**154.7**
Other Dispatchable fossil fuelled (GW)	86.3	7.9	11.4	**105.7**
Nuclear (GW)	104.1	7.1	12.4	**123.6**
Other Non-Dispatchable Generation (GW)	19.8	2.2	8.0	**30.0**
Hydro (GW)	98.0	1.7	60.4	**160.1**
Pumped storage (GW)	39.9	3.1	9.1	**52.1**
Onshore wind (GW)	166.0	18.0	9.3	**193.3**
Offshore wind (GW)	12.2	14.9	0.0	**27.1**
Solar (GW)	80.1	2.7	0.0	**82.8**
All generation (GW)	877.1	118.1	126.2	**1121.5**
Peak demand (GW)	*450*	*70*	*88*	
Annual electricity consumption (TWh)	*2779*	*396*	*493*	***3668***

Table A.2: simulation results: annual transfers between regions

TWh (number of hours in parentheses)	**Default merit order**			**'Reverse' merit order**	
	Radial	**Radial + new 3GW interconnectors**	**Radial + new 1GW interconnectors**	**Radial**	**Radial + new 1GW interconnectors**
Continent to Isles	18.4 (7509)	37.9(8105)	25.7 (7881)	15.1 (7272)	14.8 (7272)
Isles to Continent	1.7 (1251)	1.8 (655)	1.6 (879)	2.5 (1488)	2.5 (1488)
Continent to Scandinavia	22.5 (7472)	39.3 (7840)	28.6 (7567)	21.2 (6882)	20.9 (6882)
Scandinavia to Continent	1.7 (1288)	2.2 (920)	1.9 (1193)	2.3 (1878)	2.0(1878)
Isles to Scandinavia	0.0 (0)	9.0 (4921)	2.5 (3764)	0	1.4 (2510)
Scandinavia to Isles	0.0 (0)	7.4 (3839)	4.2 (4996)	0	5.1 (6250)

Table A.3: assumed capital costs for network elements [27]

System Element	Min Cost (€m)	Max Cost (€m)
800MW Converter	98	105
1250MW Converter	121	150
2000MW Converter	144	196
Platform	123	157
HVDC 1000MW 500kV Cable per km	0.575	0.863
DC 1000MW Circuit Breaker	121	150