The Economics of Offshore Wind

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Abstract

This paper presents an overview of the main issues associated with the economics of offshore wind. Investment in offshore wind systems has been growing rapidly throughout Europe, and the technology will be essential in meeting EU targets for renewable energy in 2020. Offshore wind suffers from high installation and connection costs, however, making government support essential. We review various support policies used in Europe, concluding that tender-based feed-in tariff schemes, as used in Denmark, may be best for providing adequate support while minimising developers' rents. It may prove economic to build an international offshore grid by connecting wind farms belonging to different countries that are sited close to each other.

JEL Codes: D43, L13, L94, Q41, Q42

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1. Introduction

Over the past decade, many countries have invested heavily in wind power, and current energy policies imply that there is a lot more investment to come. Most existing wind farms have been built on land (onshore) but some countries in north-west Europe have also started to invest in offshore wind, and the UK (in particular) has aspirations for offshore wind farms to make up nearly one-third of its generating capacity in the 2020s. This is in the context of the EU's demanding targets for renewable energy – 20 per cent of final energy demand is intended to come from renewables by 2020, and this could mean that one-sixth of Europe's electricity comes from wind.[1]

Why would governments be interested in promoting offshore wind farms? Higher and steadier offshore winds make offshore wind farms more productive (UK figures suggest a capacity factor of about 36% compared to an average of 27% for onshore wind farms (Boyle, 2006)), which in turn implies a higher capacity credit, and thus smaller back-up costs (Milborrow, 2009). Against this, the costs of building offshore are much higher, and there are bottlenecks in the supply chain, mostly due to the relatively limited number of installation vessels and the long queues in suppliers' order books – due to the (so far) limited production volumes of equipment and parts (Krohn et al, 2009). In the UK context, where many onshore wind farms have been delayed or blocked by difficulties in getting planning permission, the lower visual and other impacts of offshore wind farms are important, and they can offer the flexibility to locate closer to (some) load centres, thus helping to reduce transmission losses and avoid congestion bottlenecks. Even if there were no problems in getting planning permission, the physical space available for onshore turbines in the UK is limited, and building offshore allows a significant increase in the total potential contribution (MacKay, 2008).

[1] The European Commission (2007) has produced a scenario in which wind power provides 41 % of the renewable electricity generation, which in turn makes up 43% of total generation, giving an overall proportion of 17%. The relative ease of producing renewable electricity implies that it will provide much more than 20% of the final demand for power, while the proportion of renewable energy in transport (in particular) will be well below 20%.

This paper discusses the economic implications of the move to offshore wind. Section 2 illustrates the dramatic increase in capacity and generation over the last decade, and the even faster rise predicted for the next. This comes despite the higher cost of building stations offshore than onshore, discussed in section 3. Additional costs come from the need to use subsea cables to connect the stations to the transmission system, raising issues which we cover in section 4. The following section concentrates on the interaction between wholesale markets and the output from offshore wind farms, showing that they are at risk of earning less than the time-weighted average price of power, should they depend on wholesale market revenues. Given this, and their high costs, government support is likely to be needed for many years to come. Section 6 discusses the main ways of supporting offshore wind stations. Finally, section 7 concludes.

2. Offshore wind: current status and plans

New investment in offshore wind generation capacity has shown a remarkable increase, particularly in Europe, over the last two decades. Total offshore installed capacity in Europe has increased from under 50MW in 2000 to about 1,471 MW by the end of 2008 (EWEA 2009), translating to an average annual rate of growth of about 50% per year. Although currently the bulk of operating offshore systems concentrates within a small number of Northern European countries, the interest in offshore wind farms is widening rapidly around the world.

Currently, most of the existing installed offshore capacity concentrates within a handful of Northern European countries: the UK, Denmark and the Netherlands. As of 2008, these three countries accounted for 85% of the EU-27 offshore wind capacity (their corresponding combined share for onshore capacity was just over 11%). In particular, the UK had the highest total installed offshore capacity, with 591MW followed by Denmark (409 MW) and the Netherlands (247 MW). Although these shares are likely to decrease over the coming years, as investment in offshore starts to catch up in the rest of Europe, the UK is expected to maintain its current leading position in this market.

Indeed, the European Wind Energy Association (EWEA) has targets for the distribution of offshore wind capacity around EU-27 (EWEA, 2009), which imply a UK share between 32.5-36.5% of total EU-27 offshore generating capacity.

Despite its spectacular growth, the current share of offshore capacity remains relatively low when compared to operating onshore (and just over 2% of total wind capacity for EU27). The higher costs associated with offshore wind farms, as well as supply chain bottlenecks (mainly attributed to yet small scale production of turbines – implying capacity limitations - and the limited availability of suitable installation vessels, Musial and Butterfield, 2004) are often seen as the main drivers behind this gap. As interest in the market expands both of these constraints are becoming increasingly less binding, and the supply chain is now showing signs of catching up with demand.

EWEA (2009) provides "conservative" (low) and "ambitious" (high) scenarios about the total number of wind onshore and offshore installations by 2020. According to these figures, the conservative scenario suggests an increase of total offshore wind installations in EU-27 to over 19% of total wind power capacity, that is 40 GW of offshore and nearshore wind installations. According to this scenario, the UK is expected to increase its share of capacity derived from offshore wind farms from 2.65 GW in 2008 to 13 GW in 2020 (thus deriving 50% of its total wind capacity offshore). The "high" scenario suggests that the share of offshore wind will increase to 22.7% of total wind capacity in EU-27, with the UK's share now assuming the value of 58.82% (20 GW). In both scenarios, the UK is expected to maintain its current leading position in offshore wind generation, followed by Germany with a total offshore capacity of 8-10 GW. The details of the current shares and EWEA's estimates for 2020 for EU-27 are summarised in table 4.

	2008 Capacity (GW)		2020 Low capacity (GW)		2020 High capacity (GW)		Share of wind in electricity consumption	
Country	**Onshore**	**Offshore**	**Onshore**	**Offshore**	**Onshore**	**Offshore**	**2008**	**2020 high**
UK	2.7	0.59	13.0	13.0	14.0	20.0	2%	25%
Germany	23.9	0.01	41.0	8.0	42.0	10.0	7%	17%
France	3.4	-	19.0	4.0	20.0	6.0	2%	11%
Netherlands	2.0	0.25	5.0	4.5	5.4	6.0	4%	22%
Sweden	0.9	0.13	6.0	3.0	8.0	3.0	2%	16%
Denmark	2.8	0.41	3.7	2.3	4.0	2.5	20%	46%
Belgium	0.4	0.03	2.1	1.8	2.5	2.0	1%	12%
Spain	16.7	-	39.0	1.0	41.0	1.5	12%	26%
Finland	0.1	0.02	1.5	0.4	2.0	1.0	0%	8%
Ireland	1.0	0.03	5.0	1.0	6.0	1.0	9%	55%
Italy	3.7	-	15.0	0.5	17.0	1.0	2%	9%
Poland	0.5	-	10.0	0.5	12.0	0.5	1%	15%
Greece	1.0	-	6.5	0.0	8.3	0.2	4%	29%
Estonia	0.1	-	0.5	0.0	0.5	0.1	2%	11%
Latvia	0.0	-	0.2	0.0	0.2	0.1	1%	9%
Lithuania	0.1	-	1.0	0.0	1.0	0.1	1%	13%
Others	4.3	-	21.5	0.0	26.1	-		
EU-27	63.5	1.47	190.0	40.0	210.0	55.0	4%	17%

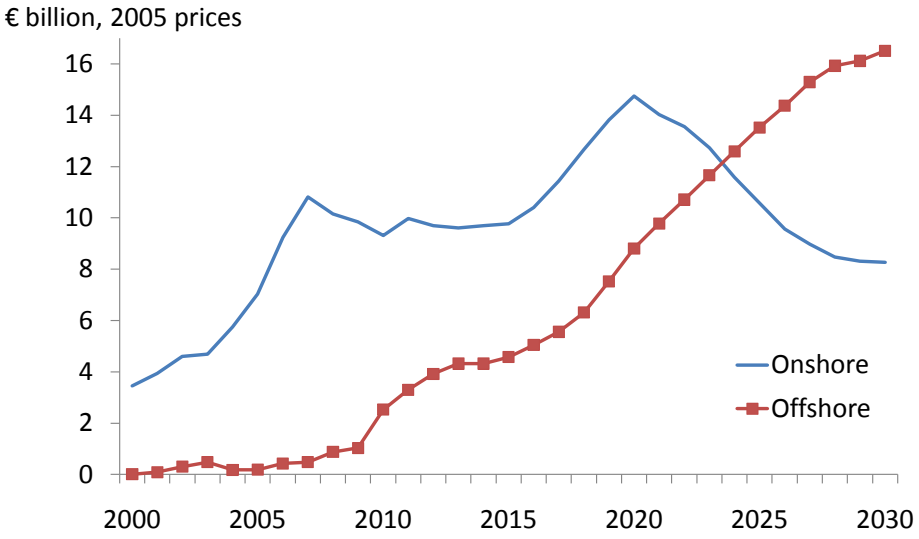
Table 1: Offshore and Onshore wind capacities in EU-27.

Source: EWEA – Pure Power: Wind Energy Scenarios up to 2030 (2009)

The value of investment in offshore wind follows a similar pattern to the one described for installed capacity and is shown in figure 1. Assuming the capacity prices suggested by the EWEA (1,250 €/kWh for onshore and 2,400 €/kWh for offshore, in 2005 constant prices, EWEA 2009) and the "conservative" ("low scenario") capacity targets summarized in table 1,

investment in offshore wind capacity is expected to grow from its current value of about €2 billion per year to just under €9 billion in 2020, reaching over €16 billion in 2030. EWEA expects the market for onshore capacity in Europe to start showing signs of saturation after 2020, partly due to a deceleration in the demand for onshore turbines (e.g. due to utilisation of productive sites) and partly due to a shift in interest to the more productive (and by that time more cost efficient compared to present) offshore generation. As a result, EWEA expects offshore investment to overtake onshore in about 2023.

Figure 1: Predicted wind capacity investments in Europe



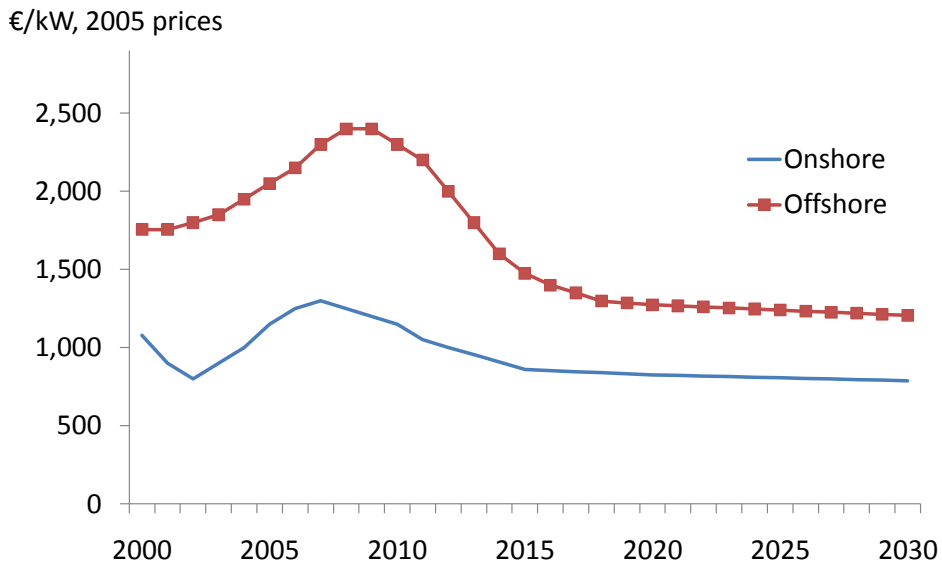
Source: EWEA (2009)

3. Costs of offshore wind

As with most new technologies, one of the factors that determines the speed with which it is deployed and established is the cost curve that is associated with its usage. The costs for offshore wind generation have indeed been significantly higher throughout than for onshore wind farms, although recent technological improvements in the size and design of turbine technology and, in general, more

efficient production patterns, have seen this gap narrowing down. EWEA (2008) develops estimates about the capacity costs of offshore and onshore wind installations for up to 2030, taking into account the recent data on the price, demand and supply of turbines[2]. According to these figures, the average capital cost for a kW of offshore wind to be installed in 2009 was in the region of €2,300, compared to €1,300/kW for onshore capacity. Although the investment costs for onshore wind are also expected to fall over time, the price of offshore capacity is expected to fall faster, as scale economies are achieved by manufacturers, bottlenecks in the supply chain are further eased and newer, larger turbines are put to use enabling higher efficiency. Figure 2 visualises EWEA's scenario for the evolution of cost of offshore and onshore investment up to 2030.

Figure 2: Predicted wind capacity costs



Source: EWEA (2008), Annex 5

[2] As noted in the report, the market for wind turbines has seen a fair share of price volatility for the greatest part of the decade, driven partly by demand conditions for wind capacity and partly by the ability of the industry to fulfil that demand. Excess supply (due to slow growth rates of new investment) over the period 2001-2004 was followed by a period during which the market grew by an average of 35% per annum, leading to capacity shortages, long order books for manufacturers and thus resulting to a price surge.

These cost differences for offshore and onshore wind stations are often attributed to factors associated with the design, building and transmission of offshore stations. For instance, laying foundations for an offshore (or nearshore) wind station can be 50% more expensive (or more) than for a conventional land-based turbine. The exact level of the cost premium depends on factors including water depth and distance from shore. Recent cost data collected from the two largest Danish offshore wind farms (the Horns Rev project and the Nysted offshore wind farm) suggests that foundations for offshore wind turbines can claim as much as 21% of total cost expenditure (as against 5-9% for onshore turbines, EWEA, 2009).

Table 2: The impact of depth and distance on costs

Water depth (m)	Distance from shore (km)							
	0-10	10-20	20-30	30-40	40-50	50-100	100-200	>200
10–20	1	1.02	1.04	1.07	1.09	1.18	1.41	1.60
20–30	1.07	1.09	1.11	1.14	1.16	1.26	1.50	1.71
30–40	1.24	1.26	1.29	1.32	1.34	1.46	1.74	1.98
40–50	1.40	1.43	1.46	1.49	1.52	1.65	1.97	2.23

Source: EEA (2009)

All costs increase significantly with distance from shore and water depth, as shown in table 2. The table shows the adjustment factor by which investment and installation costs (based on a turbine close to shore in shallow waters) should be multiplied for deeper water and greater distances. This relationship between water depth and costs has discouraged the development of deep-water turbines, despite the extra productivity benefits that are often achieved from distance to shore (due to higher

wind speeds). Indeed, at present, operating wind farms tend to be located no further than 20km from shore and in water depths of no more than 20m (EWEA, 2009). Future developments will involve greater distances and depths – the UK's Round Three includes the Dogger Bank, almost 200 km from shore, and with a maximum depth of 63 metres. The costs of building and maintaining wind turbines in these conditions will be significantly higher than those in easier waters, especially when we consider the need to connect them to the main electricity system onshore.

4. Connecting Offshore Wind to the Grid

All new generators will need a connection to the electricity network, and this will be particularly challenging for offshore wind farms.[3] First, subsea cables are much more expensive (per km) than overhead transmission lines. Second, some of these cables will have to travel long distances to a suitable point on the transmission system, and will then still be a long way from the main centres of demand. Third, a cable connecting a particular generator can only be used when that generator is actually producing, and we have already seen that wind stations have relatively low load factors, increasing the average cost per MWh generated. Some economies are possible by building a wind farm slightly larger than the capacity of the cable (cables come in fixed capacities that are many times bigger than a typical wind turbine) as the wind farm will rarely generate at full capacity. National Grid (2008) have calculated that the optimal balance between reducing the connection cost per generator and increasing the amount of electricity that has to be spilled (when generation does exceed the capacity of the cable) is obtained with a wind farm capacity that is 112% of its connection capacity. Even so, with a station load factor of around 40%, the connection assets will be used at less than half of their capacity, on average.

This makes it particularly important to minimise the cost of connecting offshore wind farms to the grid. There are two offsetting concerns. First, if many different connections are designed piecemeal,

[3] Again, data from Horns Rev and Nysted show that the average cost of transmission claimed a share of 21% compared to an average 5% for land-based farms.

early decisions may affect the costs of the schemes that are connected later – and those may well be the larger, more expensive, projects. Second, a monopoly developer will be under less pressure to keep costs down than a group of competing companies. The first concern suggests that there should be an overall development plan taking account of the interactions between projects, and with the existing onshore grid. This would have to be prepared by, or in close collaboration with, the onshore transmission operator. The second concern might suggest that a single onshore operator should not automatically be allowed to develop the individual connections that the development plan requires.

One obvious way of organising this would simply be to allow each wind farm's developer to be responsible for connecting their station to shore, following the overall development plan, just as they are responsible for building the station itself. The developer has a strong financial incentive in obtaining a cost-effective connection – high costs or low availability will directly affect its profits from the station. The early British wind farms used this approach, but their regulator has decided that it falls foul of the EU Third Electricity Directive, which requires a high degree of separation between generation and transmission activities.[4] In future, the regulator will run tenders to appoint the Offshore Transmission Owner (OFTO) which will build, own and operate the connection assets for each wind development zone. The Crown Estate, which is responsible for the economic use of the seas around the UK, has appointed a single lead developer for each of these zones, which allows for coordination between that developer and the OFTO for the zone. OFTOs will also be appointed for the existing stations, paying their developers to take over the connection assets those developers have built.

However the OFTO has acquired its assets, the generator will pay for their use through the main system of regulated transmission tariffs used in Great Britain. Generators pay a charge per kW

[4] If the same company owns both generation and transmission, a fully independent transmission system operator must be appointed to ensure that the transmission system is not run in a way that might be anti-competitive. It should be noted that other countries take a different view of the Directive's requirements: in Sweden, for example, a wholly-owned subsidiary of the developer (Vattenfall) runs the transmission connection for the Lillgrund offshore wind farm (Söderberg and Weisbach, 2008).

of capacity which is based on the impact of their output on peak flows through the grid. Charges have been calculated based on the number of MW-km of extra capacity required to accommodate the output from stations located in different zones on the network – the further a station is from the main demand centres, the more capacity would be needed, and the higher its charge. The same principle will be used in future, but new zones will be set up so that each offshore generator pays its own specific charge. The modelled length of the line between the offshore zone and the rest of the transmission system will be calibrated to ensure that the OFTO for that zone recovers an amount of revenue dependent on its tender bid. This will be equivalent to the offshore generator paying a connection charge to the OFTO, based on the cost of connecting it to the main onshore grid, and also paying the onshore transmission companies for the use of their systems, taking the onshore connection point as the generator's "location".

One potential disadvantage of the OFTO approach, with (potentially) different companies running the connections for neighbouring wind farms, is that it will be harder to arrange for wind farms to share connections. Could this be a major issue in practice? The opportunity to share transmission assets is one thing that keeps down the cost of the onshore grid – a properly planned system does not need the transmission capacity to run every power station at once, because generating capacity should significantly exceed the peak demand, and so we would never experience every power station running simultaneously. The best level of transmission capacity between two zones is based on the largest likely transfers between them, not on the total generation in the exporting zone. Could this lead to a similar saving for offshore lines, connecting several stations to an offshore grid? Early, small, wind farms had capacities that were typically too small to make full use of a single transmission cable, with the implication that it would be worth building short spurs between nearby wind farms (if any) in order to make better use of the main cable to shore. The wind farms now being planned, however, are much larger, and will need several cables to bring their power to shore. There could still be savings in capacity if two farms expected to have different generation patterns shared their connections. The optimal capacity for the two stations together would be less than the sum of their individual needs if there would be few times when both stations were generating at high output

levels. The problem is that if the wind farms are to be close enough to connect them without greatly increasing the length of cables, they are likely to have very similar wind conditions, and hence output patterns.

A second possibility for an offshore grid is to transfer power between the countries on two sides of a sea. This would not make sense for wind farms close to shore, but some will be nearly halfway between two countries. The cost of a cable from the wind farm to the "foreign" country may be significantly lower than the cost of a cable for the full distance between the two countries. It would give the wind generator the option of exporting its power in either direction, wherever the market price is higher. When the wind farm is not generating (or not generating as much as the cable's capacity), power can be transmitted from one country to the other.

The saving in cable costs needs to be considered against the lower availability of the cable for trade. If the wind farm has a load factor of just over 40% (and a slightly greater capacity than the cable, as recommended above), then less than 60% of the cable's capacity will be available for trade, on average. If the wind farm was nearly midway between the countries, this 60% of capacity might be obtained for roughly 50% of the cable costs of a standalone interconnector. Since the cable would still need to be connected to the wind farm and the foreign grid onshore, the cost saving may not be as great as the loss of usable capacity. In other words, if it is worth paying 60% of the cost to get a cable between two countries available 60% of the time, it may well be worth paying the full cost for a cable that is available all the time. The presence of a single offshore wind farm should not significantly change the cost-benefit analysis on an interconnector.

The economics change dramatically if there are two offshore wind farms in close proximity that would otherwise be connected to different countries. In this case, the marginal cost to interconnect the two countries is the cost of connecting two nearby wind farms, well below the cost of connecting a wind farm directly to the foreign country. In the Baltic Sea, Germany is building a wind farm on Kriegers Flak, and Denmark is likely to follow suit; Sweden may build a third wind farm nearby in due course. A feasibility study conducted for the three transmission system operators shows

that the cost of connecting the three wind farms, and increasing the possible power transfer from Denmark and Sweden by building a second line to Germany, would be less than the economic benefit of doing so (50 Hertz Transmission et al, 2010). The central estimate of the additional costs of the additional connections had a present value (at a 6% real interest rate) in 2010 of around €350 million, with benefits of between €400 million and €1400 million, depending on the model used. This shows that, in the right place, an offshore grid to connect nearby wind farms can have significant benefits, but there may be few locations as well-sited as Kriegers Flak.

5. Offshore wind and the wholesale market

As pointed out in the earlier sections, the amount of investment in offshore wind generation is expected to increase significantly over the next two decades. Some of the latest EWEA forecasts suggest that by 2030 as much as 50% of total wind capacity maybe installed offshore. With such large amount of extra wind installations coming online in a relatively short period of time, a relevant question to ask is how they are going to affect electricity prices and overall market structure of the industry.

The impact of increased amounts of intermittent generation on prices and market structure has been discussed in a number of recent papers, although the majority of them tend to assume that most investment is located onshore. Green and Vasilakos (2010) use hourly data on windspeeds for a number of representative weather stations over a 13-year period to simulate the impact of a high level of intermittent output on electricity prices and generators revenues for Great Britain. Demand levels were calibrated to possible levels for 2020, when they assume that there would be 19 GW of offshore wind capacity, compared to 11 GW onshore. Their findings suggest that as the amount of wind penetration increases, so does price volatility and that this impact is exacerbated further in the presence of market power. The effect of market power on price volatility is also discussed by Twomey and Neuhoff (2010), who present a theoretical framework which explains that market power can lead to higher levels of revenue volatility for renewable generators, because the margins between

price and marginal cost are likely to be at their highest when thermal demand is high (that is, during periods with low wind output), and lower when during the hours of the day that the wind blows.

The volatility of prices in response to renewable output is a problem for wind generators, for their output is greatest at the times when it is depressing prices. This reduces their average revenue (if based on market prices) below the time-weighted average of wholesale prices, and well below the demand-weighted average received by thermal stations. The prices simulated by Green and Vasilakos (2010) had a time-weighted average of £35.45/MWh in a (relatively) competitive scenario, but onshore wind stations would receive only £33.59/MWh. Offshore stations do even worse, receiving £32.42/MWh on average. This is because many of those stations are predicted to be in a similar area of the North Sea with (as modelled, based on a single weather station) identical output patterns. When these stations are generating, they have a big impact on the power price, which reduces their average revenues. Smaller stations, on- or offshore, have much less individual impact on the wholesale price, and although they do suffer from the impact of other wind stations' outputs (since these are correlated) this is a less important effect. While this would tend to imply that there are benefits from finding a site a long way from other wind generators, thus minimising the correlation between the station's own output and that from the rest of the industry, the least fortunate stations received only 5% less per MWh than the best in these simulations. The impact of wind conditions on the station's annual output will have a much more important effect on its profits.

The current evidence on the productivity of "typical" offshore and onshore based turbines suggests that the former do indeed benefit from a significantly higher number of full load hours per year (about 4,000 compared to about 2,500 for onshore (Krohn et al, 2009)), though of course the actual performance is strictly dependent on the locational characteristics of the offshore farm. Deeper water farms tend to achieve higher productivity rates, but at a higher overall investment cost. These differences in the actual distribution of wind output in onshore and offshore locations throughout the day will determine the actual market impact of large amounts of offshore investment on prices and revenues.

6. Supporting offshore wind

From the information on costs given above, it is clear that there would be little investment in offshore wind in the absence of specific policy support – very high fossil fuel prices would be needed to make offshore wind competitive against conventional plants, and offshore stations would still be more expensive than onshore wind (at reasonable sites). Nonetheless, several European governments are counting on investment in offshore wind in order to meet their targets for renewable energy production, and are supporting it accordingly.

Two main approaches for supporting renewable energy are currently being used in Europe, as shown in table 2, which gives the schemes used specifically to support offshore wind. Under a feed-in tariff, the policy-maker sets a fixed price which is paid for every qualifying unit of electricity. The price can depend on the technology used to produce the power, on the year in which the station was commissioned (later stations often receive a less generous price) and even on the local wind conditions. (Germany pays a lower price for electricity generated at sites with the best wind conditions. This might seem counter-intuitive, but if the national targets require that less windy sites are also developed and the feed-in tariff makes this (just) profitable, then paying the same tariff for power produced at better sites would give excessive returns to those generators.

Under a system of tradable green certificates, renewable generators receive certificates for each unit that they generate, and electricity retailers (typically) are required to surrender certificates equal to a set proportion of the power they sell. Retailers with insufficient certificates can buy themselves out, and the level of this buy-out price determines the value of the certificate. (The certificate may be worth more than the buy-out price, as holders of the UK's Renewables Obligation Certificates are entitled to receive a pro-rata share of the buy-out payments, creating a ROC price based on the expected payment avoided plus the share to be received.) As with a feed-in tariff, different technologies may receive different numbers of certificates per unit generated, giving greater support to the more expensive generators. Alongside the certificate, the generator also sells its power, and can expect to receive a market price for this.

Hybrid schemes are also possible. In Spain, the system of support for most renewable generators has moved from a pure feed-in tariff, to a fixed premium on top of the market price, to a premium that is adjusted to keep the generator's overall revenue within a particular range (Klessmann et al, 2008). While the pure feed-in tariff remained available to the generators that had signed up to it, the premium was set at a level that made most willing to change to it. The UK government has promised to keep the size of the Renewables Obligation a fixed percentage above the expected level of generation. This should have the effect, as with a feed-in tariff, of providing the same level of support to any volume of generation (until the policy is changed).[5] The (previous) government had also suggested that it should offer fixed price contracts (or contracts for differences) to hedge renewable generators' revenues from selling energy, thus further reducing the variation in their revenues.[6]

The advantage of these hybrid schemes is that they reduce the generators' revenue risks, compared to a pure certificate scheme, while still providing some more market exposure than the pure feed-in tariff. If lower risks lead to a lower cost of capital, this will be particularly useful for wind farms, since the cost of construction is such a high proportion of the station's lifetime costs. The European Commission (2008) has assessed the effectiveness (in promoting increases in renewable generation) and efficiency (in terms of avoiding excessive generator profitability) of renewable support schemes across the EU, concluding that "*well-adapted* feed in tariff regimes are generally the most efficient and effective support schemes for promoting renewable electricity" (page 3, italics in original).

The difficulty in setting a feed-in tariff is that if the level is too high, generators will make excessive profits, whereas if it is too low, little or no development will take place. When a technology is well-developed, it is relatively easy to identify the appropriate level of the tariff, and to adjust it (for

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[5] With a standard green certificate system, which requires a fixed amount (or proportion) of power, the price of certificates will fall (perhaps precipitately) as the amount of generation nears the level of the obligation.

[6] A number of respondents to the consultation on this policy opposed it, and since the government changed after the 2010 election, it is quite possible that the idea will be dropped.

new generators) to encourage or discourage further investment. When the technology is relatively new, however, this information may not be available. One possibility, adopted in Denmark, is to run a tender for new projects. This requires the generators to bid for the right to develop the project. As with any auction, this can be an efficient way of discovering the value of a scarce resource and allocating it to the most appropriate party, as long as the costs of participation are sufficiently low to attract a reasonable number of competing bidders.

Table 2: Support for Offshore Wind

Country	Main support policy
Belgium	Supplement to market price of €107/MWh for output from the first 216 MW in a concession, and €90/MWh for additional output. Formally organised as green certificates, which transmission operator must buy.
Denmark	Feed-in tariff to supplement the market price, with the level set by competitive tenders. For Horns Rev 2, a total (premium plus market price) of DKK 518/MWh; for Rødsand 2, DKK 629 /MWh.
France	Feed-in tariff of €130/MWh for ten years, falling (except for stations with bad wind conditions) for the next ten years
Germany	Feed-in tariff of €150/MWh
Italy	Tradable Green Certificates, with offshore wind earning 1.1 certificate per MWh (10% more than onshore wind)
The Netherlands	Feed-in tariff (but market price if this exceeds the tariff)
Sweden	Tradable Green Certificates (worth about SEK 300/MWh in 2009, although prices fluctuate)

United Kingdom	Tradable Green Certificate – offshore wind farms commissioned by 2014 will receive 2 Renewables Obligation Certificates (ROCs) per MWh of output; each ROC can be sold for around £50 at present.

Source: International Energy Agency, Global Renewable Energy Policies and Measures database

7. Conclusion

It is clear that a number of EU countries will need to make significant investments in offshore wind power if they are to meet their targets for renewable energy in 2020. These stations will be expensive, but they will be more expensive than necessary if the recent sellers' market continues. Governments must help the industry to develop the supply chain for offshore wind power, so that construction costs and margins can fall. Even so, most offshore wind farms will require financial support, unless fossil fuel and carbon prices reach, and stay at, very high prices. European experience suggests that a feed-in tariff offers more cost-effective support than a tradable green certificate, because it is less risky and allows these capital-intensive projects to be viable with a lower cost of capital. The problem with feed-in tariffs is the need to set the tariff at an appropriate level, and the risk that it will be too generous, creating excessive rents for well-sited generators, or too mean, stifling development. The costs of offshore wind farms are likely to be much more diverse than those of most other renewable technologies, raising this risk. The Danish support method, which uses competitive bids to set the tariff actually required by each developer, has the prospect of minimising the cost of support, while still ensuring that projects remain viable.

Many offshore wind farms could conceivably build a second line to another country, allowing them to sell their output in whichever market offers the higher returns. Where offshore farms connected to different countries are located close to each other, this could be a cost-effective way of building an interconnector between those countries. At times when the wind farms do not need to use the line (and they will typically occupy less than half of its annual capacity), traders can move power from whichever country has lower prices to the other. As the proportion of Europe's electricity

generated by wind rises, differentials between short-term prices are likely to rise, making interconnectors much more profitable. Where a wind farm is located between two countries, but not close to a wind farm from the foreign country, it is unlikely that its presence will aid the development of an interconnector by a significant amount. The line needed by the wind farm will indeed reduce the net cost of the interconnector, but it will also reduce its availability for trading between the two countries. If the interconnector with reduced cost and reduced availability is economic, it is likely that a dedicated line for international trade, by-passing the wind farm, would also be a worthwhile investment. Europe will need more interconnection as it develops its wind energy resource: the presence of isolated offshore wind farms will not help it to do so.

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