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2014 JRC wind status report

Technology, market and economic aspects of wind energy in Europe

Roberto LACAL ARÁNTEGUI

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Joint Research Centre

Cover picture: Looking up. © Jos Beurskens.

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Abstract
This report presents key technology, market and economic aspects of wind energy in Europe and beyond. During 2014 the wind energy sector saw a new record in actual installations in a context of healthy manufacturer balance sheet and downward trend in prices. The global market reached 52.8 GW of installed capacity in 2014 of which 2.7 GW offshore, whereas in Europe 11.8 GW were installed. Global cumulative installed capacity reached 370 GW at the end of 2014 and in Europe 130 GW. The installed capacity at the end of 2014 in the EU produces 265 TWh of electricity in an average year.
From a technology point of view in 2014 larger turbines were sold and in particular those with larger rotors relative to their electricity generator, designed for sites with lower wind resources.
In 2014 both turbine and project prices onshore dropped. Energy costs (levelised cost of energy, LCoE) for projects with final investment decision in 2016/7 are estimated between EUR 90 and 150 per MWh, with main influences being water depth and whether offshore substation and connection to the onshore grid costs are included or not. Onshore, recent research suggest European LCoE in 2012 between EUR 45 (Denmark) and EUR 97 (Germany, low wind area) per MWh, with a clear trend to lower prices. Recent turbine prices are estimated to vary from EUR 770 to 880 per kW.

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Technology, market, economic and regulatory aspects of wind energy in Europe

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ABBREVIATIONS AND ACRONYMS:

Throughout this report 2-letter country codes are used as per the International Organisation for Standardisation: http://www.iso.org/iso/country_names_and_code_elements. Other abbreviations and acronyms are:

bn	Billion (1 000 million)
BoP	Balance of plant
CapEx	Capital expenditure, or capital cost
CF	Capacity factor
CfD	Contract for difference
CIEMAT	Centro de Investigaciones Energéticas, Medioambientales y Tecnológicas (Spain)
CoE	Cost of energy
DD	Direct-drive
DG	Directorate General (of the European Commission)
DFI	Development Financial Institutions
DFIG	Doubly-fed induction generator
DSCR	Debt service coverage ratio
EBIT	Earnings before interest and tax
EBRD	European Bank for Reconstruction and Development
ECA	Export credit agencies
EEA	European Economic Area, includes the EU plus Iceland, Liechtenstein and Norway
EIB	European Investment Bank
EMG	Electromagnet generator
EPO	European Patent Office
ERDF	European Regional Development Fund
EU	European Union
FID	Final investment decision
FiP	Feed-in premium (scheme)
FiT	Feed-in tariff (scheme)
FP	Framework Programme (of the EU) for Research and Technological Innovation
GO	Grid Operator
GW	Gigawatt (= 1 000 000 000 watts)
HTS	High-temperature superconductor
IEA	International Energy Agency
IEAWind	International Energy Agency Implementing Agreement for Cooperation in the Research, Development, and Deployment of Wind Energy Systems
IEE	Intelligent Energy Europe programme of the European Commission
IGBT	Insulated-gate bipolar transistor
IRR	Internal rate of return
JRC	Joint Research Centre, a directorate-general of the European Commission
JTI	Joint Technology Initiative
KfW	Kreditanstalt für Wiederaufbau, a German development bank
kW	Kilowatt (= 1 000 watts)
LCCC	Low-Carbon Contracts Company
LCoE	Levelised cost of energy

m	Million, metres
MS	Member State (of the EU)
MW	Megawatt (= 1 000 000 watts)
MWh	Megawatt-hour
NPV	Net present value
NREAP	National Renewable Energy Action Plan
O&M	Operations and maintenance
OEM	Original equipment manufacturer, in the context of this report OEM is the wind turbine manufacturer.
OpEx	Operational expenditure or O&M cost
PCSD	Price contract by signature date
PD	Plant Developer
PM	Permanent magnet
PMG	Permanent magnet generator
PTC	Production Tax Credit
R&D	Research and development
RD&D	Research, development and demonstration
RES	Renewable energy system/source
RoI	Return on investment
RoW	Rest of the world
RPM	Revolutions per minute
SCIG	Squirrel-cage induction (or asynchronous) generator
SET-Plan	(European) Strategic Energy Technology Plan
TGC	Tradable green certificates
TPA	Turbine purchase agreement
TWh	Terawatt-hour
VTT	Technical Research Centre of Finland
WACC	Weighted-average cost of capital
WIPO	World Intellectual Patent Organisation
WRIG	Wound-rotor induction (or asynchronous) generator
y-o-y	Year-on-year
yr	Year

In addition to the euro the following currencies were used:

BRL	Brazilian Real
BGN	Bulgarian Lev
DKK	Danish Krone
GBP	British Pound Sterling
PLN	Polish Zloty
RON	Romanian Leu
SEK	Swedish Krona
USD	United States Dollar

EXECUTIVE SUMMARY

The year 2014 was overall a good year for the wind energy sector. The level of installations represented a new record and turbine manufacturers — some of whom were in a poor economic condition over the previous 2 years — saw healthy economic indicators.

Turbines commissioned in 2014/15 are larger and taller than ever. European onshore turbines in this group average 2.71 MW of rated power (+ 20 % on 2012 installations), 106.4 metres rotor diameter (+ 20 % as well), and 113.2 metres hub height (+ 17 %). The evolution in blade design is enabling an increasing trend to low-wind turbines, with larger rotors and moderated rated power. Drive train configurations are evolving towards the employment of full converters whereas doubly-fed induction generators are losing ground in the market. In Europe, permanent magnets are mostly employed in geared wind turbines (mainly because less rare earths are required), whereas direct drive with permanent magnets-based generators are increasingly common in Asia.

The global market in 2014 reached 52.8 GW of newly installed capacity, of which 1.45 GW offshore were connected to the grid and 1.2 GW were not ([1]). In the European Union 13 GW of new turbines were installed, of which 11.8 GW were connected to the grid. Global cumulative installed capacity thus reached 370 GW whereas the EU connected cumulative capacity reached 129 GW and will produce 265 TWh of electricity in an average year, which is equivalent to the full demand of Belgium, the Netherlands, Greece and Ireland.

The 2014 manufacturers market saw the return of the traditional leader Vestas to the top position in terms of installed capacity, followed this time by another European company, Siemens. As in 2010–12, four Chinese firms were included among the top 10 in 2014, but it was only in 2013 and 2014 that eight Chinese firms were in the top 15.

In 2014 both turbine and project prices onshore continued to drop, and 2015 showed the first results of the way to a 40 % reduction in offshore costs for wind farms with final investment decision (FID) in 2020. Energy costs (levelised cost of energy, LCoE) for projects with FID in 2016/7 are estimated ***between EUR 90 and 150 per MWh***, with main influences being water depth and whether offshore substation and export cable costs are included or not. Onshore, recent research suggest European LCoE in 2012 ***between EUR 45 (Denmark) and EUR 97 (Germany, low wind area) per MWh***, with a clear trend to lower prices. Recent turbine prices are estimated to vary ***from EUR 770 to 880 per kW***.

With the increasing need to integrate large amounts of variable renewable electricity into the electricity system and market, 2014 saw regulatory support for wind swinging towards market-linked and/or market-like structures (e.g. tenders/auctions) to replace feed-in tariffs.

This report discusses the technology, economics and market aspects of wind energy in Europe and beyond — because the wind energy sector is a global sector. Its intended audience includes policymaking and support officers in the European institutions and Member States and the wind energy sector from developers through manufacturers to academia.

([1]) In most cases the connection exporting electricity to the onshore substation was not yet commissioned.

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1. INTRODUCTION

Figure 1: Wind farm at sunset. Courtesy of Vestas.

This report presents the technology, market and economics of the wind energy sector with a focus on the European Union.

Wind power has seen an impressing deployment over the last two decades, from 3.5 GW in 1994 to around 370 GW of cumulative global capacity at the end of 2014 of which 130 GW are installed (although not all connected to the grid) in the EU. This was a year when Denmark generated enough wind electricity to cover 40 % of its internal demand, in Ireland, Portugal and Spain the share of wind reached between 19 % and 25 % of final consumption, and 15 other EU Member States generated 4 % or more electricity from wind. Wind energy will provide at least 12 % of European electricity by 2020, which is a very significant contribution to the 20-20-20 targets of the European energy and climate policy.

This report focuses on the wind energy sector in Europe but, because this sector is a global industry, some sections have a global scope. The report is based on industry annual reports and other declarations; on the JRC research work in wind technology; on JRC databases of wind turbines and installations, models and other internal research; on research by key players from industry and academia; and on direct industry consultation.

The report comprises regular sections and ad hoc research chapters focusing on specific technology issues. Section 2 investigates the technological situation: state of the art of wind turbines and of their main components, research and innovations, and its possible future evolution, with a focus on technological changes brought about during 2014, or those hinted at by industry and research institutions as the possible future. Section 3 analyses the market situation, what happened in 2014 plus the longer-term trends that emerge; proposes some deployment scenarios and analyses industrial strategies as made public by manufacturers and developers. Section 4 focuses on the economics of wind projects: financing, project and turbine capital expenditure (CapEx), operational expenditure (OpEx), energy produced and cost of energy (CoE). The ad hoc research in Section 5 this year focuses on the regulatory situation in the EU Member States (MS).

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2. TECHNOLOGY STATUS

A wind turbine starts to capture energy at the cut-in speeds of 3–5 m/s (11–18 km/h) and the energy produced increases initially in relation to the cubed wind speed until levelling off at the turbine rated power of around 12 m/s (43 km/h), then remaining constant until strong winds force the turbine rotor to slow down, e.g. at around 25–28 m/s (90–100 km/h) in order to avoid putting at risk its mechanical stability. At higher wind speeds the wind turbines are switched to idle mode to withstand wind speeds of up to 70 m/s (252 km/h). The exact values depend on the wind regime the wind turbine is designed for.

2.1. Wind turbine design

Out of a wide variety of wind turbines, in the 1980s the Danish three-bladed, single fixed speed, stall-regulated turbine became the dominant model in the market at rated power levels of less than 200 kW. Since then, turbine dimensions, both in terms of generator capacity and of rotor diameter, have grown steadily and currently 2–3 MW/97–117 m rotor diameter wind turbines are commonly installed in onshore projects and 3–8 MW/112–164 in offshore wind farms.

The main technological characteristics of current turbines are:

- Steel, concrete or hybrid towers reaching 150 m in height.
- An upwind rotor with three blades, active yaw system, preserving alignment with the wind direction. Rotor efficiency, acoustic noise, costs and visual impact are important design factors. Some turbine designs have only two blades.
- High-wind-speed control. Pitch regulation, an active control where the blades are pitched along their axis (flapwise) to regulate the extracted power and reduce loads.
- Variable rotor speed. This was introduced to allow the rotor and wind speed to be matched more efficiently in particular at lower wind speeds, reduce mechanical loads and to facilitate an output according more with the needs of the electricity grid.
- A drive train system. Three main drive train configurations are currently adopted: (i) fast-rotating electric generator with a gearbox to adapt the slow-rotating rotor to the higher rotational speed of the electric generator, (ii) low-speed generator directly coupled to the turbine rotor (i.e. without a gearbox) and (iii) a medium-speed generator with a gearbox.

The main wind turbine design driving goal is to reduce the levelised costs of energy through lower capital and operating costs, increased reliability and higher energy production, which translate into: specific designs for low and high wind sites, grid compatibility; low noise, good aerodynamic performance and redundancy of systems in offshore machines.

Generally, utility-scale wind farms require minimum average wind speed of 5.5 m/s for profitable operation. Table 1 shows the classification of wind turbine classes depending on wind

Wind class turbine		I	II	III	IV
Annual average wind speed (m/s)		10.0	8.5	7.5	6
Extreme 50 year-gust (m/s)		70	59.5	52.5	42
Turbulence classes (%)	A:	18	18	18	18
	B:	16	16	16	16

Table 1: Main features of wind classes according to IEC 61400. Class S is at manufacturer's disposal

conditions. As a general rule, wind turbines aimed for low wind locations are equipped with larger and more slender rotors that have higher aerodynamic efficiency, as well as taller towers and moderate rated power (as a compromise between equipment costs and energy output). Overall, wind turbines aimed at low wind-speed sites imply higher specific (per rated power) capital costs than turbine designs aimed at high wind sites. Nevertheless, the higher costs of larger rotors and taller towers is partly compensated by smaller electric generators, power converters and gearboxes (if applicable) enabling low wind turbines to be competitive in locations with less favourable wind resources.

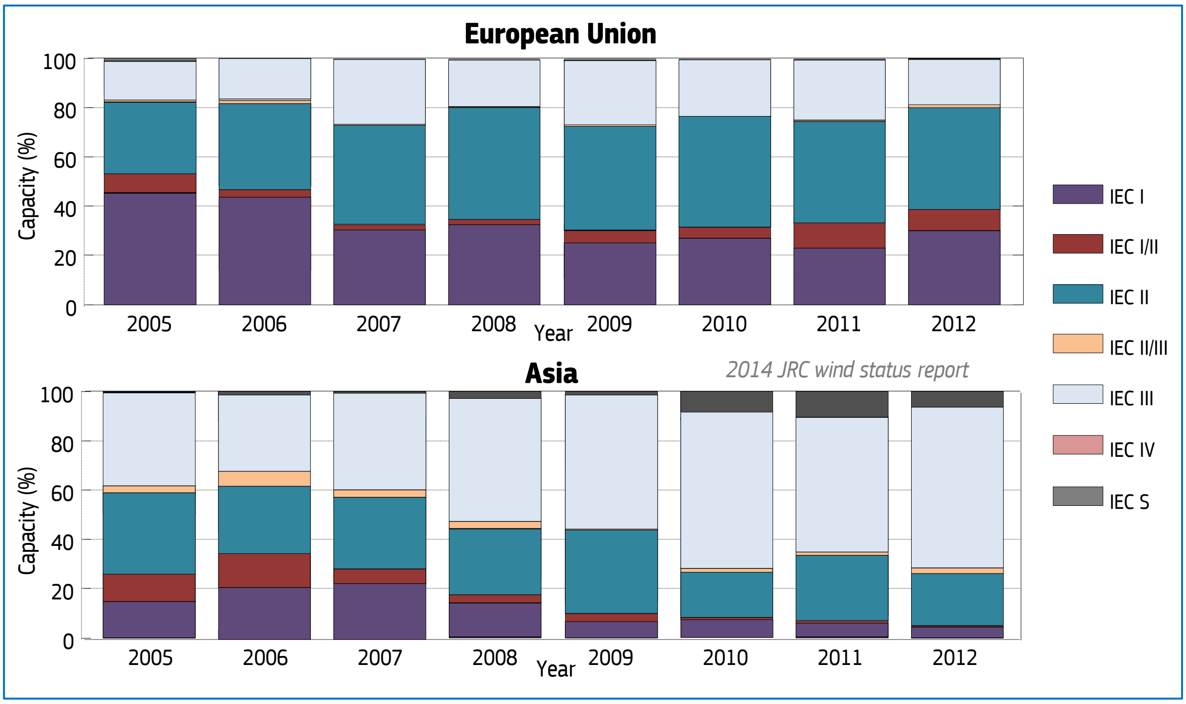


Figure 2: Evolution of the share of onshore installed capacity by wind classes (Source: JRC Database). See Table 1 for a definition of wind classes according to IEC 61400.

In order to cope with different site conditions, manufacturers are adopting a modular approach to enhance product flexibility, at the same time as component production is standardised. With this aim, two main strategies are being implemented (de Vries, 2013): (i) using the same platform (using the same/similar power rating, i.e. using the same electric generator, converter and/or gearbox) that can be combined with different rotor diameters and hub heights (this strategy is implemented by manufacturers Alstom, Gamesa or Siemens) and (ii) the same rotor diameter can be used in several platforms (e.g. Nordex implements this strategy), or both.

Figure 2 shows the evolution of onshore installed capacity share according to the different wind classes. As can be observed, Class I wind turbines are progressively losing ground in the European Union in favour of Class II and Class III wind turbines. Nevertheless, even though this is a general trend in EU MSs, this is an evolution highly dependent on the specific conditions of each MS. In particular, Germany is increasingly becoming a low-wind market (80 % of installed capacity in 2012 was Class II and III turbines (Lüers, et al., 2015b) as a consequence of the reduced availability of high wind locations along with the implementation of a support scheme tailored to the local wind resource quality. Conversely, the UK onshore market is intrinsically a high wind market (76 % of installed capacity in 2012 was Class I).

Manufacturer	Model	Size: MW/m	Market	IEC Class	Status	SP W/m²
Enercon	E126-7.5	7.58/127	Onshore	Ia	Commercially available (2010)	***598***
Senvion	6.2M126	6.15/126	On/Offshore	Ib	Commercially available (2009)	***493***
XEMC-Darwind	XE/D115	5.0/115	Offshore	Ic	Commercially available (2013)	***481***
Areva	M5000/116	5.0/116	Offshore	Ia	Commercially available (2009)	***473***
Sinovel	SL6000	6.0/128	Offshore	I	Commercially available (2011)	***466***
Ming Yang	6.5MW SCD	6.5/140	Offshore		Prototype installed (2015)	***422***
Guodian UP	UP6000	6.0/136	Onshore	IIa	Prototype installed (2012)	***413***
Gamesa	G128/5.0	5.0/128	Offshore	IIa	Prototype installed (2013)	***389***
Vestas	V164-8.0	8.0/164	Offshore	S	Prototype installed (2014)	***379***
Siemens	SWT-7.0-154	7.0/154	Offshore	Ib	Prototype installed (2015)	***376***
Areva	M5000/135	5.0/135	Offshore	I	Prototype installed (2013)	***349***
Alstom	Haliade 150	6.0/150	Offshore	Ib	Certification received (2015)	***340***
Senvion	6.2M152	6.15/152	Offshore	S	Prototype installed (2014)	***339***
Siemens	SWT-6.0-154	6.0/154	Offshore	Ia	Commercially available (2014)	***322***
Mitsubishi	SeaAngel	7.0/167	Offshore	S	Prototype installed (2015)	***320***
Samsung	S7.0	7.0/171	Offshore	Ia	Prototype installed (2014)	***305***
Vestas	V126-3.3 MW	3.3/126	Onshore	IIIa	Commercially available (2013)	***264***
Acciona	AW125/3000	3.0/125	Onshore	III	Commercially available (2013)	***244***
General Electric	GE 2.75-120	2.75/120	Onshore	IIIb	Commercially available (2014)	***243***
Senvion	3.0M122	2.0/122	Onshore	IIIa	Commercially available (2013)	***235***
Nordex	N131/3000	3.0/131	Onshore	IIIa	Commercially available (2014)	***223***
Vestas	V110-2.0 MW	2.0/110	Onshore	IIIa	Commercially available (2013)	***210***
Gamesa	G114-2.0 MW	2.0/114	Onshore	IIa / IIIa	Commercially available (2014)	***196***
Leitwind	LTW77/800	0.85/77	Onshore	IIIa	Commercially available	***173***

Table 2: Sample of largest wind turbines in the market or being introduced, sorted according to specific power (SP). Size includes the electric generator rating (MW) and the rotor diameter (metres). The small Leitwind LTW77/800 was included because it is the utility-level turbine with the lowest specific power. *Sources:* Turbine technical specifications.

Class III wind turbines predominate in the Asian market mainly because of the prevailing low-wind resource in large parts of China and India. On the other hand, the North American market was mainly dominated by Class II turbines to 2012, but in 2013 and 2014 there has been a further swing to Class III turbines (Wiser, 2015).

Table 2 includes a selection of commercial or recently presented/announced large turbines sorted according to their specific power (2). The upper part of the table refers to the larger wind turbines for high wind locations, whereas larger wind turbines with the lower specific power (W/m²) are presented below. As can be observed, large wind turbines with high specific power are generally aimed at the offshore market which is usually gifted with high wind resource. Figure 3 shows the annual evolution of specific power for new wind turbines installed in the world from 2000 to 2012. A trend can be identified in this figure: the average specific power of new installed turbines progressively decreased.

(2) A wind turbine's specific power is the ratio of its rated power to its rotor-swept area. All else being equal, a decline in specific power should lead to an increase in capacity factor (Wiser and Bolinger, 2014).

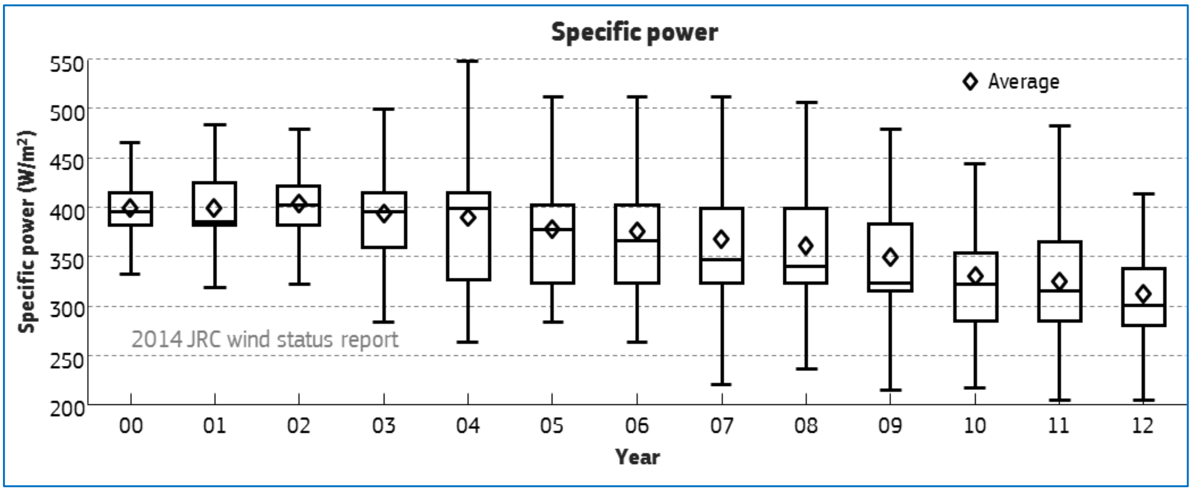


Figure 3: Boxplot representation of specific power (W/m^2) for onshore wind turbines annually installed in the world. Bottom and top sides of each rectangle refers to the 25th and 75th percentiles. The horizontal line inside each rectangle represents the median and the lower and upper horizontal lines outside the rectangles are the minimum and maximum values. *Source:* JRC wind farm database.

2.2. Towers

Figure 4 represents the hub heights of new wind turbines annually installed in Europe during 2007–12. The trend to taller towers is clear, and it is mainly motivated by the larger rotor diameters deployed in recent years (as shown later in Figure 6 and the emerging demand for low wind turbines, since the increase of wind speed with height is generally more pronounced in low wind locations (e.g. forested areas).

Tubular steel towers have been the most widespread solution, but the growing demand for taller towers is encouraging the development of alternative tower designs. As the diameter of the towers increase with height, wind turbines taller than 100 m usually require a base diameter above 4 m, which may pose a transport problem.

The increase in hub heights is ensuring that concrete towers increasingly emerge as an alternative to tubular steel towers supported by lower cost in particular for greater heights and markets with high local content. Another solution, based on hybrid steel–concrete towers, is offered by manufacturers such as Gamesa, Enercon, Nordex or Senvion. The base of the tower is made in concrete (either cast on site or composed by precast elements) and the upper part of the tower is compounded using tubular steel sections.

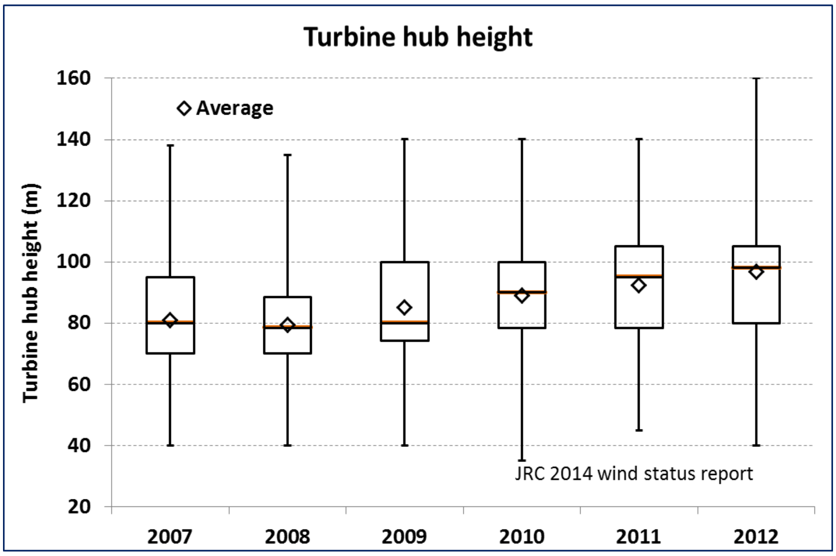


Figure 4: Boxplot representation of hub heights of onshore wind turbines installed each year in EU MS. *Source:* JRC wind farm database.

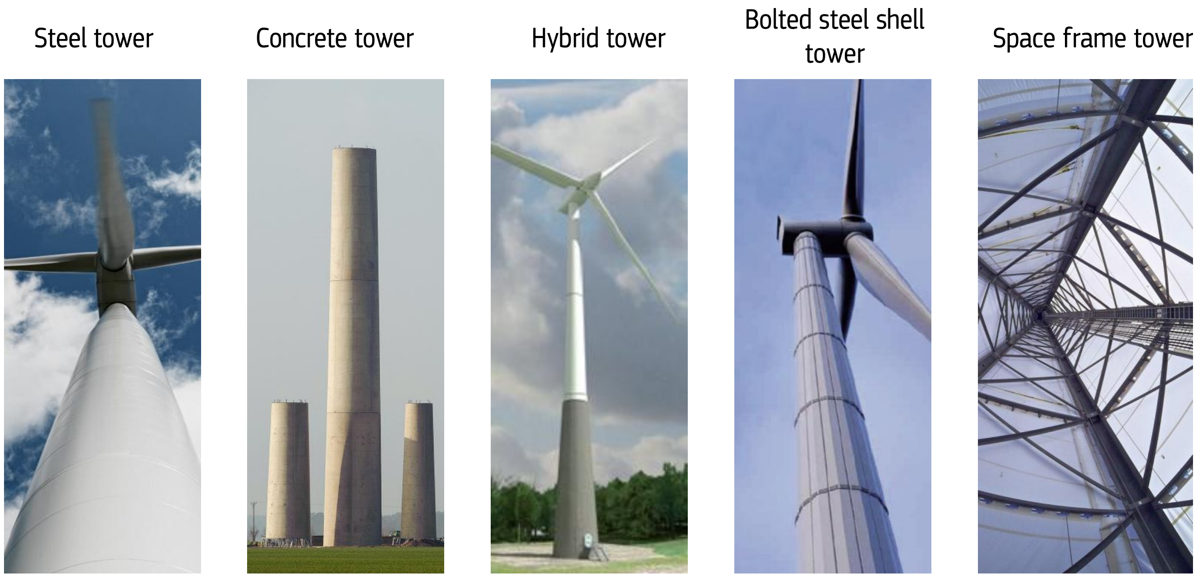


Figure 5: Different kinds of towers. Courtesy: Siemens, Acciona, GRI Renewable Industries and General Electric.

Some innovative solutions for taller towers include (de Vries, 2014a) (i) the bolted steel shell tower (used by Siemens and Lagerwey), consisting of multiple sections made out of steel shells which are assembled on site, (ii) the space frame tower proposed by General Electric, based on a steel lattice design covered with polyester cover, and (iii) the large diameter steel tower, where the bottom section is larger but of thinner walls, that is delivered in three lengthways segments which are transported on a flatbed truck. Innovative vertical flanges allow the reassembly of parts on site, thus easing the limitations of standard road transport (Vestas, 2014).

2.3. Blades

Blade technology has developed to be at the leading edge of wind energy technology development. Blades are made (using moulds) of fibre-reinforced polymers (resins) in the form of laminates and/or sandwich substructure. Traditionally blades were made of glass fibre and polyester resin. Current materials include, as well, epoxy resins reinforced mainly with glass fibre, and to some extent with the lighter but more expensive carbon fibres in selected areas or points sustaining high loads (e.g. spar caps).

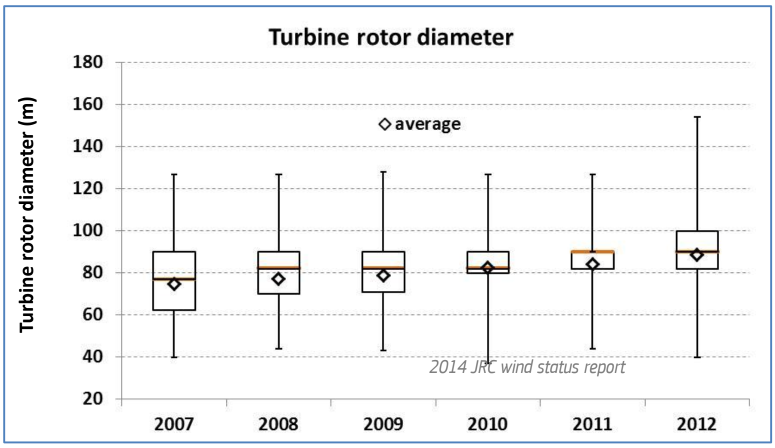


Figure 6: Boxplot representation of rotor diameters of onshore wind turbines installed each year in EU MS. (*Source:* JRC wind farm database).

In the evolution to longer blades (see Figure 7) carbon fibre was expected to be a key component in order to keep the blade light at the same time as stiff and slender. However, higher costs of carbon fibre and difficulties in the manufacturing process are preventing its generalised use (BNEF, 2014). New

New materials and processes that allow the design and manufacture of more slender blades include:

- new fabrics with higher modulus and better performance;
- new matrix (resins) that enhance the performance against inter-laminate loads and efforts, and with better properties in the fabric-matrix junction;
- new technologies or processes for the inclusion of carbon fibre in the 'hybrid' glass–carbon blades, that could solve issues related to the different modulus and the different coefficient of thermal expansion (this is key for curing processes);
- new processes for the positioning or design of the layup, and laminates to make the most of the materials, through their optimum use.

Source: Daniel Román-Barriopedro, Gamesa Technology Department, personal communication.

materials generally have higher efficiency (in terms of Cp/CT ratio), but they also present some structural challenges that are continuously being overcome (see box).

There are several ongoing research projects on new materials for blades. LM Wind Power announced ongoing research on new carbon hybrid materials. The European-funded projects, WALiD and MARE-WINT, aim at researching new material for offshore wind turbines. The CARBOPREC project started in January 2014 with the objective of producing cost-effective carbon fibres from raw materials widely available in Europe, such as lignin and cellulose.

A non-blade technological development that has also enabled the design of more slender blades is the new load control algorithms.

The increasing size of rotors has resulted in new challenges with regard to manufacturing (requiring larger moulds and costlier processes) and ground transportation. To overcome these challenges, manufacturers such as Gamesa (G128/5.0 MW) and Enercon (E126/7.58 MW) commercialise segmented blades that can be transported in two pieces and assembled on site. General Electric (GE) proposes blade extension by cutting the blades in half and adding a new section (General Electric, 2014). Thus, the area swept by the rotor is increased and, therefore, the more energy would be generated especially in moderate wind conditions. LM Wind Power is leading a Dutch-supported project to develop a new flexible blade length concept, based on a standard basic blade part plus variable tip sections (LM Wind Power, 2014). This approach would lead to tailored solutions according to the local wind conditions of each individual wind turbine; at the same time the manufacturing process can lead to a modular product. A different approach is pursued by the Blademaker project (founded by the German Federal Ministry for the Environment) aiming at developing new concepts to automate the blades manufacturing process.

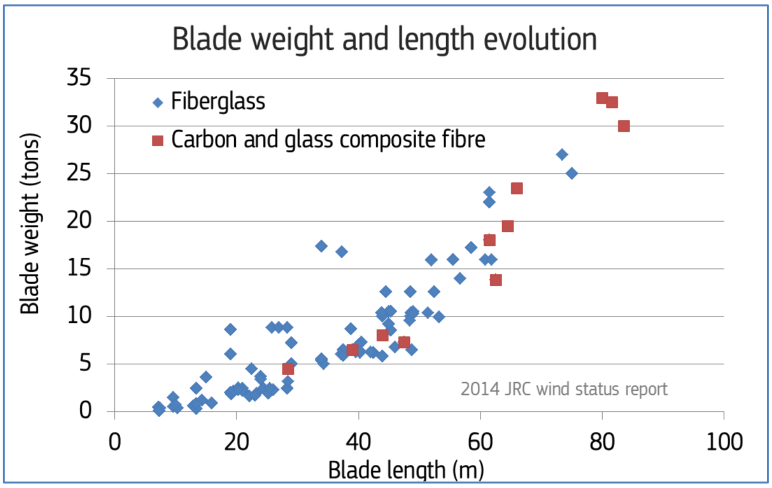


Figure 7: Blade weight relationship with length. (*Source:* BNEF and JRC wind turbines database).

Other innovations are aimed at improving aerodynamic efficiency. Generally, the root of the blade is designed attending to structural requirements rather than maximising the aerodynamic performance. In order to improve lift in this part of the blade, some manufacturers are including vortex generators to reduce the flow separation. As an example, Senvion equips the 3.2 M114 and 3.4 M114 wind turbines with vortex generators. Siemens offers vortex generators in the form of add-ons as a part of the Power Curve Upgrade services (Siemens Wind Power, 2012).

A lot of effort is also being put into anti-icing systems. This is very relevant as about a quarter of the world wind installed capacity of wind power is located in areas which are prone to icing conditions. Icing reduces efficiency and can severely impact energy yields; shortens life expectancy of the turbines and increases safety risks due to potential ice throw. Table 3 shows installed and forecast capacity in cold climates (IEAWind, 2014) (3).

Cumulative capacity by end of 2012 (MW)		
Low temperature	Light icing	Moderate to heavy icing
18 945	41 079	11 478
Total 69 000		

Table 3: Total installed capacity in cold climates. *Source:* IEAWind (2014).

Icing protection has two orientations: preventing and removing ice formation, anti- and de-icing respectively:

- Passive anti-icing systems based on hydrophobic coatings to prevent the formation of ice. The European project HYDROBOND is researching on the development of new hydrophobic coatings based on spraying nanoparticles. In another example, Gamesa's Bladeshield™ coating (Gamesa, 2014) is a result of the Spanish-supported AZIMUT research project.
- Active systems based on thermal solutions, such as distributing hot air throughout the blades (introduced by Enercon in 2011 and also used by Vestas, Gamesa and Senvion) or including heating mats selectively embedded in areas of the blade (e.g. Nordex and Siemens). However, heating from the inside, while the heat is needed at the outside, has shortcomings with respect to material properties and energy consumption. That is why also other technologies are being explored.
- A dual system developed by VTT of Finland incorporates 'a thermo-resistive carbon fibre mesh in the critical areas of the blade's leading edge during the manufacturing process'. The IPS is activated when ice could start building up on the blade, thus it acts as anti-icing system, but it can also be operated as a de-icing system using the 'thermo-resistive elements integrated into the structure' (Gamesa, 2014).

The reduction of noise is another objective that can influence (and is aided by) the technology and design of blades. The most common solution consists of including serrations at the trailing edge of the blade (Enercon, Gamesa and Siemens). Also, there are other solutions (not based on the design of the blade) to reduce noise emission. Manufacturers including Gamesa, Nordex, Senvion or Siemens offer a solution to mitigate sound emission consisting of control strategies to de-rating the wind turbine under certain noise requirements.

Advances have also been made in remote sensing systems to measure the blade deflection under operating conditions. A better knowledge of blade deformation enables the

(3) Cold climate refers to sites that have either conditions favourable for icing to occur or temperatures that are lower than the operational limits of standard wind turbines.

development of improved control strategies to maximise the energy output and reduce mechanical stress. LM Wind Power is researching on a monitoring system based on radio-based sensors. Part of the European-funded project MARE-WINT aims at simulating the airflow in the near-blade area in order to develop algorithms for the effective aeroelastic analysis of large offshore wind turbines.

Finally, aeroelastic tailored blade (ATB) technology, based on computer-intensive multidisciplinary design optimisation (Martins, 2013), offers the perspective of better blades more adapted to different wind conditions. Siemens offers this option since the B53 blade, but other manufacturers are exploring the technology (Siemens Wind Power, 2015a).

2.4. Drive train

For the purpose of this assessment the main components of the drive train are the gearbox, the electric generator and the power converter.

2.4.1. Drive train configuration

The drive train converts the mechanical power captured by the rotor into electric power. The steps involved in this conversion, and hence the drive train components, depend on the configuration:

- Geared wind turbine with doubly-fed induction generator (DFIG). Under this arrangement, the gearbox converts the slow rotating speed of the blades (usually around 4.5–20 rpm) into the high rotational speed required by standard induction generators (600–1 800 rpm). A partial power converter allows the control of the electric generator speed so that it can be adapted to the rotational speed of the mechanical system.
- Gearless or direct-drive configuration. A synchronous generator, either electrically excited or using permanent magnets (PMG) is directly coupled to the main shaft without gearbox (i.e. spinning at the same speed as the turbine rotor). The electric generator is connected to the grid through a full power converter that adapts the variable frequency/voltage of the electricity generated to the grid frequency.
- Hybrid configuration. Slow rotating electric generators require a large number of poles which are translated into larger generator diameters (and hence heavier machines). This issue is even more pronounced in large wind turbines where the rotational speed of the blades is slower. Alternatively, in the case of geared wind turbines, higher speed conversion ratios imply more demanding operating conditions for the gearbox components and bearings. A compromise solution can be achieved by this hybrid configuration equipped with a gearbox — which converts the slow rotational speed of the blades to medium speed, around 60–600 rpm — and a generator coupled with a full converter.

Geared wind generators have the advantage of lower upfront costs, since they do not require a full power converter and the generator is significantly smaller than a direct-drive one. However, direct-drive generators overcome the reliability issues related to the gearbox; even though power electronics have also a relatively high failure rate, the typical repair time is much lower than in case of gearbox failures (Tavner, et al., 2008), and offer more flexibility thanks to a full power converter, thus allowing easier compliance with the most demanding grid 'fault ride-through' capabilities as well as frequency regulation required by recent grid codes.

The wind turbine classification defined by Hansen et al. (2004) is essentially based on drive train configuration.

- Type A. Fixed-speed generator. The rotational speed of the electric generator (asynchronous generator) is the same as the spinning speed of the blades with very limited range response to variations in wind speed. No power converter nor other speed regulation techniques are employed in this configuration (NEG Micon N48 and Vestas V27 are examples of wind turbines employing this configuration).
- Type B. The speed of the asynchronous generator is controlled by a variable resistance that enables modification of the circulating current in the rotor of the electrical generator. This solution provides higher control flexibility than Type A. However, the electrical losses are relatively high and the response to grid requirements is limited (Vestas V52 and Suzlon S82 are the main representatives of Type B wind turbine in the market).
- Type C. This configuration is known as doubly-fed induction generator (DFIG). The current in the electric generator's rotor is controlled by a power converter. Thus, electrical losses are lower and the response to grid requirements is enhanced. Since the power converter is only connected to the rotor of the generator, the rated power of the converter is around 30 % of the rated power of the wind turbine (Vestas V90, Gamesa G80 and General Electric GE 1.5 are some representative models of this configuration).
- Type D. A full power converter enables decoupling the generator from grid frequency, so that frequency (and hence rotational speed) of the generator can be freely controlled and the use of a gearbox can be avoided. Additionally, the full converter provides enhanced grid services. Enercon is the dominant manufacturer in direct drive wind turbines based on a synchronous generator, whereas the Goldwin GW 1.5 is the predominant wind turbine in the market employing direct drive combined with permanent magnet-based generator.

Hansen's Type D configuration covers either direct drive or gearbox-equipped wind turbines as well as synchronous (both permanent magnet or electrically excited) or asynchronous generator (Hansen, et al., 2004). However, the market has changed and recent years have seen the development of new turbine models with increasing variations on the Type D configuration, which under the original definition would now be a kind of box for 'all other' configurations in the market other than Type C (as shown later in Figure 9). This market evolution suggests that the different configurations currently classified as Type D may (or perhaps we should say "should"?) be redefined in several categories for market-analysis purposes. Therefore, hereafter when we refer to Type D we consider only full-converter, direct-drive machines with either PMG or EEG, and define the following categories to cover for gearbox-equipped full-converter drive trains:

- Type E. Gearbox-equipped wind turbine with a full converter and medium-speed synchronous generator (PM or EE). In practice (with the exception of the old model Made AE-52), all Type E wind turbines use permanent magnets (Gamesa G128-4.5 MW pioneered and Vestas V112-3.0 are perhaps representative of this wind turbine configuration).
- Type F. Gearbox-equipped wind turbine with a full converter and high-speed asynchronous generator. As the full converter enables the speed to be controlled by modifying the operating frequency, a squirrel cage induction generator (SCIG) is

generally employed under this configuration. Siemens employs this technology in the SWT-2.3 and SWT-3.6 series.

2.4.2. Electric generator

According to the above-introduced classification, conventional geared wind turbines are equipped with induction (asynchronous) generators that can be arranged in four different forms (Types A, B, C and F). Likewise, synchronous generators are used in two configurations (Type D and Type E).

As shown in Figure 8 Types A and B have become marginal, the market being dominated by type C, and to a lesser extent by type D but with an increasing trend. Nevertheless, Types E and F are gaining more market share (in particular Type E in European countries and Type F in the North American market). This trend is expected to continue in the following years as the grid codes are becoming more demanding.

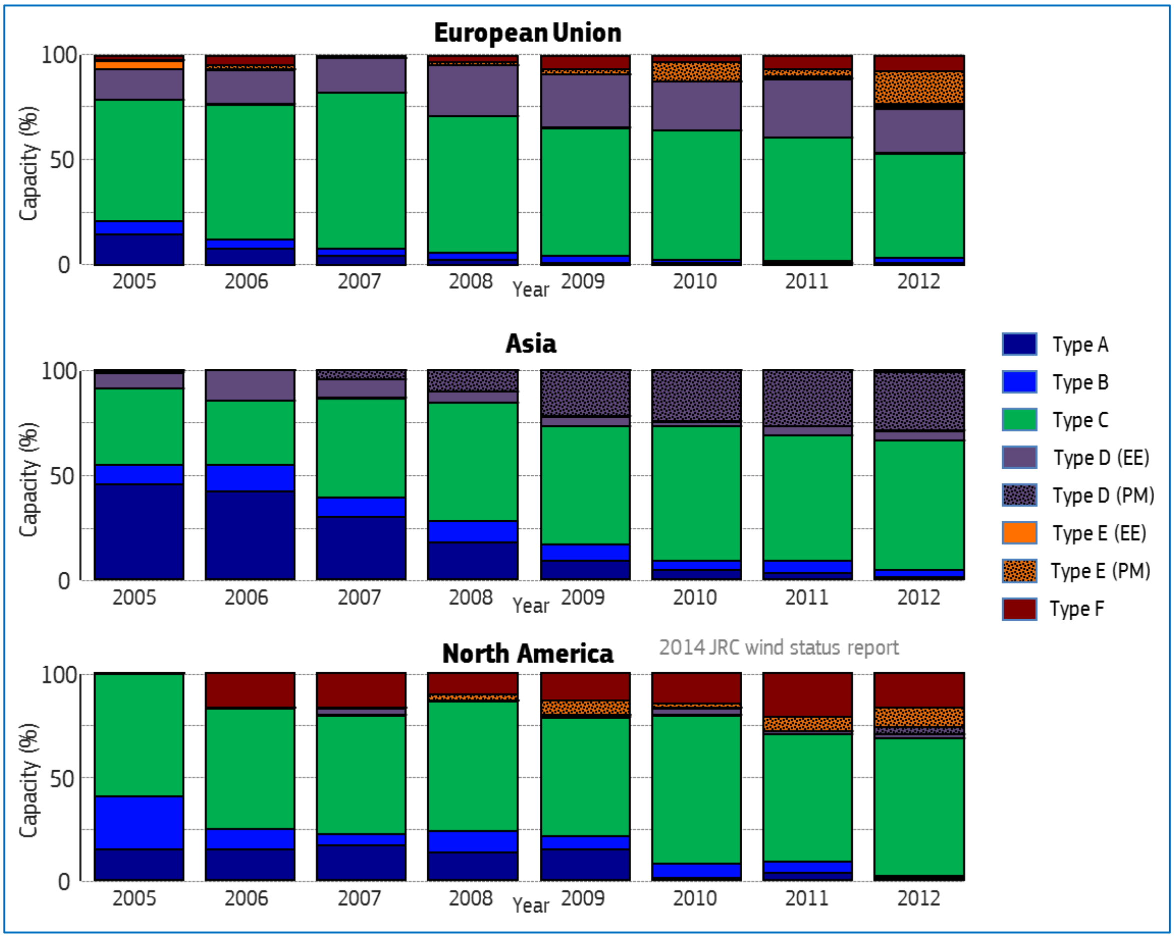


Figure 8: Evolution of the share of installed capacity by wind turbine configuration (*Source:* JRC Database). PM: permanent magnet, EE: electromagnetic excitation.

The share of PMG installed has increased in the recent years and, especially in the case of the Asian market, where most installed Type D generators are based on permanent magnets. PMG are more efficient than the traditional doubly-fed induction generators (DFIG) when operating at partial loads, which happens more often with lower winds (and turbines are increasingly being deployed in low-wind areas). Additionally, PMG have fewer moving parts than DFIG and moving parts require more maintenance, thus the evolution from DFIG to PMG is expected to continue, which would reduce O&M costs.

The main problem faced by a PM generator is the high variability in the price of its basic elements, namely the rare earths needed to manufacture permanent magnets, mostly neodymium (Nd) and dysprosium (Dy) (Lacal-Arántegui, 2015). The price of the latter increased in 2011 to reach more than 20 times above its previous 5-year average (a more detailed analysis can be found in the 2013 issue of this report and in Section 2.2 of Lacal-Arántegui (2015)). The effect of this spike in prices is reflected by the reduction in the share of installed wind turbines employing permanent magnets during the following years, mostly in the European and North American markets. A further problem with rare earths is the double risk associated with the high geographical concentration of the supply of rare earth elements, with about 90 % of them extracted in China.

There is a clear and seemingly successful trend towards permanent magnets with lower rare earth content, in particular of the scarcer heavy group (e.g. Dy). Neorem Magnets introduced several manufacturing innovations, based on transversal pressing, which resulted in improved alignment of magnetic particles and increased yield and effectiveness of magnets (Naukkarinen, 2014). Another way of reducing the dysprosium content consists of keeping the magnets at lower operating temperature, which can be achieved by better electric generator design. Siemens is working on permanent magnets with reduced dysprosium (Semmer & Urda, 2012). Although this solution would not be free of rare earth metal (it would use neodymium), the higher scarcity of dysprosium implies that its price will likely further increase in the next years. For example, Siemens claims that the development of stronger permanent magnets has enabled it to upgrade the 3 MW platform to 3.2 MW while maintaining the same stator dimensions (de Vries, 2014b), and the 6 MW offshore turbine to 7 MW (Siemens Wind Power, 2015b).

There are several ongoing projects financed by the European Union under the FP7 research programme with the objective of reducing the usage of rare earths in permanent magnets. The ROMEO project aims at developing new microstructural-engineering strategies to improve the properties of magnets based purely on light rare earth elements and, eventually, developing a totally rare-earth-free magnet.

The Suprapower project aims at developing a superconductor-based generator by using the superconducting properties of magnesium diboride (MgB_2) wires. Task 3.1 in work package 3 (Electromechanical Conversion) of INNWIND.EU has as its main objective the design and analysis of superconducting direct drive generators, based on the analysis of different superconducting wires, several electromagnetic generator designs, and different cryogenic cooling systems. Finally, the EcoSwing Horizon 2020 project aims at demonstrating a superconductor generator on a direct-drive 3.6 MW wind turbine by 2019.

2.4.3. Gearbox

A gearbox consists of several (usually three) planetary or helical gears. Three-stage gearboxes (two parallel and one helical gears) are typical for wind turbines of moderate size (below 1 MW). However, planetary gears provide a reduction in volume for higher speed ratios. For this reason, bigger wind turbines employ one or two planetary gears combined with (two or one, respectively) helical gears.

Gearboxes are seen as the least reliable part of high-speed wind turbine configurations, although most often it is the third stage (the fastest one) that is problematic. Several studies, including the European project Reliawind, concluded that the electrical systems (including the power converter) and the pitch system cause more failures. It was also found that electrical system failures are not necessarily the costlier, nor do they cause more downtime that any other turbine sub-assembly (Wilkinson, et al., 2011).

In addition, research shows that gearbox failures are most often due to unexpected loads originating somewhere else, e.g. in the turbine rotor or in its control system as a consequence of forcing the generator to maintain grid frequency. More detailed data are needed to improve the designs and, for example, sensors originally from the automobile industry are now available which can be used for this. System aspects which protect the

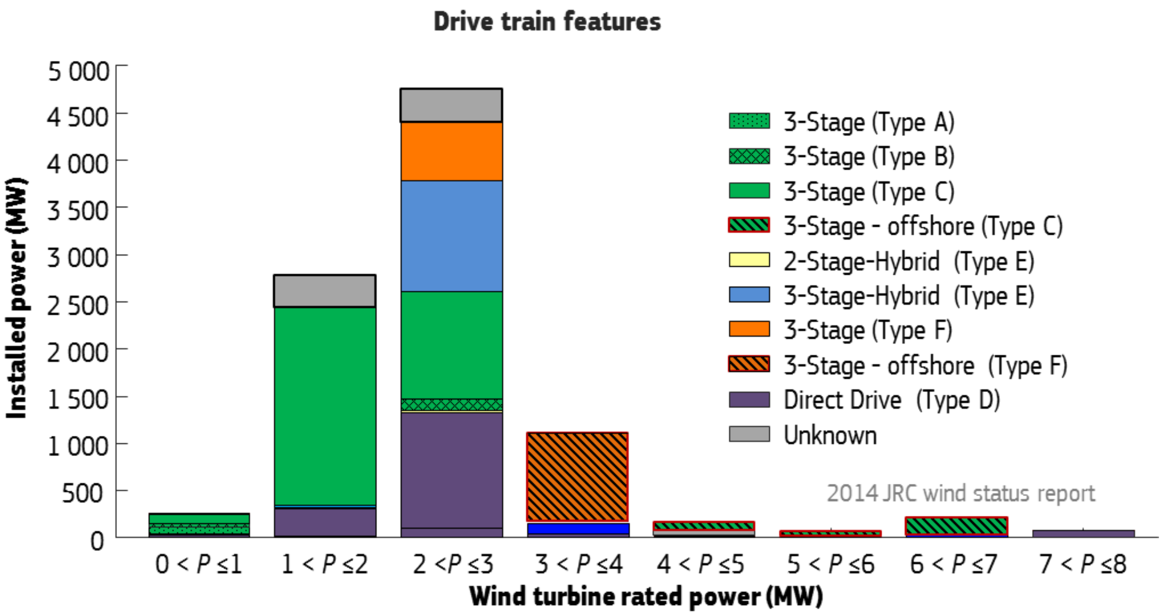


Figure 9: Drive train features classified according to wind turbine rated power. Data corresponding to installations in EU MS during 2012. *Source:* JRC Database.

gearbox and lengthen their life include using a full converter which reduces grid-induced loads or individual-blade pitch feeding which reduces loads when the blades reach the extreme positions (vertical up or down).

New gearbox designs aim at lighter gearboxes, higher reliability and efficiency to reduce both CapEx and OpEx. For example, bearings that are reinforced at the exact points where they support the highest loads and better transfer of loads to the tower (thus by-passing the gearbox), also help in improving gearbox reliability.

Winergy disclosed in 2014 the development of a new gearbox concept including journal bearings (4). This solution would be an alternative to rolling element bearings by reducing wear, noise and vibration. Also, efforts are being made in order to reduce the weight and size of the gearbox. In this sense, Moventas presented the ongoing developments in a new gearbox with higher ratio torque-weight.

Figure 9 shows the type of drive train employed in wind turbines installed in European Union Member States during 2012, classified according to wind turbine rated power. Onshore installations were mainly dominated by wind turbines in the range 1–3 MW, whereas turbines with higher rated power (in the range 3–7 MW) are employed for offshore installations as well. As regards drive train configuration, a 3-stage gearbox coupled with an asynchronous generator (Type C) is the most common arrangement for wind turbines

(4) Unlike ball bearings, this bearing type does not employ rolling-elements. The shaft directly slides over the bearing surface.

under 3 MW. However, Type D (either direct drive or hybrid configuration) is the prevailing arrangement for wind turbines specifically in the 2–3 MW range. Looking at the offshore market, most wind turbines installed during 2012 were Type F with a three-stage gearbox and a full converter, the Siemens machines. Nevertheless, this scenario is expected to change as most wind turbines addressed to the offshore market introduced in recent years are based on permanent magnets either direct drive (Type D) or hybrid drive train (Type E). Incidentally, Figure 9 shows a clear segmentation — in terms of rated power — of wind turbines aimed at the onshore and offshore market.

2.4.4. Power converter

The power converter is a key element in modern wind turbines that acts as an interface between the electric generator and the power grid. On the generator side, converters enable the control of the rotating speed and the output power. On the grid side, the converter has the ability to control the reactive power and response to fast demand changes on the active power (Blaabjerg, et al., 2012). This flexibility introduced is even higher in case of full converters, being both sides — generator and grid — fully decoupled and operation is possible with any ratio reactive to active power. The main drawbacks of power converters are (i) they are expensive, (ii) reliability, (iii) relatively low efficiency at partial loads and (iv) they distort the electrical waveform (especially because of the emission of high frequency harmonics).

New grid code demands include a longer low-voltage ride through of up to one second in Germany, improved reactive energy output and remote control by system operator (Obando-Montaño, et al., 2014). Power converter innovations can realise this whether the turbine uses a partial converter (e.g. Gamesa) or a full converter (e.g. XEMC Darwin). New converters resist better weak grid situations.

Research on power electronics is also focused on improving reliability. The OHMWIT project funded under the FP7 programme aims at creating a new online condition monitoring system for generators and power converters. The WINDTRUST project (also funded under the FP7 programme) aims at improving the reliability of key components of the turbine. With regard to power electronics, the objective is reducing the number of components and interfaces by using new assembly technologies such as all sintered modules and by reducing the volume of the inverter by 30 %.

The SPEED project researches on developing a new generation of high power semiconductor based on Silicon carbide (SiC), in order to improve the efficiency of power electronics employed in power generation, transmission, and distribution. With regard to wind energy, a semiconductor able to operate at voltages above 10 kV would be crucial to reduce the cost of power electronics at the same time as enhancing its performance.

2.5. Offshore foundations

The most popular foundations for offshore wind farms are monopiles and, to a lesser extent, jacket foundations for shallow-to-medium water depths.

Figure 10 shows the breakdown of installed foundations per type. Even though the most suitable foundation type also depends on the different site conditions, monopiles have proved to be the most popular solution.

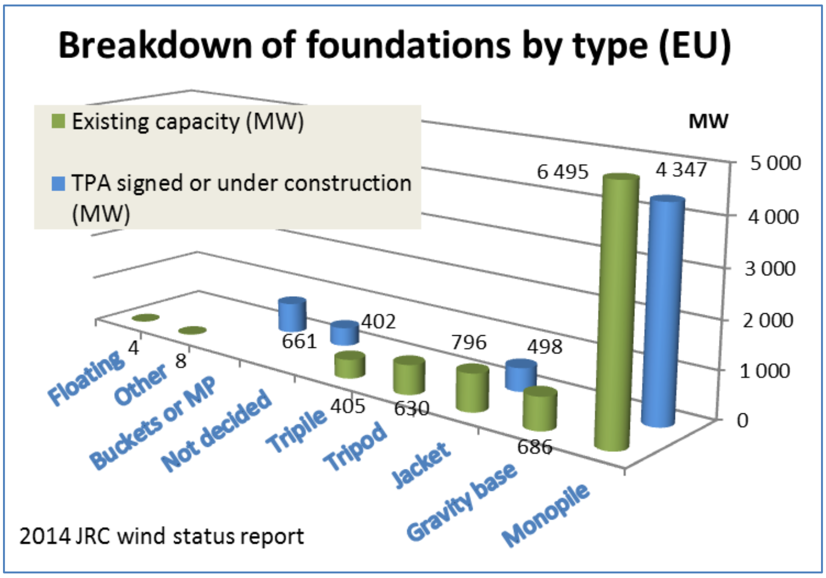


Figure 10: Split of foundations by type, both for existing wind farms and for wind farms under construction (early 2015). *Source:* JRC database.

As wind turbines with increasingly larger rotors are installed at depths of 30–50 m, monopiles were expected to lose ground in favour of other solutions, mainly jackets or new designs. However, to some extent this trend seems to be reversed after the latest developments concerning extra-large (XL) monopiles. Figure 11 shows how the diameter of installed monopiles has grown over the years. As shown, current monopiles with diameters higher than 7 m have become a suitable solution for 6 MW wind turbines at a depth around 35 m, as is the case with the Gode Wind I and II wind farms, currently under construction, or the Nordsee wind farm that for the first time will use XL monopiles for the Senvion 6.2M152 wind turbine.

The Carbon Trust of the United Kingdom has supported the installation of a new suction bucket jacket foundation at DONG Energy's Borkum Riffgrund I wind farm in Germany. If suitable, this technology concept will allow for more time- and cost-efficient installation as jacking-up can be avoided, and at very low noise levels. The prototype foundation is a three-legged jacket with bucket-foundations which used a vacuum-assisted installation method. As a first commercial contract the substation of the offshore wind farm Dudgeon in the UK will use a four-leg suction bucket jacket foundation by the same manufacturer, SPT (Weston, 2015). We expect suction bucket jackets to start commercial installations perhaps as early as 2016.

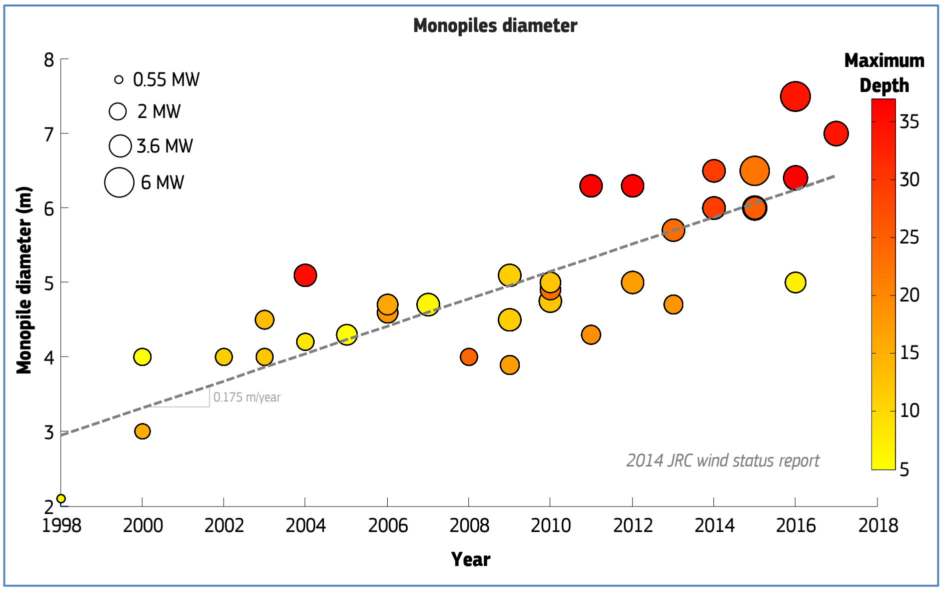


Figure 11: Evolution of monopiles diameter (installed and planned). Circle size relates to wind turbine rated power and colour to maximum seabed depth at the wind farm location.

Van Oord, a Dutch offshore contractor, introduced an innovation at Eneco's Luchterduinen offshore wind farm which consists of doing away with the transition piece. The foundations, whose installation started in June 2014, require less material overall. The foundation is 13 metres longer than a traditional monopile for the same site, and its flange connection (between the turbine and the foundation pile) 'can directly sustain the impact of the pile driver'. The components usually in the transition piece (e.g. ladders and platform) will be connected to the pile offshore, after completion of the pile driving process. Even when this offshore working time is not necessary when using the traditional monopile plus transition piece approach, the innovation is still expected to have a shorter offshore installation process and thus an additional cost reduction (Eneco, 2014), but it is not expected to be cost-effective in all circumstances.

There are several experimental designs of floating foundations (spar-buoys, semisubmersible, barges and tension leg platform), which are being explored in order to capture the very large resource available in deep-water areas. As at mid-2015 three prototypes with floating foundations were being tested in the world, one in Norway, one in Portugal and one in Japan. The first deep-water demonstration wind farms in Europe will likely be the NER300-supported WindFloat and VertiMED projects ([5]).

Also on floating structures, the EU-supported project FLOATGEN will build a prototype of multi-megawatt floating turbine in southern Europe, based in IDEOL's (France) square ring-shaped concrete.

2.6. Offshore installation

One of the problems restricting the development of offshore wind farms, and increasing their cost, is the noise generated by existing methods of installing monopiles, and the impact that this noise has in particular on the hearing and navigating abilities of marine mammals (Bergström, et al., 2014). Different methods are being explored to reduce this noise including vibro-driving, bubbles curtains and others. The Carbon Trust under its Offshore Wind Accelerator programme is supporting the substitution of vibration piling for hammering as the most popular technique for installing monopiles.

The old installation vessels, basically modified existing jack-up vessels, will not be able to install the next-generation wind turbines (farther offshore and in deeper waters) at a rate that can significantly reduce the cost of energy. The first generation of specialised (wind-only) installation vessels that came into play during 2010–13 are much more capable in respect of installation at the current distances to shore and water depth, but they will show their limitations with the next generation of offshore turbines and with XL monopiles. Table 4 shows some of the technical specifications of recently-commissioned or ordered installation vessels.

A significant part of the approximately 15–25 GW of offshore wind farms that will be installed during 2015–23 will use XL monopiles and turbines whose nacelle (weighting 350–450 t) has to be lifted to above 100 metres — higher than nearly any turbine installed offshore so far. Those turbines, mostly rated in the 6–8 MW range, can be already transported and installed by some of the existing installation vessels — but the deck space in these vessels is limited and not many turbines can be transported in a trip. Next-generation installation vessels must be capable of covering those specifications, and to

([5]) NER300 is a funding mechanism of the European Union which will provide EUR 30 m and EUR 34 m respectively to the WindFloat and VertiMED projects.

carry 7–9 new turbines per trip at a high transit speed (e.g. 15 knots), or else alternative transport must be designed.

Vessel	Cargo area/ Deadweight	Transit speed (knots)	Crane capacity @ radii	Jacking wave limits	Delivery year
Seajacks Scylla	4 600 m^2, 8 180t	12	1 500t at 31.5 m	2.0 m	2015
Rambiz 4000	2 000 m^2 (*), 4 000t	7	2 x 2 000 t	N/A	2016
Apollo	2 000 m^2, 4 450t	9	800 t at 25 m	1.4 m	2017
Wind Server (**)	1 000 m^2, 1 760t	9	400 t at 20 m	1 m	2014
Aeolus	3 300 m^2, 6 500t	12	900 t at 30 m		2014
Sea Challenger	3 350 m^2, 5 000t	12	900 t at 24 m	2.0 m	2014

Table 4: Examples of key technical specifications of new installation vessels. *Source:* Company brochures and (Douglas-Westwood, 2013). *Note:* The knot (ISO standard kn) is the marine unit of speed, one knot equals one marine mile (1 852 m) per hour.
(*) This is the deck area, the Rambiz 4000 is a heavy-lift self-propelled vessel.
(**) The Wind Server was included here as a case of a vessel designed specifically for O&M of wind turbines.

The FP7 project Leanwind (which started in December 2013 with an EU contribution of EUR 10 m) is aimed at applying lean principles to the critical project stages of offshore wind farm project development. The objective is to streamline the flow between the different stages and to remove complex and wasteful phases during installation, operation and maintenance as well as decommissioning. The main preliminary findings presented by the project are summarised below:

- Innovations related to installation provide a potential cost reduction (taking into account the extent of installation costs for offshore wind farms, of usually around 10–15 %, see Figure 35 in section 4.5 for further details) by (i) reducing the time needed for the various installation operations and (ii) extending the availability period of time to operate under unfavourable meteorological conditions.
- New techniques are being developed to improve the accessibility of the wind turbine to technicians in order to undertake unplanned maintenance depending on weather conditions. The current typical limit is 1.5 m of significant wave height and 12 m/s wind speed at hub height. However, it would be desirable to ensure accessibility to the wind turbines with waves of 3 m significant height.
- Increasing automation for surveillance and monitoring of wind turbines may provide a reduction on the levelised cost of energy by limiting manned interventions just to heavy maintenance.
- Operation and maintenance activities can be optimised by applying optimal decision-making techniques based on risk-based approaches.
- International standards for data capture, storage and presentation should be adopted by the wind power industry. The availability of open data protocols would enable development of new and innovative solutions. Two main variants of standardisation are described in the results of the project: (i) development of standard operations for operation and maintenance activities that would be applicable to many different wind farms/wind turbines, and (ii) specification of the minimum requirements to ensure a sufficient safety level for personnel.

3. Wind energy market status

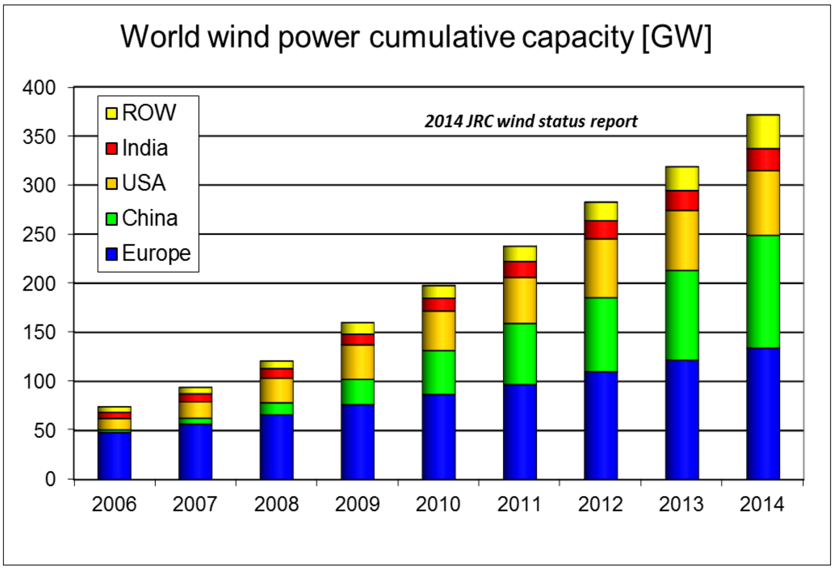


Figure 12: Cumulative worldwide installed wind power capacity from 2006 to 2014. Sources: (GWEC, 2015) and similar reports of previous years.

Last year brought about a new annual record with 52.8 GW of wind turbines installed in the world (6), an increase of 48 % year-on-year (y-o-y) and 17 % over the 2012 record of 45.2 GW. The cumulative worldwide total of installed wind capacity reached 370 GW (Figure 12). Whereas since 2006 the installed capacity offshore boomed from less than 1 GW to 9.5 GW, onshore the 22 % annual growth expanded installations from 73 to 360 GW. The installed capacity can produce about 820 TWh (7) of electricity in an average year, or approximately 4.3 % of the global electricity final consumption of 2012 (8).

With 23.2 GW of new installations and a market share of 44 %, China is well ahead of the next market in 2014, Germany (6.5 GW). European Union Member States added in total 13.05 GW (31.6 %), with Germany followed by the UK (1.74 GW), Sweden (1.05 GW) and France (1.04 GW) as the only four EU countries installing more than 1 GW in 2014. No other EU country added 500 MW or more, and the next significant markets were Poland (444 MW), Austria (411 MW), and Romania (354 MW). Other European countries and Turkey added 2 542 MW (of which Turkey added 804 MW).

Countries offering a positive trend, even a qualitative jump forward in some cases, include the US — recovering after the disastrous 2013 — which installed 4.85 GW in 2014, Brazil (2.47 GW), India (2.32 GW), and Canada (1.87 GW), which also exceeded the 1 GW mark. Mexico (567 MW), South Africa (560 MW), Chile (506 MW), Uruguay (405 MW), Morocco (300 MW), Pakistan and Philippines (150 MW each) and Peru (146 MW) are remarkable as well for what it means in terms of change of trend or the establishment of a new market, the case of South Africa, Uruguay and Peru, and somehow Chile and Philippines.

The Australian market (567 MW) offered stable behaviour. However, other traditional markets performed disappointingly, e.g. Poland with 444 MW, Romania with 354 MW, Denmark with 67 MW, or Norway with 45 MW (Weir, 2015), or even disastrously, e.g. Bulgaria with 9 MW, Spain with 28 MW and Italy with 108 MW (GWEC, 2015) (EWEA, 2015).

(6) This figure is made up of 51.5 GW globally installed and commissioned (except in China, where installed capacity is reported) plus some offshore installations finished but not commissioned in Germany (1.218 GW): *Sources:* (GWEC, 2015), (Lüers & Wallasch, 2015a).

(7) Assuming an average capacity factor of 2 200 hours or about 25 %.

(8) According to IEA Electricity Information 2014 (IEA, 2014a, p. III.4) the final consumption in 2012 was calculated at 18 912 TWh, and this gives a 4.33 % contribution from 820 TWh of wind electricity.

The EU was still leading cumulative installed capacity with 129 GW commissioned at the end of 2014, whereas China is fast approaching with 115 GW installed (of which only 96 GW is connected to the grid (Publicover, 2015), and increased its lead over the United States to 49 GW (114.6 GW vs. 65.9 GW, see Figure 12). They were followed by Germany (39.2 GW), Spain (23.0 GW) and India (22.5 GW).

The overall shift in market weight towards Asia continues for another year. After Europe led the world market in 2004 with 75 % of new installations, it took only 5 years for Europe, North America and Asia to reach an almost even distribution of annual market shares. Then, last year Asia dominated installations with 49.6 % followed by Europe with 26.7 % and the Americas with 20.9 %. Other continents still had a marginal contribution at 2.8 %.

In terms of percentage annual growth, in 2014, the EU's wind capacity grew by 10 %, significantly below the global average of 16.6 %. The total EU grid-connected capacity of 129 GW is capable of producing, approximately 265 TWh ([9]) of electricity or roughly 9 % of the 2012 EU final electricity consumption.

Country	< 2005	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Total
Belgium						30	165		185	186	147	712
China				2		65	275	75	127	53	26	622
Denmark	427					238	207	4	50	349		1 274
Finland	0.7			15	9		2.3				1.3	28
Germany	5		3		5	60	40	88	80	560	904	1 745
Ireland	25											25
Japan		11						14		0	23	48
Netherlands	19		108	120								247
Norway						2			0			2
Portugal								2				2
South Korea								2	5			7
Sweden	24			110		30			4	48		216
UK	124	90	95	95	194	187	556	667	1340	351	832	4 530
Vietnam										16		16
Total	623	101	206	342	208	612	1 244	851	1791	1564	1932	9 474

Table 5: Annual installations offshore in MW based on ***installation*** (not on ***commissioning***) year. 2014 data include turbines commissioned by the end of the year in partly operational wind farms. Intertidal, shoreline (i.e. physically connected to the shore) and in-lake wind farms are included in this table. *Source:* JRC database.

Figures for offshore wind installations vary widely depending on the source, due to the different milestones used, e.g. whether the year of turbine installation or of commissioning. In addition, date information can be corrected significantly *a posteriori*. Based on the date that individual turbines started producing electricity, 2014 saw a 23 % increase in annual installed capacity from 1 564 MW to 1 931 MW (including intertidal plant ([10])), which compares with the 13 % decrease in 2013 regarding the previous year, see Table 5.

([9]) Assuming a capacity factor of 1 984 hours (22.6 %), equal to the European average for the years 2004–13. *Source:* Author's calculations based on the historical wind energy capacity factor (CF) from Eurostat data on generation and installed capacity.

([10]) Intertidal wind farms are located in the intertidal area of low-depth sea areas that are covered by the sea in the high tides.

3.1. Global market status

3.1.1. The European Union and beyond in Europe

At the end of 2014 the European markets that are actively deploying significant amounts of wind energy include Germany, the UK, Sweden, France, Turkey, Poland and Austria.

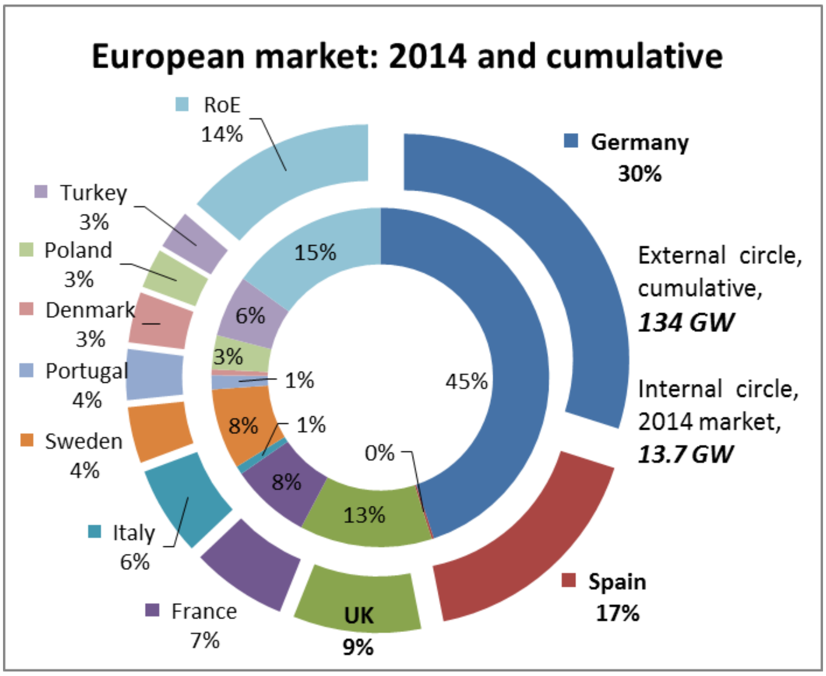


Figure 13: Installed capacity in the whole Europe during 2014 and cumulative, for the main markets. 2014 market includes the non-grid-connected offshore wind farms in Germany. *Source:* JRC based on (EWEA, 2015) and (Lüers & Wallasch, 2015a).

During 2014 the significant ***year-on-year*** (y-o-y) growth of the market, in both percentage and volume, took place in Germany (+ 83 % or + 2 780 MW or + 57 %, + 1 900 MW if the offshore installed but not connected capacity is not included), France (+ 65 %, + 411 MW) and Sweden (+ 45 %, + 326 MW). Stable markets include Turkey (+ 24 %, + 158 MW), and Belgium (+ 18 MW). Markets that did not grow nor reduced y-o-y installations significantly include Greece (0 MW), Portugal (– 12 MW), Finland (– 4 %, – 8 MW), and the UK (– 147 MW). On the negative side, Denmark (– 90 % and 590 MW less installed capacity than in 2013), Spain (– 84 %, – 147 MW), Bulgaria (only 9 MW installed), Romania (– 49 %, – 341 MW) and Italy (– 76 %, – 336 MW), Norway (– 54 %, – 53 MW), and the Netherlands (– 53%, – 162 MW) present perhaps the most disappointing y-o-y evolution. See Sections 3.2.4 and 5.9 for additional assessment of reasons behind this performance.

Over the last few years annual European installations have remained at between 9 GW and 12 GW. Overall stability is therefore the norm in Europe, with offshore wind and new onshore markets likely to push up annual figures to around 11–12 GW per year for the next 4 to 6 years.

Market concentration. The year 2014 showed a trend towards concentration in a few markets, namely Germany and at much lower levels the UK, France and Sweden, which among the four cover 71 % of all European installations whereas the top four markets only covered 56 % in 2013 and 52 % in 2012. The poorer performance of emerging markets (e.g. Romania and Poland) and the demise of Bulgaria, Spain and Italy also helped in creating a picture of a concentrated European market.

Cumulative capacity. As shown in Figure 13, Germany (39.2 GW) and Spain (23.0 GW) still led in terms of cumulative capacity at the end of 2014 followed by the UK with 12.5 GW and two countries in the 8.5–9.5 GW range, France (9.3 GW) and Italy (8.6 GW). Then came Sweden (5.4 GW), Portugal (4.9 GW) and Denmark (4.9 GW), followed by Poland (3.8 GW) and Turkey (3.8 GW).

3.1.2. China

China achieved a new record when it expanded in 2014 to install 23.2 GW (+ 45 % y-o-y, + 7.25 GW) after having markedly contracted in 2012 to 13 GW installed and a partial recovery in 2013 (16.1 GW installed). Still, it has to be noted that for the last 6 years China has added capacity at a very high level and has been the world market leader with 13.8, 18.9, 17.6, 13, 16.1 and 23.2 GW respectively (Frank, 2015) (CWEA, 2015) ([11]) to reach 114.6 GW accumulated capacity at the end of 2014. Accumulated capacity grew by 25 % during 2014.

The installed capacity that was not connected to the grid reached 19 GW at the end of 2014, or 16.5 % of the total, a year when a record 18.7 GW were connected (Publicover, 2015). Although the non-connected capacity marks a new record, this is caused by the record new installed capacity rather than by a slowing down in the enlargement and reinforcement of the grid. The 16.5 % figure is worse than the 15 % at the end of 2013 but still a significant improvement over the 20 % of the end of 2012 or the 26 % of the end of 2011.

3.1.3. North America

The US market recovered in 2014 with 4.85 GW installed (+ 330 % y-o-y or + 3.7 GW), from the disastrous 2013, and helped by Canada (+ 17 % y-o-y or + 270 MW to reach a new annual record of 1.87 GW), and by the partial recovery of the Mexican market (+ 45 % y-o-y or + 172 MW, to reach annual installations of 552 MW), put the North American annual market at 7.3 GW.

Cumulative capacity reached 65.9 GW in the US, 9.7 GW in Canada and 2.4 GW in Mexico for a total 78 GW in the North American continent. These figures represent an annual growth of 7.8, 24, 28 and 10 % respectively.

3.1.4. Rest of the world

The Indian market recovered from a bad 2013 to levels similar to 2012 (2.3 GW were installed in 2014, + 4 % y-o-y or + 586 MW), although this was still lower than the 2011 record of 3 GW. Brazil actually overtook India in terms of annual market (2.47 GW installed, + 160 % y-o-y or + 1.5 GW) thanks to the completion of grid extensions that also connected wind farms installed in previous years. After some delay, South Africa finally took off as the expected star of the continent with 560 MW installed that need to be compared to the mere 10 MW existing before the end of 2013. Other bright stars because of annual installations and because of prospects for a good future include Chile (+ 506 MW installed, + 290 % y-o-y), Uruguay (+ 362 MW, 840 % y-o-y), Morocco (+ 300 MW, zero installed in 2013), the Philippines (+ 150 MW, zero installed in 2013) and Peru (+ 144 MW versus only 2 MW in 2013). In Oceania, only Australia presented new installed capacity (567 MW, – 13 % y-o-y or 88 MW less than 2013).

In terms of cumulative capacity in the rest of the world, after India (22.5 GW), Brazil's impressive 2014 performance put it well in front of Australia (5.9 GW versus 3.8 GW), both ahead of Japan (2.8 GW). They are followed by a group of countries presenting between 0.5 and 0.9 GW of cumulative capacity: Chile, Taiwan, South Korea, Morocco, South Africa, Egypt, New Zealand and Uruguay.

([11]) CWEA statistics from previous years were consulted as well.

3.1.5. The offshore market

The offshore market has the perspective of continuous — but not explosive — growth. The main reasons include the perceived benefits from developing a new technology in terms of competitiveness, the extent of the wind resource available, the wide public support, and the clear prospects for cost reductions.

Wind farm name	Country	MW	Status	Operational
Borkum Riffgat	Germany	108	Operational	2014
Northwind	Belgium	216	Operational	2014
Meerwind	Germany	288	Operational	2014
Dan Tysk	Germany	288	Operational	2015
West of Duddon Sands	United Kingdom	389	Operational	2015
EnBW Baltic II	Germany	288	Under commissioning	2015
Gwynt y Mor	United Kingdom	576	Under commissioning	2015
Trianel Windpark Borkum 1	Germany	200	Under commissioning	2015
Global Tech I	Germany	400	Under commissioning	2015
Nordsee Ost	Germany	295	Under commissioning	2015
Westermost Rough	United Kingdom	210	Under commissioning	2015
Amrumbank West	Germany	288	Under construction	2015
Borkum Riffgrund I	Germany	312	Under construction	2015
Butendiek	Germany	288	Under construction	2015
Humber Gateway	United Kingdom	219	Under construction	2015
Luchterduinen	Netherlands	129	Under construction	2015

Table 6: List of European offshore wind farms operational or under construction in 2014 and 2015. *Source:* JRC database.

Table 6 shows a list of wind farms commissioned in 2014 and early 2015 or under construction and with expected commissioning in 2015.

The offshore turbine market during these 2 years (2014 and 2015), taken as the date of final commissioning ([12]) was led by Siemens with 68 % of installations — measured in megawatts — followed by Areva (Turbine M5000-116), Vestas (Turbine V112-3.0) with 13 % each, and finally Senvion (Turbine 6.2M126) with 7 % of the total (see Figure 14).

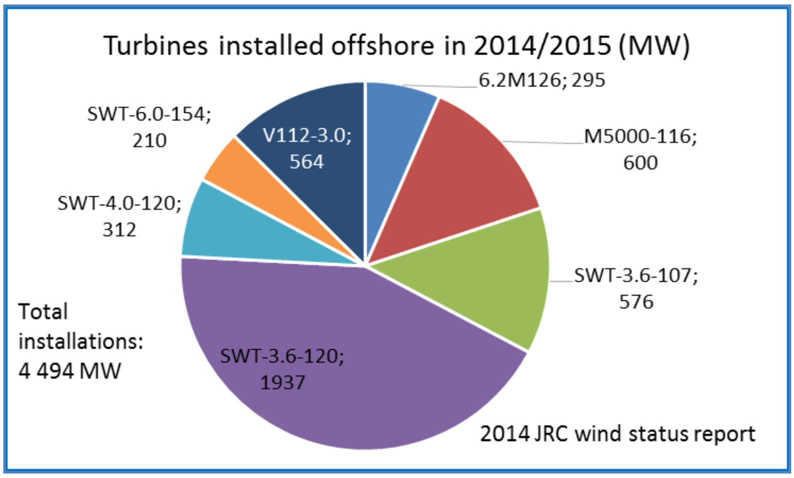


Figure 14: Share of the turbine market offshore, 2014/2015. *Source:* JRC database.

Wind farms have reached similar capacities to conventional generation plant. Currently the largest wind farm in the world, Alta Wind Energy Center in California (US) has installed capacity of 1 320 MW. In Europe, the largest wind farm onshore is Fantanele-Cogealac in Romania with 600 MW and offshore it is London Array with 630 MW.

([12]) Note that some of those wind farms started installation in 2012.

3.2. Analysis and projections

3.2.1. Short-term perspectives

Annual market projections have recovered thanks to the good performance in 2014 and to the large amount of projects announced during 2014 and early 2015. This positive spirit is supported as well in the continuous reduction of the cost of energy from both onshore and offshore wind (see Section 4.8), as shown in different auctions [13].

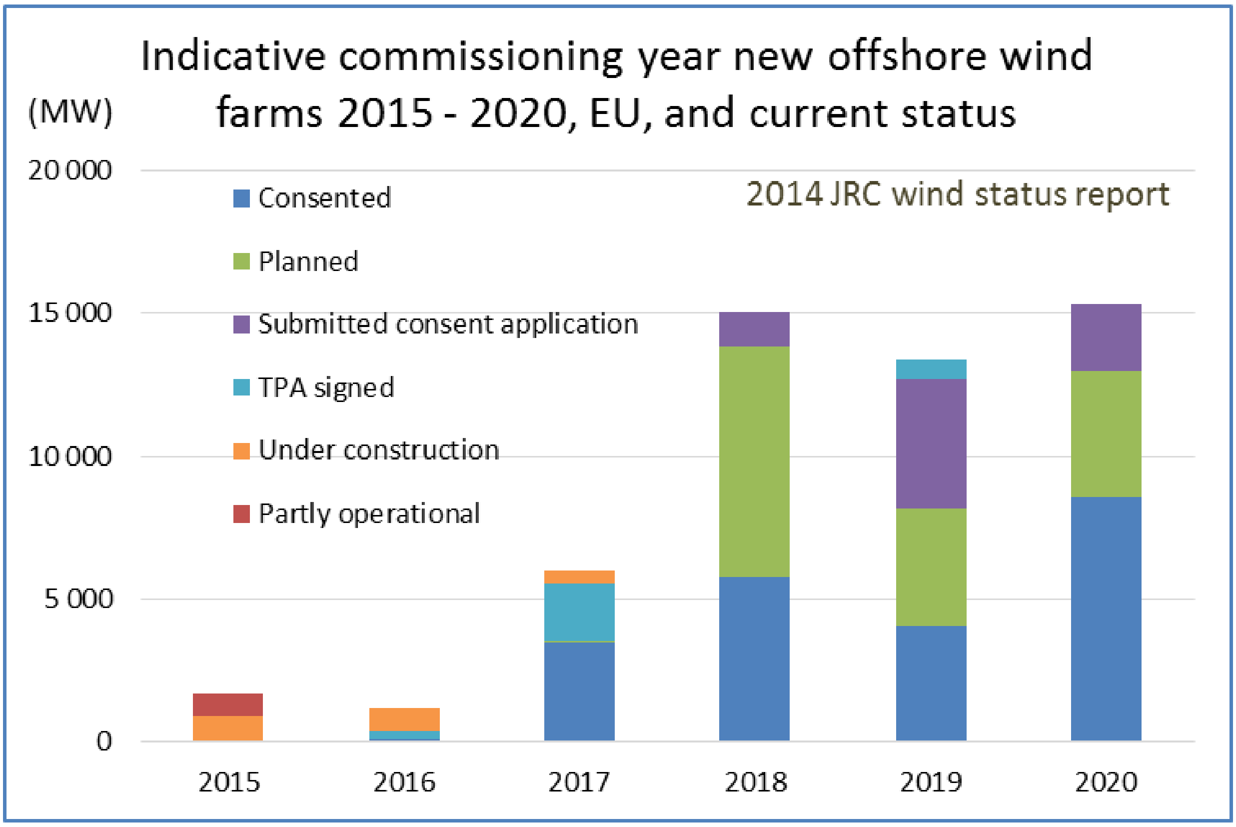


Figure 15: Status of the pipeline of offshore wind farms in the EU, in megawatts, according to the indicative commissioning year. TPA stands for turbine purchasing agreement. *Source:* JRC database.

For the period 2015–17, we expect a strong performance initially and perhaps a slight reduction of annual installations afterwards. The JRC's 2020 projections include 215 GW installed in the EU, of which 27 GW is offshore, and 715 GW globally, of which 40 GW is offshore. Note that a comparison with Figure 15 shows that the pipeline of projects is more optimistic at about 55 GW.

Factors that influence current onshore projections include an expected high delivery of the Chinese market in 2015 due to a forthcoming reduction in its feed-in tariff; continuous overall stability in Europe with the main market (Germany, also subject to forthcoming FiP reductions) being supported by others (France initially, the UK and the emerging markets); the policy boost in India getting steeper towards 2015–16; the execution and

[13] Note, however, that auctioned prices can be highly variable when highly affected by currency exchange rates, as was the case in Brazil.

commissioning of all pending auction winners in Brazil and South Africa; and strong growth in Mexico, Canada, and some South American markets other than Brazil.

In North America, the US market will further increase in 2015/2017 due to the projects under construction from the 2013 Production Tax Credit (PTC) extension and to the brief (2 weeks) 2014 extension, for which qualifying projects need to have committed 5 % of funds by end-2014 but can be finished in the following 2 or even 3 years.

Canada will continue to grow, based on the tenders organised by regional governments, the latest of which is Ontario's 300 MW in March 2015. However, it is less clear whether those tenders will be enough to sustain the very high level of growth of late (1.9 GW/yr).

Mexico continues its reform of the electricity market to allow higher penetration of wind electricity. The structure that enables this is the direct sale of wind electricity from projects to end consumers, generally industrial plans or mines, through the transmission network. The government's Secretaría de Energía expects exponential growth from 2.5 GW at the end of 2014 to 9 GW at the end of 2018, which will cover 8 % of national demand (SENER, 2013) (REVE, 2015a), and projects are fast being built with 730 new megawatts expected for 2015.

In Central and South America, Uruguay has backed with facts its claims that it is on its way to be one of the countries with higher wind energy penetration in the world (Montautti, 2013), whereas Brazil's auctioning system is on its way to delivering some 7–8 GW more from 2014 to 2017. Chilean growth also presents a very positive outlook and particularities such as high penetration of installations supplying mines.

The predictions of Japan becoming an exploding market have not been realised in 2014 either, which makes the observer question whether Japanese politicians are truly supporting the technology. The problems, discussed in last year's report, of excessively demanding environmental impact assessment requirements is still the main barrier. Pakistan's resource-rich Gharo–Keti Bandur wind corridor will continue to produce installations in a market with fierce competition among American (namely GE), Chinese and European manufacturers.

3.2.2. Long-term deployment scenarios

Last year the European Wind Industry Energy Association reduced its estimated targets to 192 GW installed in Europe by 2020, of which 23.5 GW is offshore. We believe that a more optimistic scenario is possible of around 210 GW including 25–30 GW offshore.

In addition to the increasingly recognised dangers of human-induced climate change, the following aspects formed the basis of our assessment for Europe and beyond:

- Security of supply issues: in addition to being a local resource, wind is widely distributed. Its use makes countries independent from fuel imports from unstable countries, and thus improves security of supply.
- Increasing availability of economically exploitable resource: thanks to the improvement of the technology, areas with low wind resource which were not economic to exploit become profitable, which is another way to increase the resource.

- A second effect of the cost reductions brought about by wind energy technology evolution is the increasing competitiveness of wind versus other generation technologies.
- New markets were consolidating in 2014 (Brazil, South Africa, Uruguay ...) and more will be created as costs reduce further.
- The first months of 2015 have brought the good news of offshore wind demonstrating that it is reducing its cost significantly (see Subsection 4.8).
- In Europe, although support policies have been reversed or reduced lately in a number of countries, the policy push to mitigate climate change and the need to reduce dependency from natural gas will make renewables receive increasing attention and support, notwithstanding (or perhaps focused on) grid integration issues.

In Europe, the 2020 projections from the National Renewable Energy Action Plans (NREAPS, see Table 8) suggest that offshore installations will increase from 8 to 38 GW (32 GW or a four-fold increase from 2014), significantly more than onshore, from 100 to 169 GW (69 GW or less than an two-fold increase). From the viewpoint of early 2015, this offshore figure is clearly not realistic as e.g. both France and the Netherlands will fail to meet their ambitious 2020 offshore targets of 6 and 5.2 GW respectively.

Worldwide offshore is also slow to take off, with China failing to meet their targets of 5 GW installed by 2015 and 30 GW by 2030, and the United States still experiencing a slow start with only 30 MW likely in the medium term.

In the longer term the prospects are brighter than in previous assessments as a result of continuous technological cost reduction.

Therefore we suggest in Table 7 a deployment scenario for the European Union and the whole world.

Gigawatts	European Union			World		
	Total	Onshore	Offshore	Total	Onshore	Offshore
Cumulative capacity 2013	116.5	111	6.5	319	312	7
Cumulative capacity 2014	130	121	9	371	361	10
Installations 2015–20	78	60	18	310	280	30
Annual installation rate	13	10	3	52	47	5
Cumulative by 2020	208	181	27	681	641	40
Installations 2021–30	145	60	85	710	550	160
Annual installation rate	24	6	9.5	71	55	16
Cumulative by 2030	353	241	112	1 391	1 191	200
Installations 2031–50	150	40	110	1 055	725	330
Annual installation rate	25	2	5.5	53	36	17
Cumulative by 2050	503	281	222	2 446	1 916	530

Table 7: Estimated installed capacity in GW, 2015–50. *Sources:* GWEC (2015) for 2013 and 2014 data, and JRC analysis.

The European share of world cumulative capacity will continue to shrink from the current 35 % to 30 % by 2020, 24 % by 2030 and 22 % by 2050. In 2006 this share was 69 %.

Repowering will play an increased significant role (see Section 3.6) in the new installed capacity and after 2030 in the pioneering countries (Germany, Denmark, the Netherlands, Spain) new installed power is likely to correspond only to repowering of current wind farms.

In central and northern Europe and possibly in Japan, offshore deployment will probably dominate beyond 2030. In the rest of the world onshore installations will probably dominate all the way to 2050, supported by the cost reductions that continue materialising.

Both in Europe sometime after 2030 and in the world after 2050, the pace of installations will slow down to the level of replacement of obsolete equipment. New technologies will still allow cumulative capacity to increase with regard to the decommissioned capacity (repowering).

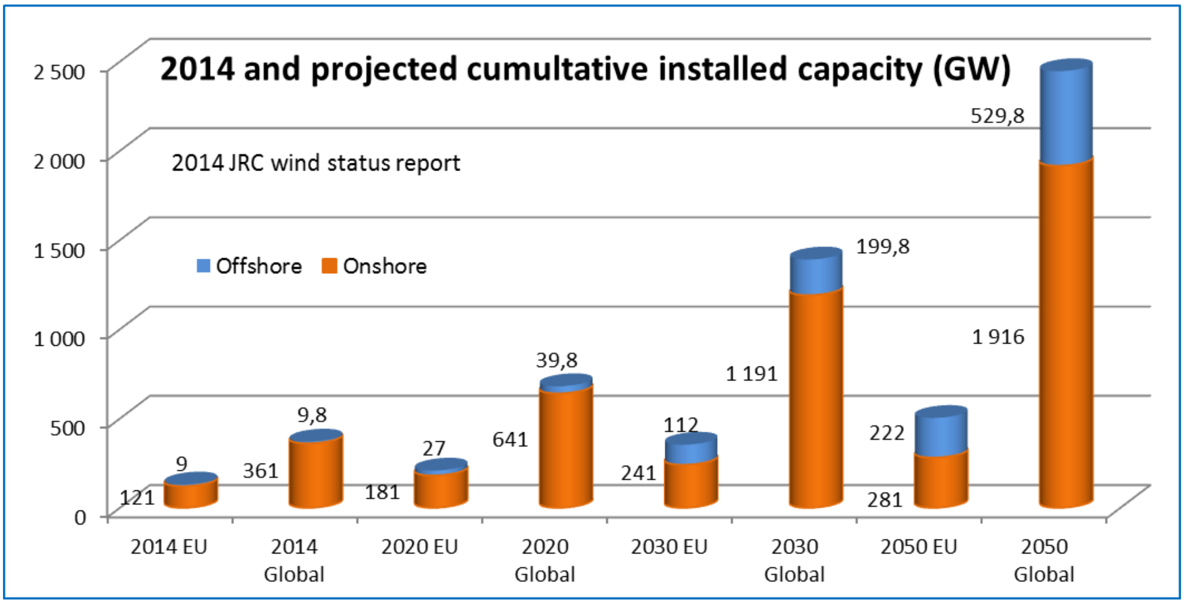


Figure 16: Projected cumulative installed capacity (GW). *Source:* GWEC (2015) for 2014 data and JRC estimates for the projections.

3.2.3. Progress towards the European Union 2020 goals

The EU Climate and Energy policy foresees that the EU has a target of achieving 20 % of final energy from renewable origin by 2020. Within this context, EU Member States and Norway have drawn wind deployment targets for 2020. Table 8 shows these (non-binding ([14])) targets as well as progress in terms of percentage of the 2020 target already achieved at the end of 2014. The colour assessment is as follows: green if already achieved 75 % of the 2020 target, yellow if between 40 % and 75 % and red if less than 40 % ([15]). Figure 17 shows the information in the last column in a more visual way.

([14]) In any case the only legally binding target is the target on the overall renewable energy share. So, even if a country is lagging behind in wind energy, this does not mean it will miss the overall target.

([15]) Note that the trajectory defined by MS is not necessarily linear. Thus, a MS with relatively low installed capacity in 2014 might still be following its track to reach its 2020 wind targets as defined in its own trajectory.

Member State	NREAPs capacity 2020 (MW)			Cumulative installations end 2014			Share already achieved
	Onshore	Offshore	Total	Onshore	Offshore	Total	
Austria	2 578	0	2 578	2 095		2 095	81 %
Belgium	2 320	2 000	4 320	1 247	712	1 959	45 %
Bulgaria	1 440		1 440	691		691	48 %
Croatia	400	0	400	347		347	87 %
Cyprus	300		300	147		147	49 %
Czech Rep.	743		743	282		282	38 %
Denmark	2 621	1 339	3 960	3 571	1 274	4 845	122 %
Estonia	400	250	650	303	0	303	47 %
Finland	1 600	900	2 500	600	27	627	25 %
France	19 000	6 000	25 000	9 285	0	9 285	37 %
Germany	35 750	6 500	42 250	37 973	1 192	39 165	93 %
Greece	7 200	300	7 500	1 980	0	1 980	26 %
Hungary	750		750	329		329	44 %
Ireland	4 094	555	4 649	2 247	25	2 272	49 %
Italy	12 000	680	12 680	8 663	0	8 663	68 %
Latvia	236	180	416	62	0	62	15 %
Lithuania	500		500	279		279	56 %
Luxembourg	131		131	58		58	44 %
Malta	15	95	110	0	0	0	0 %
Netherlands	6 000	5 178	11 178	2 558	247	2 805	25 %
Poland	5 600	500	6 100	3 834	0	3 834	63 %
Portugal	6 800	75	6 875	4 912	2	4 914	71 %
Romania	4 000		4 000	2 954		2 954	74 %
Slovakia	350		350	3		3	1 %
Slovenia	106		106	3		3	3 %
Spain	35 000	750	35 750	22 987	0	22 987	64 %
Sweden	4 365	182	4 547	5 209	216	5 425	119 %
UK	14 890	12 990	27 880	7 989	4 451	12 440	45 %
EU-28	169 189	38 474	207 663	120 624	8 131	128 754	62 %
Norway	3 535	0	3 535	854	2	856	24 %

Table 8: Assessment of progress towards the 2020 objectives. *Source:* JRC assessment based on National Renewable Energy Action Plans submitted by the EU MS, on EWEA (2015a) and on country declarations at the IEAWind Executive Committee meetings.

Note that some countries have declared lower ambitions which should modify their 2020 targets but these changes have not been made official, nor notified to the Commission as NREAP updates.

3.2.4. EU Member State analysis

The main major event that influenced and even determined EU and MS energy policies during the last year was probably the situation in Ukraine. It triggered a desire, even an urgency, for higher levels of security of supply, in particular in MS highly dependent on Russian fuel and electricity supply. Events of a lesser importance that nevertheless influence policy initiatives include the existence of electricity tariff deficits (Bulgaria, Greece, Spain, Italy) and the increasing data about the risks of climate change.

The following paragraphs discuss our assessment of whether MS will reach their targets for wind energy deployment, and as such they expand on the figures presented in Table 8:

- **Austria** is accelerating deployment thanks to a now generous FiT and will all being well reach the target. However, its FiT might prove too high given the cost reductions trend, a situation that in other countries led to downwards revision of support sometimes with retroactive effect. National estimates are significantly above the target.
- **Belgium** had reached only 45 % of the target by end 2014, thus there is a significant gap. The resolution of grid connection bottlenecks for OWFs suggests that the offshore target will likely be met, but there are still many issues impacting the necessary onshore deployment, e.g. social acceptance.
- **Bulgaria**: although mid-way to the target, deployment stalled in 2013 because of a moratorium on renewable electricity plant. Because the target is not very high a positive shift in support policy would make Bulgaria reach the target — the problem is that this shift seems unlikely. Security of supply issues could help.
- **Croatia** has a relatively small target that it has nearly reached. Given the current support and turbine orders, the country is likely to surpass its target.
- **Cyprus** is lagging behind with only 50 % of the target reached and only one installation permitted and under development. Currently, policies that would allow reaching the target have still to be defined, amid concerns that the country's low wind resources might make wind too expensive, in a context of a weak electrical grid.
- **Czech Republic**: because the solar photovoltaic boom of 2010 caused the country to surpass its NREAP renewable electricity target, the Czech Republic has no interest in further wind deployment and thus it will not reach the target. Still, a new energy bill recently presented could stimulate wind deployment.
- **Denmark**: having already reached the 2020 target, Denmark has set more ambitious decarbonisation objectives that include 50 % of electricity from wind. Other than the new offshore wind projects, modest annual capacity additions onshore can be expected because of saturation, repowering is the main option.
- **Estonia**: although still short of the target with 47 % at the end of 2014, with a favourable policy context Estonia should reach the target. However, the current support limitation needs to change for this to happen.
- **Finland**: there is a significant gap (only 25 % of the target was achieved by 2014) yet Finland is boosting deployment with as much wind power under construction as is already installed. Because of this change, Finland seems increasingly likely to reach 2020 just short of the target, a prospect unthinkable just 2 years ago.
- **France**: with only 37 % of the target achieved by end 2014, and a gap of 16 GW to reach the target, it will be very difficult for France to reach the target. The low annual installation rate of late, with a low of 631 MW in 2013, does not bode well either.
- **Germany**: with 93 % of the target already in place at the end of 2014, projections suggest that the target will be surpassed by up to 40 %. The steady increase in annual capacity since 2010 reinforces this point.
- **Greece**: because of the slow economic recovery and the ongoing reduction in wind energy costs, deployment in Greece is seen more positively than in previous years. Still, it is unlikely that it will reach the target and projections suggest it will be short by 50 %.
- **Hungary**: does not have the favourable policy context necessary to reach the target.

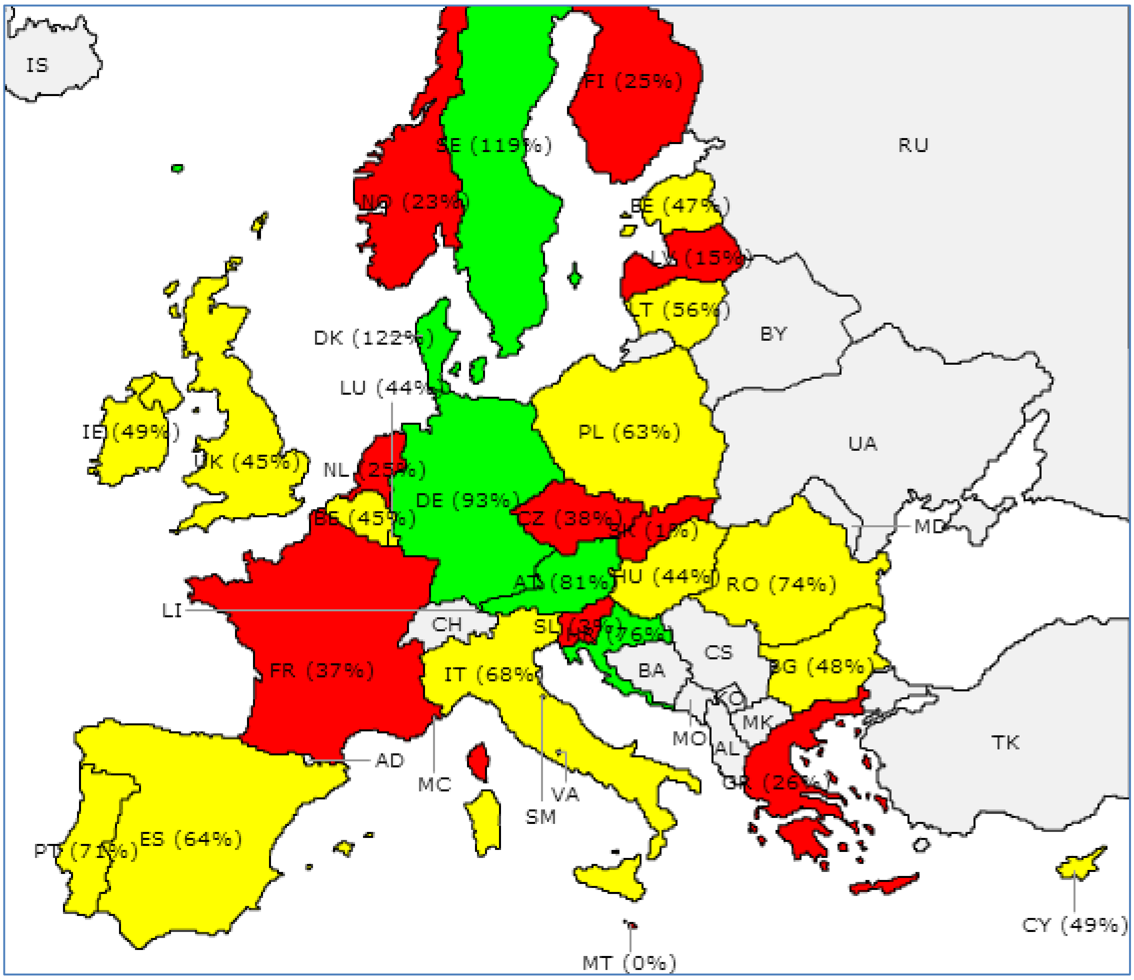


Figure 17: Snapshot of current status of achievement of the 2020 wind energy targets in MW. Source: JRC analysis

- **Ireland**: there is a significant gap but also some positive developments, namely a high number of installations in 2013 and 2014, and improved political support, that puts Ireland closer to reaching the target. Social acceptance is a problem and curtailment is still an issue which introduces financial uncertainty.
- **Italy**: although there is still a significant gap, Italy published new legislation improving the support scheme for renewables at the end of 2013. As of the end of 2014 that legislation was not successful (installations sank) but it is perhaps too early to assess the legislation.
- **Latvia**: even though the gap is very significant, it is possible to reach such a low figure (in MW) once the necessary policy context is in place. Security of supply and new interconnections should drive such a policy change.
- **Lithuania** is short of installations (56 % of the target at the end of 2014), but has the policies in place to reach the target.
- **Luxembourg**: is not very rich in wind resources, but a recent change in support policies could allow the country to reach the target.
- **Malta**: does not have the favourable policy context to reach the target.
- **Netherlands**: there is a very significant gap still there. Recent improvements in support might cause a leap forward in deployment, but the gap to reach the target is too large (only 25 % of the target reached by end 2014).

- **Poland** offers a scene full of contrasts: whereas its electricity system is heavily based on local coal resources, opportunities for wind deployment still exist, as shown by the high number of installations in 2013 (894 MW) and by a high volume of turbine purchasing agreements announced. However, 2014 showed a poor deployment (444 MW) and retroactive policy changes, but a new renewable energy law was signed in March 2015 (TheNews.pl, 2015) and is expected to help Poland to reach the target.
- **Portugal**: a significant gap still there, but the target can be reached thanks to its high wind resources and to a market that seems to timidly get out of the crisis. The repowering market could play an important role.
- **Romania**: legal changes with retroactive effect (deferred one of the two green certificates per MWh from the first of July 2013 to the first of January 2018) put investment trust in jeopardy and brought about impairment losses for developers (Verbund, CEZ). Unless policy changes Romania will not reach its target.
- **Slovakia**: despite the large gap to the target, the total figure (350 MW) is small and given a favourable policy framework the target might be reached.
- **Slovenia**: a similar situation to that of Slovakia.
- **Spain**: regulatory changes with retroactive effect brought the market to a halt. Lack of political support means that the target will not be reached.
- **Sweden**: has already reached the target.
- **UK**: a significant gap is still there, but the UK will reach the target if the expected increase in the annual installation rate (from 1.8 to 2.6 GW) materialises.
- **EU-28**: although there is a significant gap still there, the EU as a whole will probably reach the 2020 target because it needs some 11 GW of annual installation, which is doable.
- **Norway**: a significant gap means that there will be difficulties in reaching the target.

Chapter 5.9 expands on the country analysis by reviewing the historical evolution.

3.3. Turbine manufacture market

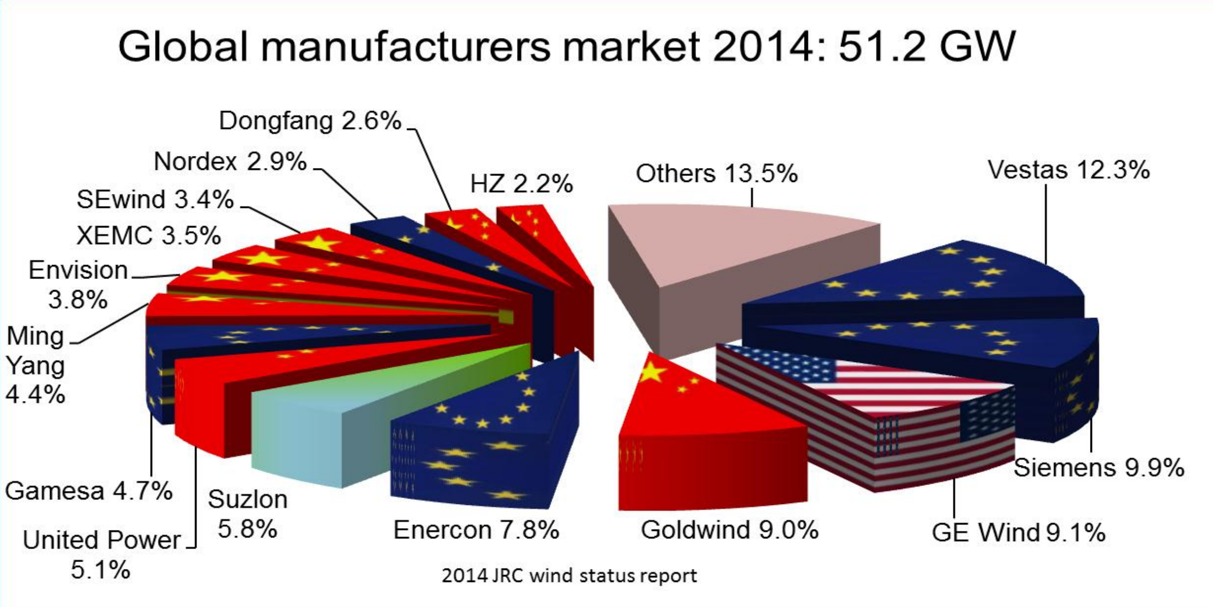


Figure 18: Manufacturer market share 2014 over 51.2 GW of installations. Elaborated with data from BTM (2015). Suzlon data includes its subsidiary Senvion (Germany).

The turbine manufacturers market share (Figure 18) revealed by BTM (2015) shows long-term leader Vestas (DK) ahead of another European manufacturer, Siemens, and of GE Wind from the US and Goldwind from China. Enercon from Germany follows, then Suzlon of India (half of whose installations belong to its European subsidiary Senvion — formerly called REpower), then Guodian United Power from China, Gamesa from Spain and six more Chinese manufacturers (Ming Yang, Envision, XEMC, SEwind, Dongfang and CSIC Haizhuang) with one European (Nordex) in between. Other manufacturers with strong performance include Acciona from Spain (1.3 %) and several more Chinese: Windey, Sinovel, CCWE, Energine, CSR, etc.

	2006	2007	2008	2009	2010	2011	2012	2013	2014
1	Vestas	Vestas	Vestas	Vestas	Vestas	Vestas	GE	Vestas	Vestas
2	Gamesa	GE	GE	GE	Sinovel	Goldwind	Vestas	Goldwind	Siemens
3	GE	Gamesa	Gamesa	Sinovel	GE	GE	Siemens	Enercon	GE
4	Enercon	Enercon	Enercon	Enercon	Goldwind	Gamesa	Enercon	Siemens	Goldwind
5	Suzlon	Suzlon	Suzlon	Goldwind	Enercon	Enercon	Gamesa	GE	Enercon
6	Siemens	Siemens	Siemens	Gamesa	Suzlon	Suzlon	Suzlon	Gamesa	Suzlon
7	Nordex	Acciona	Sinovel	Dongfang	Dongfang	Sinovel	Goldwind	Suzlon	Guodian
8	REpower	Goldwind	Acciona	Suzlon	Gamesa	Guodian	Guodian	Guodian	Gamesa
9	Acciona	Nordex	Goldwind	Siemens	Siemens	Siemens	Sinovel	MingYang	MingYang
10	Goldwind	Sinovel	Nordex	REpower	Guodian	MingYang	MingYang	Nordex	Envision

Table 9: Evolution of the top 10 manufacturers 2006–14. *Source:* BTM (2015) and similar reports from previous years). Senvion, formerly called REpower, was part of the Suzlon group from 2010 to 2014. and it's therefore included as Suzlon.

The five largest firms together covered 48 % of the market (BTM, 2015), showing similar levels of market concentration during the last 6 years, 47–55 %. However, the share of the top 10 manufacturers slowly but continuously diminished from 93–94 % in 2005/2006 to 70–72 % in 2013/2014. European manufacturers (16) increased their market share from 42 % in 2009/11 to 48 % in 2012/13 and then down to 43 % in 2014 (BTM, 2015; JRC data). Given that the Chinese market is overly dominated by local manufacturers (17), this means that European manufacturers had a 78 % share of the global non-Chinese market. However, this share will be reduced mostly because of Chinese policies: their financial institutions that are starting to fund projects abroad require Chinese equipment to be used in those projects (18).

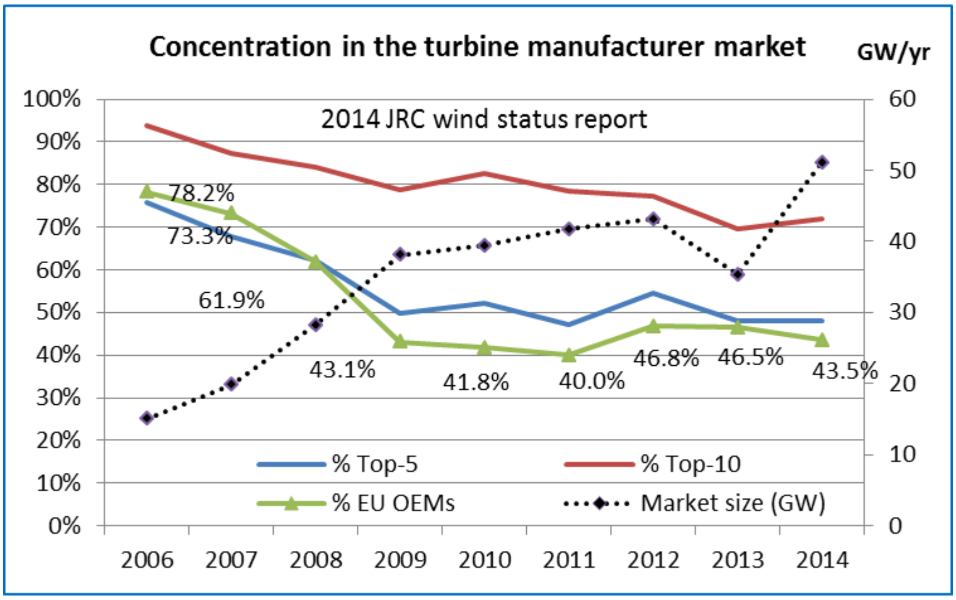


Figure 19: Evolution of turbine manufacture market concentration 2006–2014. *Source:* BTM (2015) complemented with data from the JRC database for the smallest European manufacturers. Note: the dark dotted line, against the right axis, reflects the annual market volume of installations in megawatts.

The annual composition of the top 10 manufacturers per market share is an indicator of how the market has shifted in two ways: (a) influenced by the national market and (b) overall towards China. Table 9 shows the top 10 manufacturer position from 2005 to 2014 with Chinese companies with a red background and European with a blue background. It is clearly visible that Chinese companies started growing at the beginning of the period with Goldwind as pioneer, and from 2009, then China started contributing 35–50 % of annual world installations, at least three Chinese manufacturers populated the top 10.

Three among the top 10 manufacturers (Vestas, Siemens Wind Power AS and Gamesa) had no home market at all in 2014 as installations in Denmark and Spain stalled. Those three companies had been able to detach from a single market and into multiple markets, which made them less dependent on the political support in a single country and thus more resilient to a crisis of support.

(16) Including Senvion, the European subsidiary of Suzlon from 2010 to 2014.
(17) Non-Chinese manufacturers share of the Chinese market was reduced to 1.7 % in 2014.
(18) Under the China–Pakistan Economic Corridor project, Chinese banks that provide loans require that the equipment suppliers are Chinese. This has already affected negatively European suppliers, e.g. caused the change from Vestas to Goldwind in a 50 MW wind project developed by China Sunec Energy (BNEF, 2015b).

Interestingly, the huge growth of the Chinese market (+ 45 % on 2013 and also 43 % of the global 2014 market) did not result in Chinese manufacturers moving ahead in the top 10 order, see Table 9.

Group	2013			2014		
	No of manufacturers	MW	Share	No of manufacturers	MW	Share
Tier 1	1	3 750	23.3 %	1	4 434	19.1 %
Tier 2	5	5 968	37.1 %	7	12 562	54.2 %
Tier 3	14+	6 371	39.6 %	18	6 200	26.7 %

Table 10: The convention used for a split of suppliers in tiers is that their share of the market is significantly different. In this case, Tier 1 manufacturers supply more than 3 000 MW per year, and Tier 2 supply more than 1 000 MW per year. Tier 2 included United Power, Ming Yang, Envision, XEMC, and Shanghai Electric in 2013, and added Dongfang and HZ in 2014.

Instead, the Chinese market became less concentrated when it went through a real transformation in terms of 'tier' (19) suppliers from 2013 to 2014. In effect, as Table 10 shows, in 2014 we could consider seven Tier 2 manufacturers, growing from five in 2013, that grabbed 54 % of the market versus 37 % in 2013. The leader (and perhaps only Tier 1 manufacturer), Goldwind, in 2014 installed 700 MW more than in 2013, that is 18 % more capacity versus a 45 % overall Chinese market growth. In consequence, the bulk of the market growth was captured by Tier 2 suppliers if we include two manufacturers that are promoted from Tier 3, Dongfang and HZ.

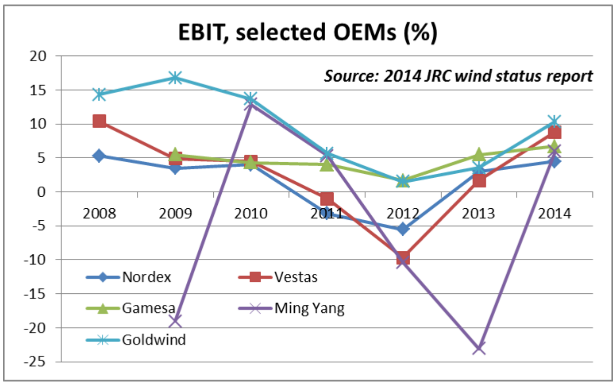
Export of Chinese manufacturer turbines (20) was also reduced from 692 MW in 2013 (4.3 % on national installations) to 369 MW in 2014 (1.6 %) (CWEA, 2015), probably because manufacturers were too busy with a booming internal market to care about exports. Three foreign firms (Vestas, Gamesa, and GE) installed 383 MW in China in 2014, but a significant increase is expected for 2015 judging from the turbine order placed in 2014.

Turbine manufacturers are in a much better financial situation than 2 years ago. Figure 20 shows a sample of the business evolution of selected European and Chinese wind turbine manufacturers as reflected in their annual EBIT (earnings before interest and tax). The 2012 percentage figure for Vestas includes restructuring costs (one-off items such as write-downs of assets), but not for Gamesa, and this difference allows — by comparing with the figures in the right graph) to perceive a part of the impact of those one-off costs.

Production overcapacity and fierce competition were two of the causes of the general dip shown in 2011 and 2012, but most companies restructured their operations (sometimes at the expense of reducing company size, as in the case of Vestas) and by last year they presented a healthy financial and market situation. Other companies have lost significant market share — e.g. the case of Sinovel, no longer the significant player that it used to be in the Chinese market.

(19) For market analysis it is sometimes convenient to split manufacturers or suppliers according to their relative importance in market share. The term **tier** is often used and three categories assumed (Tier 1, 2 and 3).

(20) It has to be highlighted that western manufacturers now make in China a significant part of their turbines, or the whole turbine, mostly for export.



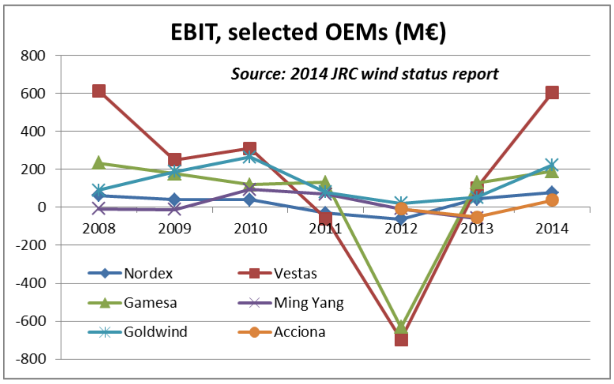


Figure 20: Evolution of the EBIT margin of selected wind turbine manufacturers (OEMs), 2008–14. *Source:* JRC based on company annual reports.

3.4. Globalisation of turbine manufacturers

The analysis of installed capacity by country and turbine manufacturer, shown in Figure 21 for the period 2008–12, suggests a rather stable situation rather than a trend towards globalisation, and this is despite the growth in the number of countries installing wind farms ([21]) — but it also shows the manufacturer dependencies on a single market or a handful of markets highlighted above.

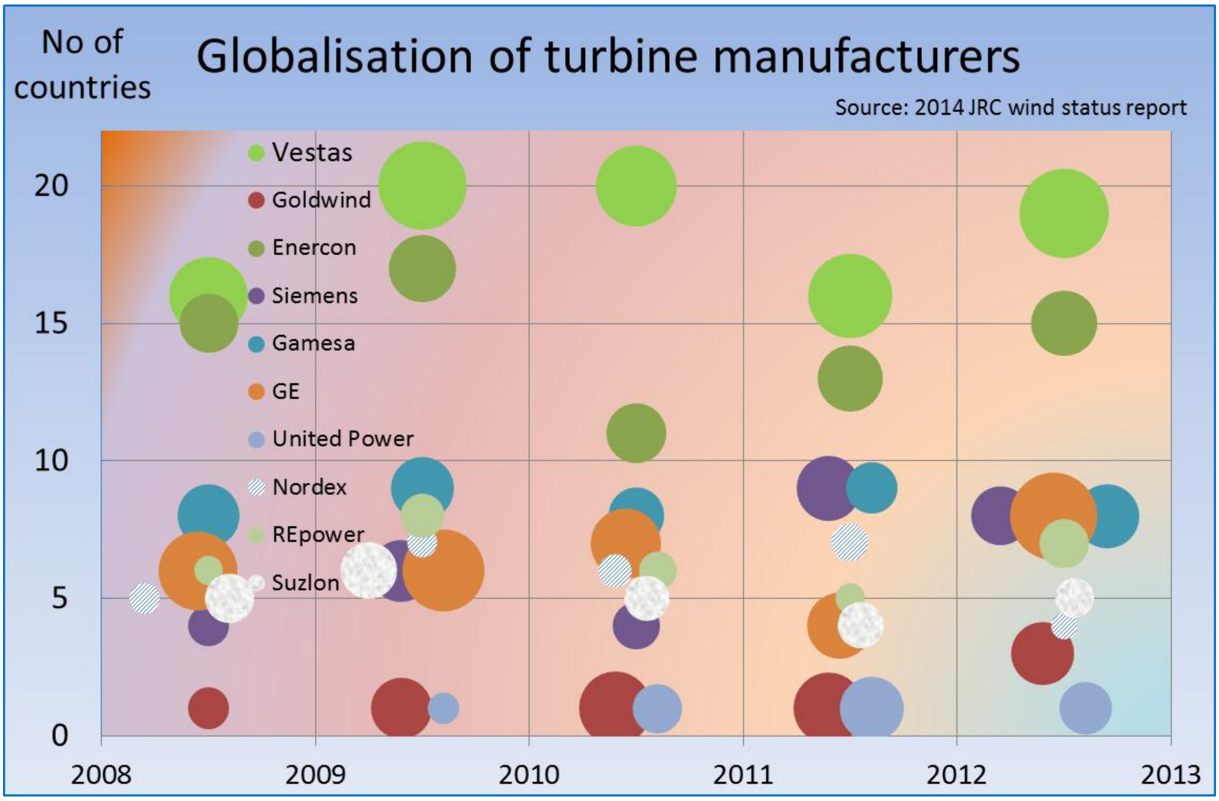


Figure 21: Evolution of turbine manufacturers towards globalisation, 2008–12. The vertical axis represents the number of countries for which each turbine manufacturer installed, in the given year, at least 50 MW. The area of the bubble represents the sum of installed capacity **in those countries** by the given manufacturer. *Source:* JRC database.

([21]) For example, 14 countries installed more than 250 MW in 2008 versus 18 in 2012.

Vestas is clearly the most globalised manufacturer, as it has led the table throughout the period that we can assess, which is until 2012. After Enercon, noted as second most globalised manufacturer, Gamesa consistently leads a group that includes Siemens, GE and Repower (Senvion). Lastly, Nordex and Suzlon are present in a few more markets than the Chinese manufacturers Golwind and United Power.

3.5. The 2014 'harvest'

The analysis of a sample of wind turbine purchase agreements (TPAs) ([22]) announced in 2014, those made public by different manufacturers and/or developers, shows a picture of the technology that is being sold nowadays and will be installed in 2014/2015/2016. The picture is one of larger, taller turbines with more diverse drive train technology.

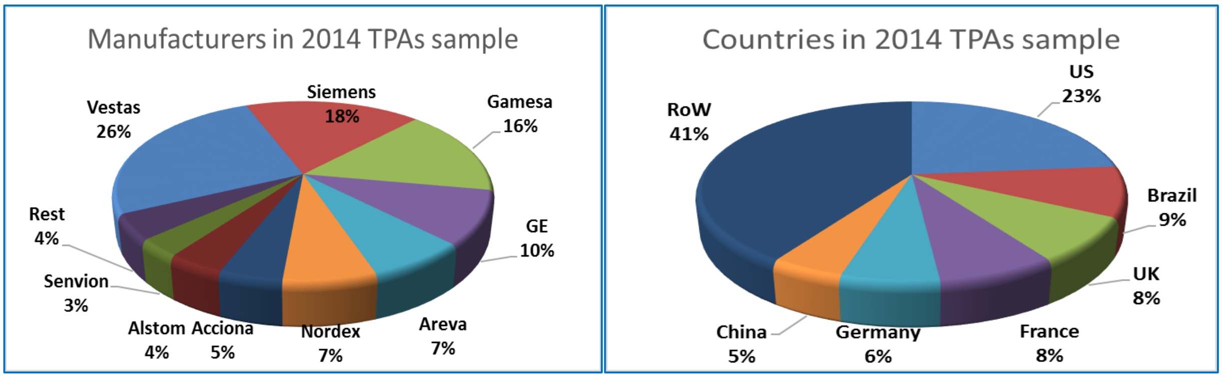


Figure 22: Breakdown of the 18.5 GW in the TPA sample per manufacturer. Rest of the world (RoW) here refers to countries with less than 5 % representation in the sample, and includes some European — unlike RoW from now on in this analysis which refers to non-EU countries other than the US.

Although the global figures have significant gaps, in certain technological elements the conclusions of analysing these TPAs hold generally valid. This is mostly the case regarding wind classes, where perhaps only the limited share of Chinese data might influence the overall picture. Figure 23 shows the breakdown of wind classes for the whole sample whereas Figure 24 shows the breakdown per sector.

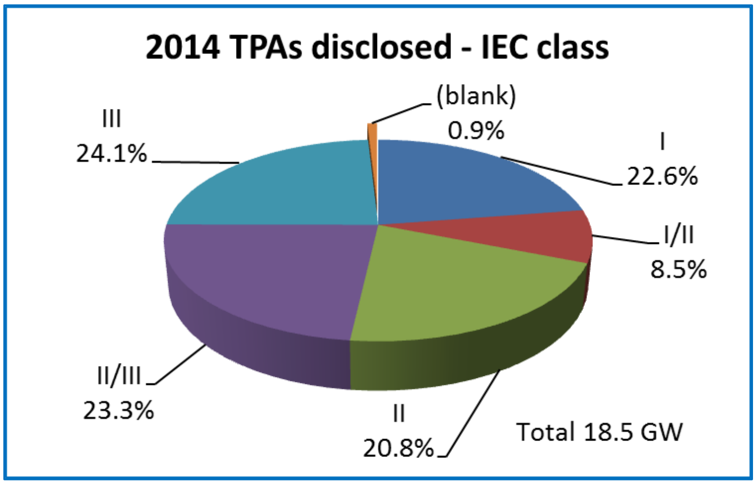


Figure 23: IEC classes in TPAs disclosed in 2014

([22]) In the cases when the wind farm developer is the turbine manufacturer, the 'TPA' is internal to the company. In these cases the date of the announcement of wind farm investment decision is taken as TPA. For tenders/auctions where the turbine model is part of the bid, the deadline for bid presentation is taken as TPA and, if it is not known, 2 months before the publication of the tender/auction results is the date taken.

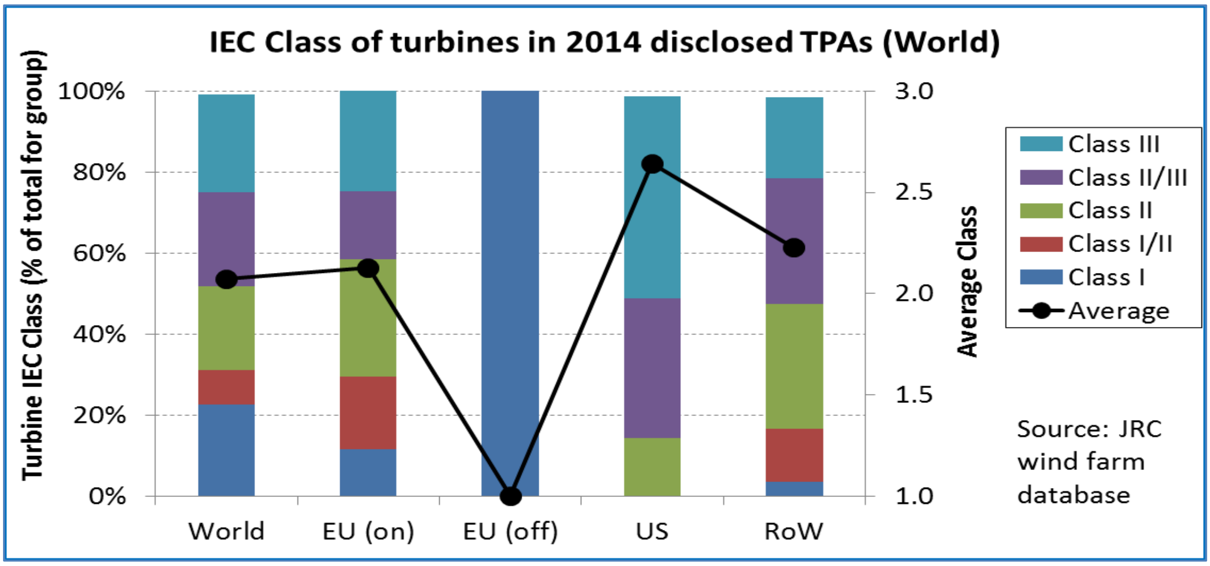


Figure 24: Breakdown of wind classes in the 2014 disclosed TPAs by group: US, EU onshore and offshore, rest of the world (RoW) and overall world figures.

Not surprisingly, offshore turbines are Class I in all cases, whereas the data shows that the US does not install Class I turbines. The latter information, combined with the knowledge that the US has still many Class I sites under development, suggests that non-Class I turbines are used in the windiest sites. In Europe and the rest of the world, Class I turbines constitute a minority and most turbines installed correspond to lower-wind conditions (Classes II, II/III and III).

Regarding turbine configurations, full-converter turbines (Types D, E and F) are becoming more popular (compare Figure 26 to Figure 8 or, for global figures, to Figure 12 of (Llorente-Iglesias, et al., 2011)). The bias of the data is away from Type D configuration because of the absence or low representation of manufacturers Goldwind, Enercon and XEMC in the sample (maximum representatives of the direct drive configuration). This means that the reality is likely to be an even higher trend towards full-converter machines. Therefore, the pre-eminence of DFIG (see (Llorente-Iglesias, et al., 2011) and Section 2 above) seems ready to end in the short to medium term.

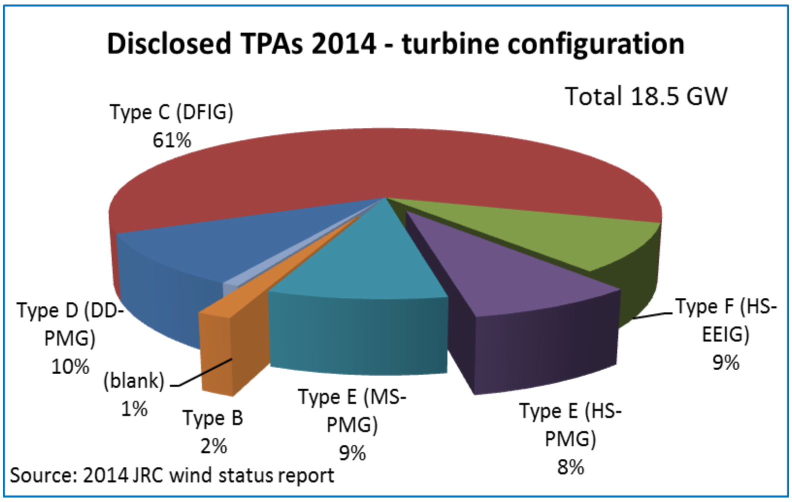


Figure 25: Turbine configuration breakdown in TPAs disclosed in 2014

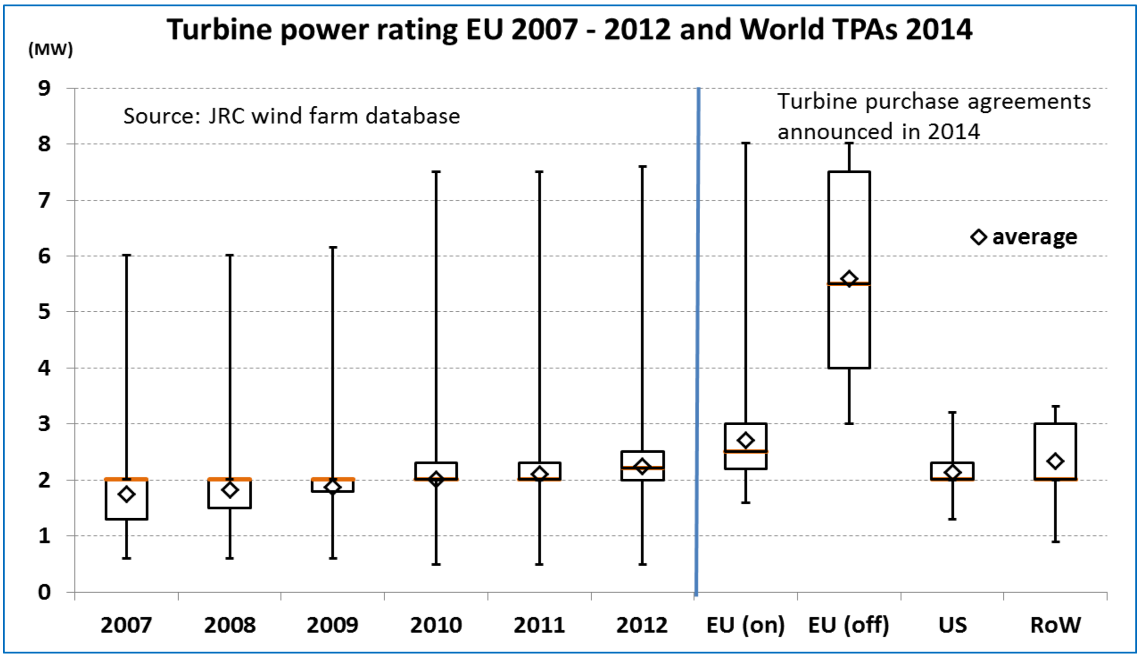


Figure 26: Turbine power rating in European onshore machines: evolution from 2007 to 2012 and comparison of data according to TPAs disclosed in 2014. *Source:* JRC database.

One element that does not need to be influenced by the limitations of the sample is the average turbine power rating. Figure 26 compares the power rating of commissioned wind turbines in the EU during the period 2007 to 2012. It also shows the power ratings of TPAs disclosed in 2014 under the four categories: EU onshore and offshore, US and rest of the world.

The graph shows the continuous increase in the average European turbine rating for onshore machines from 1.75 MW in 2007 to 2.25 MW in 2012, an increase of 29 %. But the jump to the new machines, as reflected by the 2014 TPAs, is even more spectacular: + 20 % from 2012 to 2.71 MW.

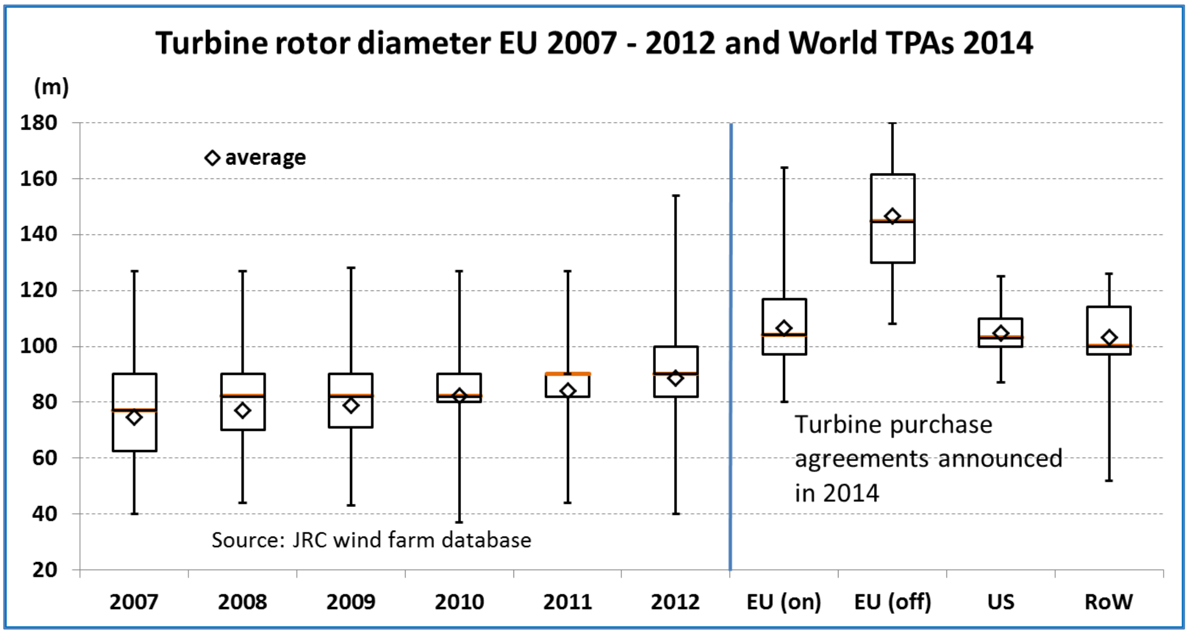


Figure 27: Rotor diameter in European turbines commissioned between 2007 and 2012, and in the TPAs disclosed in 2014. *Source:* JRC wind farm database.

As it could be expected, it is the forthcoming offshore installations, as reflected by the TPAs, that have the highest average rating with 5.6 MW. In the US, turbines tend to have lower ratings (this is consistent with the offer of its main supplier, GE) at 2.14 MW.

The evolution of a second technological feature, rotor diameter, is presented in Figure 27. Here too the continuous increase is clear, from an average diameter of 74.8 m in 2007 to 88.6 m in 2012 (an 18 % increase). The jump to the newer technology is clear here as well when the TPAs disclosed in 2014 present an average rotor diameter of 106.4 m for

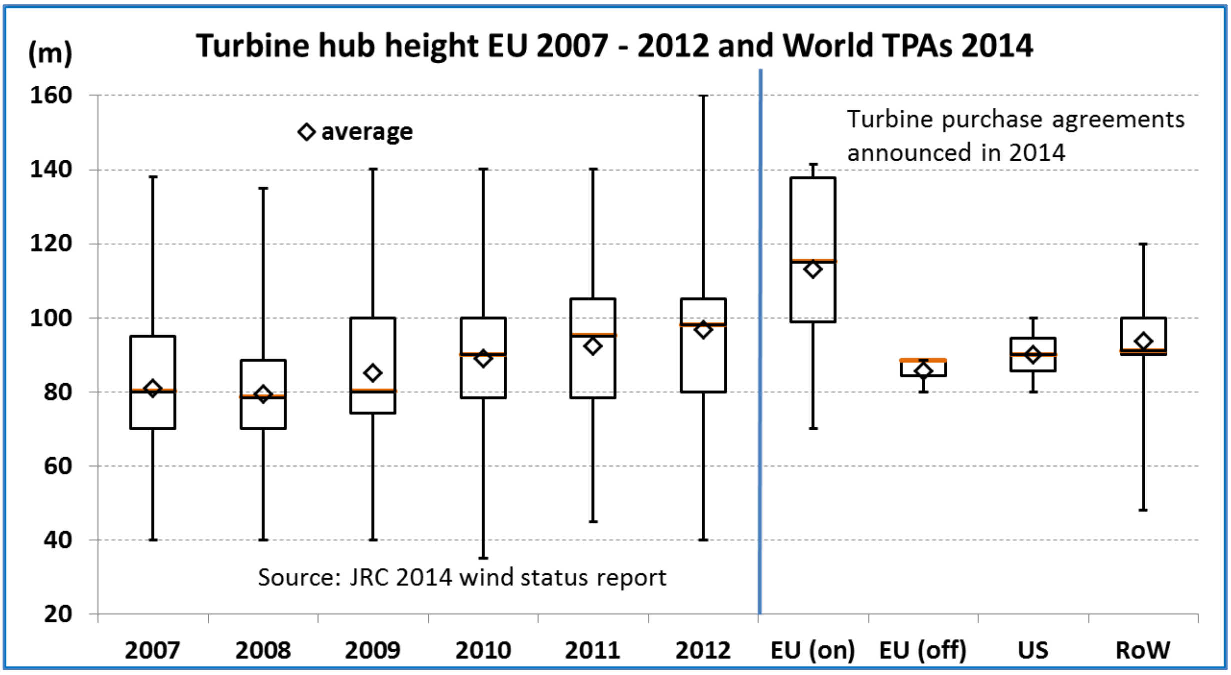


Figure 28: Plot of turbine hub height in turbines installed in the EU during 2007–12, and in the TPAs disclosed in 2014

European onshore turbines (+ 20 % from 2012). The size of the European onshore TPA sample is 3.5 GW out of the 18.3 GW for all TPAs 2014.

As for the comparison between TPAs, again offshore turbines lead with an average 146 m rotor. However, unlike the average power rating, the average rotor diameter is very similar in the EU onshore, the US (104.7 m) and the RoW (103.1 m).

Turbine hub height is the last element analysed here. Figure 28 shows that its evolution in the EU from 2007 to 2012 is a little bit less steady than in the previous cases, with 2008 providing figures (all figures: median, average and also the 25 % and 75 % percentiles) lower than 2007. At the beginning of the period the average hub height was 81.1 m and it climbed to 96.8 m in 2012 (+ 19 %). The TPAs present an increase to 113.2 m (+ 17 %) in European onshore wind farms, and a differentiated pattern to previous parameters: the offshore turbines present lower hub heights because the wind gradient (increase in wind speed with height) is smaller at sea and the decision on hub heights depends on totally different parameters than onshore. Both the US and the RoW present lower average hub heights (and a significantly smaller spread) than the EU onshore.

3.6. Repowering

Figure 29 shows that a small capacity was installed more than 20 years ago thus constituting a candidate market for repowering in Germany and, to a lesser extent, in Denmark, Spain, the UK and the Netherlands. The prospective market for repowering constituted by turbines between 15 and 20 years old is, however, very significant in Germany, Denmark and Spain up to 10 GW. Turbines younger than 15 years are being repowered under certain circumstances in Germany, where repowering projects have the attractiveness for developers that only the net increase is included in the national annual quota of installations.

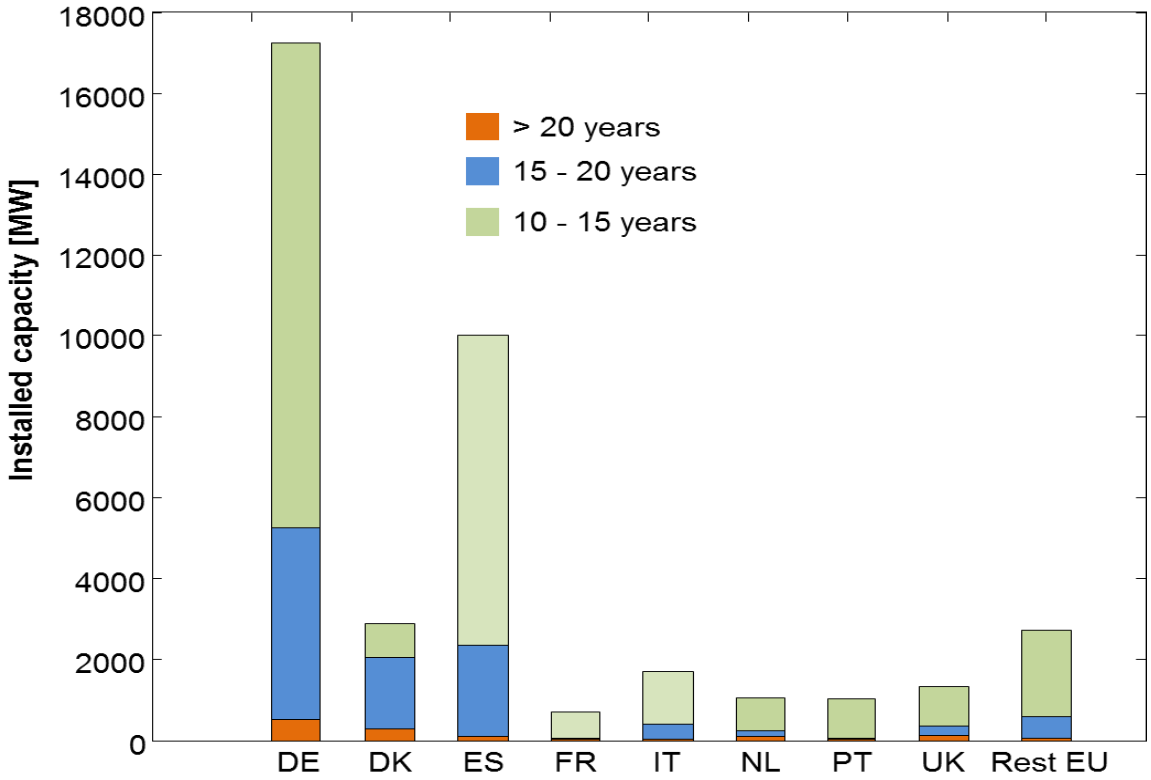


Figure 29: Wind installations older than ten years (at the end of 2013) in the EU Member States, showing the prospective repowering markets.

Although there are no technological differences between turbines for a repowering versus greenfield projects, there are certainly other differences. For example, repowering projects have access to long-term local wind resource data that can be used for optimising the turbine type and for reducing the uncertainty on future energy production (the latter improves the financing conditions). Also, repowering projects use land with higher wind resources and where the local community is already used to wind turbines, and thus likely to offer higher social acceptance.

4. Economic impacts of wind energy

The cost of wind energy depends on the wind resource available, cost of capital, prices of raw materials; technology selection; installation costs (including grid-connection/extension when necessary); operation and maintenance costs; supply bottlenecks (e.g. limited competition in offshore export cable supply); market supply/demand balance; non-technical barriers (administrative, permitting, social acceptance, etc.); the mode and level of remunerating wind electricity; and on risks and uncertainties impacting on the investors and lenders and creating a need for technical and price contingencies.

The indicator currently generally accepted to assess the cost of wind is the levelised cost of energy (LCoE) ([23]), a standard for all energy-generating technology. However, this was not always the case, as years ago capital investment (CapEx) was used as main indicator thus disregarding financial and operations and maintenance (O&M) costs, or performance. LCoE is also employed to define the support level (Held et al., 2014).

The impact of wind in society reaches much beyond its costs and into social aspects (e.g. employment, well-being, emotional issues), environmental benefits (e.g. supporting the fight against climate change, local environmental issues), taxes, employment created (and/or replaced from other generation technologies), etc.

Lastly, the indicator generally used at project level is the return on investment (RoI) with any of its similar definitions, e.g. internal rate of return (IRR) or the net present value (NPV). Interestingly, the RoI is used with two very different purposes, i.e. by developers when assessing the expected profitability of a wind farm project, and by public authorities when defining the correct level of economic support for the technology.

4.1. Cost of capital — evolution of main factors

Wind energy plant is capital-intensive in that the share of capital in the LCoE is significantly

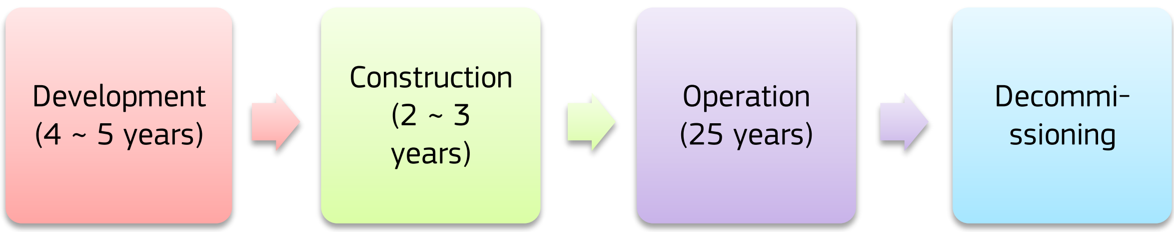


Figure 30: Typical phases and their duration for an offshore wind farm cycle in Europe

higher than for technologies extracting energy from fuels. For example, an offshore wind farm needs usually above EUR 1 billion, distributed between equity (the property of the farm) and debt finance (or loans of different type) ([24]).

An offshore wind farm project, or a similarly large onshore project ('the project'), is typically split into several phases, as in Figure 30.

At the outset the owner of the project is a developer — either a utility or an independent company — who designs the wind farm and takes the project through the permitting and

([23]) A summary definition of the levelised cost of energy (LCoE) indicator is included in the 2012 issue of this report (Lacal Arántegui, et al., 2013).

([24]) The combined remuneration of equity and debt is called weighted-average cost of capital (WACC).

consenting stages, signs conditional supply contracts with the main suppliers, and gets an agreement with the financial institutions that provide debt. At this point (called financial close) the decision whether to carry out the project (final investment decision, FID) is taken. At this stage the **sponsor** assumes the responsibility to provide the equity part of the project cost, although it might share this responsibility with other entities and they all are called **equity providers**. The developer might take the sponsor role or sell the project at this stage. The development phase is the riskiest part and thus it has the prospects for higher returns-on-investment.

The ratio of the mix of debt and equity (called **gearing**) was recently 70 % (i.e. 70 % debt), and recent developments suggests that deals with a 75 % gearing are possible in the medium term and even 80 % when certain conditions are met ([25]).

Traditionally, financial institutions providing debt included commercial banks, development finance institutions (DFIs, also called multilateral banks) such as EIB or KfW, public export credit agencies (ECAs) such as EKF from Denmark or Euler Hermes from Germany. There are now new players in the debt market including the so-called institutional players or investors, e.g. pension funds or insurance companies ([26]).

After completion and commissioning of the wind farm a number of important risks (e.g. construction risk) are over and the asset changes character from a financial point of view. Other financial players, seeking more secure assets, may refinance the debt towards more favourable terms, and the sponsor could launch asset bonds which normally require even cheaper interest rates. The funds previously used as debt are then released for new projects.

Market situation. There is abundant liquidity in the market at this moment (February 2015). Banks are willing to invest in large wind facilities such as offshore even well beyond what is needed (see examples in Table 11), and other players are entering the sector. Banks that only 18 months ago offered EUR 50–60 m per project are now offering EUR 100–150 m. In addition, the need for 'recycling' funds released after commissioning is more acute than before. The bond market is thrilling with increasing demand, and increasingly lower yields in the 2.5–3 % area: green bonds by a German AAA bank were issued with a 0.25 % coupon, Vestas issued bonds for EUR 500 m with a 2.75 % coupon (Vestas, 2015b).

Equity 'markets' are not as liquid as debt markets (in particular during construction) and this makes room for government-backed banks and institutions such as the UK's Green Investment Bank, the European Investment Bank and others. There might be perhaps further room for these institutions — and even for targeted government support — in financing the first commercial-scale offshore wind farm ('first-of-a-kind') using a new wind turbine model, a project entailing higher risks.

In summary: there is competition among financial institutions to provide debt to large wind projects. The consequences might include:

- lower interest rates (significantly lower than was expected 2 years ago);
- higher gearing ratios (optimistically, 80 % could be possible in the medium term for reputed sponsors); and

([25]) The Westermeerwind nearshore wind farm in the Netherlands was financed with nearly 80 % gearing (Westermeerwind.nl, 2014).
([26]) The document: 'Global financial investors into offshore wind', by Sustainable Development Capital LLP, contains lists of leading institutional investors.

- perhaps even lower debt service coverage ratios (DSCR). This is an indicator of the level of expected regular cash flow related to debt payments (capital + interest) required by banks in the project cash flow.

Project	Country	Financial close	Debt	Over subscription
Greater Gabbard OWF's transmission	UK	Nov 2013	(Bond) GBP 300 m	3 times
Meerwind	Germany	March 2013	EUR 385 m	Yes, undisclosed
Gemini OWF	Netherlands	May 2014	70 %, EUR 2.2 bn	Yes, undisclosed
Welspun Renewables' 126 MW wind project.	India	Dec 2014	INR 6.3 bn (EUR 78 m)	2 times
Nordsee One	Germany	March 2015	70 %, EUR 870 m	Yes, undisclosed

Table 11: Examples of recent debt deals with excess of demand from financial institutions. The percentage in the debt column reflects the share of CapEx covered by debt. *Source:* Press releases.

All three aspects increase the internal rate of return and eventually will reduce the cost of energy. See in Section 4.8 evidence of this cost reduction.

4.2. Prices of raw materials

The reduction in the prices of raw materials during the last year affected in particular steel (see both raw steels and stainless in Figure 31). As industry analysts MetalMiner™ puts it: 'Low demand touched most of our metals this month, but the Stainless MMI took the

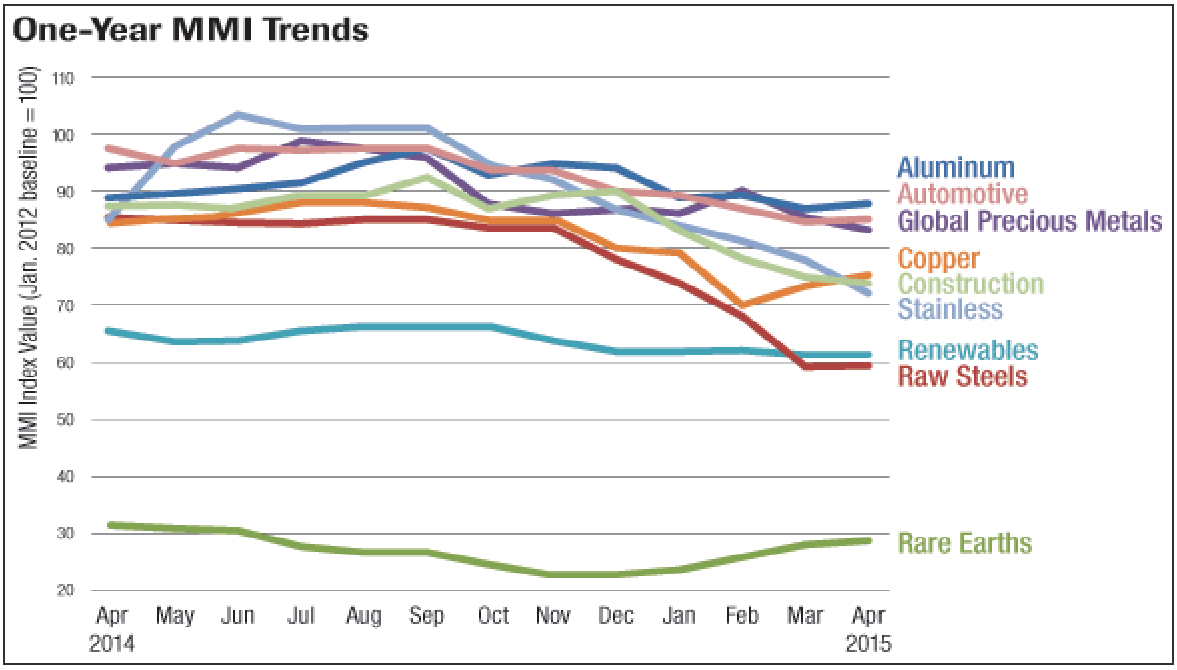


Figure 31: Evolution of the prices of raw materials during the last year, indexed to 100 in January 2012. *Source:* MetalMiner April 2015 Price Index Trends report (MetalMiner, 2015).

biggest hit as the entire 2014 stainless/nickel rally has now been erased and the demand picture from China has eroded so much that it's difficult to predict a recovery without new demand sprouting up from somewhere else.' (MetalMiner, 2015). We believe this is a good summary of the current situation.

The implications, given the high component of steel in the cost of wind turbine raw materials, include that turbine manufacturers able to ensure this low price for the future might have a competitive advantage, as it may steel towers over concrete ones.

4.3. Evolution of turbine prices

Average onshore turbine prices kept trending down in 2014 despite a significantly larger market demand, which is somehow counter-intuitive and thus suggests either a real effort to reduce costs on the side of manufacturers and/or strong market competition. New technology continues to be more expensive but anecdotal evidence collected at the Hamburg Wind Energy Fair (September 2014) suggests that even new wind turbine technology, with taller towers and larger rotors, is reducing costs (the figure of 877 EUR/kW was mentioned for a French project confidentially by its developer). Also anecdotal but more significant, developer Gas Natural Fenosa inaugurated in March 2015 the Spanish wind farm Cordal de Montouto, the first one not receiving any production subsidy and only the revenue from selling electricity in the Iberian wholesale market (GNF, 2015). At a claimed 1100 EUR/kW CapEx this could involve a turbine cost of 770 EUR/kW for class I and II wind turbines with rotors smaller than 95m.

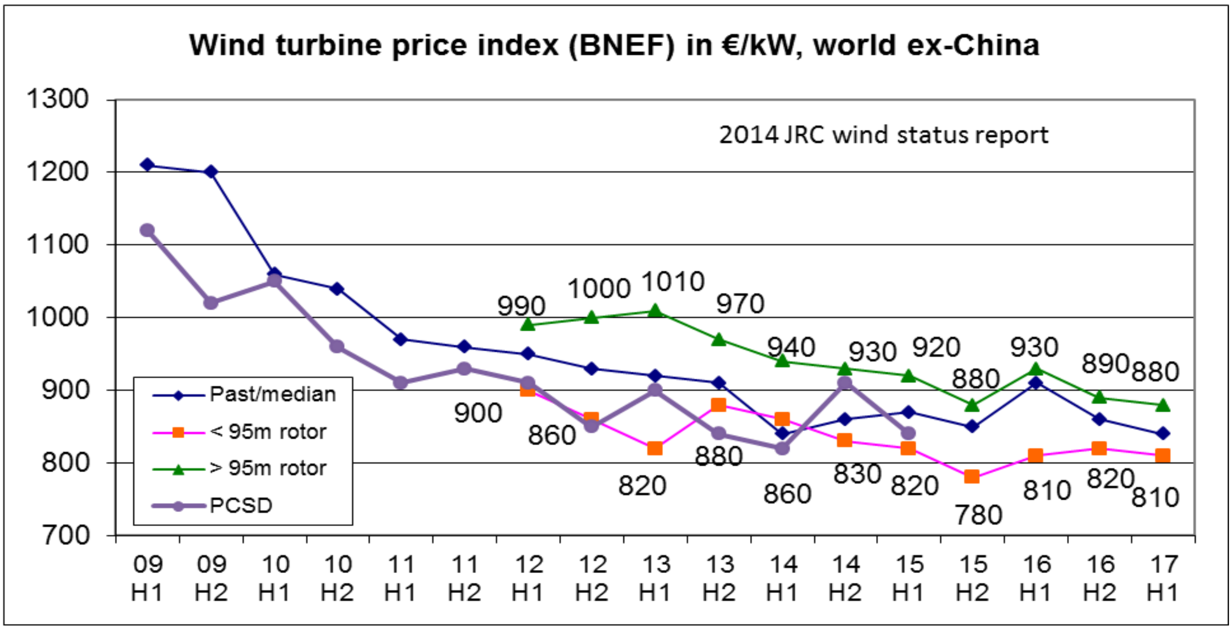


Figure 32: Evolution of wind turbine prices based on the year of delivery (past/median, less or more than 95 metres rotor) and per year of contract signature (PCSD), except China. *Source:* BNEF (2015c).

Historically, turbine prices declined until 2004 influenced by technology learning and the increasing volumes of production, then supply/demand imbalances and the increase of raw material and component prices pushed up global onshore turbine prices — related to the generator rated power — (other than in China) to around 1 200 EUR/kW in late 2007 for delivery in 2009. Then, manufacturing overcapacity, the reduction in raw materials costs caused by the financial crisis and increasing competition pushed down prices to around 840 EUR/kW for turbines to be supplied by mid-2017 (BNEF, 2015c). In the US, the

Department of Energy estimated 2013 turbine prices between 678 and 979 EUR/kW (at EUR 1 = USD 1.328) (Wiser & Bolinger, 2014).

Figure 32 shows the evolution of average world turbine prices excluding Chinese installations, from Bloomberg New Energy Finance (BNEF, 2015c) ([27]). The graph shows prices both by contract signature date (PCSD) and by turbine delivery date in three ways: turbines with small rotors (< 95m), with large rotors (> 95m) ([28]), and a single past price when no distinction of technology was made. The latter becomes the median of new and old technology since the moment a technology distinction is possible. From 2012 onwards the graph shows price differentiation between new and old technology as described above.

There are two main elements affecting offshore turbine prices: the level of competition and the nearly exponential need for materials with as turbine size increases. The entry of MHI-Vestas' V164-8.0 MW turbine into the sales phase is likely to have stimulated price reduction based only on competition. However, as shown for blades in Figure 7 and for castings and forgings in Section 2.2.6 of last year's JRC wind status report, technology advancement has only smoothed but not prevented a nearly exponential need for materials and thus larger machines cost more to build per unit of nominal power.

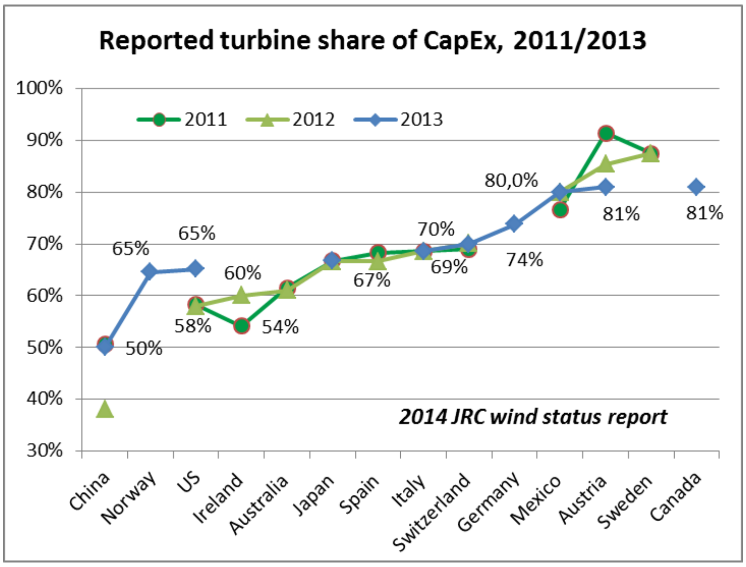


Figure 33: Turbine share of CapEx in onshore projects, 2011, 2012 and 2013. *Source:* JRC elaboration with data from IEAWind (2012, 2013, 2014).

4.4. Capital expenditure (CapEx), onshore and offshore

The main single contributor to project CapEx continues to be the cost of the wind turbine but its share has been slowly reducing from around 70 % to around 62 % in a few years. Figure 33 shows the different share of the cost of the turbine in the total CapEx for selected countries onshore. Chinese data has slightly different components ([29]) and it is therefore not comparable with the rest (its presence in the graph somehow confirms these differences). The figures for Mexico, Austria and Sweden seem high, and Austria shows a clear reduction from 2011 to 2012 and then 2013. The US shows an increase into 2013 which is likely due to the use of turbines with larger rotors.

([27]) However note the low representativeness of the data, which comprise only 17.1 GW of contracts signed from 2006 to H1 2015, an 8% of the estimated amounts of contract signed during the period of 220 GW. In all cases onshore ex-China.
([28]) With the tower plus the rotor covering 40 – 45 % of the turbine cost, and an increasing number of new turbines having larger rotors and taller towers, there is a natural distinction between the most expensive new technologies and the old ones which BNEF has chosen to describe as rotors smaller or larger than 95 m.
([29]) As discussed earlier, Chinese data cannot be compared with the rest of the world because they might not include towers or foundations, nor significant electrical equipment (e.g. transformers), nor certain ancillary (e.g. health and safety) equipment.

Country	Turbine costs (EUR/kW (*))		Capital costs (EUR/kW (*))		Installed capacity (MW)	
	2012	**2013**	2012	**2013**	2012	**2013**
Austria	1 430	**1 390**	1 675	**1 715**	296	**308**
China (*)	464	**480**	1 220	**960**	12 960	**16 048**
Germany onshore		**1 053**		**1 427**		**2 904**
Italy	1 200	**1 200**	1 750	**1 750**	1 273	**444**
Japan	1 740	**1 380**	2 610	**2 070**	88	**50**
Norway		**912**		**1 412**	195.5	**97.5**
Portugal		**1 080**		**1 350**		**196**
Switzerland	1 450	**1 450**	2 070	**2 070**	4	**13**
United States	853	**799**	1 470	**1 227**	13 124	**1 129**

Table 12: Estimated average turbine cost and total project cost in 2013, as declared by country representatives to IEAWind. *Source:* IEAWind (2014) (**) for all costs but 2013 US CapEx, where the source is (Wiser & Bolinger, 2014), and GWEC (2013, 2014) reports from national administrations, e.g. (Weir, 2015), for installed capacity. See footnote (30) for exchange rates.

(*) China turbine cost figures often exclude components than in most countries are generally included. For this reason these figures are included for reference only.

(**) Canada, China, Germany, Denmark, Finland, Greece, South Korea, the Netherlands, and Norway, were excluded from this assessment because of methodological differences or lack of complete data. Chinese data, however, was included in the table for illustration purposes, given its significant differences with the rest.

The world weighted average CapEx, (without China) for onshore projects in 2013 was 1 485 EUR/kW (IEAWind, 2014) vs. 1 513 EUR/kW in 2012, a figure higher than previous expectations (see Section 4.2.2 in (Lacal-Arántegui, 2014)). If Chinese data were included (see footnote (29)), the world weighted average would have been 1 123 EUR/kW in 2012. Wiser and Bolinger (2014) found that in the US a CapEx level around in of 2 100 USD/kW (1 510 EUR/kW) in 2011 and 1 940 USD/kW (1 510 EUR/kW) in 2012, and a sharp reduction to 1 630 USD/kW (1 227 EUR/kW) (30) in 2013. However, the 2013 figure is based on limited data (650 MW) due partly to the demise of the US market that year.

It is important to note the variability of CapEx figures between countries and over time. Table 12 shows CapEx (and turbine costs) for a range of the countries contributing to the joint international effort IEAWind.

To find out more about reducing the cost of energy country differences should be analysed and a model built which should show the impact in CoE of technology advancement and other key factors, whether legislative, materials, design, etc.

Offshore, the share of turbine costs in total CapEx is still the highest component but significantly lower than onshore at 30–40 %, see Figure 34.

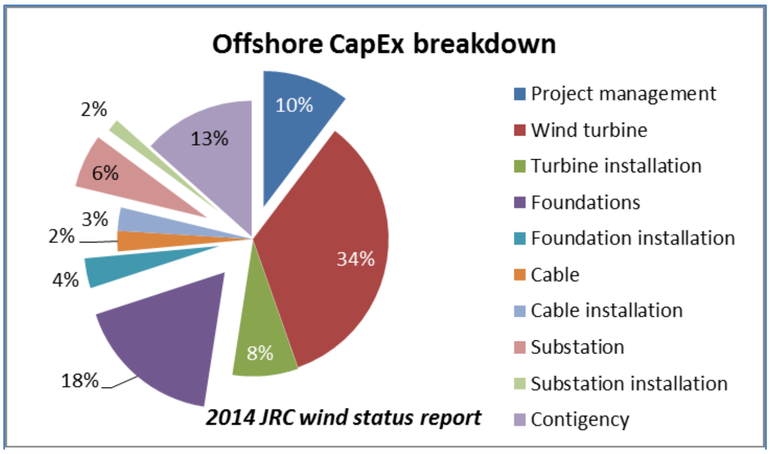


Figure 34: Sample breakdown of offshore investment costs for a generic project in Germany. *Source:* JRC analysis of (Fichtner-prognos, 2013).

(30) Annual exchange rates averaged 1.392, 1.2848 and 1.3285 USD/EUR in 2011, 2012 and 2013 respectively (European Central Bank).

Offshore wind CapEx is very dependent on water depth and, to a lesser extent but still very importantly, on distance to the construction port or ports, and to the onshore substation. Offshore wind CapEx can vary between 2 300–4 200 EUR/kW in 2015 with the upper end covered by farther offshore, deep-water wind farms and includes transmission to the shore, and the lower end applicable to nearshore projects without including transmission.

4.5. Offshore wind turbine installation — cost reduction potential

Author: Cedric Dewandre, Tractebel Engineering (GDF Suez) [31]

An overview of the turbine installation cost breakdown is shown in Figure 35 by the pie chart main slices. Potential cost reductions can be identified and estimated for these main cost items, and some of them are shown in the chart outer sub-slices. These cost reductions can result from industry novel techniques or innovations, different choices, improved processes, etc ...

This particular example is given for a typical 480 MW offshore wind farm case, with 3.6 MW turbines, for a P50 (50 % probability) year-round average weather, with a 50 km distance to port.

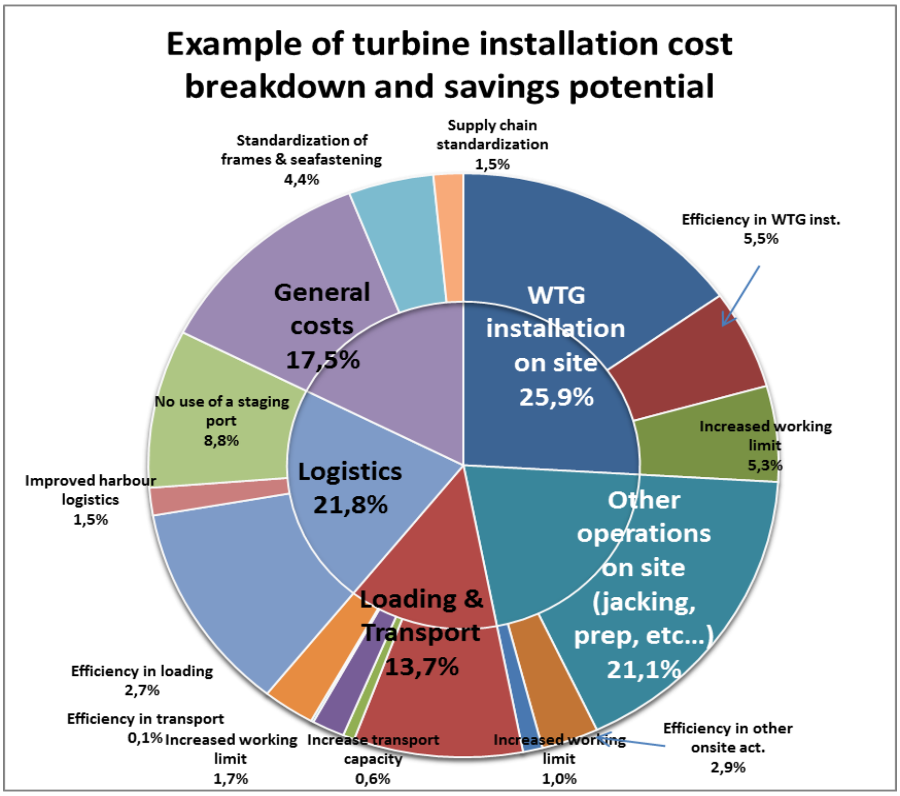


Figure 35: Turbine installation cost breakdown and savings potential. The inner circle reflects a high level breakdown whereas the outer circle shows the areas for cost reduction highlighted by the model. *Source:* Tractebel Engineering.

The model shows that important cost reduction opportunities exist on the installation activities. Though some of this cost reduction potential has already been addressed by the market, the saving potential can be found in the following items:

— Increasing weather workability limits. These can have a major effect on cost reduction, and the market is addressing this with, for example, component handling tools that can cope with higher wind speeds being developed and starting to be used. Naturally it must not be forgotten that with increasing turbine sizes, such higher wind speed workabilities will be more difficult to reach.

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— More efficient operations. These will be the product of a series of optimisations throughout the whole process. The first item would of course be using the most adequate and performant vessels, i.e. latest generation purpose-built vessels compared to 'older' more general vessels used in the offshore wind market. A second item would be more adequate and earlier consideration of installation during turbine design phases. However, other optimisation examples could be loading of complete blade racks in one lift instead of one blade at a time, starting lowering spuds before arrival, better lifting logistics and procedures, reducing the number of lifts …

— Use of a staging port vs. transport from the base port with the transport and installation vessel. Feeder concepts could also be a solution as they are increasing in reliability. A trade-off needs to be made for each specific project, to find the best logistical configuration. In this particular case long-distance transport from the turbine loading port with the installation vessel transpired to be more interesting than long-distance transport to a staging port and short-distance transport with the installation vessel from the staging port to the site.

— Standardisation of frames and seafastening for different wind turbines, in cooperation with turbine manufacturers. In the meantime, an endeavour to reuse frames from a project to another could already bring its share of optimisation.

Recently built turbine transport and installation vessels already feature some of these cost reductions, through larger deck space, optimised deck layouts for example.

Innovative/futuristic installation vessel concepts could also bring a large deal of cost reduction if they become reality.

Notwithstanding, when it comes to overall turbine installation, it is expected that the largest impact will come from increasing turbine sizes which will bring about a considerable share of cost reduction per installed MW, although this is not taken up in the above figure. Larger turbines will bring new logistical and installation challenges but this will largely be outweighed by key cost reductions from installing fewer foundations and array cables. Incidentally, larger turbines also increase their capacity factors (production/MW) due to greater wingspans which will help reduce the cost per MWh.

4.6. Operational expenditure (OpEx)

Operational expenditure mostly consists of fixed costs, with some of them being variable:

1. Fixed O&M costs: staff costs, turbine scheduled O&M, balance of plant (BoP) maintenance, some consumables.

2. Variable O&M costs: unscheduled O&M, repairs, some consumables.

3. Other fixed operating costs: electricity connection (fixed part), insurance, project administration management fees, other general and administration costs.

4. Other variable operating costs: electricity connection (energy imported), wind integration (mostly balancing) charges, property tax/business rates.

Land leases or royalties may take the form of a fixed annual or a variable fee.

There is anecdotal evidence suggesting that land leases are increasing in some Member States.

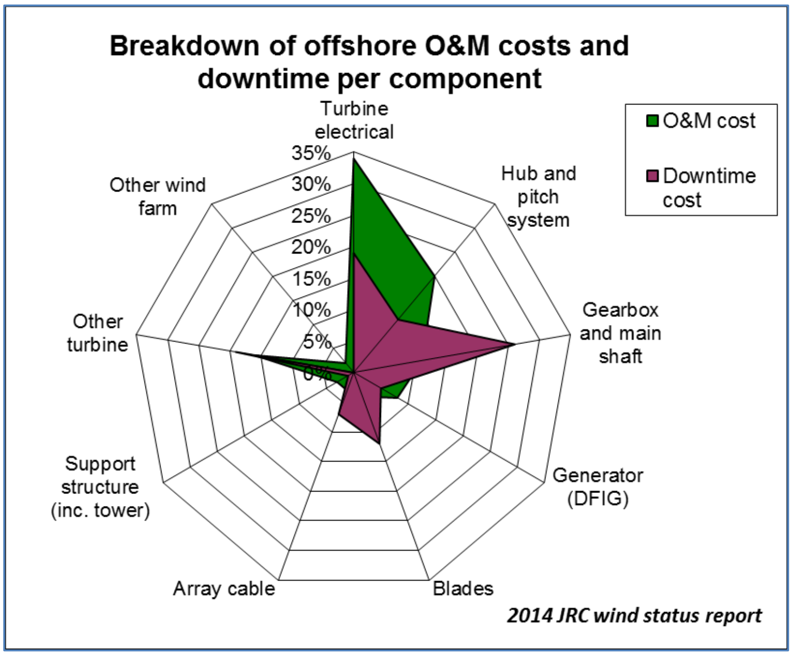

Figure 36: Breakdown of O&M costs, in percentage of monetary units, in an offshore wind farm. *Source:* JRC elaboration from (BVG, 2012).

The details of current O&M costs are included in the 2012 and 2013 issues of this report. The authors estimate that O&M costs onshore have not changed in a substantial way from 2013 to 2014, mostly based on the significant changes that took place from 2012 to 2013, where the O&M servicing market became highly desirable for original equipment manufacturers (OEMs) and thus highly competitive.

Offshore the picture is slightly different. Notwithstanding industry expectations for lower O&M costs of around 100–130 EUR/kW/yr for projects with FID by 2020, banks reported that the current levels of O&M cost in the UK are above 150 and they could reach 200 EUR/kW/yr, a figure above initial project expectations.

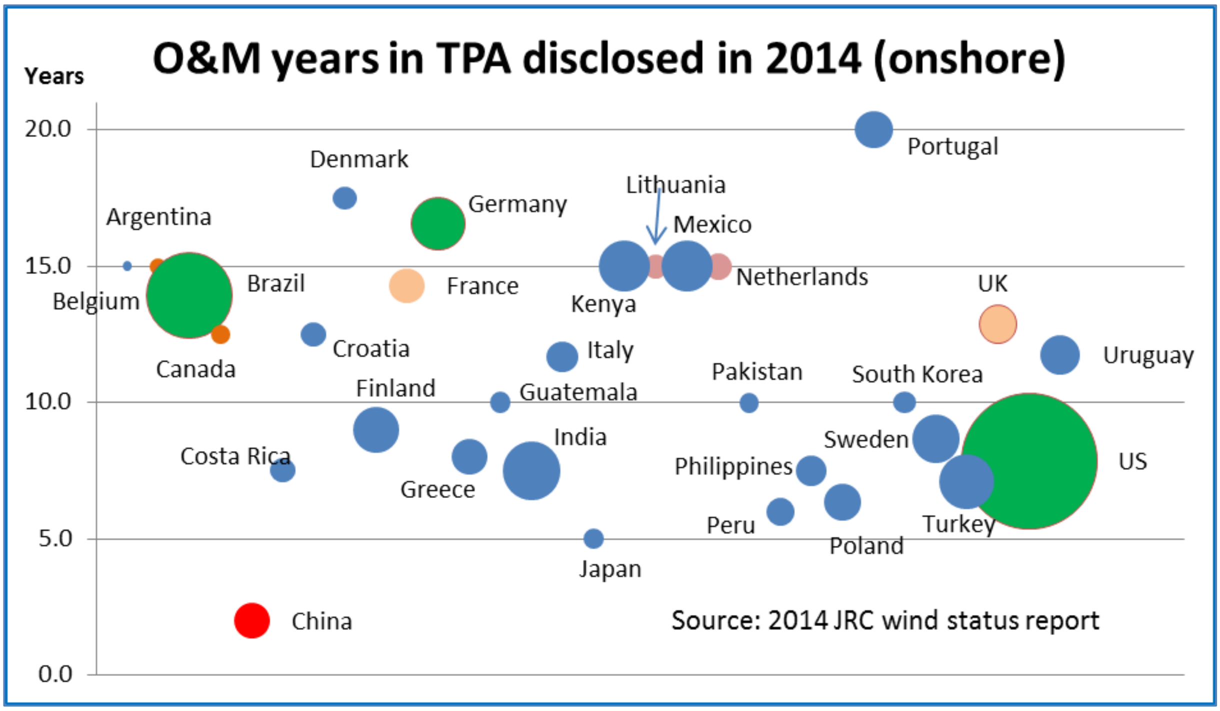

Figure 37: Length of O&M contracts included as part of turbine purchase agreements. The thickness of the bubbles represents the country volume in MW, whereas the horizontal axis does not have any unit. *Source:* JRC.

An aspect of O&M that is not frequently analysed is the length of O&M service contracts. Turbine purchase agreements include by default 2 years of service. However, it is in the interest of the manufacturer to ensure a flow of income during a long period, and for this TPAs include O&M contracts for a number of years. Figure 37 shows that long O&M contracts are included with the TPA in some countries (Portugal, Germany, Brazil) whereas in others this is far from the case (China). Most countries are now signing up for between 5 and 15 years of maintenance.

This situation has different implications. For example, the longer the O&M service included with turbine purchase, the less O&M market is left for third parties. Also, the O&M market is increasingly interesting for manufacturers: at the end of 2014, Vestas had a wind turbine order backlog of EUR 6.7bn (7 513 MW) and a service order backlog of EUR 7.0bn (Vestas, 2015a).

4.7. Electricity generation and capacity factors

Based on data from Eurostat, Figure 38 reports the capacity factor and the share of electricity in the final consumption for the EU Member States where wind contributes most to the electricity supply. Data are the sum of onshore plus offshore wind farms.

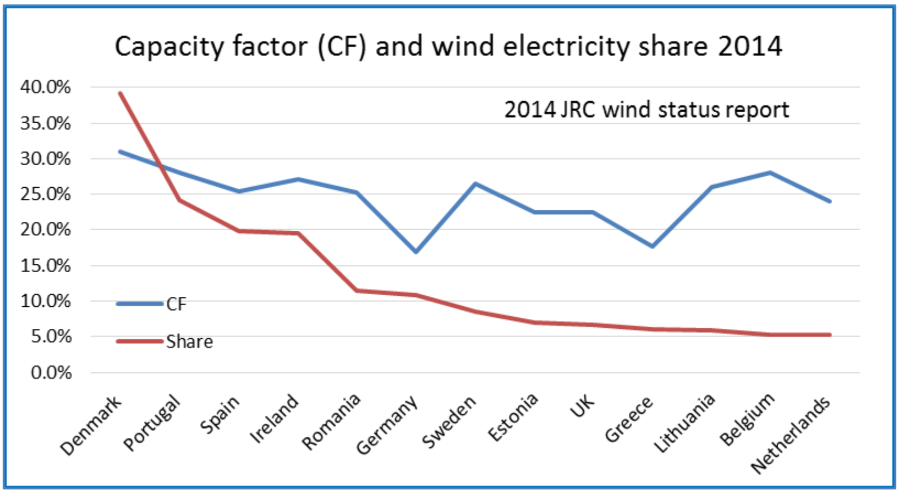

Figure 38: Mapping capacity factors and the share of wind electricity in the different EU Member States. *Source:* JRC based on Eurostat data.

The capacity factor is an indicator of electricity production but not necessarily the most adequate in all occasions. In the EU MS, CF varies generally from 20 to 30 % with extremes (in 2013) in the UK and Germany with 32 and 18 % respectively.

The share of wind electricity related to final consumption is highest in Denmark, then Portugal, Spain and Ireland with 18–24 %, then Romania and Germany just below 10 % and leading a group of 13 MS that obtain between 4 and 9 % of their electricity from wind.

4.7.1. Electricity generation

Electricity generation from wind energy reached 238 TWh in 2014 according to preliminary figures by ENTSO-E (ENTSO-E, 2015). In the US, 182 TWh were generated during the same period (EIA, 2015), and in China 153 TWh (Chabot, 2015).

Table 14 shows the electricity generation [32], the final consumption and the share of wind electricity in final consumption in most EU Member States, as reported by ENTSO-E (2015).

	Wind electricity (TWh)	Final/total electricity generation/consumption (TWh)	Share of wind	Capacity factor
EU	238	2 942 (consumption)	8.08 %	22 %
US	182	3 862 (consumption)	4.71 %	33 %
CN	153	5 649 (generation)	2.72 %	17 %

Table 13: Comparison of the wind electricity production, share of wind in final consumption or generation, t and wind capacity factors. *Sources:* (ENTSO-E, 2015), (EIA, 2015), (Chabot, 2015).

Country	Wind generation	Consumption	Share	Country	Wind generation	Consumption	Share
Denmark	13 061	33 349	39.16 %	Poland	7 255	146 885	4.94 %
Portugal	11 812	48 797	24.21 %	Italy	15 068	308 428	4.89 %
Spain	51 005	257 758	19.79 %	Cyprus	198	4 201	4.71 %
Ireland	5 116	26 188	19.54 %	Austria	2 998	69 294	4.33 %
Romania	6 138	53 290	11.52 %	Croatia	702	16 407	4.28 %
Germany	55 170	504 862	10.93 %	Bulgaria	1 313	31 221	4.21 %
Sweden	11 475	135 579	8.46 %	France	16 984	465 666	3.65 %
Estonia	575	8 193	7.02 %	Latvia	126	7 372	1.71 %
UK	22 621	339 979	6.65 %	Hungary	632	39 518	1.60 %
Greece	2 982	49 258	6.05 %	Finland	1 113	83 346	1.34 %
Lithuania	637	10 715	5.94 %	Luxembourg	79	6 254	1.26 %
Belgium	4 437	83 728	5.30 %	Czech Republic	470	62 000	0.76 %
Netherlands	5 808	110 942	5.24 %	EU	237 784	2 942 556	8.08 %

Table 14: Wind electricity production, final consumption and share of wind in the EU Member Estates with installed wind energy. *Source:* ENTSO-E (2015).

4.7.2. Capacity factors

The typical European capacity factors onshore are 1 800–2 200 annual-equivalent full-load hours (in which a wind turbine would produce at full capacity) and 3 200–4 300 hours offshore. The clear technological trend is to increase these figures even when the best sites onshore have already been taken and new wind farms are built at lower wind speed sites.

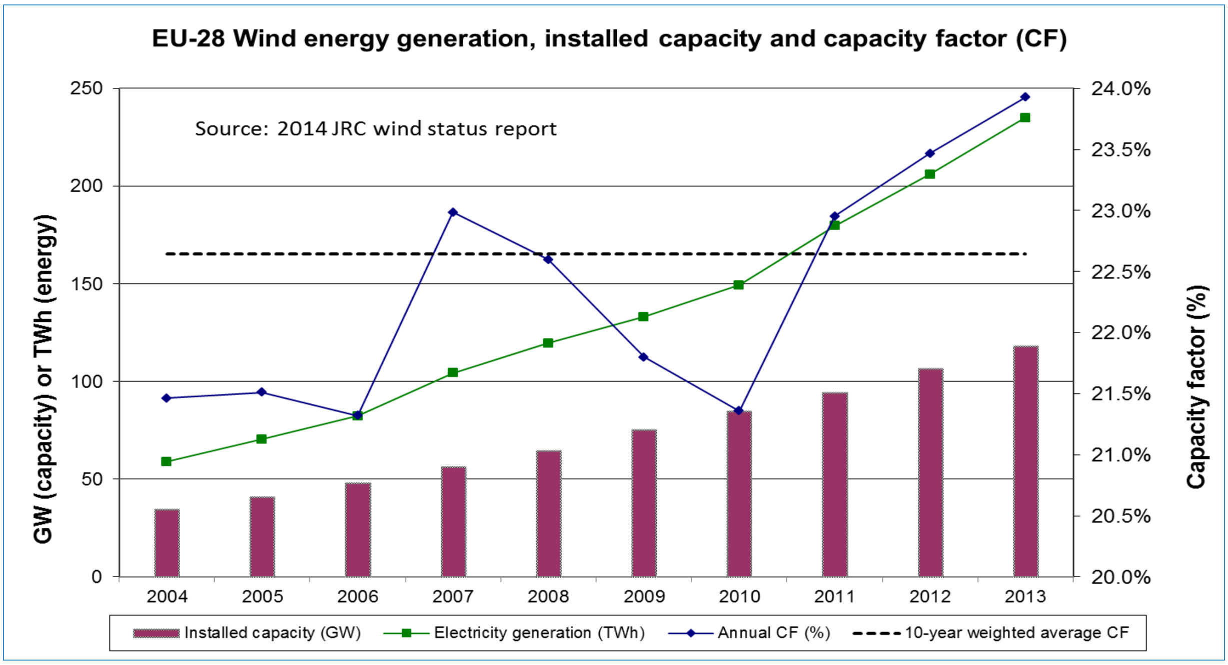

Figure 39: Set of production indicators for the EU per year — installed capacity, electricity generation and capacity factor. *Source:* JRC based on Eurostat and EWEA data.

The comparison of capacity factors between the US, the EU and China in 2014 (Table 14) suggests the figures of 33 %, 22 % and 17 % respectively. Whereas in the EU the year 2014 was not a high-wind year, the reasons for the lower Chinese capacity factor are more complex but they seem to include high curtailment (Wong & Zhu, 2015).

Figure 40 shows the evolution of annual production in the Danish offshore wind farms using the capacity factor as the indicator. It has to be noted that year 2011, 2012 and

2014 were, in general, good wind years in Northern Europe whereas 2010 and 2013 were not. The figure therefore serves as well as an example of year-to-year variability.

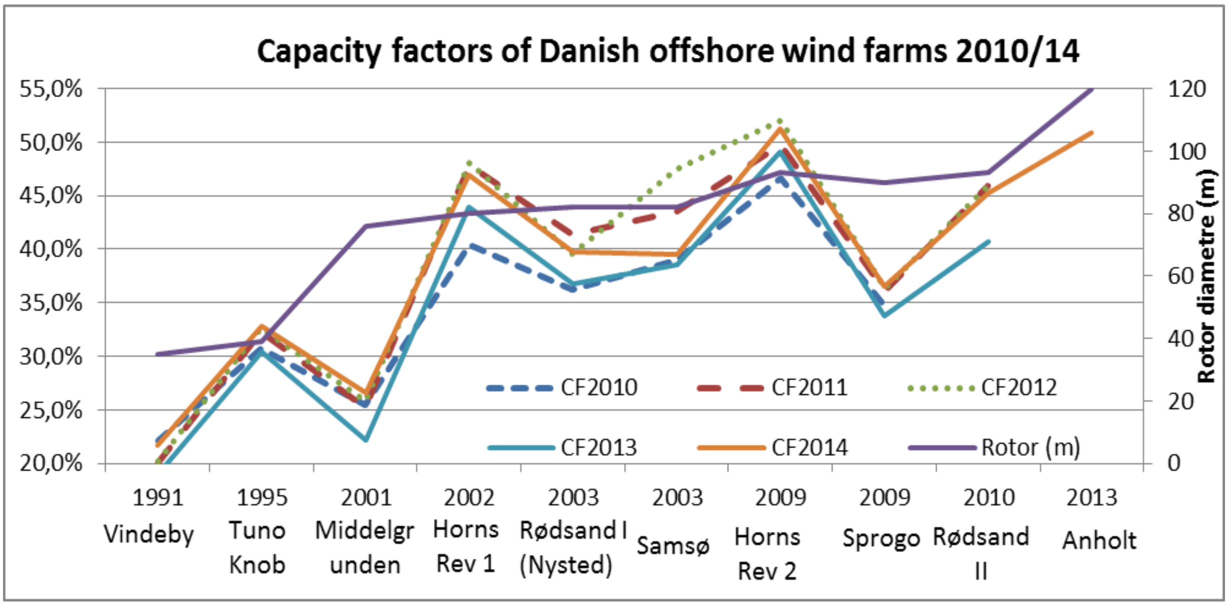

Figure 40: Capacity factors in Danish offshore wind farms related to the commissioning year. *Source:* JRC calculation from the Danish registry of wind turbines (Danish Energy Agency, 2015).

It is interesting to note that the facilities with the highest capacity factor use turbines with the lowest specific power: Anholt (318 W/m^2) and Horns Rev II (339 W/m^2). However, Rodsand II, with the same turbines as Horns Rev II, presents a 5 % lower capacity factor.

4.8. Cost of energy

The fundamentals of the calculation of the levelised cost of energy (LCoE) were described in Section 4.1 of the 2013 issue of this report.

Different reputable sources regularly or occasionally publish LCoE estimates including IEA, IRENA and the US Lawrence Berkeley National Laboratory on behalf of the US Department of Energy. Table 15 summarises the ranges of levelised cost of energy according to some of those sources.

The cost drivers can be summarised as: turbine technology and in particular tower height and length of rotor diameter; distance from turbine factory to wind farm site and complexity of transport; length of the connection to the grid; cost of land rental or purchase; length and complexity of the permit process; gearing (see section 4.1), debt interest rate and equity return-on-investment levels; type and level of the support scheme. These drivers are responsible for the wide range offered by these cost estimates.

However, one of the problems of the LCoE as an indicator is that it is heavily dependent on assumptions such as the discount rate (or weighted-average cost of capital, WACC), project life, etc. For example, a 4 % reduction in WACC (from 10 % to 6 %) brings about a 35 EUR/MWh reduction in LCoE, a 25 % benefit, in a modelled offshore wind farm (Hundleby, 2015).

Source	Scope	Onshore (USD/MWh)	Offshore (USD/MWh)	Currency year	Cost year	Reference
IRENA	World	60–120	100–210	2014	2014	(IRENA, 2015)
DoE (*)	US	37–75		2013	2013	(Wiser & Bolinger, 2014)
IEA	World	60–130	190–260		2014	(IEA, 2014b)
Lazard	US	37–81	162	2014	2014	(LAZARD, 2014)
BNEF	World	48–160	140–230	2015	2015	(BNEF, 2015a)
ECOFYS (**)	EU	67–144	122–206	2012	2013	(ECOFYS, 2014)

Table 15: Comparison of LCOE-equivalent from different sources.
(*) The figures are the result of adding the estimated impact of subsidies (15 USD/MWh) to the range of purchasing-power agreements (PPAs).
(**) 52–112 EUR/MWh onshore and 95–160 EUR/MWh offshore, exchange rate EUR 1 = USD 1.2848

A second approach to finding the cost of energy is to use as a proxy its remuneration when the latter is based on competitive bidding (auctions/tenders). This assumption has a danger though: the winners, the lowest prices, sometimes bid at unrealistic prices (e.g. in the hope that other bidders with higher bids raise the final price [33]), and thus their wind farm will not be profitable at the given price and will not be built.

4.8.1. Cost of energy onshore

Task 26 of the IEA Wind Implementing Agreement just published the analysis of the cost of energy onshore for the Task participating countries. The 2012 LCoE figures vary between EUR 45 (Denmark) and EUR 97 (Germany, low wind area) per MWh, with a clear trend to lower prices (Hand, et al., 2015). Table 16 summarises these figures

Country	LCoE 2008	LCoE 2012	LCoE 2014	Remarks
Denmark	54.9	44.9		
Germany	89	97		2008 resource quality 90 %, 2012 resource quality 70 % (corresponding to a low-wind site (inland)
Germany	89	75		2008 resource quality 90 %, 2012 resource quality 100 % (corresponding to a high-wind site (coast)
Ireland	59.45	61.53		Slight increase due to turbine rating, rotor diameter and hub height
Norway	65	70	59	2014 value is for a reference project
US	74.7	70.3	42.9	2014 project in the windiest areas, the US interior, using Class III turbines

Table 16: LCoE in countries participating in IEA Wind Task 26, in EUR_{2012} per MWh. Summary of (Hand, et al., 2015)

[33] This situation can occur when all winning bidders receive the marginal price, i.e. the price asked by the most expensive bid accepted, as in the UK's CfD (Contracts for Differences).

Based on the approach to explore the cost of energy based on auctions, the auction scheme in Brazil was perhaps providing among the cheapest onshore wind electricity in the world, thanks partly to its subsidised debt (under certain conditions of local content), partly because of very good wind resource which provides capacity factors around 50 %. Figure 41 shows an evolution of the prices of the winning bids in the local currency (BRL) and a comparison with the equivalent price in euro.

The first take from the picture is the effect of currency exchange; more interestingly, the picture shows a trend to continuous reduction of the price in euro, albeit with a slight increase in the later bids claimed to be due to local conditions (increasing debt and production costs).

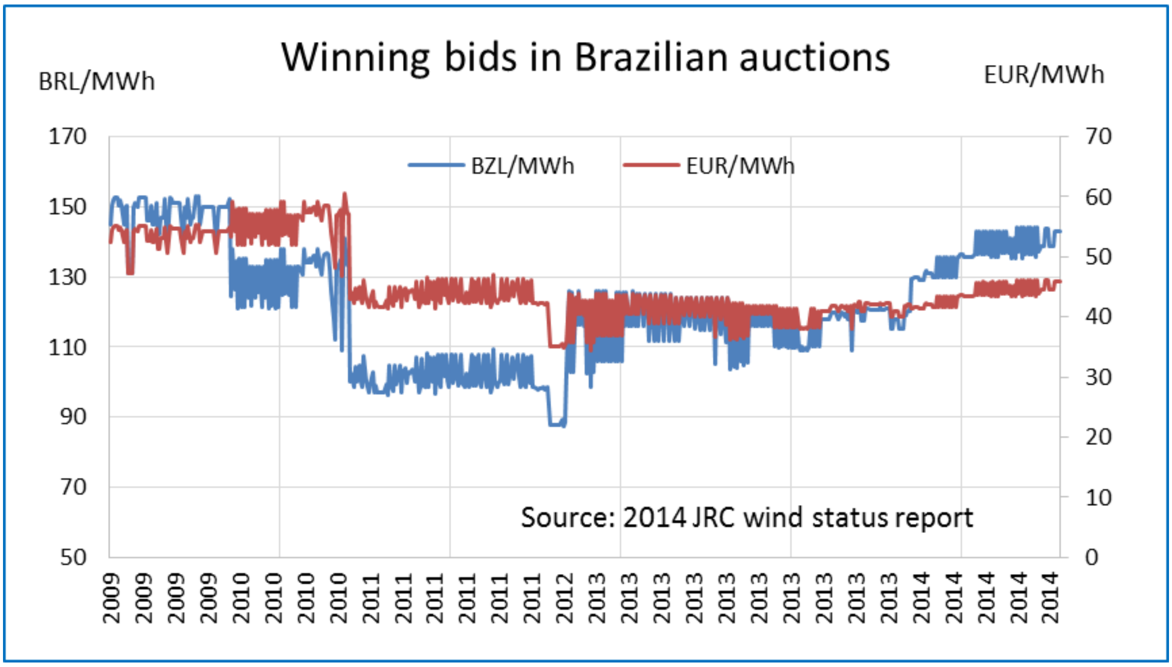

Figure 41: Prices resulting from the Brazilian auction scheme. The conversion to EUR was made at the average annual exchange rate. Source: (ANEEL, 2015).

However, it has to be noted that the latest (and very recent) tender, not included in Figure 41, resulted in a further increase of prices in both BRL and EUR.

4.8.2. Cost of energy offshore

Two recent auctions/tenders suggest that the cost of offshore wind is reducing significantly. In the UK the recent Contract for Differences auction set a cost of 119.89 GBP/MWh (164.72 EUR/MWh) for East Anglia One (depth 30–40 m, distance to shore 45 km) commissioning in 2018 and 114.39 GBP/MWh (157.17 EUR/MWh) for Neart na Gaoithe (depth 45–50 m, distance to shore 20 km) commissioning in 2019. Those costs include full cost of connection to the onshore grid substation.

In Denmark, the tender for Horns Rev 3 offshore wind farm (depth 10–15 m, distance to shore 32 km) with expected commissioning in 2019 resulted in a price of 770 DKK/MWh, or 103.2 EUR/MWh, with connection costs to shore being the responsibility of the system operator ([34]). To put those winning prices in context, in the UK the maximum price of that auction was 140 GBP/MWh, and in Denmark the last tender (Anholt, 2010) was granted at 1 051 DKK/kWh (equivalent to 140.7 EUR/MWh).

A simplified calculation of LCoE based in the previous figures would result (see footnote [34]) in some **145 - 155 EUR/MWh in the UK case and 90 – 95 EUR/MWh for Horns Rev II**, depending on assumption such as whether the offshore substation and connection to shore costs are included, corporate tax, debt interest, whether nominal or real figures are used, non-subsidised revenue and a 20 or 25-year useful life.

([34]) These figures are not to be confused with LCoE, as they are simply the revenue stream for the projects for a period shorter than the plant operating life: 15 years in the UK and about 12 years in Denmark. LCoE is normally calculated assuming 20 to 25 years of operating life, which results in a lower figure.

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5. THE REGULATORY FRAMEWORK

5.1. Introduction

The Renewable Energy Directive 2009/28/EC (EU, 2009) established a European framework to promote renewable energy by setting mandatory national targets in order to achieve at least a 20 % renewable energy share in final energy by 2020. Each Member State was required, by June 2010, to set out the sectorial targets by their National Renewable Energy Action Plans (NREAPs). Each individual plan defined the technology mix scenario, the trajectory to be followed and the measures and reforms to overcome barriers and ensure the developing of renewable energy. According to the plan defined in the NREAPs, wind energy has a significant role in order to achieve the 2020 renewable energy targets: expected installed capacity by 2020 in the EU is 207.7 GW (169.2 GW onshore and 38.5 GW offshore).

5.2. Support schemes

Support to renewable energy is usually performed by the combination of several measures. Feed-in tariffs (FiTs), feed-in premium (FIPs), tenders, quota obligations —combined with tradable green certificates (TGCs) — or Contracts for Difference (CfDs) are applied as major support instruments. Whilst investment grants, fiscal measures and financing are employed to provide an extra level of support. The authors would like to refer to Couture (2009) for a thorough explanation of support schemes.

FiTs have been historically the most common support scheme. However, a higher market exposure of renewable generators is essential in order to boost market competition as well as promoting the integration in the electricity system. The guidance from the European Commission — published in November 2013 — for the design of renewables support schemes (EC, 2013) recommends preference for FiPs over FiTs.

According to the desired exposure of renewable generators to risk, the premium can be set as a fixed add-on to be paid over the electricity market price or as a sliding premium to achieve an objective price. Tenders or auctions are also a recommended practice to foster competition and track the actual costs of technology, and can be used to define the support level for the different instruments.

Along the same lines, the 'Guidelines on State aid for environmental protection and energy 2014–20' (EC, 2014), published in June 2014, call for market-based support mechanisms. The guidelines set the following conditions to be applied from 1 January 2016: (i) the support is provided as premium to be paid in addition to the market price, (ii) renewable generators will be subject to balancing responsibilities (unless no liquid intra-day markets exist), (iii) measures have to be taken to avoid renewable generators producing electricity under negative prices. Additionally, during the period 2015–16, the support has to be established by a competitive bidding process for at least 5 % of the new renewable capacity. This condition is extended for all new projects from 1 January 2017. Unless Member States (MSs) demonstrate that (i) a very limited number of projects are eligible, (ii) competitive bidding would lead to higher support levels and (iii) competitive procedures would result in low projects realisation.

Figure 42 shows an overview of support schemes currently applied for new onshore wind installations in EU MSs. Additional support (by investment grants, tax exemptions or favourable financing conditions) is provided in Belgium, Germany, Finland, Ireland, Italy, the Netherlands, Poland, Sweden and the United Kingdom. The same support mechanisms (with tailored conditions, in some countries) apply for offshore wind energy, except in Denmark where the feed-in premium is selected by tenders.

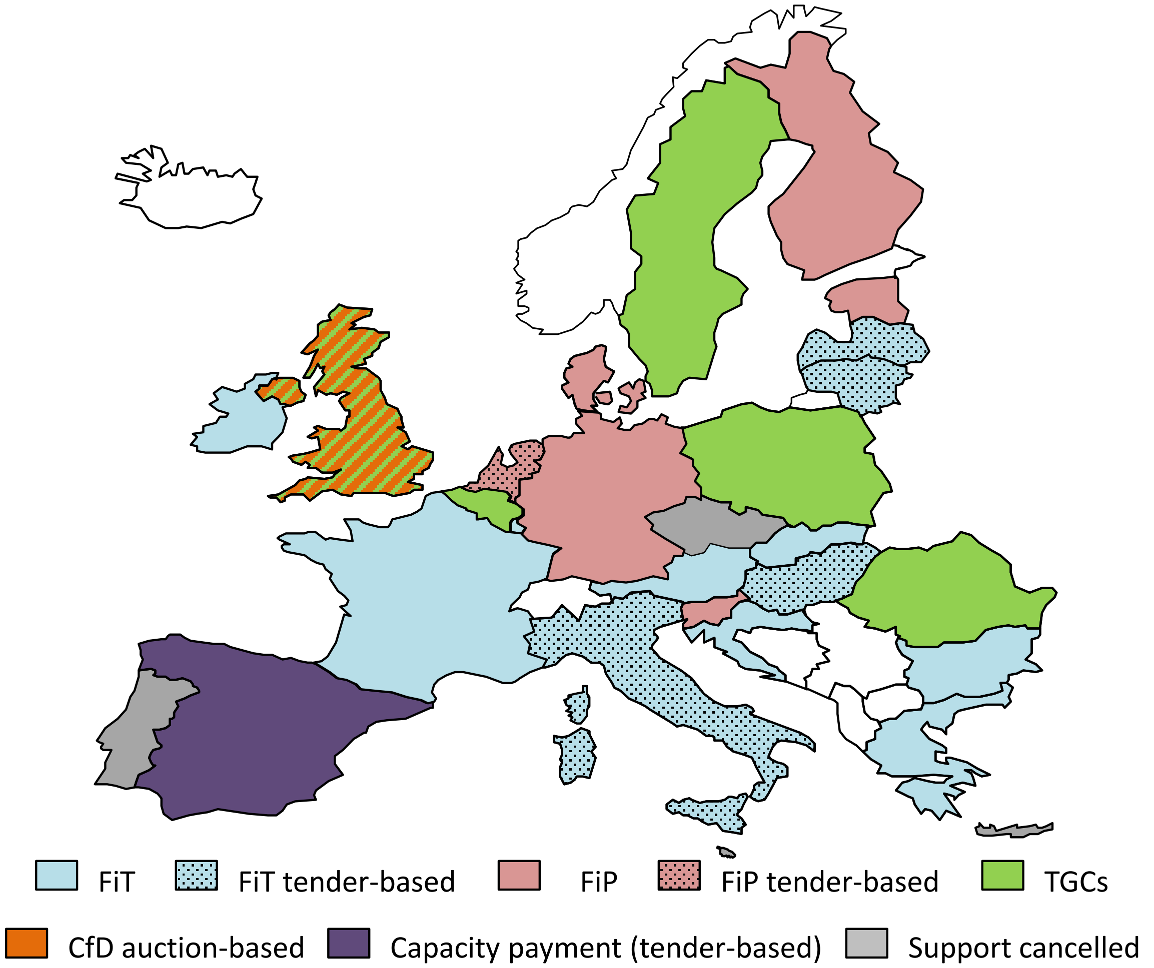

Figure 42: Overview of support schemes for utility-scale onshore wind energy in EU MS (early 2015).

5.3. Support schemes for onshore wind energy

Table 17 summarises the specific features of FiTs and FiPs offered for new onshore wind power plants among MSs.

Tenders are gaining prominence to establish the support level. In Italy, Latvia and Lithuania tenders are used to establish the fixed remuneration to be received by plant operators during the eligibility period. In the Netherlands a specific tender procedure is used to determine the target price (alike a sliding FiP). The procedure consists of six stages depending on the application date of the plant. The later the generator applies, the higher the target price: 87.5 EUR/MWh, 100 EUR/MWh, 112.5 EUR/MWh; respectively for the first to third stages and 121.3 EUR/MWh for the fourth to sixth stages. However, as the total budget of the programme is capped to EUR 3.5 bn (for all renewable electricity technologies, renewable heat and cogeneration) and the procedure is based on a first-come, first-served basis, it is likely that the first stages use up the budget.

The CfD scheme was recently introduced in the United Kingdom. Under this remuneration scheme wind generators will receive the so-called strike price (established by auction). Under this scheme, generators are required to participate in the market. In case the market price is lower than the strike price, the difference is paid to the generator. Conversely, if the market price is higher than the strike price, the generator pays back the difference.

The support scheme introduced in Spain in 2014 is also based in a tender procedure. Bidders specify a series of retributive parameters (including, among others, the life span of the project, number of equivalent hours and lower/upper limits of electricity prices). These parameters are employed to determine the reduction percentage over the standard value of the initial investment for a predefined reference installation.

Country	**Support**	**Amount (EUR/MWh)**	**Period (years)**
Austria	FiT	93.6	13
Bulgaria	FiT	49 (95.55 BGN/MWh)	12
Croatia	FiT	Depending on reference price	14
Denmark	FiP	33.5 (250 DKK/MWh), fixed add-on	Based on rotor area[(1)]
Estonia	FiP	53.7, fixed add-on	12
Finland	Sliding FiP	83.5 ([2])	12
Germany	Sliding FiP	Years 0–5: 89; years 6–20: 49.5[(3)]	20
Greece	FiT	82, 90 ([4])	20
Ireland	FiT	69.5	15
Luxembourg	FiT	92	15
Slovakia	FiT	70.3	15
Slovenia	Sliding FiP	< 10 MW: 95.38; < 125 MW: 86.75[(5)]	20

Table 17: Summary of FiTs and FiPs for onshore wind energy support implemented in MSs (early 2015). Yearly average currency exchange rates were used to convert BGN and DKK to EUR.

(1) The FiP is received for a number of hours resulting from the sum of two concepts: 6 600 equivalent full load hours plus 5.6 MWh per each square metre of rotor area.
(2) If the average market price drops under 30 EUR/MWh, the subsidised amount is calculated as the target price minus 30 EUR/MWh; if the market price falls below zero no subsidy is paid. An early bird premium was granted to wind farms installed before 31/12/2015 with a target price of 105.3 EUR/MWh for the first 3 years from 2011. A cap of maximum installed capacity of 2.5 GW is included.
(3) An extension of the initial period is granted by taking into account the wind resource at the location of the wind farm with respect to a reference value (mean wind speed: 5.5 m/s at 30 m with roughness length 0.1 m).
(4) Wind farms above 5 MW. 82 EUR/MWh for wind farms in the interconnected grid (105 EUR/MWh if no capital grant was received); in not interconnected islands: 90 EUR/MWh (110 EUR/MWh if no capital grant was received).
(5) Reference prices to calculate the premium as the reference price minus the average electricity market price multiplied by a factor (0.8 up to 10 MW and 0.86 up to 50 MW).

Belgium, Sweden, Poland, Romania and United Kingdom apply TGCs and quotas to promote wind energy. In the United Kingdom, one certificate is issued for each 1.11 MWh of energy produced by an onshore wind farm. A different approach is applied in the Belgian regions of Wallonia and Brussels by issuing the green certificates indexed to the amount of CO_2 saved. In Romania 1.5 certificates per MWh are issued until 2017 and 0.75 certificates per MWh from 2018. The penalty for missing a certificate ranges from EUR 72.9 in Poland to EUR 119.3 in Romania. In the United Kingdom the penalty is calculated as a function of the buy-out price during the period of the missing certificate plus interest.

5.4. Suspension of support schemes and retrospective measures

There are some MSs that, for different reasons, currently do not provide any of the main support schemes (FiTs, FiP or TGCs). Cyprus stopped wind energy support for new projects with the exception of a 30 MW ongoing project.

In January 2012, Spain suspended the existing support schemes for promoting new renewable energy installations. The price regulation system was eventually phased out in 2013. Additionally, a series of retrospective measures that reduced support payments have been put into force since: modification of the reward system for reactive power control, annual cap of production receiving the FiP (2011 and 2012) and a 7 % flat rate tax applied on the gross revenues for electricity sale (KoT, 2014b). As commented on above, a new remuneration scheme entered into force in June 2014.

In October 2014 a new policy for renewable energy support was published in Portugal. This new policy does not consider any support for large-scale projects, just for micro- and mini generation. Portugal had stopped supporting new installations in 2012 and negotiated a levy on existing wind producers to do away with their situation of overcompensation.

The Czech Republic abolished, in August 2013, the FiT scheme for all renewable technologies except for small hydro. However, wind power plants that got the building permit approved before 31 December 2013 will be entitled for support if they are put into operation before 31 December 2015 (RES-Legal, 2015).

Additionally, several MSs introduced retrospective measures (Schmidt, 2013):

- In Belgium's Walloon region a specific fee for green electricity producers was introduced in mid-2012; in addition, some municipalities are adopting special taxes over new and existing wind turbines.
- In Bulgaria, since May 2012, the connection to the grid of renewable plants with preliminary grid connection contract was postponed to 2016. Furthermore, since mid-March 2014, the distribution system companies have been limiting the maximum power generation of all wind and photovoltaic power plants by 60 % (KoT, 2014b).
- Greece imposed in 2012 a levy on the gross income of all operating renewable energy sources (RES) projects.
- The Polish indexing of green certificate prices to inflation was removed.
- Romania introduced in 2013 retroactive regulatory changes that fundamentally changed the economics for existing installations. Green certificates mandatory acquisition quotas — which were defined by law till 2020 — were slashed drastically (in 2014 the quota reduction versus the established in the law was over 25 %, as the obligation was reduced from 15 % to 11.1 %); energy-intensive companies were exempted largely without redistribution of the obligations; the validity of green certificates was reduced from 16 months to 12 months. Furthermore, half of the green certificates produced between 2013 and 2017 were delayed to the period of 2018 and 2020.

5.5. Specific support schemes for offshore wind energy in EU MSs

Offshore wind is a less mature technology. There is evidence of the quickly falling costs achieved in recent years (see Section 4.8) and this trend is expected to continue. As a consequence some MSs implemented specific support schemes or adapted the remuneration level: Belgium, Denmark, Germany, Italy, the Netherlands and the United Kingdom.

Offshore wind in Belgium depends on the federal government, which set up a TGC support scheme with a minimum certificate price of EUR 107 for the first 216 MW and EUR 90 for the capacity exceeding this amount (Held, et al., 2014).

In Denmark the sliding FiP (i.e. variable payment depending on the market prices in order to achieve a predefined amount) is selected based on one of two following approaches: (i) tender-based FiP; (ii) open-door procedure. Other offshore wind farms under the FiP scheme commissioned after February 2008 receive a premium of 30 EUR/MWh for 22 000 equivalent full hours plus 3 EUR/MWh for covering the balancing costs. Also, in near-shore projects a 20 % of the ownership share of the project has to be offered to local residents or companies. If this share achieves 30 %, an extra bonus of 1.3 EUR/MWh can be awarded over the FiP (RES LEGAL, 2015).

In the Netherlands, offshore wind farms can apply for the subsidy under the same specific tender procedure introduced for onshore. In this case, offshore wind farms applying at the first to third stages receive the same remuneration as onshore wind farms. However, the tariff is different for the next stages: 137.5 EUR/MWh, 162.5 EUR/MWh and 187.5 EUR/MWh, respectively for the fourth, fifth and sixth stages. The subsidy is granted for a period of 15 years and a maximum of 3 000 equivalent hours each year. Under the current scheme, offshore wind farms compete with the remaining technologies under the EUR 3.5 bn cap mentioned in the previous section. However, a new offshore-only tender is planned by July 2015.

In the United Kingdom offshore wind farms are also eligible to support via TGCs or the new CfDs scheme. Two certificates are issued per MWh (i.e. 0.5 MWh/certificate) generated by an offshore wind farm, and this amount will be modified in 2015/2016 to 0.53 MWh and finally to 0.55 MWh after 2016.

5.6. Grid issues

This section presents grid issues regarding grid connection (procedure and cost allocation) and operation (priority use of the grid and balancing), both onshore and offshore.

The costs of grid connection between producers and grid operators are shared following two approaches: (i) **shallow cost approach** where plant developers bear the cost of equipment necessary to connect the generator to the allocated point on the already existing grid network; (ii) **deep cost approach** where plant developers bear, in addition, any further reinforcement expenses that can arise downstream.

	Connection	Reinforcement	Approach	Comments
AT	PD	PD	Deep	
BE	PD	GO	Shallow	Offshore connection costs partially subsidised.
BG	GO	GO	Shallow	
CY	PD	PD	Deep	
CZ	PD	PD	Deep	
DE	PD	GO	Shallow	Plant developer bears cost to closest connection point. If grid operator requires a different point of connection, grid operator bears the additional costs.
DK	Both	GO	Shallow	Plant developer bears a cost equivalent to the costs that would be incurred if his plant was connected to the medium voltage grid. The remainder is borne by the grid operator.
EE	PD	PD	Deep	Reported lack of regulation regarding responsibilities of grid reinforcement.
ES	PD	GO	Shallow	
FI	PD	PD	Deep	No clear rules: grid reinforcement borne by plant developer if it is for the only benefit of the plant.
FR	PD	GO	Shallow	
GR	PD	PD	Shallow	
HR	PD	PD	Deep	
HU	PD	GO	Shallow	
IE	PD	GO	Shallow	
IT	PD	GO	Shallow	
LT	PD	Both	Deep-shallow	Plant operators contribute with no more than 10 % of the costs of reinforcement.
LU	PD	PD	Deep	
LV	PD	PD	Deep	
MT	PD	PD	Deep	
NL	PD	GO	Shallow	
PL	PD	GO	Shallow	Despite grid operator being responsible for upgrading the network, rules are not clear.
PT	PD	GO	Shallow	
RO	PD	GO	Shallow	
SE	PD	PD	Deep	Grid reinforcement borne by plant developer if it is only for the benefit of the plant.
SI	PD	GO	Shallow	
SK	PD	Both	Deep-Shallow	Costs of reinforcement are shared between plant and system operators.
UK	PD	Both	Deep-Shallow	Plant operators pay the Connection Charges to grid operators distributed over time

Table 18: Distribution of the connection costs and reinforcement between plant and system operators (PD: Plant Developer; GO: Grid Operator).

Table 18 summarises the cost distribution of grid connection in EU MSs. In those countries with specific regulation for offshore wind energy, the connection procedure differs:

- In Belgium the plant developer bears the costs of the grid connection to the onshore substation (shallow approach). Nevertheless, these costs are partially subsidised by a 33 % of the investment with a maximum of EUR 25 m. The subsidy is spread over 5 years (by providing 1/5 each year).
- In Denmark, for the further-offshore ongoing tenders the transmission system operator bears the costs of grid connection to the offshore substation (ultra-shallow

approach). However, plant developers of near-shore projects, either established by tenders or by the open-door procedure, have to bear the costs of their own offshore substation and connection to land (shallow approach) (Held, et al., 2014).

- In Germany, the costs of grid connection to shore are born by the grid operator (ultra-shallow approach). The connection of new offshore wind farms is based on planned capacity allocation. Capacity allocations up to 7.7 GW are possible till the end of 2017 and 6.5 GW afterwards till 2020.
- In the Netherlands the cost of the connection was borne by the plant developer (shallow approach), but under the forthcoming scheme the grid operator bears the cost of the offshore substation, i.e. the developer is offered a connection point at the offshore substation.
- In the United Kingdom the transmission infrastructure to shore is usually built by the developer, and then outsourced (through a tender) to other entities that receive a transmission fee.

5.7. Operation and use of the grid by wind energy generators

As shown in Table 19, some MSs establish conditions for preferential access to the grid by renewable installations by either the **priority access** (in presence of purchase contracts with transmission operators) or **guaranteed access** (when the wind generators participate in the market). Table 19 also shows that in some MSs, wind operators are required to cover balancing responsibilities and pay the cost. The new Guidelines on state aid for environmental protection and energy 2014–20 from the European Commission introduce the obligation for large renewable generators to be subject to balancing obligations on the conditions that liquid balancing markets exist.

	AT	BE	BG	CY	CZ	DE	DK	EE	ES	FI	FR	GR	HU	HR	IE	IT	LT	LV	LU	MT	NL	PL	PT	RO	SE	SI	SK	UK
Priory/guaranteed access	Y	Y	N	Y	N	Y	Y	N	Y	N	N	Y	Y	N	Y	Y	Y	N	N	Y	N	Y	Y	Y	N	Y	Y	N
Balancing costs	N	Y	N	N	N	Y	Y	Y	Y	Y	N	N	Y	N	N	N	N	Y	N	N	Y	Y	N	Y	Y	Y	N	Y

Table 19: Priority/guaranteed access and balancing responsibility/costs for energy produced by renewable sources in EU MSs (Y: Yes; N: No).

5.8. Potential barriers for wind energy deployment

According to the results of the DiaCore project (based on the interactive database, RE-frame.eu ([35])), issues related to the political and economic framework are the most relevant barriers for wind energy diffusion. A summary of those (in bold the barriers considered as more severe) is shown in Table 20.

([35]) The RE-frame database is an online tool (associated with the European Projects DiaCore and 2020 Keep-on-track) where stakeholders can report (or validate existing) barriers as well as adding recommendations. Additionally, competent authorities can acknowledge or refute the reported issue.

MS	Potential barriers	MS	Potential barriers
AT	- Spatial and environmental planning - Cost of administrative procedure	IE	- Duration of grid connection procedure - Curtailment
BE	- Uncertainty of the support scheme - Long lead time for grid connection - Complexity of administrative procedure	IT	- Long lead time for grid connection - Grid development
BG	- **Retroactive measures** - Lack of fair and independent regulation - **Lack of transparency on the connection procedure**	LT	- Reliability of the regulatory framework - Complex administrative procedure - Long lead time for grid connection
CY	- **No support scheme for wind energy** - Lack of electricity market competition - Complexity of administrative procedure	LU	- Spatial Planning
CZ	- **Support scheme cancelled** - Retroactive measures - Transparency of the administrative procedure	LV	- **Reliability of the regulatory framework** - Lack of liberalised electricity market - Grid development
DE	- Curtailment - Grid development - Spatial and environmental planning	MT	- **No support scheme for wind energy**
DK	- Grid development (interconnection) needed to achieve higher wind penetration - Unclear pipeline for offshore wind	NL	- Reliability of the general RES strategy - Grid development - Spatial Planning
EE	- **Lack of reliable support scheme** - Complex connection procedure - Complex administrative procedure	PL	- Reliability of the regulatory framework - Long administrative procedure - Grid development
ES	- **Lack of reliable support scheme** - **Retroactive measures** - Grid development - Complex administrative procedure	PT	- **Reliability of the regulatory framework** - Long and complex administrative procedure - Long and complex connection procedure
FI	- Spatial planning - Grid development	RO	- **Retroactive measures** - Lack of market competition - Grid development - Lack of transparency of the grid connection procedure
FR	- Lack of stable support - Complex administrative procedure - Long lead time for grid connection	SE	- Low remuneration level - Grid development
GR	- **Lack of reliable support scheme** - Retroactive measures (for other RES) - Grid development - Complexity administrative procedure	SI	- Reliability of the regulatory framework - Duration of the administrative process -Spatial and environmental planning
HU	- Lack of reliable support scheme - **No call for tenders since 2007** - Grid development - Transparency of the connection procedure	SK	- Reliability of the general policy for RES-E - Transparency of the connection procedure
HR	• **No new purchase agreements from January 2015** • Cost of connection procedure • Spatial Planning	UK	- Long and costly administrative procedure - Insufficient total budget for large scale RES support - Costly connection costs - Political scepticism for onshore wind

Table 20: Main barriers for wind energy deployment reported in EU MS. Collected from (Binda, 2012), (RE FRAME, 2015), (KoT, 2014a), and with feedback from reviewers.

5.9. Evolution of support schemes, installed capacity and current state in order to meet the 2020 targets.

This section provides an analysis of the progress of wind energy deployment in the EU countries, and thus it complements Section 3.2.4. The aim is to match the regulatory framework (and its evolution over time) in each Member State to actual rates of deployment. In addition, an analysis of both regulatory framework and installation rates along with the trajectories (defined by annual intermediary objectives) set in each NREAP is presented.

Figures 42/43 and 44 show, respectively for onshore and offshore wind energy, the progression of annual installed onshore capacity in each MS during the period 2000–14. Above each individual figure a line shows the evolution of the support schemes and both together show that the different policies adopted in each MS have led to diverse and non-homogenous deployment profiles. The particularities of each MS regarding wind energy deployment and regulatory framework are detailed below.

Germany: The strong, reliable policy framework has enabled a rather constant annual installed capacity since the early 2000s. During this period, several adaptations of the system took place. Currently, Germany offers a FiP tailored to the specific wind resource availability. This feature has opened new market possibilities by enabling the placement of new wind turbines in less windy locations. In 2014 the onshore cumulative capacity was 38 364 MW, above the 32 763 MW planned and also above the planned capacity for 2020 (35 750 MW). Offshore wind presents a gap between the currently commissioned capacity (1 049 MW) and the planned capacity in the NREAP for 2014 (2 040 MW).

Spain: was in line with the defined trajectory in the NREAP by the end of the 2000s. However, several amendments in the regulatory framework (described above) brought deployment to a halt. In June 2014 a new support scheme entered into force but it seems unlikely it will stimulate the necessary annual rate of deployment (around 1 500 MW per year) that would be necessary to meet the capacity set in the NREAP for 2020. The current gap between planned capacity and actually installed is 3 429 MW (22 987 MW installed versus 26 416 MW planned by 2014). In addition, the NREAP estimates 750 MW of offshore wind energy for 2020, but as of 2015 there are no offshore wind farms installed in Spain.

Italy: Italy replaced the TGCs system with a tender scheme in 2013. Although Italy is comfortably above the trajectory to achieve total renewable energy share for 2020, it might lag behind in its specific wind target (see Section 3.2.3). The 8 660 MW installed to date is a figure slightly above the scheduled amount for 2014 (8 280 MW), but recent changes resulted in the collapse of annual installations with only 108 MW in 2014. The perspectives are worse for offshore wind energy: Italy planned 680 MW of offshore wind energy for 2020 (129 MW by 2014) but no offshore capacity has already been deployed and no new capacity has been allocated by tenders yet.

United Kingdom: The deployment of both onshore and offshore wind installations in the United Kingdom are in line (slightly above) with the trajectory set in the NREAP: 7 953 MW installed onshore (7 540 MW planned by 2014) and 4 494 MW installed offshore (4 450 MW planned), although the annual installation rate should increase to around 2 600 MW. The TGCs system has been effective in attracting new investors to the United Kingdom wind energy sector.

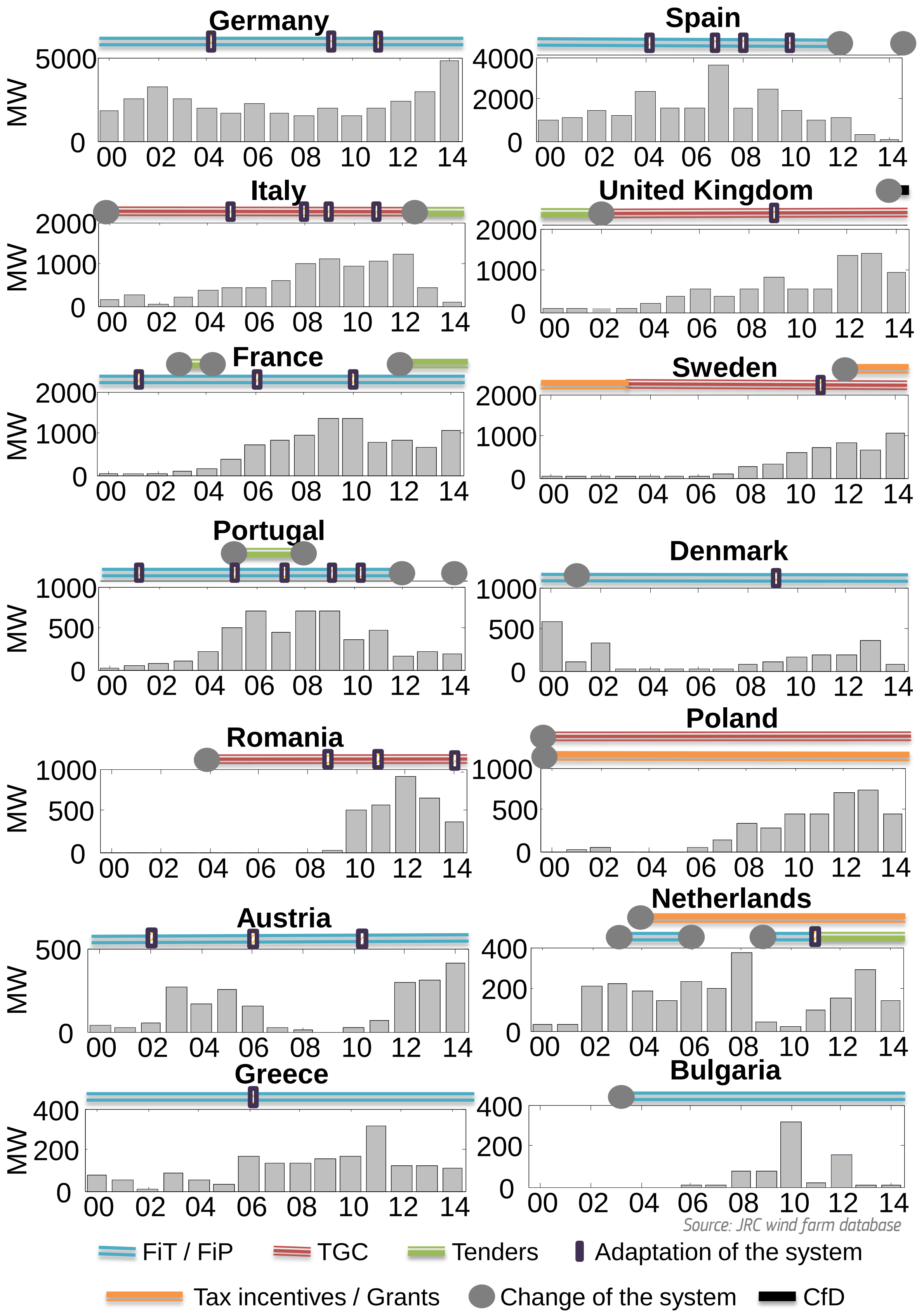

Figure 43: Annual deployment of onshore wind energy and evolution of support schemes in EU MSs countries.

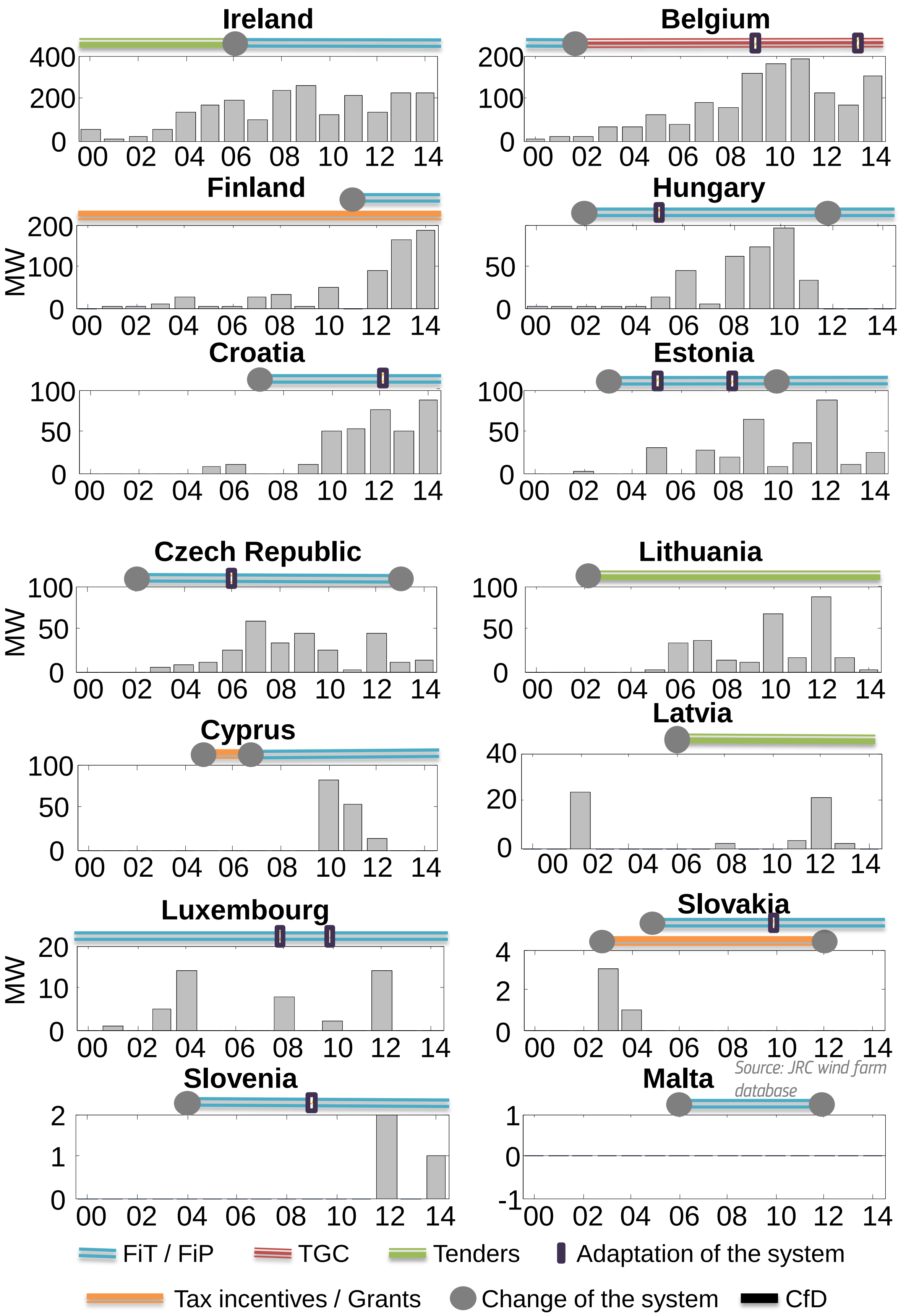

Figure 44: Annual deployment of onshore wind energy and evolution of support schemes in EU MSs countries.

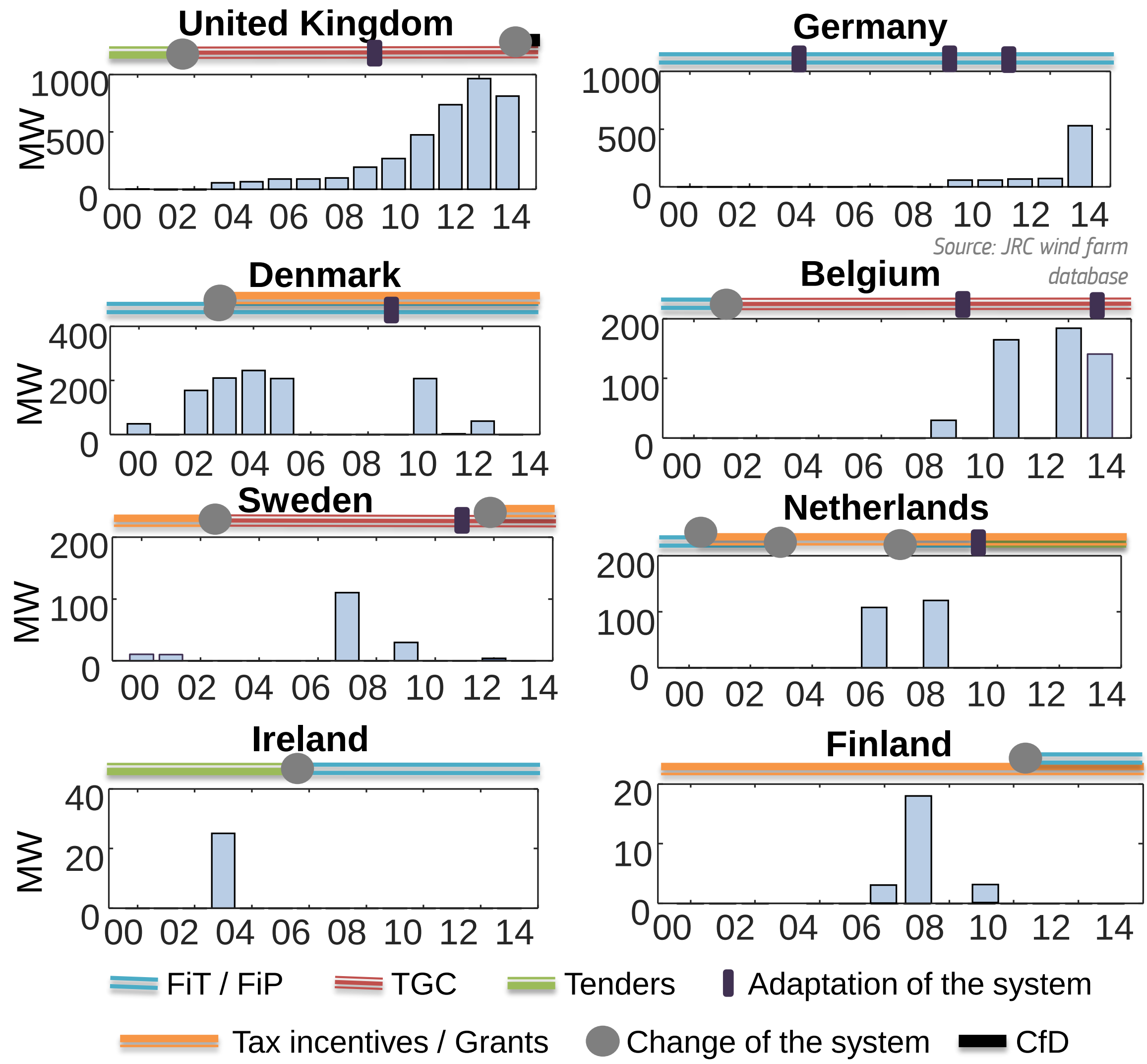

Figure 45: Annual deployment of offshore wind energy and evolution of support schemes in EU MSs countries.

France: The installed capacity progressively increased during the 2000s decade. However, in 2010, changes in the FiT and conditions induced a reduction in the annual installed capacity during the following years. Nevertheless, the introduction of call tenders can set a more a favourable regulatory framework in the next few years. The current onshore installed capacity is 9 259 MW versus 9 572 MW planned. Additionally, in the trajectory to achieve 6 000 MW of offshore wind energy, France estimated 2 000 MW by 2014. Even though 1 900 MW were awarded by tenders in 2012 and another 1 000 MW were awarded in 2014, the first offshore wind farms are only expected to be commissioned by 2018.

Sweden: Even though the price of certificates are relatively low (quota is expected to be revised to encourage higher price of certificates), the TGCs in Sweden has been effective in stimulating the deployment of both onshore and offshore wind energy. There are 5 220 MW of installed power, above the 2 824 MW estimated by 2014 and very close to the 2020 target (4 365 MW). The situation is even better for offshore wind energy with 212 MW already installed, exceeding both the estimated capacity for 2014 (118 MW) and 2020 (182 MW). However, offshore wind is not expected to be further developed, at least in the near future.

Portugal: The good deployment achieved during the 2000s decade was hindered by several regulatory changes and a moratorium — suspending the FiT for new projects — entered into force in 2012. Currently there are 4 914 MW of onshore installed power in contrast to 5 600 MW planned. There are 75 MW of offshore wind energy planned for 2020; however, currently there is only an experimental offshore wind turbine (2 MW).

Denmark: Although Denmark has already exceeded the onshore installed capacity set for 2020 (3 574 MW already installed versus 2 621 MW set in the NREAP for 2020), a positive regulatory framework has recently driven deployment. However, it is worth noting that due to the early developments in the 1980s, 460 MW (301 MW since 2005) of old wind installations were decommissioned in Denmark by the end of November 2014. An advanced state of deployment is also observed for offshore wind energy: 1 271 MW actually installed in 2014 versus 1 256 MW expected for 2014 (and very close to the 1 339 MW planned for 2020).

Romania: The TGCs system enabled Romania to be in line with the trajectory set in the NREAP during the early 2010s. Romania met the planned capacity for 2014 with 2 954 MW installed above 2 880 MW planned. However, the retroactive measures described above affect the deployment of future projects.

Poland: The TGCs system has enabled a high deployment onshore, 3 834 MW were installed in 2014, clearly above the 2 900 MW planned. The certificates system is being phased out and substituted by a CfD tender scheme. 500 MW of offshore wind energy are planned in the NREAP, but currently there is no offshore installed capacity nor there are prospects in the near future.

Austria: A strong deployment of wind energy took place in the early 2000s due to a favourable regulatory framework. However, in 2006, FiTs and duration of the support were reduced thus slowing down the development of new installations. This situation was reversed with the amendment introduced in 2010 by offering finely tuned tariffs and extending the payment period. The cumulative installed power by the end of 2014 was 2 095 MW. This deployment is above the trajectory set in the NREAP, 1 793 MW for 2014.

The Netherlands: even though the annual installed capacity has increased since the tender scheme entered into force, there is a significant gap with the trajectory to achieve the targets: 2 558 MW installed onshore (versus 3 943 MW planned for 2014) and 247 MW installed offshore (in contrast to 940 MW planned).

Greece: Retrospective measures shattered the positive trend witnessed until 2011. There is a gap between the planned capacity for 2014 (3 716 MW) and the actual installed (1 980 MW). In the NREAP also 300 MW of offshore installed capacity are projected for 2020. However, to date there are no offshore installations.

Bulgaria: The cumulative capacity installed in 2014 was 690 MW (1 115 MW were planned in NREAP). Retrospective measures were introduced in 2012 affecting the positive trend observed in the previous years.

Ireland: The annual installed capacity remained at similar values during the last few years but this deployment did not enable Ireland to achieve the planned capacity for 2014: 2 656 MW planned instead of 2 246 MW actually installed. The gap is even higher in case of offshore wind energy: 25 MW already installed versus 252 MW planned by 2014.

Belgium: The TGC system established in 2002 enabled a good deployment of wind installations. The minimum prices of green certificates were lowered in 2010 causing a slowdown of new installations in the following years. Belgium has exceeded the NREAP's estimations for onshore wind energy in 2014 (1 387 MW actually installed versus 616.9 MW planned). The offshore cumulative capacity by the end of 2014 was 713 MW (versus 1 122 MW planned for the end of 2014).

Finland: There is a trend towards increasing deployment since the introduction of the FiT scheme in 2011. There were 627 MW installed by 2014 versus 580 MW planned (onshore plus offshore) in the NREAP, and 11 GW in the different phases of the project planning process (Holttinen, 2015). In addition, the NREAP defines 900 MW of offshore wind energy in 2020 but the current offshore installed capacity is only 28 MW.

Hungary: Support is available for wind generators by call for applications. The first call for applications allocated 330 MW in 2006. However, a second call to allocate 410 MW was cancelled in 2010 and no new calls have taken place since then. This unfavourable regulatory framework has led to a considerable gap between the planned trajectory in the NREAP (568 MW by 2014) and actual installed capacity (330 MW).

Croatia: The FiT system was introduced in 2007 with a positive response by investors. After the amendment on the support scheme in 2012 a slowdown trend has been observed. The cumulative capacity at the end of 2014 was 261 MW (slightly below the 280 MW planned in the NREAP).

Estonia: By the end of 2014 the cumulative installed capacity in Estonia was 303 MW (below the 400 MW planned in the NREAP). The cap of maximum energy (600 GWh per calendar year) subsidised for wind farms, in force under the current FiP scheme, can prevent the deployment of new installations.

Czech Republic: The positive trend observed until the late 2000s was reversed by the introduction of retrospective measures and the final abolition of the support scheme in 2014. By the end of 2014 the cumulative installed capacity was 282 MW (below the planned 333 MW in the NREAP).

Lithuania: Despite the irregular evolution of installed capacity during the last few years, Lithuania is close to the planned onshore capacity for 2014: 280 MW (actually installed) versus 350 MW (planned). However in 2011 a new cap was introduced: a maximum of 500 MW are supported by the scheme till 2020. From these 500 MW, around 270 MW were already installed in 2013 plus another 200 MW already allocated.

Cyprus: Installations started in 2010. However, yearly installed capacity decreased during 2011 and 2012. No new farms were installed in 2013 and 2014. The onshore cumulative capacity was 146.7 MW by the end of 2014 as compared to the 165 MW originally planned in the NREAP.

Latvia: The total cumulative capacity installed in 2014 was just 62 MW. Nevertheless the relatively low capacity planned for 2020 (236 MW, 80 MW by 2014) implies that the targets may be met with a favourable regulatory framework. However, the system has been under review since 2012 and the scheme is closed to new submissions until 2016.

Luxembourg: There is a gap with the trajectory set in the NREAP: 58 MW installed by 2014 (89 MW planned). Nevertheless, the FiT was increased in August 2014 and the 2020 objective of 131 MW may be achieved.

Slovakia: The regulatory framework was not suitable to enable a proper deployment of wind energy; just 3.2 MW currently installed in contrast to 150 MW expected by 2014 (560 for 2020).

Slovenia: Currently, there are just 2 MW of installed power. However, the relatively low capacity set in the NREAP for 2020 (106 MW) can be achieved under a favourable regulatory framework.

Malta: With an unfavourable regulatory framework there are no commercial wind turbines installed in Malta. The lack of support for wind energy deployment makes unlikely that Malta will achieve the 2020 objectives planned in the NREAP for wind energy (14.45 MW onshore and 95 MW offshore).

5.10. Conclusions

Recent developments and changes performed in some MS, are in line with the Commission's 'Guidelines on State aid for environmental protection and energy' by increasing the exposure of wind generators to the markets. Two main objectives are sought when exposing wind generators to market signals: (i) track technology-cost reduction and (ii) avoid possible distortions introduced in the electricity market by insensitive generators to market signals.

A number of countries implemented abrupt changes and sometimes retroactive and/or retrospective measures hindering investor's confidence and putting at risk the development of future projects and hence, the likelihood of meeting the 2020 targets.

As wind energy is deployed, locations with better wind conditions are expected to be taken first. If schemes do not offer the suitable level of support according to local wind resources, there is a risk that projects in low wind conditions do not get enough income or, in the opposite case, projects in favourable wind conditions can get windfall profits. Also, competitive bidding is a suitable measure in order to establish the remuneration according to the specific conditions of each project.

In the case of offshore wind, calls for tender — as in Denmark, France, Italy and the Netherlands — or fine-tuned schemes — as in Germany — seem to be the most suitable support mechanisms in order to adapt to technological evolution (since offshore wind is a less mature technology to onshore wind) as well as tailoring the remuneration to the specific conditions of the project (the costs for offshore project are highly dependent on local conditions and, especially, on the seabed depth).

ANNEX: ONSHORE WIND INSTALLATIONS IN THE EU

Annual installation	Pre-2005	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Austria	606	218	146	19	14	0	19	70	296	308	411
Belgium	97	71	28	93	135	119	160	191	113	90	147
Bulgaria	10	0	26	21	63	57	322	28	158	7	9
Croatia	0	6	11	17	1	10	61	42	48	122	86
Cyprus	0	0	0	0	0	0	82	52	13	0	0
Czech R.	20	11	26	63	34	44	23	2	44	9	14
Denmark	2 822	22	12	3	60	104	108	211	167	308	67
Estonia	3	26	0	27	19	64	7	35	86	25	23
Finland	81	-3	7	8	24	4	48	0	61	192	183
France	384	367	810	888	950	1 088	1 396	837	816	631	1 042
Germany	15 754	1 809	2 233	1 667	1 660	1 857	1 453	2 012	2 335	2 904	4 608
Greece	415	100	173	125	114	102	238	316	117	116	114
Hungary	0	14	43	4	62	74	82	34	0	0	0
Ireland	323	157	250	49	232	233	157	208	125	288	222
Italy	1 234	452	417	603	1 010	1 114	947	1 090	1 273	444	108
Latvia	5	0	0	0	0	2	1	18	21	0	0
Lithuania	6	0	42	7	3	37	72	16	84	50	1
Luxembourg	49	0	0	0	0	8	1	1	13	0	0
Malta	0	0	0	0	0	0	0	0	0	0	0
Netherlands	981	154	246	210	380	39	56	3	119	303	141
Poland	65	19	69	123	268	181	456	436	880	894	444
Portugal	507	500	694	434	712	673	171	673	145	196	184
Romania	0	1	1	95	3	3	449	520	923	695	354
Slovakia	6	0	0	0	0	0	0	0	0	0	0
Slovenia	0	0	0	0	0	0	0	0	0	2	1
Spain	8 135	1 764	1 595	3 508	1 558	2 459	1 463	1 050	1 122	175	28
Sweden	414	68	62	107	262	482	604	736	683	676	1 050
UK	757	355	544	343	569	695	449	685	957	1 150	941
EU-28 total	*24 958*	*6 204*	*7 592*	*8 535*	*8 484*	*10 163*	*9 648*	*9 664*	*11 895*	*11 159*	*11 791*
Norway	160	110	55	60	46	2	18	85	195	98	45

Table 21: Onshore wind installations in the EU Member States based on commissioning year. *Source:* annual reports by EWEA, country presentations at IEA Wind Executive Committee meetings, and JRC wind database.

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