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Key Performance Indicators for the European Wind Industrial Initiative

SETIS - TPWind

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1 Introduction

1.1 Background

In March 2010 the SET Plan Steering Group agreed to launch six EIIs in the framework of the Strategic Energy Technology Plan (SET-Plan) and called for the establishment of a common set of principles and practices for their implementation, which include the development and systematic use of key performance indicators (KPIs). In response to this, the SET-Plan Information System (SETIS) has engaged with all the EII Teams to contribute to the identification and quantification of a preliminary set of KPIs, which were incorporated in the Implementation Plans for 2010-2012.

The present document describes the performance indicators, which will be used for monitoring the progress of the projects stimulated or stemming from the European Wind Industrial Initiative (EWI).

1.2 KPIs

A single overarching KPI has been adopted and developed in order to monitor the impact of the Wind Energy Roadmap (2010-2020) on the sector. This overarching KPI is the levelised cost of electricity produced by wind power, and it is expressed in Euro per Megawatt-hour (€/MWh). In addition to the overarching KPI two other performance indicators will be used for the first two prioritised specific activities of the EWI Implementation Plan, (i) the development of a new European wind atlas, and (ii) improving the reliability of wind turbines. Furthermore, work is ongoing to qualify and quantify performance indicators for other activities of the Implementation Plan such as floating turbine projects.

2 Overarching KPI: cost of electricity from wind energy

The proposed methodology was discussed and approved on the first EWI Team meeting (19th May 2010). Several more meetings were held where TPWind together with the JRC developed the methodology. As a result, a model was defined based on EWEA's model for calculating the levelised cost of electricity. This has been benchmarked against the JRC-SETIS model that was used for the 2nd Strategic Energy Review[1].

This document describes the basic methodology behind the model, makes a proposal for reference case values and suggests the way of using the model in order to monitor the impact of the Roadmap.

2.1 Methodology

The levelised cost of electricity will be calculated using the following formula:

$$LCOE = \frac{L.I. + DO\&M}{E}$$

where

LCOE (€/MWh): The levelised cost of generating electricity
L.I. (€/y): Levelised investment
DO&M (€/y): Annualised operation and maintenance cost
E (MWh/y): Annualised energy production.

2.2 L.I. - levelised investment

To convert the capital cost in a levelised cost component, the levelised investment cost will be calculated using the following formula:

$$L.I. = C \cdot P \cdot CRF$$

[1] SEC/2008/2872 , "Energy Sources, Production Costs and Performance of Technologies for Power Generation, Heating and Transport", related documents at http://ec.europa.eu/energy/strategies/2008/2008_11_ser2_en.htm

where

C (€/kW): is the specific capital cost
P (kW): is the capacity of the reference case
CRF: the capital recovery factor.

This methodology does not take into account the calculation of any project risk; neither quantifies nor takes into consideration the societal costs and benefits of wind power [2]. As regards to the costs related to the integration of wind into the electricity system this methodology includes only balancing, because balancing costs can be improved through activities included in the wind energy roadmap. This mathematical model does not consider revenues from the integration of wind energy into the system.

From a methodological point of view, capital (C) and power (P) could be better described in terms of ***€/m² of rotor swept area*** because this indicator, unlike the nominal power one (€/kW), is directly related to the electricity produced by the turbine. Unfortunately this would require a much more complex model and further data uncertainties, and therefore this consideration was disregarded at the EWI Team meeting of June 2011.

2.2.1 C – capital cost

This refers to specific project capital costs in euro per kW of installed capacity. The system which determines capital costs includes all the elements needed to provide the grid with electricity according to the respective grid code standards:

- Wind turbine costs including all the parts necessary for its functioning: blades, rotor hub and systems, nacelle, gearbox (if any), generator, power electronics (in the turbine or at wind-farm level), transformer (if any), tower.
- Wind farm internal grid and substation.
- Civil works: in-farm roads and other works, foundations, installation, submarine structures.

The reference system will not include:

- Permitting cost.
- Connection from the wind farm substation to the external grid.
- Civil works outside the wind farm (i.e. access roads).
- Financing costs.
- Overheads.
- Decommissioning costs.

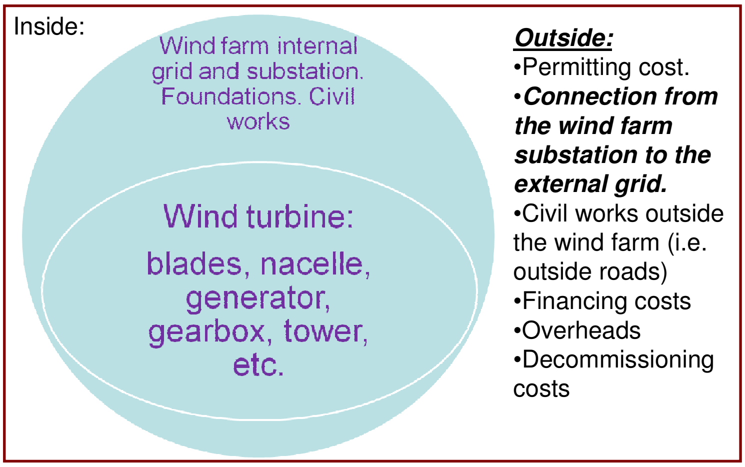

Figure 1: Reference system for capital costs and its boundary, elements included and excluded

2.2.2 CRF – capital recovery factor

Levelising the investment is based on the capital recovery factor (CRF) concept which breaks down the initial capital cost in equal annual payments using a discount rate and the lifetime of the technology. The levelisation is performed using the following formula:

$$CRF = \frac{d}{\left(1-(1+d)^{-N}\right)}$$

where

d (%) : discount rate[3]

[2] The analysis focuses on the economic aspects without taking into account taxes, revenues and externalities, and uses current monetary values not adjusted for inflation.

[3] Because the objective of the model is to monitor the technology progress, discount and inflation rates were fixed from the onset and not changed irrespective of the changing economic situation.

N: lifetime

2.3 DO&M - annualised O&M costs

This parameter will include operation, maintenance (planned and unplanned) and balancing costs. The inclusion of the latter was deemed controversial but it was finally included because the EWI will act upon elements that should improve balancing costs, e.g. better wind prediction models. Therefore, elements included in the annualised O&M costs include:

- Operation and maintenance costs including both fix and variable annual costs:
  - preventive and corrective maintenance,
  - condition monitoring
  - any component replacement expected during the plant/turbine lifetime (e.g. regular gearbox replacement)
- Balancing cost: cost paid because of differences between forecasted and actual electricity generation. The latter is reported to the system operator who has to balance with other generation units any imbalance due to imprecise prediction, and this has a cost.

2.4 E - Annualised energy production

This parameter will be based on the installed capacity and the reference capacity factors.

2.5 Reference cases

The impact of the Roadmap can be monitored by comparing the current reference levelised cost of electricity with that resulting from projects after the implementation of the Roadmap. A necessary step is the definition of two reference cases, onshore and offshore wind, in terms of cost components. Values for the basic cost components were identified, consulted, and consented so that they are representative of the current cost of electricity produced by onshore and offshore wind energy. The literature describes country variations, but the reference values are reflecting adequately enough European-wide best-practice averages.

The system in which the reference cases are to apply must be clearly defined (see Figure 1) by delimiting which aspects are within the system boundaries and which are not, and is described above for the purpose of identifying capital costs. Other parameters necessary for the calculation of the LCOE are listed in Table 1 below along with their consented value.

WIND POWER FARM	ONSHORE	OFFSHORE
Capital, investment cost (€/kW)	1 250	3 500
O&M costs including insurance(€/kW/yr)	47	106
Balancing costs (€/MWh)	3	3
Capacity factor (%)	25	40
Project lifetime (years)	20	25
Real discount rate (%)	5.39	5.39
Total plant capacity (MW)	40	300
Size of wind turbines (MW)	2.5	5-7

Table 1: Reference case values consulted with industry and consented within the EWI Team

For reference the conversion between O&M costs in fixed terms (€/kW/yr) into variable terms (€/MWh) is: onshore wind – ***€21.5/MWh***, offshore wind – ***€30.3/MWh***. This conversion takes into account the reference capacity factors.

Total plant capacity and the size of wind turbine are parameters provided for reference only and do not influence the LCOE.

2.6 *Some notes on parameters:*

a) Capital cost – onshore €1 250/kW, offshore €3 500/kW

A number of published onshore figures (e.g. ARUP [2011], MML [2011]) suggest slightly higher figures, but they apply to only one MS and, as discussed above, the reference systems attempt to show European averages.

The offshore figure initially proposed was considered too low by MS (EWI Team meeting), consultants, and the industry. Mott MacDonald ([MML, 2011]) gives a figure of GBP 3 088/kW (€3 551/kW @ 1.15 EUR/GBP), and in a personal communication (Mr John Porter) considered values around €3 000/kW valid for the UK context, around €4 000/kW for German wind farms farther away/deeper waters. Turbine manufacturers suggested figures of €3 000-3 500/kW in the UK and € 4000 for Germany. ARUP's [2011] estimates a median cost of GBP 2 722-2 825/kW (€3 130-3 250/kW @ 1.15 EUR/GBP) for current large offshore wind farms/Round 3 projects.

b) O&M cost – €47/kW/yr onshore and €106/kW/yr offshore

A clear factor is the cost of insurance. This was valued by different sources at €10/MWh (Spain, onshore), €5-12/MWh (turbine manufacturers, offshore)

Maintenance costs are mostly a fixed cost, therefore it makes more sense to include them in terms of €/kW/yr. The formula linking the fix and the variable part of O&M cost for offshore wind is very empirical but a mathematical expression could be:

$$\text{Final O \& M cost (€)} = \text{Fix O \& M cost (€)} * (1 + 50\% * \text{increase in capacity factor})$$

Where capacity or load factor is a proxy for wind speed.

Turbulence is another important wind characteristic impacting the variable part of O&M costs. In the formula above the parameter "50 %" reflects the effect of turbulence among other less-important factors. This parameter would be definitely lower than 50 % for onshore installations.

One limitation was that the linking of O&M costs to capacity factors would imply that the assessment of EWI-promoted project results would take into account progress to increase the efficiency of wind energy conversion. However, the impact of technology improvements on capacity factors is more limited than the impact from e.g. sitting at a good or bad site in terms of wind conditions. Thus, in the evaluation of projects the energy generation has to be "brought back" to the reference capacity factors in order to avoid this distortion with the drawback that then the effect of technology improvement in wind energy conversion efficiency is discounted.

At the initially assumed capacity factors (25 % onshore, 35 % offshore), the equivalent of €0.145 and €0.190/kWh are €31.76 and €58.26/kW/yr respectively. Other sources give figures of €17.11/kW/yr (MML, onshore), €65.78/kW/yr (ARUP, onshore); €106.15/kW/yr (MML, offshore), €219/kW/yr (ARUP, offshore)

With the addition of insurance costs at a rate of €15/kW/yr onshore and €36.75/kW/yr offshore (equivalent to around €6.5 and €12/MWh respectively at 25/40 % CF), the final figures for O&M cost become ***€47/kW/yr onshore and €106/kW/yr offshore***.

c) Capacity factor – 25 % onshore and 40 % offshore

Initially the offshore figure considered was 35 %, close to the current average. However, discussions with the industry suggested that future offshore figures will rather been in the range of 40-45 % (MML, manufacturers) than around 35 %. ARUP model also uses the figure of 38 % for modelling the LCOE and 40 % in general.

d) Project lifetime – 20 years onshore and 25 years offshore.

There were strong suggestions (manufacturers, members of the EWI Team and others) that offshore project lifetime is already 25 years. New offshore turbines are designed for a 25-year lifetime and, in addition, the first offshore wind farms are still generating power (Vindeby, DK, 1991, in 2010 generated at 22 % CF; Tuno Knob, DK, 1995, in 2010 generated at 30.1 % CF).

e) Plant capacity and size of turbines – respectively 40 MW and 2.5 MW onshore and 300 MW and 5-7 MW, offshore

Plant capacity: Spain pointed out in the EWI team that the initial figures were very low; in addition, German projects, for example, often have been presented at 400 MW per plant at the planning stage although then they may scale down to e.g. 288 MW. The size of turbines is growing more offshore (5 MW by 2020 is likely to be at the low end of the installed capacity) than onshore because of transport limitations.

Both figures are therefore speculative and none are included in the calculation of the LCOE, thus 2.5 MW and 5-7 MW seems reasonable.

f) Accessibility time – parameter dropped.

The accessibility time was initially included in the reference system as reference, but then it was dropped.

Experts consulted (UK at the EWI Team meeting, manufacturers) highlighted that 85 % accessibility offshore was too high a figure. Manufacturers confirmed that 85 % is high for 2010 values, and one explained that this is heavily dependent on the payload as well as on technology and site conditions. This suggested splitting the parameter into "smaller components, max about 300 kg by helicopter (access 90 %); medium size components max about 700 kg (access 70 %), and main components replacement by jack up vessel (access 50-60 %)". However, this approach would complicate the reference system in a way unnecessary for its objectives and, furthermore, the question arises whether we should include the figure in the table.

g) Decommissioning costs – not included.

The issue of decommissioning costs was discussed and finally decided not to consider those costs. The reasoning behind include the many uncertainties at the end of the useful life of the turbines resulting from the SET-Plan-supported projects. For example, the high metal content of turbines along with the increased scarcity of metal will create a stream of income from decommissioning which might compensate for decommissioning costs. Or, offshore, technology that will make new turbines lighter could involve that new, larger turbines can be installed in the current monopiles for repowering.

2.7 LCOE figures.

Table 2 shows the results of those calculations assuming a linear reduction of the LCOE from 2010 to 2020 that reaches 20 % by 2020. These figures are the result of EWEA's cost model updated and adapted as described above.

WIND POWER FARM	**ONSHORE**		**OFFSHORE**	
	Abs.	**Rel.**	**Abs.**	**Rel.**
LCOE by 2010 **(€/MWh)**	71.8	100	106.93	100
LCOE by 2015 **(€/MWh) (-10%)**	64.43	90	95.57	89
LCOE by 2020 **(€/MWh) (-20%)**	57.15	80	84.77	79

Table 2: LCOE values and evolution according to the reference models and the cost model.

2.8 Reporting needs

It was considered necessary to describe the data needs and use for monitoring purposes and this is done in Table 3.

All the costs in the table are part of any economic appraisal of a wind farm project and therefore are known to a wind farm developer, to the bank that grants the loan and, possibly, to some local authority.

Therefore, for those entities reporting does not cause an additional data-collection burden but an efficient reporting tool is needed.

ITEM	PURPOSE
Total plant capacity (MW)	For information only
Size of wind turbines (MW)	Analysis of technology evolution
(1) Capital investment cost (CapEx)	Modelling technology evolution
- Wind turbine costs including:: blades, rotor hub and systems, nacelle, gearbox (if any), generator, power electronics, transformer (if any), tower.	Make up CapEx. Needed for CapEx disaggregation The cost of turbine parts can be necessary for analysing the impact of specific EWI sub-programmes
- Tower cost (€/kW?, €/t?)	Make up CapEx, specific KPI for activities 1.3 & 2.2
- Blade cost (€/t)	Make up CapEx, specific KPI for activity 1.1.1
- WT foundation cost (€/t)	Make up CapEx, specific KPI for activities 1.3 &2.2
- Main shaft cost (€/kW, €/t)	Make up CapEx, specific KPI for activities
- Gearbox(€/kW)	Make up CapEx, specific KPI for activity
- Generator (€/kW)	Make up CapEx, specific KPI for activities
- Bed plate (€/t, t/kW)	Make up CapEx, specific KPI for activities
- WT submarine structures	Make up CapEx, specific KPI for activities 1.3 &2.2
- WT installation cost (€/WT-t)	Make up CapEx
- Wind farm internal grid and substation cost.	Make up CapEx.
- Civil works: in-farm roads and other works.	Make up CapEx
(2) Cost of permitting process	Joint purpose: LCOE and activity KPI: better spatial planning and other EWI activities may reduce this cost
(3) Balancing costs (€/MWh)	Monitoring the assumptions of the reference systems
(4) O&M costs fix/variable (€/kW AND €/MWh)	Make up OpEx in LCOE formula
- O&M cost disaggregation (corrective, preventive, condition monitoring, facilities, access systems)	Analysis of technology evolution
- Number of weather days per year	Analysis of technology evolution – access vessels
(5) Energy produced (MWh/y)	Evolution of LCOE
- Average wind speed	Evolution of energy produced
- Project lifetime	Evolution of LCOE

Table 3: data needs for monitoring the different KPIs

The items included as capital investment cost are country-dependent, e.g. grid connection costs, which are outside the boundary of the reference systems, are part of the offshore wind farm project costs in most countries whereas in Denmark and Germany they are covered by the transmission system operator.

3 PI for the wind atlas

The wind atlas is an activity included in sub-programme 4.1 (wind resource assessment) of the EWI Implementation Plan 2010-2012.

The wind atlas will be made of three parts:

1. Creation of an atlas of wind in electronic form, including the underlying data to a coarse resolution, for resource assessment and thus to help decision making by planning authorities.

2. Creation of open-source model that can be used to improve the resolution to a level of detail that can be used for wind-farm design conditions.

3. Validation of the model through adequate measuring campaigns.

There are at least two kinds of users identified for this activity: (1) planning and other authorities, and (2) developers, financing entities, etc. Whereas the level of resolution and the specific data required by the former is coarse and not very detailed (resource-assessment level), the latter require levels of detail that would enable them to reduce or eliminate the need for further measurement (wind speed, turbulence, etc.), decide which kind of turbine to purchase, or whether the expected energy produced is acceptable for project financing (wind design conditions level). This latter group of uses are served by the development of a validated model providing adequate level of detail.

Two draft performance indicators are therefore defined:

1. The generation of a wind atlas and its underlying data available in the public domain, for at least the EU-27 plus the MS exclusive economic zone, providing wind speed, direction and Weibull distribution with an accuracy of 10 %, at a height of 80 m, with a resolution of 1 x 1 km, based on 3-year data, with ISO icing days/year based on longer-term data. The atlas will include wind data on areas restricted (e.g. military or Natura 2000, infrastructure, etc.) and the delimitation of those areas.

2. The creation of a new, open-source, model, put in the public domain, validated through selected measurement campaigns, which will result in a much more precise output: a resolution of 100 x 100 m, including average wind speed, direction and Weibull distribution with an accuracy of 5 %, turbulence with an accuracy of X %, at a height of 100 m, for the whole of Europe and its exclusive economic area, based on 3-year data.

Parameter	**Wind atlas value**	**Model value**
Availability	Public domain	Public domain
Scope	EU-27 plus EEZ	Based on wind atlas
Average wind speed/accuracy	Yes/10 %	Yes/5 %
Maximum height of data	80 m	100 m
Height intervals	10 m	10 m
Wind direction/accuracy	Yes/10 %	Yes/5 %
Weibull distribution	Yes	Yes
Turbulence/accuracy	No	Yes/ X %[4]
Resolution	1 x 1 km	100 x 100 m
Surface heat fluxes	Yes	Yes
Natural spaces	Yes	Yes
Military areas	Yes	Yes
Infrastructure	Yes	Yes
Measurement data	3-year[5]	3-year
ISO icing days	Yes	Yes

Table 4: Summary of specifications for the wind atlas and for the results of operating the model.

The measurement campaigns are not part of the indicator but they will serve to validate the model that is the object of the indicator 2 above. Those campaigns will be designed to cover a wide range of distinct orography conditions including complex terrain.

This PI should be first discussed with the future users, and then included in the corresponding call for proposals.

[4] To be decided by experts when the wind atlas project is launched
[5] Correlated with longer-term meteorological data from less-detailed met stations

4 PI on reliability of wind turbines

The activity is included as sub-programme 1.1.2 (Improved reliability of large turbines, and wind farms) of the EWI Implementation Plan 2010-2012.

Methodological note: there is a significant difference between reliability and availability. Availability is affected by reliability and accessibility to the wind farm, e.g. for maintenance & repairs. Reliability is therefore much more difficult to define than availability and, in addition, the elements that can improve accessibility for offshore installations (new vessels) are not considered in the EWI Implementation Plan. Other than accessibility, reliability includes aspects such as planned maintenance, and the number of failures weighted by the severity of the failure in terms of time to repair and/or cost of repair.

An economic KPI was originally proposed: annual O&M costs as a percentage of annualised (or total) capital costs. With this indicator the target would be a 40% reduction in O&M costs by 2020 regarding the 2010 figures. However, this indicator would not capture the lost income due to lost of production during downtime.

The proposed performance indicator is the "lost production factor" (LPF) as follows:

$$\boxed{LPF = \left(1 - \frac{actual\,output}{potential\,output}\right) x100}$$

The bidders of research projects will propose how to identify potential and actual output figures.

5 References

[ARUP, 2011] Ove Arup & Partners Ltd: *Review of the generation costs and deployment potential of renewable electricity technologies in the UK*. Study report for the Department of Energy and Climate Change, June 2011. Consulted on 25.10.11, available at http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Renewable%20energy/policy/renew_obs/1834-review-costs-potential-renewable-tech.pdf

[MML, 2011] Mott MacDonald: *Costs of low-carbon generation technologies*. Report for the UK's Committee on Climate Change, May 2011. Consulted on 25.10.11, available at http://hmccc.s3.amazonaws.com/Renewables%20Review/MML%20final%20report%20for%20CCC%209%20may%202011.pdf