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Comparison of Resource and Energy Yield Assessment Procedures 2011-2015: What have we learned and what needs to be done?

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Summary

From 2011 to 2015, the European Wind Energy Association arranged four open exercises to benchmark the wind resource and wind farm energy yield assessment procedures of the wind energy industry. Two case studies were for land-based Scottish wind farms in hilly to complex terrain, and two case studies for medium- to large-scale offshore wind farms in the Irish Sea. A total of 157 submissions were received, 97 land-based and 60 offshore, and all four exercises were analysed and presented previously by DTU Wind Energy.

Results are summarised here for each of seven specific steps in the resource and energy yield assessment procedure: Site wind observation, long-term extrapolation, vertical extrapolation, horizontal extrapolation, wake modelling, technical losses estimation, uncertainty estimation and calculation.

For each step and each wind farm a summary is given of the magnitude of the effects, the spread of the predictions, the methodologies used, and some general, qualitative conclusions. For one offshore wind farm, Barrow, the predicted yield was found to be 104% of the observed yield, with a spread of predictions of 3%.

Based on the results of the four case studies and the statistics of the submitted data, two prioritised lists of actions that could be taken in order to improve the overall process in the most cost-effective way are given; one for land-based and one for offshore wind farms.

1 Introduction

From 2011 to 2015, the European Wind Energy Association (EWEA) arranged four *Comparison of Resource and Energy Yield Assessment Procedures* (CREYAP) exercises, in which parties from the wind energy industry and academia were invited to carry out and submit wind climate and energy yield predictions for case study wind farms. The primary aim was to compare results of different industry-standard models and approaches, but the exercises also provided data for in-house training and R&D, and have pointed to specific areas where more research and development are needed or where current engineering practices can be improved.

A total of 157 submissions were received, each of which containing detailed wind resource and energy yield assessment results for one of the four case study wind farms. This has led to a unique dataset which provides insight into the current status of the industry and which further points to areas where knowledge is lacking and research and development may be needed.

The teams come from 27 countries and represent all areas of the wind energy industry: consultants, developers, wind turbine manufacturers, electricity generators (utility), R&D (university), component manufacturers, and service providers. The representativity of the participants cannot be evaluated directly, but the lists of company and institution names testify to the quite broad representation of the wind power industry. These lists and the results for each wind farm case study have been presented separately in [1-9].

2 Case study wind farms

Two exercises were focussed on wind farms in hilly to moderately complex terrain in Scotland, and two exercises on medium- to large-scale offshore wind farms in the Irish Sea. Table 1 and Figure 1 provide overviews of the main wind farm characteristics.

Table 1. The four case study wind farms: name, rated power of wind farm, number of turbines and rated power of each turbine, hub height above terrain surface or mean sea level, rotor diameter, height of site meteorological mast, and ratio of mast to turbine hub height.

Wind farm	Size [MW]	Wind turbines [MW]	Hub height [m]	Rotor diameter [m]	Mast height [m]	Mast/Hub ratio
Scotland W	28	14 × 2	60	80	50	0.83
Scotland E	29	22 × 1.3	47	62	50	1.06
Gwynt y Môr	576	160 × 3.6	79	107	85	1.07
Barrow OWF	90	30 × 3	75	90	80	1.16

The layouts of the four wind farms are shown in Figure 1. For each farm, the estimated annual energy production for the wind turbines is shown in a coloured map; the colour scale is local for each farm and extends from the minimum to the maximum yield value in the wind farm.

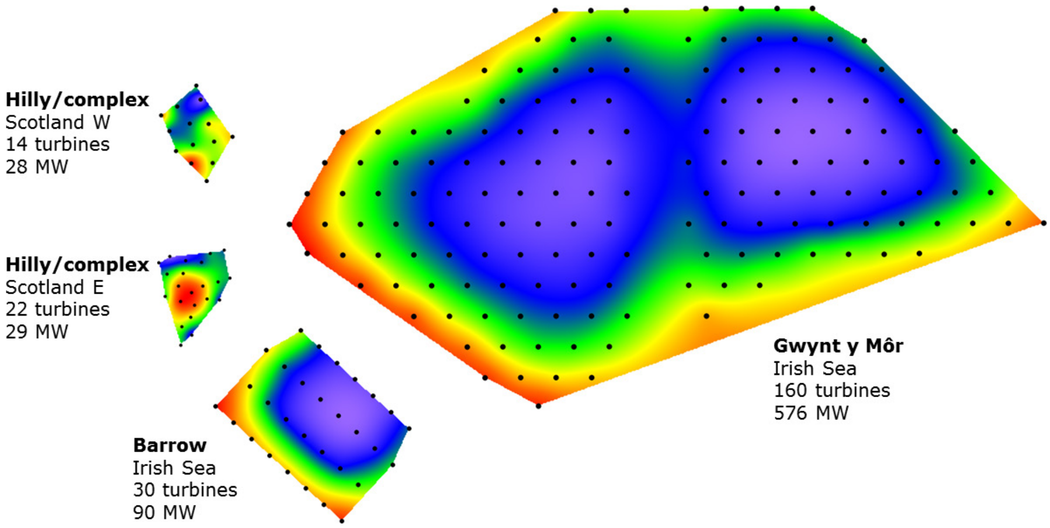

Figure 1. Layout of the four case study wind farms. The black dots represent the wind turbines and the size of each dot is scaled to represent the wind turbine rotor diameter.

3 Methodology

The framework for data collection and data analyses is shown in Figure 2. The wind resource and energy yield prediction process has been divided into a number of steps, which allows for specific comparisons of the different calculation results and procedures [2].

These steps and their definitions are not universally known and used; so even though the submission forms (spreadsheets) were designed to collect data according to this division, there is a small risk that the teams could have interpreted the wording in a slightly different way. This was indeed experienced in a number of cases.

For each exercise and wind farm, a data pack was established, containing the necessary meteorological, topographical and wind farm data needed for the calculations. The data packs also contained a description and definition of the case study and a spreadsheet for submitting the results for analysis and comparison. Invitations to participate in the exercises were publicised openly and without any requirements to the participants.

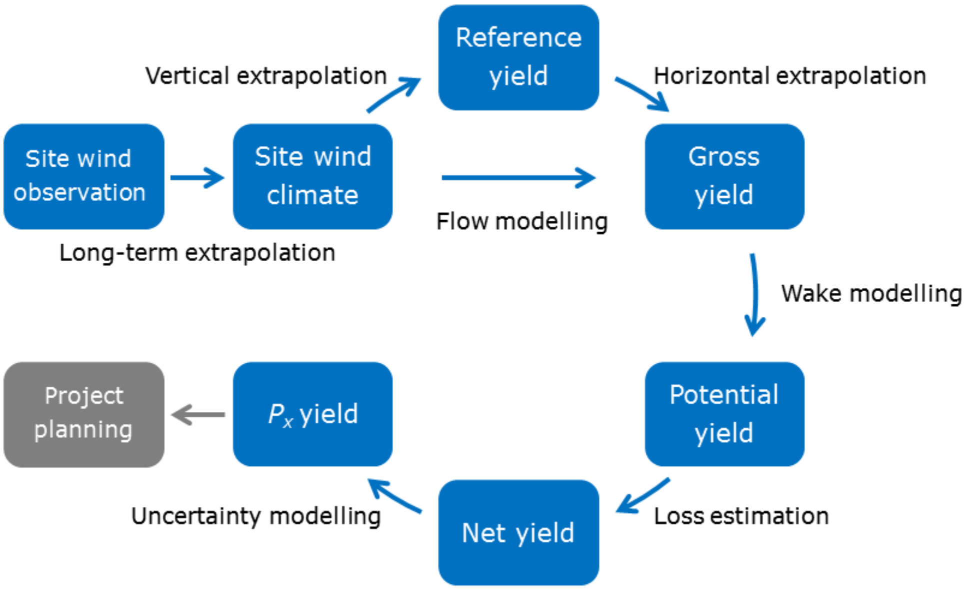

Figure 2. Steps in the wind resource and energy yield assessment procedure [2].

The data material thus consists of results spreadsheets received from the 157 participants. Submission of results was done through EWEA so the identity of each participant is not known to the authors. Additional questions were in a few cases mailed through EWEA to participants in order to clarify certain results.

The data analysis consists of simple reformatting, quality control and copying of the data received, in order to make sure that results are not biased because of different conventions, formats, country settings, etc. Whenever possible, missing results have been calculated from the teams submitted results, in order to get as many valid results as possible in each category. A comprehensive reanalysis of the submitted results have not been carried out and no other background material was received or has been available.

Detailed results for each wind farm have been presented previously in [1-9]. Many results have been compared using non-parametric box-whisker plots and statistics: median value, quartiles, and interquartile range (IQR). For some numerical results, the overall distribution of these is also described by a normal distribution fitted to the results and standard statistics have been calculated: mean value, standard deviation (σ), coefficient of variation (CV), and range.

4 Results

In order to systematically compare the results of the different participants and to compare the methods and models employed, we divide the energy yield prediction process into the six main steps shown in Figure 2. Each step is associated with one or more specific models or procedures (shown in black text in Figure 2) in order to derive at the result of each step.

The flow modelling procedure in Figure 2 is divided into a vertical extrapolation step at the mast site and a horizontal extrapolation from the mast site to the turbine sites. This has been done strictly for the purpose of the comparisons; in general, the two extrapolations are done simultaneously using a flow model [10].

The step from gross yield to net yield in Figure 2 is also divided into a wake modelling step and a technical losses estimation step. This corresponds to common practice in the wind industry, even though one could also argue that the wake effects simply represent another loss [10]. The term *potential yield* is proposed here as describing the maximum yield that one could obtain if the technical losses were close to 0.

Step 0: Site wind observations (→ observed wind climate)

The observed wind climate at the height of the reference anemometer on the site mast consists of the statistics of the wind speed and direction measurements, i.e. the sector-wise wind speed distributions and the wind rose. The mean values, spread and relative spread of the observed wind speeds at the four wind farm sites are given in Table 2.

Table 2. Observed mean wind speeds for the four wind farm sites: name and size of farm, mean wind speed, standard deviation and coefficient of variation of observed mean wind speed.

Wind farm	Size [MW]	Wind speed U [ms^{-1}]	Spread σ_U [ms^{-1}]	Rel. spread CV [%]
Scotland W	28	8.70	0.31	3.6
Scotland E	29	8.33	0.19	2.2
Gwynt y Môr	576	9.12	0.06	0.7
Barrow OWF	90	9.59	0.14	1.5

The participants were not asked to report any method (or software) used to derive mean wind statistics, so no comparison of procedures or methods is possible. Calculating the mean wind statistics is the starting point for most wind resource and energy yield procedures; interestingly, the relative spread among the teams is already between 0.7 and 3.6% at this early stage.

Step 1: Long-term extrapolation methods (→ site wind climate)

The long-term (LT) wind climate at the height of the reference anemometer consists of similar statistics as described above, but referenced to a long-term period; often 10 years or longer. In all four case studies, the site and long-term data were included in the data pack. A summary of the long-term extrapolation results is given in Table 3.

Table 3. Estimated long-term extrapolation effects for the 4 wind farms: name and size of farm, long-term extrapolation effect, standard deviation and coefficient of variation of LT effects.

Wind farm	Size [MW]	LT extrapolation [%]	Spread σ_{LT} [%]	Rel. spread CV [%]
Scotland W	28	1.8	2.5	139
Scotland E	29	n/a	n/a	n/a
Gwynt y Môr	576	0.2	0.7	282
Barrow OWF	90	−2.2	1.8	80

The long-term wind data for Scotland E were unfortunately corrupted and it is not possible to report reliable results for this study. For the other three case studies, the standard deviation of estimates is about the same magnitude or larger than the long-term extrapolation effect itself.

The methods employed by the participants are mainly variations of measure-correlate-predict (matrix methods or MCP using hourly/daily/monthly means), correlation with numerical weather prediction or reanalysis data, or wind index methods. Several participants chose not to apply any long-term correlation procedure at all. The long-term extrapolation effects are small on average in all three cases, but with a significant spread (Table 3). Furthermore, method categories were difficult to establish from the submitted information [1, 3].

Step 2: Vertical extrapolation methods (→ reference yield)

The wind farm reference energy yield is defined as the yield of a single turbine erected at the site of the site meteorological mast, times the number of turbines in the wind farm. It is calculated from the predicted wind distributions at hub height and the wind turbine power curve. The ratios of anemometer height to hub height are between 0.83 and 1.16 for the four case studies. Using WAsP 11.4 [11], we can then derive typical ratios between the mean wind speeds (and wind turbine yields) at mast and hub height for the wind farm sites, see Table 4.

Table 4. Approximate vertical extrapolation effects for the four wind farm sites: name and size of wind farm, anemometer height, turbine hub height, height ratio (mast/hub), mean wind speed ratio and wind turbine energy yield ratio at met. mast position. Calculated using WAsP 11.4.

Wind farm	Size [MW]	Mast height [m]	Hub height [m]	Height ratio	Wind speed ratio	Yield ratio
Scotland W	28	49.6	60.0	0.83	0.97	0.95
Scotland E	29	50.0	47.0	1.06	1.01	1.01
Gwynt y Môr	576	85.0	79.4	1.07	1.01	1.01
Barrow OWF	90	87.3	75.0	1.16	1.02	1.02

For comparison, a site in flat terrain with roughness length z_0 = 0.03 m, a mast height of 50 m and a hub height of 75 m could have a wind speed ratio of 0.91 and a wind turbine yield ratio of 0.81 (WAsP 11.4, default parameters). Consequently, the tests of vertical extrapolation procedures have not been very challenging in the four case studies and it is difficult to draw firm quantitative conclusions.

For the two land-based wind farms, the vertical extrapolation methods employed by about half of the teams can be described as ‘shearing-up’ or ‘shearing-down’ the observed wind climate to hub height using a power law or logarithmic wind profile equation. The other half of the teams have estimated the wind speed distributions at hub height using flow modelling [1, 3].

The spread of estimated mean shear exponents in the land-based case studies is 10-22%, and 0.7-3.6% on observed mean wind speed. About 7-11% of the exponent value results can be classified as outliers [1, 3]. A much more challenging case study would be needed to investigate the difference between different methods and the consequences of applying different methods.

Step 3: Horizontal extrapolation methods (→ gross yield)

Adding or subtracting the horizontal extrapolation effects – which are caused by topographical differences between the mast and turbine sites – to the reference energy yield, we get the gross energy yield, see Figure 2. The horizontal extrapolation effects may represent an increase or decrease in wind farm yield: for the two onshore wind farms, one represented an overall increase of +3.2% (−3 to +11%) and the other a decrease of −8.7% (−18 to +2%), see Table 5.

Table 5. Estimated overall horizontal extrapolation effect for two land-based wind farms: size of farm, elevation range of turbine sites, RIX index range [12], median horizontal extrapolation, spread of extrapolation effects, and topographical effects (WAsP) compared to flat terrain.

Wind farm	Size [MW]	Elevations [m a.s.l.]	RIX range [%]	Hor. extrapolation [%]	Rel. spread CV [%]	Topo effects [%]
Scotland W	28	343-379	1-2	3.2	132	22
Scotland E	29	276-338	1-3	−8.7	113	23

The two wind farms are situated in hilly to moderately complex terrain. All teams employed dedicated flow models [1, 3] to calculate horizontal extrapolation effects over land; the flow model speed-up is about 22-23% on average.

Most flow model results turned out not to be significantly different. Figure 3 shows a closer comparison of linearized and CFD-type flow models. The linearized flow models are the WAsP BZ-model and MS Micro; CFD-type models are WindSim, Meteodyn, Ventos, CresFlow NS, and Ansys CFX. The median values of the predicted wind turbine yields for 22 turbines are compared to the observed turbine yields. For both types of model, the model results ranges are too narrow compared to observations.

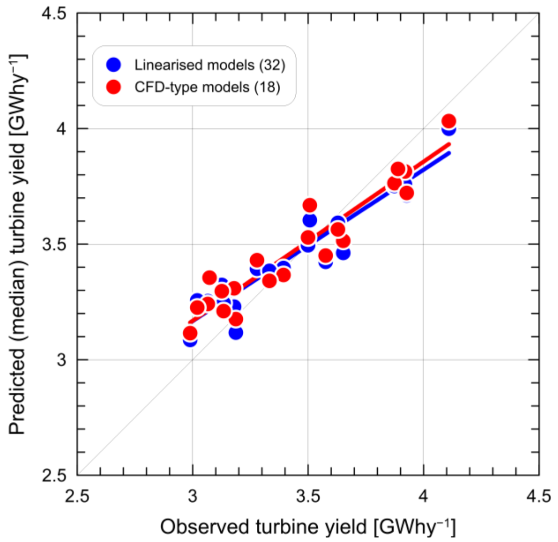

Figure 3. Comparison of predicted (median) wind turbine energy yields to observed wind turbine yields for an onshore wind farm in Scotland (E).

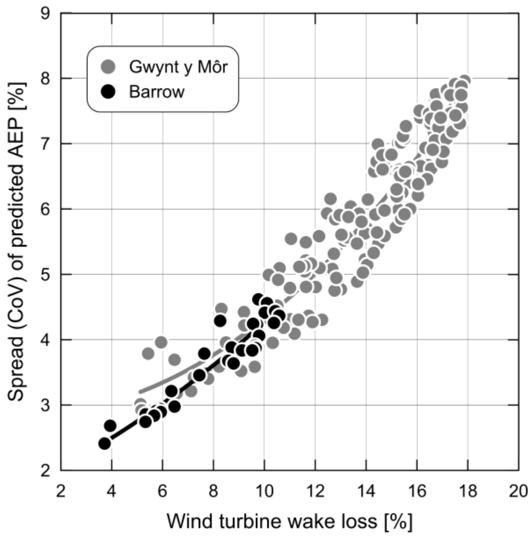

Figure 4. Spread (coefficient of variation) of predicted wind turbine energy yields versus wind turbine wake loss for Gwynt y Môr and Barrow OWF.

The spread of the horizontal extrapolation predictions may provide an estimate of flow modelling uncertainty (CV): for the two land-based wind farms 113-132%, i.e. the standard deviation of estimates is about the same magnitude as the median value. Part of this spread is caused by some teams having misunderstood the submission instructions; however, even without results from these teams, the spread is large. There are only 0-2% outliers, judged from the box plot analyses [1, 3]. The detailed comparison of wind flow models will be reported elsewhere.

Step 4: Wake modelling (→ potential yield)

Subtracting the wind farm wake losses from the gross energy yield we get the potential energy yield, see Figure 2. Wakes represent a significant loss in wind farm yield: for the two onshore wind farms about 6-10% and for the two offshore wind farms 8-14%. All teams employed dedicated wake models for the wake loss calculations.

For the two offshore farms, it is possible to extract the energy yields and wake losses for each wind turbine site. The spread of the predicted wind turbine energy yields increase with depth into the wind farms; i.e. the different wake models used provide increasingly different results. This is illustrated in Figure 4, in which we use the observed wake loss (Barrow) or WAsP wake loss (Gwynt y Môr) as a proxy for 'depth into wind farm'.

The spreads of the overall wind farm energy yield and wake loss predictions provide estimates of wind farm wake modelling uncertainty (CV): for onshore farms 13-18%, and for offshore 16-22%, see Table 6. The uncertainty is proportional to the wake loss itself: increasing wind farm wake loss leads to increasing spread of the predictions.

Table 6. Estimated overall wake loss for the four wind farms: size and configuration of wind farm, wind farm layout, estimated wake loss, spread of wake loss estimates.

Wind farm	Size [MW]	Wind turbines [MW]	Layout	Est. wake loss [%]	Rel. spread CV [%]
Scotland W	28	14 × 2	Irregular, 3.7-4.8 *D*	6.1	13
Scotland E	29	22 × 1.3	Irregular, 4-5 *D*	10.3	18
Gwynt y Môr	576	160 × 3.6	Regular, 6-7 *D*	14.3	22
Barrow OWF	90	30 × 3	4 staggered, 5.5×8.5 *D*	7.9	16

The main wake models used to calculate the wind farm wake effects and potential energy yield are listed in [1-9]. The wake modelling should be qualified for each project: not only by model type, name, implementation and version number; but also model configuration and parameter values should be stated. Classic momentum-deficit and eddy viscosity wake models seem to provide realistic results for Barrow Offshore Wind Farm [8].

Step 5: Systematic technical losses estimation (→ net yield P_{50})

For the land-based wind farms, the technical loss estimates used to calculate the net energy yield (P_{50}) were based on given categories of availability and technical losses. Losses associated with availability are: turbine availability, balance of plant availability, grid availability and other availability. Technical losses were listed as: electrical transmission loss, power curve performance, high wind speed hysteresis loss, other turbine performance (high turbulence etc.), blade degradation and other losses.

Wake losses are by definition not considered a technical loss here; wake modelling and wake losses are treated separately above. Wakes change the predicted wind climates at the turbine sites just as any other feature of the topography.

For the offshore wind farms, technical loss values were mostly provided in the case study texts, so only high wind speed hysteresis effects for Gwynt y Môr were to be estimated by the teams. No calculation method was specified by the case study though, so this could be tested.

The overall estimated technical losses for the four wind farms are given in Table 7, including the coefficient of variation of the distribution of estimates. The variation coefficients for the offshore wind farms are of course low because the losses were prescribed by the case studies.

Table 7. Estimated overall technical losses for the four wind farms: name and size of farm, loss classification scheme, average estimated loss, spread of loss estimates, and spread of net yield P_{50}.

Wind farm	Size [MW]	Technical loss classification	Est. technical loss [%]	Rel. spread CV [%]
Scotland W	28	10 categories given [1]	9.2	32
Scotland E	29	10 categories given [3]	8.0	34
Gwynt y Môr	576	Losses given, except hysteresis	9.6	(8)
Barrow OWF	90	Losses given, but not combined	9.3	(1)

The technical losses are about 10% for all four wind farms and the spread about 1/3 of the mean value. It was difficult to determine exactly how the teams had estimated the losses. Recalculation of the overall loss in each submitted spreadsheet revealed that the calculation procedures were sometimes wrong: losses were added, rather than factored together.

Step 6: Uncertainty estimation and calculation (→ net yield P_{90})

Two different approaches were used to investigate the teams uncertainty estimation practice: user-specified uncertainty categories and fixed categories. For one land-based and one offshore wind farm, uncertainty classifications were completely user-specified; while for Barrow OWF, for example, the main categories were given as: wind data, future wind variability, flow modelling, wake modelling, power conversion, plant performance/losses, and other.

The user-specified classifications provide insight into local engineering practices and experience, but results are quite difficult to categorise for comparison. The fixed classifications were easy to compare and local practice could be specified to some extent in the Other category. The overall estimated uncertainties for the four wind farms are given in Table 8, including the coefficient of variation for the distribution of estimates.

It can further be seen from Table 8 that the spread, σ_{P50}, of P_{50}-estimates (column 6) is always smaller than the spread or uncertainty estimated by the teams (column 4) – which is what one would expect, since the uncertainty estimates likely contain more factors than are present in the case studies. The detailed comparison of uncertainty estimates will be reported elsewhere.

Table 8. Estimated overall uncertainty for the four wind farms: name and size of farm, uncertainty classification scheme, average estimated uncertainty, spread of uncertainty estimates, and spread of the corresponding net yield P_{50}.

Wind farm	Size [MW]	Uncertainty classification	Est. uncertainty [%]	Rel. spread CV [%]	Spread σ_{P50} [%]
Scotland W	28	User-specified	11	34	4.4
Scotland E	29	10 categories	8	28	5.8
Gwynt y Môr	576	User-specified	10	29	7.0
Barrow OWF	90	7 categories	9.7	23	3.1

The internal consistency of the submitted spreadsheets was investigated as part of the analysis and quality assurance. For both of the offshore wind farms [4, 8], about ¼ of the teams submitted P_{90}-results that were significantly different from what could be deduced from the teams own P_{50}- and uncertainty-values using the equation:

$$\text{Net AEP } (P_{90}) = \text{Net AEP } (P_{50}) - 1.282\times[\text{uncertainty estimate}]$$

The origin of these discrepancies is mostly related to the process of combining the individual uncertainties: some teams used a simple sum rather than quadratic summation, other teams forgot the factor 1.282, etc. This suggests that uncertainty calculations may not be a standard part of some teams procedures.

Predicted vs observed AEP from operating wind farms

Two wind farms, Scotland E and Barrow, provided power production statistics for comparison of predicted and observed wind farm yields. However, due to an error in the case study data, only the Barrow case study can be used here. Of course, only the authors had access to the observed energy yields.

The average estimated wind farm yield for Barrow OWF is 104% of observed yield, which is determined from one years worth of SCADA data. Incidentally, two independent calculations of the SCADA statistics were about 1% different. The spread for the net yield (P_{50}) estimated by the teams is 3% and the distribution of estimates follow a nice bell-shaped curve. There are no outliers, and only one team result being a bit outside the interval [mean yield] $\pm 2\sigma$. There is no simple relation between how well teams perform, i.e. how close their estimate is to the observed yield, and the methodology employed.

5 Discussion and conclusions

The four comparison exercises [1, 3, 4, 8] reveal that definition and usage of some concepts and terms in the industry are ambiguous; e.g. the term ‘reference yield’ is not understood in the same way by different participants. Likewise, engineering practices and ways of reporting seem to be quite different, making detailed comparisons of certain steps difficult. Apparently, a robust and unambiguous framework for calculation, reporting and documentation would help.

Not surprisingly, it is clear that all steps in the wind resource and energy yield assessment procedures can be improved. It is further clear that the different steps have quite different ‘improvement potential’. Based on the results of the four case studies and the statistics of the submitted data, we have attempted to make prioritised lists of actions that could be taken in order to improve the overall process in the most cost-effective way.

In Table 9 we assign a simple score to each step in each wind farm. The score is based on four criteria: the magnitude of the effect (larger effect ⇒ more weight), spread among participants estimates (larger coefficient of variation (CV) ⇒ more weight), number of outliers (more outliers ⇒ more weight), and how much each step contributes to the overall spread or uncertainty of the net energy yield (larger contribution ⇒ more weight).

The six steps in each wind farm are first ranked according to these four criteria, and the ranks are then added together to get the score shown in Table 9. Steps with low score are more critical, either because of the magnitude of the effect or the spread of results, or both.

Table 9. Score to evaluate the relative importance of the different steps for the four wind farms; and for land-based and offshore wind farms , respectively. Lower score means higher importance.

	Scotland West	Scotland East	Onshore	Gwynt y Môr	Barrow OWF	Offshore
Long-term extrapolation	11	9	10 (1)	16	8	12 (3)
Vertical extrapolation	18	20	19 (6)	n/a	12	12 (4)
Horizontal extrapolation	14	12	13 (3)	16	18	17 (6)
Wake modelling	18	13	16 (5)	5	11	8 (2)
Technical losses	12	14	13 (2)	12	19	16 (5)
Uncertainty estimation	11	16	14 (4)	10	6	8 (1)

Bearing in mind the limited data material and the limitations of the analyses, we conclude that for both the land-based and offshore wind farms the long-term extrapolation, technical loss estimation and uncertainty estimation get low overall scores and therefore seem to deserve the most attention.

Long-term extrapolation procedures, though seemingly simple and well described, provide widely different results for the same input data. Well defined and validated procedures seem to be needed in order to obtain more reliable results.

Uncertainty estimation (and calculation) seem to be one of the weakest steps in the teams assessment procedures and an entire framework of definitions, methodologies and tools need to be established, disseminated and employed.

Estimation of systematic technical losses was also a weak step in the assessment procedures. These losses correspond to about 10% of the yield, and the coefficients of variation of the estimates for the two land-based wind farms were about 1/3 of the median value. In addition, the calculation procedures were sometimes wrong: losses were added, not factored together. So, the methodology was not clear and tools or procedures seem to be lacking.

For the offshore wind farms, wake modelling is also particularly challenging. Many different wake models were used, in many different versions and configurations. The complete model specification is important for evaluation of the results; the submitted results suggest that the choice and configuration of wake model should be based on reliable validation data.

For the land-based wind farms, all teams used flow modelling for the horizontal extrapolation of wind climates. As with the wake modelling, the complete model specification is important for evaluation of the results. Many different models were used, but on average it was difficult to show that e.g. linearised and CFD-type models provided *significantly* different results for the two Scottish wind farms. Nevertheless, the submissions suggest that the choice and configuration of flow model should be based on reliable validation data.

The vertical extrapolation tests for the land-based wind farms were not demanding and the results therefore inconclusive. The methods employed by about half of the teams can be described as extrapolation to hub height using a power law or logarithmic wind profile. While this may work well for homogeneous conditions, the flow modelling approach employed by the other half of the teams is more general and sound [1, 3].

In conclusion, benchmark exercises (and validation data sets in public domain) can help improve the wind energy industry's procedures, standards and best practices. The present data set of 157 results turned out to be quite small when divided into several categories; more such data sets and exercises would significantly strengthen the analyses and conclusions.

Future comparisons could address wind resource and energy yield assessment at wind farm sites with significant roughness effects and roughness changes, sizeable vertical extrapolation effects, and atmospheric stability effects (coastal site) – or wind farm sites located in forested or very steep terrain. One could also include other site assessment characteristics, e.g. extreme winds, turbulence, flow inclination and wind shear [14].

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