Comparative Resource and Energy Yield Assessment Procedures (CREYAP) Pt. II

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Acknowledgements

• The data pack used for the comparison was made available by Renewable Energy Systems Ltd. (RES); thanks to Mike Anderson and Euan George.
• The 60 sets of results were submitted by 56 organisations from 17 countries; thanks to all of the teams for making the comparison and this presentation possible!
• Thanks to Tim Robinson and his team for arranging the 2013 comparison exercise and wind resource workshop.
Outline

• Purpose and participants
• Case study wind farm
  – Wind farm and turbine data
  – Wind-climatological inputs
  – Topographical inputs
• Comparisons of results & methods
  – The prediction process
  – Long-term wind climate
  – Wind farm energy yields
  – Comparison to observed AEP
  – Mast strategy and site results
• Summary and conclusions
• Appendices
  – Team results and statistics
Purpose and participants

CREYAP Pt. II
- 60 teams from 56 organisations in 17 countries submitted results!
  - consultancy (41)
  - developer (7)
  - R&D/university (5)
  - wind turbine manufacturer (3)
  - electricity generator/utility (2)
  - certification body (1)
  - service provider (1)

Visit www.ewea.org for more info on the CREYAP comparison exercises.

Reliable energy yield predictions are obtained when the bias and the uncertainty are both low.
Note, that the ‘true value’ is often measured – with some uncertainty...
What’s different compared to CREYAP Pt. I?

**General**
- Complete case study
- Operating wind farm
- Production data available (5y)
- Data and info not scrambled

**Input data**
- Seven measurement locations
  - One reference, six auxiliary
- Two types of long-term data
  - Ground-based
  - MERRA reanalysis
- Roughness data for site
  - Wind farm site only
- Obstacle data for site

**Modelling**
- Air density correction needed
- Larger terrain effects
- Larger wake effects
These effects are all of order 10%
Case study wind farm

- 22 wind turbines (28.6 MW)
  - Rated power: 1.3 MW
  - Hub height: 47 m
  - Rotor diameter: 62 m
  - Spacing: irregular, 4-5 $D$ between neighbouring WTG
  - Air density: 1.208 kg m$^{-3}$

- Primary site meteorological mast
  - Wind speed @ 50 and 40 m
  - Std. deviation @ 50 and 40 m
  - Wind direction @ 48.5 m a.g.l.

- Two 50-m site assessment masts
  - Same levels as primary mast
Wind-climatological inputs – site measured data

M49 site data (5y)
- 2001-10 to 2006-09
- Recovery rate 94%
- Statistics:
  - $U = 8.3 \text{ ms}^{-1}$
  - $P = 649 \text{ Wm}^{-2}$
  - $A = 9.4 \text{ ms}^{-1}$
  - $k = 2.05$
Wind-climatological inputs – reference data

Ground-based
- 5 years of hourly mean data
- 16+ years of monthly mean data
- 11- y historic wind data statistic

MERRA reanalysis
- 16+ years of hourly mean data
Topographical inputs – elevation

50-m DEM, 20 × 20 km²
Elevation 48-464 m a.s.l.
Vertical exaggeration × 3

Wind farm sites
276-338 m a.s.l
RIX index 1-3%
Data analysis & presentation

Data material
• Results spreadsheets from 60 teams

Data analysis
• Quality control and reformatting
• Consistent results (loss factors)
• Calculation of missing numbers – no comprehensive reanalysis!

Data presentation
• Comparison of results and methods
  – Non-parametric box-whisker plot
  – Statistics (median, quartiles, IQR)
• Overall distribution of all results
  – Normal distribution fitted to the results
  – Statistics (mean, standard deviation, coefficient of variation)
• Team results for each parameter (see appendix)
Comparisons of results and methods

1. LT wind @ 50 m (mast) = Measured wind \pm \text{[long-term adjustment]}
   • comparison of long-term adjustment methods

2. LT wind @ 47 m (hub height) = LT wind @ 50 m + \text{[wind profile effects]}
   • comparison of vertical extrapolation methods

3. Gross AEP = Reference AEP \pm \text{[terrain effects]}
   • comparison of flow models

4. Potential AEP = Gross AEP - \text{[wake losses]}
   • comparison of wake models

5. Net AEP (P_{50}) = Potential AEP - \text{[technical losses]}
   • comparison of technical losses estimates

6. Net AEP (P_{90}) = Net AEP (P_{50}) - 1.282 \times \text{[uncertainty estimate]}
   • comparison of uncertainty estimates

7. Comparison to observed AEP - spread and bias
Long-term wind at the meteorological mast

LT wind @ 50 m = Measured wind ± [long-term adjustment]
Comparison of LT adjustment methods

- Merra hourly MCP (16)
- Merra hourly matrix (7)
- Merra daily MCP (4)
- Merra monthly MCP (5)
- Wind index (6)
- No adjustment (5)
- Miscellaneous (13)
- All methods (50)

Legend:
- Minimum value
- Q1
- Median value, Q2
- Q3
- Maximum value
Long-term wind at hub height at the met. mast

LT wind @ 47 m (hub height) = LT wind @ 50 m + [profile effects]
Wind profile and shear exponent

Data points used = 55 (of 60)
Mean shear exponent = 0.127
Standard deviation = 0.013
Coefficient of variation = 10%
Range = 0.105 to 0.179
Comparison of vertical extrapolation methods
**Gross energy yield of wind farm**

Gross AEP = Reference AEP ± [terrain effects]
Comparison of flow models
Potential energy yield of wind farm

Potential AEP = Gross AEP − [wake losses]
Comparison of wake models

![Comparison of wake models](image-url)
**Net energy yield of wind farm, $P_{50}$**

Net AEP (P50) = Potential AEP − [technical losses]

where [technical losses] = AEP $\times f_1 \times f_2 \times ... \times f_n$

and $f_1$, $f_2$, ..., $f_n$ are the individual loss factors.
Technical losses by type

- Overall availability given as 96.8% (first 4 columns)
- Electrical loss given as 1.2% (first column)
Net energy yield ($P_{50}$)

Data points used = 58 (of 60)

Mean net yield = **75.7 GWh**
Standard deviation = 4.4 GWh
Coefficient of variation = 5.8%
Range = 64 to 91 GWh
Net energy yield of wind farm, $P_{90}$

Net AEP (P90) = Net AEP (P50) − 1.282×[uncertainty estimate]
Uncertainty estimates by type
# Wind farm key figures

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<th>Mean</th>
<th>σ</th>
<th>CV*</th>
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<th>Max</th>
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<td>−19</td>
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<td>10</td>
<td>1.8</td>
<td>18</td>
<td>3.9</td>
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<td>34</td>
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<td>3.6</td>
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</tr>
<tr>
<td>GWh</td>
<td>66</td>
<td>4.7</td>
<td>7.1</td>
<td>56</td>
<td>79</td>
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</table>

* Coefficient of Variation in per cent.
Spread for different steps in the prediction process

- Measurements
- LT wind @ 50 m
- LT wind @ 47 m
- Gross yield
- Potential yield
- Net yield, P50
- Net yield, P90

Coefficient of Variation [%]

- Wake modelling
- Loss estimation
- Uncertainty est.

> > > Steps in the prediction process > > >
Comparison to observed AEP – spread and bias

Observed long-term energy yield based on 5 years of production data; corrected for windiness, as well as an overall plant availability of 96.8%. This produces an observed yield of **76.25 GWh/year**.
How do the predictions compare to the observed AEP?

Observed AEP = median of 58 results!
The six teams closest to the observed AEP

- Long-term adjustment
  - None, unknown daily, Merra hourly or monthly, wind index monthly, wind index Weibull scale.

- Vertical profile
  - log law, power law, modelled, CFD, linearised model

- Flow modelling
  - Linearised model, CFD model

- Park modelling
  - Eddy viscosity, Jensen-type

- Strategy
  - All masts, M49 only (50/50)

These teams are close to the overall median every step of the way
The six teams furthest away from the observed AEP

- Long-term adjustment
  - NWP hourly ERA Interim, NWP hourly, Merra 7-day, NWP ERA-1, MCP hourly matrix + index, MCP unspecified

- Vertical profile
  - not used, power law, log law, modelled, NWP

- Flow modelling
  - Mesoscale model, mass-consistent model, CFD model, WRF, linearised model

- Park modelling
  - Frandsen-type, CFD actuator disk, eddy viscosity, Jensen-type, proprietary, Jensen model + GCL (Larsen)

- Strategy
  - not used, all masts, m49 only
Mast strategy – impact on gross AEP

What is the consequence of using a single mast (49) vs. multiple masts?

- For all teams:
  - Single-mast predictions +2% higher than multiple mast do.
  - Single- and multiple-mast predictions are different!

Try now with one model only to see if pattern persists.

- Say, for WAsP teams only:
  - Single-mast predictions +2% higher than multiple mast do.
  - Single- and multiple-mast predictions are different!

Rather clear signal, and significant.
Mast strategy – impact on net AEP $P_{50}$

*Does mast strategy have an impact on the final estimate of the net AEP?*

- For all teams:
  - Single-mast predictions +1% higher than multiple mast do.
  - Single- and multiple-mast predictions are ‘not different’!
  - Multiple-mast prediction is closer to the observed AEP.

- For WAsP teams only:
  - Single-mast predictions are almost equal to multiple mast.
  - Multiple-mast prediction is closer to the observed AEP.

*Less clear signal, not significant.*
Predicted turbine site **mean wind speeds**
Predicted turbine site mean wind speeds

![Graph showing predicted turbine site mean wind speeds](graph.png)
Predicted turbine site wake effects
Predicted turbine site wake effects

![Graph showing the comparison between modelled and WASP Park model wake effects. The graph includes data points and trend lines for different models: Jensen-type models (20), Ainslie eddy viscosity (11), and OpenWind Deep Array (5).]
Turbine AEP contribution – predicted vs. observed
Turbine energy yields – predicted vs. observed
Turbine energy yields – predicted vs. observed

![Graph showing predicted vs. observed turbine energy yields. The x-axis represents the observed turbine yield [GWh/y], and the y-axis represents the predicted (median) turbine yield [GWh/y]. The data points are scattered along the diagonal line, indicating a close correlation between predicted and observed values.](image-url)
Turbine energy yields – predicted vs. observed
Summary and some conclusions...

- Wind resource assessment works
  - if you do it right...

- Wind farm AEP predictions
  - Mean bias is very small
  - $P_{50}$ standard deviation is 6%
  - Reported ‘Uncertainty’ is 8%

- Mesoscale and NWP models are powerful, but not sufficient (give lower AEP)

- Mast strategy not quite clear?

- Single-site predictions work well

- The prediction process is complex and it is different to isolate effects

- What about the human factor!?!?

- Steps that add little to the spread
  - Vertical extrapolation
  - Wake modelling
  - Technical loss estimation

- Which steps could be improved
  - Long-term correlation
  - Flow and terrain modelling
  - Uncertainty estimation

- What else could be improved?
  - Definition and usage of concepts (e.g. reference yield and topographical effects)
  - Standards and guidelines
  - Engineering best practices
  - Guidelines for reporting
Future comparisons

After CREYAP Part I and II, one could step up the challenge, e.g.:

- Wind farm site where vertical extrapolation is very important
- Wind farm site where stability effects are important (coastal site)
- Offshore wind farm site
- Forested wind farm site
- Complex terrain wind farm site
- Wind farm with user-provided topographical inputs

Future comparison exercises could thus be more focussed in order to highlight specific topics – and should preferably be

- Real wind farm(s) with production data

— Thank you for your attention!
Appendices

Team results, statistics and additional information
Contents

- **Input data**
  - List of participants
  - Wind farm photographs
  - OS topographical map
  - Domain and roughness map

- **Long-term wind at the met. mast**
  - Long-term adjustment effect
  - LT mean wind speed @ 50 m
  - Turbulence intensity @ 50 m

- **LT hub height wind at met. mast**
  - Wind profile shear exponent
  - LT mean wind speed @ 47 m
  - Turbulence intensity @ 47 m

- **Energy yield of wind farm**
  - Reference energy yield
  - Topographical effects
  - Gross energy yield
  - Wake losses
  - Potential energy yield
  - Technical losses
  - Net energy yield ($P_{50}$)
  - Capacity factor
  - Uncertainty estimates
  - Net energy yield ($P_{90}$)
  - Wind farm energy yields
  - Turbine site terrain effects

- **Legend and references**
Who submitted results?

- 60 teams from 56 organisations in 17 countries submitted results!
  - consultancy (41), developer (7), R&D/university (5), wind turbine manufacturer (3), electricity generator/utility (2), certification body (1), service provider (1)

- Names of the organisations
  - 3E (Belgium); 3TIER (USA); ALTRAN (Spain); ATM-PRO (Belgium); AWS Truepower (USA); Barlovento Recursos Naturales (Spain); BBB Umweltechnik (Germany); Casa dos Ventos (Brazil); CENER (Spain); China Wind Power Center / CEPRI (China); CIRCE (Spain); CRES (Greece); Deutsche WindGuard (Germany); Digital Engineering (UK); DTU Wind Energy (Denmark); EDF Renewable Energy (USA); Edison (Italy); EMD International (Denmark); ENALLAKTIKI ENERGIKI (Greece); Enerpark (Poland); EREDA (Spain); ESB International (Ireland); Estia (Greece); Etha (Finland); European Weather Consult (Germany); Fichtner (Germany); Fujian Hydro Power (China); GAMESA (Spain); GDF SUEZ (France); IMPSA (Brazil); INOVA Energy (Brazil); International Wind Engineering (Greece); Istos Renewables (Greece); ITOCHU Techno-Solutions (Japan); Kjeller Vindteknikk (Norway); Lahmeyer (Germany); Mainstream (USA); Megajoule (Portugal); Meteodyn (France); Mott MacDonald (UK); MS Techno (China); NREL (USA); Natural Power (UK); North China Electric Power University (China); Prevailing (UK); REpower Systems (Germany); RES Ltd. (UK); RSE S.p.A. (Italy); SgurrEnergy (UK); The Wind Consultancy Service (UK); Tractebel Engineering (Belgium); Wind Energy Corporation (Japan); Wind Prospect (UK); WIND-consult (Germany); WindSim (Norway); Winwind (Finland).
Case study wind farm
Case study wind farm
Case study wind farm
Case study wind farm
Topographical inputs – land cover
Long-term wind at the meteorological mast

LT wind @ 50 m = Measured wind ± [long-term correlation effect]
Long-term adjustment effect

Data points used = 57 (of 60)
B45, 53 and 58 report no results

Mean long-term effect = 0%
Standard deviation = 2.2%
Coefficient of variation = n/a
Range = −9 to 6.5%
(observed $U_{50}$ of 8.3 ms$^{-1}$ assumed)
LT mean wind speed @ 50 m

Data points used = 57 (of 60)
B45, 53 and 58 report no results

Mean wind speed = 8.3 ms\(^{-1}\)
Standard deviation = 0.2 ms\(^{-1}\)
Coefficient of variation = 2.2%
Range = 7.6 to 8.9 ms\(^{-1}\)
Turbulence intensity @ 50 m

Data points used = 55 (of 60)
B11, 27, 37, 45, 58 report no results

Mean turbulence intensity = 10%
Standard deviation = 1.4%
Coefficient of variation = 14%
Range = 9 to 16%
Long-term wind at hub height at the met. mast
LT wind @ 47 m = LT wind @ 50 m + [wind profile effects]
Wind profile shear exponent

Data points used = 55 (of 60)
B27, 45, 53, 58, 60 report no results
B2, 11, 46, and 57 inferred by DTU

Mean shear exponent = 0.127
Standard deviation = 0.013
Coefficient of variation = 10%
Range = 0.105 to 0.179
LT mean wind speed @ 47 m

Data points used = 52 (of 60)
B5, 10, 27, 37, 49, 53, 58 and 60 report no results.

Mean wind speed = 8.3 ms\(^{-1}\)
Standard deviation = 0.2 ms\(^{-1}\)
Coefficient of variation = 2.4%
Range = 7.5 to 8.8 ms\(^{-1}\)
Turbulence intensity @ 47 m

Data points used = 49 (of 60)
B5, 10, 11, 27, 31, 37, 49, 55, 56, 58, 60 report no results.

Mean turbulence intensity = 10%
Standard deviation = 1.2%
Coefficient of variation = 12%
Range = 9 to 15%
Gross energy yield of wind farm

Gross AEP = Reference AEP ± [terrain effects]
Reference energy yield

Data points used = 52 (of 60)

Mean reference yield = 97.8 GWh
Standard deviation = 5.7 GWh
Coefficient of variation = 5.8%
Range = 79.3 to 106 GWh
Topographical effects

Data points used = 51 (of 60)

Mean terrain effect = $-7.5\%$
Standard deviation = 4.4%
Coefficient of variation = n/a
Range = $-19$ to $1\%$
**Gross energy yield**

Data points used = 58 (of 60)

Mean gross yield = 91.5 GWh
Standard deviation = 4.3 GWh
Coefficient of variation = 4.7%
Range = 76.4 to 113 GWh
Potential energy yield of wind farm

Potential AEP = Gross AEP − [wake losses]
**Wake losses**

Data points used = 58 (of 60)

Mean wake loss = **10.3%**

Standard deviation = 1.8%

Coefficient of variation = 18%

Range = 3.9% to 17%
Data points used = 58 (of 60)

Mean potential yield = 82.2 GWh
Standard deviation = 4.6 GWh
Coefficient of variation = 5.6%
Range = 67.2 to 102 GWh
**Net energy yield of wind farm, $P_{50}$**

Net AEP (P50) = Potential AEP – [technical losses]

where [technical losses] = AEP × $f_1 × f_2 × ... × f_n$

and $f_1, f_2, ..., f_n$ are the individual loss factors.
Technical losses

Data points used = 59 (of 60)

Mean technical loss = 8.0%
Standard deviation = 2.7%
Coefficient of variation = 34%
Range = 4.4 to 20%
Net energy yield ($P_{50}$)

Data points used = 58 (of 60)

Mean net yield = 75.7 GWh
Standard deviation = 4.4 GWh
Coefficient of variation = 5.8%
Range = 64 to 91 GWh
Capacity factor

Data points used = 58 (of 60)

Mean capacity factor = 30.2%
Std. deviation = 1.8%
Coefficient of variation = 5.8%
Range = 26 to 36%
Net energy yield of wind farm, $P_{90}$

Net AEP (P90) = Net AEP (P50) − 1.282×[uncertainty estimate]
Uncertainty estimates

Data points used = 46 (of 60)

Mean uncertainty = 8%
Standard deviation = 2.2%
Coefficient of variation = 28%
Range = 3.6 to 12%
Net energy yield ($P_{90}$)

Data points used = 53 (of 60)

Mean net yield = 66 GWh
Standard deviation = 4.7 GWh
Coefficient of variation = 7.1%
Range = 56 to 79 GWh
Wind farm energy yields

![Box plot showing energy yields for different scenarios.](image)
Predicted turbine site terrain effects
Legend and references

Legend to graphs

• Distribution graphs: histograms + fitted normal distribution. Statistics given next to graph.

• Team result graphs: mean value is base value for histogram, y-axis covers a range of ±2 standard deviations, x-axis covers teams 1-60. No team number means ‘result not submitted’.

• Box-whisker plots: whiskers defined by the lowest datum still within 1.5 IQR of the lower quartile (Q1), and the highest datum still within 1.5 IQR of the upper quartile (Q3).

For more information on CREYAP Pt. I

• Mortensen, NG & Ejsing Jørgensen, H 2011, 'Comparison of resource and energy yield assessment procedures'. in: Proceedings. EWEA.