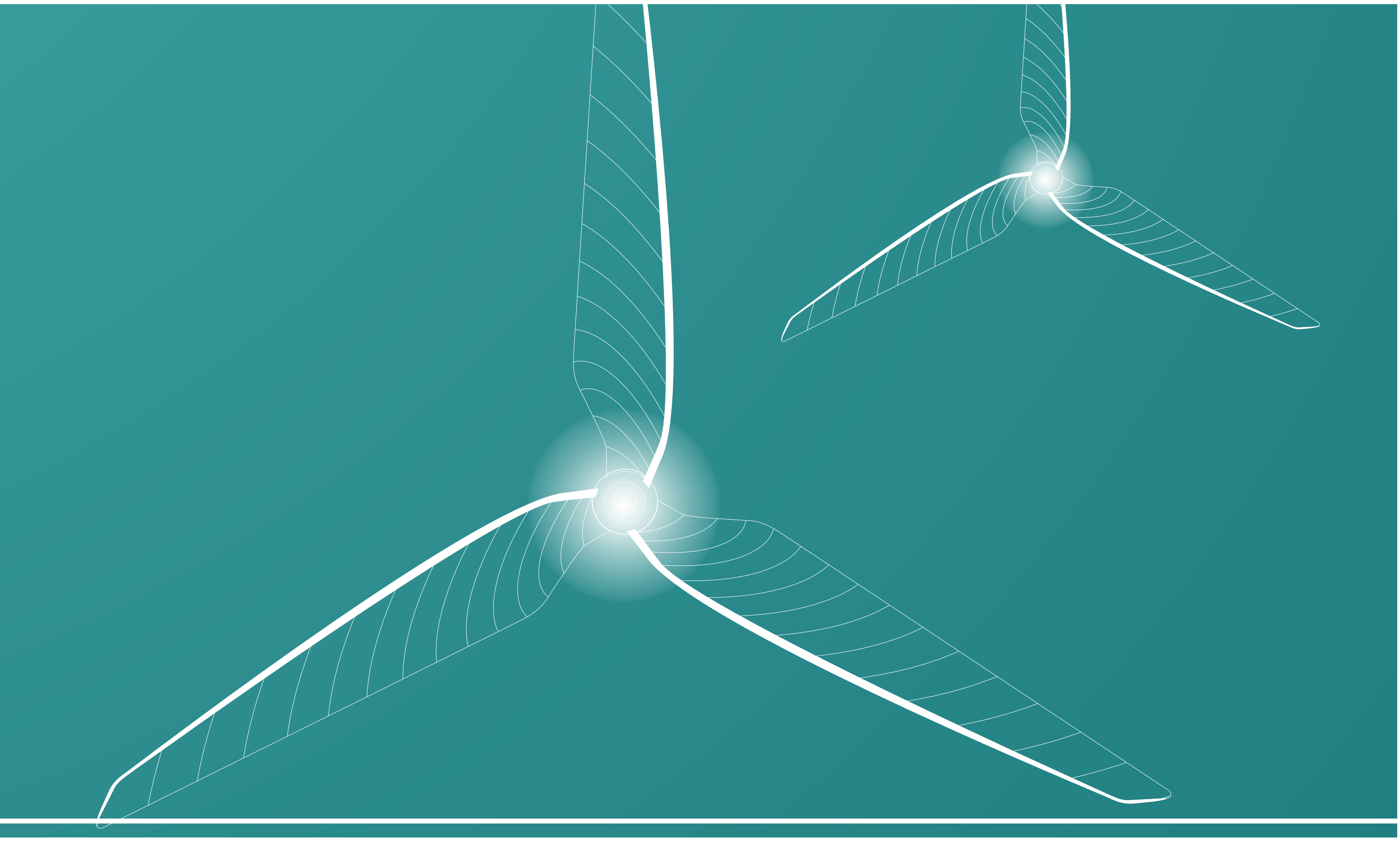
DNV·GL

THEORY MANUAL

WINDFARMER

Version: 5.3
Date: April 2014
DNV GL - Energy



SAFER, SMARTER, GREENER

DISCLAIMER

Garrad Hassan & Partners Ltd. accepts no liability for any loss or consequential damage arising directly or indirectly from the use of its products.

This document is subject to change without notice.

COPYRIGHT

Garrad Hassan & Partners Ltd., St Vincent's Works, Silverthorne Lane, Bristol, BS2 0QD England

www.dnvgl.com
windfarmer@dnvgl.com

Contents

1 INTRODUCTION

The WindFarmer software package allows the user to design a wind farm to achieve maximum energy production within the geometric and environmental constraints of the site. Through continuous development, WindFarmer is at the forefront of wind farm technical analysis while meeting the changing needs of the industry.

This manual provides background information on some of the core features:

- Wind data analysis and correlation
- Flow modelling
- Energy and wake loss calculation
- Site conditions assessment
- Noise propagation model
- ZVI analysis
- Electrical loss calculation
- Shadow flicker calculation

2 WIND FLOW MODELLING

The speed and direction of the wind varies as it moves across a wind farm site due to changes in the terrain height, roughness and the presence of obstacles. The process of calculating these changes is known as 'wind flow modelling'. There is a multitude of flow models that range from very simple models that are based on terrain height only to sophisticated CFD models. WindFarmer can use results from any wind flow model as long as they are available in WAsP RSF or WRG file format. WindFarmer also includes a simple flow model that combines customisable vertical shear models and a simple horizontal model that is based on the terrain height.

2.1 The Simple Wind Flow Model for Feasibility Studies

The 'Simple' wind flow model has been included to enable wind flow model calculations to be performed quickly and cheaply, without the need for external software. As the name suggests, it uses a simple algorithm which can produce results with a level of accuracy appropriate for use in early feasibility studies.

The wind speed is assumed to change linearly with terrain altitude relative to a given point, as suggested in [1.1] and [1.2]. When the terrain slopes are less than 3 degrees, the relationship between wind speed-up factor and the terrain height is

$$s = 1 + 0.001 * \Delta z$$

where Δz is difference in terrain altitude in m. The topographic sensitivity is expressed in a speed-up change per m, here 0.001.

The follow inputs are required to estimate the flow with the Simple Flow Model:

- Topographic information: digital maps in a raster format.
- Wind data: Tab files, mean wind speed or Weibull parameters.
- Definition of the area to be considered

Shear model

The Simple Flow Model will calculate the change in wind speed between the height above ground level at which the wind was measured, and the hub height. This is performed using the wind shear model.

The following shear models can be used:

- Log law – the surface roughness length z_0 is the input parameter. The speed-up factor between mast height and hub height is calculated as follows,

$$s = \frac{ln\left(\frac{z_{hub}}{z_0}\right)}{ln\left(\frac{z_{mast}}{z_0}\right)}$$

- Power law – the power exponent, alpha, is the input parameter. The speed-up factor between mast height and hub height is calculated as follows,

$$s = \left(\frac{z_{hub}}{z_{mast}}\right)^{\alpha}$$

2.2 Wind flow calibration factor (all flow models)

WindFarmer calculates a calibration factor that is based on the production data and user defined weighting factors for each turbine. It represents the difference between the calculated energy yields of the turbines and their production data. This calibration factor can be used to scale the wind resources that have been calculated by the flow model so that the resulting energy yield for existing turbines better match the actual production data.

The calibration factor is calculated as follows:

$$C = \sum_t \frac{E_{actual,t} - E_{calculated,t}}{Sensitivity_t} \times Weighting_t$$

Where

$E_{actual,t}$	Actual energy yield for turbine t
$E_{calculated,t}$	Calculated net energy yield for turbine t
$Sensitivity_t$	Wind speed sensitivity in the energy yield for turbine t
$Weighting_t$	Relative weighting factor for turbine t

The wind speed sensitivity is calculated in a perturbation calculation where the wind speed is reduced by 3%. The wind speed sensitivity is defined as (difference in net energy in MWh)/(difference in wind speed in m/s).

The weighting factor represents the confidence that the user has in the quality of the production data of a turbine or the relevance of the reference turbine for the proposed turbines. A turbine with low quality data should be given a low weighting. The individual weighting factors get normalised in the calculation of the calibration factor.

The calculated calibration factor can be entered in the Flow Model page in the Control Panel. The mean wind speed of wind resources that have been calculated with a flow model are then multiplied with the calibration factor. Wind speed and wind energy maps are also scaled by the calibration factor.

3 ENERGY CALCULATION

An energy calculation combines the incident wind speeds at each turbine with the power curve of the turbine to give the power output for the whole wind farm, applying the frequency distribution results in the expected energy yield.

The energy production of the wind farm is calculated using WindFarmer in conjunction with WAsP or a wind flow model with compatible output. The wind flow model is used to determine the ambient wind speeds at each turbine location. The output of a wind flow model consists of the directional Weibull A and k parameters which represent the wind speed probability distribution and a directional probability for every point on a grid. WindFarmer enables you to use the probability distribution of wind speed and direction measured at an on-site mast by associating this file with the predictions of the wind flow model. Through this Association Method, the measured data are scaled to the turbine locations using the predictions of the wind flow model.

A wake model is used to determine the changes to the incident wind speeds at each turbine within a wind farm due to the effects of other turbines. The accuracy of wake prediction has become increasingly important as larger wind farms are developed and turbines are placed closer together.

3.1 Program inputs

The following inputs to the WindFarmer model are required to produce an estimate of the wind farm energy production:

- A WAsP wind resource grid (WRG) format file at the turbine hub height with extents covering all the intended turbine locations or a WAsP discrete resource (RSF) format file with wind speed results at individual turbine locations
- Turbine locations as grid co-ordinates
- Turbine performance data, which includes power, thrust and rotor speed characteristics
- Turbine dimensions, specifically hub height and diameter

The resource file is generated with WAsP or any other flow model that produces an equivalent output and is a representation of the directional wind speed distribution at each point over the site. Program parameters used in the energy yield calculation are listed in the table below.

Energy calculation	Default value	Description
Site reference air density (kg/m³)	1.225	The air density for each turbine is calculated from the site air density according to height above sea level (ASL) and the power curve used is adjusted according to IEC 61400-12-1 [3.1].
Lapse rate ((kg/m³)/km)	-0.113	The lapse rate describes the variation of the air density with height.
Apply direction shift to sector probability	Not ticked	Shifts the directional probabilities following the predictions of the flow model used. Use with care.
Site roughness length (m)	0.03	This parameter can be used to calculate turbulence levels at hub height. The equations used are only valid for flat smooth uniform terrain. The use of measured turbulence data is recommended.
Maximum wind speed (m/s)	70	Maximum wind speed for which energy is calculated. The mean wind speed calculation from a Weibull distribution requires a high value.
Number of direction steps	72	The complex geometry of wind farms needs to be captured. For accurate calculations do not use less than 72 steps. The large wind farm model requires 180 or 360 direction steps. For cases with one or two very dominant wind direction sectors the use of 180 or 360 steps for a 12 sector TAB file; or of 90 or 360 steps for an 18 sector TAB file is recommended.

Summary of energy calculation inputs

3.2 Association Method

The wind flow model calculations result in wind resource data expressed in terms of Weibull coefficients. This is a less accurate way of expressing wind speed distributions than the frequency distribution table which has been loaded at the mast location. The Association Method is a technique used by WindFarmer to preserve the accuracy of the frequency distribution, and apply it to wind resource data at turbine locations.

It may be beneficial to use the association method in complex terrain in order to get more realistic results from the wake model even if there is no measured frequency distribution available. The required data for the association method can be generated from the existing data.

For the Association Method, it is required that the following optional input files are used in addition:

- A single point WAsP wind resource grid file for the reference mast at measurement height, and when using an RSF file; an additional single point WRG file at hub height at the mast location
- A joint wind speed and direction frequency distribution table for the reference mast location, in the format of the WAsP table file (TAB)

If these two files are not specified, WindFarmer can generate the information from the wind resource grid file that is based on a fit of a Weibull distribution to the measured data. For certain wind regimes, the Weibull distribution may not give a good representation of the wind climate at the site.

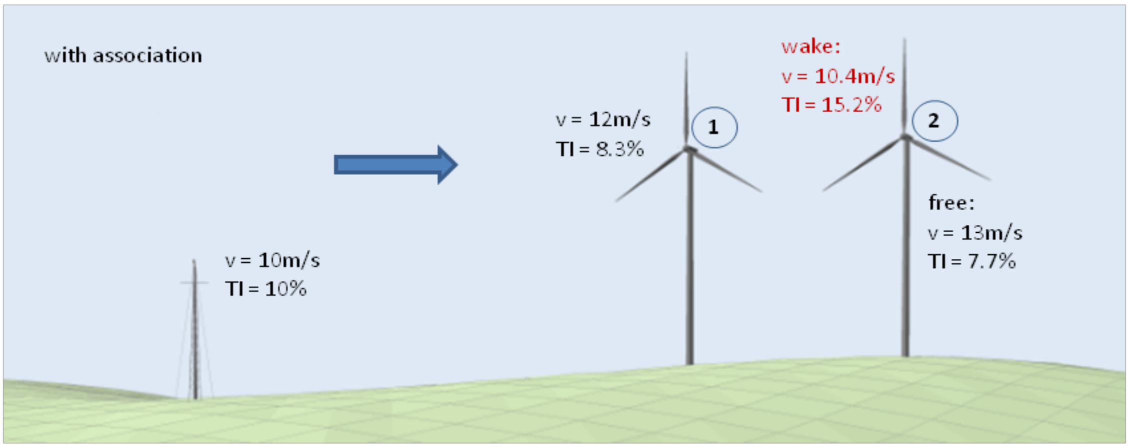
Using the Association Method allows the user to

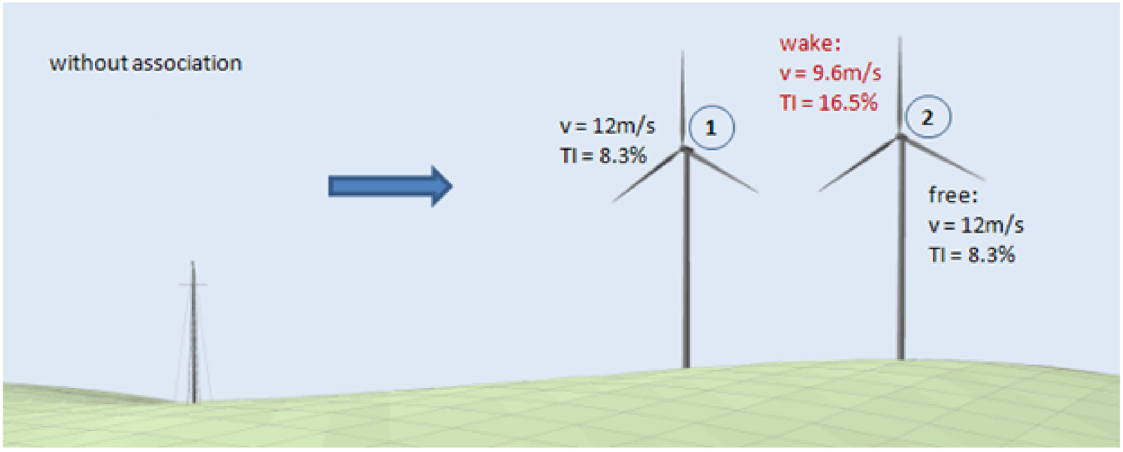
- Use the measured wind speed and directional distribution instead of a Weibull distribution
- Model the variation of the turbulence intensity over a wind farm
- Model the influence of the topography on turbine wakes.

Mean wind speeds are derived from the wind resource Weibull data at turbine and mast locations on a directional basis. The ratio of the mean wind speed at a wind turbine and its associated mast is the speed-up factor. These speed-up factors are used to determine the resulting wind speed at each turbine for a given wind speed at the mast.

The wake effect is calculated for each wind speed and direction step. When using the association method, the speed-ups between turbines is taken into account in the calculation of the incident wind speed of the turbines that are in the wake of upstream turbines. The method is illustrated below:

In the example, the speed-up between the turbines and the mast is 1.2 for turbine 1 and 1.3 for turbine 2. Turbine 2 is located in the wake of turbine 1. If the wind speed is 12m/s and the turbulence intensity is 8.3% at turbine 1 then the wind speed at turbine 2 is 10.4m/s and the turbulence intensity is 15.2% when using the association method. Without the association method, the higher free wind speed at turbine 2 is not considered and the wind speed reduces to 9.6m/s and the turbulence increases to 16.5%.





By default WindFarmer assumes that the directional distribution at the point of measurement is representative for the turbine sites when using the association method. However the direction of the wind flow as predicted by the wind flow model may change when passing over terrain. WindFarmer allows optional use of this shift in direction. Directional correction factors are obtained with the same methodology as the non-directional speed-up factors. By using this function the accuracy of energy results can be improved in areas where the measured distribution is no longer an adequate representation of the site conditions. Users are however advised to use this function with care as sparsely occupied direction sectors may lead to unrealistic results.

In the following Section, it is assumed that the Association Method is applied.

3.3 Net yield with wake losses

In analysing the wind farm energy production, the program performs three energy calculations for the following situations:

A. Ideal Energy: All turbines experiencing the same wind regime at the hub height as at the reference location, without any losses

B. Gross Yield: All turbines at their true locations with topographic speedups relative to the mast, including possible large wind farm modifications to the ambient flow and without any allowance for wake losses.

C. Net Yield without additional losses: All turbines with topographic speed-ups and calculation of wake losses

The Net Yield without additional losses (Calculation C) is equivalent to the ideal output (Calculation A) multiplied by the two following efficiencies:

- Topographic efficiency = Calculation B / Calculation A
- Array efficiency = Calculation C / Calculation B

The program calculates the net energy output, array and topographic efficiency for each individual turbine and for the wind farm as a whole. To calculate the net energy production of each wind turbine only calculation C is required. Calculations A and B are used to estimate the wake and topographic effects experienced by each turbine.

3.4 Net yield including additional losses

The following additional losses are calculated by WindFarmer and are expressed in the form of efficiencies:

Sector management - includes losses due to the shut down of turbines and its impact on the wake effects in the wind farm

Electrical efficiency (requires the Electrical Module)

Additional efficiencies can be entered manually by the user

For each new loss the efficiency is derived by carrying out a yield calculation taking the loss factor into account and dividing the original energy yield by the new energy yield. Following this procedure the final Net Yield including losses is the product of the Ideal Energy and all efficiencies.

3.5 Methodology of the energy calculation

Before performing an energy calculation, the program determines the topographic speed-ups over the site. Using the Association Method, this is the ratio of the wind speed at each grid point in the WAsP wind resource grid file to the wind speed at the reference location. The topographic speed-up is determined separately for each of the direction sectors in the wind resource grid file. The speed-up factors are then applied to the measured wind speed and direction frequency distribution table that is assumed to be representative for the site. This method avoids errors due to fitting a Weibull distribution to measured data.

The program considers each wind direction sector in turn and each wind speed bin individually. For each wind direction, the program determines the topographic speed-up of wind speed for the grid points nearest each turbine location. This speed-up factor is assumed to be constant for all wind speeds considered.

The wake effect of each turbine on the other turbines is calculated for each wind speed step as the wake effect varies with wind speed. The methodology for modelling the wake of each turbine is detailed in the Wake Models section. The first step in this process is to calculate the wind speed and turbulence intensity incident upon the turbine. If a turbine is in more than one wake, the overall wake effect is taken as the largest wind speed deficit and other (smaller) wake effects are neglected. This methodology is based on the results of the assessment of measured data from a large number of wind farms.

The wind speed incident on each turbine is therefore a combination of the topographic speed-up and the wake loss. This incident wind speed can then be used to determine the power output. A power look-up table is created where the power output of each turbine is stored for each reference wind direction and wind speed considered.

The energy output is calculated as the sum product of the reference wind speed and direction frequency distribution table and the power output look-up table.

4 WAKE MODELS

The calculation of wake effects employs a systematic approach where each turbine is considered in turn in order of increasing axial displacement downstream. By this method, the first turbine considered is not subjected to wake effects. The first turbine's incident wind speed, the thrust coefficient and the tip-speed ratio are calculated. Its wake is then modelled, as described below, and the parameters which describe its wake are stored. The effect of this wake on all turbines downstream can then be modelled. If any of the downstream turbines fall within the wake of this turbine, the velocity and turbulence incident on these turbines can be determined, solely due to this upstream turbine being considered. As the calculation progresses through the turbines, the incident wind speed on the turbine is the sum of the wake and topographic effects as described in the energy calculation section.

There are two wake models available within WindFarmer;

- Modified PARK model based on the method presented by Jensen and Katic [4.3]
- Eddy Viscosity model based on work conducted by Ainslie [4.1, 4.2]

Due to the complexity of the wake directly behind the rotor, all models are initiated from two diameters (2D) downstream. This is assumed to be the distance where pressure gradients no longer dominate the flow. If a turbine is within this limit, the program resets the axial distance offset to a value of two rotor diameters.

The input parameters to the two models are listed in the table below. For a comparison of the model results with that of real wind farms please refer to the Validation Report.

	Default	**Description**
Modified PARK		
Wake expansion factor (k)	0.07	Describes the rate of the assumed linear expansion of the wake. Increase this value for a high turbulence situation, decrease for offshore.
Surface roughness length (z_0)	0.03 m	Formula {4.1.2} is used to obtain the wake expansion factor from a surface roughness length
Eddy Viscosity		
Maximum allowable turbulence	20 %	Calculation will return a warning if a set incident turbulence level is exceeded; the turbulence is calculated as average over all wind speed conditions.

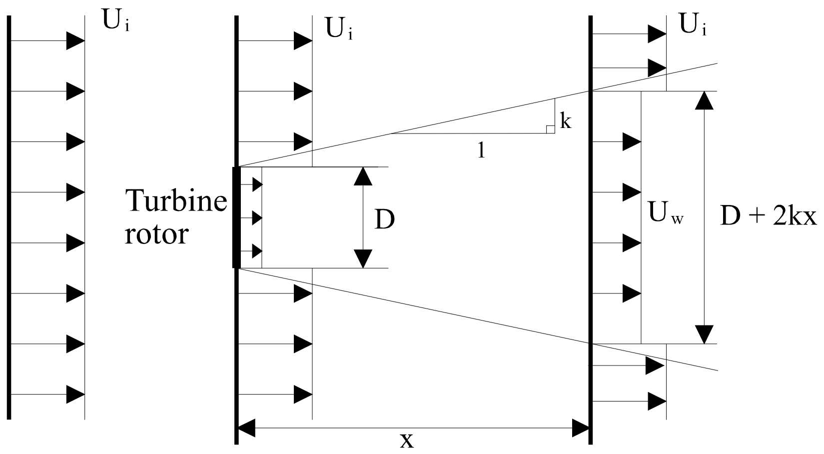
Summary of wake calculation inputs

4.1 Modified PARK model

This is a simple model of the wake that is based on the same algorithm used in PARK [4.4, 4.5].

4.1.1 Model initialisation

This two-dimensional model uses the momentum theory to predict the initial profile from the thrust coefficient assuming a rectangular wind speed profile, and that the wake expands linearly behind the rotor. The figure below outlines the flow field used by the model.



Flow field used in the Modified PARK model to calculate the wind turbine output

4.1.2 Wake development

The downstream wind speed is calculated using the following formula [4.4]:

$$U_w = U_i\left[1 - \left(1 - \sqrt{1 - C_t}\right)\left(\frac{D}{D + 2kx}\right)^2\right] \qquad \{4.1.1\}$$

Here U_i is the axial wind speed incident on the turbine, C_t is the thrust coefficient and k is the wake decay constant that is defined by the following expression [4.5]:

$$k = \frac{A}{\ln(h/z_0)} \qquad \{4.1.2\}$$

where A is a constant equal to 0.5 and h is the turbine hub height.

The nature of the program means that k is set at the same value for all wind directions. This assumes that there is no significant variation in surface roughness length over the site and the surrounding area.

4.1.3 Wake superposition

For each turbine downstream of the turbine under consideration, the program determines the axial displacement assuming rotational symmetry of the wake. The wake width and the wind speed at this displacement are then calculated. The turbines affected by the wake may not be totally in the wake so the percentage cover of the turbine's rotor in the wake is determined. If the whole rotor is within the wake, then the turbine wind speed is set as U_w. If some of the rotor is outside the wake, the wind speed at the turbine is the sum of U_w and the upstream velocity of the turbine creating the wake multiplied by the relative percentages of rotor cover.

If the turbine under consideration is in the wake of another turbine, the initial wake velocity deficit is corrected from the incident rotor wind speed to the free stream wind speed. This correction is necessary in order to ensure that at distances far downstream, the wake wind speed will recove4r to the free stream value rather than that incident on the rotor. Therefore, the initial centre line velocity U_{wi} is scaled by the ratio of average influx velocity U_i and free upstream wind velocity according to the following formula:

$$U_W=(U_0/U_i)U_{wi} \qquad \{4.1.3\}$$

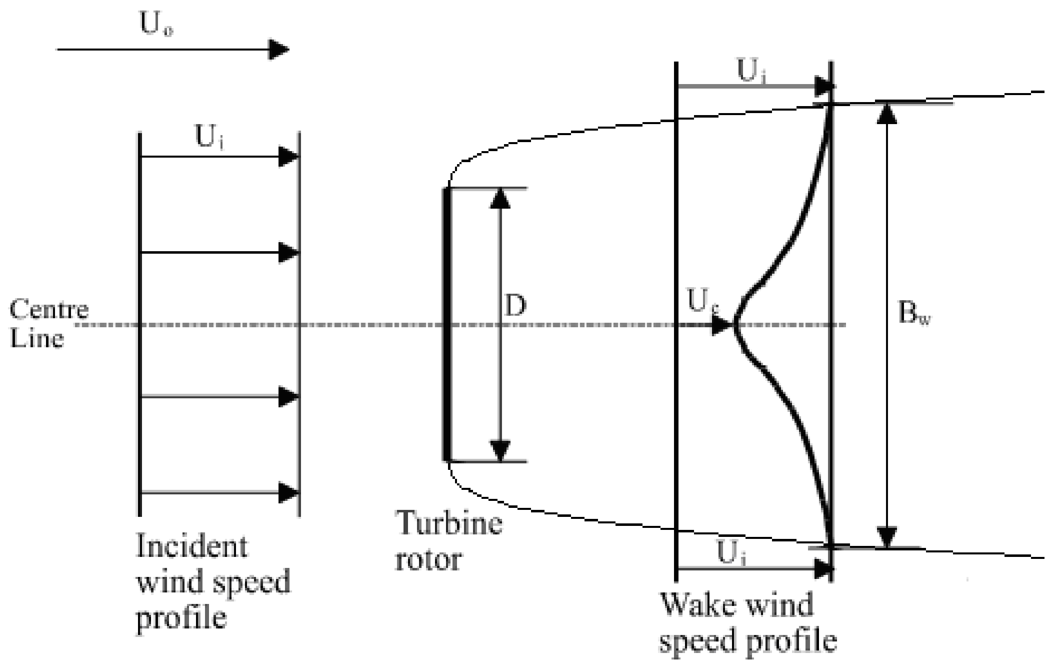
To combine the wakes of two wind turbines onto a third turbine the overall wake effect is taken as the largest wind speed deficit and other smaller wake effects are neglected. This methodology is based on the results of the assessment of measured data from a number of wind farms.

Furthermore, where multiple turbine types are present, the model takes into account any variation in hub height and rotor diameter.

4.2 Eddy Viscosity model

The Eddy Viscosity wake model is a CFD calculation representing the development of the velocity deficit field using a finite-difference solution of the thin shear layer equation of the Navier-Stokes equations in axi-symmetric co-ordinates. The Eddy Viscosity model automatically observes the conservation of mass and momentum in the wake. An eddy viscosity, averaged across each downstream wake section, is used to relate the shear stress to gradients of velocity deficit. The mean field can be obtained by a linear superposition of the wake deficit field and the incident wind flow.

Below is an explanation of how this theory has been adapted for use within WindFarmer. An illustration of the wake profile used in the Eddy Viscosity model is shown in the figure below.



Wake profile used in the Eddy Viscosity model

4.2.1 Model equations

The Navier-Stokes equations with Reynolds stresses and the viscous terms dropped gives [4.6]:

$$\mathrm{U}\frac{\partial \mathrm{U}}{\partial \mathrm{x}} + \mathrm{V}\frac{\partial \mathrm{U}}{\partial r} = \frac{-1}{r}\frac{\partial (r\overline{uv})}{\partial r} \qquad \{4.2.1\}$$

The turbulent viscosity concept is used to describe the shear stresses with an eddy viscosity defined by [4.7]:

$$\varepsilon(\mathrm{x}) = \mathrm{L_m}(\mathrm{x}).\mathrm{U_m}(\mathrm{x}) \qquad \{4.2.2\}$$

and $$-\overline{\mathrm{uv}} = \varepsilon\frac{\partial U}{\partial r} \qquad \{4.2.3\}$$

L_m and U_m are suitable length and velocity scales of the turbulence as a function of the downstream distance x but independent of r. The length scale is taken as proportional to the wake width B_w and the velocity scale is proportional to the difference $U_i - U_c$ across the shear layer.

Equation {4.2.3} permits the shear stress terms $\overline{uv}$ to be expressed in terms of the eddy viscosity. The governing differential equation to be solved becomes:

$$U\frac{\partial U}{\partial x}+V\frac{\partial U}{\partial r}=\frac{\varepsilon}{r}\frac{\partial(r\partial U/\partial r)}{\partial r} \qquad \{4.2.4\}$$

The ambient wind flow for a wind farm must be considered as turbulent. Therefore, the eddy viscosity in the wake cannot be wholly described by the shear contribution alone but an ambient term is included. Hence the overall eddy viscosity is given by [4.8]:

$$\varepsilon = \mathrm{F}\mathrm{K}_1\mathrm{B}_\mathrm{w}(\mathrm{U}_\mathrm{i}-\mathrm{U}_\mathrm{c})+\varepsilon_\mathrm{amb} \qquad \{4.2.5\}$$

where the filter function F is a factor applied for near wake conditions. This filter can be introduced to allow for the build up of turbulence on wake mixing. The dimensionless constant K_1 is a constant value over the whole flow field.

The ambient eddy viscosity term is calculated by the following equation proposed by Ainslie [4.8]:

$$\varepsilon_{amb} = F\cdot {K_k}^2\cdot I_{amb}/100 \qquad \{4.2.6\}$$

K_k is the von Karman constant with a value of 0.4. As a result of comparisons between the model and measurements reported by Taylor in [4.9] the filter function F is fixed at unity.

4.2.2 Initialisation of the model

The centre line velocity deficit D_{mi} can be calculated at the start of the wake model (two diameters downstream) using the following empirical equation proposed by Ainslie [4.8]:

$$\mathrm{D}_\mathrm{mi} = 1-\frac{U_c}{U_i} = \mathrm{C}_\mathrm{t} - 0.05 - \left[(16\mathrm{C}_\mathrm{t}-0.5)\mathrm{I}_\mathrm{amb}/1000\right] \qquad \{4.2.7\}$$

Assuming a Gaussian wind speed profile and momentum conservation, an expression for the wake width is obtained.

$$\mathrm{B}_\mathrm{w} = \sqrt{\frac{3.56\mathrm{C}_\mathrm{t}}{8\mathrm{D}_\mathrm{m}(1-0.5\mathrm{D}_\mathrm{m})}} \qquad \{4.2.8\}$$

The wake width B_w used is defined as 1.89 times the half-width of the Gaussian profile.

Using the above equations, the average eddy viscosity at a distance 2D downstream of the turbine can be calculated.

4.2.3 Wake development

The wake development is calculated by applying a parabolic solution to the RANS equations (equation 4.2.4) starting from the most upstream turbine.

For each downstream turbine that falls inside the wake, the incident wind speed needs to be calculated. The velocity profile across the turbine affected by wake is calculated by assuming a Gaussian profile based on the centre line velocity at that distance downstream. If some of the rotor is outside the wake then the wind speed for that portion of the rotor is set as the incident wind speed of the turbine creating the wake. The velocity profile across the turbine rotor at hub height is integrated to produce a mean wind speed incident across the rotor at the height. This is assumed to represent the incident wind speed across the whole rotor disc.

When multiple turbine types are present, any differences in hub height and rotor diameter are taken into consideration.

4.3 Turbulence intensity

The Eddy Viscosity model relies on a value of incident ambient turbulence intensity for equations 4.2.6 and 4.2.7. For a turbine in the free wind stream, the calculation must be initiated using the ambient turbulence level. For a turbine within a wind farm, it is necessary to calculate the increased turbulence level that results from the presence of upstream turbines.

Wind farm turbulence levels are calculated using an empirical characterisation developed by Quarton and Ainslie [4.11]. This characterisation enables the added turbulence in the wake (I_{add}) to be defined as a function of ambient turbulence (I_{amb}), the turbine thrust coefficient (C_t), the distance downstream from the rotor plane (x) and the length of the near wake:

$$I_{add} = 4.8 C_t^{0.7} I_{amb}^{0.68} \left(x/x_n \right)^{-0.57} \qquad \{4.3.1\}$$

where x_n is the calculated length of the near wake using the method proposed in [4.12, 4.13].

The characterisation was subsequently amended slightly to improve the prediction, as shown below [4.14]:

$$I_{add} = 5.7 C_t^{0.7} I_{amb}^{0.68} \left(x/x_n \right)^{-0.96} \qquad \{4.3.2\}$$

Using the value of added turbulence and the incident ambient turbulence, the turbulence intensity at any turbine position in the wake can be calculated. The model also accounts for the turbine not being completely in the wake.

The ambient turbulence intensity is best derived from measurements. Alternatively WindFarmer can predict the turbulence intensity at the turbine hub height (h) from an input surface roughness length (z_0) which is representative of the site, using [4.6]:

$$I_{amb} = \frac{1}{\ln\left(h/z_0 \right)} \qquad \{4.3.3\}$$

The turbulence intensity is defined here as the quotient of standard deviation and mean wind speed at high wind speeds.

4.4 Eddy Viscosity wake model for closely spaced turbines

It is known that where turbines are closely spaced within a row, the wake losses of subsequent downwind turbines are significantly under-predicted by industry standard wake models, including the Modified PARK and standard Eddy Viscosity models in WindFarmer. This under-prediction occurs when the within-row turbine spacing is around 2D or less and where the turbines are placed in rows perpendicular to the prevailing wind directions. This type of layout is usually only chosen where there is a uni- or bi- directional wind regime.

Garrad Hassan have developed a modification of the Eddy Viscosity model specifically for turbine arrays with these characteristics, which has been validated using data from several wind farms [4.15]. For closely spaced turbines, the following alterations are made to the Eddy Viscosity model:

- The velocity deficit is allowed to add up cumulatively
- The added turbulence is reduced in the wake
- The Gaussian profile is replaced by a blunter profile

If the within-row spacing is greater than approximately 2D, then the modified model will give the same results as the standard Eddy Viscosity model.

Please note, if the closely-spaced wake model is used, the turbine array in question must be similar to that described above for it to fall within the realms of validity of the model. The validation for this model has been undertaken using very specific uni- and bi-directional wind regimes.

4.5 Correction for large wind farms

The modelling of wind farms is traditionally a two-step process. In the first step the ambient wind flow without the presence of a wind farm is established. The wind turbines are placed within this wind flow in the second step. The ambient wind flow is assumed to be independent from the wakes generated by the wind turbines.

It is well-recognised that wind turbines do not only react passively to the wind regime, but at the same time they are part of it [4.18-4.21]. Qualitatively, the wind farm can be thought of an area of higher roughness. It is considered that modern wind farm developments do not affect weather systems significantly. However, locally, the boundary layer profile is disturbed by the extraction of momentum by the wind turbines. In particular, offshore wind farms cause a more pronounced local effect similar to an onshore forest, due to the lower roughness offshore. Onshore the effect of a large wind farm is less pronounced and to some degree masked by the higher roughness of the local terrain.

A large wind farm correction has been developed by Garrad Hassan [4.22] and [4.23], based on modelling the disturbance caused by each individual turbine. This allows numerous wind farm layouts to be considered during the design phase of a wind farm layout. The model approach can be described in three steps:

1. Use the wind flow model and data of choice that best describe the ambient wind flow over the proposed wind farm site.
2. Place the turbines in the wind flow and calculate the large wind farm correction to the ambient flow due to the presence of the turbines.
3. Use a standard wake model with the corrected ambient wind speeds as boundary conditions to describe the inter-turbine wake deficits.

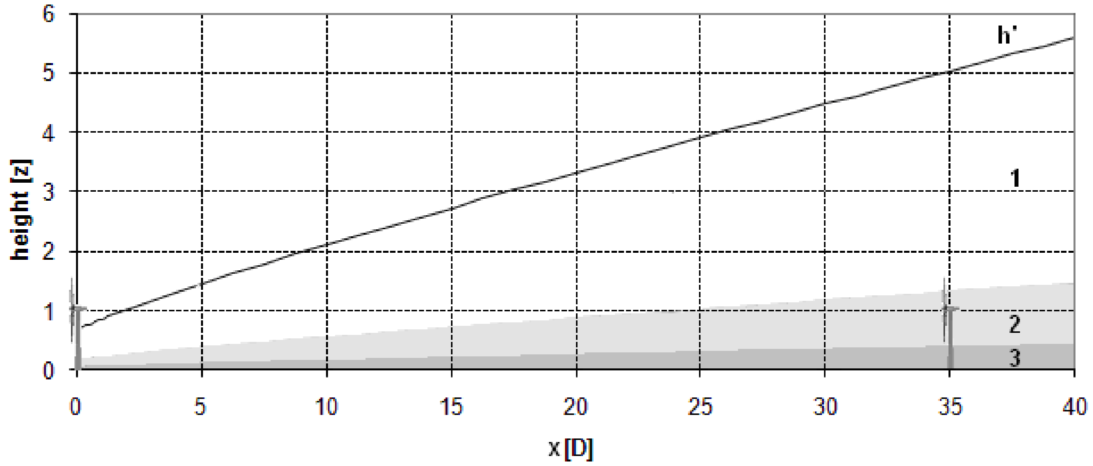
The second step above details an empirical correction to describe the disturbance of the atmospheric flow caused by the wind farm. This breaks with the traditional assumption that the wind flow can be treated as independent from the wind farm. The large wind farm correction consists of the following components:

- Boundary layer modification – establishes the magnitude of correction to the ambient wind profile downwind of each individual turbine
- Wind turbine density – considers relative turbine positions and decides if a correction should be applied in a particular direction sector
- Row-to-row distance – the correction is applied only if adjacent lines of turbines are closer than a threshold
- Downstream recovery – from a certain distance downstream, the wind speed recovers to ambient levels and no correction is applied.

The component models are presented in the following sections.

4.5.1 Boundary layer modification

Momentum is continuously generated on top of the boundary layer and is transferred downward to the ground surface in a dynamic equilibrium. Wind turbines that take out some of this momentum are part of the dynamic equilibrium similar to trees or other roughness elements. However as the impact of the wind turbines on the boundary layer profile is not yet well researched, we take some guidance from forest canopy and roughness change models.



Internal boundary layer (IBL) development after disturbance caused by the first turbine, with Zones 1, 2 and 3 marked. The ambient wind speed for the downstream turbines is reduced.

An internal boundary layer (IBL) develops from each turbine location. The height (h) of the IBL for a roughness change, as a function of the fetch (x) and (z'_0), the larger of the two roughness values (z_{01}) and (z_{02}), can be determined from

$$\frac{h}{z_0^{'}}\left(\ln\frac{h}{z_0^{'}}-1\right)=0.9\frac{x}{z_0^{'}} \qquad \{4.5.1\}$$

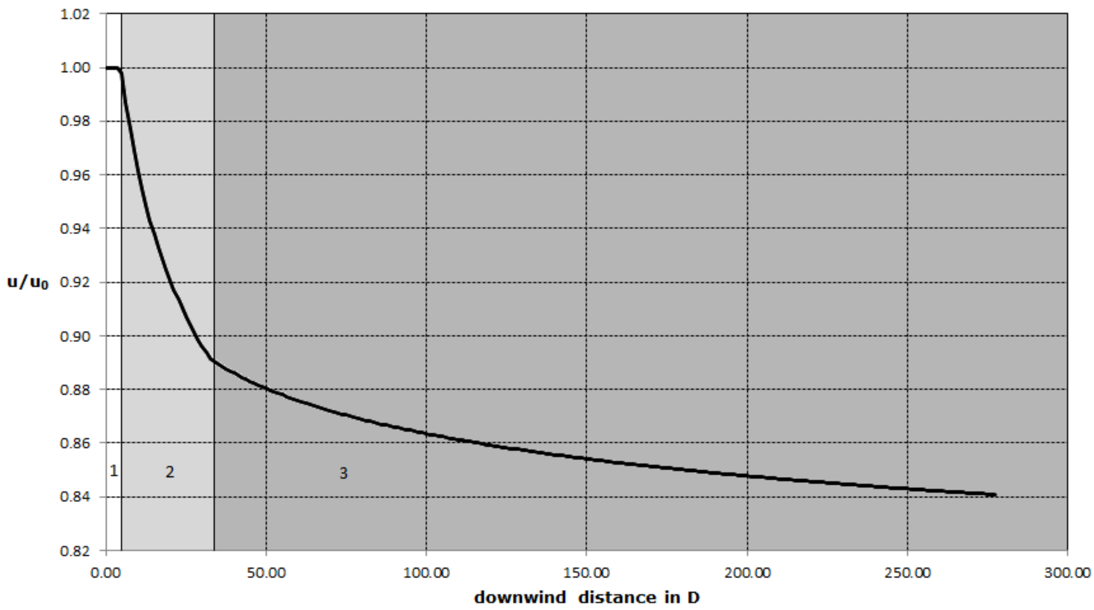
To take into account that the momentum is not extracted at ground level, an offset of 2/3 hub height (z) is used leading to a new height (h'). The disturbance to the ambient wind speed (u_1) is injected in the flow over an area with the dimension of the upstream turbine rotor. This spatial dependency is considered in the model by introducing a vertical offset to z resulting in a new height z'. The wind speed (u) is then expressed as:

$$u(z)=\begin{cases} u_1(z) \quad for\ z'\geq 0.3h' \\ \dfrac{u_1(z)}{ln\left(\dfrac{z'}{z_{01}}\right)}\left[\dfrac{ln\left(\dfrac{h'}{z_{01}}\right)}{ln\left(\dfrac{h'}{z_{02}}\right)}\cdot ln\left(\dfrac{0.09h'}{z_{02}}\right)\left\{1-\dfrac{ln\left(\dfrac{z'}{0.09h'}\right)}{ln\left(\dfrac{0.3}{0.09}\right)}\right\}+ln\left(\dfrac{0.3h'}{z_{01}}\right)\cdot\dfrac{ln\left(\dfrac{z'}{0.09h'}\right)}{ln\left(\dfrac{0.3}{0.09}\right)}\right] \quad for\ 0.09h'<z'<0.3h' \\ u_1(z)\left[ln\left(\dfrac{h'}{z_{01}}\right)\cdot ln\left(\dfrac{z'}{z_{02}}\right)\right]\Big/\left[ln\left(\dfrac{h'}{z_{02}}\right)\cdot ln\left(\dfrac{z'}{z_{01}}\right)\right] \quad for\ z'\leq 0.09h' \end{cases}$$

{4.5.2}

In the upper part of the IBL (Zone 1) the free wind speed is unchanged compared to the upstream conditions. In the lower part (Zone 3) the free wind speed changes according to roughness length z_{02} and the downwind distance from the roughness change. In Zone 2 the free wind speed is interpolated between the lower and the upper section.

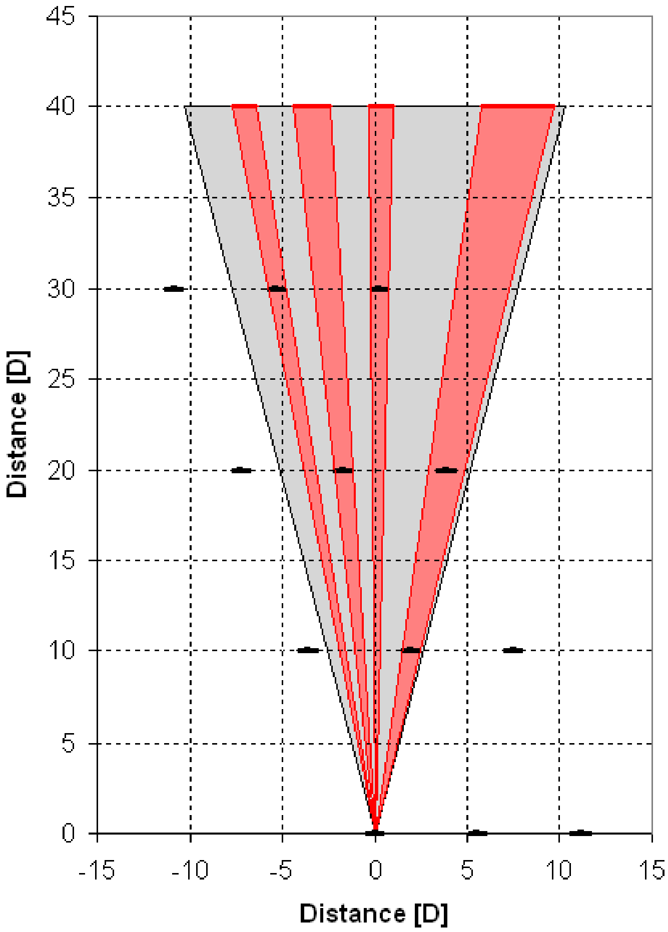
The resulting free wind speed is shown below for a turbine downstream of another turbine of the same hub height and rotor diameter, where the large wind farm criteria apply.



Reduced free wind speed for a turbine downwind of a turbine causing the large wind farm effect. The shading marks the zone of the IBL where the lower blade tip of the downstream turbine is located.

4.5.2 Wind Turbine Density

The momentum extracted per given area increases with the number of wind turbines in that area. Changing the area roughness to achieve this is an option, but it is impractical for wind farm design purposes, as the distribution of wind turbines may be irregular and is subject to iterative change and no fixed relationship with roughness can be established. Instead, a geometric measure of turbine density is used.



Geometric model to consider the turbine density for a 30 degree sector. The large wind farm correction to ambient wind speed is applied for wind arriving from the red sectors.

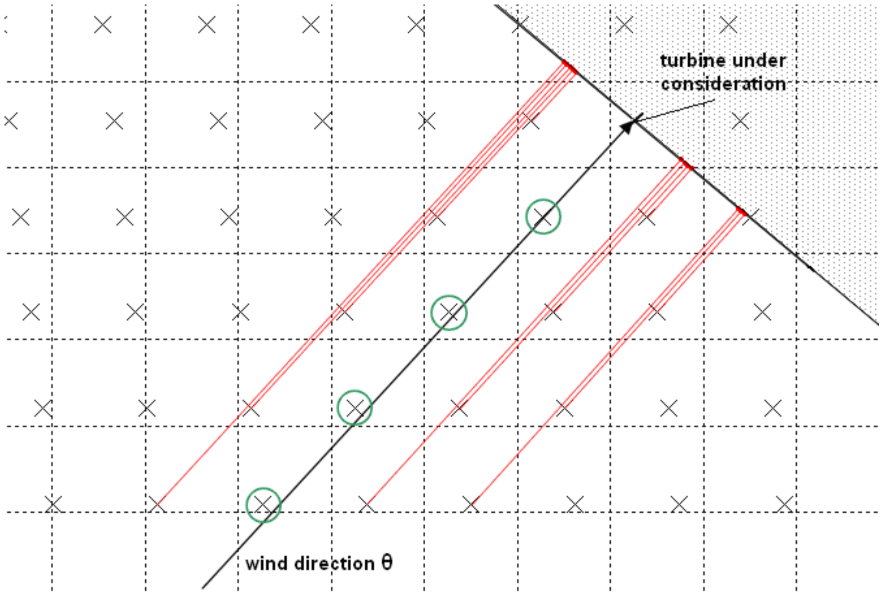
For each small direction sector, the horizon is scanned from the target turbine and the presence of upstream turbines is detected. The ambient wind speed correction is applied if and only if one or more turbines are present in the sector.

The consequences of the geometric model are that the overall magnitude of the correction is reduced with distance from turbines due to a smaller aspect ratio; and increased at a fixed distance with increased turbine density due to more turbines contributing.

The geometric model considers how much of the horizon is filled with turbines. Wake expansion is not considered in this step, since the model is to be used in conjunction with standard wake models that already consider the effect of wake expansion and consequential wake recovery.

4.5.3 Wind blows along wind farm geometry axis

When the wind direction is such that it blows along the turbine rows, and the cross-wind spacing between the rows is more than a given number of turbine diameters, then the wind turbine wakes in each row are considered to develop independently of other rows. Experimental evidence suggests that no large wind farm correction should be applied for this narrow wind direction sector.



The crosswind distance is determined by projecting upstream turbines onto a plane perpendicular to the flow direction.

4.5.4 Downstream recovery

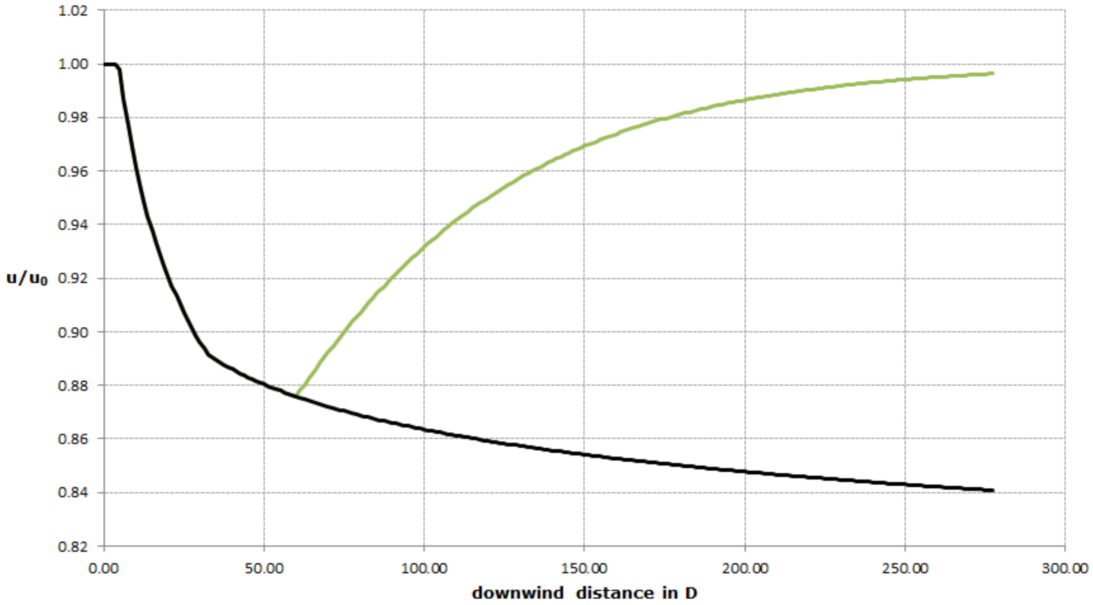
The disturbance of the wind profile caused by a wind turbine is expected to subside after a certain distance. Investigation is ongoing to establish details of the processes and relevant scales. However as an initial approximation, this recovery can be modelled as exponential.

The recovery is calculated using

$$u_r = u_1\left(1-\left(1-\frac{u}{u_1}\right)*0.5^{\frac{x-x_{start}}{x_{50\%}}}\right) \qquad \{4.5.3\}$$

where

x_{start} start distance for the recovery function
$x_{50\%}$ distance from the start distance, where the large wind farm wind speed correction has reduced to 50%



Reduced ambient wind speed (black line) with exponential recovery to ambient level (green line).

4.5.5 Model application

For every direction step the model checks if there are upstream turbines causing a wake, as given in section 4.5.2. If this is the case, the distance to the neighbouring rows is checked, as described in section 4.5.3. If the row distance is less than the maximum row spacing value where wakes develop independently from the neighbouring rows, then the correction of the free wind speed is applied. For all upstream turbines the free wind speed is reduced with downwind distance as given in sections 4.5.1 and 4.5.4 up to the distance of the individual downwind turbines. The resulting free wind speed at the downwind target turbine is then the lowest free wind speed caused by one of the upstream turbines.

The wake effect is then calculated in the usual manner, using the corrected free wind speed at the individual downwind turbines.

4.5.6 Model parameters

The parameters in the calculation are

- Base roughness that represents the surface without wind turbines. The default value for the Base roughness is 0.0002 m (offshore). For onshore applications, a single value of Base roughness, representative of the site and surrounding area is appropriate.
- Increased roughness representing the effect of the wind turbines. An increase from the Base roughness between 0.02 and 0.03 m has been found to provide a good match. A higher value of 0.05 m can be used, when looking at specific wind speed cases with deep wakes. The default setting for the increased roughness is 0.03 m.
- Geometric width: this parameter determines the sector for which an upstream turbine has an affect on the downwind turbines. The default setting is 1 turbine diameter.
- Maximum row spacing. This parameter is used to detect situations when the wind blows along a row of turbines, when the offshore deep array effect is not visible in the wind farm data. The row spacing represents the distance to the next row of turbines in the projection plane perpendicular to the wind direction. If this distance is greater than the maximum row spacing, the correction is not applied. The default value is 5 turbine diameters.
- Start and 50% deficit distance parameters for recovery. It is expected that the total disturbance declines as the distance behind the wind turbine increases. An exponential recovery to the unaffected free stream conditions is assumed behind the recovery start distance. The defaults are 60 and 40 diameters respectively.

Considerable caution is required with regard to the application of the large wind farm correction. The model has not yet been validated against a substantial number of wind farms. As soon as operational data from additional wind farms become available, an update of the model is likely; therefore, the current model results may be subject to change as the model is refined further.

4.6 Terrain modification of the wake and turbulence

The wind flow around a wind turbine, including the wake, will be accelerated when passing over terrain. This acceleration is calculated by the wind flow model and affects both mean wind speeds and turbulence. WindFarmer allows optional consideration of this effect on the mean wind speed (incident on the next turbine) by scaling the wake deficit with the terrain speed-up derived from the flow model.

Using the assumption that the standard deviation stays constant while the mean wind speed is modified over the terrain, WindFarmer also varies the turbulence intensity over a given terrain. Three-dimensional modifications of the turbulence and terrain-induced modifications of the turbulence spectrum are neglected.

5 LAYOUT OPTIMISATION

5.1 Automatic elliptical minimum turbine separation

In addition to using a manually defined elliptical exclusion zone around the turbines, automatically generated elliptical zones may be used in WindFarmer.

The automatic ellipse is defined by three parameters:

- length of the long axis, in rotor diameters
- direction of long axis
- minimum separation distance (short axis), in rotor diameters

During wind farm design, the long axis of the ellipse is often aligned with the main wind direction in order to minimise both losses due to wake effects and loads on downwind turbines. Once the user has defined the minimum separation distance, the other two parameters are optionally set automatically by WindFarmer.

First the energy density for each direction sector and its opposite sector are calculated based on the wind speed probability distribution and the turbine power curve. The direction with the highest energy density is then designated as the direction of the long axis of the elliptical exclusion zone.

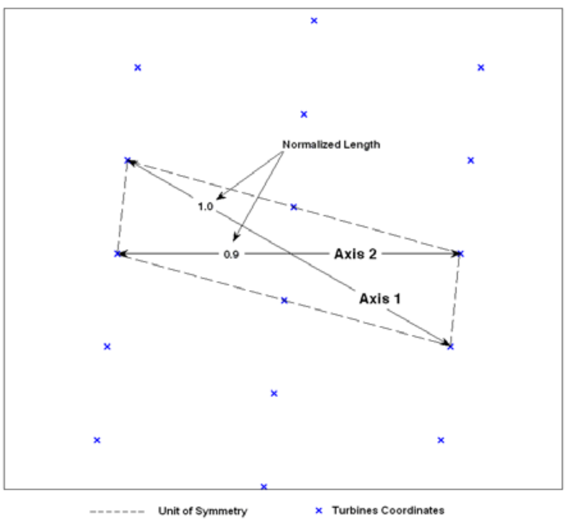
In the second step, the ratio of the major and minor axis lengths is derived by fitting an ellipse based on the energy densities from all the sectors.

5.2 Optimisation of symmetrical layouts

For wind farm sites with low spatial variation in wind resource, symmetrical wind farm layouts may offer solutions to minimise infrastructure costs at the price of acceptable performance loss.

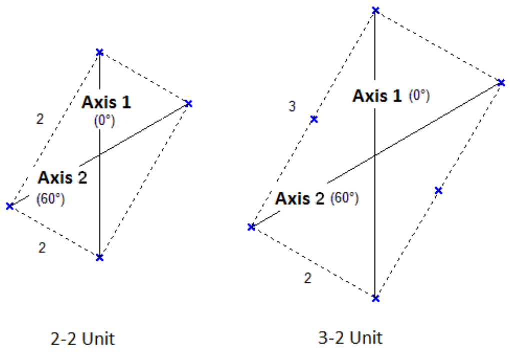
The symmetry used in the layout optimisation is based on geometric units that are aligned in two principal wind directions, which need not be orthogonal. The two principal axes are determined from the energy density calculated for each wind direction sector. This is based on the long term distribution of wind speeds and directions at a site mast, combined with the turbine power curve. The two principal axes then point towards the two direction sectors with the highest energy density.

The relative turbine spacing along the principal axes of a unit is determined by the weight of their relative corresponding energy densities. The principal axes and the corresponding weights define the basic shape of the symmetry unit, as shown below.



Basic shape of the symmetry unit

A symmetry unit can consist of either 4 turbines with 1 turbine at each corner of the unit ”2-2“ ,or of 6 turbines with two additional turbines at the centre of the longer sides of the unit “3-2”. In the end, the whole layout is composed of such repetitive units. The two unit types are shown below.



"2-2" and "3-2" unit types

A 2-2 unit has fewer turbines per unit and therefore the units need to be smaller (with shorter diagonal spacing in direction of the priority planes) to accommodate a certain number of turbines. In comparison a 3-2 unit contains more turbines per unit and they can afford to be larger (with longer diagonal spacing). On the other hand, a 3-2 unit has less angular freedom than a 2-2 unit because there are turbines at the midpoints of the longer sides of the unit, which means a certain deviation of the wind direction can cause these middle turbines to be in the wakes of the upwind turbine in the unit.

During the optimisation process, the units are expanded or compressed uniformly in order to place the number of turbines desired inside a specific area. This is accomplished by scaling the lengths of the axes whilst the aspect ratio of the unit remains the same. Additionally, variations of the layout are considered by rotation and counter-rotation of both principal units.

The symmetric layout optimisation uses a deterministic algorithm where a discrete number of cases are investigated and the layout with the maximum energy yield selected. With this approach, the global maximum may well be missed; however the automatic analysis that is carried out allows a symmetrical layout with competitive high energy yield to be generated very quickly.

Other constraints such as exclusion zones, noise limits at nearby houses and turbine visibility can be considered. Some results from the symmetric optimiser are presented in [5.1]

6 ESTIMATIONS OF DESIGN TURBULENCE

6.1 Introduction

From the definition of the mean wind speed, turbulence is defined as all wind fluctuations with periods less than the averaging period. One common measure of turbulence is the turbulence intensity - defined as:

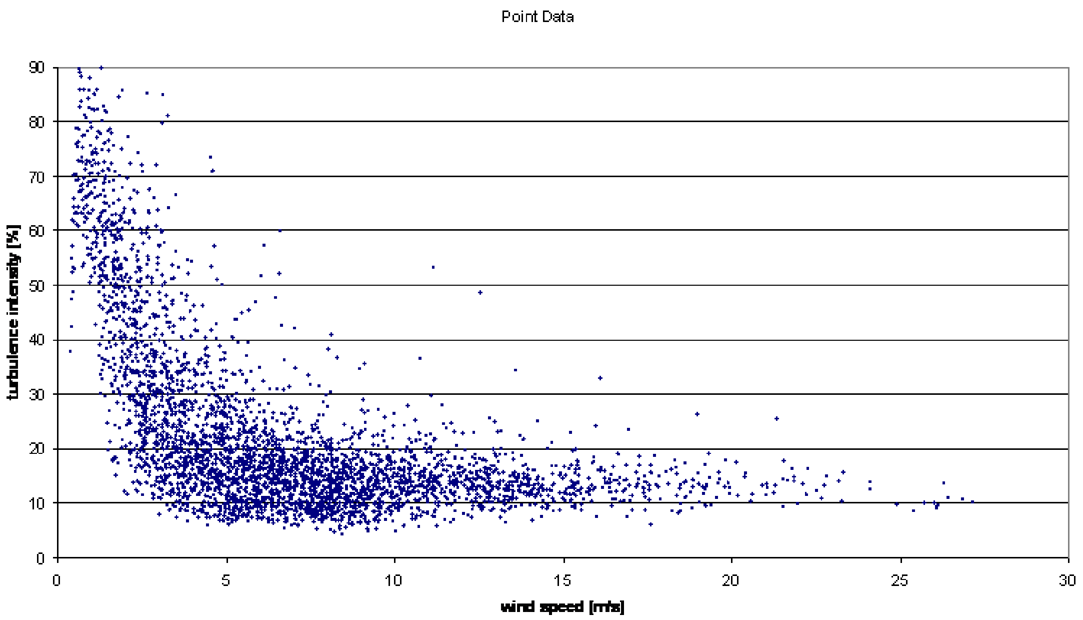
$$I = \frac{\sigma_v}{\bar{v}} \qquad \{6.1.1\}$$

where

σ_v standard deviation of wind speed v in the averaging period
$\bar{v}$ mean wind speed in the averaging period

The same notation is used here as in the relevant IEC Standards [6.1, 6.2]. Both values must be determined from the same set of measured data samples of wind speed. The typical averaging period is 10 min.

When a set of turbulence intensity measurements is taken over a period, it is possible to plot all the single values of turbulence intensity as a function of the single measured mean wind speeds $\bar{v}$. The plot may look like this:



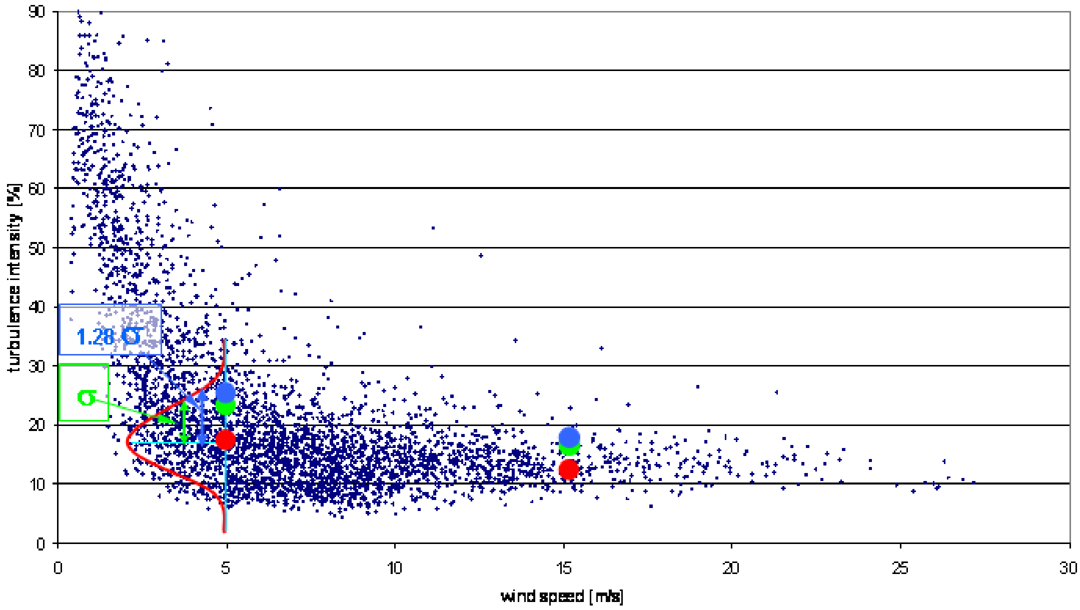
Measured turbulence intensities as a function of the mean wind speed over the averaging period

For every wind speed bin, a mean turbulence intensity is calculated from the single values. With regard to turbine loads, single turbulence intensities greater than the mean value are more relevant. To analyse these, it is assumed that all the single values within a wind speed bin have a normal distribution, with a mean value and a standard deviation that can be calculated from the sample data in the specific bin. In terms of turbine loads, specific quantiles of the turbulence intensity distribution are used, depending on the definition in the design standards.

Values used in the standards are:

- Characteristic value: mean turbulence intensity plus one standard deviation. This represents the 84% quantile of a normal distribution, which means that 84% of the data are smaller than, or equal to, the characteristic value.
- Representative value: mean turbulence intensity plus 1.28 times the standard deviation. This is the 90% quantile of a normal distribution, which means that 90% of the data are smaller than, or equal to, the representative value.

The Mean, Characteristic and Representative turbulence intensities are marked in the figure below, for specific wind speed bins.



Mean (red), Characteristic (green) and Representative (blue) turbulence intensities of turbulence measurements

6.2 Design Standards

The assessment of structural integrity of wind turbines is done via comparison of the site-specific wind parameters at the wind turbine site with those used for the design. There are different design standards that define the wind conditions a wind turbine shall be designed to withstand, in different ways.

Using WindFarmer, design turbulence estimates can be produced with respect to the following design standards

- IEC 61400-1:1998 (Edition 2)
- IEC 61400-1:2005 (Edition 3)
- IEC 61400-1:2005/A1:2010
- DIBt

The design turbulence definitions in these standards and the methods used in WindFarmer to calculate the site specific design turbulence, are given in the following sections.

For calculation of design turbulence estimates, turbulence intensity values measured at the site masts are input in the Turbulence Intensity tab in the Project Properties window. It is important not to input Characteristic or Representative turbulence values here. Values for the standard deviation of wind speed standard deviation, known as “sigma-sigma”, can be calculated with the MCP$^+$ Module of WindFarmer when time series of wind speed and wind speed standard deviation data are available.

The calculations by WindFarmer of Effective turbulence estimates are designed for use with the Modified PARK wake model.

The turbulence intensity outputs from the Eddy Viscosity wake model of WindFarmer are true meteorological turbulences. They should not be compared directly with the IEC or DIBt turbulence models but it is recommended that they are used in conjunction with the WindFarmer Bladed Link and GH Bladed software tools to obtain the most accurate description of the design loads.

6.2.1 IEC 61400-1, Edition 2

In this Standard [6.2] the design turbulence is defined as a **"Characteristic"** value.

The maximum allowed Characteristic turbulence is defined according to the turbine class. The Characteristic turbulence and the longitudinal wind velocity standard deviation σ_1 are linked through the following formula:

$$\sigma_1(v_{hub}) = I_{15}(15 + a \cdot v_{hub})/(a+1) \qquad \{6.2.1\}$$

where

- σ_1 is in this case called the Characteristic value of the standard deviation of the longitudinal wind speed component
- I_{15} is the characteristic value of the turbulence intensity at 15m/s
- a is the slope parameter
- v_{hub} is the wind speed at hub height in m/s

The parameters I_{15} and a are specified in the standard according to the turbulence level of the turbine class. For low turbulence (I_{15}, a) = (0.16, 3) and for high turbulence (I_{15}, a) = (0.18, 2).

The standard does not state how wake effects at the site may be taken into account in the calculation of the site specific characteristic turbulence. One method how to do this is published in [6.3], whereby the wake effects from neighbouring turbines are taken into account by an **Effective** turbulence. The Effective standard deviation is defined as

$$\sigma_{eff}(v_{hub,i}) = \left(\sum_j P_{i,j} \cdot \sigma_{eff\,i,j}^{\,m} \right)^{1/m} \qquad \{6.2.2\}$$

where

- $P_{j,j}$ is the probability of the wind speed bin i and the wind direction bin j. In WindFarmer the predicted turbine-specific probability is used.
- m is the Wöhler coefficient representative for the turbine and component receiving turbulence.

The Wöhler coefficient is specific to component material and geometry and is derived from the slope of the log-log plot of the S-N curve (magnitude of a cyclical stress (S) against the cycles to failure (N)), where the relation $S \propto N^{-1/m}$ is assumed. Typical values for wind turbines range between 3 and 15 where 4 is appropriate for simple steel components and values 10 to 15 are suitable for simple composite components. The turbine manufacturer should be consulted for advice on an acceptable range of Wöhler indices for these calculations.

The estimate of a site specific effective turbulence can be expressed following [6.3] as:

$$\sigma_{eff\,i,j} = \sqrt{\frac{v_{hub,i}^2}{(1.5 + 0.3 \cdot d_j \cdot \sqrt{v_{hub,i}})^2} + \sigma_{char\,i,j}^{\,2}} \qquad \{6.2.3\}$$

where

d_j is the distance to the neighbouring turbine that causes the wake in direction bin j normalised by the rotor diameter of the turbine causing the wake.

$\sigma_{char\ i,j}$ is the characteristic ambient wind speed standard deviation in wind direction bin j and wind speed bin i

As an option the actual thrust coefficient can be used instead of the approximation given above. In equation 6.2.3 v_{hub} is then replaced by 7/ct.

For wind directions where there are no upstream turbines or turbine distances greater than 10 rotor diameters $\sigma_{eff\ i,j} = \sigma_{char\ i,j}$.

With these definitions $\sigma_{eff}(v_{hub,\,i})$ represents the Characteristic value of the wind speed standard deviation.

The estimate of the Effective turbulence I_{eff} is calculated in WindFarmer for all wind speeds and directions and is available as output in the Flow and Performance Matrix.

The characteristic wind speed standard deviation is defined as

$$\sigma_{char\,i,j} = \overline{\sigma}_{i,j} + \sigma_{\sigma\,i,j} \qquad \{6.2.4\}$$

where

$\overline{\sigma}_{i,j}$ is the mean of wind speed standard deviation in wind direction bin j and wind speed bin i

$\sigma_{\sigma\,i,j}$ is the standard deviation of wind speed standard deviation in wind direction bin j and wind speed bin i (“sigma-sigma”)

If $\sigma_{\sigma\,i,j}$ is not available from measurements it can be assumed [6.3] that it is 20% of the mean wind speed standard deviation, so that

$$\sigma_{char\,i,j} = 1.2 \cdot \overline{\sigma}_{i,j}$$

The corresponding estimate of the Characteristic turbulence intensity $\dfrac{\sigma_{eff}\left(v_{hub,i}\right)}{v_{hub,i}}$ as a function of wind speed is available in the Flow and Performance Matrix of WindFarmer.

To get a measure of the suitability of a wind turbine for the site, the wind turbine should satisfy the condition that the estimated Characteristic value of the turbulence standard deviation σ_1 (Equation 6.2.1) shall be greater than or equal to σ_{eff} at hub height wind speeds v_{hub} within the operational range of the turbine.

6.2.2 IEC 61400-1, Edition 3

In this Standard [6.1] the design turbulence is defined as a **“Representative”** value.

The maximum allowed turbulence is defined according to the turbine class. The expected value of the hub height turbulence intensity at a 10-min average wind speed of 15m/s and the turbulence standard deviation σ_1 are linked through the following formula:

$$\sigma_1\left(v_{hub}\right) = I_{ref}\left(0.75 \cdot v_{hub} + b\right) \qquad \{6.2.5\}$$

where

σ_1 is in this case called the representative value of the standard deviation of the longitudinal wind speed component
I_{ref} is the mean value of the turbulence intensity at 15 m/s
b 5.6 m/s
v_{hub} is the wind speed at hub height in m/s

The parameter I_{ref} is specified in the standard according to the turbulence level of the turbine class. For low turbulence I_{ref} is 0.12, for medium turbulence it is 0.14 and for high turbulence 0.16.

The wake effects from neighbouring turbines can be taken into account by an effective turbulence which, according to the standard, may be derived using a Frandsen method. The Effective turbulence estimate is defined as

$$\sigma_{eff}(v_{hub,i}) = \left(\sum_j P_{i,j} \cdot \sigma_{eff\,i,j}^{\;m} \right)^{1/m} \qquad \{6.2.6\}$$

where

P_j is the probability of the wind speed bin i and the wind direction bin j. In WindFarmer the predicted turbine- specific probability is used.
m is the Wöhler coefficient.

The Wöhler exponent is specific to component material and geometry and is derived from the slope of the log-log plot of the S-N curve (magnitude of a cyclical stress (S) against the cycles to failure (N)), where the relation $S \propto N^{-1/m}$ is assumed. Typical values for wind turbines range between 3 and 15 where 4 is appropriate for simple steel components and values 10 to 15 are suitable for simple composite components. The turbine manufacturer should be consulted for advice on an acceptable range of Wöhler indices for these calculations.

Within WindFarmer, the site-specific Effective turbulence estimate derived from the Frandsen method is expressed as:

$$\sigma_{eff\,i,j} = \sqrt{\frac{0.9 \cdot v_{hub,i}^2}{(1.5 + 0.3 \cdot d_j \cdot \sqrt{v_{hub,i}})^2} + \overline{\sigma}_{i,j}^2} \qquad \{6.2.7\}$$

where

d_j is the distance to the neighbouring turbine that causes the wake in direction bin j normalised by the rotor diameter of the turbine causing the wake
$\overline{\sigma}_{i,j}$ is the mean ambient wind speed standard deviation in wind direction bin j and wind speed bin i

WindFarmer provides an option to use the actual thrust coefficient instead of the approximation used in the standard. In equation 6.2.7 v_{hub} in the denominator is then replaced by 7/ct.
For wind directions without upstream turbines or turbine distances greater than 10 rotor diameters $\sigma_{eff\,i,j} = \overline{\sigma}_{i,j}$.

The estimate of the Effective turbulence intensity I_{eff} is calculated in WindFarmer for all wind speeds and directions and is available in the Flow and Performance Matrix.

The representative value of wind speed standard deviation σ_{rep} is defined as the 90% quantile of the turbulence standard deviation

$$\sigma_{rep_i} = \sigma_{eff}(v_{hub,i}) + 1.28\sigma_{\sigma\,i} \qquad \{6.2.8\}$$

where

$\sigma_{\sigma i}$ is the standard deviation of wind speed standard deviation in wind speed bin i, given as a mean over all wind directions

If $\sigma_{\sigma i}$ is not available from measurements, it can be assumed that it is 20% of the mean wind speed standard deviation [6.2], so that

$$\sigma_{rep_i} = \sigma_{eff}(v_{hub,i}) + 0.256\overline{\sigma}_i \qquad \{6.2.9\}$$

where

$\overline{\sigma}_i$ is the mean of standard deviation of ambient wind speed in wind speed bin i, given as a mean over all wind directions

The corresponding Representative turbulence intensity $\frac{\sigma_{rep_i}}{v_{hub,i}}$ is available in the Flow and Performance Matrix of WindFarmer.

To get a measure of the suitability of a wind turbine for the site, a wind turbine should satisfy the condition that the estimate of the representative value of the turbulence standard deviation σ_1 (Equation 6.2.5) shall be greater than or equal to σ_{rep} at hub height wind speeds v_{hub} between 0.2 v_{ref} and 0.4 v_{ref} of the turbine, with v_{ref} the reference wind speed of the turbine class defined in the standard. When the turbine properties are known, it is adequate to verify this for hub height wind speeds between 0.6 rated wind speed and cut-out wind speed.

6.2.3 IEC 61400-1, Edition 3, Amendment

The amendment to IEC 61400-1 Edition 3 [6.5] introduces the following key changes for calculating an estimate of the effective design turbulence:

The site-specific Effective turbulence estimate derived from the Frandsen method is expressed as:

$$\sigma_{eff\ i,j} = \sqrt{\frac{v_{hub,i}^2}{\left(1.5 + 0.8 \cdot \frac{d_j}{\sqrt{c_t}}\right)^2} + \sigma_{rep_{i,j}}^{\ 2}} \qquad \{6.2.10\}$$

where

d_j is the distance to the neighbouring turbine that causes the wake in direction bin j normalised by the rotor diameter of the turbine causing the wake

$\sigma_{rep_{i,j}}$ is the representative ambient wind speed standard deviation in wind direction bin j and wind speed bin i

c_t is the turbine thrust coefficient of the upwind turbine at wind speed $v_{hub,i}$

Optionally the thrust coefficient or an approximation of the actual thrust coefficient can be used. In equation 6.2.10 ct is then replaced by $7/v_{hub}$.

For wind directions without upstream turbines or turbine distances greater than 10 rotor diameters $\sigma_{rep\ i,j}$ = $\overline{\sigma}_{i,j} + 1.28\sigma_{\sigma i,j}$. Please note that this term is calculated in the amendment as part of equation 6.2.10 rather than applied afterwards.

6.2.4 DIBt

The calculation method defined in [6.3] must be read in conjunction with the DIBt Standard [6.4]. In the Standard [6.4], the design turbulence is defined as a "Characteristic" value. In general the maximum turbulence allowed, defined according to the turbine class, is equivalent to the definition in IEC 61400-1 (Edition 2). The calculation method for site specific design equivalent turbulence intensity is defined in [6.4], similar to the method used in the WindFarmer calculation according to IEC 61400-1 (Edition 2). But, contrary to the IEC 61400-1 (Edition 2) calculation, the thrust coefficient is not replaced by the approximation (7m/s)/v_{hub}, as proposed in [6.3]. The site specific effective turbulence is defined by

$$\sigma_{eff\ i,j} = \sqrt{\frac{v_{hub,i}^2}{\left(1.5 + 0.8 \cdot \frac{d_j}{\sqrt{c_t}}\right)^2} + \sigma_{char\ i,j}^{\ 2}} \qquad \{6.2.11\}$$

Where

d_j is the distance to the neighbouring turbine that causes the wake in direction bin j normalised by the bigger of the rotor diameters

c_t is the turbine thrust coefficient of the upwind turbine at wind speed $v_{hub,i}$

WindFarmer provides an option to use the actual thrust coefficient instead of the approximation used in the standard. In Equation 6.2.7 v_{hub} is then replaced by 7/ct.

The general calculation methodology is equivalent to that described for IEC 61400-1 (Edition 2).

6.3 Large wind farm turbulence correction

The ambient turbulence level increases within large wind farms. An adjustment has been suggested when the number of wind turbines from the receiving wind turbine to the 'edge' of the wind farm is more than 5, or the spacing in the rows perpendicular to the dominant wind direction is less than 3 rotor diameters [6.1].

In this case $\overline{\sigma}_{i,j}$ is replaced by $\overline{\sigma}'_{i,j}$, which is

$$\overline{\sigma}'_{i,j} = \frac{1}{2}\left(\sqrt{\sigma_w^2 + \overline{\sigma}_{i,j}^2} + \overline{\sigma}_{i,j}\right) \text{ with} \qquad \{6.3.1\}$$

$$\sigma_w = \frac{0.36 \cdot v_{hub,i}}{1 + 0.2\sqrt{\frac{d_r \cdot d_t}{c_t}}}$$

where

c_t is the turbine thrust coefficient of the upwind turbine at wind speed $v_{hub,i}$

d_r is the turbine separation within rows in rotor diameters

d_t is the turbine separation between rows in rotor diameters

The correction is applied for wind directions with a wake from an upstream turbine for IEC Edition 2, IEC Edition 3 and DIBt. WindFarmer approximates d_r, and d_t for all layouts to be the distance to the closest neighbouring turbine and the distance to the upstream turbine causing the wake.

In the calculations according to IEC Edition 3 Amendment the correction is applied for wind directions without a wake from an upstream turbine. The thrust coefficient is then that of the turbine under consideration.

WindFarmer approximates d_r, and d_t for all layouts to be the distance to the closest neighbouring turbine and the distance to the 3rd closest turbine.

If this correction is selected by the user, it is applied to all wind directions whether or not the number of wind turbines from the receiving wind turbine to the 'edge' of the wind farm is more than 5, or the spacing in the rows perpendicular to the dominant wind direction is less than 3 rotor diameters.

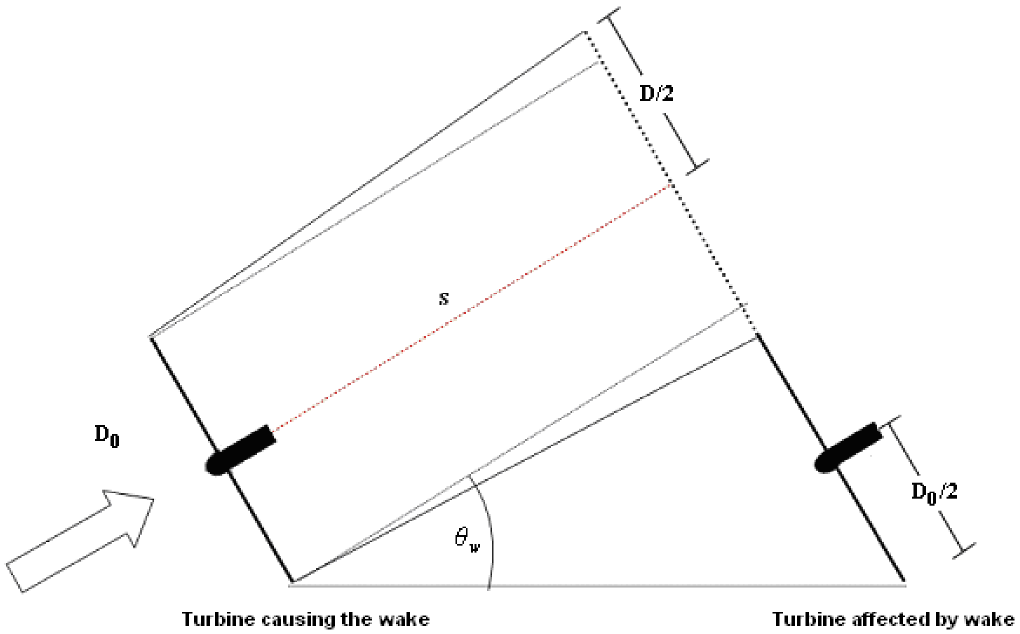
6.4 Simple and Advanced approach

The calculations models given in the Design Standards are intended for use in wind farms with a regular turbine layout. The model described in [6.3] has been derived for wind farms in simple terrain and consisting of just one turbine type. In many cases, wind turbines are not in a regular layout, they are located in complex terrain and there are also different turbine types at the wind farm. Some assumptions have been made to take this into account. On the other hand a simple approach has also been made, which is called the 'Simple Model' in WindFarmer. Differences between the Advanced and Simple models are explained below.

Depending on the circumstances either the Simple or the Advanced model may give more conservative results.

6.4.1 Direction sectors with increased turbulence

To implement the above, it is necessary to identify the wind direction sectors in which a turbine will experience increased loads due to the wakes of upstream turbines. These sectors are determined by applying the approach proposed in [6.3]. Effective turbulence is calculated using equations {6.2.3}, {6.2.7} or {6.2.10}, as soon as a part of the rotor is within the wake of an upstream turbine as represented by a view angle θ_w.



Definition of the view angle θ_w. D_0 is the rotor diameter of the turbines and D is the diameter of the wake at the downstream distance s.

The view angle can be described as

$$\theta_w = \arctan\left(\frac{1}{s} + k\right) \approx \arctan\left(\frac{1}{s}\right) + \arctan(k), \; for \; \frac{k}{s} << 1 \qquad \{6.4.1\}$$

where

s is the downstream distance in rotor diameters
k is the wake decay constant

which, following recommendations of [6.3], is derived on the basis of the linear wake expansion equations of the PARK model.

With k = 0.087, equation {6.4.1} becomes

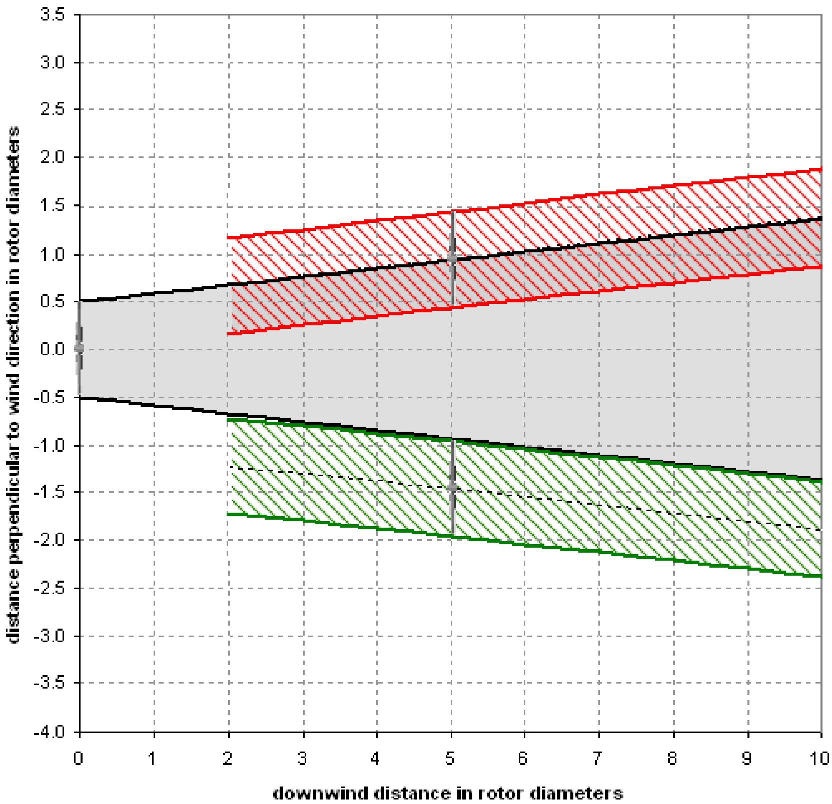
$$\theta_w = \frac{1}{2}\left(2\arctan\left(\frac{1}{s}\right) + 10^{\text{o}}\right) \qquad \{6.4.2\}$$

Also in [6.3] (equation 3.18) a 'characteristic view angle' is defined as:

$$\theta_w = \frac{1}{2}\left(\arctan\left(\frac{1}{s}\right) + 10^{\text{o}}\right) \qquad \{6.4.3\}$$

Equation {6.4.2} is used in the advanced model while equation {6.4.3} is used in the simple model.

Both definitions of the view angle comply with IEC61400-1 Ed.3 and are compared in the figure below (k = 0.087):



The area that a downstream turbine can be placed without being exposed to increased load due to the wake of an upstream turbine when using Equation {6.4.3} (red) and Equation {6.4.2} (green). The area shaded in grey represents the wake behind the upstream turbine. The bold red and green lines represent the rotor edge.

In both cases it is assumed that the wake angle is measured downstream from the rotor centre of the turbine that generates the wake. The figure illustrates the area where a downstream turbine can be placed without being exposed to increased load due to the wake of an upstream turbine. It can be seen that when using equation {6.4.3} the downstream turbines can be placed so that half the rotor is within the wake without getting any increase in load whereas when using equation {6.4.2} the load increases as soon as a part of the rotor is within the wake.

The model given by equation {6.4.3} should only be used for calculation of wake turbulence aggregated over a complete wind rose since it can produce non-conservative turbulence estimates for individual wind directions at close spacing.

6.4.2 Other model assumptions

For several upstream turbines the Simple model considers only direct wake effects i.e. the upstream turbines are never considered themselves to be in a wake. The Advanced model considers direct and indirect wake effects of all upstream turbines on all downstream turbines.

The differences in free wind speed due to the terrain are taken into account in the Advanced model while the same free wind speed at all turbine locations is assumed in the Simple model.

If a turbine thrust coefficient is used then in the Simple model it is assumed that the thrust coefficient of the turbine causing the wake is the same as for the turbine receiving the wake. In the Advanced model the actual thrust coefficient of the upstream turbine is used in the calculation.

In both models the hub heights of the turbines are taken into account when determining if the turbine rotor is completely below or above the wake of an upstream turbine so that there is no wake effect. As soon as the tip of the downwind turbine gets into the wake, it is assumed that the turbine has the same hub height as the upstream turbine and how much of the rotor is in the wake is determined. Afterwards, the analysis described in chapter 6.4.1 is carried out.

6.5 Wind speed and sector management

During the calculation of the design equivalent turbulence, the program checks whether the turbine under consideration is operational or not, taking into account the cut-in and cut-out wind speeds and sector management, and using the incident wind speed, including any wake effects. If the turbine is not in operation, the design equivalent turbulence is set to zero.

6.6 Evaluation

After deriving the estimates of Characteristic or Representative Turbulence intensity for a particular turbine, they can be plotted as a function of hub height wind speed and compared with the allowable values over the operational wind speed range of the turbines. It should be noted that the allowed wind speed standard deviations $\sigma_1\left(v_{hub}\right)$ defined in the design standards must be divided by the hub height wind speed for direct comparison with the Flow and Performance Matrix output of WindFarmer. This is because WindFarmer provides outputs of turbulence intensity and not wind speed standard deviation.

If there are any doubts concerning the suitability of the turbine, a site-specific load calculation should be considered. For this purpose, the use of the WindFarmer Bladed Link is recommended.

7 MCP METHODOLOGY

Measure-Correlate-Predict (MCP) methods are used to derive long-term representative wind speed and direction frequency distributions at planned wind farm sites from short-term measurements at the wind farm site and long-term measurements at a nearby reference station. In these processes, concurrent time series at both locations are compared and relationships between the two are determined. These will comprise wind speed relationships and possibly direction shifts.

These relationships are then applied to the long-term reference measurement to obtain a long-term frequency distribution at the site. This long-term frequency distribution derived will be representative of the period of the reference measurements.

7.1 Correlation methods

In the MCP$^+$ Module of WindFarmer, linear correlation methods are used to derive relationships between reference and site wind speed measurements. It is assumed that for each direction sector the pairs of wind speed data can be fitted to a straight line that is characterised by its slope and offset.

To calculate slope and offset, either a least squares method or a PCA method can be selected in WindFarmer

The general linear relationship between site and reference wind speed is therefore defined as

$$y = a + b \cdot x$$

where x is the wind speed at the reference station, b is the slope and a is the offset of the linear fit, and y is the concurrent wind speed at the site.

The correlation coefficient indicates the strength and direction of a linear relationship between two random variables. It ranges from +1 to -1. A correlation coefficient of +1 means that there is a perfect positive linear relationship between the variables: when the reference variable increases, the dependent variable also increases. A correlation coefficient of -1 means that there is a perfect negative linear relationship between the variables: when the reference variable increases, the dependent variable decreases. A correlation of 0 means that there is no linear relationship between the two variables. The directional and overall correlation coefficients (r) are given in the "MCP -Speed trends" window.

The linear correlation coefficient is defined as

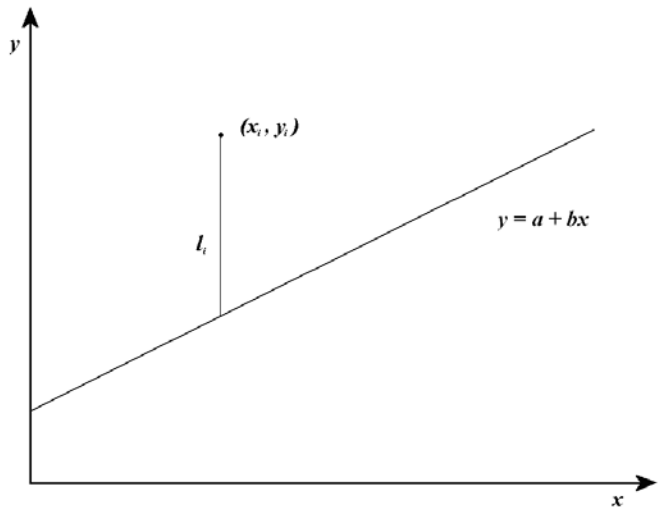
$$r = \frac{\sum_i (x_i - \bar{x})(y_i - \bar{y})}{\sqrt{\sum_i (x_i - \bar{x})^2 \sum_i (y_i - \bar{y})^2}}$$

7.1.1 Least Squares method

Assume that the measured wind speed is x_i at the reference station and y_i at the site, at a specific time. For a number n of such points, the least square method derives the linear fit that minimises the sum of squared distances in y from the fit, as illustrated in the figure below.

This gives

$$\frac{\partial S}{\partial b} = \frac{\partial\left(\sum_i l_i^2\right)}{\partial b} = \frac{\partial\left(\sum_i (y_i - b \cdot x_i - a)^2\right)}{\partial b} = -2 \cdot \sum_i x_i\left(y_i - b \cdot x_i - a\right) = 0$$
$$\frac{\partial S}{\partial a} = \frac{\partial\left(\sum_i l_i^2\right)}{\partial a} = \frac{\partial\left(\sum_i (y_i - b \cdot x_i - a)^2\right)}{\partial a} = -2 \cdot \sum_i \left(y_i - b \cdot x_i - a\right) = 0 \qquad \{7.1.1\}$$



Least Squares method

This leads to an estimation of the slope and offset of the best fit of

$$b = \frac{\sum_i \left(x_i - \overline{x}\right)\left(y_i - \overline{y}\right)}{\sum_i \left(x_i - \overline{x}\right)^2} \qquad \{7.1.2\}$$
$$a = b\overline{x} - \overline{y}$$

With $\overline{x}$ and $\overline{y}$ the mean wind speeds of the reference and site data.

When forcing the regression line through the origin (a=0) then the slope of the best fit becomes

$$b = \frac{\sum_i \left(x_i y_i\right)}{\sum_i \left(x_i\right)^2} \qquad \{7.1.3\}$$

7.1.2 PCA (Principal Components Analysis) method

The PCA fitting method involves a mathematical procedure that transforms a number of correlated variables into a smaller number of uncorrelated parameters called principal components. The approach is equivalent to a least-squares fit that minimises the squared orthogonal (i.e. perpendicular) distance of the measured points from a linear function, as illustrated.

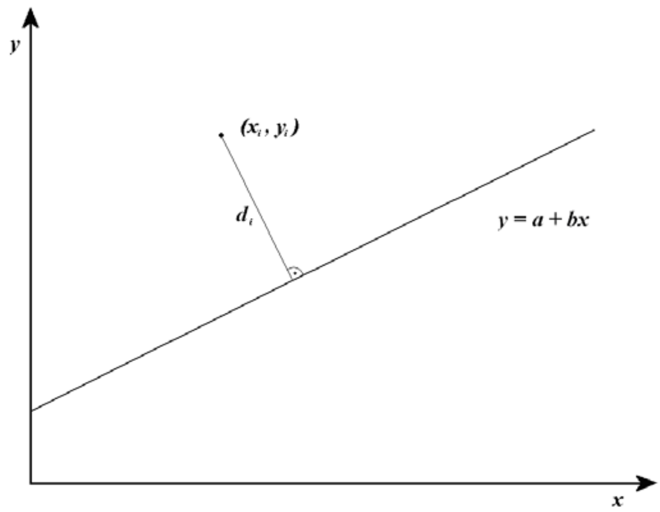
The perpendicular distance from the fit is

$$d_i = \frac{y_i - bx_i - a}{\sqrt{b^2 + 1}} \qquad \{7.1.4\}$$

Minimising the sum of the squared distance results in the estimation of the slope and the offset of the best fit being

$$b = -B + \sqrt{B^2 + 1}, \quad with \quad B = \frac{1}{2}\frac{\sum_i \left(x_i - \bar{x}\right)^2 - \left(y_i - \bar{y}\right)^2}{\sum_i \left(x_i - \bar{x}\right)\left(y_i - \bar{y}\right)} \qquad \{7.1.5\}$$

$$a = \bar{y} - b\bar{x}$$



PCA method

When forcing the regression line through the origin (a=0) then the slope of the best fit becomes

$$b = -B + \sqrt{B^2 + 1}, \quad with \quad B = \frac{1}{2}\frac{\sum_i \left(x_i^2 - y_i^2\right)}{\sum_i \left(x_i y_i\right)} \qquad \{7.1.6\}$$

7.1.3 Handling of low wind speed cut-offs

In the MCP^+ Module it is possible to exclude data at low wind speeds when determining correlation relationships. Usually for the low wind speeds, scatter is relatively high and from the energy point of view, low wind speeds below turbine cut-in wind speeds are not relevant.

There are two options available in the MCP^+ Module for handling correlation cut-offs:

- The low wind speed cut-off set in the 'Measure Correlate Predict' window refers to the wind speeds **both at the reference and the site location**. All points x_i, y_i having x_i and/or y_i smaller than the cut-off wind speed are excluded from the correlation analysis.
- The low wind speed cut-off set in the 'Measure Correlate Predict' window refers to the wind speed **at the reference station only**. This option is implemented by activating calculation of the site cut-off. All points x_i, y_i having x_i smaller than the cut-off wind speed are excluded from the correlation analysis. The calculated speed-up is then applied to the cut-off wind speed to derive the corresponding wind speed at the site. All points x_i, y_i with y_i smaller than the cut-off wind speed at the site are then excluded from the second correlation iteration and a new speed-up determined. The new speed-up is then applied to obtain a new site cut-off and this process is repeated until the slope of the linear fit no longer changes.

Note that in the prediction phase of the MCP process, the correlation relationships are applied to data of all wind speeds to be sure that a complete wind speed distribution is derived.

7.2 Calculation of direction shifts

Systematic direction shifts between the reference and site measurements can be applied, if required, when the long-term site wind speed and direction distribution is predicted. Otherwise, the long-term wind direction distributions at the reference station and site are assumed to be the same.

The direction shift between the time series is calculated for each direction sector in the following way. First, the reference direction time series is binned into direction sectors. For each time step, the difference is calculated between the direction measured at the site and the reference mast. For all reference wind directions within a direction sector, the mean of these direction differences is calculated and is output in the 'MCP-Direction trends' window as the Calculated Site Offset.

7.3 Application of speed-ups and direction shifts to reference data

In the prediction phase of the MCP method, the correlation relationships can be applied to either the long-term time series or the long-term wind speed and direction frequency distribution (*.tab file) measured at the reference station. If wind speed data become negative due a negative offset of the linear fit derived in the correlation, the wind speeds are assumed to be zero instead.

7.3.1 Applying speed-ups and direction shifts to long-term reference time series

If a long-term time series at the reference mast is used, the directional speed-ups and optional direction shifts are applied directly to each line of the reference time series according to the measured wind direction at the reference mast. The adjusted time series is then used for the creation of a long-term representative *.tab file. This *.tab file can then be used in flow models to calculate the long-term representative wind flow over the wind farm site.

7.3.2 Applying speed-ups and direction shifts to long-term *.tab files

If a long-term wind speed and direction distribution (*.TAB file) is used, the directional speed-ups and optional direction shifts are applied to the reference *.tab file according to the wind direction in the *.tab file.

First, the directional speed-ups are applied according to the wind direction sector in the *.tab file. For each sector, this is done by applying the speed-up to the wind speed bin boundaries, then re-binning the probabilities to obtain new wind speed bins in steps of 1 m/s.

After this has been done for all direction sectors, the direction shifts are applied by adding them to the respective direction bin boundaries, then re-binning the probabilities to obtain direction sectors in equal steps.

7.4 Removing seasonal bias in tab files

When a *.tab file is created that is based on a time series not covering an integer number of complete years, or when there are data missing in the time series, the *.tab file will be biased according to the seasonal variation of wind speed.

This bias can be removed using the ‘Remove Seasonal Bias’ function in WindFarmer. This can be applied when creating a *.tab file directly from a time series or when applying the MCP method to the short-term time series. This function is not available when a long-term reference *.tab file is used, because *.tab files do not include seasonal information. In this case, the user must use a long-term reference *.tab that is not seasonally biased.

In the first step, monthly seasonal wind speed and direction distributions are created using all data in the time series within a specific month, e.g. all data in a January. The annual *.tab file is then calculated by summing these monthly tables using a weighting according to the number of days in each month.

To remove the seasonal bias the time series must contain data for all months. It should be noted that seasonal bias is not removed in wind roses and turbulence *.wti files.

8 UNCERTAINTY ANALYSIS

The energy production calculation of a wind farm is always subject to uncertainties and these should be accounted for in assessing the accuracy of the calculation model. The three main areas of uncertainty are outlined below:

- Measurement uncertainties due to anemometry characteristics of reference meteorological stations and on-site masts. Furthermore correlation between masts and wind indices contribute to measurement uncertainty.
- Modelling uncertainties due to complexity of topography and site roughness, layout induced wakes, wind shear, turbine power curve, meter accuracy, utility downtime, etc.
- Wind speed variability uncertainties due to the statistical fluctuations of the wind resource over the historical period when measurements have been carried out and the future period during which the wind farm will be operational

These uncertainties can either be calculated or estimated. Ideally, the wind farm development should aim to minimise overall uncertainty.

8.1 Measurement uncertainties

Anemometry uncertainties:

- Steady state calibration uncertainty is associated with the assessment of the transfer function frequency (Hz) to wind speed in a wind tunnel. This uncertainty is usually expressed in the calibration certificate as % of wind speed or as standard deviation (m/s) per speed bin
- Variability of calibration uncertainty is associated with the variation of the transfer function with time. Weather conditions can affect the transfer function of the sensor during the measurement campaign
- Flow inclination uncertainty is expected when the axis of rotation of the anemometer is not perfectly vertical
- Flow distortion uncertainty is caused by the proximity of the anemometer to the supporting mast and horizontal or vertical booms. The closer the anemometer is to these structures, the higher is the uncertainty caused by flow distortion.

The anemometry uncertainties above are usually combined into a single uncertainty value.

The correlation uncertainty is determined by the scatter of the correlation between reference mast and site mast. The lower the scatter, the lower is the correlation uncertainty. Note that there is no simple relationship between the correlation coefficient (see chapter on MCP methodology) and correlation uncertainty. Nevertheless some estimates are given below as guidance:

Correlation coefficient, r	**Wind speed correlation uncertainty**
> 0.9	< 1%
0.9 – 0.8	1 – 2%
0.7 – 0.6	3 – 5%

It is recommended that correlation results with a correlation coefficient less than 0.6 are not used. In this case, it may be worthwhile looking for other reference stations, or to carry out an energy calculation with only the wind data measured on site. This will then increase historical uncertainty due to annual variability but this may be balanced by the absence of a correlation uncertainty.

8.2 Modelling uncertainties

Topographic model uncertainties:

The wind flow model is not always capable of predicting the site wind regime generated from an initiation mast on site to the turbine location. The complexity of terrain, the site roughness, the presence of obstacles and the distance between each turbine and the initiation mast are factors determining the magnitude of this uncertainty. The difference in height between the mast and predicted hub height is also a factor computed in the assessment of this uncertainty.

Wake model uncertainty:

Wake model uncertainty relates to the wake loss calculations with respect to calculated wake loss. The area of uncertainty includes wake model uncertainties and uncertainties related to the thrust characteristic of the turbine.

Vertical extrapolation uncertainty:

Uncertainty lies in the wind shear model used to extrapolate the frequency distribution from mast height to hub height at the mast position. This should be accounted for if it is not already included in the topographic model uncertainty.

Horizontal extrapolation uncertainty:

This is usually an alternative to the topographic uncertainty, if the latter is split between vertical and horizontal extrapolation uncertainty. It relates to the extrapolation of the wind regime at turbine positions from the wind regime predicted at mast position at hub height.

Power curve uncertainty:

The uncertainty of the power curves used in the energy prediction. Uncertainties can be measured uncertainties, uncertainties due to measurement setup or model uncertainties (if a calculated power curve is used) or can represent tolerances between different turbines of the same type.

Further to the list above, other uncertainties can be identified for a specific project. For instance, wind vane misalignments may lead to wind rose uncertainties; wind indexes also carry uncertainties when used in extrapolating a long-term site wind regime.

In this regard, for each project the modelling uncertainty list and relevant uncertainty values must be individually assessed to reflect specific issues.

8.3 Wind speed variability uncertainties

Wind speed is stochastically variable over the historical period, when the measurement campaign is carried out, and over the future period, when the projected wind farm will be operational. The equation below defines the conversion from an annual wind speed variability uncertainty to an uncertainty over a reference number of years:

$$U_{NWSV}(\%) = \frac{U_{AWSV}(\%)}{\sqrt{N}} \qquad \{8.1\}$$

With:

$U_{NWSV}(\%)$ = uncertainty wind speed variability over N years

$U_{AWSV}(\%)$ = uncertainty annual wind speed variability

N = reference number of years

It is assumed that annual wind speed variability is the same for the past and the future periods.

In some regions, there are sufficient data to describe a region-specific value for annual wind speed variability. In the absence of this, an annual wind speed variability of 6% is recommended.

The Future Uncertainty describes the uncertainty for the target period. Future Uncertainty periods are usually:

- 1 year (to assess uncertainty over a single operational year of the projected wind farm);
- 10 years (a typical period for simple payback period of the investment); and
- 20 years (being the standard life span of a wind farm project).

8.4 Sensitivity

The type of uncertainty can be user-defined, or one of four predefined types: wind speed, energy yield, topographic effect or wake losses. Before combining them to a global uncertainty level, all uncertainties are first converted to an uncertainty in energy yield. The conversion factor of a particular uncertainty to an energy yield uncertainty percentage is defined as a sensitivity.

The four predefined types are:

- Wind speed: WindFarmer perturbs the wind speed by a percentage (3%) and the resulting perturbed energy is calculated. The normalised relative increase is the wind speed sensitivity as a percentage.
- Topographic: the sensitivity is (100% - Topographic Efficiency)
- Wake Loss: the sensitivity is (100% - Array Efficiency)
- Energy Yield: Uncertainties defined with respect to the energy yield have a sensitivity of 100% in net yield.
- User Defined: the sensitivity is a manual input, derived outside WindFarmer

8.5 Combination of the uncertainties

Once the uncertainties have been converted with appropriate sensitivity to energy yield uncertainties, they are combined assuming statistical independence to form the Total Uncertainty:

$$U_{TOT}(\%) = \left[\Sigma U_{HP}^2 + U_{FP}^2\right]^{1/2}$$

where:

U_{TOT} = Total Uncertainty

U_{HP} = Historical Period uncertainties (measurements, modelling and wind variability over the reference period of the measurement campaign)

U_{FP} = Future Period uncertainty (over reference periods when the projected wind farm is operational)

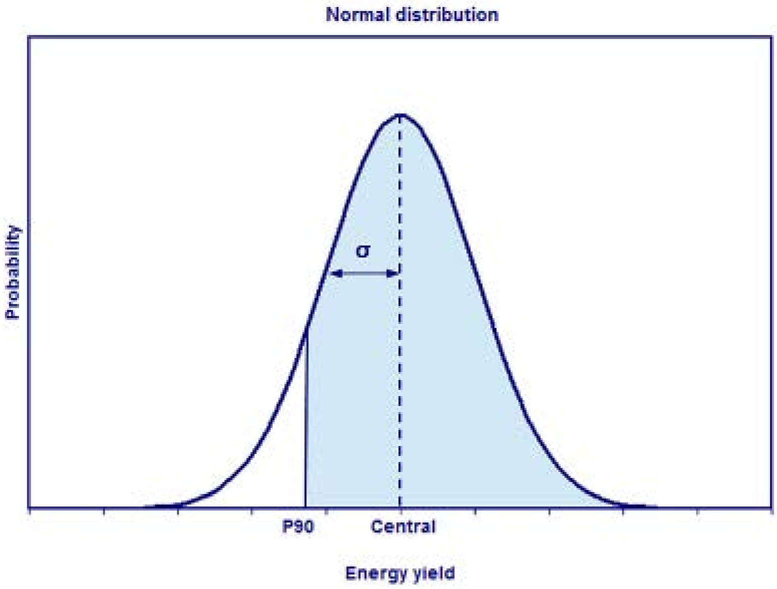
8.6 Exceedance levels

The estimated annual Net Energy Production and the Total Uncertainty determine respectively the mean and the standard deviation of a Normal Gaussian Distribution. The absolute standard deviation is obtained by multiplying the Total Uncertainty by the Net Energy Production.

In general, the probability distribution of energy production E, when assuming a Gaussian Distribution, is

$$f(E) = \frac{1}{\sigma\sqrt{2\pi}} e^{-\frac{(E-E_m)^2}{2\sigma^2}}$$

with E_m as the central estimate of the predicted energy prediction (calculated net energy) and σ as the overall absolute standard deviation of the predicted energy production. The equation is shown graphically in the following plot. The plot shows the central, most likely, energy yield, predicted as the Net Yield of WindFarmer; this is also called the P50 value or central estimate.



The probability P that E exceeds a certain value e is

$$P(E > e) = 1 - \int_{-\infty}^{e} f(t)dt = 1 - F(e) = F(-e).$$

In order to be able to use tabulated values for F(-e), it is necessary to convert F(-e) into a Normalised Normal Gaussian Distribution:

$$P(E > e) = P\left(\frac{E - E_m}{\sigma} > \frac{e - E_m}{\sigma}\right) = P(Z > z) = F(-z)$$

As we want to know the energy production that is exceeded with a specific probability, we need F(-z). This cannot be derived analytically but there are look-up tables for the Normal Distribution for specific probabilities of exceedance and corresponding values for z. This is the reason why WindFarmer provides confidence limits only for specific probabilities of exceedance. These are 1%, 10%, 25%, 50%, 75%, 80%, 84%, 85%, 90%, 95% and 99%.

The energy production that is exceeded with a certain probability is then derived from:

$$-z = \frac{e - E_m}{\sigma}.$$

This results in: $e = E_m - z\sigma$.

The central estimate is exceeded with a probability of 50%. So, for the central estimate of the predicted energy production, z is equal to 0.

P [%]	**z**
99	2.326
95	1.645
90	1.282
85	1.036
84	1.000
80	0.842
75	0.674
50	0
25	-0.674
10	-1.282
1	-2.326

9 NOISE MODELS

9.1 Introduction

The noise functions in the Base Module allow the user to input the sound power levels for turbines and calculate the noise distribution. The aim of the functions is to design wind farms within legal limits based on giving information about turbine sound power levels. There are three noise models available within WindFarmer. All three are based on ISO 9613-2 [9.1]:

- Simple noise model
- Complex (ISO9613) General
- Complex (ISO9613) Alternative

The Simple noise model calculates the attenuation for a single representative frequency and assumes hard ground surfaces. The model Complex (ISO9613) General considers noise attenuation for separate octave bands and includes the effect of ground attenuation as well as directional meteorological effects. The model Complex (ISO9613) Alternative also includes ground attenuation, however in this case the result is not a function of frequency or specified ground properties.

Additionally a Custom model has been implemented where all parameters are freely selectable.

Equations from the ISO standard are referred to below as ISO (x) where x refers to the equation number in the standard.

9.2 Simple Noise Model

The Simple noise model is recommended for a first fast assessment or if no frequency dependent turbine sound power levels are available. The Simple noise model in WindFarmer calculates the noise propagation at a fixed reference frequency of 500 Hz. The continuous octave-band sound pressure level at a receiver location (L_{ft}) is calculated using the equation ISO (3):

$$L_{ft} = L_W + D_C - A \qquad \{9.2.1\}$$

where

L_w: is the sound power level in dB(A) produced by each turbine taking the turbine as a point source.

D_c: is the directivity correction in decibels. For the case of an assumed omni-directional point sound source (Wind Turbine) D_c= 0 dB. The directivity of the wind turbine noise is considered when measuring the sound power level.

A: is the attenuation that takes place during the propagation from the point sound source to the receiver in decibels.

Note: WindFarmer does not perform an A-weighting. Please enter A-weighted sound power levels if you need your result in dB(A).

Equation {9.2.1} relates the sound power level of a turbine to the sound pressure level at a reference distance from an omni-directional sound source. The attenuation A in equation {9.2.1} is defined by ISO (4):

$$A = A_{div} + A_{atm} + A_{gr} + A_{bar} + A_{misc} + A_{met} \qquad \{9.2.2\}$$

where

A_{div} is the attenuation due to geometrical divergence

A_{atm} is the attenuation due to atmospheric absorption

A_{gr} is the attenuation due to ground effects

A_{bar} is the attenuation due to barriers

A_{misc} is the attenuation due to other effects like foliage and buildings

A_{met} is the attenuation due to meteorological effects

In the case of a wind farm with multiple turbines (T_1, T_2, ….., T_n), it is necessary to find the combined sound pressure level for all the turbines at a point. WindFarmer calculates the effective sound pressure level using:

$$L_{TOTAL} = 10\log\left[10^{\frac{L_{ft1}}{10}} + 10^{\frac{L_{ft2}}{10}} + 10^{\frac{L_{ft3}}{10}} + ... + 10^{\frac{L_{ftn}}{10}}\right] \qquad \{9.2.3\}$$

9.2.1 Geometrical Divergence (A_{div})

This attenuation accounts for spherical spreading in the free field from a point sound source over hard ground. The next equation is used in WindFarmer to calculate the attenuation due to geometrical divergence, ISO (7):

$$A_{div} = [20\log(d) + 11] \quad dB \qquad \{9.2.4\}$$

where

d: is the (3-dimensional) distance between the source and the receiver.

The combination of this spherical spreading and a hard ground plane is sometimes called a hemispherical model.

9.2.2 Atmospheric Attenuation (A_{atm})

The attenuation due to atmospheric absorption is calculated with the next equation, ISO (8):

$$A_{atm} = \left(\frac{\alpha d}{1000}\right) \qquad \{9.2.5\}$$

where

α: is the atmospheric attenuation coefficient in decibels per kilometre for each octave band (see Table 2, ISO 9613-2)

9.2.3 Ground Attenuation (A_{gr})

The ground attenuation is calculated using the equations given in Table 3, ISO 9613-2 using a ground factor of zero (hard ground) and the fixed reference frequency of 500 Hz. The total ground attenuation is the sum of the ground attenuation in the source region (A_s), the middle region (A_m) and the receiver region (A_r). In the source and receiver regions the ground attenuation is -1.5dB. The ground attenuation in the middle region is given by

$$A_m = -3q\ dB$$
$$q = \begin{cases} 1 - \dfrac{30(h_s + h_r)}{d_p} & \text{when } d_p > 30(h_s + h_r) \\ 0 & \text{when } d_p < 30(h_s + h_r) \end{cases} \qquad \{9.2.6\}$$

where:

h_s is the hub height of the wind turbine

h_r is the height of the receiver above ground

d_p is the distance from the wind turbine base to the receiver base projected onto the ground plane

9.3 Complex Noise Models

The complex noise model in WindFarmer considers the noise attenuation as a function of the frequency distribution of noise. The noise emission of the turbine(s) needs to be defined in octave bands. Frequency-specific attenuation coefficients are then used to calculate the attenuation of noise.

9.3.1 Noise in Octave Bands

WindFarmer calculates the noise propagation by summing the contributing sound pressures for each source and for each octave band.

The next equation replaces Equation 9.2.3 and shows the method of adding octave bands:

$$L_{TOTAL} = 10\log\left[\sum_{i=1}^{n}\left(\sum_{j=1}^{8} 10^{0.1(L_{ft}(ij))}\right)\right] \qquad \{9.3.1\}$$

where

n : is the number of sources i

j : indicates the eight standard octave band frequencies [63 Hz to 8KHz]

L_{ft}: is the octave band sound pressure level

Note: WindFarmer does not perform any A-weighting. If you need your result in dB(A) you need to enter the A-weighted sound pressure levels.

9.3.2 Atmospheric Attenuation (A_{atm})

Atmospheric absorption is calculated for each octave the same way as described above for the simple noise model. The attenuation coefficients can be set by the user and are a function of frequency, humidity and temperature. This dependency is described in detail in ISO-9613-1 [9.2]. The set default attenuation coefficients in WindFarmer are valid for 10° Celsius and 70% humidity and represent a conservative choice.

9.3.3 Ground Attenuation (A_{gr})

The ground attenuation considers the sound reflected or absorbed by the ground surface. ISO 9613-2 divides the path where the sound propagation is affected into three regions: the source region, the receiver region and a middle region. The acoustic properties of each of these regions are taken into account separately through ground factors (G).

The table below defines the ground factors (G) for three different kinds of surfaces:

Type of Ground	Example	Value of G
Hard Ground	Low porosity surfaces (Paving, water, ice, concrete)	0
Porous Ground	Porous surfaces suitable for growth of vegetation (ground covered with grass, trees and vegetation)	1
Mixed Ground	Both hard and porous ground	Between 0 and 1

The total ground attenuation for the octave band is calculated as the sum of individual absorption coefficients for the source region (A_s), the receiver region (A_r) and the middle region (A_m):

$$A_{gr} = A_s + A_r + A_m \qquad \{9.3.2\}$$

where A_s, A_r and A_m are calculated as a function of G by WindFarmer using the equations given in Table 3, ISO 9613-2

9.3.4 Alternative method to calculate the Ground Attenuation (Agr)

This alternative method is suggested in ISO 9613-2, as an option for specific situations where only the A-weighted sound pressure level at the receiver position is of interest, the sound propagation occurs over porous ground or mixed ground (most of which is porous) and the sound is not a pure tone. The calculation then depends on two terms ISO-(10) and ISO (11) given below.

$$A_{gr} = 4.8 - (2h_m/d)[17+(300/d)] \text{ dB} \qquad \{9.3.3\}$$

$$D_\Omega = 10\lg(1+(d_p^2+(h_s - h_r)^2)/(d_p^2+(h_s+h_r)^2))\text{dB} \qquad \{9.3.4\}$$

where

h_m is the mean height of the propagation path above ground

d is the distance of the receiver from the wind turbine

h_s is the hub height of the wind turbine

h_r is the ground height of the receiver

d_p is the distance from the wind turbine base to the receiver base projected onto the ground plane

The first term is for the ground attenuation, the second term is a correction for the reflections of sound from the ground near the source. A_{gr} is limited to a number equal or greater than 0dB.

9.3.5 Meteorological correction (A_{met})

The meteorological correction allows the user to correct for statistically changing meteorological conditions. This correction may be applied if a long-term average sound pressure level is required and sufficient information about the local meteorological statistics is available to establish a value for the site specific factor, C_0.

9.3.6 Miscellaneous types of attenuation (A_{misc})

This parameter considers two factors that attenuate sound:

- Attenuation due to foliage (A_{fol})
- Attenuation due to buildings or industrial sites (A_{site})

WindFarmer allows the user to input site specific attenuation A_{misc}.

Attenuation due to the foliage of trees and bushes is usually small. However, in some cases, when the foliage is dense and close to the source of sound, to the receiver or to both, the attenuation could increase considerably. It is suggested that the values of Table A1, ISO 9613-2, are used to calculate attenuation due to foliage.

To calculate attenuation due to industrial sites, use Table A2, ISO9613-2. This table is an approximation, as this parameter has a strong dependency on the site conditions.

9.3.7 Accuracy of the method

The propagation of sound and its attenuation depends on the meteorological and geographical conditions along the propagation path. A typical error associated with an assessment using the above method is +/- 3 dB.

The ISO 9613-2 standard that is used in the noise propagation models is only strictly applicable when the terrain is almost flat or with a constant slope.

The application of this standard to wind turbine noise is, with large heights above ground and large propagation distances, outside the usual scope of the standard [9.3]. GH recommends that the complex model with G = 0 (hard ground) is used for all surfaces, to account for seasonal variation of ground properties as well as possible differences in the behaviour of wind turbine noise as opposed to typical industrial noise.

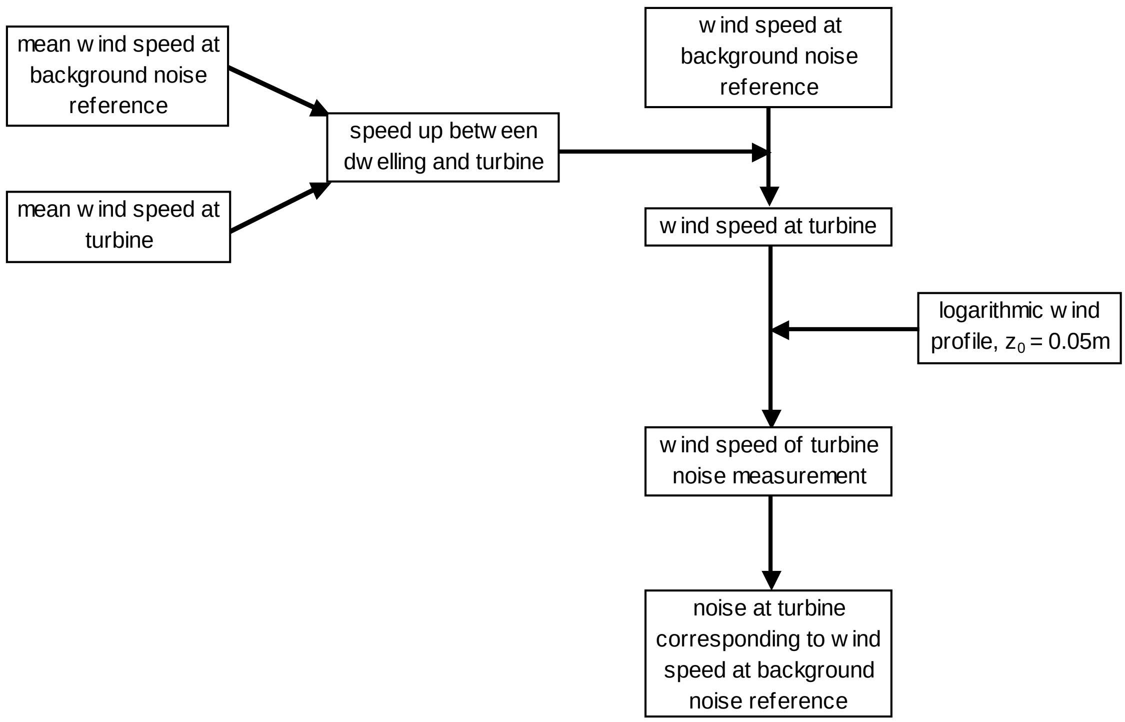
9.4 Turbine noise vs. background noise

Depending on the national limits and guidelines on wind turbine noise, it may be necessary to calculate the wind farm noise relative to background noise at sensitive locations. Both wind turbine noise and background noise are a function of their respective (different) local wind speeds.

The turbine sound power level is provided by the turbine manufacturer, as a function of wind speed at a reference height (typically 10m) and reference roughness (usually 0.05 m). Within the wind farm, the wind speeds will at any given time vary from turbine to turbine, as will the resulting turbine sound power level. Each turbine sound power level is calculated using the turbine sound power levels at different wind speeds, as provided by the turbine manufacturer.
The background noise level is usually measured as a function of the local wind speed, in a location representative for the dwelling.

Also required is a measure of the wind speed differences between turbines and between turbines and dwellings. For this, the mean wind speed defined at the background noise reference is compared with the mean free wind speed at the turbine hub and calculated using WRG/RSF information. Using this ratio, the hub height wind speed at the turbine for each background noise reference wind speed is calculated internally.

The process is illustrated in the flow chart, below:



10 ELECTRICAL CALCULATIONS

10.1 Input data checks

The following data checks are required before attempting any calculation:

- Check node connections: each node must eventually be connected, to one (and only one) root node.
- Check cable and line connections: each cable and line must be connected between two different nodes.
- Check that substations, cables, lines and transformers are not beyond root nodes, i.e. between a root node and a turbine, or PFCDs (if installed).
- Check for loops: check that there is only one route from each turbine to a metering point.
- Check for correct voltage allocation: check that each cable or line has both ends eventually connected to turbines, transformers and substations with the same nominal voltage. (Note: assume the primary side of a transformer is the side closest to the root node.)
- Check for correct cable or line selection: check that each cable or line has a nominal voltage - the same as or greater than its operating voltage.

Note that it is not necessary for all turbines to be connected to the electrical system (for example, a neighbouring wind farm included in the analysis, in order to represent wake effects correctly). In this case, the user could leave those turbines without connection or use another root node for that wind farm, if required.

10.2 Electrical losses

10.2.1 Cable and line losses

The annual loss in each cable and line is calculated as follows:

- Calculate the resistance R (ohms per phase) for each cable and line, from specified data and calculated length.
- As a function of site wind-speed and direction:
    - calculate the current I in the cable or line (See Section 10.4.1)
    - calculate the loss L in the cable or line ($L = 3 \cdot I^2 \cdot R$) [Watts]
- Check for cable and line overloading: i.e. compare if the highest value of current exceeds the maximum continuous current rating of the cable or line, if specified by the user

If there are N parallel cables/lines between two nodes, current and losses are split into these elements. Section 10.4.6 shows the calculation to obtain currents for each cable/line I1, I2, ..., IN from the total current I and the impedances Z_1, Z_2, … Z_N.

10.2.2 Transformer no-load losses

For each transformer, the annual no-load loss is the stated no-load loss figure (Watts) multiplied by the number of hours per year.

10.2.3 Transformer load losses

The annual loss in each transformer is calculated as follows:

- Calculate the resistance R (ohms per phase), referred to the secondary side (See Section 10.4.3)
- As a function of site wind-speed and direction:
    - o calculate the current I in the transformer (See Section 10.4.2)
    - o calculate the loss L in the transformer ($L = 3 \cdot I^2 \cdot R$) [Watts]
- Check for transformer overloading: i.e. compare if the highest value of current in the transformer exceeds the nominal current rating of the transformer. (The nominal current rating of the transformer Inom is as calculated in Section 10.4.3).

If there are N transformers in parallel at the substation, current and losses are split into these elements. Section 10.4.6 shows the methodology to obtain the currents for each transformer I_1, I_2, .., I_N from the total current I and the impedances Z_1, Z_2, … Z_N.

10.2.4 Total active power import and export

As a function of site wind speed and direction, the wind farm net production or consumption at each metering point is calculated. This calculation takes into account:

- production of each turbine
- cable and line losses
- transformer losses

By summating the above amounts for the whole year, the outputs specified in the User Manual are given.

10.3 Reactive power

10.3.1 Reactive power, turbines

The reactive power produced and consumed by each turbine, as a function of wind speed and direction, is calculated. The relationship between active and reactive power can ideally be entered by the user as either of the following:

- a table of reactive versus active power
- a table of power factor versus active power, with a tick box or other device for each point, to allow the user to specify whether reactive power is imported or exported (default is import). Section 10.4 presents the expression to calculate the reactive power from the active power and power factor.

10.3.2 Reactive power, cables and lines

The reactive power produced and consumed by each cable and line is calculated as follows:

- Calculate the series reactance, per phase X (ohms), for each cable and line, from specified data and calculated length
- Calculate the capacitance per phase C (microfarads), for each cable and line, from specified data and calculated length:
    - o As a function of site wind-speed and direction
    - o Calculate the current I in the cable or line (See Section 10.4.1)
    - o Calculate the reactive power consumption Q_x due to the series reactance X in the cable or line ($Q_X = 3 \cdot I^2 \cdot X$) [VAr] (this will be a negative number)
    - o Calculate the reactive power generation Qc due to capacitance C in the cable or line ($Q_C = U^2 \cdot 2\pi \cdot f \cdot C \cdot 10^{-6}$) [VAr] (this will be a positive number and is constant for each cable or line)
    - o Add Q_x and Q_c to get total reactive power produced or consumed by the cable or line

10.3.3 Reactive power, transformers

The reactive power consumed by each transformer is calculated as follows:

- Calculate the transformer series reactance per phase Xs (ohms) for each transformer (See Section 10.4.4)
- As a function of site wind speed and direction:
  - Calculate the current I in the transformer (See Section 10.4.2)
  - Calculate the reactive power consumption Q_x due to the series reactance X_s ($Q_X = 3 \cdot I^2 \cdot X_s$) [VAr] (this shall be a negative number)
  - Calculate the reactive power consumption Q_m due to the magnetising reactance X_m ($Q_m = U^2 / X_m$) [VAr] (this will be a negative number and is constant for each transformer type). Note that U is the nominal secondary voltage of the transformer. See Section 10.4.5 to see how to obtain X_m from I_{ec}
  - Add Q_x and Q_m to get total reactive power consumed by the transformer.

10.3.4 Total reactive power import and export

As a function of site wind speed and direction, the net production or consumption at each metering point is calculated. This calculation takes into account the reactive power produced and consumed by:

- each turbine
- each cable and line
- each transformer

Then by summating the above amounts for the whole year, the outputs specified in the User Manual are given.

10.3.5 Power factor correction requirements

If this option is chosen, for each PFCD, the following steps are carried out:
As a function of site wind speed and direction:

- Calculate the active P and reactive Q power produced and consumed by all the "downstream" components at the metering node
- Calculate the PFCD size:
  - $Q_{PFCD} = P_{PF} \cdot \tan(\arccos(\cos ø_c)) - Q_{PF}$
  - (positive number for capacitor bank, exporting kVAr)
  - (negative number for reactor bank, importing kVAr)

The program should keep a record of the lowest and highest Q_{PFCD} values that will be part of the output as shown in the User Manual.

10.4 Formulae

10.4.1 Calculation of the current in each cable or line

- Identify each "downstream" turbine and PFCD, i.e. each turbine and each PFCD whose output must flow through the cable or line in question, before it reaches a root node.
- For each downstream turbine, determine the power P produced or consumed by the turbine, for the given hub-height wind speed.
- For each downstream turbine, calculate the reactive power Q produced or consumed by the turbine for the given hub-height wind speed, from the user-defined table of Q or PF versus P.
- For each downstream PFCD, calculate the reactive power Q produced by this element, as shown in Section 10.3.
- Summate to find total P and total Q passing through the cable or line from all downstream turbines.
- Calculate apparent power $S = \sqrt{P^2 + Q^2}$ [kVA]
- Calculate current I for cable or line:
  - $I = (S \cdot 1000) / (\sqrt{3} U)$ [Amps]
  - where U is the operating voltage.

10.4.2 Calculation of the current in each transformer

- Identify each "downstream" turbine and PFCD, i.e. each turbine and each PFCD whose output must flow through the transformer in question before it reaches a metering point.
- For each downstream turbine, determine the power P produced or consumed by the turbine, for the given hub-height wind speed.
- For each downstream turbine, calculate the reactive power Q produced or consumed by the turbine, for the given hub-height wind speed, from the user-defined table of Q or PF versus P.
- For each downstream PFCD, calculate the reactive power Q produced by this element, as shown in Section 10.3.
- Summate to find total P and total Q passing through the transformer from all downstream turbines.
- Calculate apparent power $S = \sqrt{P^2 + Q^2}$ [kVA]
- Calculate current I for transformer secondary side:
  - $I = (S \cdot 1000) / (\sqrt{3} \cdot U)$ [Amps]
  - where U is the nominal voltage of the secondary side.

10.4.3 Calculation of the resistance of transformer

For each transformer, the user will specify a nominal rating S [kVA], a nominal secondary voltage U [volts] and a load loss P_{LL} at nominal rating [W]:

$$I_{nom} = (S \cdot 1000) / (\sqrt{3} \cdot U)$$
$$R = P_{LL} / (3 \cdot I_{nom}^2) \quad \text{[Ohms]}$$

The result is the transformer series resistance in ohms, referred to the secondary side.

10.4.4 Calculation of the transformer series reactance

For each transformer, the transformer series reactance, X_x, is obtained by means of the following expressions:

$$X_s = \sqrt{Z_s^2 - R^2}$$

$$Z_s = \left(Z_{trafo} \cdot U^2\right) / \left(S \cdot 1000 \cdot 100\right) \text{ [Ohms]}$$

where:

X_s is transformer series reactance per phase [Ohms]

R is transformer resistance as calculated above

U is transformer nominal secondary voltage [Volts]

Z_{trafo} is transformer series impedance [%]

S is transformer nominal rating [kVA]

Note: the first equation will cause errors if the transformer series impedance Z_{trafo} has been left at the default value of zero by the user. In this case, set X_s to zero.

10.4.5 Transformation of excitation current into magnetising reactance

The first thing is to calculate excitation current, referred to secondary as follows:

$$I_{ec} = I_{ec}(\%) \cdot I_{nom} / 100 \text{ [Amps]}$$

$$I_{nom} = (S \cdot 1000) / \left(\sqrt{3} \cdot U\right) \text{ (same calculation to obtain Series Resistance)}$$

where:

I_{ec} is the excitation current as percent on the nominal current [%]

I_{nom} is the nominal current of the transformer

S is the nominal rating [kVA]

U is the nominal secondary voltage U [Volts]

Then, the magnetising resistance is calculated as:

$$R_m = U^2 / P_{NLL} \text{ [Ohms]}$$

where:

P_{NLL} is the no load losses [W]

Finally, the magnetising reactance is calculated from the expression:

$$X_m = \frac{1}{\sqrt{\left(\frac{I_{ec}}{U/\sqrt{3}}\right)^2 - \frac{1}{R_m^2}}} \text{ [Ohms]}$$

Note: If excitation current is not stated, this should be equal to 0 so that the magnetising reactance should be assigned as infinite.

10.4.6 Calculate equivalent impedance of N elements in parallel

When N elements in parallel are to be connected in an electrical circuit, the following set of equations must be solved to obtain the equivalent circuit:

$$
\begin{array}{lllll}
I_1 \; + & I_2 + & I_3 \; + \ldots & I_N\text{-}1 + \; I_N & = I \\
Z_1{*}I_1 \; - \; Z_2{*}I_2 & & & & = 0 \\
Z_1{*}I_1 & - \; Z_3{*}I_3 & & & = 0 \\
Z_1{*}I_1 & & & - \; Z_N\text{-}1{*}I_N\text{-}1 & = 0 \\
& Z_2{*}I_2 \; - \; Z_3{*}I_3 & & & = 0 \\
& Z_2{*}I_2 & & - \; Z_N\text{-}1{*}I_N\text{-}1 & = 0 \\
& & Z_3{*}I_3 & - \; Z_N\text{-}1{*}I_N\text{-}1 & = 0 \\
& \ldots\ldots & & &
\end{array}
$$

It must be noted that all the matrix calculations must be conducted using complex numbers, where

$Z = R + jX$ Ohms/phase

Alternatively, this calculation could be further simplified for those expected cases, up to 3 elements in parallel;

For N = 2, the equivalent impedance is calculated as:

$$\frac{1}{\mathrm{Zeq}} = \sum_{i=2} \frac{1}{Z_i}$$

being the currents flowing across each branch:

$I_1 = Z_2 / (Z_1 + Z_2) * I$
$I_2 = Z_1 / (Z_1 + Z_2) * I$
$I = I_1 + I_2$

For N = 3, the equivalent impedance is calculated as

$$\frac{1}{\mathrm{Zeq}} = \sum_{i=3} \frac{1}{Z_i}$$

being the currents flowing across each branch:

$I_1 = Z_2 * Z_3 / ((Z_2 + Z_3)*(Z_1 + Z_2 + Z_3)) * I$
$I_2 = Z_1 * Z_3 / ((Z_1 + Z_3)*(Z_1 + Z_2 + Z_3)) * I$
$I_3 = Z_1 * Z_2 / ((Z_1 + Z_2)*(Z_1 + Z_2 + Z_3)) * I$
$I = I_1 + I_2 + I_3$

WindFarmer Electrical Module provides the results for the equivalent impedance only. If the user is particularly interested in knowing an electrical parameter of one of the branches, the user will need to determine this in a separate calculation.

10.5 Caveats

Users' attention is drawn to the caveats given in the chapter about the Electrical Module of the User Manual.

11 SHADOW FLICKER

11.1 Introduction

Shadow flicker is the occurrence of periodic changes in light intensity, due to the shadow of a wind turbine blade passing over a point of interest.

The Shadow Flicker Module simulates the path of the sun during the year and assesses at each time interval the possible shadow flicker at one or multiple receptor position(s). The output of the module can be used to design a wind farm to fulfill planning requirements. The results of the module can also be used to reduce shadow flicker annoyance at the receptors by providing the turbine controller or SCADA system with a time and date of shadow flicker occurrences, so that turbines can be switched off at these times.

11.2 Program inputs

The following inputs to the WindFarmer model are required to produce an estimate of the shadow flicker effect at the wind farm:

- Latitude where the wind farm(s) is located (γ)
- Longitude where the wind farm(s) is located (λ)
- Time Zone
- Minimum elevation angle of the sun
- Calculation time interval
- Maximum distance from turbine for calculation
- Resolution of calculation points
- Turbine and shadow receptor locations
- Turbine dimensions (hub height, rotor diameter, distance between rotor and turbine tower centre)

Latitude and longitude are derived by WindFarmer directly from the wind farm coordinates.

11.3 Methodology of the shadow flicker calculation

Before performing the actual shadow flicker calculation, the program determines the position of the sun at any time of the year. The following definitions and equations are used to determine the elevation and azimuth angle that determine the position of the sun. For more details and definitions, see [11.1] and [11.2].

The Hour Angle is the angular displacement of the sun west or east of the local meridian due to the rotation of the earth on its axis at 15° per hour.

In order to obtain the hour angle, the program first calculates:

11.3.1 Julian Date:

Julian Date (JD) is defined as the difference in days between the current Julian day and the Julian day at noon on 1st January 2000:

$$JD = 2432916.5 + 365 \cdot delta + leap + day + \frac{hour}{24}$$

where:

$$delta = year - 1949$$
$$leap = \mathrm{int}\left(\frac{delta}{4}\right)$$

where int is defined as the integer portion of the argument.

11.3.2 Elliptic coordinates:

The elliptic coordinates are the mean longitude (L), mean anomaly (g), ecliptic longitude (l) and obliquity of the ecliptic (ep). These parameters are calculated using the equations:

$$n = JD - 2451545.0$$
$$L = 280.460 + 0.9856474 \cdot n \qquad (0° \leq L < 360°)$$
$$g = 357.528 + 0.9856003 \cdot n \qquad (0° \leq g < 360°)$$
$$l = L + 1.915 \cdot \sin(g) + 0.020 \cdot \sin(2g) \qquad (0 \leq l < 360°)$$
$$ep = 23.439 - 0.0000004 \cdot n$$

11.3.3 Celestial coordinates:

For the calculation of the celestial coordinates (right ascension (ra) and declination (dec)) WindFarmer uses the following equations:

$$\tan(ra) = \cos(ep) \cdot \frac{\sin(l)}{\cos(l)}$$
$$\sin(dec) = \sin(ep) \cdot \sin(l)$$

The next step is to calculate the azimuth angle (az) and elevation (el). To calculate az and el it is necessary to calculate the hour angle, for which we must first calculate the following terms:

11.3.4 Greenwich mean sidereal time (gmst):

The formula to approximate the Greenwich mean sidereal time to an arbitrary time is given by:

$$gmst = 6.697375 + 0.0657098242 \cdot n + hour(UT) \qquad (0 \leq gmst < 24\text{ h})$$

11.3.5 Local mean sidereal time (lmst):

To calculate the local mean sidereal time (lmst) from a given gmst, we just need to add the east longitude to the gmst:

$$lmst = gmst + \frac{east.longitude}{15}$$

11.3.6 Hour angle:

Then the Hour Angle (ha) can be calculated using:

$$ha = lmst - ra \qquad (-12 < ha \leq 12\text{ h})$$

The Hour Angle is defined as negative before the sun reaches the meridian and positive when it has already reached the postmeridian hemisphere.

11.3.7 Azimuth and Elevation

Finally, to calculate the parameters that define the solar position which are the azimuth (az) and the elevation (el) WindFarmer uses the following equations:

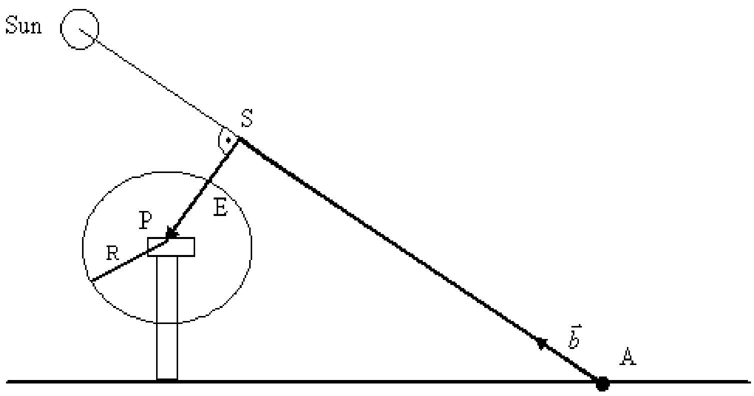
$$\sin(el) = \sin(dec)\cdot\sin(lat) + \cos(dec)\cdot\cos(lat)\cdot\cos(ha)$$

and then the calculation for azimuth angle which is measured from North (0°)

$$\sin(az) = -\cos(dec)\cdot\frac{\sin(ha)}{\cos(el)} \qquad (0° \le az < 360°)$$

11.4 Occurrence of shadow flicker

The occurrence of shadow flicker is determined by the wind turbine position (point P) and sun position (elevation angle and azimuth angle). The program calculates from these the minimum distance from the wind turbine hub to any point (S) on the line between the sun and the point of interest (A).



Shadow flicker calculation

Points A, P and S are represented by their vectors $\vec{a}$, $\vec{p}$ and $\vec{s} = \vec{a} + \lambda_S \vec{b}$

Vector $\vec{b}$ is the unit vector pointing from the receptor to the middle of the sun. It is given by:

$$\vec{b} = \begin{pmatrix} \cos(el)\sin(az) \\ \cos(el)\cos(az) \\ \sin(el) \end{pmatrix}$$

For vector AS to be perpendicular to vector PS we require: $\vec{b} \bullet (\vec{s} - \vec{p}) = 0$

This leads to vector SP, perpendicular to vector AS: $\overrightarrow{sp} = \vec{a} + \frac{\vec{b} \bullet (\vec{p} - \vec{a})}{\vec{b}\vec{b}}\vec{b} - \vec{p}$

WindFarmer compares the norm of vector PS with the radius R of the turbine. This is repeated in time intervals of, for example 1 minute, throughout one year, to detect if shadow is produced at the point of analysis, at this time. The program counts the minutes per day and the hours per year of shadow flicker caused by that wind turbine.

WindFarmer always considers the topography in the calculation, using the height ASL specified in the DTM file. WindFarmer optionally allows you to detect if the direct line of sight between receptor and turbine, or between the turbine and the sun is blocked by terrain features.

11.5 Modelling the rotor as a disc

If the rotor is modelled as a sphere, this represents the worst possible geometric scenario. This is the method we recommend. Alternative options in WindFarmer allow the rotor to be modelled in a vertical plane of defined orientation. When the distance between the rotor and the turbine tower centre is taken into account and the rotor disc model is being used, the worst case scenario occurs when the rotor is facing 180 degrees away from the sun's azimuth.

By taking into account the wind speed and direction frequency distribution, a more likely occurrence of shadow flicker can be derived, as compared with this geometric worst case.

11.6 Modelling the sun as a disc

If shadow flicker is calculated by modelling the sun as a disc, vector $\vec{b}$ points to the edge of the sun's disc closest to the rotor disc. The sun's diameter is assumed to be 0.351 degrees.

Please note that current standards and limits assume a point source and that this calculation option, whilst more accurately representing theoretical shadow flicker, should not be selected if the result is to be compared with such a limit.

11.7 Distance between rotor and turbine centre

Usually, the turbine positions are defined at the centre of the turbine tower. For the shadow flicker calculation, the position of the rotor is important as the rotor is the source of the shadow flicker. The calculation is very sensitive to changes in the relative position of source and receptor - the distance between the turbine rotor and the tower can become crucially important. WindFarmer calculates the rotor offset using:

$$rotor\ offset = \frac{1}{2} tower\ top\ diameter + tower\ \ position + disc\ depth$$

Tower top diameter, tower position and disc depth are defined in the 3D Designer in the Turbine Studio.

11.8 Notes

The shadow flicker calculation makes the following simplifications:

- that there are no clouds,
- that the turbines are always rotating
- a limit to human perception of the shadow flicker is not considered

12 VISUAL INFLUENCE

12.1 The terrain model

The Digital Terrain Model used to model visual influence consists of a regular grid of spot heights. These spot values are provided in a three column ASCII file (x, y, z) with the file extension *.DTM. Other digital terrain file formats can easily be converted to the DTM file format. The precision that can be achieved will be limited to the precision of the digital terrain model. Typically a grid resolution of 50 m is used. It is worth keeping in mind that locations (e.g. of turbines or houses), as well as heights in the DTM, typically have an associated error of 5-10 m.

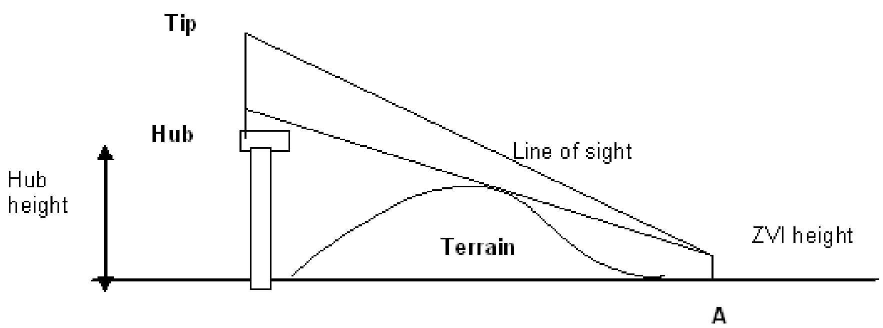
12.2 Line of sight algorithm

The algorithm checks either for a viewpoint or for each point of an area if the line of sight to the turbine is interrupted by a terrain feature. Different methods for checking this are used in the field:

- Checking if the line of sight falls below the connecting lines between pairs of adjacent DTM grid points.
- Checking if the line of sight crosses any of the two triangular areas formed by sets of three out of four corner points of a DTM cell.
- Checking if the line of sight crosses the interpolated area between the four corner points.

Methods like the first two give an advantage in speed and performance through simplification of the problem. WindFarmer uses the third method, checking the line of sight at regular intervals against the terrain height at this point. This method takes a little longer than alternative methods, but provides the highest level of accuracy.

12.3 Standard ZVI for hub and for tip visibility



Calculation of hub and tip visibility

A ZVI answers the question: “How many turbines can I see from a location?”. A ZVI calculation can be carried out for a single point, or for an area. Each ZVI point is calculated for a specific ZVI height (usually 2m) above ground level. A standard ZVI shows how many wind turbines are visible at observer point A, where visibility is defined as either

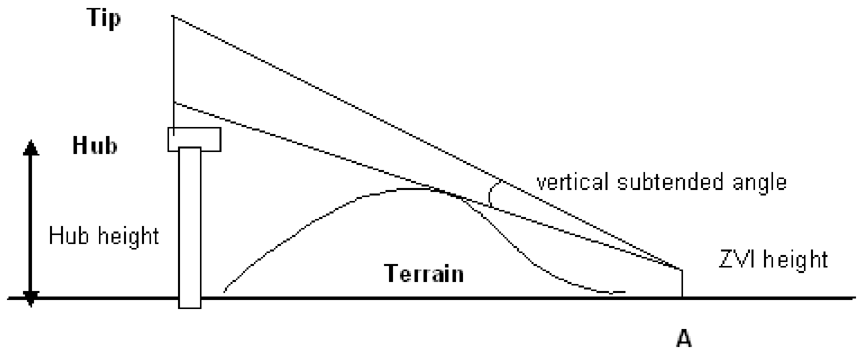
- at least the hub being visible

  or, more sensitively

- at least the tip of any blade being visible.

The accuracy of a ZVI can be assessed by comparing the result of the ZVI with a visualisation from the same point of interest. In the example above, the blade tip is visible, but the hub is not. For example comparisons with field observations, see [12.1]

12.4 Vertical subtended angle

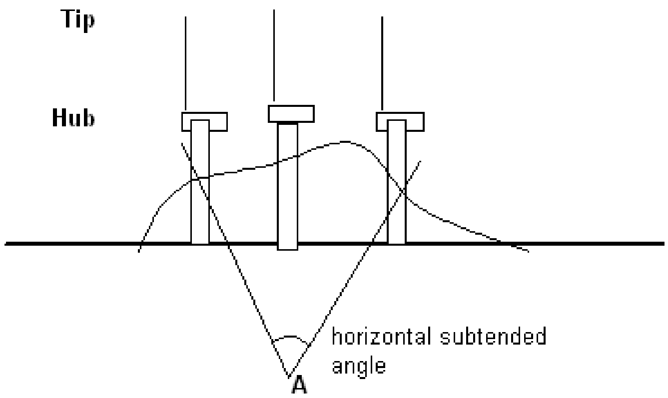


Vertical subtended angle

In flat, offshore areas or on top of hills, wind turbine visibility presented in a ZVI will show turbine visibility over large distances. The severity of the impact will, however, decline with distance. The vertical subtended angle is used to add a quantitative measure of severity to the standard ZVI, answering the question "How large are the turbines in my field of view?"

The vertical subtended angle is calculated as the vertical angle between the lowest visible part of any turbine (either tower or rotor) and the highest visible part of any other turbine.

12.5 Horizontal subtended angle



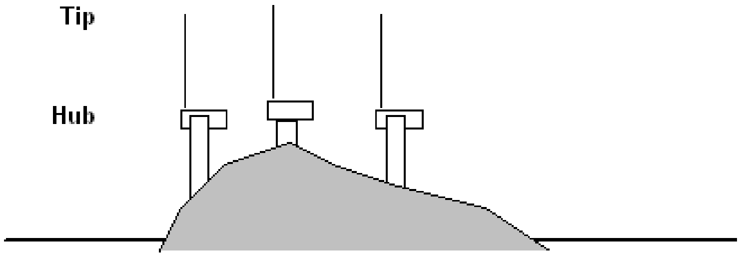
Horizontal subtended angle

The horizontal subtended angle is used in a similar way to the vertical subtended angle. It expresses the angle of horizontal view which includes turbines.

The horizontal subtended angle is calculated as the angle between the left most visible turbine and the right most visible turbine. Note that the rotor blades are not included in the horizontal subtended angle, except in determining whether a turbine is visible or not.

The subtended angles of 'All sites' provides a value for the visual impact of all the projects in a workbook. This value is simply the sum of the subtended angles of each of the individual projects.

12.6 Visibility of site



Visibility of site

Site visibility is an expression for the percentage of the whole wind farm that is visible from a location. Turbines that are close to that location get a higher weighting than turbines that are far away from the location:

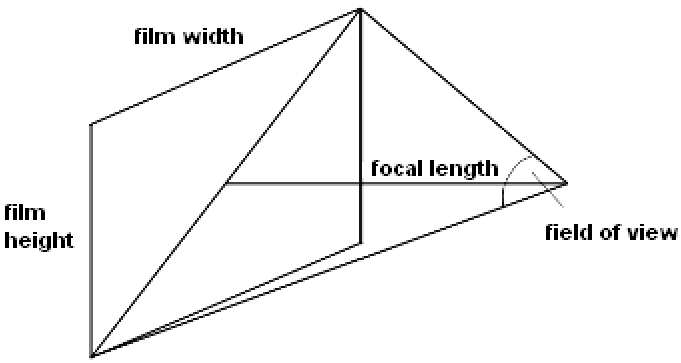
$$Visibility\ \ of\ \ site = \frac{\sum_{turbines} VSA}{\sum_{turbines} VSA_{no\ blockage}}$$

VSA Vertical subtended angle for individual turbine
VSA $_{\text{no blockage}}$ Vertical subtended angle for individual turbine without blockage by the terrain

The vertical subtended angle without blockage by the terrain is calculated as the vertical angle between the tower base and the upper tip of the turbine.

12.7 Field of view

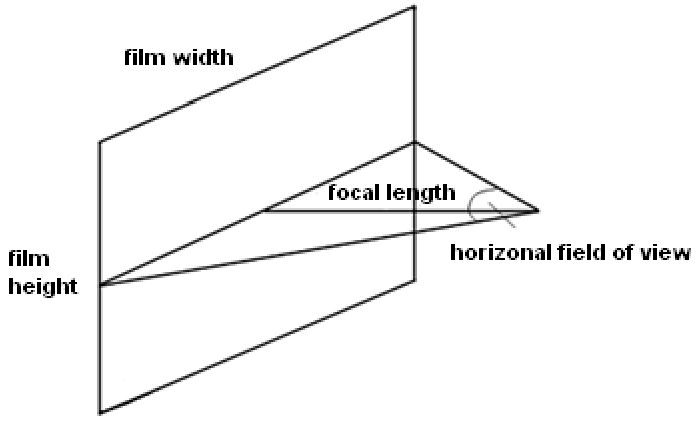
The Visualisation Module in WindFarmer allows you to create visualisations and photomontages of wind farms. The view in the Visualisation Window can be presented as it would be on a photograph when using the ‘Fit to Film’ option. This requires a correct definition of width and height of the film as well as the focal length of the camera. From these data the field of view and the horizontal field of view are calculated.



The field of view is defined as:

$$Field\ \ of\ \ view\ (\text{degrees}) = 2 \cdot \arctan\left(\frac{\sqrt{film\ width^2 + film\ height^2}}{2 \cdot focal\ length}\right)$$

12.8 Horizontal field of view



The field of view is defined as:

$$Horizontal\ \ field\ \ of\ \ view\,(\text{degrees}) = 2\cdot\arctan\left(\frac{film\ width}{2\cdot\ focal\ length}\right)$$

13 SUMMARY

WindFarmer is a sophisticated and versatile package, designed not just for the prediction of the energy yield of a wind farm, but also for:

- Long-term correlation of measured wind data
- Optimisation of wind farm layout
- Wind farm noise calculation
- Noise constrained turbine placement
- Electrical infrastructure design and loss calculation
- Shadow flicker calculation
- Prediction of wind farm induced turbulence intensity
- Financial modelling
- Visualisation and photomontage

Because of the large number and complexity of the topics, it is unfortunately not possible to describe all of them in as much detail as we would like. Please consult the quoted literature for more, in-depth reading and the WindFarmer Validation Report for comparisons with measured data. Useful information regarding the application of the WindFarmer models presented in this manual can also be found in the User Manual. Last but not least, please do not hesitate to ask the WindFarmer user support team if you need any further information or have suggestions to improve this document further.

14 REFERENCES

1.1 Euro building code – ENV 1991-2-4:1995

1.2 British standard building code - BS 6399: Part 2:1997

3.1 IEC 61400-12-1 (2005), “Wind turbines, Part 12-1: Power performance measurements of electricity producing wind turbines”, First edition

4.1 Ainslie J F, “Development of an eddy viscosity model for wind turbine wakes”, Proceedings of 7th BWEA Wind Energy Conference, Oxford 1985.

4.2 Ainslie J F, “Development of an Eddy Viscosity model of a Wind Turbine Wake”, CERL Memorandum TPRD/L/AP/0081/M83, 1983.

4.3 Sanderhoff P, “PARK – User’s Guide”, RISØ, 1993

4.4 Jensen N, “A note on wind generator interaction”, RISØ M-2411, 1983

4.5 Katic I, Høstrup J and Jensen N, “A simple model for cluster efficiency”, EWEC’86

4.6 Tennekes H and Lumley J, “A first course in turbulence”, MIT Press, 1980

4.7 Prandtl L, “Bemerkungen zur Theorie der freien Turbulenz”, ZAMM, 22(5), 1942

4.8 Ainslie J F, “Calculating the flowfield in the wake of wind turbines”, Journal of Wind Engineering and Industrial Aerodynamics, Vol 27, 1988

4.9 Taylor G J, “Wake Measurements on the Nibe Wind Turbines in Denmark”, National Power, ETSU WN 5020, 1990.

4.10 Press W H et al. “Numerical Recipes in FORTRAN”, 2nd Edition, Cambridge University Press, 1992.

4.11 Quarton D C and Ainslie J F, “Turbulence in Wind Turbine Wakes”, J Wind Eng, Vol. 14 No. 1, 1990.

4.12 Vermeulen P and Builtjes P, “Mathematical Modelling of Wake Interaction in Wind Turbine Arrays, Part 1”, report TNO 81-01473, 1981

4.13 Vermeulen P and Vijge J, “Mathematical Modelling of Wake Interaction in Wind Turbine Arrays, Part2”, report TNO 81-02834, 1981

4.14 Hassan U, “A Wind Tunnel Investigation of the Wake Structure within Small Wind Turbine Farms”, Department of Energy, E/5A/CON/5113/1890, 1992

4.15 Smith G, et al. “Advanced wake model for very closely spaced turbines” EWEC conference, Athens, 2006.

4.16 Barthelmie R et al. “Efficient development of offshore wind farms (ENDOW)”. Riso National Laboratory, Final report Riso-R-1407(EN), 2003

4.17 Rathman, O., Barthelmie R and Frandsen, S. “Turbine Wake Model for Wind Resource Software” EWEC2006 Athens

4.18 Bossanyi, E.A.; Maclean, C.; Whittle, G.E.; Dunn, P.D.; Lipman N.H.; Musgrove, P.J.; The Efficiency of Wind Turbine Clusters, International Symposium on Wind Energy Systems, Lyngby, Denmark, 1980.

4.19 Crafoord, C.; An Estimate of the Interaction of a Limited Array of Windmills, Department of Meteorology, University of Stockholm, Sweden, Report DM-16, 1975.

4.20 D.J. Milborrow; The Performance of Arrays of Wind Turbines, Journal of Industrial Aerodynamics, 5 pp 403-430, 1980.

4.21 Newman, B.G.; The Spacing of Wind Turbines in Large Arrays, Energy Conversion Vol. 16 pp 169-171, 1977.

4.22 Schlez, W., Neubert, A and Smith, G M “New Developments in Precision Wake Modelling“ DEWEK 2006, Bremen

4.23 Schlez, W. Neubert, A. “New Developments in Large Wind Farm Modelling”, EWEC2009 Marseille, France, 2009.

5.1 Neubert, A, Shah, A and Schlez, W “Maximum yield from symmetrical wind farm layouts “ DEWEK 2010, Bremen

6.1 IEC 61400-1 (2005), “Wind turbines, Part 1: Design requirements”, Third edition

6.2 IEC 61400-1 (1998), “Wind turbines, Part 1: Design requirements”, Second edition

6.3 Sten Tronæs Frandsen, “Turbulence and turbulence-generated structural loading in wind turbine clusters”, Risø-R-1188(EN), 2005

6.4 DIBt (Deutsches Institut für Bautechnik), „Richtlinie für Windenergieanlagen, Einwirkungen und Standsicherheitsnachweise für Turm und Gründung, Schriften des Deutschen Instituts für Bautechnik“, Reihe B, Heft 8; 2004

6.5 IEC 61400-1 (2005), “Wind turbines, Part 1: Design requirements”, Third edition, Amendment 1 (2010)

9.1 International Standard ISO (International Organisation for Standardization) 9613-2, “Acoustics – Attenuation of sound during propagation outdoors – Part 2: General method of calculation

9.2 International Standard ISO (International Organisation for Standardization) 9613-1, “Acoustics – Attenuation of sound during propagation outdoors – Part 1: Calculation of the absorption of sound by the atmosphere

9.3 Klug H, Mellert V, Radeke U, „Zuverlässigkeit von Geräuschimmissionsprognosen bei gewerblichen Anlagen“, Forschungsbericht 89-105 02 702, Umweltforschungsplan des Bundesministeriums für Umwelt, Naturschutz und Reaktorsicherheit, 1989

11.1 Seidelmann K (ed.) “Explanatory supplement to the Astronomical Almanac”, 1992

11.2 Michalsky JJ, “The Astronomical Almanac’s Algorithm for Approximate Solar Position (1950-2050)”, Solar Energy (40) 3 pp 227-235, 1988

12.1 Tindal AJ and Garrad AD “Zones of Visual Influence and Photomontages – a Validation” Procs BWEA 1994