12 ENERGY - LOSS & UNCERTAINTY

12.0 ENERGY - LOSS & UNCERTAINTY

12.1 Introduction, definitions and step-by-step guide

After calculating the expected AEP (Annual Energy Production) with the WindPRO PARK module, the next step to bring a wind farm project to a “Bankable” level is to estimate losses and uncertainties. Losses have the recent years become a more and more important part of the AEP estimate, partly because the losses typically are higher for modern wind farm projects, partly because the margin in AEP estimates has been lowered due to larger project sizes, and more tight budgets for wind farm projects. While wind farm investments have increased heavily, the need of knowing the uncertainties similarly has become of huge importance to get the projects financed.

With the WindPRO LOSS & UNCERTAINTY module the estimation of expected losses and uncertainties can be performed on a structured basis, with numerous tools for quantifying the individual components quite accurately.

Besides losses and uncertainties, the module also offers a Bias correction part. A Bias is a “known issue”, like model problems (e.g. RIX correction) or wind speed measurement errors, which have not been corrected in the calculation basis.

12.1.1 Basic definitions

The basic concept behind the module is:

Calculated GROSS AEP
+/- BIAS correction
- LOSSES
= NET AEP (expected sold energy production) = P50

The expected NET AEP is also named the P50 value, which is the expected outcome of the project. There is a probability of 50% that the outcome will be more than P50 and a probability of 50% that the outcome will be less. This can also be named the “central estimate”. The uncertainty must be judged/calculated to find out how accurate the estimate is, and thereby the risk of getting a lower outcome than expected.

Including the uncertainty the AEP estimate is assumed to follow a normal distribution. All uncertainty components are assumed independent and, thus, combined as standard deviations, i.e. the square root of summed squares of individual contributions. The individual uncertainty components, judged or calculated, shall be given as 1 std dev (Standard Deviation or simply σ).

If the std dev (hereafter σ) is 10%, this means that the production at a given AEP exceedance level (PXX) for a calculated result can be calculated using the inverse normal distribution as:

P84 = P50 – 1 x Uncertainty (= P50 - 10%, for σ=10% as above)
P90 = P50 – 1,28 x Uncertainty (= P50 - 12,8%, for σ=10% as above)

Below are listed additional coverage factors for other typical exceedance levels (e.g. 75%), all based on the normal distribution.

Prob. (%)	Coverage factor
50	(0,00)
75	0,67
84 *)	1,00
90	1,28

95	1,64
99	2,33

**) For P84,00 the coverage factor is not exactly 1,00 but 0,99. The coverage factor 1,00 corresponds to P84,13 which we round off to P84 here for convenience.*

A special component in the uncertainty evaluation is the year-to-year variability of the wind, which can be included in the calculations. The variability describes how much the annual average wind speed varies from year-to-year for the region. This figure can be calculated in the MCP module based on long term data series, or it can be found in different research projects.
The expected probability of exceedance is calculated for 1, 5 10, 20 years with the variability for the time span in question included in the uncertainty. Contrary to the other uncertainties the variability depends on how many years the forecast covers, referred to as “expected lifetime”. This can be of importance for judgment of the risk of the investment.

12.1.2 Understanding the uncertainty concept (Probability of exceedance)

The uncertainty concept is well illustrated by the figure below.

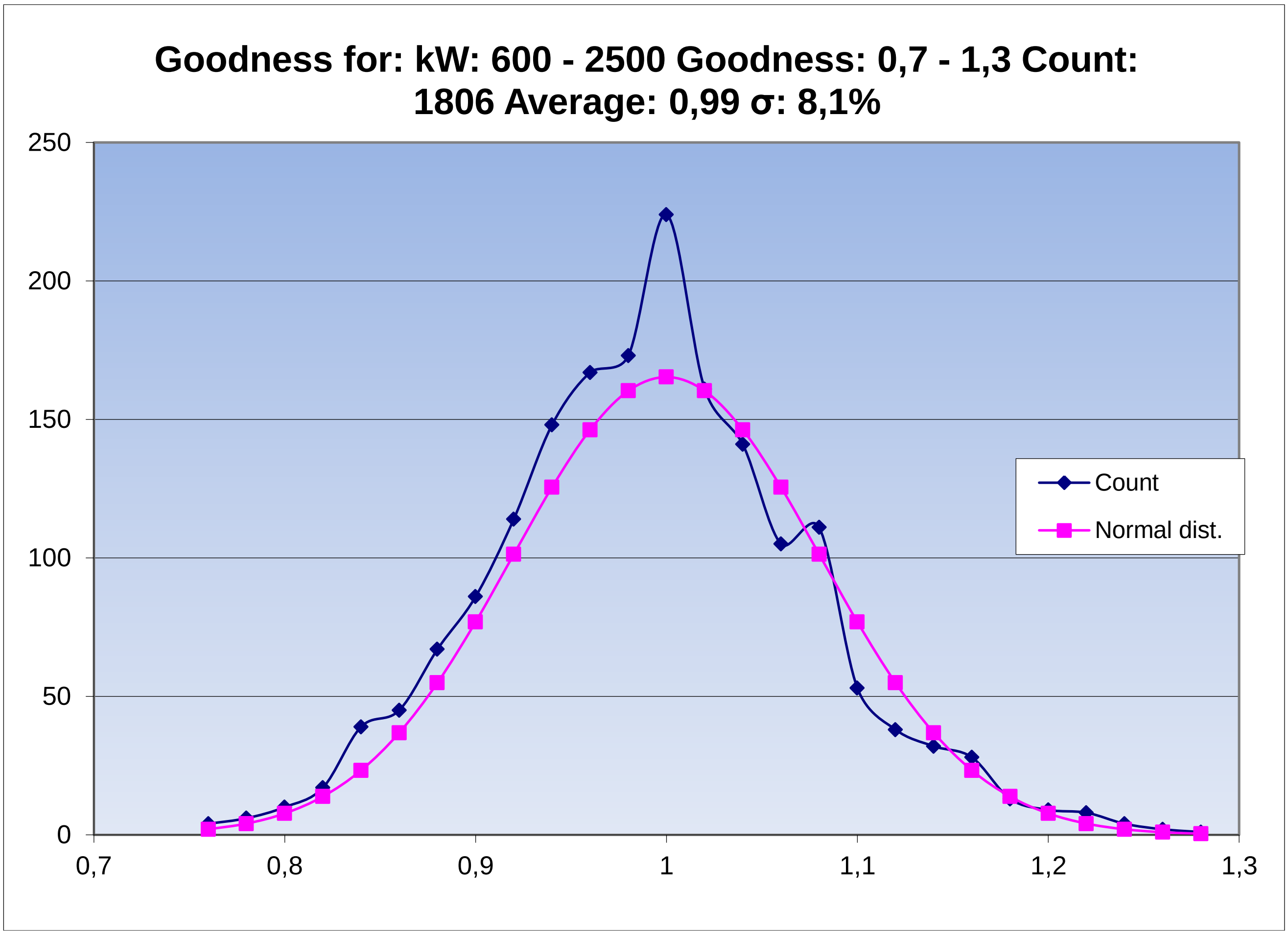


Figure 1 Based on calculations of 1806 wind turbines in Denmark, the count of goodness factor (Actual/calculated AEP corrected with wind energy index) for each turbine shows that the actual results are close to a normal distribution with a σ of 8,1%. In other words the uncertainty for these calculations is 8,1%.

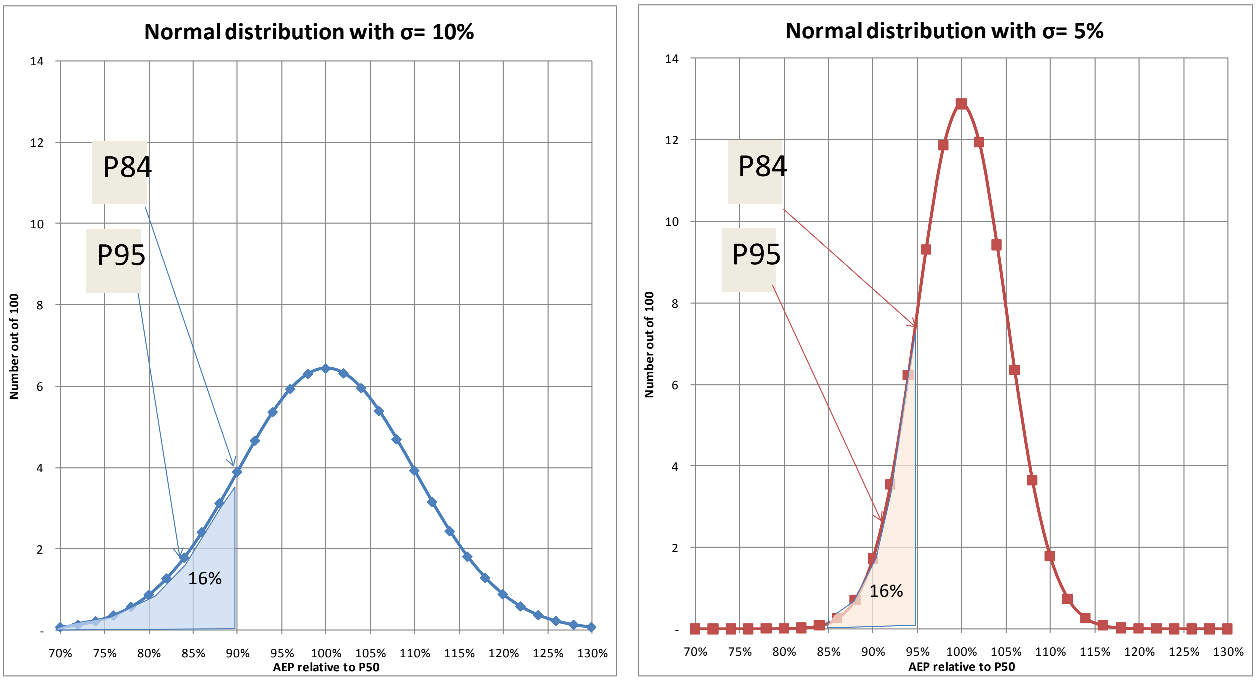


Figure 2 The Normal distribution is defined so that roughly 2/3 (more precisely 68,3%) of all events will be within +/- 1σ and around 32% is outside. In the one tail (e.g. below -1σ), there is around 16%, so there is 16% probability that the estimate will be below 1σ subtracted from P50, or 84% probability that it will be above (exceed). In other words, the P84 is the value where 84 out of 100 realizations will result in an outcome better than P84. For P95, there is only 5% probability to get an outcome poorer than this exceedance level which is found by subtracting the σ multiplied by 1,64 from the P50. So for σ=10%, the P95 value in the left graph where 5% would be "in the shaded area" (P95), would be found 16,4% below 100%, i.e. at 83,6% on the x-axis. Similarly, if σ=5%, 5% x 1,64 = 8,2%, so P95 is found at AEP of 100%-8,2% = 91,8% of the P50 on the x-axis.

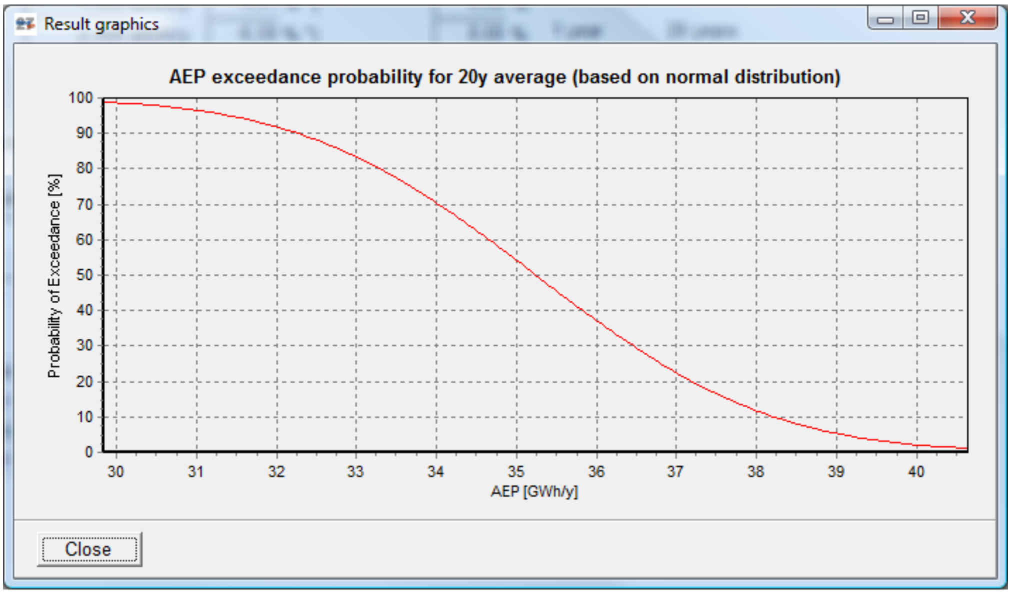


Figure 3 The probability of exceedance will normally be shown as a cumulative graph showing the probability of exceedance on the y-axis and the corresponding AEP PXX values on the x-axis.

12.1.3 What is included in GROSS value?

The module follows the DNV (Det Norske Veritas) definition as presented at AWEA 2008:

Included in GROSS calculation:
- roughness effects
- topographic effects
- obstacle effects
- air density correction
- (long term correction)
- (wind data correction)

Last two should be included, but it is up to the user to decide what is included. If e.g. a post calibration show that the wind data has been offset, it can be decided to redo PARK calculations with updated wind data or it can be decided to include the offset as a Bias correction of the GROSS.

NOT included in GROSS calculation:
- Wake losses (The PARK result includes wake losses, but these are “taken out” in the loss module so the “real Gross” based on the DNV definition is used as basis for all loss reductions.
- Other losses like availability, grid losses etc., see complete list below.
- Model issues like RIX correction or known power curve bias, will should be included as Bias, not as Losses, because these are considered “known issues” and should thereby be treated as corrections to the calculation results applied before the loss evaluation.

The structure of the module set demands to the user keeping track of what has already been compensated in the PARK AEP calculation, and what should be added in the loss, bias and uncertainty evaluation. The only “automized” issue is that the wake losses are taken out of the WindPRO PARK AEP calculation (the size of the wake loss is automatically filled in), so the LOSS & UNCERTAINTY module starts from the non wake loss added wind farm AEP calculation result.

The module has these features:
1. All Bias, loss and uncertainty components can be judged by the user and entered manually.
2. Some of the components can be calculated by the software based on different data sources, typically wind data time series.

The wind data time series are used to divide the expected AEP in time steps, to enable calculation of time, wind speed or wind direction dependent losses. But also links to other WindPRO calculations like SHADOW can be used to give an accurate estimate of AEP loss due to flicker stop, or a PARK RIX calculation can be used to perform a RIX bias correction.

12.1.4 Loss definitions

The loss definitions in the module follow the below definitions (in *italic* the EMD modifications). Note we have switched group 1 and 2 relative to the original paper so Wake effects occur first and availability second.

Paper, AWEA 2008: Standard Loss Definitions for Wind Resource / Energy Assessments
Prepared by Steve Jones of Global Energy Concepts (DNV)

Standard Loss Category	Recommended Subcategories	Comments
1. Wake Effects	Wake effects, all WTGs	Losses within the turbines which are the subject of the energy assessment. Helimax currently includes wake losses in the gross yield. Losses on the turbines which are the subject of the energy assessment, from identified turbines that are not the subject of the energy assessment, which either already operate or which are expected to operate the entire useful life of the facility being studied. *If the PARK calculation includes existing turbines (which it should), the wake losses from as well internal as external wake effects are included in the wake loss calculation, therefore the EMD has brought the two groups from original document into one.*
1. Wake Effects	Future wake effects	Losses due to additional development in the vicinity of the turbines being studied, but which would occur after commissioning of the turbines being studied.

Standard Loss Category	Recommended Subcategories	Comments
2. Availability	Turbine	GEC further divides this into routine maintenance, faults, minor components, and major components. AWS Truewind uses a separate factor (Availability Correlation with High Wind Events) that could be buried into this number or categorized with "7. Other" below.
2. Availability	Balance of plant (*Substation)*	Losses due to downtime in components between the turbine main breaker to and including project substation transformer and project-specific transmission line.
2. Availability	Grid	Losses due to downtime of power grid external to the wind power facility.
2. Availability	Other	Other availability losses not accounted for above or in other categories below.
3. Turbine performance	Power curve (can be part of Bias)	Losses due to the turbine not producing to its reference power curve (even with new blades and wind flow within test specifications).
3. Turbine performance	High wind hysteresis	Losses due to shutdown between high-wind cutout and subsequent cut back in.
3. Turbine performance	Wind flow	Losses due to turbulence, off-yaw axis winds, inclined flow, high shear, etc. These represent losses due to differences between turbine power curve test conditions and actual conditions at the site.
3. Turbine performance	Other	Other turbine performance losses not accounted for above.
4. Electrical	Electrical losses	Losses to the point of revenue metering, including, as applicable, transformers, collection wiring, substation, transmission.
4. Electrical	Facility consumption	Losses due to parasitic consumption (heaters, transformer no-load losses, etc.) within the facility. This factor is not intended to cover facility power purchase costs, but does include the reduction of sold energy due to consumption "behind the meter."
5. Environmental	Performance degradation not due to icing	Losses due to blade degradation over time (which typically gets worse over time, but may be repaired from time to time), and blade soiling (which may be mitigated from time to time with precipitation or blade cleaning).
5. Environmental	Performance degradation due to icing	Losses due to temporary ice accumulation on blades, reducing their aerodynamic performance.
5. Environmental	Shutdown due to icing, lightning, hail, etc.	Losses due to turbine shutdowns (whether by the turbine controller, SCADA system, or by an operator) due to ice accumulation on blades, lightning, hail, and other similar events,
5. Environmental	High and low temperature	Losses due to ambient temperatures outside the turbine's operating range. (Faults due to overheating of components that occur when ambient conditions are within the turbine design envelope would be covered under turbine availability category above.)
5. Environmental	Site access and other force majeure events	Losses due to difficult site access due to, for example, snow, ice, or remote project location. Note that this environmental loss and some other environmental losses may be covered under the availability definition, above. However, these "environmental" losses are intended to cover factors outside the control of turbine manufacturers.
5. Environmental	Tree growth or felling	Losses due to growth of trees in the facility vicinity. This loss may be a gain in certain cases where trees are expected to be felled.
6. Curtailment	Wind sector management	Losses due to commanded shutdown of closely spaced turbines to reduce physical loads on the turbines.
6. Curtailment	Grid curtailment and ramp-rate	Losses due to limitations on the grid external to the wind power facility, both due to limitations on the amount of power delivered at a given time, as well as limitations on the rate of change of power deliveries.
6. Curtailment	Power purchase agreement curtailment	Losses due to the power purchaser electing to not take power generated by the facility.

Standard Loss Category	Recommended Subcategories	Comments
6. Curtailment	Environmental, Noise	Losses due to shutdowns or altered operations to reduce noise and shadow impacts, and for bird or bat mitigation. This would include use of a low-noise power curve vs. a standard one from time to time. *For Noise and flicker, there are in WindPRO access to detailed calculation options. Therefore EMD has expanded this with more groups, same for Birds and Bats, which can be set based on "free of choice" parameters like date interval, hour interval etc.*
6. Curtailment	Environmental, Flicker	
6. Curtailment	Environmental, Birds	
6. Curtailment	Environmental, Bats	
7. Other		This would cover anything that doesn't fit into the above six main categories.

12.1.5 Step-by-step guide

- Establish a PARK calculation (see Energy, Section 3.3.5), <u>BUT note the following:</u>
  If more site data objects or turbine types are used, group these in separate layers before calculation.
  If RIX Bias correction should be included, make the RIX calculation in PARK
  If calculation of time dependent losses etc. makes sure you have a proper time series with required data. The WTI generator in Meteo analyzer tool may be used to establish this. Include temperature if high/low temperature shut down is expected. Include turbulence or gust if high wind hysteresis loss are expected.
- Start LOSS & UNCERTAINTY module
- Load PARK calculation
- You may attach a wind data time series from Meteo object or WTI file
- Input needed parameters in Bias, Loss and Uncertainty tab sheets
- Where "Edit" buttons are available, start detailed calculations – you might need to go back to "Main" to reselect the wind data to more a or less detailed series.
- When all inputs are established, review at "result" tab and start calculation for generating report by OK.

12.2 Basic data for calculations

A PARK calculation is the basis. From this all relevant data on AEP for each turbine, wake loss, elevation, hub height etc. are loaded. In addition sensitivity is calculated. The sensitivity defines the transfer from changes in wind speed to changes in AEP for each turbine by recalculation of the PARK with a small change in wind speed. It is worth to notice that if a RIX bias calculation is wanted, the PARK calculation loaded must hold a RIX calculation. Similarly, if a flicker stop loss calculation is wanted, there must be a shadow calculation for exactly the same wind farm configuration as in the loaded park calculation. For Noise loss calculation it must be noted that if the PARK calculation already includes turbines in noise reduced mode, no additional Noise loss should be entered. If it is a wish to present the loss due to noise in the loss calculation, the PARK calculation must be based on no noise reduced turbines, and the noise reduced modes must then be implemented in the loss module. We are aware of this is somewhat "tricky" and the handling of noise loss calculation will be improved further in the future. If for example the noise reduced mode only occurs during e.g. night hours, the Loss&Uncertainty module is very convenient to use, as the calculation setup allows limiting the noise reduced mode to specific hours or wind directions.

In addition following data can be used:

Climate data as time series: Either by link to a Meteo object time series or to a .WTI file (Wind TIme variation file that can be established from the Meteo analyzer or selected from the WindPRO Data\Standards\ folder).

Power curve uncertainty can be specified detailed in the WTG catalogue and used from uncertainty module, but also simpler approaches for this calculation are available if no detailed data are available for the turbine.

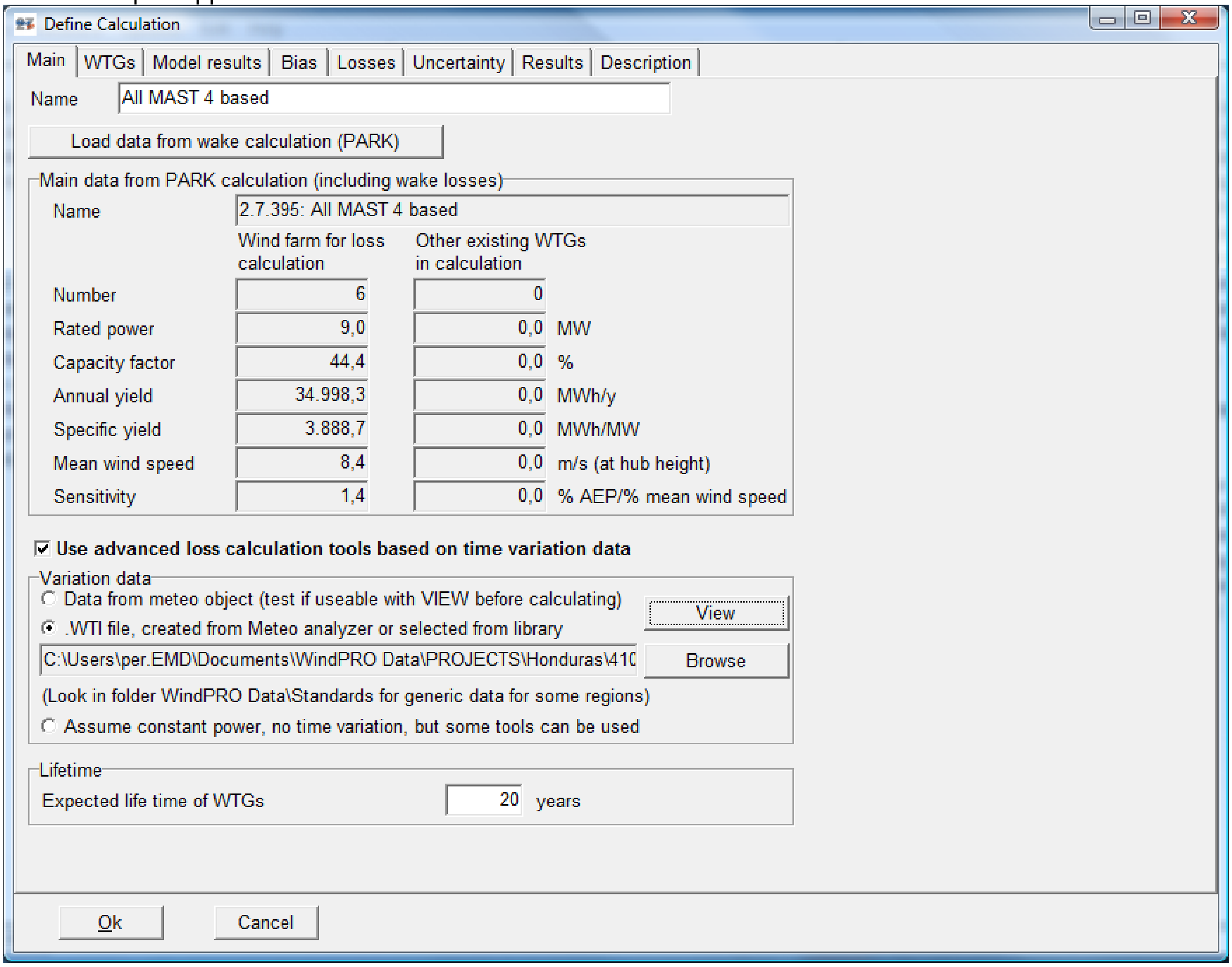


Figure 4 The "Main" tab where PARK calculation is loaded. If existing turbines are included in the PARK calculation, it can be decided if these shall be included in the loss & uncertainty evaluation. Further it is possible only to include the existing turbines if these are flagged "treat as PARK WTG" (property on existing WTG objects).

This tab shows the main results from the PARK calculation and the calculated sensitivity for propagation of changes in wind speed to changes in AEP (AEP%/ws%).

Checking the "Use advanced loss calculation tools…" gives access to add time varying data or to assume constant power. The last option is used if no time varying data are available, but the user still wants to calculate flicker or temperature loss assuming constant AEP in each time step.
The expected lifetime only influences the uncertainty contribution from the variability of the wind. All other calculations are based on annual averages. The uncertainty component coming from the year to year variability decreases with the number of years and will thereby be lower the longer the lifetime (part of the variability is averaged out).

12.2.1 Climate data

Several loss calculations are based on climate data including also temperature data. Of high importance is that the climate data represent a typical year. A time series averaged over several years will not hold the information of the dynamic behavior that is of high importance for the expected shut down situations of the wind turbines. However, calculations can be performed based on more than 1 year of data in a Meteo object.

In a Meteo object, a data set of one or more years of data can be established from more years of data by disabling data, so that one or more representative year(s) is enabled. If the data series merely holds a ½ year or 1½ year, the calculation will be seasonally biased. This should be avoided. But no matter how long (or short) period of data the Meteo object used hold, it is important to remark that the calculations always will assume these data long term representative and scale the calculations to annual values.

A specific way to establish exact 1 year of data prepared for such analysis is found in the Meteo analyzer. Here you can generate exactly 1 year of data with a specific temporal resolution (data can be down or up sampled) based on one or more time series in Meteo objects. See further details in the chapter on time varying data from Meteo analyzer.

12.2.2 Model results

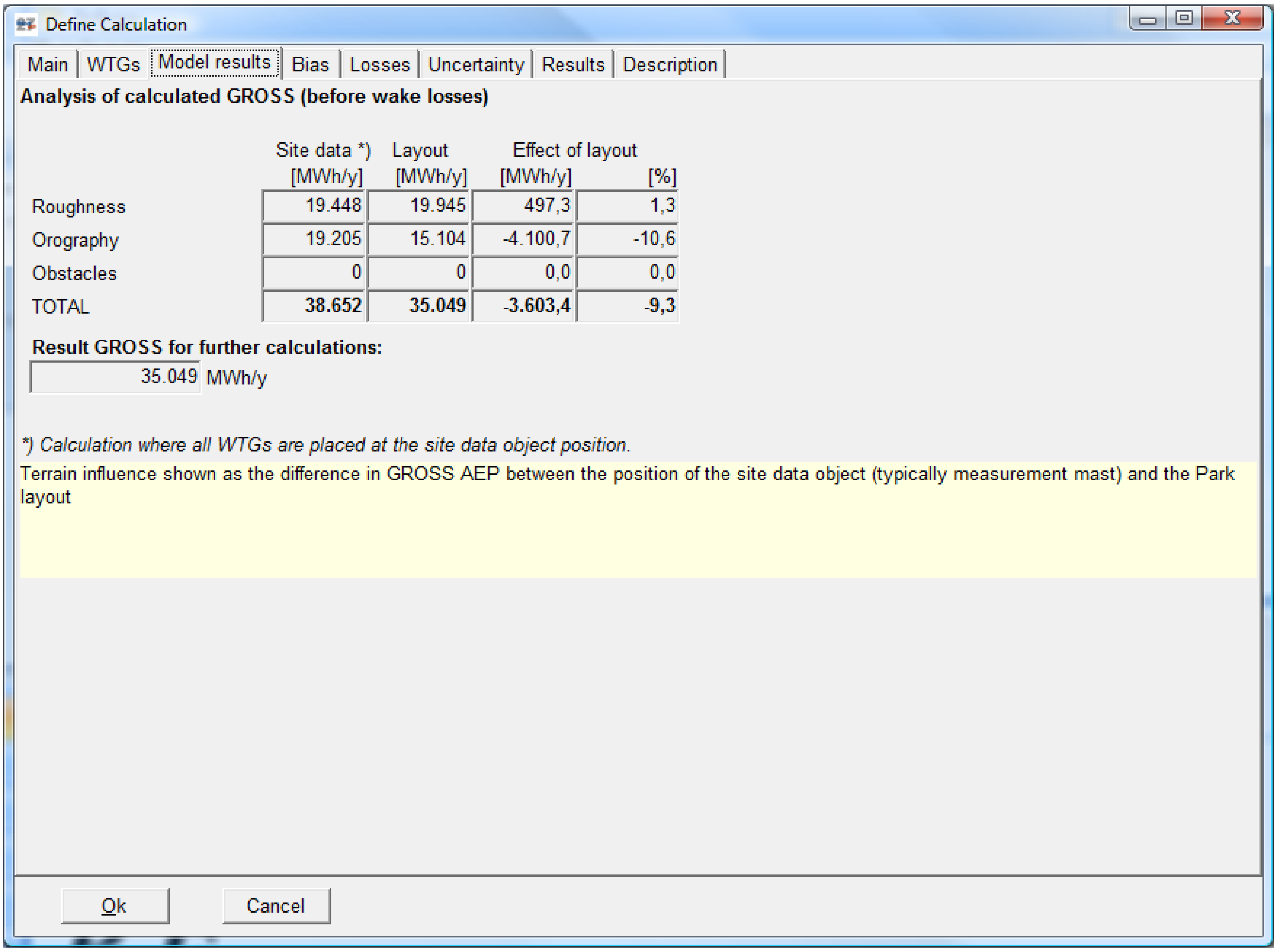


Figure 5 At the Model results sheet an evaluation of the effect of the layout is given.

The effect of the layout gives an idea of how large model corrections are applied. The software calculates the AEP if all turbines are positioned at the position(s) of the site data object(s) – if more than one site data objects, the turbines “belonging” to a specific site data object is moved to this object and calculated. This is compared to the actual calculation with the turbines at their “real positions” (the Layout). Thereby it can be seen how much the model transforms data based on roughness, orography and local obstacles. The higher the effect of the layout, the higher the risks are of errors in calculations if the model does not perform accurately. In other words, the more measurement masts the calculation is based on, the lower the effect of the layout, or the lower complexity of terrain/roughness, the lower the effect of the layout.

Note the results here are EXCLUDING wake losses; these are simply taken out of the calculation and transferred automatically to the LOSS sheet where belong according to the DNV standard definitions.

12.2.3 General concept for input of data in bias, loss and uncertainty sheets

In general there can only be entered one value for a loss/bias/uncertainty to represent the entire wind farm. But if a calculation module is available (i.e. an "Edit" tickbox), values can be entered in a more flexible way:

- Individually for each turbine
- For all turbines on a specific layer (in Maps&Objects)
- For all turbines

This means that if there is a need for specific data on half of the turbines and other values on the other half, it would be a very good idea to place these two groups in different layers in the project setup. A lot of individual input can then be avoided. An example could be if a wind farm is established with 2 or 3 different wind turbine types or if e.g. one group is more exposed (on a ridge) than another group and therefore needs a lower cut out wind speed value.

Input of data for an individual turbine or for all turbines in a layer is simply selected by clicking with the mouse on the individual turbine or on the specific layer. The input will then be assigned to the selected turbine or group.

12.3 Bias

Bias is a correction for "known issues", like e.g. the RIX (Ruggednes IndeX) modifications of wind speeds in complex terrain introduced by RISØ, or e.g. power curve correction, where those are known to be too pessimistic or optimistic based on experience or evaluation by the HP method. Also wind measurements can have a known bias. For example specific anemometers are known to have a systematic error, or post calibration could show an error, in both cases it is more convenient to include these corrections as biases than by reanalyzing all the wind data behind the calculations. It is important is that bias corrections only are included once, either in the data basis of the PARK calculation or as a bias in the LOSS & UNCERTAINTY module. An advantage by having bias corrections in the LOSS & UNCERTAINTY module is that it will be clearly documented, and easy to change if new information appears at a later stage.

A bias can be entered as a simple correction in percent either on wind speed or in percent on AEP. If entered as wind speed percentage, this quantity is converted to percent on AEP using the sensitivity AEP%/WS% (WS=Wind Speed). The AEP percentage is then multiplied with calculated GROSS and added (or subtracted) to GROSS before loss subtraction. Remember that a bias can have a positive or negative value - so do remember the sign.

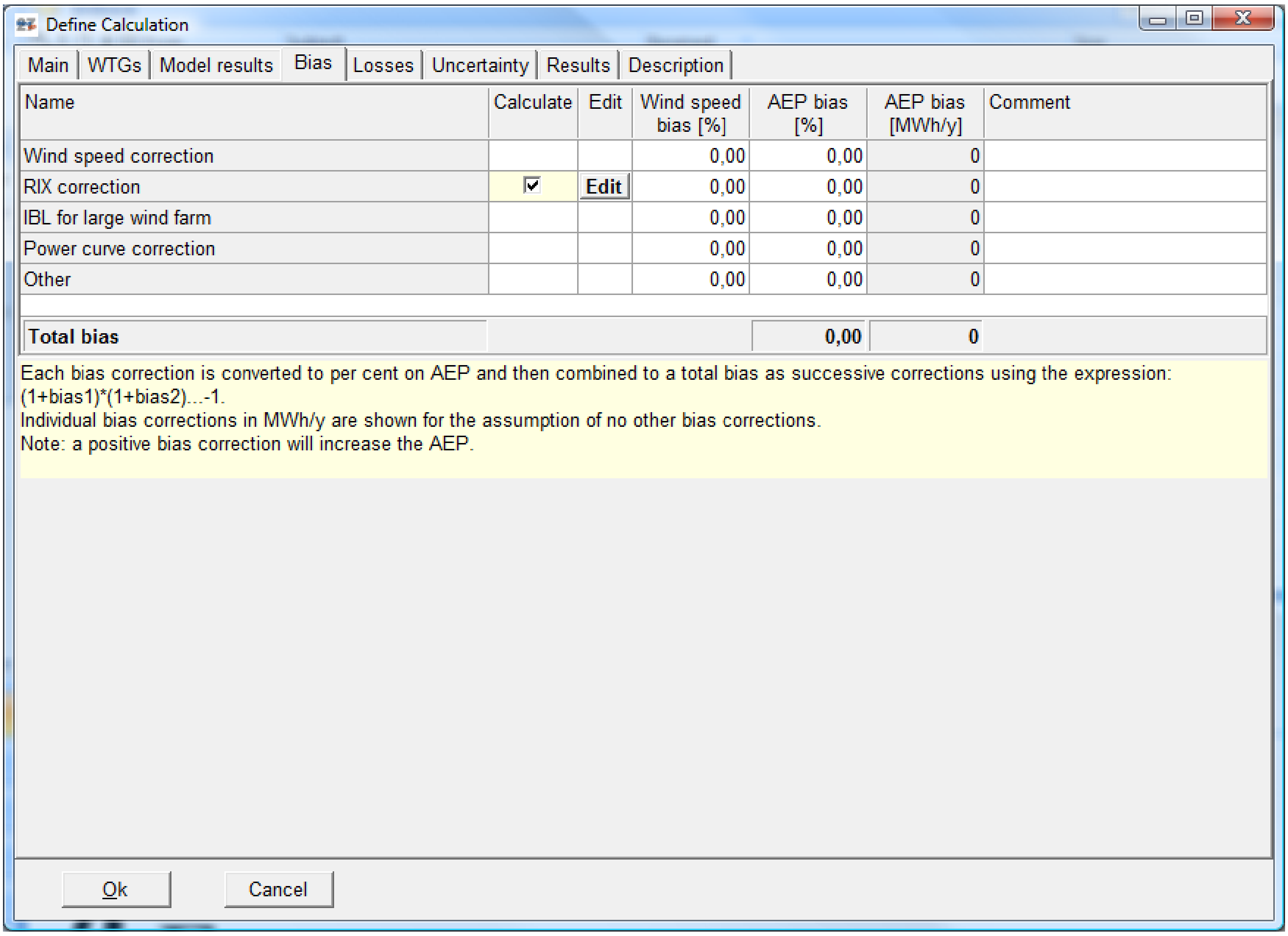


Figure 6 The input form for Bias. The RIX correction tick box is only available if the loaded PARK calculation includes a RIX calculation.

As seen above five different predefined bias input lines are available. If PARK calculation includes a RIX calculation, there will be a “calculate” tick box option for this (see next chapter for details).

12.3.1.1 Wind speed correction

If the wind data is known to have a bias, which has not already been corrected in the wind data used for the PARK calculation, the correction should be included here.

Wind data bias can have many reasons and is probably the most frequent reason for biased calculation results. But it can be very difficult to discover such a wind speed bias. The best method to avoid wind bias is to have more wind data sources for the site/region. Existing turbines with available production figures present near the site is also a valuable source of validation of the wind data level.

If local wind measurement equipment is used, the wind data correction can simply be due to known offset related to the equipment used. Often this will be corrected for at previous stage in calculations, if so it SHALL NOT be entered as a bias, the correction would then be double. But it is a good idea to write a comment if corrections are performed before PARK calculation, or if any validation of the wind speed level is made.

The correction can be entered as a modification on wind speed or AEP, remember to include the sign (- if it is a reduction) of the bias, because corrections can go in either directions.

12.3.1.2 RIX correction

For details, see 12.3.2. If a RIX correction proposal is made via another tool than WindPRO, or it just is a rough user estimate, the correction can be entered here. But it will then ONLY be as a common correction that will be the same for all turbines. So if RIX correction is issues always make a PARK calculation with RIX and use the correction calculation tool described in 12.3.2.

12.3.1.3 Model problems for very large wind farms

Very large wind farms might be over predicted due to the fact that the wind farm itself “drains” the area for energy in a way not included in wake loss calculation model. But it is still a research topic, which hopefully within few years will be solved. The problem is that some large wind farms seem clearly to indicate calculation problems (e.g. Zafarana, Egypt), while other wind farms like Horns Rev seems to be accurately calculated with the N.O.Jensen Wake loss Model. (Other wake loss models like e.g. the Ainsley model do not predict Horns Rev well and there has been made a correction to this model in the WindFarmer implementation). EMD is taking active part in the work of improving wake loss calculations for large wind farms and will hopefully during 2010 have revisions ready that can handle those more accurately. Until this is done, we leave an option in the Bias module to compensate for possible internal boundary layer effects by entering a Bias. But we cannot give any precise recommendations; we can only recommend reviewing research work done so far on the topic and decide possible reduction based on these.

12.3.1.4 Power curve correction

If it is known that a power curve is too optimistic or pessimistic, a simple correction should be entered here.

12.3.1.5 Other

Any other issues that the user knows is a bias in the calculation should be compensated here.

12.3.2 RIX correction calculation

For the RIX correction a calculation module is established. The main source for the implementation is:
EWEC06 paper:
IMPROVING WAsP PREDICTIONS IN (TOO) COMPLEX TERRAIN
By Niels G. Mortensen, Anthony J. Bowen and Ioannis Antoniou
Wind Energy Department, Risø National Laboratory

This paper describes why complex terrain with steepness > 30-40% violates the WAsP model calculation method, and how calculation accuracy can be improved by applying the RIX correction method.

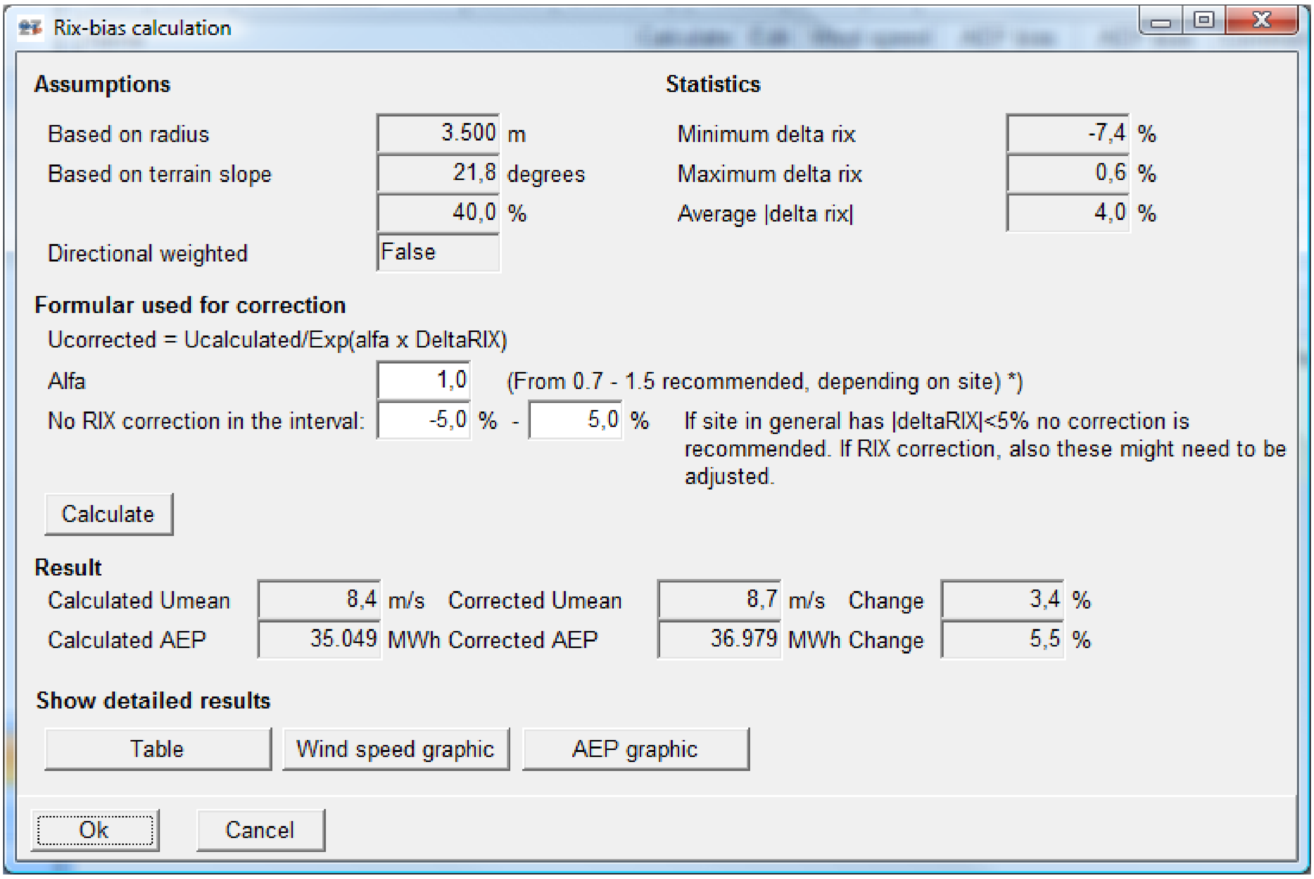


Figure 7 Input of details for the RIX correction calculation and main results.

The basic formula is: $U_m = U_p \times \exp(-\alpha \times \Delta RIX)$, where U_p is the predicted wind speed using WAsP and U_m (measured) is the corrected wind speed. The parameter α is found empirically (e.g. via cross prediction tool in Meteo analyzer in WindPRO) and ΔRIX is calculated by WindPRO in a park calculation based on the elevation data at the site. The key issue is to estimate the α value and to decide the radius and slope threshold for the ΔRIX calculation. Given these the RIX correction is simple math. The calculation tool finds the appropriate (given α and ΔRIX) correction of the wind speed at each WTG position and converts this to an AEP modification based on the AEP%/ws% sensitivity for each WTG position. The calculated modification will be stored individually on each WTG.

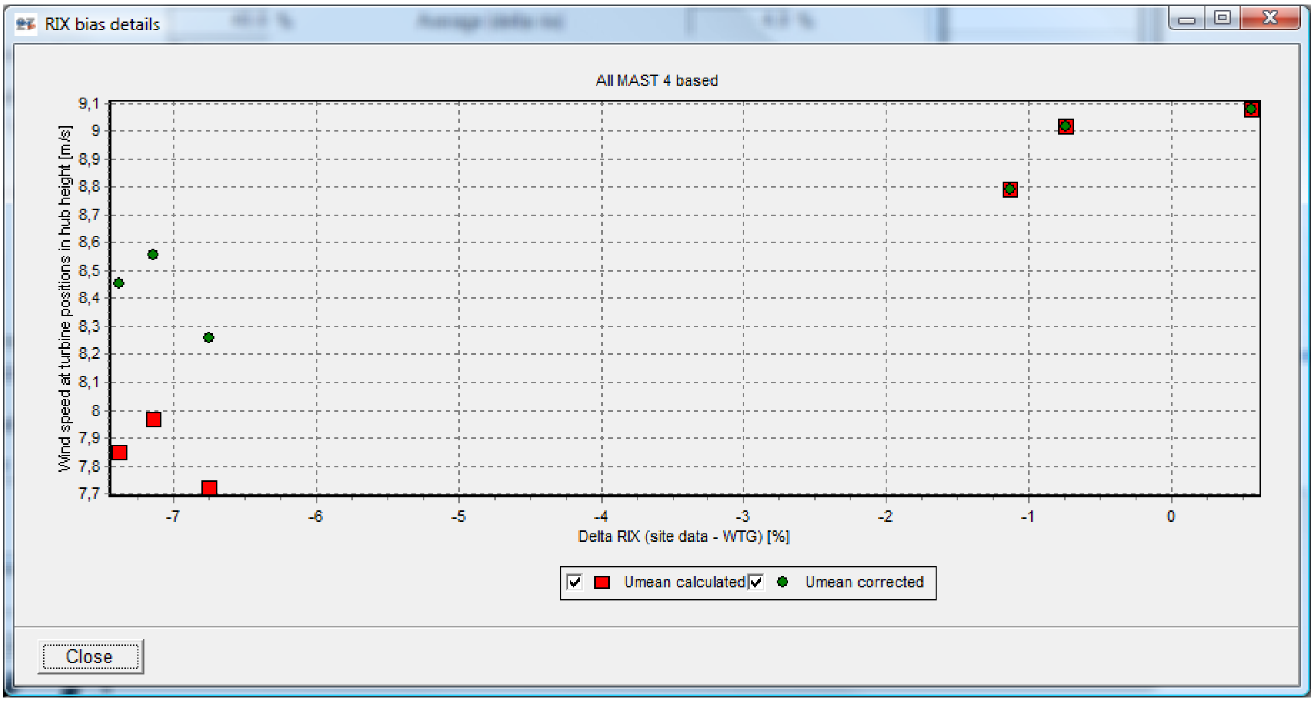


Figure 8 The Wind speed correction graphic illustrates how turbines with low D-RIX values compared to site data object position (met. mast) are corrected to higher wind speed. Similar turbines with higher D-RIX values would be corrected downwards.

12.4 Loss

Loss is the AEP that should be produced based on the available wind and the turbine power curve, but never reach the "sales metering". Partly due to physical losses such as grid losses, partly due to wake losses, where turbines takes wind from each other and partly due to reductions in turbine operation, e.g. due to shut down at low temperatures or availability losses when out of order.

The seven loss main groups defined by DNV are listed in the Intro chapter. Here is how the general calculation runs.

For each turbine a given loss component is converted to efficiency, i.e. a 3% loss is converted to 100%-3% = 97% efficiency. This is done turbine by turbine. The efficiencies from each component are then multiplied and a resulting efficiency found. This is multiplied with the GROSS AEP after Bias correction, if any. Then the NET AEP = P50 is the result of the loss reduction.

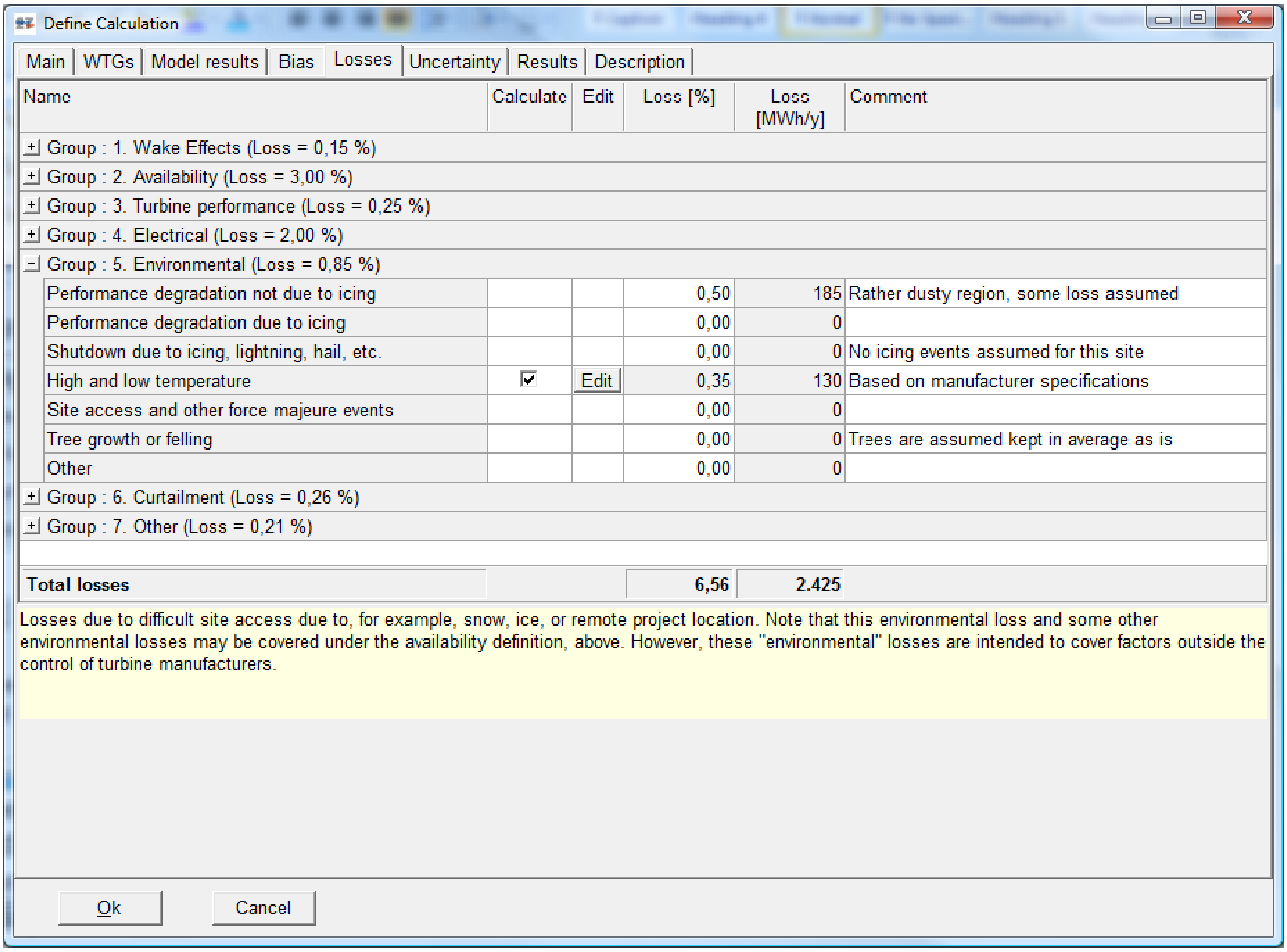


Figure 9 The loss input screen holds seven main groups that can be expanded for input of the relevant loss estimates. Some input lines hold a "Calculate" option. When checked, the edit button opens a form for detailed calculation of the loss due to the specific component.

For the losses that can be calculated by the module, a more detailed description of calculation method follows. For all components a comment can be added. This is an important part of the loss evaluation. In the report all lines with comments will be shown, so the user can see the background for the evaluation even if no loss are assumed due to the specific component.

Besides what can be calculated, it is of high importance to emphasize that two loss components always should be included:

1. Turbine availability, typically 2-5%, depending on service arrangement and turbine quality.
2. Grid losses (can be calculated with eGRID module), will typically be 1-3% depending on distance to meter point, and if e.g. staff house consumption should be included. Note that the power curves used in PARK-calculation are measured at the low voltage side of the turbine transformer so the turbine transformer losses should always be included; this alone is round 1%.

12.4.1 High wind hysteresis

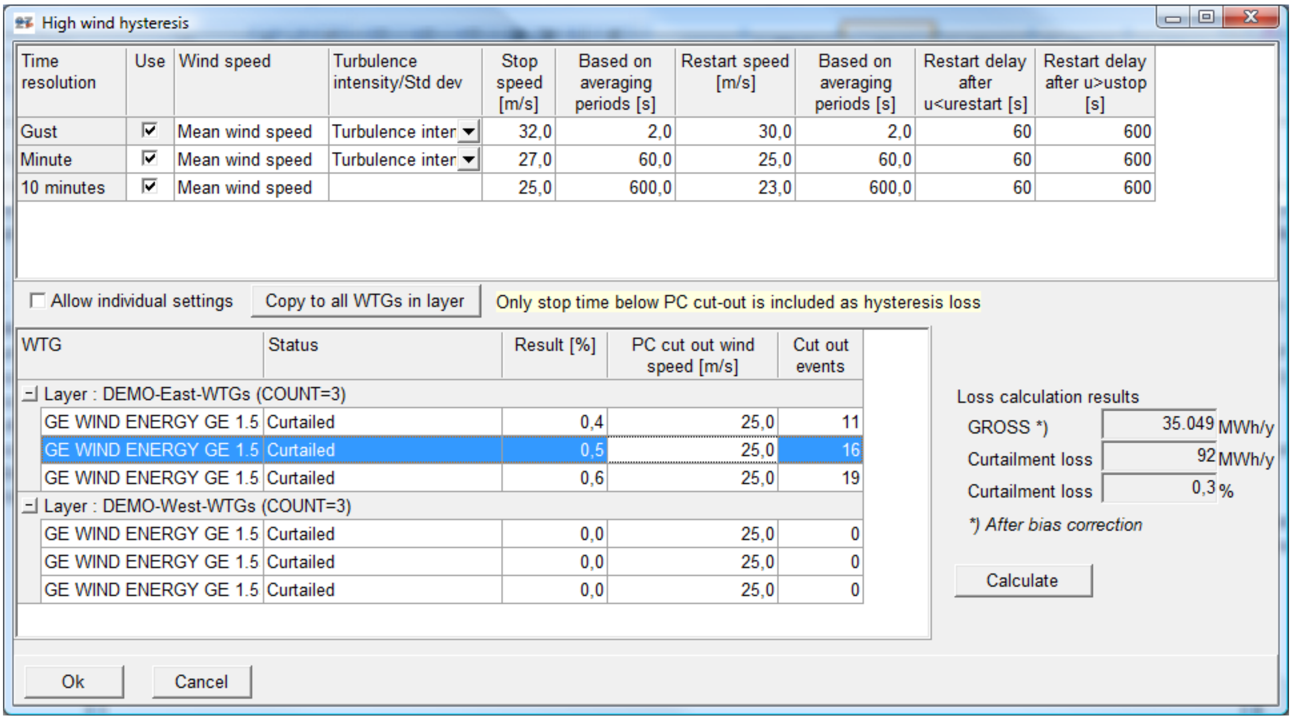


Figure 10 High wind hysteresis loss calculation.

High wind hysteresis loss is where the turbine is stopped below the cut out wind speed. All stop time above cut out wind speed (defined in power curve) are already corrected for in AEP calculation, but while the turbine sometimes stops before or restart after the wind speed is below cut out, losses in relation to AEP calculation are introduced. The setup of the stop/start procedure must be confirmed by the turbine manufacturer. This is individual from turbine type to turbine type, but is sometimes also set individually from site to site.

12.4.2 High and low temperature

AEP is calculated for each time step in the climate data time series based on a scaling of the wind speed to the calculated average wind speed for each turbine. The AEP results based on this method is then scaled so the annual sum equals the main calculation result.
Based on entered shut down threshold temperatures, the AEP calculated for each time step is summed for all time steps outside the temperature threshold values. The AEP loss sum is then converted to a loss percentage that is saved for each WTG.

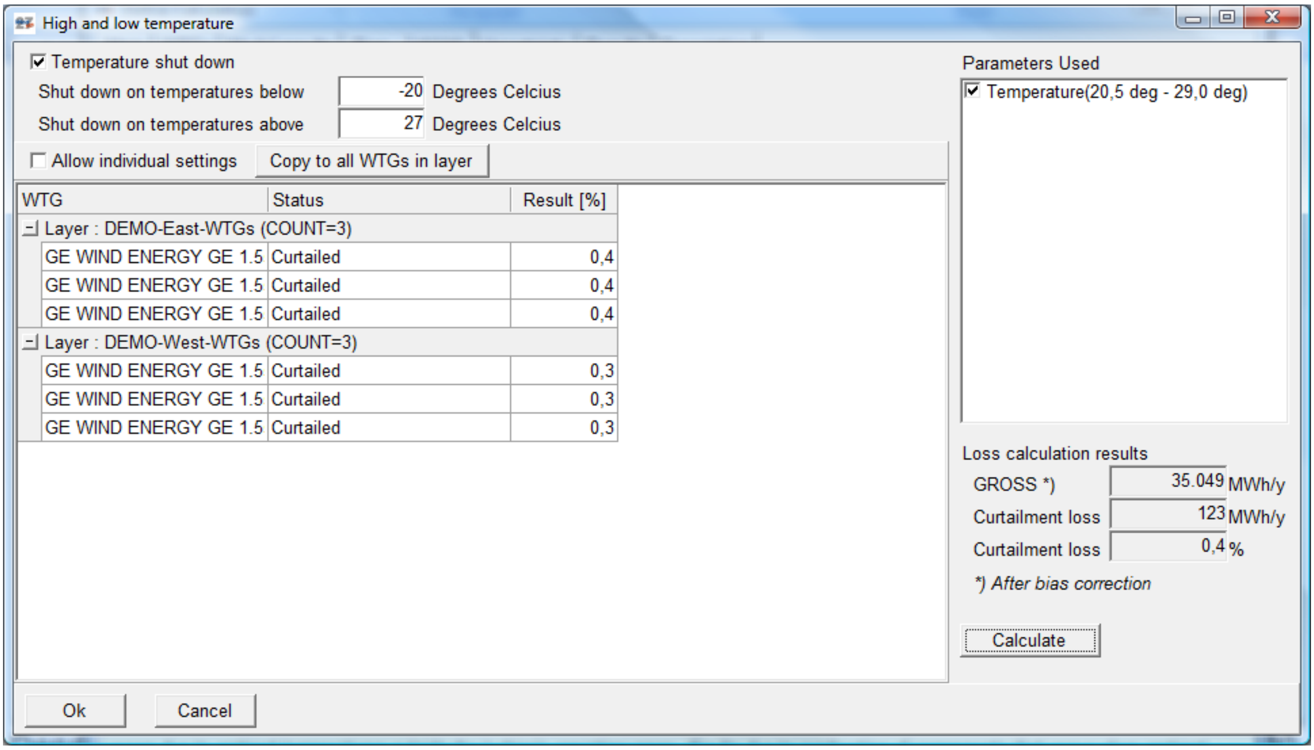


Figure 11 The loss due to high/low temperature is calculated.

In the example above it is seen that the time series with temperature vary in the range from 20,5 to 29,0 degrees. The setting for temperature shut down is below -20 and above +27 deg. C (this is set low just to illustrate the calculation). The loss is calculated to 0,4% based on an AEP calculation for each time step, where the time steps with temperatures outside operation range is summed and included as a loss. The loss calculation for each turbine is shown, in this example it is almost same for all turbines while only one time series can be handled. The differences for the two groups are due to different AEP characteristics.

12.4.4 Wind sector management

Wind sector management is stop of turbines when the wind comes from specific directions, to prevent damage of neighboring turbines due to wake added turbulence due to dense spacing. This is quite complicated to input, while it is individual from turbine to turbine. Below is seen an example where all turbines in the East group have the same settings. But to input this realistically, there must be an individual input for each turbine based on e.g. a WAsP Engineering calculation. By mouse click at one specific turbine (highlighting this), the settings in the field above will only relate to this specific turbine. For a large wind farm this work is quite troublesome. In a future version of the software tool, the sector management settings can be calculated by the software.

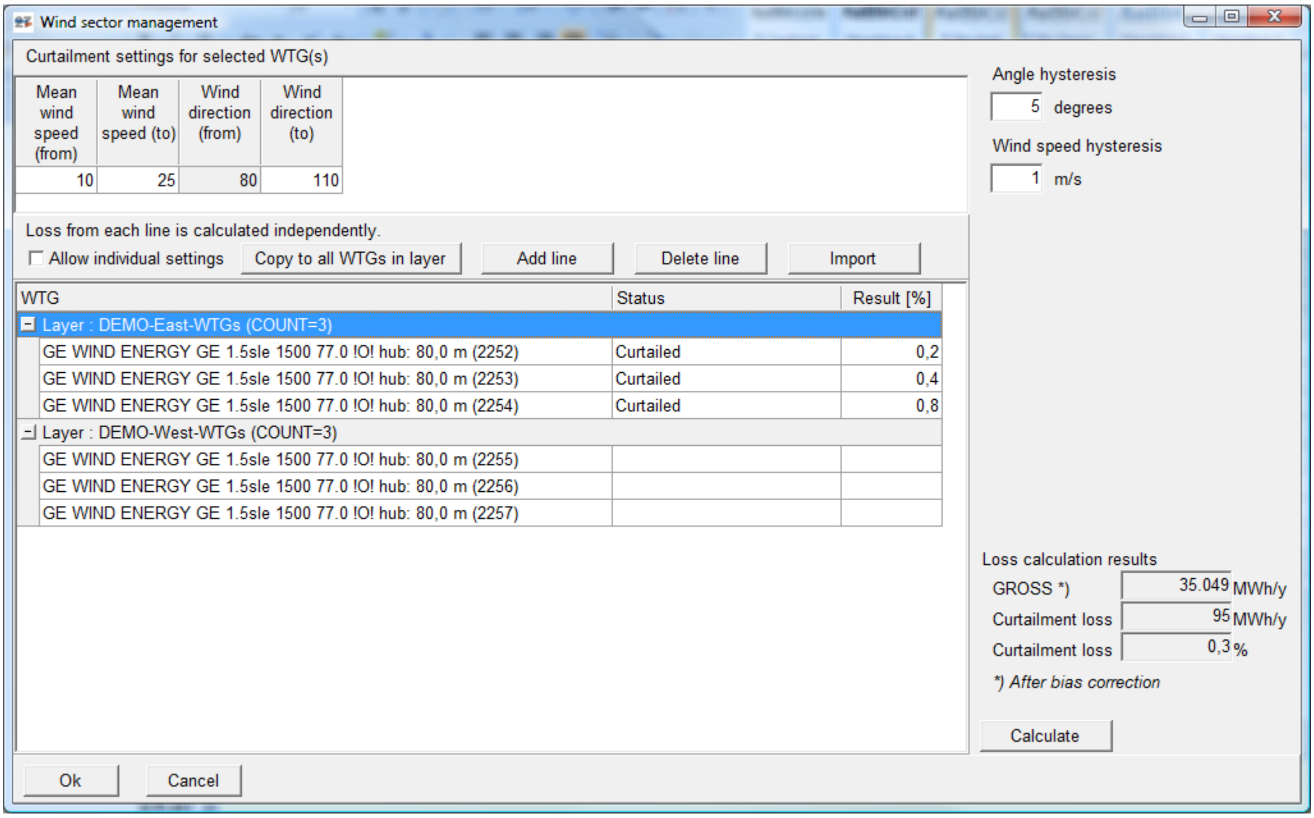


Figure 12 Wind sector management, one of the more complicated ones to input.

There is an extra possible line for wind sector management, based on time series calculation. With such, it is possible to choose an alternative power curve instead of full shut down.

12.4.5 Noise

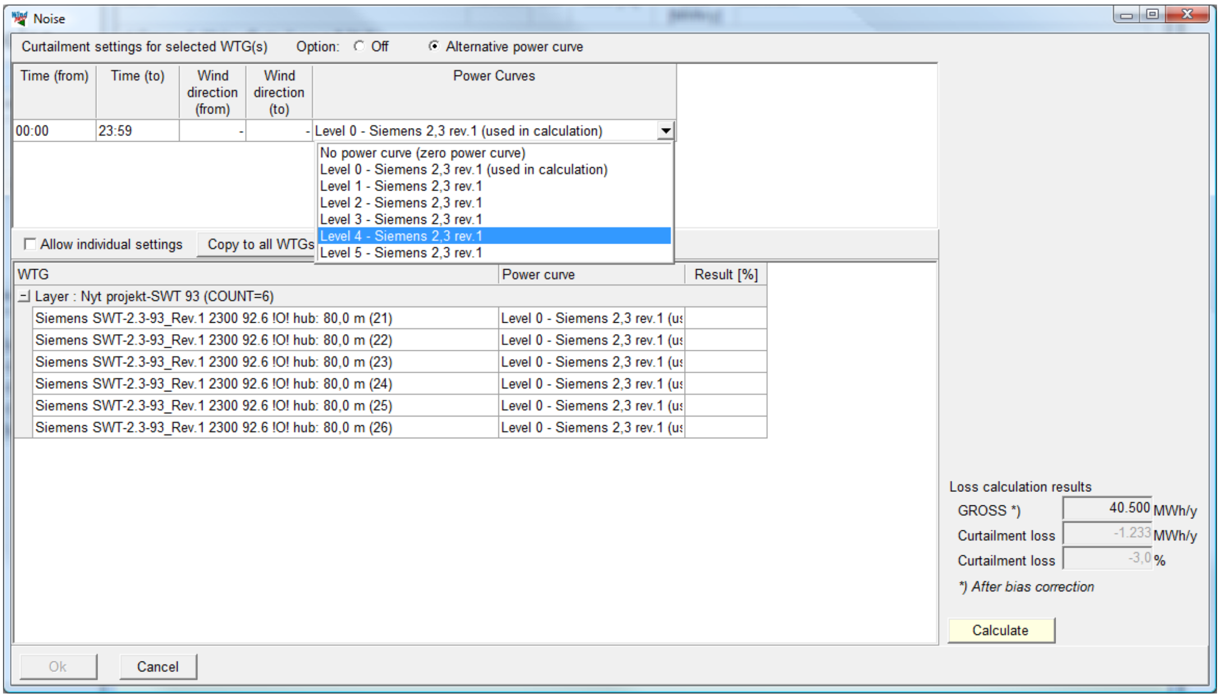


Figure 13 Input for noise loss.

Some turbines might run in noise reduced mode, maybe only within specific time of day, maybe only at certain wind directions (or combinations). Besides time and direction interval, the noise reduced power curve (or no power curve meaning full stop), can be selected. A tricky issue here is if the PARK calculation already is calculated with noise reduced power curves. In this case, there shall not be entered noise loss. So to include the noise reduced mode loss correctly, the PARK calculation must be without noise reduction, and the noise reduced modes selected here. In future version, there will be an option to treat noise reduction the same way as wake reduction, meaning the software first takes out the effect of noise reduction, and transfers the loss , where it is automatically set up. This will also include L_{den} calculations, where different settings for day, evening and night will be required. Note in the power curve selection field, there will be information telling with which power curve each turbine has been calculated.

12.4.6 Flicker

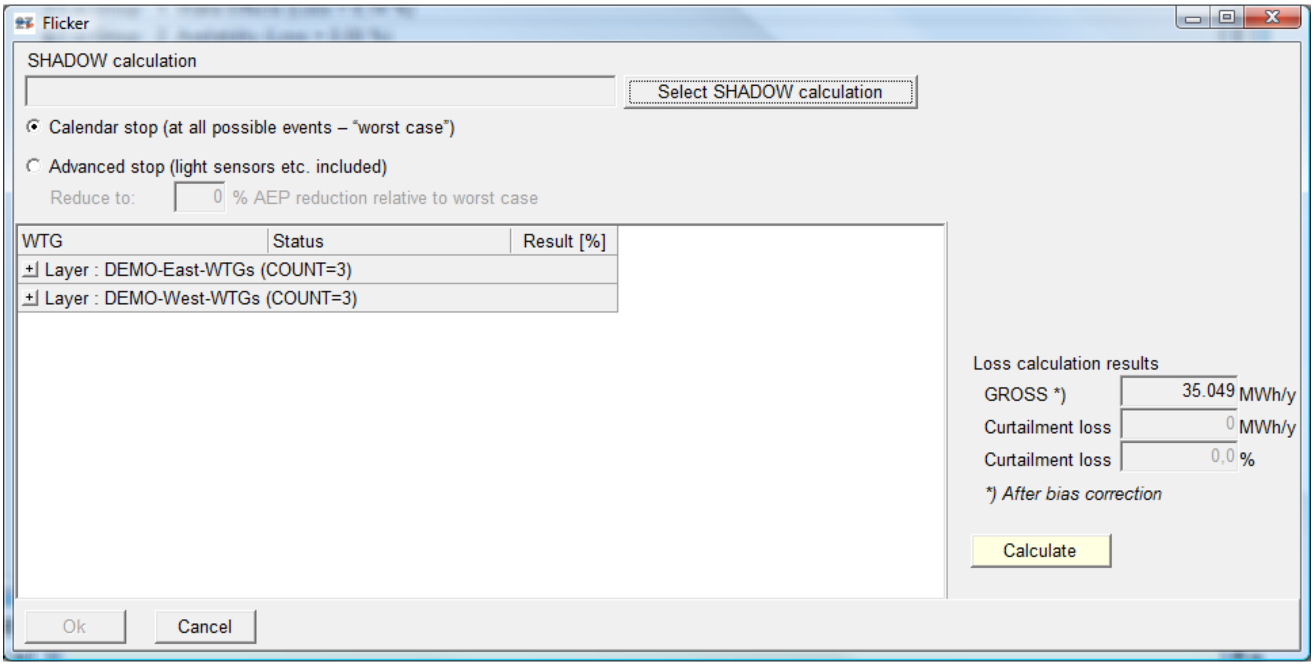
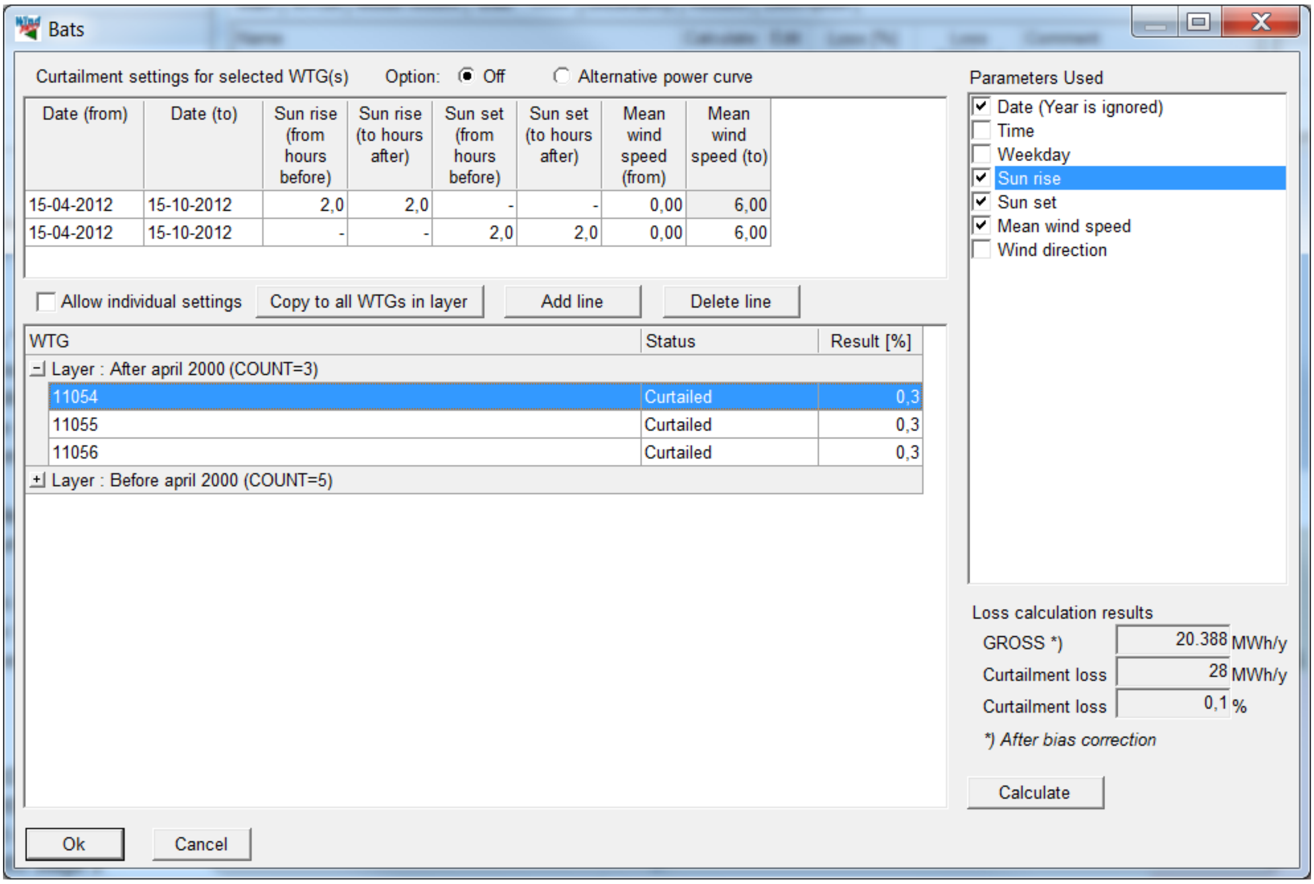


Figure 14 Setup of input for shadow flicker stops loss calculation.

Loss due to stop caused by flicker at neighbors is simple to performed. A Shadow calculation for exact the same wind farm layout as PARK calculation is based on, must be loaded. Then time step by time step it is checked if there is flicker at a neighbor and the loss due to stop within flicker time is calculated. The calculation is based on the turbine running in "calendar mode", meaning all possible events of giving flicker is included (worst case calculation). If a more advanced flicker reduction mode is implemented, the stops will be less, and a simple reduction due to this can be entered – typically around 50%.

12.4.7 Bat



A special feature for calculating Bat curtailment, sun rise and sun set can be included. But note that two separate lines must be included, while conditions in one line is AND, and therefore like 2 hours before and after sunrise/set would not work.

12.4.8 Other

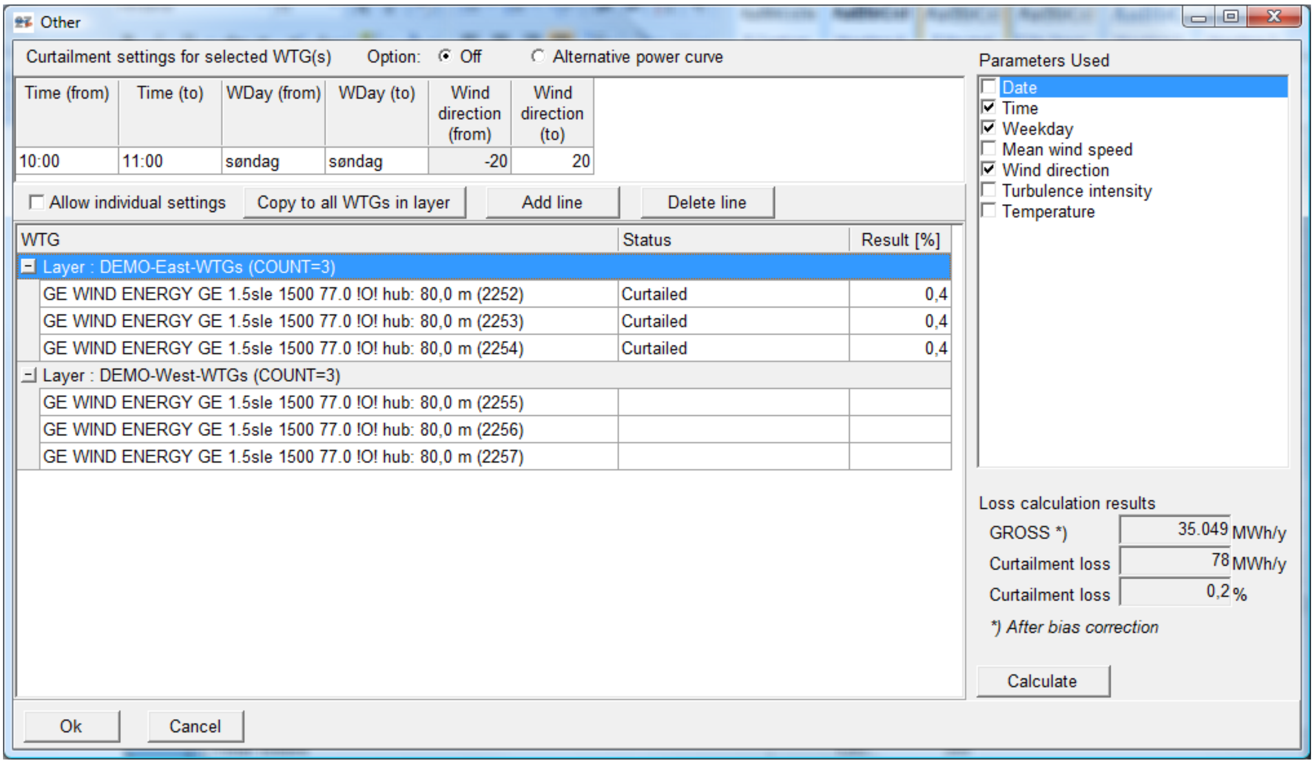


Figure 15 "Other" gives large flexibility for loss calculation depending on any parameter combination.

Using "Other" any parameters available in Meteo object or .WTI file can be used for setting up any parameter combination. In the example above, stop for the one group of turbines is every Sunday between 10:00 – 11:00 if wind direction is between -20 and 20. This could be when wind blowing towards the Church within church time.

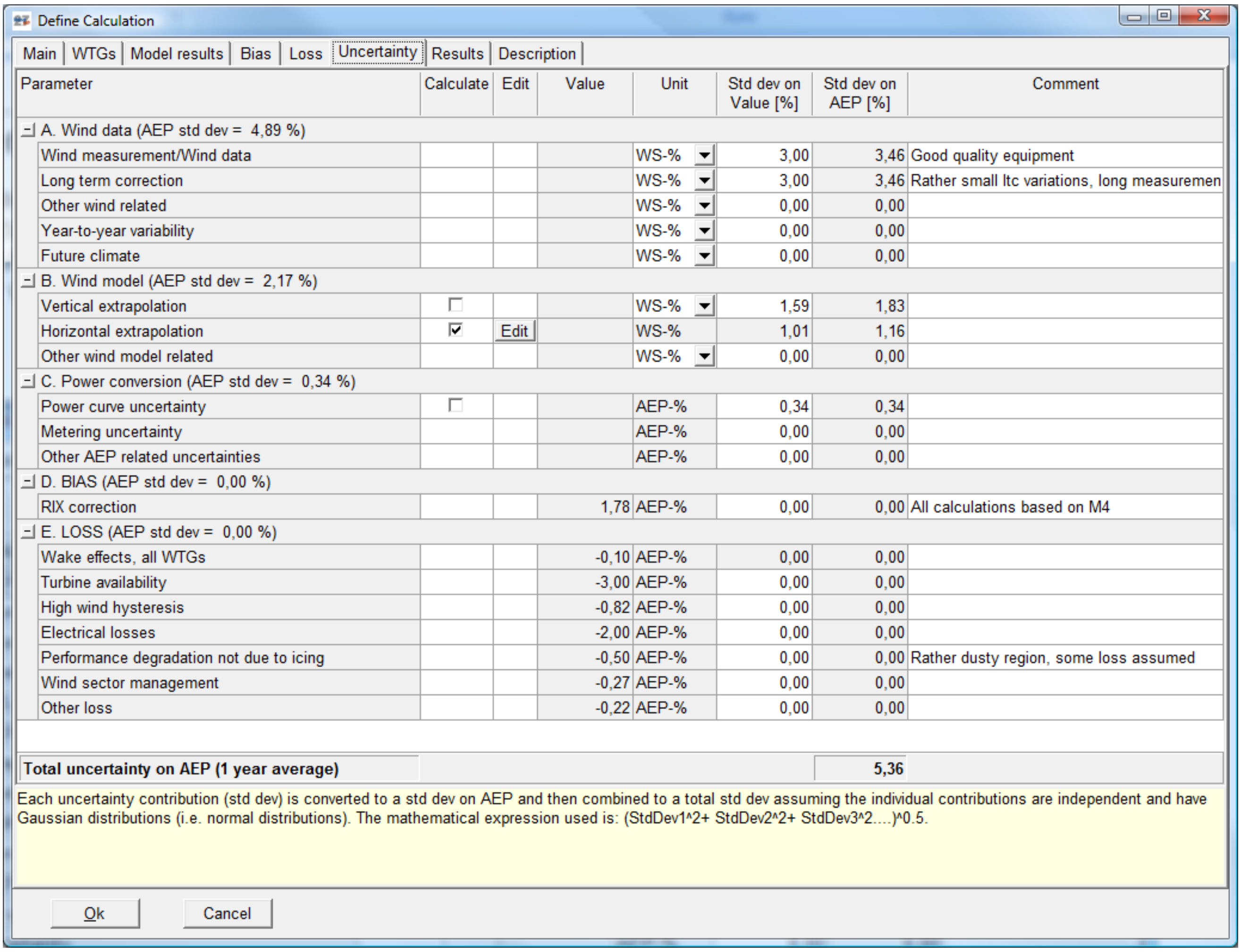
12.5 Uncertainty

Uncertainties are grouped in 5 groups,

A. Wind data
B. Wind MODEL
C. Power Conversion
D. Bias
E. Loss

Each of those groups must be judged, and as for bias and loss, some groups have calculation features which will be described in separate chapters. In later versions, more calculation features will be implemented.

Before going to the calculation features, the Wind data group will be explained, while this is one of the more important ones.



Parameter	Calculate	Edit	Value	Unit	Std dev on Value [%]	Std dev on AEP [%]	Comment
A. Wind data (AEP std dev = 4,89 %)							
Wind measurement/Wind data				WS-%	3,00	3,46	Good quality equipment
Long term correction				WS-%	3,00	3,46	Rather small ltc variations, long measuremen
Other wind related				WS-%	0,00	0,00	
Year-to-year variability				WS-%	0,00	0,00	
Future climate				WS-%	0,00	0,00	
B. Wind model (AEP std dev = 2,17 %)							
Vertical extrapolation	☐			WS-%	1,59	1,83	
Horizontal extrapolation	☑	Edit		WS-%	1,01	1,16	
Other wind model related				WS-%	0,00	0,00	
C. Power conversion (AEP std dev = 0,34 %)							
Power curve uncertainty	☐			AEP-%	0,34	0,34	
Metering uncertainty				AEP-%	0,00	0,00	
Other AEP related uncertainties				AEP-%	0,00	0,00	
D. BIAS (AEP std dev = 0,00 %)							
RIX correction			1,78	AEP-%	0,00	0,00	All calculations based on M4
E. LOSS (AEP std dev = 0,00 %)							
Wake effects, all WTGs			-0,10	AEP-%	0,00	0,00	
Turbine availability			-3,00	AEP-%	0,00	0,00	
High wind hysteresis			-0,82	AEP-%	0,00	0,00	
Electrical losses			-2,00	AEP-%	0,00	0,00	
Performance degradation not due to icing			-0,50	AEP-%	0,00	0,00	Rather dusty region, some loss assumed
Wind sector management			-0,27	AEP-%	0,00	0,00	
Other loss			-0,22	AEP-%	0,00	0,00	
Total uncertainty on AEP (1 year average)						**5,36**	

Each uncertainty contribution (std dev) is converted to a std dev on AEP and then combined to a total std dev assuming the individual contributions are independent and have Gaussian distributions (i.e. normal distributions). The mathematical expression used is: (StdDev1^2+ StdDev2^2+ StdDev3^2....)^0.5.

Figure 16 The five uncertainty groups A-E.

12.5.1 Wind data uncertainty

Wind data can be used in the PARK calculation in different ways:

- Measurements on site, typically along with a long term correction.
- A wind statistic for the region, possibly verified/calibrated based on performance from existing turbines in the region.
- A wind resource map, based on a model, like mesoscale model, CFD model or WAsP model – behind the wind resource map there will be wind data, that can be based several different sources.

To judge the quality of the wind data is probably the most essential part of the uncertainty evaluation. If turbines with longer operation period (>1y) exists in the region, a test calculation with the used wind data is one of the best ways to reduce uncertainty of the wind data basis. It is essential that the production from these turbines is properly long term corrected and cleaned for availability problems. If the actual cleaned production from those can be reproduced accurately, the uncertainty on the wind data can be assumed small.

If only local measurements are available, the uncertainty depends much on measurement equipment, mast configuration, sensor calibration and quality. Long term correction is normally a must, but here additional uncertainties are introduced, while the long term sources often are of poor quality, and might even be trended, if e.g. trees has grown up around the reference mast of if it is modeled data there might be trends due to changes in the data basis for the model. Such trends should NOT be considered just as an uncertainty, but should be corrected for up front or included as bias correction.

Even with high quality data, the wind measurement uncertainty should not be assumed lower than 2% on wind speed - an “upper limit” is difficult to give. If it is a low wind site, the wind speed uncertainty converted to AEP uncertainty can be as high as 3 times the wind speed uncertainty, while it at a high wind site only will be 1,5 times the wind speed uncertainty.

A specific source of uncertainty is the position on the measurement mast. If the mast location is in a hilly environment, it is crucial that the position is correct, and that the elevation information around the mast is accurate. It is often seen that measurement masts are placed on a small hill top. If the elevation data are rough, the little hilltop is not included in the data and an error is introduced when cleaning the data based on orography. This is not an uncertainty but an error that must be handled by establishing the elevation data round the mast in a correct way. Photomontage tool should be used to verify that the elevation data round the mast is correctly established. If the mast position is uncertain, this should be included in uncertainty, for instance in "Other wind related".

Long term expectations might be the component within the wind data group with highest uncertainty. It is therefore important to understand how the composition of this part should be established.

In the input forms, there are 3 different input fields related to this topic:

- Long term correction
- Year–to-year variability
- Future climate

Long term correction

Here the uncertainty based on the facts used in the long term correction, typically performed with the MCP module shall be entered. This covers the uncertainty based on:

1. The length of the concurrent data period, the eventual seasonal bias and the resolution (time step of concurrent data)
2. The length of the long time data series (possible trends should be evaluated and if there seem to be trending, this is a very critical issue and usually other data should be found)
3. The correlation (how well the reference data correlate to the local measurements)
4. The accuracy of the method used for establishment of the transfer function and thereby the correction

The uncertainty is highly based on these issues. To give some rough judgments:

QUALITY LEVEL:	5	4	3	2	1
Length of local data series (years)	0,5	1	2	3	5
Uncertainty, AEP%	8	4	3	2	1
Length of long term reference (years)	3	5	10	20	30
Uncertainty, AEP%	12	8	6	4	2
Correlation, monthly basis (r-value)	0,6	0,7	0,8	0,9	1
Uncertainty, AEP%	15	10	6	4	2
Combined, Sqrt of sum of squares	18,8	12,3	7,8	4,9	2,2

The table above is just fiction, but it gives an idea of how it works. The "fictive values" are AEP uncertainties. Having the "typical good setup", Quality level 2; with 3y local measurements, 20y long term reference, correlation 0.9, an uncertainty of 5% is the result. At lowest quality level close to 20% on AEP must be expected. The table above can be used across the columns, in the sense of having e.g. quality level 2-3-4 for the 3 rows, will yield $\mathrm{Sqrt}(2^2+6^2+10^2) = 11\%$. But still it is important to emphasize that this is an example made for illustration of how it could work, not scientifically based.

The very best way to estimate the uncertainty (and to reduce this) is to involve several long term data sources, where following can be found in EMD Online data: Synoptic stations, Airport data (Metar), NCAR data (and QSCAT for offshore) + more local meteorological masts. In addition use more methods (Regression, Matrix, Wind index) if data quality permits (NCAR data usually should be restricted to Wind index method). Based on the numerous results, the general tendency and scatter gives an indication of the level of the correction and its uncertainty. Obvious outliers should be omitted.

A typically uncertainty of Long term correction is between 1-3% on wind speed, but should not be lower than 3% on AEP.

Year-to-year variability

The figure entered here is decides how the 1,5,10, 20 year uncertainty is calculated. It tells how much the wind varies from year to year in the specific region. A typical value is a**round 6% on wind speed,** but several sources are available at the Internet giving more specific regional variations. In the MCP module, the variability is calculated based on the long term reference used. The variability entered is used for the 1-year calculated uncertainty, while the 5 year then is the σ_{1y}/sqrt(5) etc. So the 20y variability uncertainty is the σ_{1y}/sqrt(20). E.g. for σ_{1y} = 6%: 6%/sqrt(20) = 1,3% (on wind speed, which converts to AEP% depending on wind speed level). It is important to be aware of that the variability tells about the fluctuations within few years, not the very long term variations seen in e.g. Northern Europe described by the NAO index (North Atlantic Oscillations). This is handled separately in the “future climate” input field.

Future climate

E.g. in Northern Europe, we have seen large variations during the 30 year 1980-2009 of modern turbine operation in Denmark. While 1986-95 (10y) were 8% above long term average measured in AEP, 1996-2006 (11y) were 5% below long term average. This illustrates well that 10 year for sure is too short a period to use as long term, and that there are climate variations that no one can predict. So far it seems that the variations in wind climate not are related direct to global warming etc. The slow variations have been seen for 150 years (eg. by the North Atlantic Oscillation); going up and down, but not trending towards more or less wind. Prediction the future 20y wind is a hard task that no one really can do. So to assume an uncertainty around 1-3% on wind speed due to future climatic variations seems appropriate – at least for Northern Europe – other parts in the world have similar variations, some has not. This should be studied region by region.

12.5.2 Model uncertainty

Vertical extrapolation

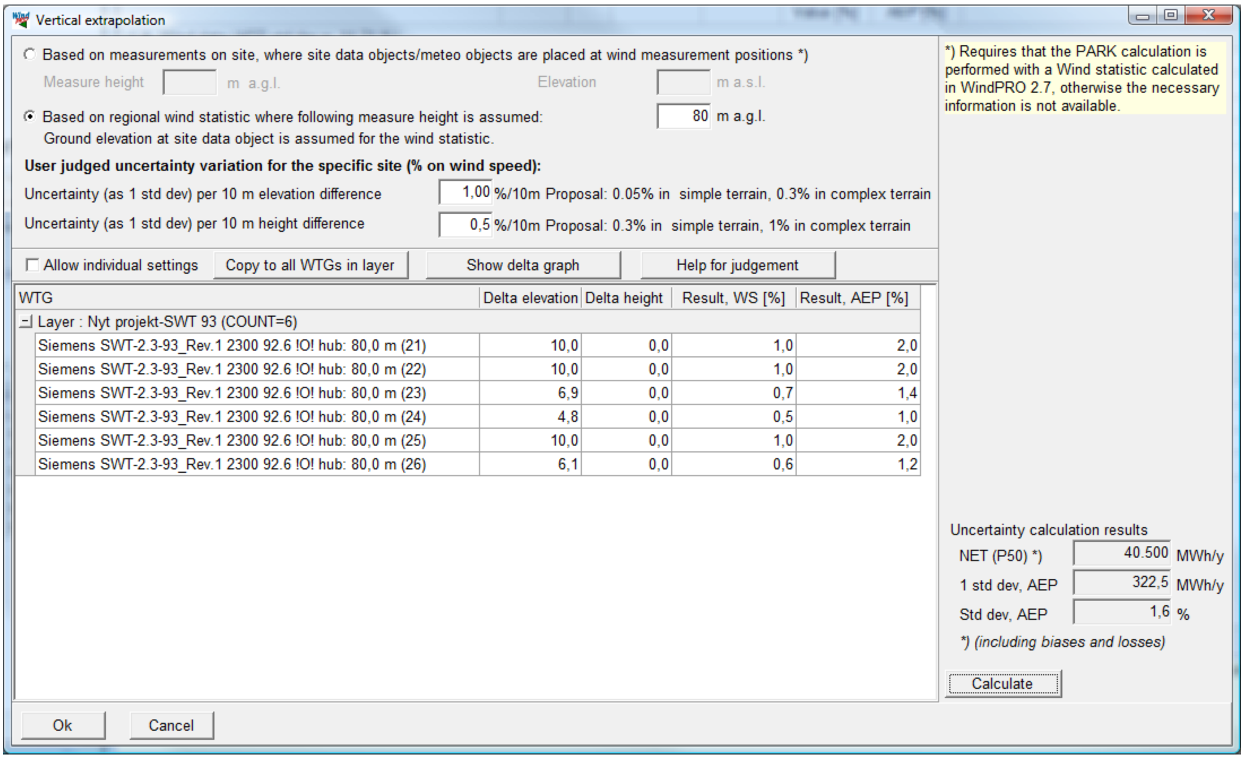


Figure 17 Input for vertical extrapolation uncertainty calculation.

The vertical extrapolation uncertainty is divided into the uncertainty due to elevation (above sea level) difference and difference between mast height and turbine height (above ground level).
The proposals given for the uncertainty is based on different studies, but can be very site dependent. The best way to get a reasonable basis for the judgment is if there are more masts at the site, the cross prediction accuracy can give an idea on the uncertainty.

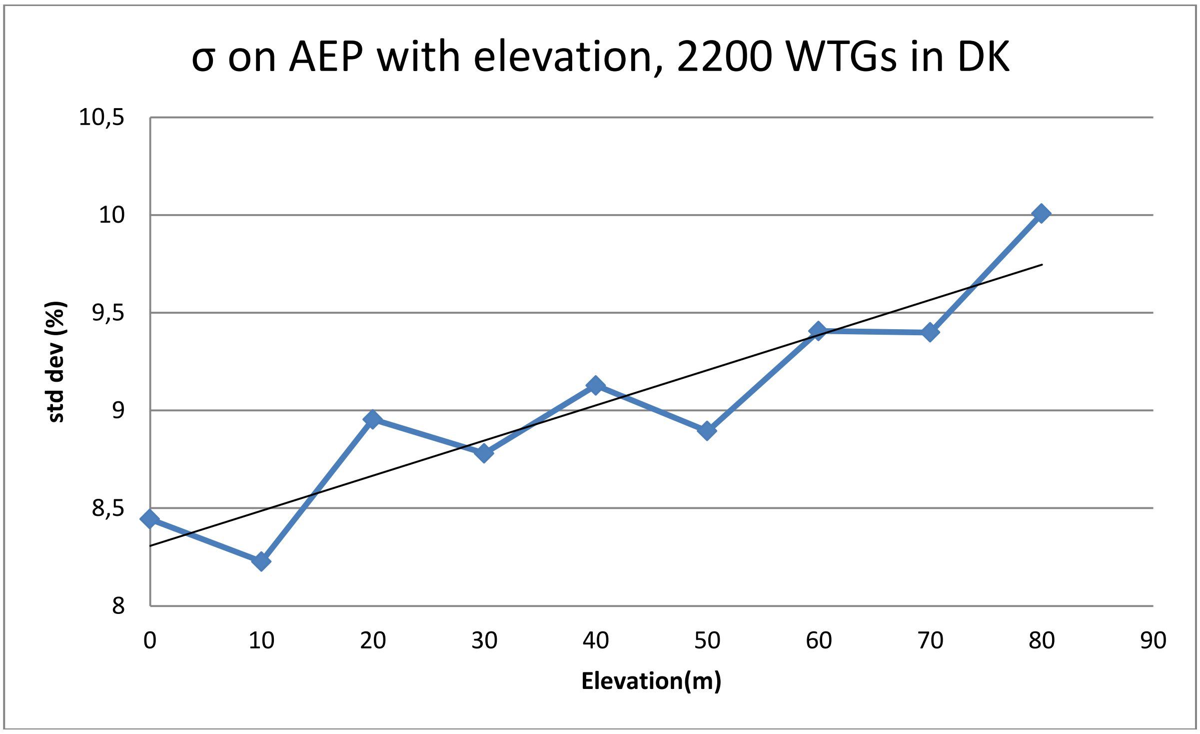


Figure 18 A large number of calculations in Denmark suggest a linear relationship between uncertainty and increased elevation in non-complex terrain.

For the DK example above it is important to emphasize that it is actually the absolute elevation that is shown. But in the Danish landscape the elevation difference is linked to the absolute elevation as the typical data basis is based at low elevation. Therefore, the figure indicates an increased uncertainty with increased elevation difference. Several other studies come up with similar findings. If the terrain is very complex, a RIX correction might have been performed. In this case the elevation difference uncertainty will be lowered.

The recommendations written in the input fields are intended to give an idea for input of uncertainty, but as terrain types vary very much from site to site, also the uncertainties vary similarly much. The best way is always to have more measurement mast at site and use the cross prediction tool in Meteo Analyzer to help give more precise indications of the uncertainty of the wind model.

Horizontal extrapolation

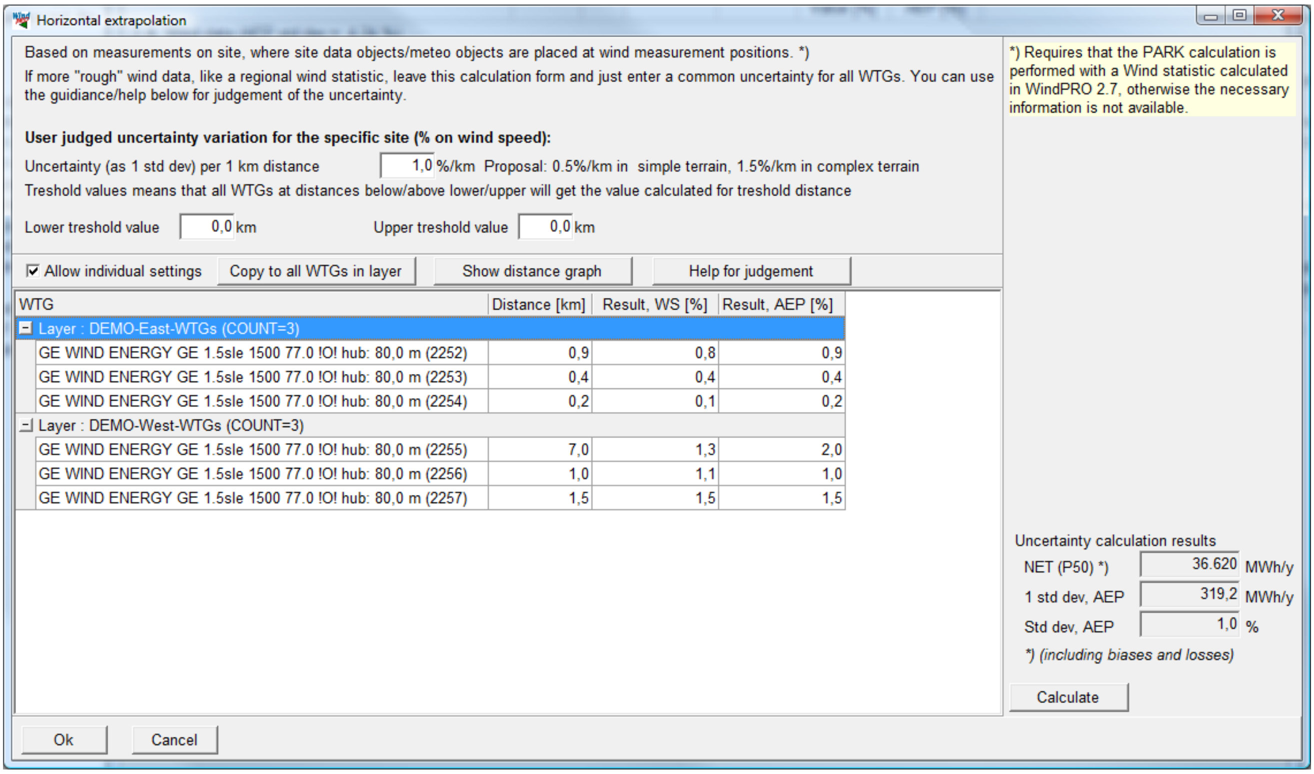


Figure 19 Input for horizontal extrapolation uncertainty calculation.

This calculation is similar to the vertical extrapolation. The critical issue is to judge the distance dependency of the uncertainty. An upper threshold value will normally be reasonable to use, while the uncertainty does not just continue to increase with distance. As for the vertical uncertainty, cross prediction based on more masts will be the best way to establish a basis for the judgments of uncertainty versus distance.

12.5.3 Power conversion uncertainty

Power curve uncertainty will often be found in the reports from power curve measurements. But please note that these will typically give very high uncertainty estimates, which might not be fair. Often power curves are measured on more turbines of the same type at different locations and the manufactures then perform their best judgments/averaging of more measurements to reduce their risk. This will reduce the uncertainty. A simple input can be given as illustrated above like a detailed input requiring input in the WTG Catalogue can be used. It is our hope to get the uncertainty included for the most power curves in future, but it will probably take some time before these are available – at least the structures are ready now.

Power curve uncertainty

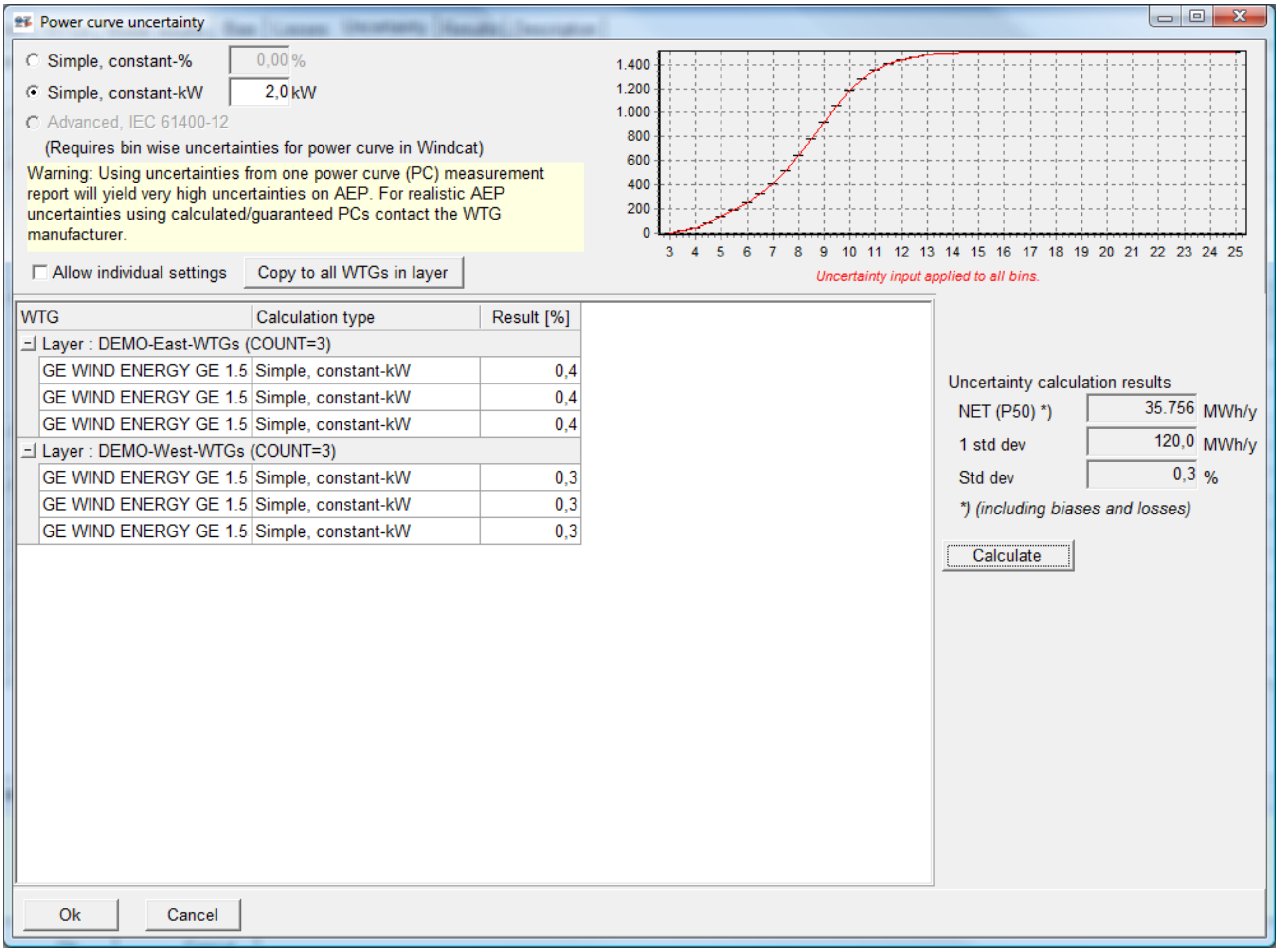


Figure 20 Input for power curve uncertainty calculation.

12.5.4 Bias uncertainty

For each bias component the user attributes a value, the uncertainty on this value can (and should) be set as well. Note that the entered uncertainty estimate is multiplied by the bias value, so if e.g. a bias is set to 5% with an uncertainty of 10% on that value, the resulting uncertainty is 0,5% on AEP resulting from that component.

12.5.5 Loss uncertainty

For each loss component included with a value, the uncertainty should also be set by the user. Note that the estimate is multiplied with the loss value-. A loss of e.g. 5% with an uncertainty of 10%, results in an uncertainty on AEP of 0,5% due to that loss component.

12.6 Results

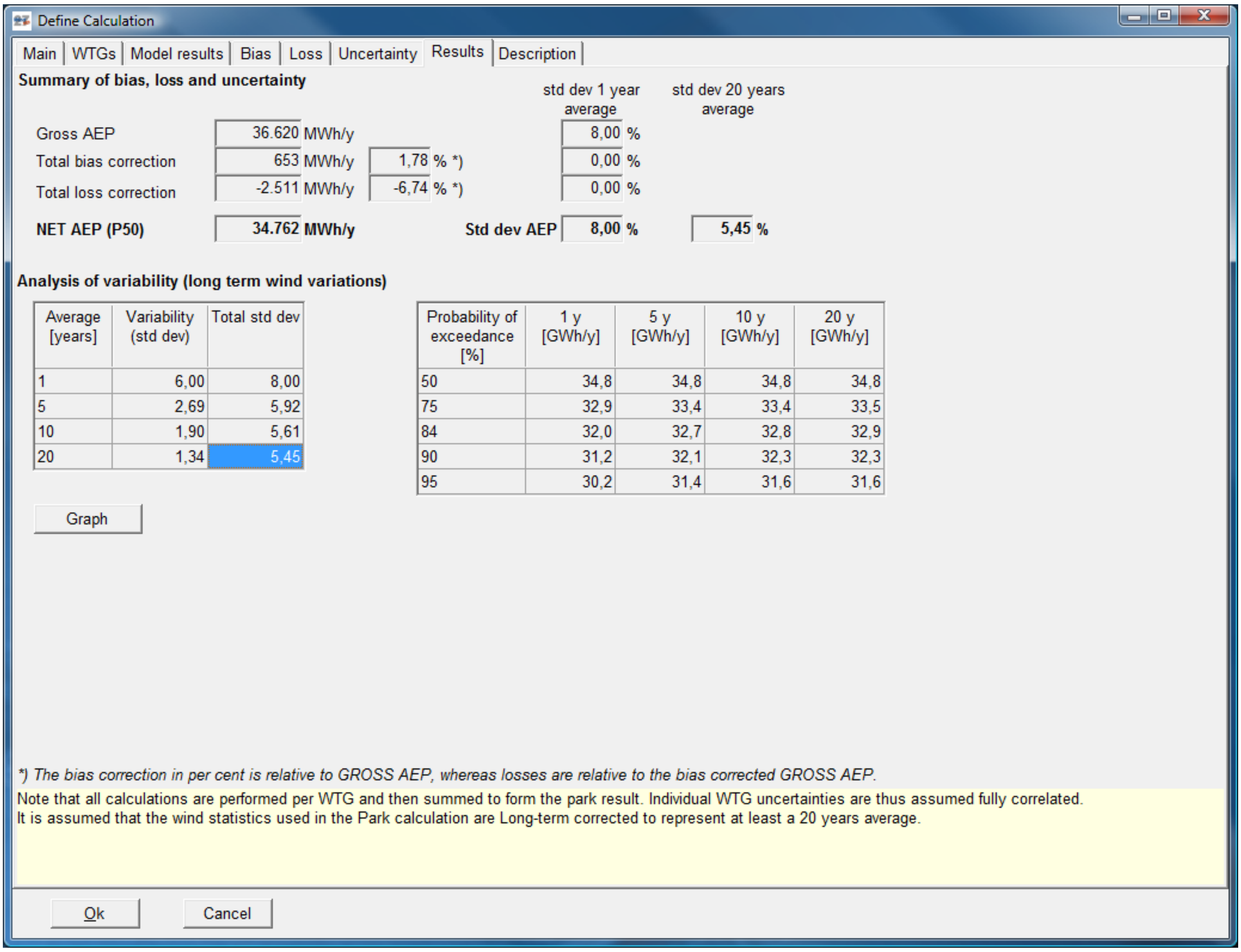


Figure 21 Evaluation of results.

On the Results sheet to the lower right presents results for 1, 5, 10 and 20 years of averaging (i.e. life time) and at several probability of exceedance values (50%, 75%, 84%, 90% and 95%).

12.7 Calculation and print

12.7.1 Main results

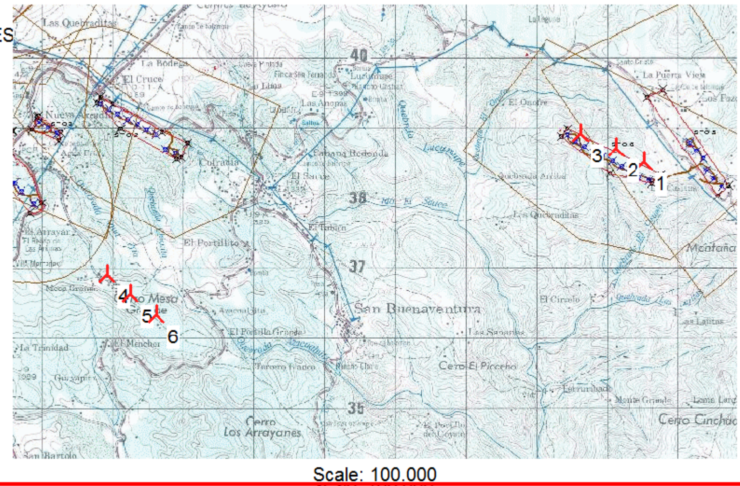
Loss&Uncertainty - Main result

Calculation: All MAST 2-4 based

Main data for PARK

PARK calculation 2.7.395: Copy of All MAST 2+4 based-NEW-TES

Count	6
Rated power	9,0 MW
Mean wind speed	8,9 m/s at hub height
Sensitivity	1,2 %AEP / %Mean Wind Speed
Expected lifetime	20 Years

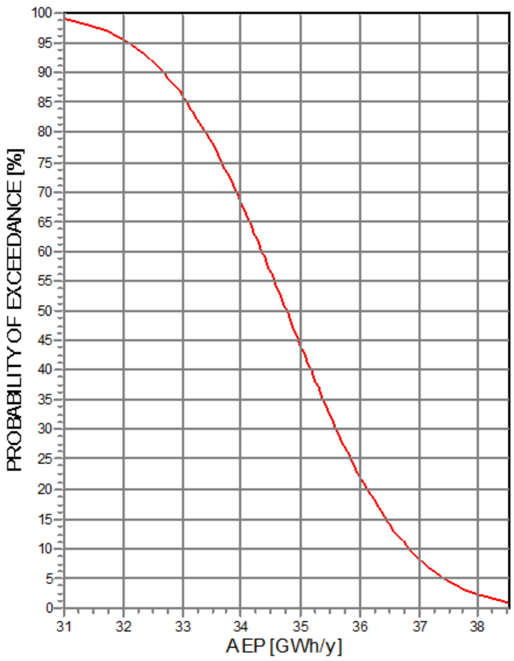


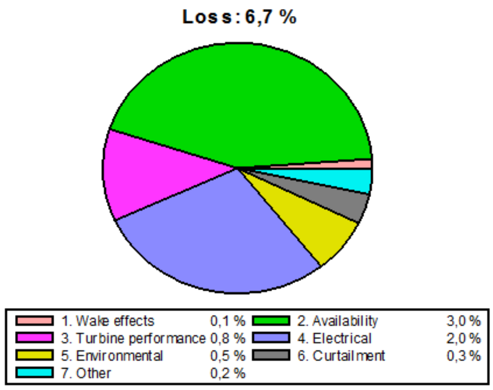
RESULTS

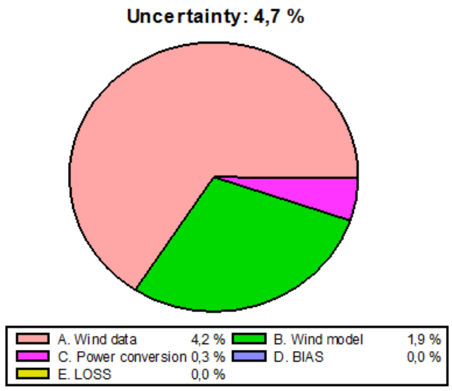
		P50	P84	P90
NET AEP	**[GWh/y]**	**34,8**	**33,2**	**32,7**
Capacity factor	[%]	44,1	42,1	41,5
Full load hours	[h/y]	3.862	3.684	3.632

Result details

	P50		Uncertainty
GROSS AEP *)	36,6 GWh/y		4,7 %
Bias correction	0,7 GWh/y	1,8 %	0,0 %
Loss correction	-2,5 GWh/y	-6,7 %	0,0 %
Wake loss		*-0,1 %*	
Other losses		*-6,6 %*	
NET AEP	**34,8 GWh/y**		**4,7 %**







*) Calculated Annual Energy Production before any bias or loss corrections
Assumptions: Uncertainty and percentiles (PXX values) are calculated for the expected lifetime

Figure 22 The printout of main result gives an overview of all results as a table and as graphics.

12.7.2 Assumptions and results

Loss&Uncertainty - Assumptions and results
Calculation: All MAST 2-4 based

ASSUMPTIONS

BIAS	Method *)	Correction Wind speed [%]	AEP [%]	Uncertainty, std dev on AEP [%]	Comment
RIX correction	Calculation	4,2	1,8	0,0	All calculations based on M4
BIAS, total			**1,8**	**0,0**	

LOSS	Method *)	Loss AEP [%]	AEP [GWh/y]	Uncertainty, std dev on AEP [%]	Comment
1. Wake effects					
Wake effects, all WTGs	Calculation	0,1	0,0	0,0	
2. Availability					
Turbine availability	Estimate	3,0	1,1	0,0	
3. Turbine performance					
High wind hysteresis	Estimate	0,8	0,3	0,0	
4. Electrical					
Electrical losses	Estimate	2,0	0,7	0,0	
5. Environmental					
Performance degradation not due to icing	Estimate	0,5	0,2	0,0	Rather dusty region, some loss assumed
Shutdown due to icing, lightning, hail, etc	Estimate	0,0	0,0	0,0	No icing events assumed for this site
High and low temperature	Estimate	0,0	0,0	0,0	Based on manufacturer specifications
Tree growth or felling	Estimate	0,0	0,0	0,0	Trees are assumed kept in average as is
6. Curtailment					
Wind sector management	Estimate	0,3	0,1	0,0	
7. Other					
Other loss	Estimate	0,2	0,1	0,0	
LOSS, total		**6,7**	**2,5**	**0,0**	

UNCERTAINTY	Method *)	Std dev on wind speed [%]	on AEP [%]	Comment
A. Wind data				
Wind measurement/Wind data	Estimate	2,7	3,0	Good quality equipment
Long term correction	Estimate	2,7	3,0	Rather small ltc variations, long measurement peri
Other wind related				
Year-to-year variability	Estimate	6,0	7,0	
Future climate				
B. Wind model				
Vertical extrapolation	Estimate	1,4	1,6	
Horizontal extrapolation	Calculation	0,9	1,0	
Other wind model related				
C. Power conversion				
Power curve uncertainty	Estimate		0,3	
Metering uncertainty				
Other AEP related uncertainties				
D. BIAS, total uncertainty			0,0	
E. LOSS, total uncertainty			0,0	
UNCERTAINTY, total (1y average)			8,4	
UNCERTAINTY, total (20y average)			**4,9**	

VARIABILITY

Years	Variability (std dev)	Total std dev
1	6,95	8,4
5	3,11	5,6
10	2,20	5,1
20	1,55	**4,9**

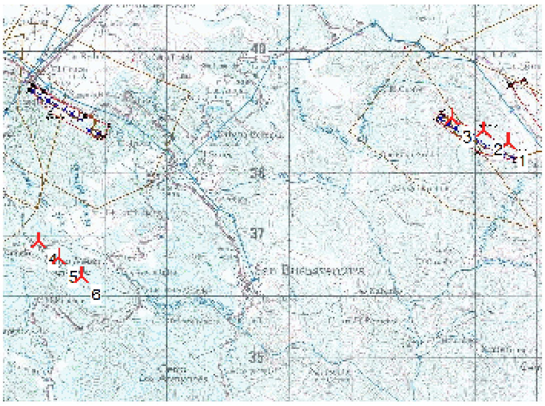
Comment
Wind measurement/Wind data
Good quality equipment

WindPRO is developed by EMD International A/S, Niels Jernesvej 10, DK-9220 Aalborg Ø, Tlf. +45 96 35 44 44, Fax +45 96 35 44 46, e-mail: windpro@emd.dk

Figure 23 Second report page collect all input data on 1-2 pages. Also the detailed result matrix will be shown at the bottom of this page (not shown here).

12.7.3 WTG results

Loss&Uncertainty - WTG results
Calculation: All MAST 4 based



Scale: 100.000

Expected AEP per WTG including bias, loss and uncertainty evaluation

	Description	Calculated GROSS*) [MWh/y]	Bias [%]	Loss [%]	20 years averaging Unc. [%]	P50 [MWh/y]	P84 [MWh/y]	P90 [MWh/y]
	Layer: DEMO-East-WTGs							
1	GE WIND ENERGY GE 1.5sle 1500 77.0 !O! hub: 80,0 m (2252)	6.062,3	5,5	6,8	6,6	5.964,1	5.573,3	5.460,5
2	GE WIND ENERGY GE 1.5sle 1500 77.0 !O! hub: 80,0 m (2253)	6.296,5	5,5	7,2	6,6	6.162,1	5.758,4	5.641,8
3	GE WIND ENERGY GE 1.5sle 1500 77.0 !O! hub: 80,0 m (2254)	6.561,3	5,5	7,6	6,6	6.396,2	5.977,1	5.856,1
	Layer: DEMO-West-WTGs							
4	GE WIND ENERGY GE 1.5sle 1500 77.0 !O! hub: 80,0 m (2255)	5.576,5	5,5	5,8	6,6	5.541,9	5.178,8	5.074,0
5	GE WIND ENERGY GE 1.5sle 1500 77.0 !O! hub: 80,0 m (2256)	5.779,1	5,5	5,9	6,6	5.735,0	5.359,2	5.250,7
6	GE WIND ENERGY GE 1.5sle 1500 77.0 !O! hub: 80,0 m (2257)	5.480,5	5,5	5,9	6,6	5.442,0	5.085,4	4.982,5
	PARK	**35.756,1**	**5,5**	**6,6**	**6,6**	**35.240,7**	**32.931,7**	**32.265,1**

*) NOTE: GROSS value is calculated as "free" turbine without wake losses or other losses.

Figure 24 This page show results turbine by turbine, thereby the needed details for projects sold turbine by turbine are available.

12.7.4 Detailed results

For each "calculation option" a separate report are available. These describe the calculation setup and partly the data basis. Only one sample is given below. These reports can be quite detailed.

17-11-2009 01:20/2.7.395

Loss&Uncertainty - High wind hysteresis, Detail

Calculation: All MAST 4 based

Shown losses is the energy content below powercurve cut-out where the WTG is stopped.
Note that all hysteresis losses in MWh are calculated for the full time series. The losses in per cent in the Main report are scaled to represent one year if the length of the data series deviates from a year.

WTG: GE WIND ENERGY GE 1.5sle 1500 77.0 !O! hub: 80,0 m (2252) in layer: DEMO-East-WTGs

Cut out time	Cut in time	Total duration [min]	Duration below PC cut out [min]	Hysteris loss [MWh]
29-10-2008 01:02	29-10-2008 01:19	17	17	0,42
29-10-2008 03:52	29-10-2008 04:30	38	38	0,95
29-10-2008 05:53	29-10-2008 08:09	136	125	3,13
29-10-2008 08:37	29-10-2008 09:18	41	41	1,02
29-10-2008 09:36	29-10-2008 10:05	29	26	0,65
29-10-2008 19:16	29-10-2008 19:30	15	14	0,36
30-10-2008 00:33	30-10-2008 04:14	220	140	3,50
30-10-2008 05:36	30-10-2008 11:53	377	213	5,33
30-10-2008 23:25	31-10-2008 00:20	55	35	0,88
31-10-2008 02:49	31-10-2008 04:35	106	90	2,25
31-10-2008 04:55	31-10-2008 07:00	125	116	2,89
17-11-2008 03:36	17-11-2008 04:42	65	35	0,88
17-11-2008 21:42	18-11-2008 04:28	406	208	5,19
18-11-2008 07:59	18-11-2008 13:32	333	301	7,53
23-11-2008 00:38	23-11-2008 15:31	893	680	16,99
04-02-2009 17:02	06-02-2009 03:22	2059	1562	39,05
23-02-2009 06:46	23-02-2009 08:19	93	64	1,60
02-03-2009 10:25	02-03-2009 12:59	154	128	3,20

WTG: GE WIND ENERGY GE 1.5sle 1500 77.0 !O! hub: 80,0 m (2253) in layer: DEMO-East-WTGs

Cut out time	Cut in time	Total duration [min]	Duration below PC cut out [min]	Hysteris loss [MWh]
29-10-2008 00:54	29-10-2008 01:24	30	28	0,70
29-10-2008 03:24	29-10-2008 05:28	124	105	2,62
29-10-2008 05:47	29-10-2008 10:09	261	212	5,29
29-10-2008 18:56	29-10-2008 19:34	38	29	0,73
30-10-2008 00:27	30-10-2008 04:19	232	102	2,55
30-10-2008 05:31	30-10-2008 11:56	386	175	4,37
30-10-2008 23:10	31-10-2008 02:22	192	134	3,36
31-10-2008 02:45	31-10-2008 08:07	322	236	5,91

Figure 25 High wind hysteresis loss is shown with a detailed list for each turbine, where as well number of expected stops as duration and losses can be seen.