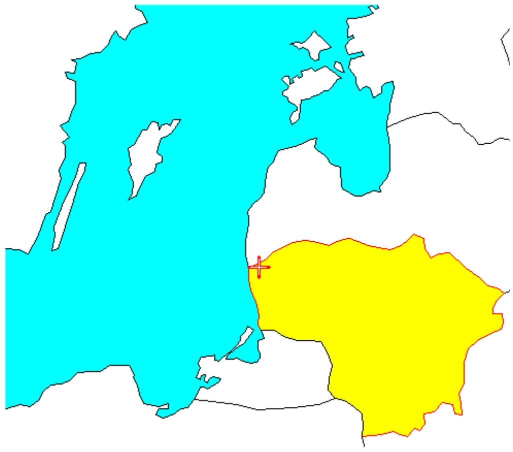
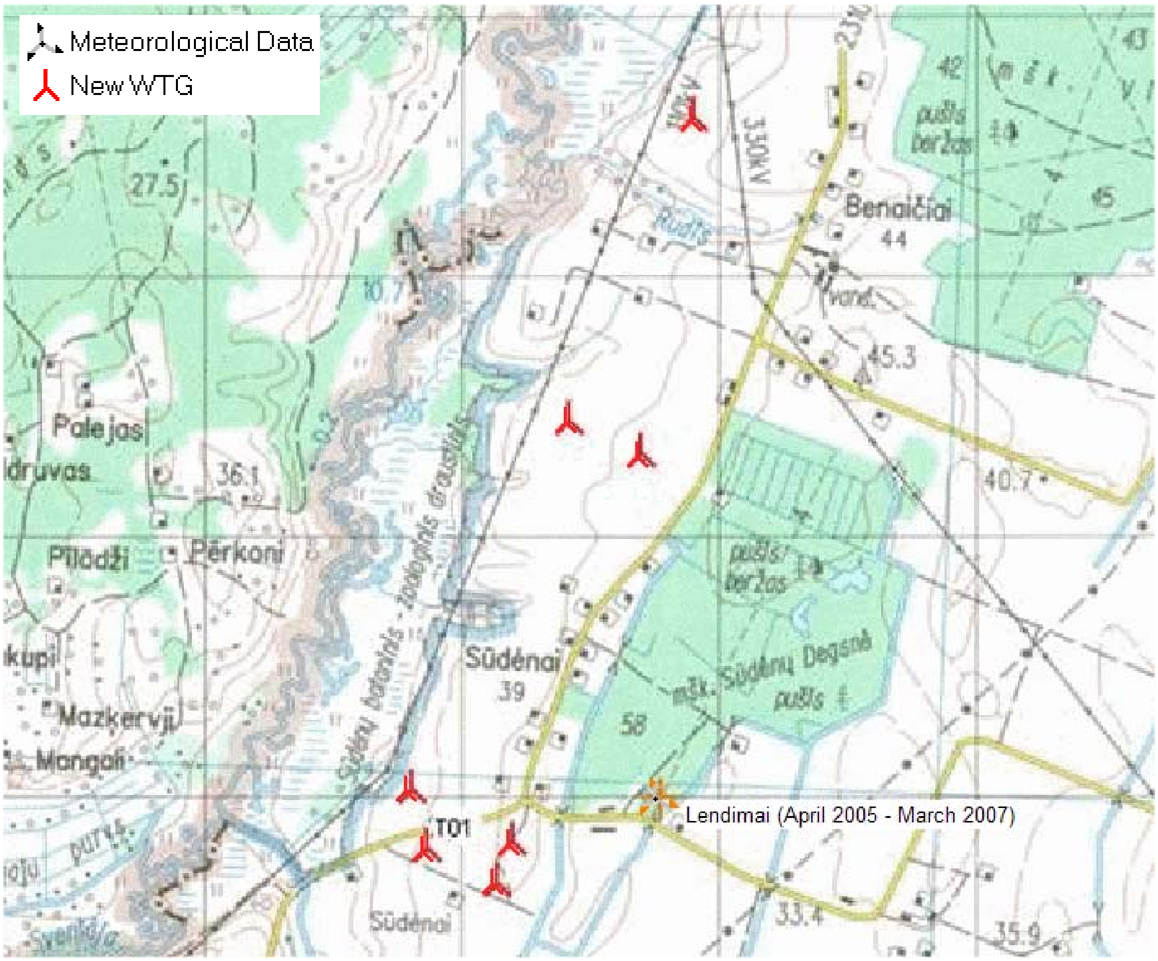
Energy Yield Assessment for:



Sudenai, Lithuania

14 MW Wind farm

7 x Enercon E-82 – 2.0 MW
78 m hub height



EMD International A/S – May 2007

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Executive summary

In this report the annual energy production for the proposed Sunedai Wind Farm, Lithuania is estimated. One wind farm layout has been calculated:

7 x Enercon E-82 (2 MW), 78 m hub height

Main calculated result:

The calculated Annual Energy Production (AEP) is presented in the table below.

Calculated AEP				
Project size: 14MW			**Cap.f.net**	**27,5%**
Based on: 7 x 2MW Enercon E-82				
			Percent	**GWh/year**
Calculated Gross incl. array losses etc.				36,168
Estimated additional losses not included in gross			-6,8%	
Calculated Net, P(50) long term estimate				33,708
Estimated uncertainty (20 y based):			10,7%	(St.dev.)
Calculated uncertainty reduced expectations including expected wind energy variations for financial evaluation:				
	1 year	5 year	10 year	20 year
P50	33,708	33,708	33,708	33,708
P84	28,800	29,822	29,969	30,045
P90	**27,383**	**28,700**	**28,890**	**28,988**

Calculated gross annual energy yield for the Sudenai Wind Farm along with loss and uncertainty deductions. In order to account for all major uncertainties and losses EMD recommends using the estimated P90 (20 years) production.

Losses

The total assumed losses are 6.8%. Below table breaks down losses into individual component losses

LOSS EVALUATION			
Gross Annual Energy Output	**36,168**	**GWh/year**	Calculated WindPRO/WAsP
	2.583	MWh/MW/year (= full load hours)	
Gross Capacity factor	29,5%		
Losses etc. included in calculation	**Loss**	**Efficiency**	**Comments**
Topographic effects	1,1%	101,1%	Calculated
Obstacles	0,0%	100,0%	Calculated
Array losses	-6,8%	93,2%	Calculated
Array losses from other projects	0,0%	100,0%	Not assumed
Included long term correction modification	8,0%	108,0%	Calculated
Sub total	2,3%	97,7%	
Estimated additional losses			
Availability, WTGs	-3,0%	97,0%	Depends on service agreement
Availability Utility grid and sub station	-0,5%	99,5%	Typical value
Electrical losses (generator to meter point)	-2,0%	98,0%	Typical value
Cold temperature shutdown/blade heating	0,0%	100,0%	Estimated, not evaluated
Icing, contamination, degradation	-1,0%	99,0%	Estimated, not evaluated
High-wind hysteresis	-0,3%	99,7%	Evaluated, 1 event per year
Power curve adjustment	0,0%	100,0%	Not assumed here
Columnar control losses (sector management)	0,0%	100,0%	Not assumed here
Sub total	**-6,8%**	93,2%	
Net Annual Energy Output = P(50)	**33,708**	**GWh/year**	
	2408	MWh/MW/year (= full load hours)	
Net Capacity Factor	**27,5%**		

Assumed losses partly based on actual data, partly assumed

Uncertainties

Uncertainties are given as standard deviations. Below table lists each component.

UNCERTAINTY EVALUATION			
	m/s	MWh/y	
WTG production at	6	4688	
	7	6386	
AEP percent change per wind speed percent change		2,17	
Uncertainty parameter	**Std. dev. of parameter**	**Sensitivity**	**Std. dev. of production**
1. Wind measurement	2,5%	2,17	5,4%
2. Wind measurement mast position	0,1%	2,17	0,2%
3. Terrain/model wind extrapolation	1,0%	2,17	2,2%
Above Std.dev is on wind speed, below on energy production			
4. Long term correction (MCP)	7,5%	100%	7,5%
5. Availability, WTG	50,0%	3,00%	1,5%
6. Availability, Grid/substation	50,0%	0,50%	0,3%
7. Power curve	4,0%	95%	3,8%
8. Array loss	20,0%	6,80%	1,4%
9. Other(environment, electric loss etc.)	25,0%	2,00%	0,5%
Square root sum of uncertainties			**10,5%**
Long term wind variability	**Period**	**St. dev.**	**Resulting std. dev of production**
	1 year	10,0%	14,5%
	5 year	4,5%	11,4%
	10 year	3,2%	10,9%
	20 year	2,2%	**10,7%**

Summary of uncertainties (details can be found in section 8. Uncertainties)

CONCLUSION

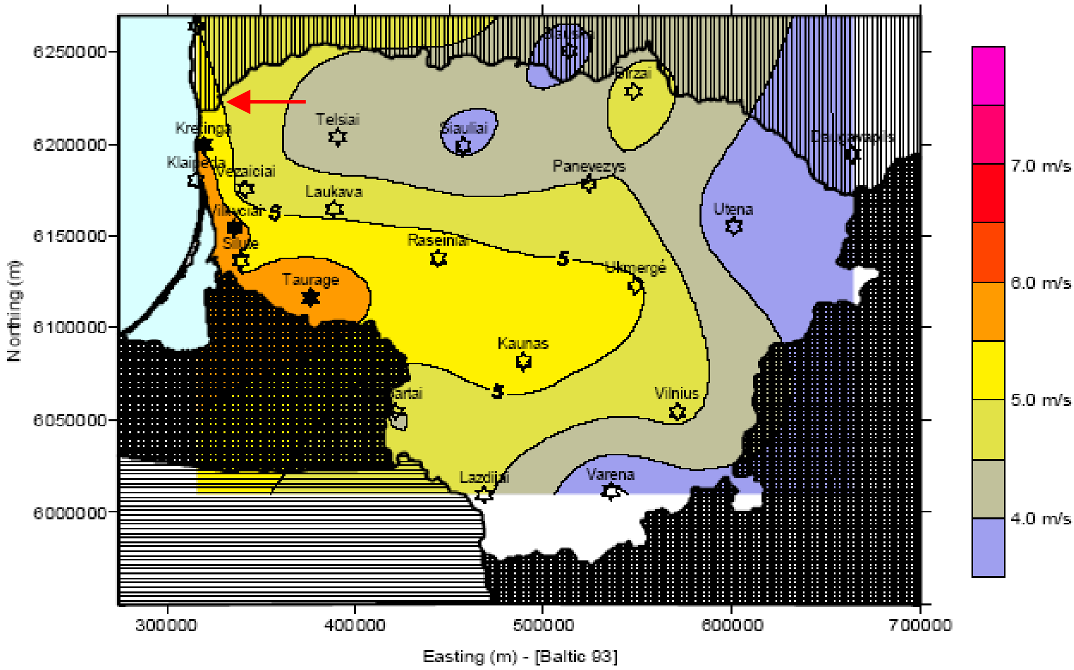
The Sudenai wind farm energy yield was calculated using measurements from a meteorological mast located on the site with 23-month measurement period. The dataset has been correlated with model data from NCAR/NCEP re-analysis data from 1975-2007 (32 years). The measured data was corrected to long-term level using NCAR/NCEP data and the wind energy index method.

The client has provided the layout for the wind farm. Losses covering electrical losses, turbine availability, utility downtime, blade contamination and degradation have been deducted using typical values. High wind hysteresis has been evaluated. The site has not been visited.

The energy capture of the proposed Sudenai Wind Farm is calculated for one turbine type – Enercon, E-82, 2.0 MW, hub height 78 m and the results can be seen in the tables. Gross production including array and topographic losses are calculated. From this 6.8% losses are deducted to give the net expected production (the P50 Annual Energy Production). Uncertainties are evaluated and presented as a probability function (P90 values etc.). The key P90 figure (the production that will be exceeded with 90% probability) after 20 years can be read in the result table.

Discussions – including comparisons to other calculations

The 23 months of local measurements on the site in 83,5 m h.a.g.l. seem to be quite long term representative based on NCAR 32 years data. The calculation results for this site therefore seem quite reliable. The site is quite simple with flat terrain. The wind conditions are measured at app. hub height and together with short horizontal extrapolation distances, it seems that no major uncertainties are induced.



If we compare our results with the Baltic Wind Atlas (The UNDP/GEF Baltic Wind Atlas, Risø-R-1402 (EN)) we see some concordance. EMD has estimated a mean wind speed at 50 m height for the site around 5,9 m/s – the Baltic Wind Atlas gives a value around 5,0 m/s.

Possible risks regarding expected energy production could be:

1. **Wind climate in the future:** In Denmark we saw a 10-year period with average 10% above long term expectations in 1985-95, while 1996-2006 were 10% below long term average. A 10 year period with wind conditions 10% below average might occur – or maybe even a 20 year period. This is a climate risk every wind project must live with, since not even the most advanced models can predict wind climate variations more than few days ahead – to predict years ahead are simply impossible. Therefore we have to rely on that “history repeats it self” – and if this is true, we can say based on the 32 years of NCAR Wind data, that the worst 20 years in a row were only 5.4% below long term average. (1972-91).

2. **Availability problems:** As well the turbines as the grid can be damaged – we have seen projects with availability as low as 50%, but this is typically where the manufacturer gets into financial trouble and not are able to meet his liability requirements, or in countries with poor infrastructure systems (grid).

All in all we consider the risk of lower performance than calculations with subtraction of the assumed uncertainties to be low. A site inspection with the purpose of taking a closer look at the site and a more thorough evaluation of the instrument calibrations and mast positions could improve the certainty of the estimates.

Energy yield assessment for the project:
Sudenai wind farm, Lithuania

Table of content:

Appendix	A	Turbine data	Technical specifications on turbines
Appendix	B	Production calculation	Energy yield assessment for Sudenai

1. Site, project and purpose description.

The site is located in Lithuania near the coordinates East: 514.400, North 6.216.500 (UTM, WGS 84). The site is shown on the overview map below.

The wind farm layout is shown on the detailed map below.

A meteorological mast, called Lendimai, is located close to the wind farm.

The purpose of this report is to assess the annual energy production of the project, based on site measurements and long-term correction with available data. In addition the uncertainty is evaluated and the production at different probability percentiles is calculated.

EMD has not visited the site.

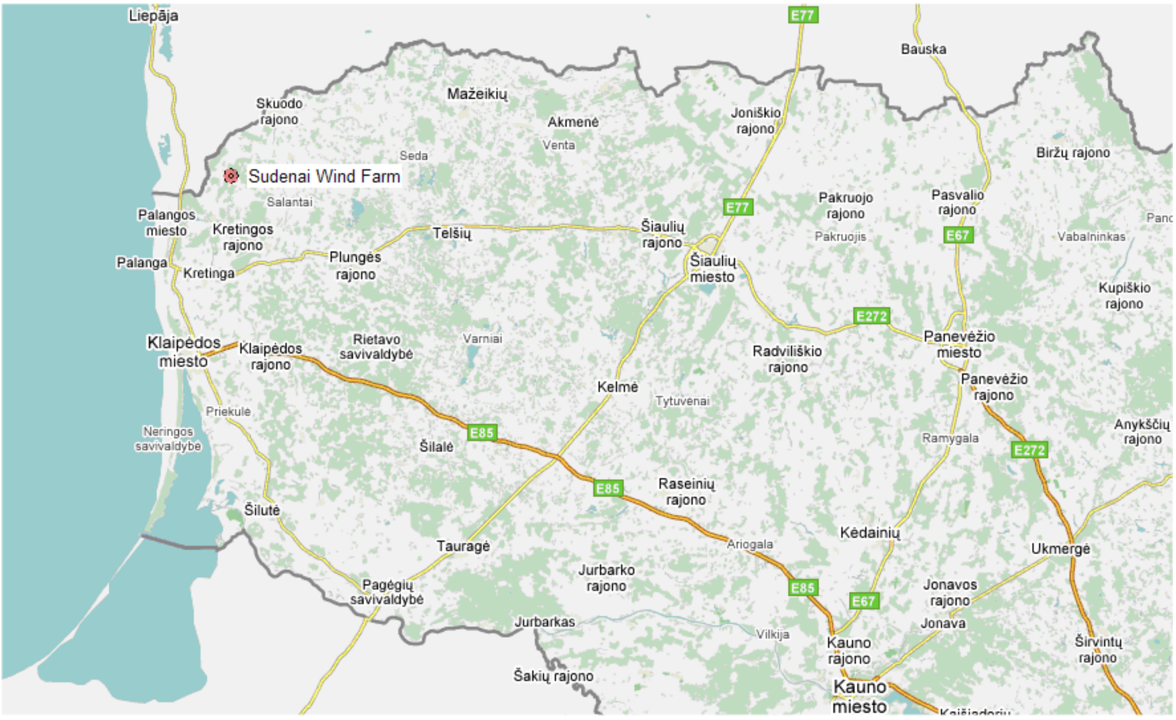


Figure 1. Location map.

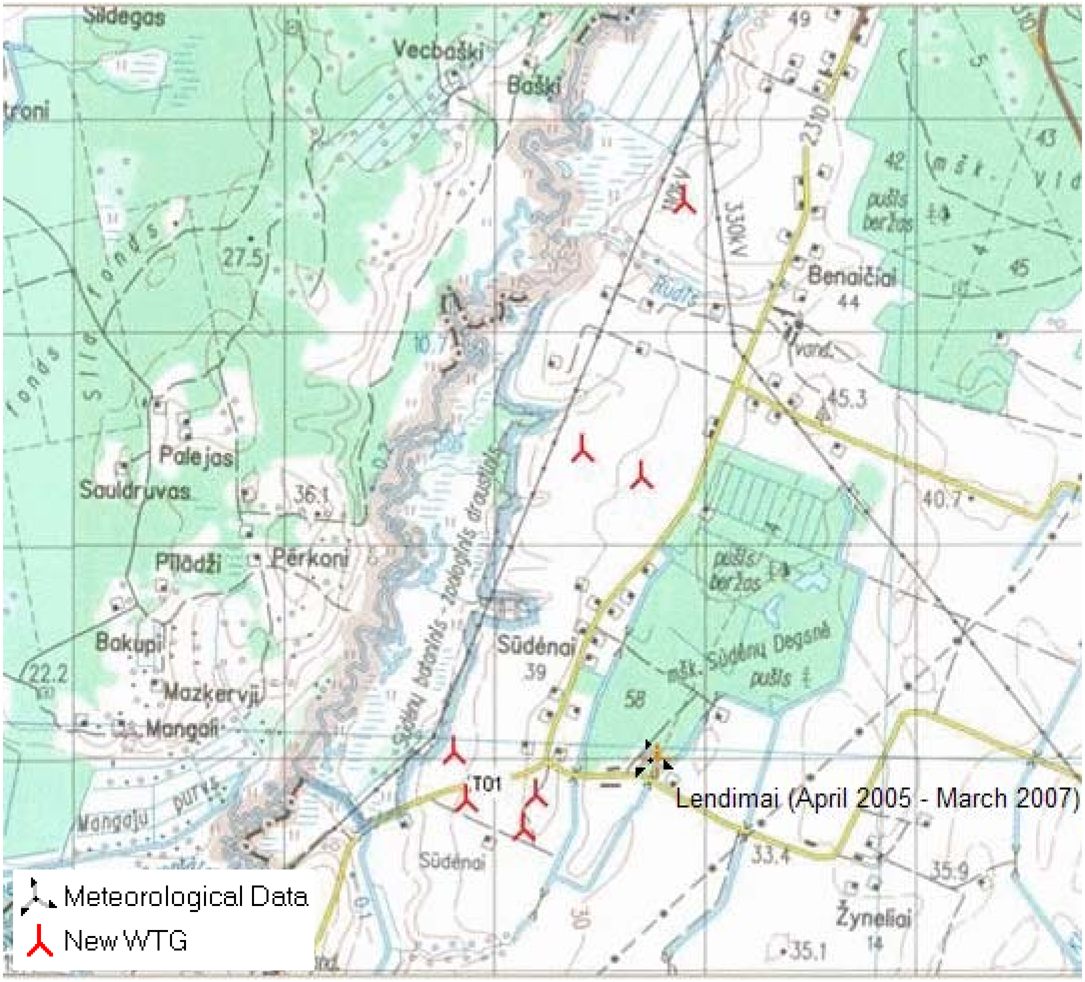


Figure 2. Local site map with local metering mast and WTG positions.

2. Available data.

OÜ Nejlja Energia has provided EMD with wind data and data concerning the site.

The following information has been supplied for the site:

Electrical grid:
No information has been provided.

Maps
Maps have been provided in appropriate scales. They have been used to evaluate the terrain conditions.

Wind turbine type and position
OÜ Nejlja Energia has provided the wind turbine type, the power curve and the positions for the turbines.

Details on the turbines can be found in appendix A.

Wind Data
Measurements from a local mast were available. These are described in detail in section 3.5. No data are available after March 31st 2007. Detailed information on the mast and the equipment were available. Detailed calibration reports were available.

Reanalysis data from the NCAR/NCEP data have been used. For NCAR/NCEP data series from 1975 to 2007 have been prepared. The data are available in a 2.5°-grid all over the world. The closest points at 57.5°N, 22.5°E; 57.5°N, 20.0°E; 55.0°N, 22.5°E and 55.0°N, 20.0°E have been used from the NCAR/NCEP database. Surface values, which are almost similar to a measuring height of 50 m, have been extracted.

Information source:
All information except NCAR/NCEP data was supplied by: OÜ Nejlja Energia.

Data material supplied by EMD:

- The general surface roughness of the terrain has been evaluated on the basis of maps and pictures delivered by the client.
- EMD International A/S provides the NCAR/NCEP references mentioned above.

3. Analysis and evaluation of data.

3.1 Power curves

The used turbine type will be described in more detail below. The power curve is not compared to a standard power curve called HP curves and a HP power test is not performed. The reason is that the HP-theory doesn't comply with the technology used in this Enercon turbine. Further information of the HP curves can be found in appendix A.

The power curve used is the official sales curve from Enercon.

In appendix A the technical information for the Enercon E-82 – 2.0 MW as used in the calculations are presented.

The power curve of the turbine is considered reasonable and need no adjustment. An uncertainty of 4.0% on the power curve has been used in the P90-calculations.

3.2 Height contours

EMD has digitized heights contours in a distance of 5 km from each turbine and mast. An equidistance of 5 meters has been used in the calculations.

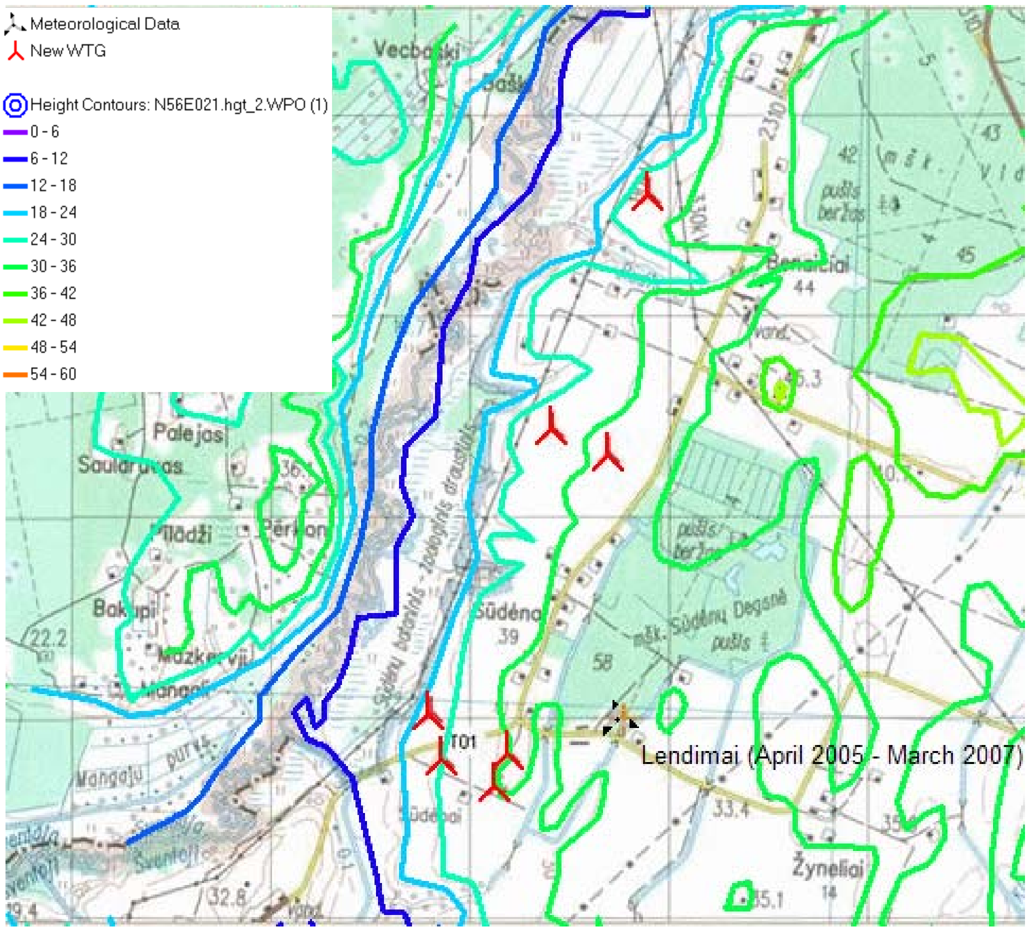


Figure 3. Height contours map

3.3 Roughness classification

The roughness of the landscape determines how much the surrounding terrain will drag the wind profile, thereby slowing the wind down. The area has been classified in a radius exceeding 20.000 m from each turbine/mast.

A section of the roughness map is shown below (fig. 4).

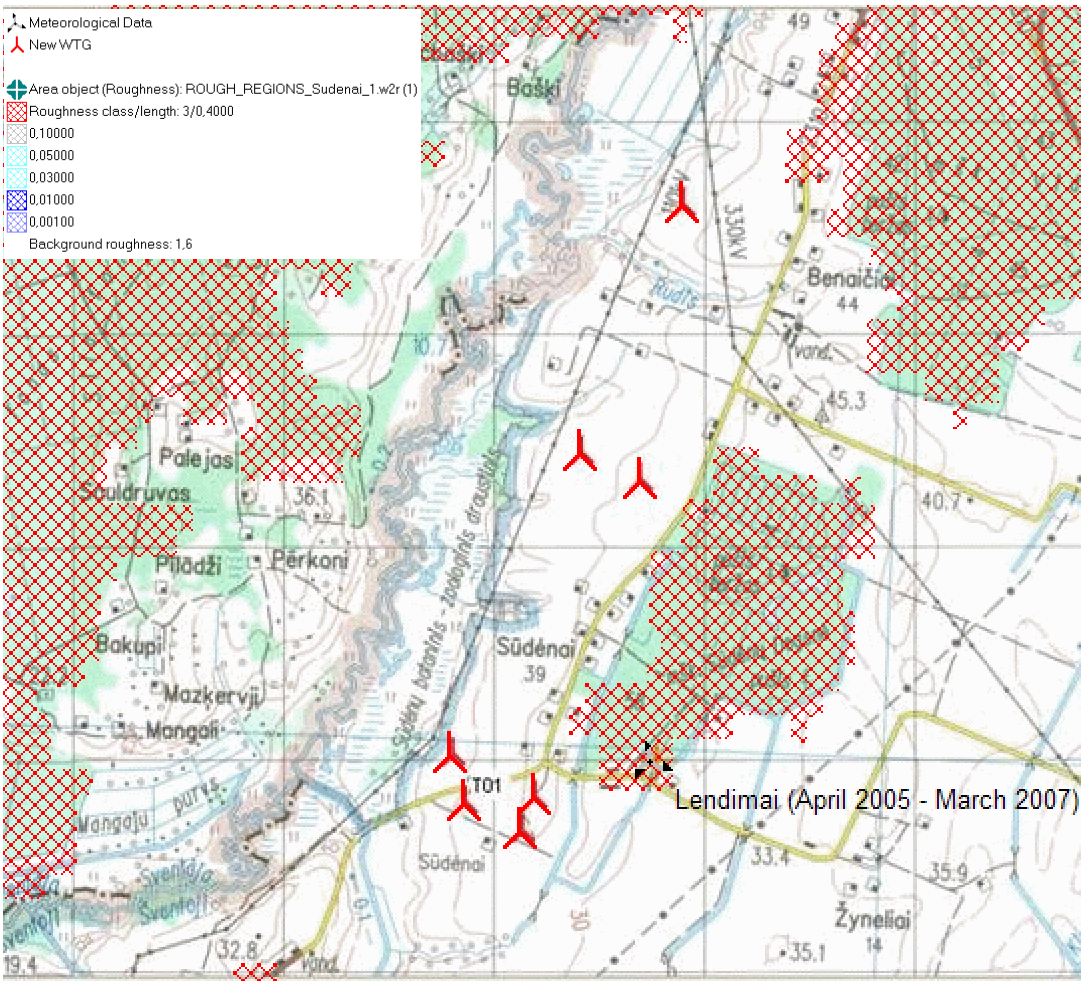


Figure 4. Section of the roughness map showing the near area. The roughness is given in roughness lengths.

3.4 The forest.

Forests have minor influence on the production calculation for this site. Even though there are forests in the region, the measuring mast and the turbines are so tall that only minor influence is discovered. Another important issue is that measuring and hub height are almost identical and therefore many uncertainties especially in connection with forest are eliminated or at least reduced significantly.

3.5 Wind data

The wind measurements consist of a local mast located in the southern part of the site (Lendimai) (see fig. 2).

As long-term reference NCAR data from the four nearest grid points have been used.

3.5.1 Lendimai

Measurements have been made on a metering mast in the southern part of the site. Detailed descriptions and some photos are available of the mast.

The mast location is shown in figure 5. Instrumentation is described in figure 6 and is based on the descriptions from OÜ Nejlja Energia.

Meteorological mast: Sudenai (UTM, WGS 84)		
Easting	Northing	Altitude (a.s.l.)
514.389	6.216.554	33 m

Figure 5. Sudenai mast coordinates

Mast: Lendimai			
Date	Height	Anemometer	Wind vane
07.04.2005 - 31.03.2007			
	42,0 m	×	
	42,0 m		×
	66,0 m	×	
	83,5 m	×	
	83,5 m		×
	85,0 m	×	

Figure 6. Instrumentation on the local mast

Figure 7. Photo of the measuring mast at Lendimai

The wind data are available for the period April 7th 2005 – March 31st 2007 as 10 min averaged values.

Calibration reports have been submitted.

The raw data of the mast have been cleaned of erroneous data and the remaining data were analysed.

Statistics for observations

Print | Close | Data from: 07-04-2005 12:15 | Data to: 31-03-2007 23:50 | Recovery rate: 96% | Observations: 100066 | Observations per day: 144

day	04-05	05-05	06-05	07-05	08-05	09-05	10-05	11-05	12-05	01-06	02-06	03-06	04-06	05-06	06-06	07-06	08-06	09-06	10-06	11-06	12-06	01-07	02-07	03-07	04-07
%	100	100	100	100	100	100	100	98	97	10	90	100	100	100	100	100	100	100	100	100	100	99	92	97	0
1		144	144	144	144	144	144	144	144	84	144	144	144	144	144	144	144	144	144	144	144	144	129	144	
2		144	144	144	144	144	144	144	79	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
3		144	144	144	144	144	144	144	144	0	129	144	144	144	144	144	143	144	144	144	144	144	144	44	
4		144	144	144	144	144	144	144	144	0	143	144	144	144	144	144	144	144	144	144	144	144	144	144	
5		144	144	144	144	144	144	144	144	0	0	144	144	144	144	144	144	144	144	144	144	144	144	123	
6		144	144	144	144	144	144	144	144	0	124	144	144	144	144	144	144	144	144	144	144	144	144	144	
7	70	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
8	144	144	144	144	144	144	144	144	144	0	37	144	144	144	144	144	144	144	144	144	144	144	144	144	
9	144	144	144	144	144	144	144	144	144	0	67	144	144	144	144	144	144	144	144	144	144	144	144	144	
10	144	144	144	144	144	144	144	144	144	0	113	144	144	144	144	144	144	144	144	144	144	144	24	144	
11	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	68	144	
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16	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	100	144	
17	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
18	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
19	144	144	144	144	144	144	144	112	144	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
20	144	144	144	144	144	144	144	99	144	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
21	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
22	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
23	144	144	144	144	144	144	144	144	68	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
24	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
25	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
26	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	144	144	
27	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	110	144	
28	144	144	144	144	144	144	144	144	144	0	144	144	144	144	144	144	144	144	144	144	144	144	130	144	
29	144	144	144	144	144	144	144	144	144	74		144	144	144	144	144	144	144	144	144	144	125		144	
30	144	144	144	144	144	144	144	144	144	144		144	144	144	144	144	144	144	144	144	144	109		144	
31		144		144	144		144		144	144		144		144		144	144		144		144	144		144	

Figure 8. The statistics for observations at 83,5 m (the finally used measuring height) Red and yellow cells are days lacking data, blue shows disabled data

Wind speed analysis

Figure 9. Wind speed measurements at 83,5m and 66,0 m are correlating perfectly

The wind speeds measured at the two heights show the expected difference in wind speed and correlate well, which is also expected. Periods with malfunctioning anemometer have been identified for every height and removed.

Wind direction analysis

Figure 10. Wind directions on the 83,5 m and 42,0 m wind vane. A difference of around 20 degrees is seen. The 83,5 m wind vane is assumed to be the most correct because the best correlation with long-term reference data is seen for this specific wind vane.

For the entire measurement period following directional distribution were obtained at Lendimai for 83,5 m and 42,0 m measurements. The directional distributions for the two masts are very similar, but apparently there is a turning of the wind of around 20 degrees. The 83,5 m measurement is assumed to be correct.

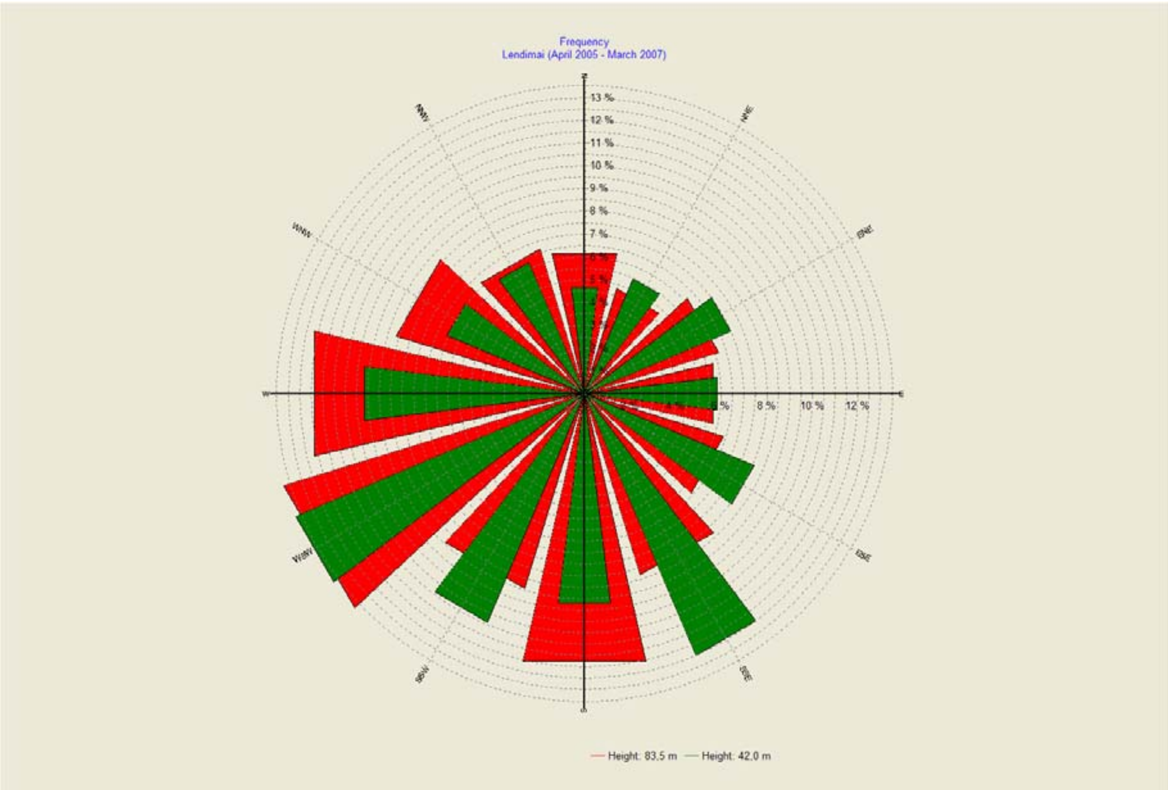


Figure 11. Directional distributions for measurement periods

Wind profile analysis

Below is shown the estimated wind profile using WAsP (data from 83,5 m height) and the measured wind data.

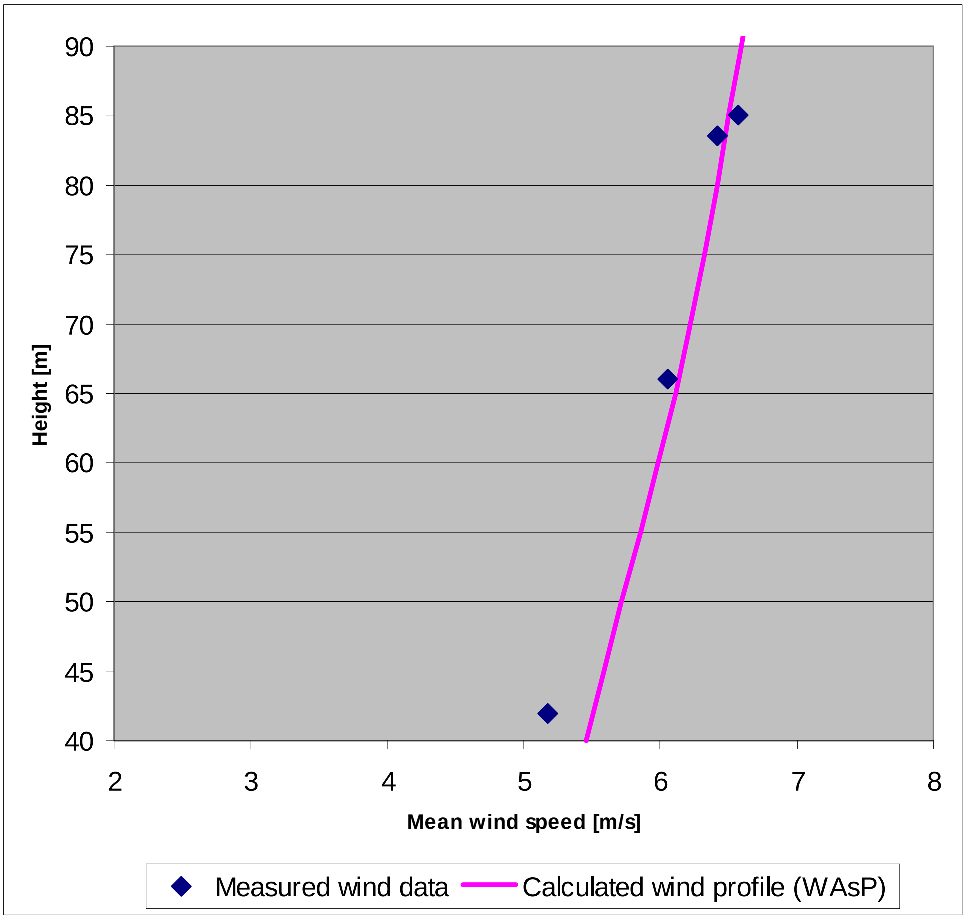


Figure 12. Estimated wind profile and measured wind speed

A very little difference is seen for the measurements at 66,0 m and 83,5 m. Both the 85,0 m and 42,0 m measurements show some difference. The 83,5 meter measurements have been used in the analysis because it is closest to hub height and it represents the wind profile in a correct way.

3.5.2 NCAR/NCEP data

NCAR/NCEP dataset are modelled data based on numerous measurements. These measurements have been used to set up a model for the atmosphere which in turn provides 6 hour frequency time series for node points around the globe with a 2,5 degree spacing. National Centre for Atmospheric Research (NCAR), Boulder, Co., USA makes this work.

With geographical coordinates 56,1°N, 21,2°E the closest points are at 57.5°N, 22.5°E; 57.5°N, 20.0°E; 55.0°N, 22.5°E and 55.0°N, 20.0°E. Time series from these four points have been extracted as surface data (app. 50 m measuring height).

Data from the period 1975 – 2007 have been used.

4. Correlation.

4.1 Correlation of energy index

In order to limit the selection of long-term references a wind energy index correlation is made. The references that best fit the energy index will best reflect the wind climate on site. In order to see which one of the NCAR data set to use a correlation analysis has been performed. Below is shown the correlation between the measurements from the site and the four different NCAR data points.

	Correlation	Standard error
NCAR 57.5N 20.0E	0,93	16,8
NCAR 55.0N 20.0E	0,93	15,5
NCAR 55.0N 22.5E	0,94	14,4
NCAR 57.5N 22.5E	**0,94**	**15,4**

(the correlation is only made for the years 2005 - 2007).

Figure 13. Correlation and long-term correction factors for the four NCAR data points and site measurements

There is no clear indication of what NCAR point that is best when looking at 83,5 m only. Taking into account the other measuring heights, the data point **NCAR 57.5N 22.5E** gave the best all over performance. In the following only data from this NCAR data point is used. The wind energy of a measurement is calculated by applying the wind speed to the power curve of the wind turbine in question. The wind speeds measured on site plus from NCAR are extrapolated to near hub height using a shear factor (actually: to the expected mean wind speed at hub height: 6,5 m/s). Thus we get a time series of what a given wind turbine would have produced at hub height. A monthly wind index can then be found averaging the available wind energy over each month.

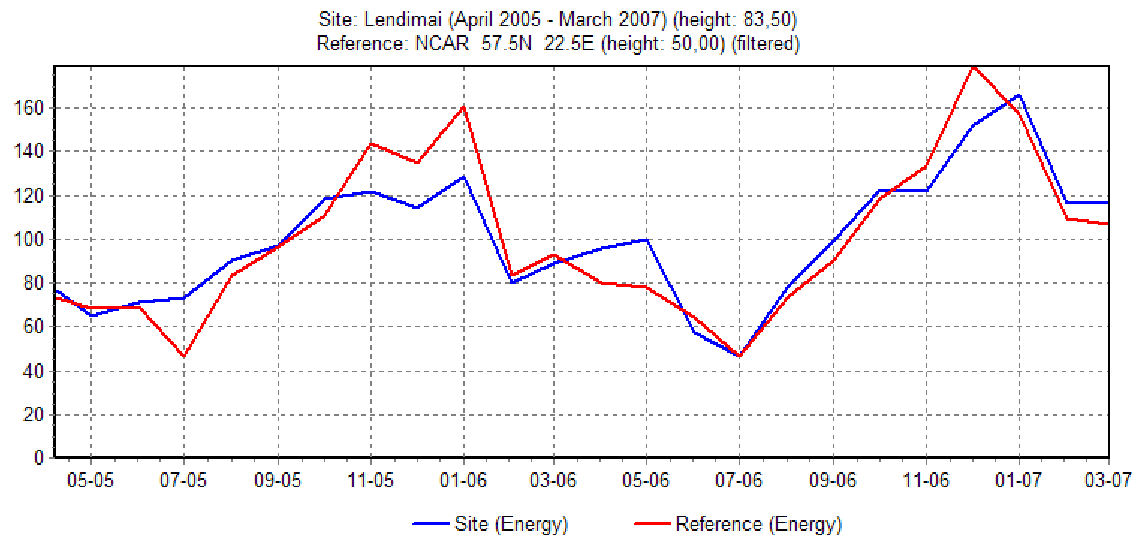


Figure 14. Monthly wind energy indexes for the period of measurement at Lendimai.

In figure 14 the monthly wind energy index is shown for the period of measurement at Lendimai compared to the monthly index for the chosen NCAR/NCEP data point. Generally there is a good fit for most of the period, with some distortion around January 06 (reason unknown). But generally the graph gives a good documentation for using NCAR as long-term reference at this location.

4.2 Correlation of wind directions

A small section of the time series for the local mast and the NCAR series were compared in figure 15. These are readings from the exact same period and the trends are consistent throughout the data sets.

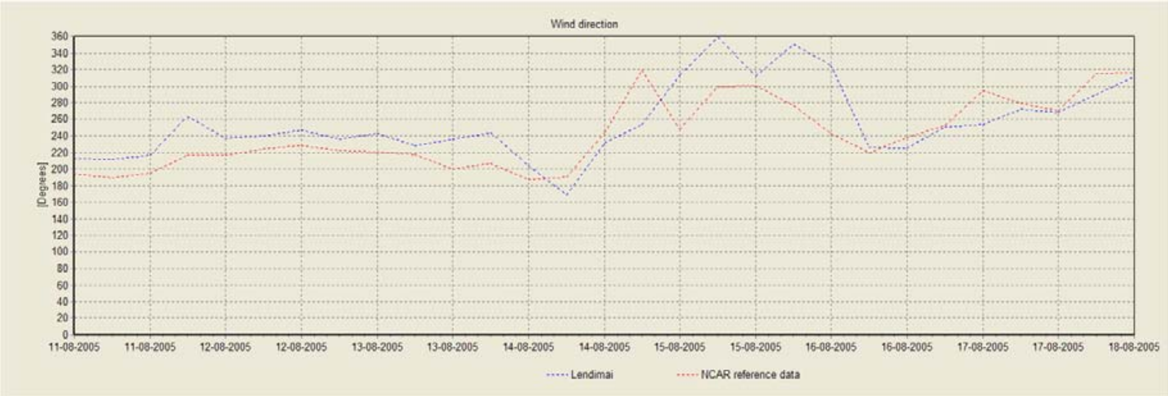
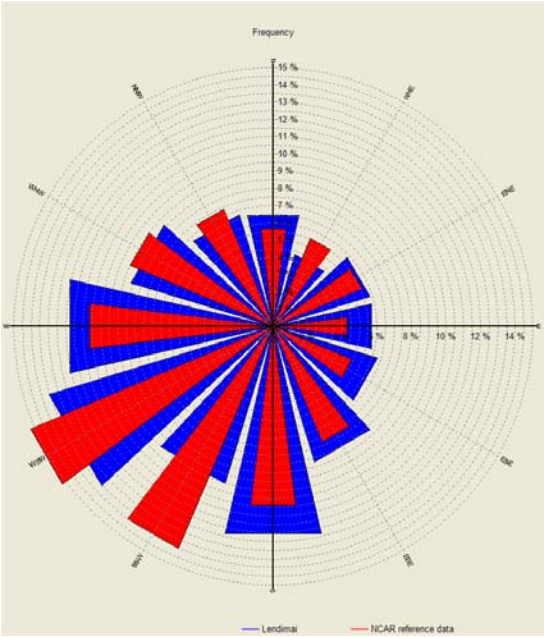


Figure 15. Comparison of wind directions (site and NCAR)



The match is very good for the two series. NCAR/NCEP data represent the wind in the upper atmosphere and while the variations in wind speed usually correlate well with observed values in the near surface boundary layer the directions usually correlate poorly if at all. With that in mind the correlation with Lendimai is really good.

The direction distributions of the overlapping periods are shown below in figure 16. The reference data does not match exactly the distribution of the local readings. However the difference is minor and therefore there is no reason to discard the NCAR series as the choice of reference.

Figure 16. Comparing directional distribution of local readings with that of overlapping reference readings

4.3 Correlation of wind speed

If the actual recorded wind speeds are compared (figure 17) it can be seen that the NCAR data match fairly well to the patterns of the local mast.

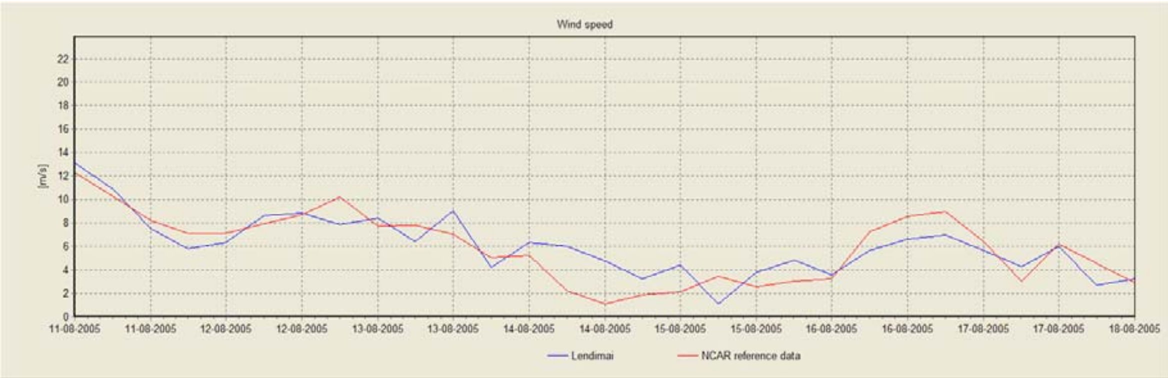


Figure 17. Actual wind speed data from the local mast and NCAR 22.5E, 57.5N.

4.4 Long term correlation

In order to detect a long-term trend in the reference data, monthly indexes are presented below for the NCAR series. From the 12 month moving average can be recognized, that the wind energy level were significantly higher in the 90'ties than in the later years. This is expected. Beside this shift there is no indication of a systematic decreasing or increasing trend and no particular deviating or incapacitating trends among the three references.

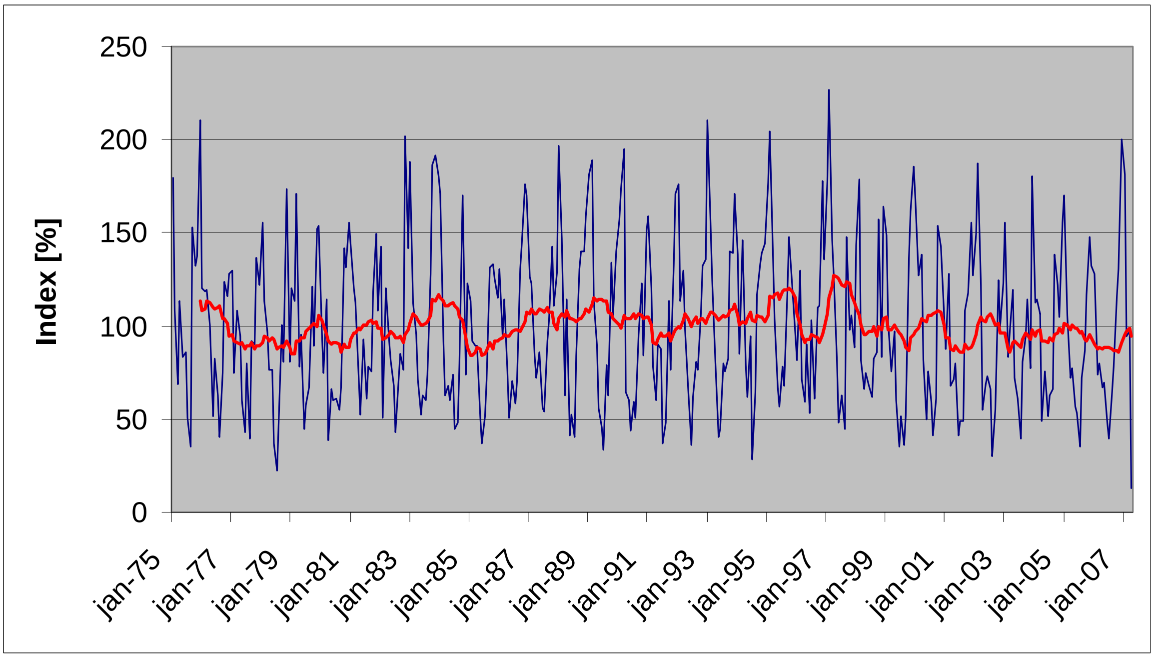


Figure 18. Monthly indexes for the full NCAR data set

In figure 19 the direction rose for the concurrent NCAR data are compared with the rose for the full NCAR series. This is done in order to verify that the direction distribution during the measured period is representative to the long-term direction distribution.

The distribution for the entire NCAR series is very similar to the concurrent period. There are minor differences, but the differences are not critical and it will be reasonable to say that the direction distribution of the measurement period is long term representative.

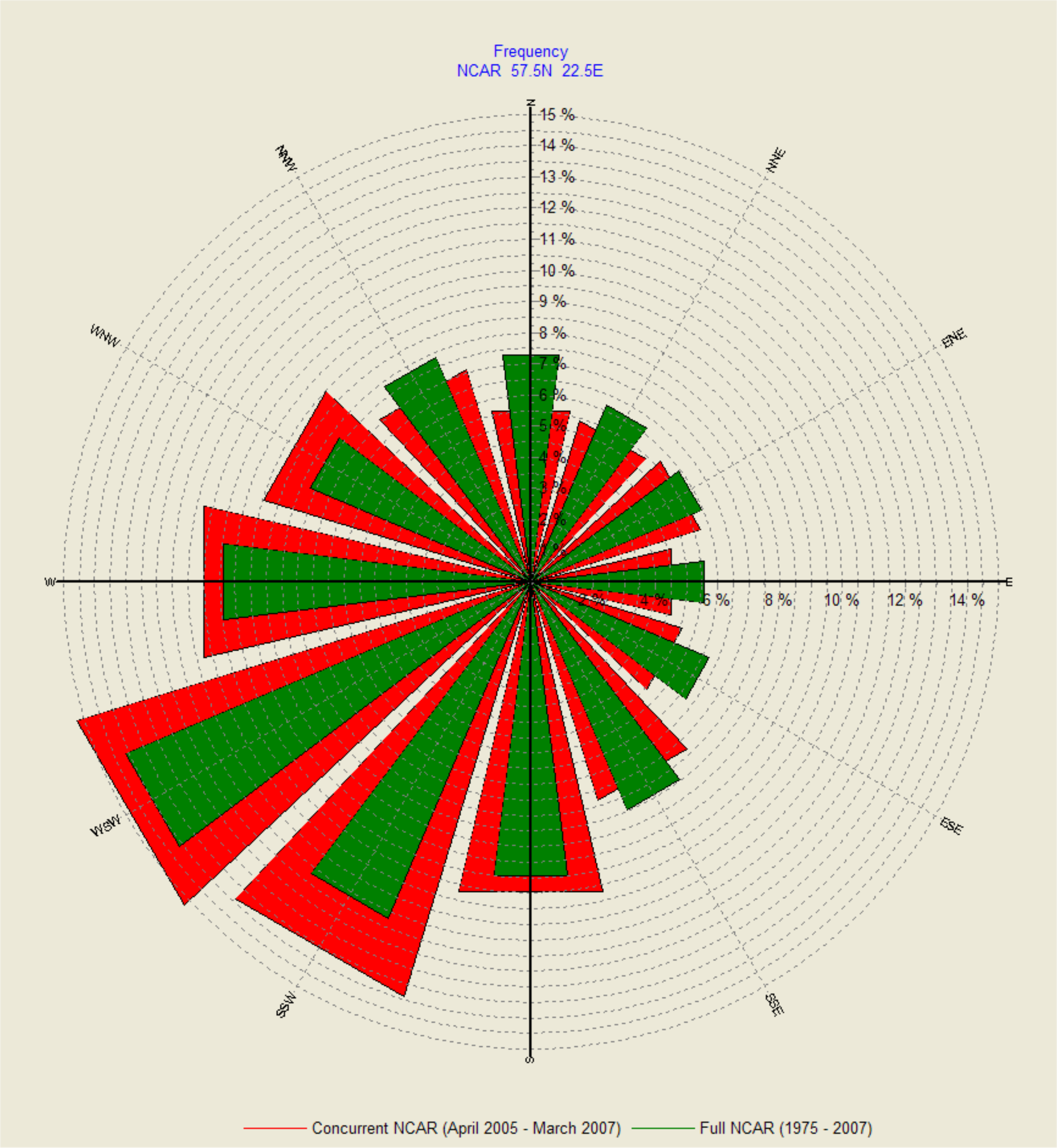


Figure 19. Comparison of NCAR overlapping period with the full reference period

5. Long term correction

5.1 Long-term correction methodology

A range of methods for long-term correction is available. In this particular case where the Lendimai measurements must be long term corrected with NCAR/NCEP data all four methods are technically possible. In the following all four methods are evaluated. The four methods are:

- Linear regression
- Wind energy index correction
- Weilbull scale
- Matrix

5.2 Comparing methodology, references and sources.

In order to test the methodologies for long-term correction results from the methods is analysed.

	WTG energy level	Correlation (index)
Linear regression	84,6	0,9573
Matrix method	75,9	0,9144
Weibull scale method	87,8	
Wind energy index method	**83,6**	**0,9361**
Average	83,0	

Figure 20. Comparison of the MCP methodologies. The WTG energy indicates the relative energy content. Correlations are for the concurrent measured and corresponding predicted data based on no averaging.

Different WTG energy levels are seen. The wind energy index method is regarded as the most reliable in this case. It is also the method that reflects the general energy level best among the four methods. The correlation values are almost similar.

For the production calculations made in this study the wind energy index correction method is preferred using NCAR 22.5E, 57.5N as reference.

6. Calculation of annual energy production.

6.1 WindPRO-WAsP calculation

The WAsP calculation model is commonly used to calculate the transformation of wind data from the point of metering to the each individual turbine. The model is described in detail by (Troen and Petersen, 1989). First step is to generate from the metering data and the terrain around the mast a description of the regional wind climate (a wind statistic), secondly to apply this wind statistic on each individual turbine at hub height, reintroducing the local terrain description.

One wind statistics for the regional wind climate has been calculated using WAsP based on long term corrected measurements at 83,5 m height (using wind energy index long-term correction and the terrain data as described in section 3).

Energy production calculations have been performed with WindPRO using the WAsP calculation engine with wind statistic and the terrain description as input. The air density is calculated individually for each turbine to between 1.255 and 1,256kg/m^3 based on height and temperature at the meteorological station nearby at Klaipeda and the height above sea level of the turbine hubs. The production estimate is adjusted with this air density by modifying the power curves of the turbines.

Calculation Settings

Air density calculation mode	Individual per WTG
Result for WTG at hub altitude	1,255 kg/m3 to 1,256 kg/m3
Hub altitude above sea level (asl)	99,5 m to 108,8 m
Annual mean temperature at hub alt.	4,4 °C to 4,4 °C
Pressure at WTGs	999,8 hPa to 1.000,9 hPa

Figure 21. Air density for the PARK calculation

Based on the layouts chosen, and the data described in the report so far, following results appear in a PARK calculation, where individual roughness, height contour lines and local obstacles are taken into consideration for each WTG position. The array losses are calculated as well using the N.O. Jensen model. Below is shown the calculated annual gross energy yield for the Sudenai Wind Farm project.

Calculated Annual Energy for Wind Farm

WTG combination	Annual Energy Result [MWh]	Annual Energy P90 incl. losses and uncertainty Result-19,9% [MWh]	Park Efficiency [%]	Mean WTG energy [MWh]	Capacity Factor for Result [%]	Capacity Factor for P90 incl. losses and uncertainty Result-19,9% [%]
Wind farm	36.167,7	28.970,3	93,2	5.166,8	29,5	23,6

Calculated Annual Energy for each of 7 new WTG's with total 14,0 MW rated power

	Terrain	WTG type Valid	Manufact.	Type	Power [kW]	Diam. [m]	Height [m]	Power curve Creator	Name	Annual Energy Result [MWh]	P90 incl. losses and uncertainty Result-19,9 % [MWh]	Park Efficiency [%]	Mean wind speed [m/s]
1	A	Yes	ENERCON	E-82	2.000	82,0	78,0	EMD	Level 0 - guaranteed* - Rev. 2.0 - 06/2005	5.324,8	4.265	98,6	6,5
2	A	Yes	ENERCON	E-82	2.000	82,0	78,0	EMD	Level 0 - guaranteed* - Rev. 2.0 - 06/2005	5.274,1	4.225	96,1	6,5
3	A	Yes	ENERCON	E-82	2.000	82,0	78,0	EMD	Level 0 - guaranteed* - Rev. 2.0 - 06/2005	5.303,0	4.248	95,8	6,5
4	A	Yes	ENERCON	E-82	2.000	82,0	78,0	EMD	Level 0 - guaranteed* - Rev. 2.0 - 06/2005	4.863,0	3.895	85,8	6,6
5	A	Yes	ENERCON	E-82	2.000	82,0	78,0	EMD	Level 0 - guaranteed* - Rev. 2.0 - 06/2005	5.264,3	4.217	92,9	6,6
6	A	Yes	ENERCON	E-82	2.000	82,0	78,0	EMD	Level 0 - guaranteed* - Rev. 2.0 - 06/2005	5.186,9	4.155	93,0	6,6
7	A	Yes	ENERCON	E-82	2.000	82,0	78,0	EMD	Level 0 - guaranteed* - Rev. 2.0 - 06/2005	4.951,6	3.966	90,4	6,5

Figure 22. Calculated gross production before assumed losses (but including array losses) – the result – 19,9% is the P(90) result, including loss and uncertainty reduction.

Printouts of the calculation results, with details on each WTG are attached as appendix B.

7. Losses

7.1 Array losses

The array losses due to the turbines sheltering effect on each other are included in the calculations above. The array losses can be read in figure 22.

7.2 Design losses

By using an official and guaranteed power curve and adjusting for the actual air density there should be no losses there that would not be accounted for by the manufacturer. This means in general that there shall not be added any design losses in the calculation.

7.3 Availability

Losses due to general availability for a land site with a good service agreement is typically extremely low (<2%), but this is very dependent on the service arrangements and guaranties of the manufacturer and vigilance of the owner of the turbines. For safety purpose a standard availability loss of 3 % has been included.

7.4 Icing losses

This region is not sufficiently prone to icing of the blades for this to be a concern in the energy calculation. For safety reasons a 1% withdraw have been included, mainly caused by the contamination of the blades.

7.5 Electrical losses

There is no information available about electrical losses. For this reason a standard 2% loss have been included in the calculation. This will have to be verified with the developer.

7.6 Substation maintenance and utility downtime

A standard value of 0,5% has been applied. The figures should be verified by the utility.

7.7 High wind hysteresis

High wind hysteresis is the losses caused by having the turbine stop at 25 m/s, but only start up again when the wind speed is significantly lower than 23 m/s. Each time this happens, an average of 0.3 % of production is lost. For the measuring period this occurs around once a year. Therefore a reduction of 0,3% has been applied.

7.8 Summary of losses

All these external losses are listed in below table. For information the array and topographic losses etc., which are included in the net AEP are listed as well.

LOSS EVALUATION			
Gross Annual Energy Output	**36,168**	**GWh/year**	Calculated WindPRO/WAsP
	2.583	MWh/MW/year (= full load hours)	
Gross Capacity factor	29,5%		
Losses etc. included in calculation	**Loss**	**Efficiency**	**Comments**
Topographic effects	1,1%	101,1%	Calculated
Obstacles	0,0%	100,0%	Calculated
Array losses	-6,8%	93,2%	Calculated
Array losses from other projects	0,0%	100,0%	Not assumed
Included long term correction modification	8,0%	108,0%	Calculated
Sub total	2,3%	97,7%	
Estimated additional losses			
Availability, WTGs	-3,0%	97,0%	Depends on service agreement
Availability Utility grid and sub station	-0,5%	99,5%	Typical value
Electrical losses (generator to meter point)	-2,0%	98,0%	Typical value
Cold temperature shutdown/blade heating	0,0%	100,0%	Estimated, not evaluated
Icing, contamination, degradation	-1,0%	99,0%	Estimated, not evaluated
High-wind hysteresis	-0,3%	99,7%	Evaluated, 1 event per year
Power curve adjustment	0,0%	100,0%	Not assumed here
Columnar control losses (sector management)	0,0%	100,0%	Not assumed here
Sub total	**-6,8%**	93,2%	
Net Annual Energy Output = P(50)	**33,708**	**GWh/year**	
	2408	MWh/MW/year (= full load hours)	
Net Capacity Factor	**27,5%**		

Figure 23. Summary of losses. Array and topographic losses are included in the net AEP.

8. Uncertainties

UNCERTAINTY EVALUATION			
	m/s	MWh/y	
WTG production at	6	4688	
	7	6386	
AEP percent change per wind speed percent change		2,17	
Uncertainty parameter	**Std. dev. of parameter**	**Sensitivity**	**Std. dev. of production**
1. Wind measurement	2,5%	2,17	5,4%
2. Wind measurement mast position	0,1%	2,17	0,2%
3. Terrain/model wind extrapolation	1,0%	2,17	2,2%
Above Std.dev is on wind speed, below on energy production			
4. Long term correction (MCP)	7,5%	100%	7,5%
5. Availability, WTG	50,0%	3,00%	1,5%
6. Availability, Grid/substation	50,0%	0,50%	0,3%
7. Power curve	4,0%	95%	3,8%
8. Array loss	20,0%	6,80%	1,4%
9. Other(environment, electric loss etc.)	25,0%	2,00%	0,5%
Square root sum of uncertainties			**10,5%**
Long term wind variability	**Period**	**St. dev.**	**Resulting std. dev of production**
	1 year	10,0%	14,5%
	5 year	4,5%	11,4%
	10 year	3,2%	10,9%
	20 year	2,2%	**10,7%**

Figure 24. Summary of uncertainties

The uncertainties are separated in two columns: Standard deviation of the relevant parameters and sensitivity to production for this parameter.

The standard deviation for parameters reflects the actual uncertainty on the respective topics (wind measurements etc.).

The sensitivity indicates how sensitive the production estimate is to the each topic. For all uncertainties regarding wind the sensitivity is calculated based on the expected production from the specific WTG at the rounded wind speed just below the expected average for the site and the one just above.

For this site and turbine the sensitivity is 2.17, which is quite standard.

1. Wind measurements
The uncertainty for the wind measurements is set to 2.5%. Normal procedure when a standard NRG system is applied for the measurements is 3%, but here we have calibrated and well documented equipment – therefore a small reduction in the uncertainty for the measure equipment.

2. Wind measurement mast position
The position relative to height contour lines used in model calculations is very important. Below is shown a resource map close to the mast showing the energy level. This indicates the significance of the precision of the mast position.

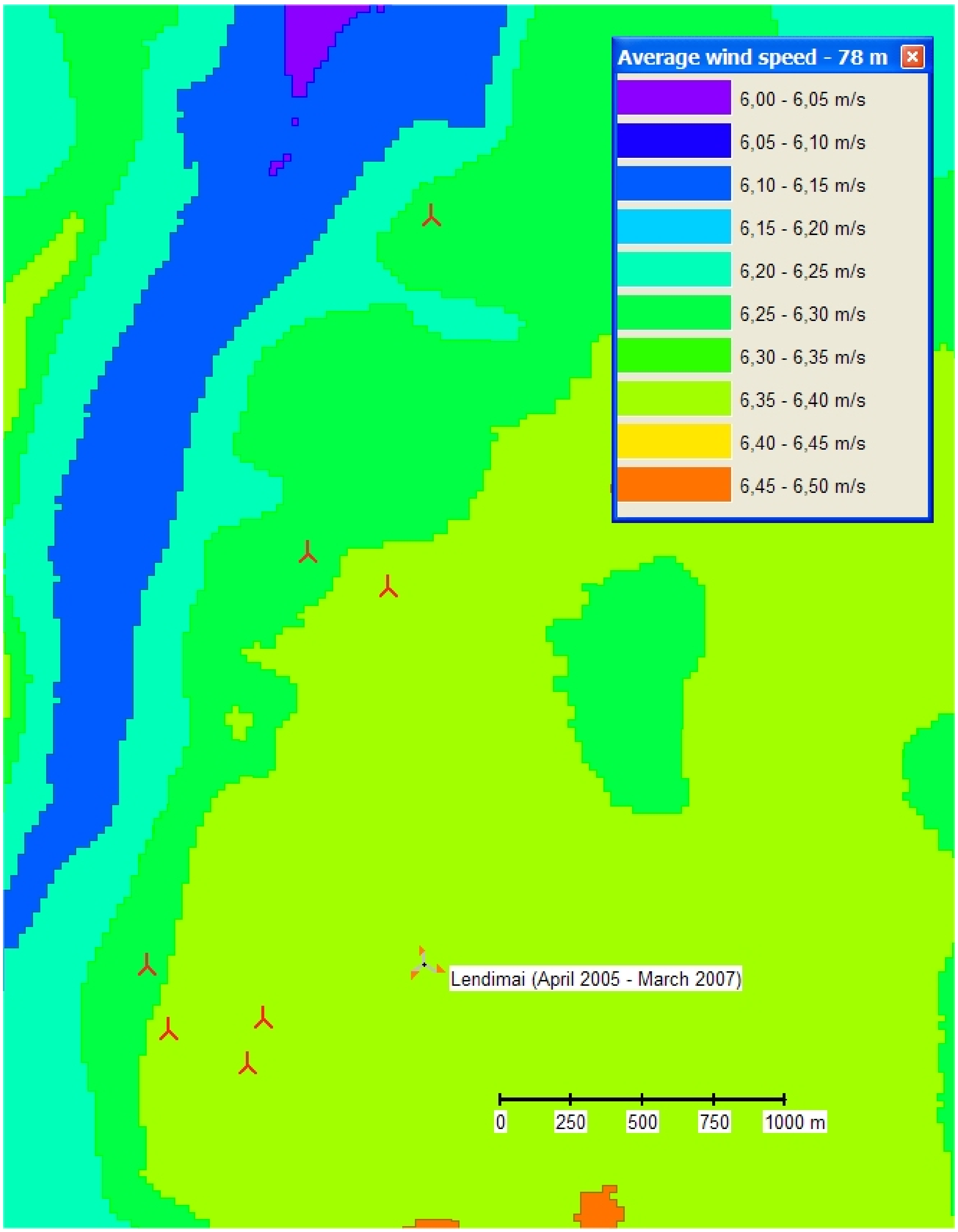


Figure 25. Wind resource map for the near surrounding of the Lendimai mast

Assuming a horizontal uncertainty of 50 m on the mast position, the energy level within the radius of 50 m is constant. The uncertainty cannot vanish so a value of 0,1% has been assigned on the wind speed. With an estimated sensitivity of 2.17 the uncertainty on the wind energy level is therefore 0,2%.

3. Terrain/model extrapolation of wind data
This standard deviation reflects the quality of extrapolating wind data from the mast to the rest of the wind farm and from measuring height to hub height. So this includes both the distance from measurement masts to WTG positions, the complexity of the terrain, the accuracy of the terrain description and how the model handles the extrapolation. A parameter to evaluate the uncertainty due to the terrain is the RIX-value. RIX is the Ruggedness IndeX, defined as the percentage of the area around an object that has steepness above a given threshold value. At 30% steepness flow separation typically start, which mean that the WAsP model assumptions are violated. Experiments show that the RIX value can help giving an idea of the uncertainty due to this. The RIX method is invented by RISØ, described in the paper from EWEC 1997, Dublin: INFLUENCE OF TOPOGRAPHICAL INPUT DATA ON THE ACCURACY OF WIND FLOW MODELING IN COMPLEX TERRAIN, by Niels G. Mortensen and Erik L. Petersen.

The main conclusion based on use of the RIX method is that if both reference site (measurement mast) and predicted site (WTG) are equally rugged (Delta RIX < 8%), very small calculation errors are expected. If reference site (measurement mast) is very rugged, e.g. RIX = 20 and predicted site (WTG) are less rugged (e.g. RIX = 0), Delta RIX will be -20%, and according to the graph, 30% too low wind speed prediction at WTG site could be expected. This could lead to around 60% too low calculated energy production. If the reference site is less rugged, e.g. RIX = 0, and the predicted site (WTG) are very rugged (e.g. RIX = 20%), Delta RIX will be +20%, and according to the graph, 40% too high wind speed prediction at WTG site could be expected. This could lead to around 80% too high calculated energy production. The correlation between ∆Rix and wind speed prediction error is shown below.

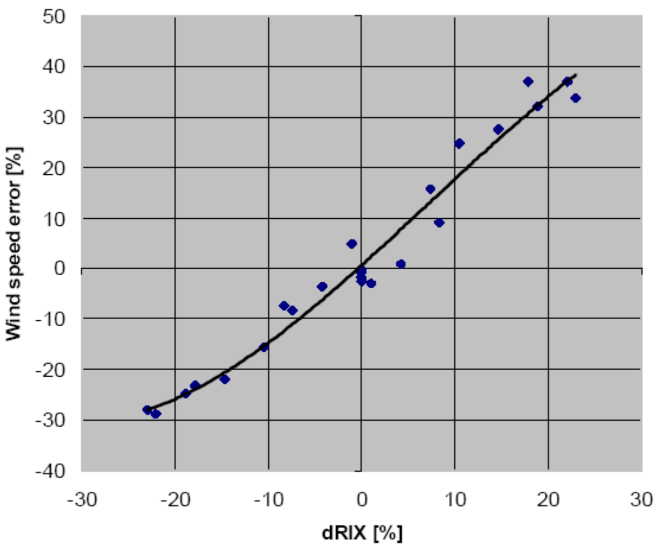


Figure 26. Correlation between ∆Rix and wind speed prediction error

Below is shown the results for the site.

Reference sites

Terrain	UTM WGS84 Zone: 34 East	North	Z [m]	Name of wind distribution	Type	Reference site RIX
A	514.389	6.216.554	33,0	Index	WAsP (RVEA0011 1, 0, 0, 13)	0,0

WTG sites

	Terrain	UTM WGS84 Zone: 34 East	North	Z [m]	Reference site RIX	WTG RIX	Delta RIX (WTG site - Reference site)
1	A	514.407	6.219.167	26,2	0,0	0,0	0,0
2	A	513.975	6.217.988	26,3	0,0	0,0	0,0
3	A	514.258	6.217.869	30,8	0,0	0,0	0,0
4	A	513.824	6.216.361	30,0	0,0	0,0	0,0
5	A	513.771	6.216.202	29,7	0,0	0,0	0,0
6	A	513.494	6.216.321	24,9	0,0	0,0	0,0
7	A	513.420	6.216.545	21,5	0,0	0,0	0,0

Figure 27. Rix-values for the site

The Rix calculation shows that no uncertainty is associated with the complexity of the terrain. The measuring height is almost identical to the planned hub height and therefore only minor uncertainty is related to the vertical extrapolation as well as the horizontal extrapolation. The uncertainty is set to 1.0%.

4. Long term correlation (MCP)

The length of the long-term data series, the quality, the length of concurrent data and the correlation decides the uncertainty. In figure 20 four different MCP methodologies are shown. There is a difference in the energy levels for the four methods of about 11,9% (87,8% - 75,9%), but where the lowest is remarkable far from the other methods. There are only 4,2% difference between the 3 of the methods. Additionally there is also an uncertainty on the 100% energy level (long term level). All together an uncertainty of 7,5% has been applied.

5. Availability, WTGs

Turbine availability is a very uncertain parameter for more reasons:

1. It is difficult to predict what kind of failures occur and how long it will take to repair them
2. It is impossible to predict when these failures will occur (one year it may be several weeks of downtime and the next year there will be almost 100 % availability).

Especially for the WTG availability, there can be contracted a minimum availability depending on the type of service agreement. (See also Loss evaluation)

6. Availability, grid/substation

A standard value of 50% has been applied. Contact to local utility service must be made in order to obtain statistics on the grid/substation availability.

7. Power curve

It is assumed that the uncertainty for the power curve is 4%. For the steep part of the power curve there is a relatively large uncertainty. On the flat part of the power curve the standard deviation is assumed to be 0%. Since approximately 95% of the power production lies on the steep part and 5% on the flat part of the power curve the sensitivity is set to 0.95. ´

8. Array loss
The standard deviation on the array loss calculation is estimated to 20% of the calculated losses and thereby only 1.4% of the resulting AEP. In general there is a good agreement between calculated and measured array losses from the several cases we have tested this. For especially large wind farms with many arrays (> 4), it is seen that the model get problems and underestimate losses, but this is not the case here.

9. Other (environment, electric loss etc.)
For the electrical losses the standard deviation can be set relatively low if a detailed calculation of the losses in the park is carried out. However since the layout of the cables and the turbine specifications are not known this has not been done. For this reason the standard deviation is set to 25 %.

8.1 Long term wind variations

Experience from Northern Europe show quite large long-term variations in the wind. Climate oscillations, partly described by the NAO-index (North Atlantic Oscillation) combined with 30 year of modern WTG operation statistics from Denmark states that 20 year is too short a period to use when estimating long term variations.

Based on these variations, the long-term variations based production estimates are calculated as minimum expectations assuming “worst case” historical event will appear for different future periods.

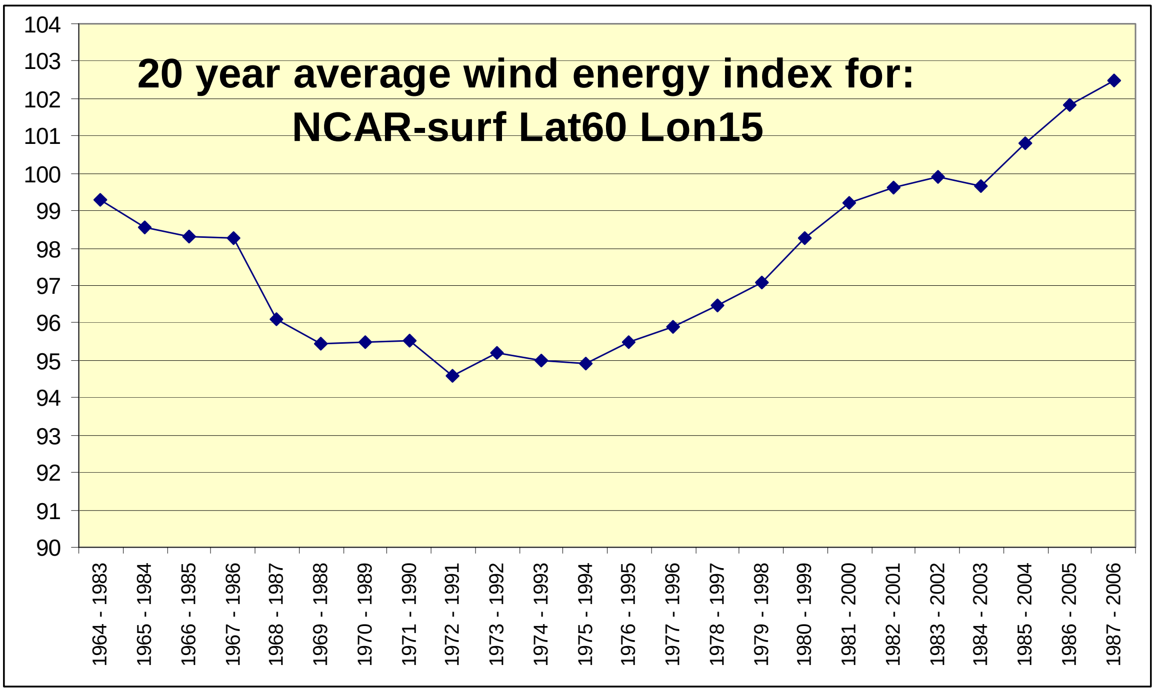


Figure 28. If a project were installed in 1972 in this region, around 5.5% less energy production in a 20 year period would have been expected. How the next 20 year will be no one can predict, but based on this long historical row of data, the risk of getting lower seem small.

LONG TERM VARIATIONS				
Project size: 14MW				
Based on: 7 x 2MW Enercon E-82				
Wind energy variability for 1 year assumed - for more years: 1y/Sqrt(years)				
Period	**1 year**	**5 year**	**10 year**	**20 year**
St.Dev windvar.%	10,0	4,5	3,2	2,2
St. Dev unc.%:	10,7			
Sqr(sum^2): %	14,6	11,6	11,2	10,9
Annual Yield Expectations based on assumed variations (GWh/y)				
For different projection periods and probability of exceedence				
Including the estimated uncertainty for the long term expectations				
	1 year	**5 year**	**10 year**	**20 year**
P5	41,827	40,137	39,893	39,767
P10	40,034	38,717	38,527	38,429
P16	38,617	37,595	37,447	37,372
P25	37,038	36,344	36,244	36,193
P50	**33,708**	**33,708**	**33,708**	**33,708**
P75	30,379	31,072	31,172	31,224
P84	28,800	29,822	29,969	30,045
P90	27,383	28,700	28,890	28,988
P95	25,589	27,280	27,524	27,649
P99	22,226	24,617	24,961	25,139
P99,9	18,455	21,631	22,089	22,325

Figure 29. AEP estimates for different projection periods and probability of exceedence.

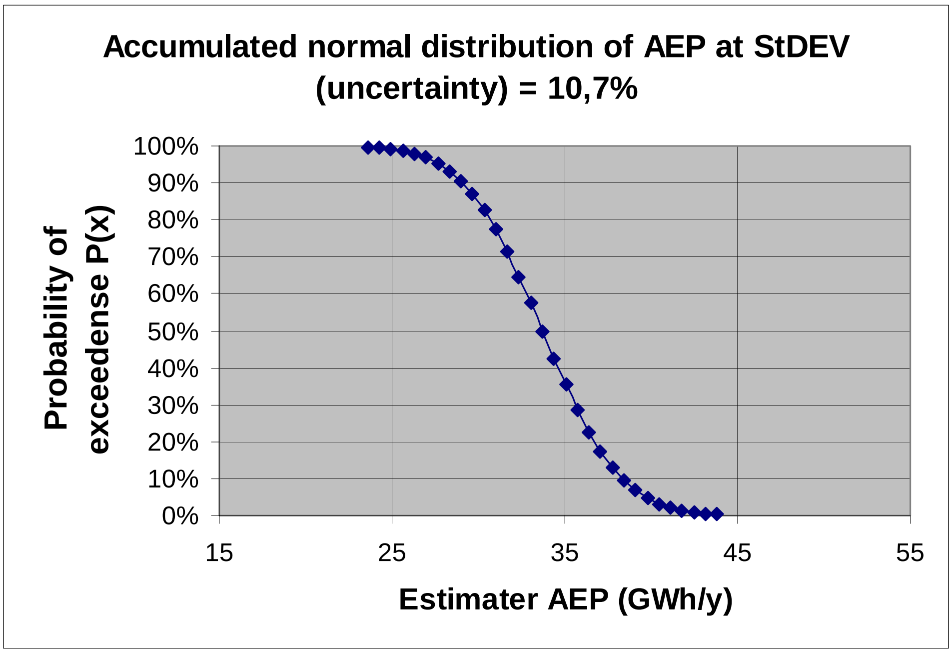


Figure 30. Exceedence curve for the net AEP (loss deducted).