POST-CONSTRUCTION PRODUCTION ASSESSMENT OF WIND FARMS

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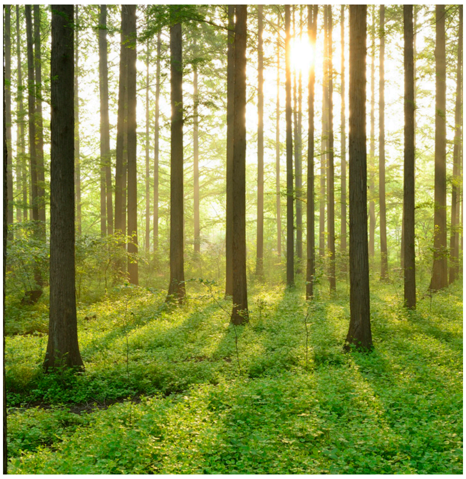

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Post-construction production assessment of wind farms

Assessment and optimization of the energy production of operational wind farms: Part 1

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Foreword

Post-construction production assessment for wind power plants is an area where little research has been done and no standard for such measurements exists today. However, establishing methods for post-construction assessment is an important part of optimizing wind farms. It allows for comparison of pre-construction assessments and actual energy production, and provides knowledge that can help increase the energy production in both operating and future wind power plants.

The aim of the project "Assessment and optimization of the energy production of operational wind farms" is to develop methods for post-construction production assessment, and to identify ways to optimize wind power production in operating wind farms. The project has been divided in three parts: Part 1 - Post-construction production assessment, Part 2 - Use of remote sensing for performance optimization, and Part 3 – Quantification of icing losses. In this report, the results from Part 1 are presented.

This project has been carried out by Kjeller Vindteknikk, with Sónia Liléo (May 2014-June 2015) and Johan Hansson (from June 2015) as project leaders. Reference group has consisted of Johannes Derneryd (Stena Renewables) and Jenny Longworth (Vattenfall).

The project is a part of Energiforsks' research program Vindforsk.

Stockholm, July 2016

Åsa Elmqvist
Progam manager, Vindforsk IV

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Furthermore, the authors are thankful to the colleagues at Kjeller Vindteknikk for valuable discussions.

Finally, the authors would like to thank Sónia Liléo for initiating the project and for managing it until June 2015.

Sammanfattning

Huvudsyftet med den här rapporten är att öka kunskapen om olika aspekter av produktionsuppskattning baserad på data från operationella vindparker och att undersöka hur lämpade olika metoder är för klimatförhållanden snarlika de i Sverige.

Produktionsdata, vindmätningar och information om operativ status från individuella turbiner från två svenska vindparker har analyserats.

En genomgång av tidigare publicerat material gällande produktionsuppskattningar baserade på operationell data presenteras i kapitel 3. Slutsatsen är att även om många konsulter tillhandahåller dylika tjänster så finns inte många detaljer tillgängliga. Vi har heller inte hittat någon litteratur som behandlar vindparker som har signifikanta förluster på grund av nedisning av rotorbladen.

Det finns idag inget standardiserat sätt att göra en produktionsuppskattning baserat på operationell data från en vindpark. Fyra metoder för långtidsjustering av produktionsdata har utvecklats i projektet och dessa diskuteras i kapitel 4. Metoderna kan delas in i två kategorier, i den första så används historiska effektkurvor och i den andra olika typer av index. Indexbaserade metoder är idag vanligast när produktionsuppskattningar baserat på operationell data görs. I kapitel 7 så dras slutsatsen att den bäst lämpade metoden för att långtidsjustera produktionsdata är parkspecifik. Men generellt så är de indexbaserade metoderna mindre lämpliga för vindparker med stora produktionsförluster på grund av nedisning. Vi ser en spridning på fyra procent i den långtidsjusterade bruttoproduktionen baserad på de fyra metoderna, spridningen beror på en underskattning från indexmetoderna. Baserat på de två analyserade vindparkerna så uppskattar vi osäkerheten i val av metod för långtidsjustering av produktionen till cirka åtta procent baserat på sex månaders operationell data, drygt två procent för 12 månaders operationell data och knappt två procent för 24 månaders operationell data.

Sex metoder för att uppskatta förluster under perioder när turbinerna inte är fullt operationella har utvecklats och finns beskrivna i kapitel 5. Metoderna kan delas in två kategorier, i den första så används vindhastighet och specifika effektkurvor, i den andra effekt. Tre av metoderna finns beskrivna i den tekniska specifikationen IEC/TS 61400-26-2. Precis som för metoderna för långtidsjustering så är den mest lämpliga metoden för att uppskatta förluster parkspecifik. Men i kapitel 7 så dras slutsatsen att de effektbaserade metoderna är mindre lämpliga för att uppskatta förlusterna för vindparker som berörs av signifikant nedisning. Det gemensamma för de effektbaserade metoderna är att de kräver att minst ett vindkraftverk i parken är fullt operationellt för att det ska vara möjligt att uppskatta den potentiella energiproduktionen (och därmed förlusten) vid varje tidssteg. Under perioder med nedisning så är det vanligt att alla vindkraftverk i en park berörs samtidigt och att det följaktligen inte finns något som är fullt operationellt.

Om nacelleanemometern och en specifik effektkurva används för att uppskatta den potentiella produktionen (och förlusterna) under perioder då vindkraftverken inte är fullt operativa är det viktigt att säkerställa att kvaliteten på nacellevindmätningen inte beror på om vindkraftverket är fullt operativt eller inte.

En bedömning av om de uppskattade förlusterna för varje vindpark är långtidsrepresentativa eller inte måste göras, om inte så måste förlusten långtidsjusteras.

Osäkerheten i den beräknade nettoproduktionen (P50) berörs i kapitel 7, den sätts i relation till osäkerheten i en produktionsuppskattning gjord innan parken byggdes. Slutsatsen är att osäkerheten i nettoproduktionen baserad på operationell data är ungefär hälften av osäkerheten i en produktionsuppskattning som är gjord innan parken byggts.

Slutligen så diskuteras i kapitel 7 hur osäkerheten i en produktionsuppskattning baserad på driftdata påverkas om vindmätningar från en nacellemonterad lidar används istället för vindmätningarna från nacelleanemometern. Vi drar slutsatsen att användning av en nacellemonterad lidar inte medför någon signifikant reducering av osäkerheten.

Summary

The main purpose with this study is to expand our knowledge on different aspects of post-construction production assessment and to investigate the suitability of the different methodologies in climatological conditions corresponding to those of Sweden.

Production and wind measurement data along with information of the operative status from individual turbines (WTGs) of two Swedish wind farms (WFs) in operation are analyzed.

A review on published material concerning post-construction assessment methodologies are presented in Chapter 3. The conclusion is that although many consultancy firms provide post-construction assessment services, the details of their methodologies are rather limited and we were not able to find any literature concerning post-construction assessment of wind farms that experience considerable losses due to icing on the blades. At the moment there is no standard on how a post-construction assessment should be carried out.

Four methods for long-term correcting the production data have been developed in the project and these are discussed in Chapter 4. The methods for long-term correcting the production data are divided into “historical power curve”-methods and “index-based”-methods, where the latter group of methods presently are the most common used in post-construction power production assessments. In Chapter 7 we conclude that the most adequate choice of method for long-term correcting the production data depends on the site. However, if the wind farm is associated with substantial production losses related to icing, the index-based methods are less suitable for long-term correcting the production data. We see a 4 % spread in the long-term corrected gross production between the four methods, which we mainly attribute to underestimation of the index-methods. Based on the two WFs analyzed, the estimated uncertainty associated with the choice of method for long-term correcting the production is about 8 % based on 6 month of operational data and slightly above and below 2 % based on 12 and 24 months of operational data, respectively.

Six methods for estimating the experienced losses during episodes when WTGs are not running in full-performance have been developed and are described in Chapter 5. They can all be categorized into “wind speed and specific power curve”-methods and “power based”-methods. Three of the methods are outlined in the technical specification IEC/TS 61400-26-2. As is the case with the long-term correction methods, also the method most suitable for estimating the experienced losses varies from site to site. However, in Chapter 7 we conclude that the power-based methods are less suitable for assessing the experienced losses for WFs associated with considerable icing. The power-based methods have in common that they require at least one WTG to be running in full performance to successfully be able to determine the potential energy production (and thus loss) at each time stamp. During icing events it is common that all WTGs are affected by the icing and that no WTGs is running in full performance.
If the nacelle anemometer and a specific power curve is used to derive the potential energy production (and thus losses) during events when the WTG is not running in full performance it is important to investigate that the quality of the nacelle wind data does not depend on whether the WTG is or is not running in full performance.
It has to be assessed for each site whether the estimated experienced loss can be

considered representative in a long-term perspective or if the loss needs to be long-term corrected.

The uncertainty in the derived P50 in the post-construction production assessment is addressed in Chapter 7 and put in perspective to the corresponding uncertainty values of the pre-construction analysis. The conclusion is that the uncertainty associated with P50 value in the post-construction assessment is approximately half the value of corresponding uncertainty in the pre-construction assessment.

Finally the uncertainty reduction in the post-construction assessment of using nacelle-mounted lidar measurements compared to nacelle-mounted anemometer measurements is discussed in Chapter 7. We conclude that no major uncertainty reduction would be expected from this.

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1 Introduction

The need of accurate production estimates requires assessment methodologies that describe in a proper way the wind conditions and the wind farm performance at sites of diversified characteristics, with the most challenging ones being mountainous, forested and cold climate sites. Several national and international research and development projects have therefore been conducted during the last years aiming to develop tools and models to assess the energy production at such sites. The majority of these projects have however focused on the development of pre-construction assessment methodologies, that is, methodologies that are used to estimate the expected production of wind farms during the development phase of the farms.

There has been a rapid increase in the installed wind power capacity in Sweden during the last decade. Many of the projects have been developed by small companies with little or no experience from the energy business. While traditional power plants have been closely monitored and performance optimized, wind turbines have more or less been left alone. They have of course been monitored in order to avoid longer stand stills and the manufacturers require regular maintenance. Apart from perhaps one or two exceptions, detailed analyses of production data in order to optimize the performance or to re-evaluate the long-term production have not been made.

The existence of a large number of wind farms that have been in operation during a number of years gives a new perspective to the development of assessment methodologies. Operational data from existing wind farms contain valuable information on the wind conditions, and on the performance of the turbines, under the site-specific conditions. The analysis of operational data is therefore a key tool for the identification of shortcomings on the existing pre-construction assessment methodologies, and for the further development of more accurate methods.

Two other important applications of the analysis of production data from operational wind farms are the following: re-calculation of the wind farms expected energy production, so-called “post-construction assessment”; and the identification of eventual optimization needs.

The project “Assessment and optimization of the energy production of operational wind farms” consists of three work packages (WPs). This report contains the results from work package one (WP1).

The objectives of WP1 are

1. Provide a description and comparison of different methodologies currently used for post-construction energy assessment.
2. Report on the sensitivity of the post-construction production estimate on the chosen method.
3. Report on the sensitivity of the post-construction production estimate on the length of the operational period.
4. Provide an estimate of the uncertainty reduction resultant from the use of nacelle-mounted lidar measurements, as compared to nacelle mounted anemometer measurements, in the assessment of the expected production of operational wind farms.
5. Present an analysis of the causes of possible deviations between pre- and post construction production estimates.

The second work package is called “Use of remote sensing for performance optimization”. In WP2 the use of a nacelle mounted lidar (Wind Iris) for turbine performance optimization is evaluated. The yaw alignment, the power curve, and the nacelle transfer functions are studied during four measurement campaigns in two different wind farms. WP3 treats the issue of icing loss estimates. A large number of the Swedish wind farms are built in cold climate sites which experience atmospheric icing. The production losses caused by icing are an essential part of the production assessment. Production and wind measurement data along with information of the operative status from individual turbines of three Swedish wind farms in operation are analyzed in order to study the icing situation in the wind farms.

2 Input data

2.1 WIND FARMS USED IN THE PROJECT

Supervisory control and data acquisition (SCADA) data from two operational onshore wind farms have been used in WP1. They are, due to confidentiality aspects, only described in general terms.

The first 6 months of operational SCADA data has been excluded from the analysis to avoid the startup phase of the wind farm to contribute with uncertainty.

2.1.1 SCADA parameters

The SCADA parameters used in the WP1 analysis are the time stamp, energy production, nacelle-anemometer based upstream wind speed and alarm/operating state information.

The SCADA data is provided for each wind turbine and with a 10-minute temporal resolution. Also wind direction1 and ambient air temperature are available in the provided SCADA data. However, in terms of wind direction there was a substantial difference in the offset of the individual turbines nacelle positions and the offsets are in addition changing throughout the analyzed period. Wind direction from a long-term reference dataset (Section 2.2) is therefore used as the source for wind direction. The use of wind direction from a long-term reference dataset will introduce some additional uncertainty in the results compared to if correct on-site measurements would have been available.

Also the air temperature data is taken from the reference dataset, since we have no knowledge of the location of the temperature sensor; the heat from the nacelle can create a bias.

In the provided SCADA data of the two wind farms, the level of detail regarding alarms/operating state varies substantially. The level of detail of alarm information of wind farm 1 (WF1) enables a relatively precise filtering while less detail are provided for wind farm 2 (WF2), which results in a somewhat more conservative filtering.

2.1.2 Wind farm 1

WF1 is located in a forested area with complex terrain experiencing rather long and harsh winters. The turbine layout consists of five 2.0 MW turbines with hub height 80 m and 12 2.0 MW turbines with hub height 105 m. The wind farm was built in two stages and only the complete park, 17 turbines, that has been in operation since 2008 is considered in this report. The minimum distance between neighboring turbines varies from 3.5 to 10.8 rotor diameters with an average of 5.2 rotor diameters.

SCADA data for the period 2008-08-07 to 2015-01-07 was provided by the wind farm owner. In the analysis SCADA data for the period 2009-03-01 to 2014-12-31 are used. A revision of the nacelle transfer functions (NTFs), relating the wind speed measured behind the rotor to the undisturbed wind speed up-wind of the rotor, was made during

[1] The turbine types are different in the two WFs and the SCADA parameters differ slightly. From one of the wind farms the directional data is from the turbine wind vane, from the other it is from the yaw system.

spring 2010. In terms of power curves, May 1, 2010 is therefore treated as a revision date.

At WF1 the wind distribution during the analyzed period is representative of the long-term wind distribution (Figure 2-1). The wind index during the analyzed period is 100.5 %. The index is calculated as the ratio between the average wind speed during the analyzed period and the long-term average wind speed.

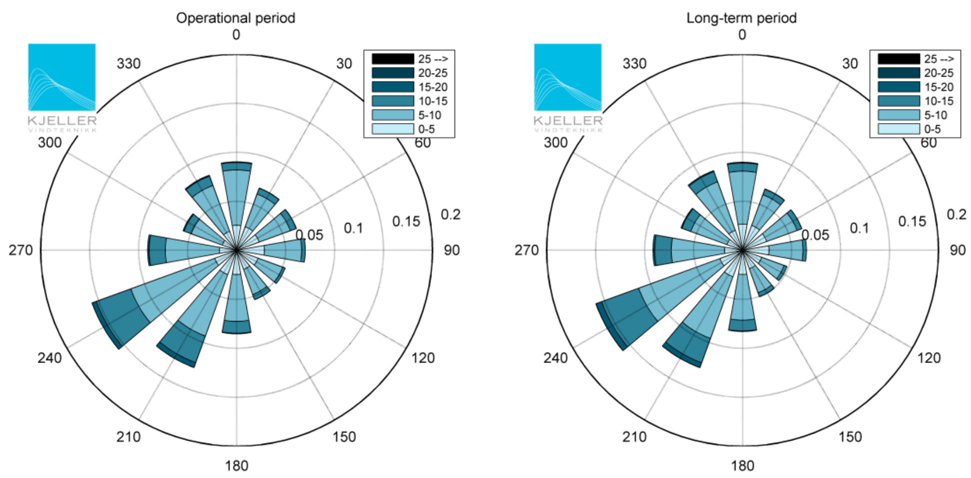


Figure 2-1: The WRF FNL wind distribution during the operative period (left panel) and during the long-term period (right panel) near the WF1 site.

2.1.3 Wind farm 2

WF2 is located in southern Sweden where the winters in general are short and mild. The terrain is rather simple and covered with production forest of varying height. WF2 is composed of 11 2.5 MW turbines with a hub height of 98.5 m. It has been operational since 2012. The minimum distance between neighboring turbines varies from 3.9 to 4.7 rotor diameters with an average of 4.1 rotor diameters.

SCADA data for the period 2012-01-01 to 2014-12-31 was provided by the wind farm owner. Considering that a major upgrade to most of the WTGs' power curve occurred in the beginning of the summer 2014 and that it is preferable to utilize full year of data to avoid seasonal bias, only data for the period 2012-06-01 to 2014-05-31 is considered in the analysis. In addition, the wind farm owner has provided us with information that the turbine manufacturer performed some changes to the operation in April 2013. In terms of power curves, April 1, 2013 is therefore treated as a revision date.

At WF2 the wind distribution during the analyzed period is representative of the long-term wind distribution (Figure 2-2). The wind index during the analyzed period is 99.2 %. The index is calculated as the ratio between the average wind speed during the analyzed period and the long-term average wind speed.

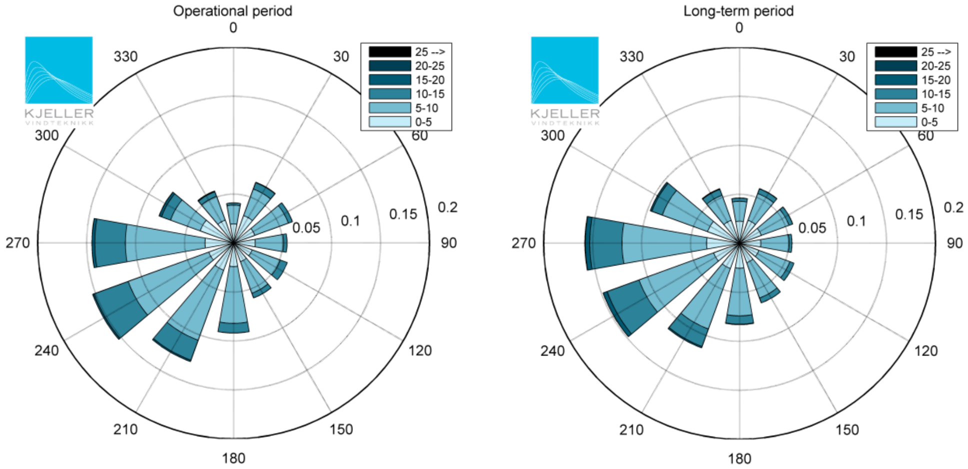


Figure 2-2: The WRF FNL wind distribution during the operative period (left panel) and during the long-term period (right panel) near the WF2 site.

2.1.4 Filtering – identifying full-performance

It is essential that erroneous data is removed from the data set so that the results are not affected. If data is removed only for specific wind situations (high/low) any statistics derived from the data set is not likely to represent the true values for the period. Alarms related to high/low wind speeds may result in such bias. Icing might also cause such effects depending on during which weather situations icing occurs. This will be site dependent. Some methods outlined in this report will not be suitable for data sets with large (seasonal) gaps. Periods when the turbines are not in full performance are therefore filtered out prior to the long-term adjustment of the power production. Production is considered as partial- or non-performing when any of the following apply:

- Periods of curtailment, below the rated power.
- Periods identified as influenced by icing.
- An alarm code is found. No detailed information on the meaning of the error codes of WF2 was available. Through an analysis, an interval of operating states were identified to clearly be associated with full-performance, the remaining operating states were treated as partial- or non-performing and filtered out. The filtering of WF2 is considered to be somewhat conservative. The time step after an alarm is also filtered out.
- Periods when neither of the above applies and the nacelle wind speed is well above cut-in wind speed but production is negligible.

In addition there are gaps in the SCADA data (missing data). Filtering statistics for the individual turbines of WF1 and WF2, for the full periods analyzed, are summarized in Table 2.1 and Table 2.2, respectively. With the applied filtering the fraction of time that all WTGs are in concurrent full performance accounts to 52 % and 62 % in WF1 and WF2, respectively. In both WFs, icing is the main reason for lowering the occasions of full performance. As mentioned above, the filtering on operative states for WF2 is conservative.

Table 2.1: Details of the filtering routines applied to WF1, numbers are given in percentage of time.

	WTG number																
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**
Missing data (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Curtailed data (%)	0.4	0.3	0.2	0.3	0.3	0.2	0.3	0.3	0.2	0.3	0.2	0.2	0.3	0.2	0.2	0.2	0.2
Man. removed (%)	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.1	0.1	0.3	0.2	0.1	0.1	0.2	0.2	0.2
Icing (%)	11.2	11.5	12.0	13.4	12.0	12.0	10.5	11.4	9.5	10.8	9.0	9.9	10.2	9.8	10.5	10.1	11.0
Alarm (%)	1.9	2.8	2.4	1.8	2.2	3.6	3.0	3.1	2.7	4.1	4.2	4.9	3.2	4.2	5.8	4.7	2.6
Full performance (%)	**86.3**	**85.2**	**85.2**	**84.2**	**85.2**	**84.2**	**86.1**	**85.0**	**87.4**	**84.7**	**86.3**	**84.8**	**86.3**	**85.7**	**83.2**	**84.8**	**86.1**

Table 2.2: Details of the filtering routines applied to WF2, numbers are given in percentage of time.

	WTG number										
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Missing data (%)	0.2	0.2	0.4	0.8	0.5	1.2	0.3	0.2	0.3	1.2	0.2
Curtailed data (%)	0.2	0.1	0.1	0.2	0.0	0.9	0.6	0.4	0.0	0.1	0.1
Man. removed (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Icing (%)	6.3	5.5	6.0	6.4	6.6	6.3	6.2	6.2	6.4	4.8	4.9
Operating states (%)	1.6	1.9	1.7	3.1	2.3	2.1	2.9	3.3	5.5	2.6	2.8
Full performance (%)	**91.7**	**92.3**	**91.7**	**89.5**	**90.6**	**89.5**	**90.0**	**89.9**	**87.8**	**91.2**	**92.0**

2.2 LONG-TERM REFERENCE DATASETS

Since wind speed and wind direction vary from year to year, the yearly energy production will also show considerable variation from a year to another. To get an expected energy production of the wind farm averaged over its lifetime, it is necessary to long-term correct the production data. There are many methodologies to carry out this long-term correction; but common for all methods is the need of a long-term reference dataset.

The long-term time-series utilized in the present analysis origin from the dataset denoted as KVT Meso. The Kvt Meso dataset is produced by Kjeller Vindteknikk using the Weather Research and Forecast model (WRF, Skamarock, et al., 2008), which is a mesoscale meteorological model used for both research and weather forecasting. The KVT Meso dataset uses FNL data (Final Global Data Assimilation System) available from the National Centers for Environmental Prediction (NCEP) as initialization and boundary data for the model. Table 2.3 summarizes the main properties of the KVT Meso dataset. More information is presented in Appendix 1.

Table 2.3. Properties of the long-term dataset KVT Meso produced by Kjeller Vindteknikk.

Long-term dataset	**Horizontal resolution**	**Temporal resolution**	**Temporal coverage**
KVT Meso	4 km x 4 km	1 hour	2000 – ongoing

Long-term time series of hourly wind speed, wind direction, temperature and air density are available in the KVT Meso dataset. In addition, based on the local terrain, surface roughness, WTG layout, and WTG power curves a long-term time series of energy production for the WF1 and WF2 wind farm are calculated using the industry standard tools WAsP and WindPRO. The calculated production time series includes wake losses but assumes 100 % availability.

Several of the methods used to derive long-term gross AEPs (Section 4) and to assess losses in the historical data (Section 5) utilize the raw SCADA data with 10 minute resolution. To avoid discarding 5/6 of the SCADA data, the hourly WRF FNL dataset (wind speed and wind direction) is linearly interpolated to 10 minute values.

3 Previously published results

3.1 GENERAL METHODOLOGY

There are no standards for how a post-construction energy assessment should be undertaken. A survey made by EWEA (Rademakers, 2012) showed that there is an interest for an increased level of standardization. But the survey also showed an agreement in that it probably would be difficult to achieve such standards.

The information that is publicly available regarding methodologies is mainly from different conferences. Consultants have developed different methodologies that they, very briefly, present and promote on such events. The details are therefore not known, but in general the steps are as follows:

1. Filter operational data; identify episodes when WTGs are not running in full performance.
2. Assess the experienced losses during these non-full performance episodes
3. Long-term correct the actual full-performance production with long-term reference dataset. Gross value reduced since operational data already includes wake losses etc.
4. Apply experienced operational losses (2.) to the gross value (3.), long-term correct the experienced losses if necessary → P50
5. Assess the uncertainty

Uncertainties related to wind measurements, flow modeling, wake modeling, turbine power performance and electrical losses are now removed from the analysis. The observed wind conditions and the actual losses may though not be long-term representative. There is still a need for a long-term correction in order to get a representative result for the expected life time of the wind farm. There is an uncertainty associated with the long-term correction. Nevertheless, there is a substantial reduction in the overall uncertainty in a post-construction energy assessment compared to a corresponding pre- construction energy assessment.

The calculated post-construction annual energy production (AEP) might be lower or higher than the pre-construction AEP, but it is likely that the post-constructed P90[2] of the AEP is higher than the P90 of the pre-construction AEP. This makes the yearly income more predictable. Less than six months of operational data can be enough to make a reasonable accurate long-term correction (Albers A. M., 2003). However, it is important to have at least one year of good data in order to properly evaluate losses. The influence of the length of the operational data period on the long-term production estimate is investigated further in section 7.1.1.

3.2 KNOWN DETAILS

3.2.1 The metered production

The metered production, at the grid delivery point, is a direct measure of the performance of the wind farm. According to our literature study it is typically the monthly values that are used in the analysis. The metered production must be

[2] The 10^{th} percentile of the AEP estimate is denoted by P90. The probability that the AEP is higher than P90 is 90 %.

corrected so that it corresponds to 100 percent availability, otherwise it will not be useful for a long-term adjustment. Hence, information about the monthly availability is also necessary. The availability can be reported by the operator of the wind farm or it can be assessed by the consultant by analysis of SCADA-data and documentation such as faulty logs. Availability is not strictly defined and the operator can have one definition and the consultant another. The end result, the long-term AEP, can differ by a couple of percent depending on how the availability is defined and derived (Cameron, 2012). There is a technical specification, IEC/TS 61400-26-1 (2011) that aim to define a common basis for the exchange of information on the availability of wind turbines. This has the potential to make the process of post construction assessment somewhat more standardized. Read more about this technical specification in section 6.8.

3.2.2 Long-term adjustment

How to long-term correct the production data is perhaps the largest difference between the different post-construction energy yield assessments. The long-term adjustment methods that are used typically include a wind index based on a long-term reference. The theory behind this is that periods with high wind speed directly should correspond to period with high production. This is reasonable as long as the monthly availability is high. Months with poor availability should therefore not be used in the analysis and months with only a small amount of missing data should be adjusted so that it corresponds to 100 percent availability, as mentioned above.

Ecofys (Grassin, Dawant, & Coelingh, 2013) have presented a method that relates a wind index with the production in the following manner

$$AEP_{\text{long-term}} = 12 * MEP(\text{month i}) / W_{\text{index}}(\text{month i})$$

Where AEP is Annual Energy Production as defined above and MEP = Monthly Energy Production. This method gives 12 estimates of the AEP per year (given that all months have high availability). The average of all estimates is the new gross production.

The Danish company EMD provides the software WindPRO that, among other things, can be used to evaluate the performance of a wind farm. It can also be used to assess the long-term production based on operational data. They also use a wind index as a long-term reference. Two methods for the long-term adjustment is included

a. The sum method: The sum of the monthly productions is divided with the sum of the wind index for the respective months, where the wind index is defined as percentage level of the monthly wind speed compared to the mean annual wind speed (106 means that the level of the mean wind speed of the month is 6 % higher than the long-term annual mean wind speed). This gives the production per index unit. Multiplied with 100 and then by 12 gives the new yearly (long-term) gross production.

b. The regression method: A linear regression is made with monthly production and corresponding wind index as the parameters. The production at index 100, predicted by the regression, multiplied with 12 is the new yearly (long-term) gross production.

3.2.3 Assess the losses

Some losses are included in the production data, such as wake losses, while others, such as downtime and icing losses can be assessed more accurately than in the pre-construction assessment using SCADA-data. The methodologies used probably differ between different consultants but we have found no information about how these loss assessments have been performed.

3.2.4 Assess the uncertainties

Large contributors to the total uncertainty in the pre-construction energy assessment, such as the uncertainties related to the wind measurement and to the wind flow modeling, are now eliminated since we have correct production data from all turbines. The major contributors of the total uncertainty in a post-construction assessment are uncertainties related to the long-term adjustment and to the loss assessment. Read more in section 7.3.

3.3 ALTERNATIVE METHODOLOGY

A more pragmatic approach to assess the long-term energy yield of a WTG (or wind farm) that is used in the industry is to create a production index based on the aggregated production data of a relatively nearby located long-standing WTG. By relating the index to the aggregated production of the WTG (or wind farm) it is possible to estimate the long-term energy yield. Monthly aggregated production reports from many WTGs are for example freely available from www.vindstat.com. The monthly reports also include a measure of availability. As mentioned above availability is not strictly defined and the turbine manufacturer can have one definition and the owner another. In addition, losses associated with partial performance, for example due to ice on the blades, are not included in the definitions of availability. For sites with considerable icing losses it is therefore difficult to adjust the reference turbine to the potential energy production.

4 Methods, post-construction long-term gross AEP

In this Chapter a number of methods for long-term correcting the observed power production are outlined. Common for the methods are the use of a long-term reference dataset and use of the concurrent time period of the SCADA and the reference data to derive relationships to be applied on the long-term data. All methods have pros and cons and the method(s) suitable will vary from site to site.

Also common for all methods investigated is that only data from when the wind turbine generators (WTGs) are operating in full performance should be used. In our analysis, the following data has been filtered out:

- Data with an alarm code, along with the time steps after the alarm occurred.
- Data for periods with curtailed power output below rated power.
- Data that is affected by icing.

4.1 HISTORICAL POWER CURVE METHODS

4.1.1 Nacelle anemometer and actual production data (LT-PC1)

For each of the turbines, power curves have been calculated from the nacelle anemometer and power data. A significant amount (several months) of operational data when the WTG is operating in full performance is necessary to calculate a historical power curve (PC). On the other hand, to account for potential changes of the nacelle transfer functions (NTFs, translate the measured wind at the hub to upstream wind speed) and changes to the nacelle anemometers or the WTG itself, the periods for which the historical power curve is calculated should not be too long. In this project, 12-month periods have been used to define the historical PCs. If one or several revisions to the NTFs are known the 12-months periods are defined never to overlap such occasions. If 12-month of operative data is not available prior to, or after, the revision date the historical PC is defined from the production data available before or after the revision data, respectively.

In the calculation of the power curves the nacelle wind speeds have been adjusted for varying density according to IEC 61400-12-1 (2005). The median power curve has been calculated using the median power values for wind speed bins at every 0.5 m/s

Figure 4-1 shows an example of how the median power curve may differ between different periods. The differences in the power curves calculated for different periods can indicate that changes to the NTF (calibration of the nacelle anemometer) have occurred, or that the nacelle anemometers have been exchanged, during the time period of operation. It could also indicate differences to the turbine itself or that the characteristics of the nacelle anemometer have changed due to wear and tear.

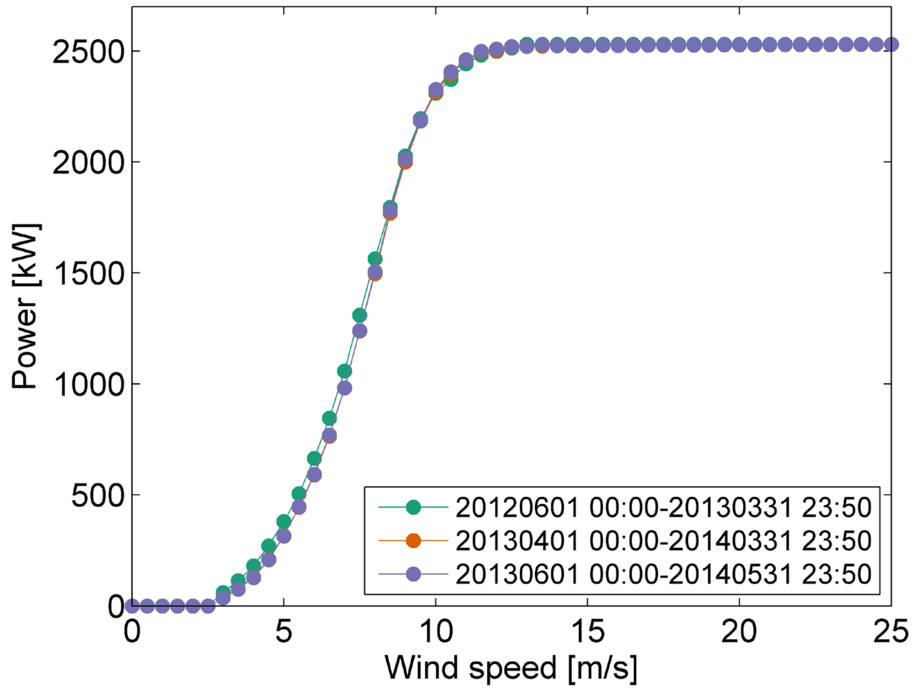


Figure 4-1: The derived median power curves for three different periods for one turbine in WF2. A revision to the WTGs occurred in March/April 2013. The red curve is almost identical to the purple and is hidden behind it. As an example, the maximum difference between the green and the red/purple is 76 kW for 7 m/s (corresponding to 7 %).

For each of the period for which the power curves have been derived, transfer functions relating the modeled wind speed to the nacelle wind speed are calculated sector-by-sector based on the occasion when the WTG is operating in full performance. Applying these transfer functions on the long-term WRF wind speed time series and then applying the calculated historical power curve to the adjusted WRF wind speed a long-term production time series is derived. The Wake Reduced Annual gross Energy Production (WRAEP) is calculated as the annual mean value of the long-term production time-series.

Optionally, if the availability of data is high, historical power curves can be derived sector-wise. This has been investigated for both WF1 and WF2, but no significant differences to the long-term energy yield estimates were seen compared to when using power curves consisting of data from all sectors, and the results are therefore not shown.

4.1.2 Modeled wind and actual production data (LT-PC2)

In this method, historical power curves are derived directly from the filtered production data and the concurrent WRF wind speed and wind direction. The nacelle anemometer, used in method LT-PC1, measures the wind speed upstream of the WTG; this wind speed may be influenced by wake effects from other nearby located WTGs. The modeled WRF wind speed is not affected by wake effects. The historical power curve based on the production data and the modeled wind speed therefore needs to be constructed with respect to the wind direction. Compared to LT-PC1 a larger amount of valid operational data is needed to get a well defined wind direction dependent power curve. However, LT-PC2 does not have to rely on the robustness of nacelle anemometer and potential revisions of the NTF.

Based on production data and modeled wind speed and wind direction, historical PCs are calculated for each of the turbines. Only occasions when all WTGs were operating in full performance are used in the construction of the power curves. Since the PCs are derived sector-wise they are more sensitive to filtering than the PCs in LT-PC1. It is recommended that at least one year of operational data is available for LT-PC2. The derived PCs have power values for eight directional sectors and for 1 m/s wide wind speed bins. The power values are calculated as the mean value of all the occasions in each velocity-wind direction bin. Power values that are calculated from less than 15 samples are discarded and instead interpolated from neighboring velocity bins.

For reference, the eight power curves for one of the WTGs in WF1 is shown in Figure 4-2. The power curves are noisy at high wind speeds where data is sparse. Compared to commercial PC the derived PCs overestimate power at low velocities and underestimate power at high velocity. This is an inherent feature of the method and is a result of combination of a power distribution that is bounded at zero and rated power and the inaccuracy of the WRF data. The WRF wind speeds will both over- and underestimate the actual wind speed but for a wind speed bin above the rated wind speed only the occasions when WRF is underestimating the actual wind speed affect the power value since the power has an upper bound. Correspondingly only overestimation of the actual wind speed will affect the power value in the lower wind speed range.

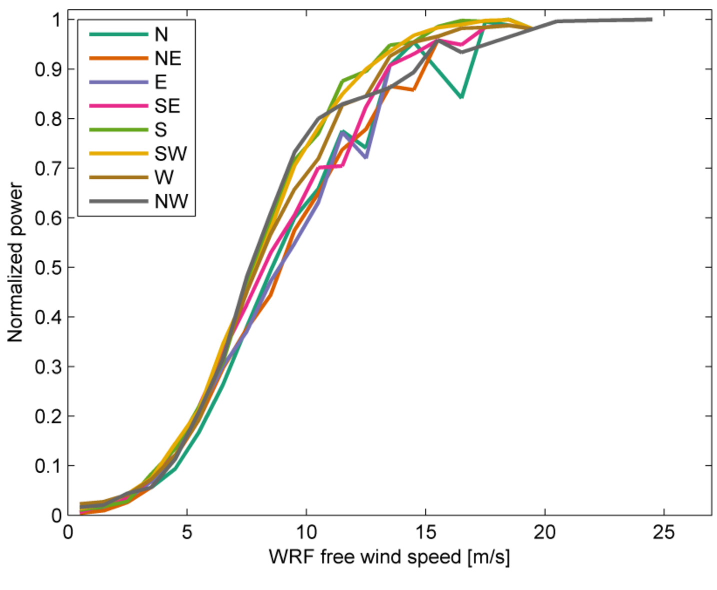


Figure 4-2: Example of eight sector-wise power curves derived from actual production from one WTG in WF1 during periods when the WTG is running in full-performance and concurrent WRF wind speed and direction. The power curves are noisy at high wind speeds where data is sparse.

The long-term WRF time-series of wind speed and wind direction were applied to the calculated power curves to derive a long-term time-series of production. In accordance with LT-PC1, the Wake Reduced gross Annual Energy Production (WRAEP) is calculated as the annual mean value of the long-term production time-series.

The WRF data (described in the Appendix 1) has a horizontal resolution of 4 km x 4 km and the modeled wind speed and wind direction are thus not able to be influenced by the local topography and surface characteristics. On top of that the hourly WRF wind speed and wind direction is interpolated to 10 min temporal resolution of the SCADA data. This method may be considered somewhat crude and our investigations show it to be associated with considerable inaccuracy. However, if enough historical operational data is available to ensure a robust derivation of the specific power curves the bias is small. The use of LT-PC2 is therefore a method suitable for estimation of the WRAEP of WF1 and WF2.

4.2 INDEX METHODS

Another way of estimating the long-term WRAEP is to find a function that relates the observed full-performance energy production, corrected for periods of unavailability and partial performance (hereafter we will include periods of partial performance in the context of unavailability), to an index based on a long-term time-series of either production or wind speed.

The index is typically constructed on a monthly basis, but since considerable uncertainty is associated with the correction for unavailability, it can be more strategic to construct the index on weekly basis if the site for some reason has low availability. The fraction of production data classified as non-full performance is quite large both for WF1 and WF2 (Table 2.1 and Table 2.2), which justifies the use of weekly indexes.

The observed weekly (or monthly) energy production corrected for unavailability is here defined as the energy that would have been produced if the WTGs had been constantly running in full performance. Estimating the loss due to WTGs not running in full performance can be a challenging task (and is further discussed in Chapter 5). For now we are using the most straight-forward approach, assuming that the loss due to unavailability is directly proportional to the time of the WTGs not running in full performance. The observed production corrected for unavailability has therefore been calculated as the measured full-performance production divided by the given availability. Only weeks/months with availability (WTGs in full performance) above 95 % are included in the analysis and the calculations are made for individual WTGs. An investigation about the sensitivity of the result with respect to the chosen threshold is made in section 7.1.2.

The difference among the methods described below is the index used. As mentioned, the index is typically constructed on a weekly or monthly basis and in such a way that the normal value has an index of 100 % and values below/above the normal value have index lower/greater than 100%. A weekly production index, for example, would be calculated as:

$$P_{index}(week_i) = \frac{Production(week_i)}{\frac{1}{n}\sum_{i=1}^{n} Production(week_i)}$$

A monthly index could be calculated by simply changing $week_i$ to $month_i$.

Given that an index and production data corrected for unavailability is at hand, expected production can be calculated. Figure 4-3 illustrates how the expected weekly production is deduced. In the figure, WRF weekly production index (see Section 4.2.1) is plotted versus observed corrected weekly production for one WTG in WF2. From the resultant linear fit, the expected weekly energy production for a "normal week", i.e. for a production index equal to 100 %, may be calculated (indicated by the gray cross). The WRAEP, considering 100 % availability is calculated as 52.18 (the average number of weeks in a year) times the expected production for a normal week:

$$\text{WRAEP} = 52.18 \times \text{Expect prod normal week}$$

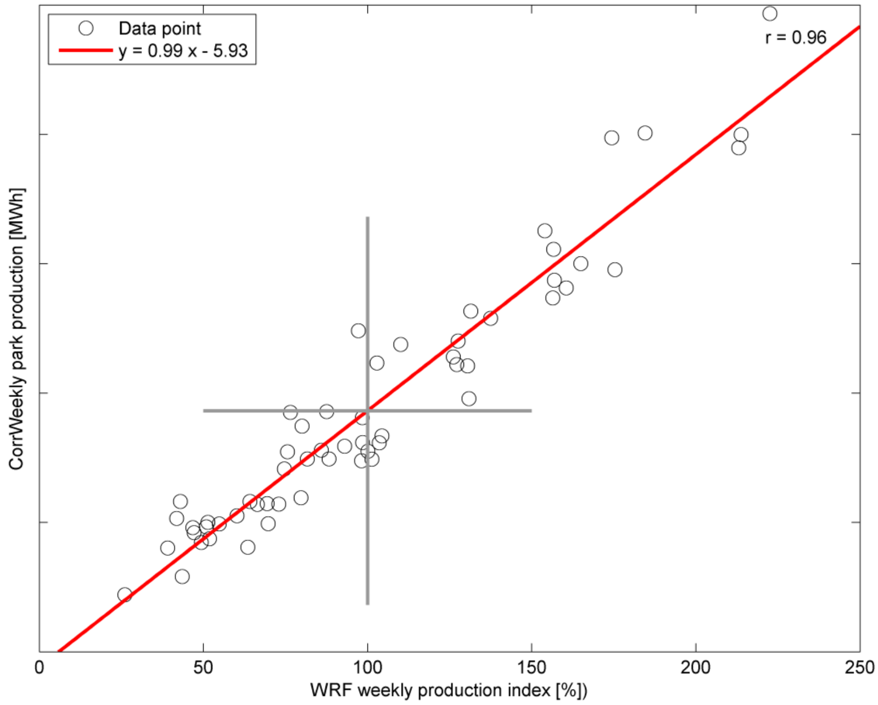


Figure 4-3: The observed corrected weekly energy production versus WRF weekly production index for WTG 8 of WF2.

If a monthly index is used instead, the WRAEP is calculated as:

$$\text{WRAEP} = 12 \times \text{Expect prod normal month}$$

4.2.1 Model production index (LT-PRODIND)

The modeled production index (LT-PRODIND), which is used in the methodology described in Section 4.2, is derived from a park power curve that is calculated in WindPro. The park power curve relates the wind speed and wind direction time series from the KVT Meso long-term data set to the park's energy production. The model grid point closest to the wind farm is normally chosen. Prior to calculating the park power curve, the flow model WAsP 11 is used to horizontally extrapolate the model wind speeds to the turbine locations, taking local topography and surface characteristics into account.

The park power curve has 1 m/s wide velocity bins and 12 wind direction bins. Hence, for each wind direction and wind speed bin the park power curve gives the total power produced by the wind farm. Wake losses are the only loss included in the calculated park power curve, and therefore also in the weekly (or monthly) production index.

4.2.2 Modeled wind index (LT-WINDIND)

The modeled weekly (or monthly) wind index (LT-WINDIND) is calculated from the KVT Meso long-term wind data time-series for the model grid point closest to the wind farm. Using the regression method described in 4.2 between the wind index and the concurrent observed corrected production data there is an underlying assumption of a linear relationship between the wind index and the production.

4.3 SUMMARY OF CHAPTER 4

A number of methods for long-term correcting the observed power production have been outlined. Common for the methods are the use of a long-term reference dataset and use of the concurrent time period of the SCADA and the reference data to derive relationships to be applied on the long-term data. Also common for all methods investigated is that only data from when the wind turbine generators (WTGs) are operating in full performance should be used. The methods can be divided into two categories

- Historical power curve methods
    - Power curves are derived based on production data and related to a long-term reference. A long-term time series of production is created and used to derive the annual production.
- Index methods
    - The relationship between production data and an index based on a long-term reference is used to derive the annual production.

5 Methods, assessing losses from SCADA data

In the calculation of an expected annual energy production (AEP) a careful loss assessment needs to be performed. By analyzing historical production data for the periods when the turbines are not in full performance useful information on experienced losses can be achieved. The losses experienced during the operational period is not necessarily representative for the life-time of the wind farm but may serve as an indication of what to expect. The total loss addressed here are power production reductions related to icing, operating states/alarms and curtailment. The basis for the assessment is the filtering of production data for periods when WTGs are not running in full performance, described in Chapter 2.1.4. The relative production loss (*Rloss*) we define as:

$$Rloss = \frac{Loss}{P_f + P_p + Loss} \qquad \text{Eq. 5-1}$$

Where *Pf* is the total production for periods when WTGs are identified to be running in full performance, *Pp* is the total production for periods when the WTGs are identified to be in partial/non performance due to icing/operating states/curtailment and *Loss* is the estimated production loss due to icing/operating states/curtailment defined as:

$$Loss = PEP - Pp \qquad \text{Eq. 5-2}$$

Where *PEP* (potential energy production) is the total theoretical production summed over all episodes when the WTGs have been identified to not be running in full performance. Hence, *Rloss*, is the percentage of production that is lost with respect to the sum of the actually produced energy and the estimated production loss. *Rloss*, can be used in a post-construction AEP estimation as a first guess of the losses. The loss used in an AEP estimation is normally divided into different categories and separate *Rloss* can be calculated for different loss categories (e.g. icing, operating states/alarms and curtailment). Dividing the losses into separate categories will also make it easier to assess if they are long-term representative.

In this chapter we describe six methods used to estimate the potential energy production (PEP) for periods when turbines are not in full performance. Four of the described methods are outlined in IEC/TS 61400-26-2, the remaining methods are developed by KVT. The different methods are described in the following sections and their main characteristics are given in Table 5.1. All methods have their advantages and disadvantages and the method most suitable for estimating the PEP is specific to the site and to the quality and amount of data available. In accordance with IEC/TS 61400-26-2 the methods are categorized into power based methods and methods based on velocity and power curves. A comparison of the losses estimated with the different method is found in section 7.2.

Table 5.1: Summary of the main characteristics of the potential energy production methods used in the analysis.

Name	Short name	Outlined in IEC/TS 61400-26-2	Needs historical data	Needs wind data	Relies on other WTGs in full perf.	Sensitive to conservative filtering	Level of accuracy
Historical PC, nacelle wind	**PEP-PC1**	Yes	Yes	Yes	No	No	Good
Historical PC, modeled wind	**PEP-PC2**	No	Yes	Modeled wind data	No	No	Low
Power ratio matrix	**PEP-PRM**	Yes	Yes	No	Yes	Yes	Medium
Park average	**PEP-PA**	Yes	No	No	Yes	Yes	Medium
Representative WTGs average	**PEP-PR**	Yes	No	No	Yes	Yes	Medium
Neighboring WTGs	**PEP-N**	No	Yes	No	Yes	Yes	Medium

5.1 WIND SPEED AND SPECIFIC POWER CURVE METHODS

Common for this group of methods is that they need a long-enough record of operational data to be able to specify the specific power curves. Neither of the methods relies on data availability of neighboring WTGs, which results in a higher success-rate in the estimation of the expected PEP (assuming that data is logged by the SCADA system as expected, missing data will of course make the methods to fail). Furthermore, as there is enough data to determine the specific power curves this group of methods should not be sensitive to conservative filtering, which makes them (as a group) suitable for both WFs.

5.1.1 Historical power curve and nacelle wind (PEP-PC1)

Similar to Method LT-PC1 (section 4.1.1), the basis for this method is to define specific power curves for each WTG based on the calibrated nacelle wind measurements and the actual production from the SCADA system for occasions when the WTG is in full performance. To estimate PEP for occasions when turbines are not running in full performance the measured nacelle wind speeds are applied to the derived power curves.

Since the PEP-PC1 method relies on the wind speed measured at the nacelle it is important that the quality of the data can be assured, and that no unknown major revisions have been made to the nacelle transfer functions during the period investigated. One important thing to investigate is if the characteristics of the nacelle anemometer are similar during full performance and non-full performance occasions. If this is not the case, then PEP-PC1 can produce erroneous results. Such an investigation can be made by comparing the ratios from two nearby nacelle wind speed measurements for wake free conditions during periods when both turbines are in full performance and during periods when one of the turbines is in full performance and the other in non-full performance.

5.1.2 Historical power curve and modeled wind (PEP-PC2)

In this method modeled WRF wind data and the actual production data for WTGs running in full performance is used to derive specific power curves for each WTG. Considering that the modeled wind speed is not influenced by wake effects, the specific power curves are derived with respect to the wind direction to account for wake effects. The methodology of deriving specific power curves is shared with LT-PC2 (section 4.1.2).

For periods when a WTG is identified not to be running in full performance the PEP is calculated by applying the modeled WRF wind speed and wind direction to the derived specific power curves of that WTG.

5.2 POWER BASED METHODS

Common for the power based methods are that they are based on production data and that they neither need a site specific power curve, nor wind speed data. Using a power based method, a requirement to be able to estimate the potential power production for a WTG not running in full performance, is that production data from, at the very least, one other WTG running in full performance is available. This makes this group of methods sensitive to park-wide environmental conditions that result in park-wide non-optimized performance (e.g. icing). The group of methods is, for the same reasons, sensitive to conservative filtering. In section 7.2.1 statistics on the rate of success of the different PEP methods are given. Issues related to icing are discussed in detail in (Hansson, Lindvall, & Byrkjedal, 2016).

The derived losses are adjusted for the periods when the methods are unsuccessful in deriving the PEP. The adjustment is made on the assumption that the PEP during occasions when PEP estimation fails, on average equals the successful PEP estimates during periods of non full performance. In practice, this means that the calculated loss is divided by the time-fraction of successful PEP calculation to the total number of occasions when the WTG is classified as not to be running in full performance.

5.2.1 Power ratio matrix (PEP-PRM)

In this method inter-turbine power production relationships are derived for different wind directions and normalized park power production classes. The power production classes are in this project defined as steps of 0.04 times the rated power of the wind farm. Hence, the first couple of classes for a wind farm with rated power 10 MW would be 0 - 0.4 MW, 0.4 – 0.8 MW etc. The method therefore requires a long-enough record of operational data, with all WTGs running in full performance, to set up the relationships properly.

For both WFs, power ratio matrices were setup for 12 wind direction sectors (30° resolution) and for 27 power classes (resolution 0.04 of park rated power). An example, the power ratio matrix for south-westerly wind conditions (195° < wind direction < 225°) and normalized park production between 72 % and 76 % for WF2 is shown in Figure 5-1.

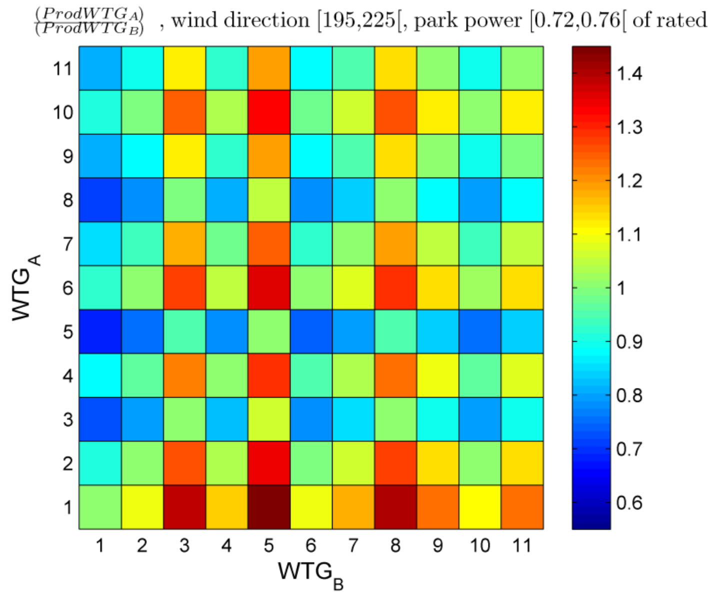


Figure 5-1: Example of a power ratio matrix for WF2.

For each occasion when a WTG is not running in full performance (identified when the data was filtered) its PEP is calculated in the following steps:

- Identify the WTGs that are in full performance at this occasion
- Calculate the average normalized power production of these WTGs
- Based on wind direction and the average normalized power of the WTGs in full performance, identify which power ratio matrix to be used
- The PEP is then calculated as the average product of the inter-turbine relationships ($WTG_{not\_full}/WTG_{full}$) and the production data of the WTGs running in full performance. An example. Turbine 1 is found to be in non-full performance while the rest of the wind farm is in full performance. The average of the following products is the PEP value for turbine 1

$$\frac{T1}{T2}Prod_{T2}, \qquad \frac{T1}{T3}Prod_{T3}, \qquad \dots \frac{T1}{T11}Prod_{T11}$$

5.2.2 Park average (PEP-PA)

This method is based on the assumption that the potential power production of a WTG not running in full performance can be estimated by analyzing the power production of the WTGs in the wind farm that are running in full performance. Following IEC/TS 61400-26-2, an average production factor (actual power divided by rated power) is calculated over the WTGs in full performance. The average production factor is then multiplied with the rated power of the WTG not in full performance to get the potential power production.

PEP-PA is not dependent of historical production data. In terms of individual WTGs there will be a tendency that the potential power production of the WTG associated with the highest (lowest) energy yield will be biased low (high). Averaged over the park, however, these biases are expected to cancel out. There are of course always exceptions. For wind farms with a turbine elevation distribution that is very unsymmetrical, the PEP-PA method might be less suitable.

5.2.3 Average of subset of representative WTGs (PEP-RA)

This method is very similar to previous method (PEP-PA), but in the PEP-RA method only WTGs considered representative of the WTG not running in full performance are used when calculating the PEP. The selection of representative WTGs is subjectively based on the wind farm layout, directional wake effects and wind levels.

As an example the selection of representative WTGs for WF2 is shown in Table 5.2. Referencing the table, in the event that WTG 2 is not running in full performance, its PEP will be determined by averaging the production over the subset of WTG 1, WTG 3, WTG 10 and WTG 11 that are running in full performance.

Table 5.2: Groups of representative WTGs chosen for WF2.

	WTG number										
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Representative WTGs	2, 10	1, 3, 10, 11	7, 8, 9, 11	5, 6, 7, 8	4, 6, 7, 8	4, 5, 7, 10	4, 5, 6, 8 , 9	3, 4, 5, 9	3, 5, 7, 8	1, 2, 6, 11	1, 2, 3, 10

5.2.4 Neighbor WTG (PEP-N)

In this method the PEP for a WTG not running in full performance is estimated from the “closest” neighbor WTG running in full performance. The most evident approach is to use distance as the variable of determining the neighboring WTGs. However, if operative production data is available, more sophisticated and more appropriate approaches in determining the neighboring WTGs may be used.

In this study the “neighboring” WTGs have been determined by assessing the bias in operative production data. The bias is calculated for all possible WTG pairs, considering the periods when both the WTGs are classified to be running in full performance. The evaluation has been made for 12 wind direction sectors, and for each of the direction sectors, the four WTGs with lowest bias to each WTG have been determined and ranked. As an example, Table 5.3 shows the rank matrix for WF2 and for west-southwesterly wind direction (the most frequent wind direction at WF2). Referencing the table, for an occasion with WSW winds when WTG 5 is not running in full performance, the PEP for WTG 5 will be equal to the production of WTG 3 if it is classified to be running in full performance, if not the PEP for WTG 5 will be equal to the production of WTG 8 and so on.

Table 5.3: Neighboring ranking based on smallest bias and west-southwesterly wind direction, WF2.

	WTG number										
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Rank 1 WTG	10	6	8	7	3	10	4	3	11	6	9
Rank 2 WTG	6	10	5	11	8	2	11	5	7	2	7
Rank 3 WTG	2	4	9	9	9	1	9	9	4	1	4
Rank 4 WTG	4	7	11	2	11	4	2	11	8	4	8

6 Causes of possible deviations between pre- and post-construction production estimates

There are assumptions and simplifications in both pre- and post-construction analyses that can cause deviations between the estimates. The following items are discussed in the subsequent sections

- Wind measurements
- Long-term correction of the measurements
- Vertical extrapolation
- Horizontal extrapolation
- Power curve
- Wake losses
- Icing
- Unavailability

6.1 WIND MEASUREMENTS

Wind measurements are normally always used in pre-construction AEP estimations, although there are exceptions when data from nearby operational wind turbines are available. In Chapter 4 and Chapter 5 it is seen that wind measurements can be part also of post-construction analyses. Uncertainties in the measured wind translate into uncertainty in energy and are thus a contributor to possible differences between pre- and post-construction estimations.

6.1.1 Pre-construction

Wind measurements can be made with different types of instruments, i.e. lidar, sodar, propeller anemometers, ultrasonics. Below we only discuss traditional cup-anemometers.

Mounting of the anemometers according to best practice[3] is crucial for high quality, undisturbed, wind data. Short booms can cause, up-wind blockage effects, down-wind wake effects and speed up at the sides. Lightning rods mounted close to the sensor can cause similar effects. Spires for mounting of single top anemometers can be too short, this can cause speed-up effects from the met mast. Boom orientation can be chosen less favorable with respect to the prevailing wind direction, making it necessary to filter more disturbed data. The quality of the used instruments (if used according to the manufacturer's instructions) is of course also important for the final quality of the wind measurements.

[3] What is considered as best practice can change over time. It is here assumed that the last revision of the IEC 61400-12-1 is best practice.

6.1.2 Post-construction

The nacelle anemometers can be of a variety of types and is normally not as accurate as the anemometers used in a pre-construction measurement campaign. The anemometers are also highly disturbed at their positions behind the rotor. The NTF is used to correct the measured wind to free, up-rotor conditions. There is however a large uncertainty in the NTFs, especially during periods when the turbine is not in full operation.

6.2 LONG-TERM CORRECTIONS OF THE MEASUREMENTS

There exist a vast number of methods for long-term correction of wind measurements (e.g. Liléo et al., 2013). The uncertainty in the result depends on both the method and on the reference data used.

The long-term correction of production data is discussed in Chapter 4.

Different methods and different datasets are used in pre- and post-construction analyses and it is obvious that this can lead to differences in the estimations of the AEP.

6.3 VERTICAL EXTRAPOLATION

The vertical extrapolation of the wind measurements to hub height can be a significant source of uncertainty in the pre-construction AEP assessment. The extrapolation is often made with simple expressions, such as the empirical power law or the more physical sound logarithmic wind profile. Both expressions are however valid only for the lowest part of the atmosphere, over flat and homogenous terrain and during neutral atmospheric conditions (e.g. Emeis, 2013). State-of-the-art turbines are normally having hub heights considerable higher than 100 m and the terrain is rarely flat. The extrapolation can also be made using a numerical wind flow model. The models can be sophisticated but are nevertheless simplifications that cannot describe the true variability of the atmosphere. All methods are associated with uncertainties that will affect the estimation of the pre-construction AEP.

The uncertainty related to vertical extrapolation disappears in the post-construction assessment and this will for sure be responsible for differences between pre- and post-construction AEP assessments when pre-construction measurements are made at heights different from the hub height.

A perhaps more exotic cause of differences between pre- and post-AEP related to the vertical extrapolation can arise if the installed turbines do not have the specified hub height. It is believed that the installed turbines have the specified hub height while it in reality does not. If the turbine manufacturer is unaware of this or has failed to communicate it to the wind farm owner, wrong conclusions about the performance of the wind farm can be drawn. Kjeller Vindteknikk has come across a couple of such cases.

6.4 HORIZONTAL EXTRAPOLATION

The horizontal extrapolation of the wind from the measurement position to the turbine positions is in all practical cases made with a numerical model. The uncertainty depends on the size of the wind farm, the complexity of the terrain, the number of measurement points and the type of numerical model that is used. In the majority of the pre-construction AEP estimates made by Kjeller Vindteknikk, the largest uncertainty in the analysis is related to the horizontal extrapolation of the wind. This uncertainty is not present in the post-construction assessment since data is available from all turbine positions. Hence, here is most likely one of the major reasons for deviations between pre- and post-construction energy estimations.

6.5 POWER CURVE

The power curve used in the pre-construction analysis must of course be valid for the site conditions. For typical Swedish conditions (relatively complex terrain and forest) both turbulence and wind shear is normally too high for the "standard" power curves provided by turbine manufacturers to be used without modifications.

The rotor equivalent wind speed (REWS, e.g. Wagner, 2010) accounts for the variation of wind across the whole rotor and is most likely a better input for the energy calculation when the on-site wind shear differs significantly from the conditions present when the standard power curves were calculated/derived by turbine manufacturers.

High turbulence is expected to have an impact on the power production. This can be evaluated through the A. Albers' method (Albers A. , 2010).

It is obvious that the site wind shear and turbulence can cause differences in pre- and post-construction energy estimations. And there is of course always a risk that the actual power curve of the installed turbine differs from the power curve used in the pre construction analyses. This can be a result of turbine changes or resulting from errors or non optimal parameter settings.

These issues are further discussed in WP2.

6.6 WAKE LOSSES

The wake losses in the pre-construction phase are normally assessed by applying simple wake loss models when the energy yield is calculated. The simple models cannot describe the complex interactions that occur in a real wind farm where wind speed, wind direction, stability, turbulence etc. is constantly varying. The true wake losses were not investigated in this project.

The wake losses are included in the operational data used in a post-construction assessment and this is one factor affecting the difference in AEP between pre- and post-construction assessments.

6.7 ICING

Losses due to icing can be significant in some areas. In a pre-construction estimate, an educated guess or a figure based on numerical modeling of the icing conditions on the site is normally used. The uncertainty in the estimates is rather high.

There is also an uncertainty related to the detection of icing in operational data, as discussed in WP3. Due to this, it is clear that the differences between the pre- and post-construction icing losses, and also AEP, can differ quite a lot.

6.8 UNAVAILABILITY

The unavailability in the post-construction assessment can be analyzed using SCADA data while standard values, reflecting figures used in the warranty contracts, normally are used in pre-construction assessments. The definition of unavailability can be different depending if seen from the perspective of the owner of the turbine or from the perspective of the turbine supplier. If different definitions are used in the pre- and post-construction analyses, there will be discrepancies between the pre- and post-construction results.

The unavailability typically covered by an availability warranty is 3 %. The definition of unavailability used in a typical warranty is the so called “technical unavailability”. According to the IEC/TS 61400-26-1, the definition of technical unavailability only includes the categories “Planned corrective action” and “Forced outage” as unavailable. That is, only the periods when the turbine is in one of these categories are considered to be of the turbine manufacturers’ responsibility. All other categories are, either considered as available, or are not included in the calculation of availability. If production loss occurs during these categories, the loss is not covered by a typical availability warranty. From the turbine owner’s view, the definition of “operational unavailability” is however more appropriate. Operational unavailability is typically higher than the technical unavailability since is includes more categories as unavailable. Table 6.1 presents typical definitions of technical and operational unavailability.

Table 6.1: Definition of technical and operational unavailability. Categories shadowed in red are considered as unavailable, and green shadowed categories are considered as available. Categories shadowed in grey are not considered in the estimate of unavailability.

Categories	Technical unavailability	Operational unavailability
Full performance		
Partial performance		
Technical Standby		
Out of environmental specification		
Requested shutdown		
Out of electrical specification		
Scheduled maintenance		
Planned corrective action		
Forced outage		
Suspended		
Force majeure		
Information unavailable		
Typical value	3 %	5 %
View	Turbine manufacturer	Turbine owner

Unavailability is defined according to the following equation

$$\text{Unavailability} = \frac{\text{Red categories}}{\text{Green categories} + \text{Red categories}}$$

Categories shadowed in red are considered as unavailable, and in green as available. Categories shadowed in grey are not considered in the estimate of unavailability.

7 Results; Post-construction energy assessment

7.1 LONG-TERM WAKE REDUCED GROSS PRODUCTION

Figure 7-1 shows the estimated WRAEP of WF1 and WF2. The long-term WRAEP are estimated based on 70 and 24 months for WF1 and WF2, respectively.

The estimates for WF1 (left panel) show a spread of about 4 %. The two estimates based on historical power curve methods results in higher estimates compared to the index methods. For WF2 (right panel) five out of the six methods agree within 1 % on the estimated WRAEP. The LT-PC1 shows a smaller estimate, which also for WF2 results in a total spread among the methods of about 4 %, although the operating period is shorter.

The actual production during the operational period, adjusted to account for experienced losses (section 7.2.2) is also shown in Figure 7-1. It should be emphasized that a perfect agreement is not expected since we are comparing the operational period with the long-term estimates (wind-index during operational period is 100.5 % and 99.2 % for WF1 and WF2, respectively) and also since the experienced losses have not been long-term corrected.

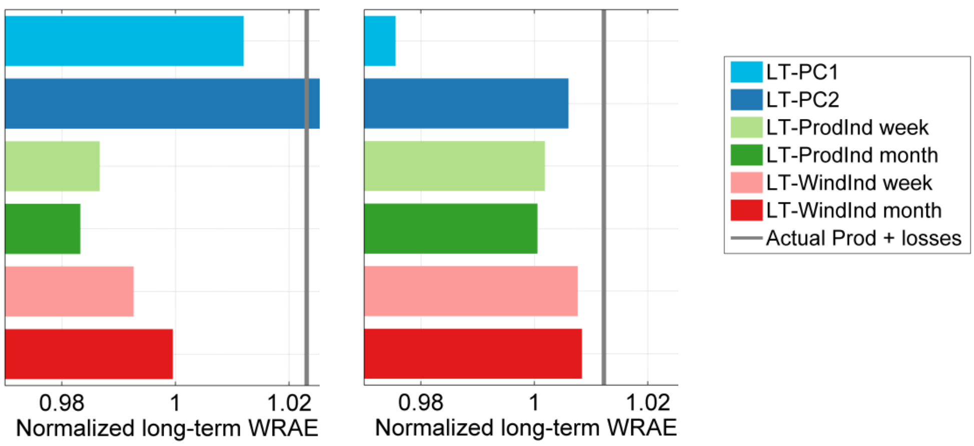


Figure 7-1: Estimates of the normalized wake reduced gross annual energy production (WRAEP) for WF1 (left) and WF2 (right). The estimates are based on 70 and 24 months of production data, respectively. The values have been normalized with the average value of the estimates. Also included is the actual production during the full period, normalized to a yearly value. The actual production has been adjusted to account for experienced losses (see section 7.2.2 for the choice of losses).

7.1.1 Sensitivity of the post-construction production estimate on the length of the operational period

Figure 7-2 shows the evolution of the WRAEP estimates as a function of operational months included in the analysis. From WF1 (upper panel) it is evident that the estimate of the different methods stabilizes after about 36 months of operational months and the 4 % inter-method spread remains approximately constant from this point. There is considerable variability in the estimates when less than 24 months of data is used to derive the WRAEP. Much of the variability with a small number of operational months can likely be attributed to a sampling that is seasonal biased. For example, most methods show a significant dip in the estimates at 18 months when two summers and one winter of operational data is included in the analysis. To a much smaller extent a signal from biased seasonal sampling is also evident with more operational data included in the analysis (e.g. at 54 months). The reason for the relative large inter-method spread in WF1 is further investigated in section 7.1.2

The evolution of the WRAEP estimates of WF2 (lower panel Figure 7-2) shows somewhat different behavior compared to WF1: the seasonal signal is smaller in general; there is more evident grouping, the LT-PC2 method groups with the index methods, while the LT-PC1 method deviates from the rest. For the LT-PC1 there is tendency that the WRAEP decreases with the number of operational months included in the analysis. The opposite tendency is shown for the remaining methods.

The inter-method spread of WF2 at 24 months is comparable but slightly smaller to the inter-method spread of WF1 at 70 months. However, the results in Figure 7-2 (upper panel) indicate that WRAEP has not leveled out for WF2 at 24 months.

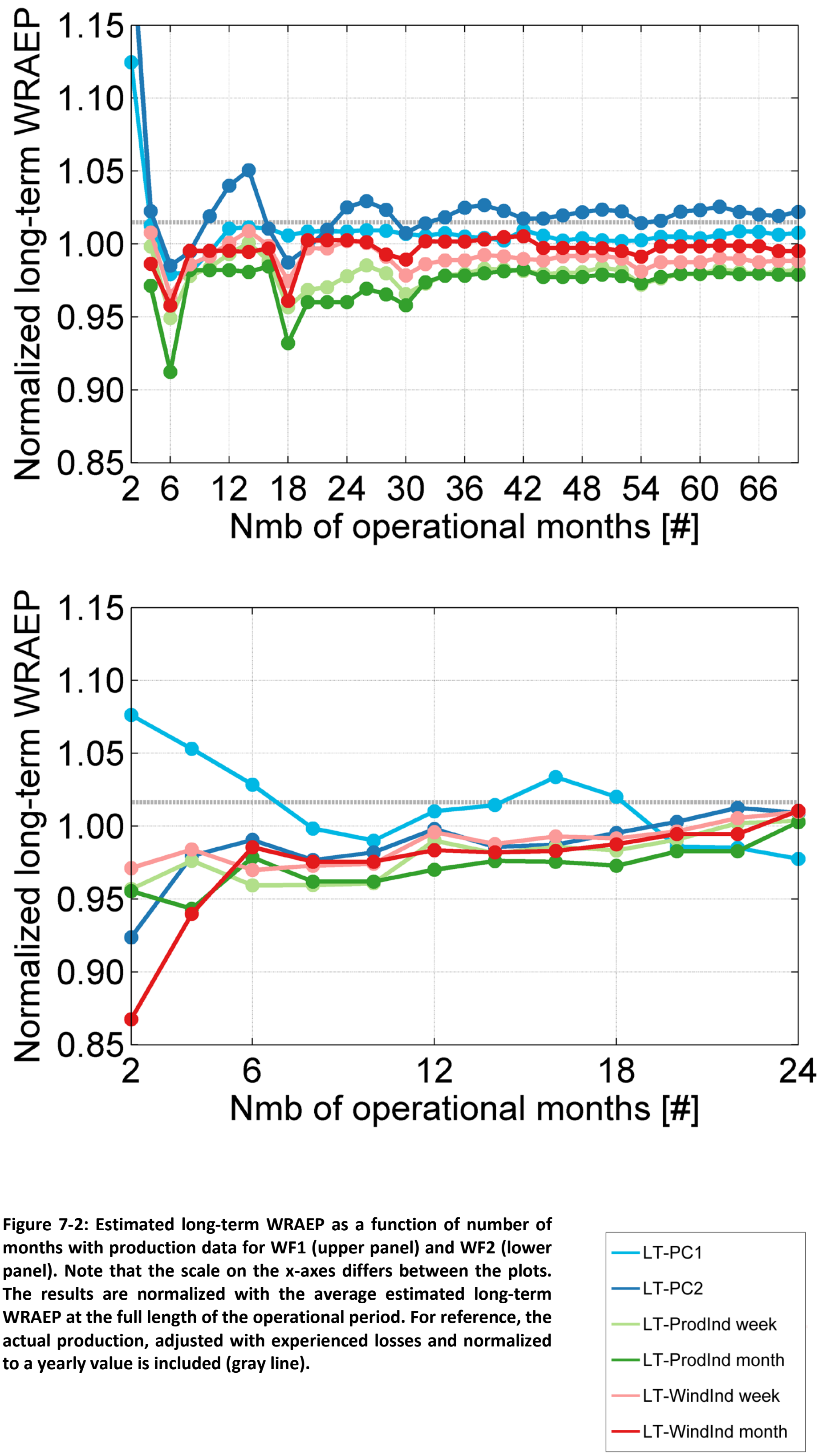


Figure 7-2: Estimated long-term WRAEP as a function of number of months with production data for WF1 (upper panel) and WF2 (lower panel). Note that the scale on the x-axes differs between the plots. The results are normalized with the average estimated long-term WRAEP at the full length of the operational period. For reference, the actual production, adjusted with experienced losses and normalized to a yearly value is included (gray line).

To assess the sensitivity of the uncertainty in the long-term WRAEP estimates to the length of the operational period estimates based on non-overlapping 6, 12, 18, 24 and 30 month periods of production data are calculated (Figure 7-3). This means that the whole length of the measurement period is divided into non-overlapping periods and that one long-term estimate is calculated based on the data from each of these periods. Using this approach, two 30 month periods can be created based on the data from WF1, three 18 month periods and so on.

For WF1, the estimates based on independent six-month periods show considerable scatter, only LTC-PC1 show a modest spread in the estimates. For all methods, except the LTC-PC1, there is a clear tendency that the six-month estimates based on a summer season are considerably lower than the estimates based on a winter season, which indicates sensitivity to seasonal sampling. Already at 12 months the scatter is smaller and only the monthly index estimates (LT-ProdInd month and LT-WindInd month) include clear outliers.

The shorter operational period of WF2 results in a smaller amount of independent 6 and 12 month periods. However, compared to WF1 there is a general tendency of smaller scatter between the estimates, although the LTC-PC1 estimates show larger scatter.

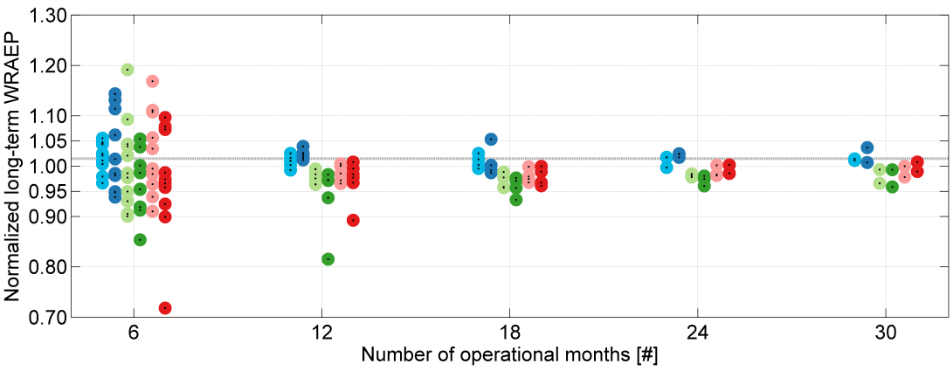
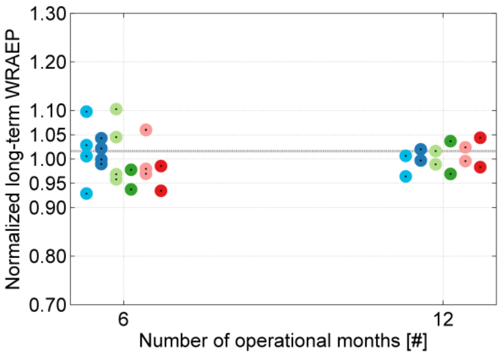


Figure 7-3: Estimates of the long-term WRAEP for non-overlapping 6, 12, 18, 24 and 30 month periods for WF1 (above panel) and WF2 (right panel). The results are normalized with the average estimated long-term WRAEP at the full length of operational period. For reference, the actual production, adjusted with experienced losses and normalized to a yearly value is included (gray line). The methods are colored according to Figure 7-2.



The uncertainty of the long-term correction of the production data is assessed by considering the relative standard deviation of all the estimates and all methods. However, to avoid giving too much weight to the index-based methods only the weekly index estimates not the monthly index estimates are included in the calculation. The results are summarized in Table 7.1.

The added uncertainty in the estimates when there is a seasonal bias in the sampling of the production data is manifested by larger uncertainties values at 6, 18 and 30 months periods compared to 12 and 24 months periods. The larger uncertainty reduction in WF1 compared to WF2 from 6 month to 12 month production period may be related to the harsher winters of WF1.

Only two WFs are included in the analysis and it is thus difficult to draw general conclusions from the results. However, they can be considered indicative of what to expect.

Table 7.1: Relative standard deviation of all independent WRAEP estimates of the LTC-PC1, LTC-PC1, LTC-ProdInd Week and the LTC-WindInd Week methods.

	Production period [#months]				
	6	12	18	24	30
WF1	7.3 %	2.1 %	2.5 %	1.9 %	2.2 %
WF2	4.9 %	2.0 %	-	-	-

7.1.2 Comment on the index methods

For the index-methods when determining the relationship between the index and production data we require monthly/weekly availability of the SCADA data above 95 %. For each turbine the months/weeks that fulfill this requirement is adjusted to 100 % availability by assuming that the production during the period of unavailability equals the mean production during the period of availability during each month/week. This assumption introduces uncertainty to the estimate. On the one hand a high number of data points are desired to increase the statistical robustness of the results; on the other hand the adjustment should not be larger than necessary. In addition, for wind farms that are subject to considerable icing, there is also a risk that the winter season is badly sampled if the availability threshold is high.

The index methods' sensitivity of the WRAEP to the availability threshold is shown in Figure 7-4. For both wind farms and all index methods the WRAEP is decreasing with increasing availability requirements. Hence, setting the availability limit too low will overestimate the WRAEP.

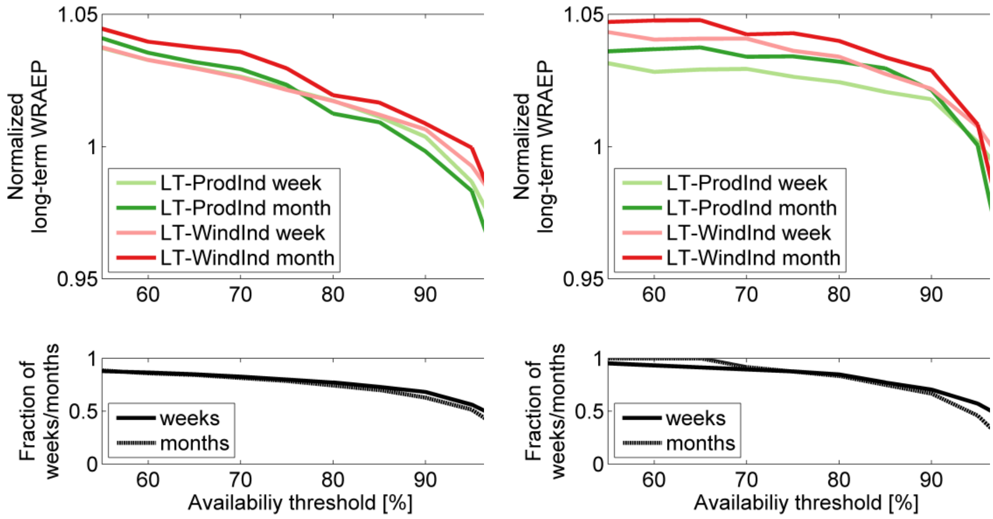


Figure 7-4: Estimated long-term WRAEP (upper panels) and fraction of month/week fulfilling the availability requirement (lower panels) as a function of the availability threshold. A value of 1 in the lower panel indicates that all months/weeks fulfill the availability requirement and are used in the calculation of the WRAEP. WF1 and WF2 results in the left and right panels, respectively. The results are evaluated for 70 months in WF1 and for 24 months in WF2 and they are normalized with the average method WRAEP (power-curve methods and index methods with 95 % availability threshold).

7.1.3 Guidelines on the choice of method(s) to long-term correct the observed power production

The choice of method for long-term correcting the production varies from site to site. Table 7.2 gives some guidelines on when the different methods are/are not suitable. LT-PC1 is said to be suitable for long operational periods having a large amount of non-full performance periods. However, it is necessary that there is enough data to define the power curves and transfer functions (section 4.1) used in the method.

Turbine layout and terrain features are not considered to be important in the process of selecting the most suitable method. Wake effects and terrain-caused speed-ups are included in the operational data and will be transferred to the long term estimate.

Table 7.2: Guidelines on choosing methodology for long-term correction of the production data.

		LT-PC1	LT-PC2	LT-PRODIND	LT-WINDIND
Recommended if	Short operational period	Yes	No	No, but weekly basis somewhat better	No, but weekly basis somewhat better
	Long operational period but large amount of non-full performance periods	Yes	Yes	No	No
	Inconsistencies in the nacelle anemometer	No	Yes	Yes	Yes

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7.2 ASSESSMENT OF EXPERIENCED LOSSES

7.2.1 Evaluation of potential energy production (PEP)

For each individual turbine and timestamp the PEP is estimated based on the six different methods described in chapter 5. Figure 7-5 and Figure 7-6 show self-prediction evaluations for WF1 and WF2, respectively. Only occasions when all turbines are in full performance are considered and the four methods that require historical data (PC1, PC2, PRM and N) are trained with the first half of the operating period (more or less) and evaluated with the remaining operating period. Data from all turbines are included in each figure.

For both WFs the PC1 method is associated with the smallest mean absolute error (MAE) as well as with the highest correlation with the actual production data. For WF1 there is a considerable bias (PEP – actual production) in the PC1 method. This is mainly attributed to a park-wide revision of the NTFs (see section 2.1.2) in the transition between the training period and the period of evaluation. This is accounted for when deriving the losses by applying different historical power curves to the nacelle anemometer wind speeds before and after the revision date.

The PC2 method is associated with the highest MAE and also has the lowest correlation with the actual production. There is a clear systematic dependence of the bias, such that the PEP is overestimated at low production values and underestimated near rated power. The large MAE and the bias dependency on the power value are expected given that the method when creating the historical PCs relates WRF wind speed and wind direction to the production data on a time-stamp level (see section 4.1.2). Nevertheless, if there is a large amount of operational data and if the wind distribution during episodes of non-full performance is similar to the distribution during episodes of full performance (i.e. the training period), the method can still be suitable for estimation of the PEP during episodes when WTGs are not running in full performance. Figure 7-7 shows the WRF wind speed distributions when WTGs are running/not running in full performance for both WFs. At WF2 the distributions show better resemblance compared to WF1.

The power based methods (PRM, PA, RA and N) show very similar behavior. The Power Ratio Matrix method (PRM) and the method relying on the average of a subset of representative WTGs (RA) are associated with somewhat lower MAE and better correlation values compared to the Park Average (PA) method and the neighboring WTG method (N). Since the evaluation is done only for episodes when all WTGs are running in full performance it is expected that the bias of the power based methods to be small or zero if the all the WTGs are considered. If the bias is evaluated on the basis of the individual WTGs the absolute bias differs considerable between the different power based methods (not shown). The PRM is associated with the smallest absolute bias, it is follow by N and the RA methods and the PA method is associated with largest absolute bias.

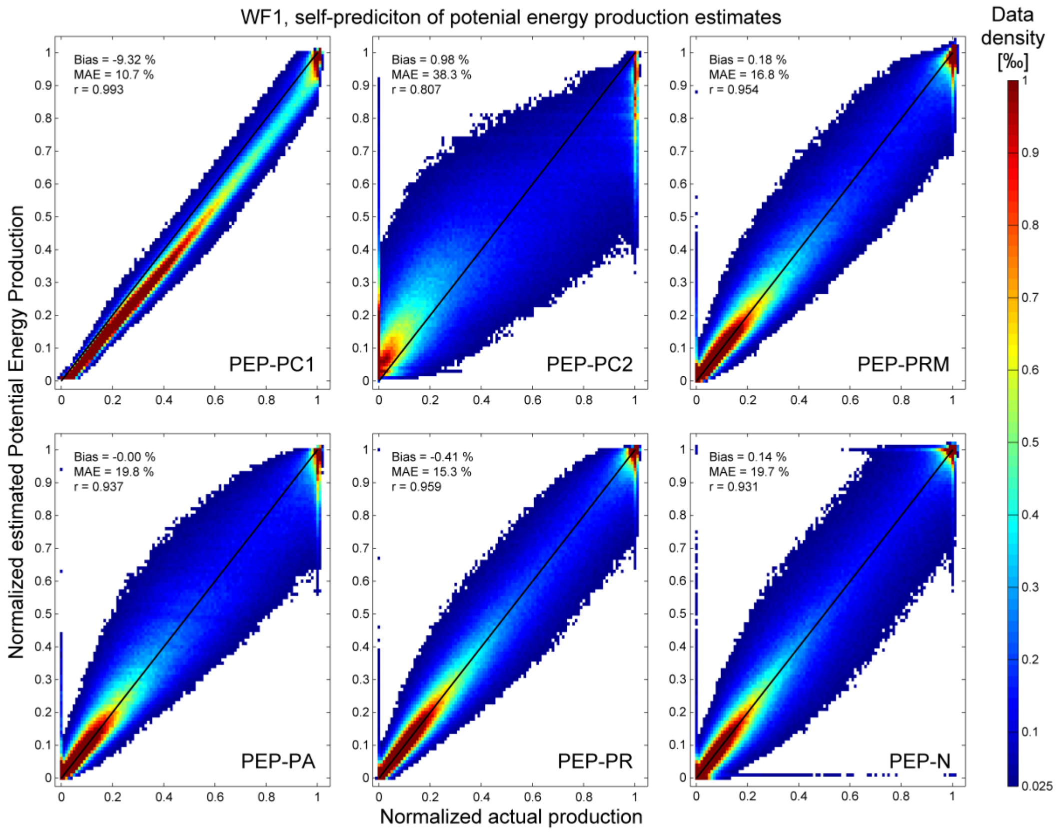

Figure 7-5: Scatter density plot of normalized actual production versus normalized estimated potential energy production (PEP) for WF1 for the six PEP methods analyzed. Data is for all WTGs and only occasions when all WTGs are in full performance are included. Values of total bias, mean absolute error (MAE) and the correlation coefficient (r) are included in each panel. The bin size is 0.01 x 0.01 of rated power.

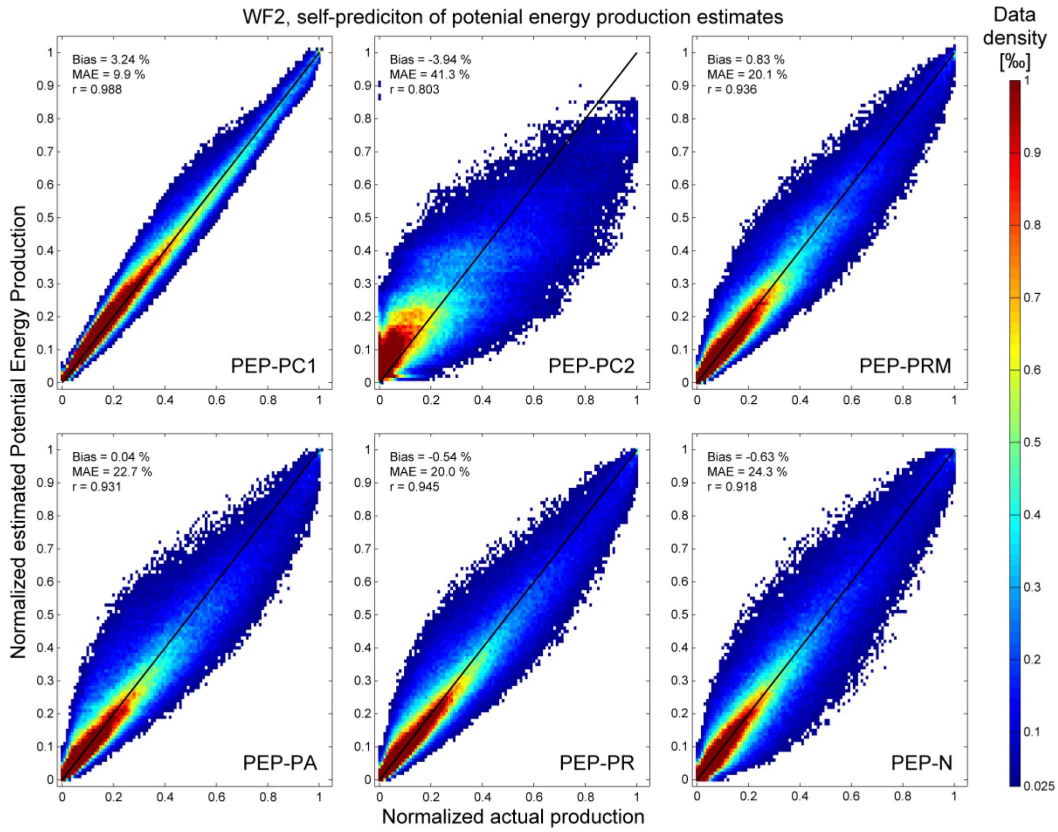

Figure 7-6: Same as Figure 7-5 but for WF2.

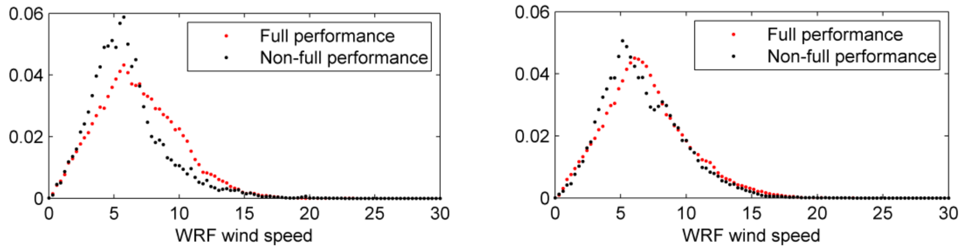

Figure 7-7: Probability density function of the modeled WRF wind speed during episodes when WTGs are running/not running in full performance for WF1 (left panel) and WF2 (right panel).

In the process of assessing the losses during the operational period it should be emphasized that it is the PEP during the occasions when the WTGs is not in full performance that are utilized. This implies extra demands on the methods that are not evaluated in Figure 7-5 and Figure 7-6. For example with one or several WTGs stopped or not in full performance the wake losses for the WTGs in full performance are expected to be smaller than when all turbines are in full performance. PEP from the power-based methods that rely on other turbines in full performance (method PRM, PA, RA and N) are thus expected to be positively biased. Another issue with the methods relying on other turbines in full performance, which is a large concern for wind farms with considerable icing, is the fact that PEP is undetermined when no turbine are in full performance. Table 7.3 summarizes the fraction of time with successful PEP estimates when WTGs are not running in full performance.

Table 7.3: Rate of success in estimating the potential energy production for episodes when WTGs are not running in full performance. The majority of difference in success rate between the historical PC methods and the power based methods is due to ice in the wind farms. When all turbines are affected at the same time the power based methods cannot calculate a PEP since they require at least one turbine to be in full performance.

	PEP-PC1	PEP-PC2	PEP-PRM	PEP-PA	PEP-RA	PEP-N
WF1	99.9%	99.9%	58.8%	58.8%	38.3%	44.0%
WF2	94.7%	94.6%	66.5%	66.7%	58.0%	59.3%

As discussed in section 5.1.1 the PC1-method relies on the nacelle anemometer to also accurately measure the wind speed when WTGs are not running in full performance. One approach for investigating this is shown in Figure 7-8. The figure shows two examples where the wind speed measured at two neighboring WTGs are plotted against each other for the occasions when both the WTGs are running in full performance and for the occasions when one of the WTGs is not running in full performance. Only occasion when neither of the two WTGs is in the wake of other WTGs are considered. In the left panel of Figure 7-8, which shows a WTG pair from WF1, the linear relationship between the WTGs are very similar regardless of the WTG status. The right panel of Figure 7-8, which is an example from WF2, shows that relationships between the measured wind speeds are different for occasions when one of the WTGs is not running in full performance to when both are running in full performance. This indicates that the measured wind speed is biased when the WTG is not running in full performance. Considering that the specific power curves are derived with the turbines in full performance the use of PC1 to estimate the potential energy production in such cases adds uncertainty to the results. To quantify this uncertainty is challenging, the relationships are changing with the choice of WTG pairs and the direction considered. However, in the case of WF1 and WF2 the tendency is that we in general see larger discrepancy in the nacelle anemometer wind speed in WF2 than in WF1.

With that mentioned Figure 7-5 and Figure 7-6 still give interesting information of the characteristics of the different methods.

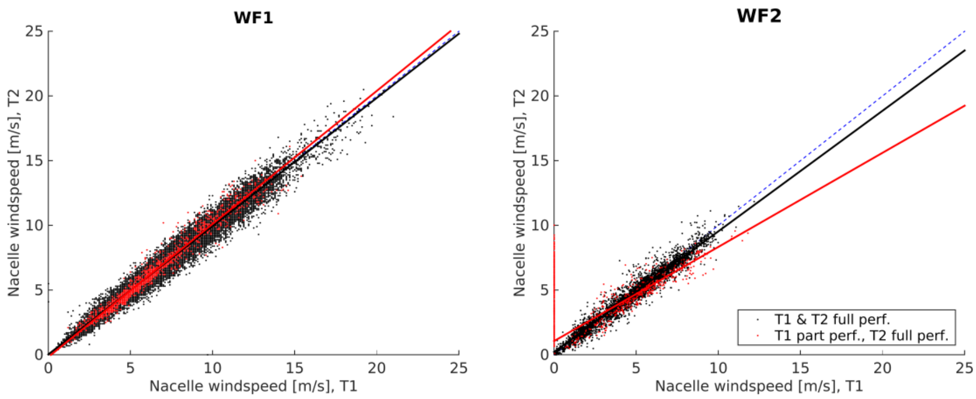

Figure 7-8: Scatter plot of nacelle anemometer measured concurrent wind speeds for an undisturbed wind direction for a pair of neighboring WTGs in WF1 (left panel) and WF2 (right panel). Black dots represent periods when both turbines are in full performance, red dots represent periods when one of the WTGs is running in full performance while the other WTG is not running in full performance. Linear fit performed only when wind speed data from both sensor > 2 m/s.

7.2.2 Experienced losses

Based on the six different methods of estimating PEP the experienced losses during the operational period are assessed in accordance to equation Eq. 5-1 and Eq. 5-2. Figure 7-9 shows the estimated total loss for the two wind farms, normalized with the average value of the methods.

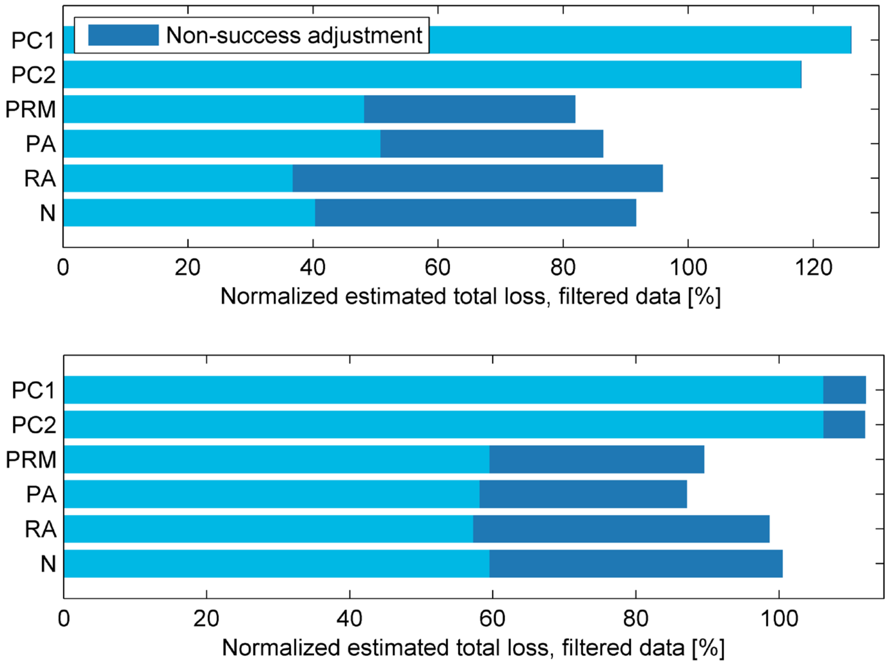

Figure 7-9: The estimated total relative loss for periods when WTGs are identified to not be running in full performance. WF1 (upper panel) is based on 70 months of operational data and WF2 (lower panel) is based on 24 months of data. Darker blue indicates the fraction of the loss that has been adjusted to account for unsuccessful determination of the potential energy production. Normalization is made with respect to the average value of the methods.

If all methods are considered there is a 45 % and 25 % discrepancy between the total loss estimates for WF1 and WF2, respectively. Common for the WFs is that the estimates based on the wind speed and specific power curve methods (PEP-PC1 and PEP-PC2) show higher values than the power based methods (PEP-PRM/PA/RA/N). In general the losses based on the power based methods are associated with a low success rate in the derivation of the PEP (Table 7.3) and the values need adjustment for the episodes when the determination of PEP fails. The adjustments have been made on the assumptions that the losses during the episodes when PEP fails on average equal the losses during the episodes when the PEP derivation is successful:

$$Loss_{adjusted} = \frac{Loss}{Rate\ of\ PEP\ success}$$

The adjustment brings general uncertainty to the loss values and in addition, if icing losses is the major contributor to the total loss (which is the case for WF1); it is likely that the above adjustment assumption underestimates the total loss. This can be understood since it is reasonable to assume that the probability of the power based methods to be successful is larger with light icing condition (small production loss) than with severe icing conditions (large production loss), because light icing would not affect the full park while severe icing conditions would. Our conclusion is that for wind farms in cold climate with considerable icing losses, the power based methods are not suitable for estimating the experienced losses.

In our analysis, for both wind farms, the discrepancy between the total losses given by the power based methods and the wind speed and specific power curve methods (Figure 7-9) is attributed to losses associated with icing. The smaller icing losses of WF2 explain the smaller discrepancy between the two groups of methods.

On a side note, if the fraction of time when WTGs are not running in full performance is assumed to be directly proportional to the fraction of energy lost the total loss is overestimated. For example, if the WTGs are in non-full performance for 10 % of the time, then a simple estimation of the losses would be 10 %. In normalized values this assumption implies a total loss of 147 % and 176 % for WF1 and WF2, respectively. It is not clear if this result is general, however it indicates that large availability adjustments in the long-term correction index methods (section 4.2) should be avoided.

7.2.3 Long-term correction of experienced losses

Given that the historical losses have been estimated from the operational data the next question to address is whether these are representative on a long-term basis. Figure 7-10 highlights how the estimated experienced total loss due to non-full performance varies with the number of months of operational data included in the analysis for WF1. With increasing number of months the total loss levels off although the seasonal dependency is still visible. However, considering the wind speed and specific power curve methods (PEP-PC1 and PEP-PC2) the estimated total loss after 12 months and 24 months are overestimated with about 50 % and 20 % compared to the estimate at 5 years (60 months), respectively.

As mention before, icing losses are the main contributor to the total loss at WF1 and these are typically associated with large inter-annual variability. Specifically for WF1, the icing losses vary with a factor 4 between different years (read further in WP3). For WFs in cold climate that are subject to icing losses, it is thus risky to assess losses and assume these to be representative in the long-term perspective from a short period of historical data. Preferably a long-term reference dataset of icing losses should be used to long-term correct the experienced losses related to icing.

In addition, the experienced losses associated with alarms may need some long-term correction. It is reasonable to assume that with increasing age, alarm will occur more frequently and that this loss needs to be increased. Analyzing a large number of UK wind farms, Staffell & Green (2014) for example showed that the wind farm output on average decreased with 12 % over a twenty year life cycle.

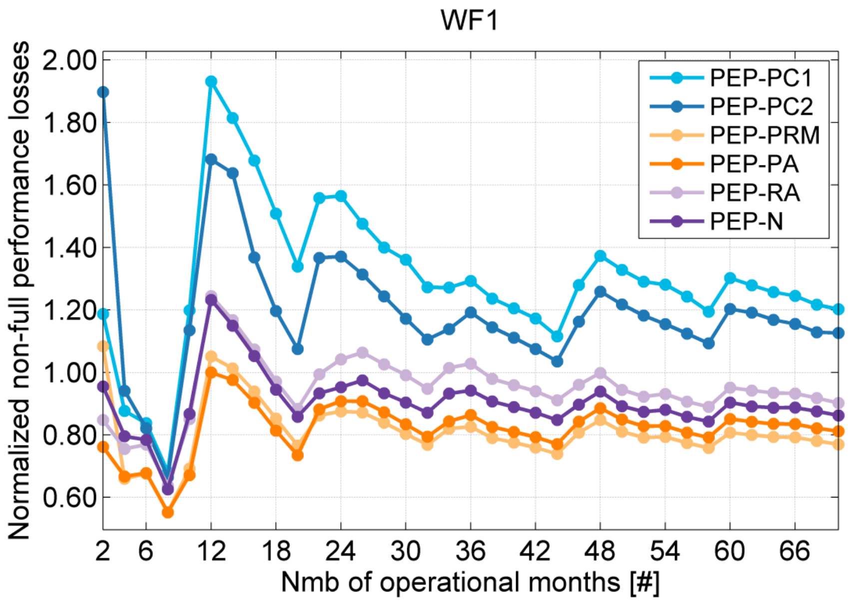

Figure 7-10: Estimated historical losses as a function of the number of months with production data for WF1. The losses are normalized with the average estimated losses when considering the full length of the operational data.

7.2.4 Guidelines on the choice of method(s) to assess the experienced losses

Data from two WFs is not enough to make general recommendations on methods suitability and either way it is questionable if there is one method that is generally preferable, more likely the method best suited varies from site to site. Based on the findings in section 7.2.2, Table 7.4 summarizes recommendation in method selection for assessing the experienced losses of historical production data.

Table 7.4: Guidelines on choosing loss assessment method.

		PEP-PC1	PEP-PC2	PEP-PRM	PEP-PA	PEP-PR	PEP-N
Recommended if	Short operational period	Yes	No	Yes	Yes	Yes	Yes
	Many park-wide episodes of non-full performance (e.g. icing or conservative filtering)	Yes	Yes	No	No	No	No
	Inconsistencies in the nacelle anemometer	No	Yes	Yes	Yes	Yes	Yes
	Wind distributions of episodes when WTGs are running/not running in full performance differ	No	No	Yes	Yes	Yes	Yes

7.3 UNCERTAINTY ASSESSMENT OF POST-CONSTRUCTION LONG-TERM ENERGY YIELD.

Except that the post-construction production assessment should result in a more accurate estimate of the most likely long-term energy yield of the wind farm (P50), one of the main advantages is that uncertainty in this estimate should be considerably smaller compared to a pre-construction P50 since several uncertainty posts can be eliminated (e.g. posts related to wind measurements and flow modeling).

As an example Table 7.5 lists the different sources of uncertainty in the estimated P50 value of a pre-construction (PrC) and a post-construction (PoC) production assessment. In the table uncertainty values are shown for WF1 under the assumption that one year of measurement are available. It should be noted that we do not have full insight into the PrC measurements campaign of WF1 and values should therefore be considered preliminary. In addition it is worth to emphasize that all values are site specific. However, a substantial reduction in the total standard uncertainty, in the same ball-park, is expected in the PoC P50 value compared to the PrC P50 value.

Table 7.5 highlights that several of the uncertainty items are eliminated in the PoC assessment compared to the PrC assessment. Of the remaining uncertainty posts the largest reduction is in the uncertainty associated with the measurement. The metering of the power is less of a challenge than measuring the wind conditions. If a methodology(-ies) that relies heavily on the nacelle anemometer is chosen in the PoC assessment the uncertainty related with the measurement data need to be increased in the PoC.

The uncertainty related to the long-term correction of the production remains more or less unchanged. Except including the uncertainty to the long-term correction method (addressed in section 7.3), this item also includes uncertainties related to potential inconsistencies in the reference dataset, the 20-year representativeness of the reference time-series and uncertainty related to potential future changes in the wind climate.

The uncertainty associated with the loss estimates is also reduced, which mainly is attributed to the fact that wake losses no longer needs to be estimated but are included in the derived gross WRAEP. The estimation of the experienced icing losses also reduces the uncertainty related to the loss assumptions in the PoC compared to the PrC.

The total standard uncertainty of the P50 of WF1 and WF2 in a PrC versus a PoC assessment and for different length of the measurement period are shown in Table 7.6.

Table 7.5: The different sources of uncertainty in the estimated P50 for WF1 in a pre-construction assessment versus a post-construction assessment. Both cases assume that 12 months of measurement are available for the analysis and the total standard uncertainty is with regards to a 20 year perspective.

Uncertainty in the Annual energy yield	Pre-construction	Post-construction
Measurements	8.0%	1.0%
Long-Term Correction of the Measurements	6.3%	6.1%
Horizontal Extrapolation	9.0%	-
Vertical Extrapolation	8.0%	-
Representativeness of the Wind Distribution	3.0%	-
Power curve and metering	1.2%	-
Loss assumptions	6.6%	5.1%
Total Standard Uncertainty	**17.4%**	**8.0%**

Table 7.6: The estimated total standard uncertainty in the P50 value of WF1 and WF2 in a pre-construction assessment versus a post-construction assessment given different length of the measurement period.

Total Standard Uncertainty	WF1		WF2	
	Pre-const.	Post-const.	Pre-const.	Post-const.
Half-year of data	18.9%	11.6%	17.4%	11.2%
One year of data	17.4%	8.0%	15.2%	8.1%
Two years of data	17.3%	7.4%	15.1%	7.9%

7.4 UNCERTAINTY REDUCTION WHEN USING NACELLE MOUNTED LIDAR MEASUREMENTS COMPARED TO NACELLE-MOUNTED ANEMOMETER MEASUREMENTS

Out of the four methods described and used in WP1 for long-term correcting the production data, only the LT-PC1 method (section 4.1.1) utilizes the nacelle-mounted anemometer. In theory, wind speed data from a nacelle-mounted lidar (with a range > 2.5 rotor diameter) could be an alternative to the anemometer when determining the historical power curves. In practice, this is not an attractive solution: lidars would have to be mounted on each individual turbine and for a long period of time; differences in the historical power curves from using an anemometer or lidar would, to a large extent be cancelled out, by differences in the transfer coefficients between the long-term reference data and the wind speed measurements that are applied to the long-term dataset.

Nacelle-mounted lidar have many applications in WTG/wind farm performance optimization (see for example WP2) but in-terms of long-term production estimates from production data our opinion is that a nacelle-mounted lidar compared to a nacelle-mounted anemometer means limited uncertainty reduction.

8 Conclusions

The main conclusions obtained in the present work are summarized below.

Chapter 3 - Previously published results

- The number of publications assessing long-term correction of production data is rather limited and the few publications available are sparse on details. Still many consultants provide services of updating the production yield post construction of the wind farm.
- The approach of long-term correcting the measured production is typically done by using a wind index created from a long-term reference data and for the concurrent period relate the aggregated measured production to the wind index.
- In deriving the above relationship it is important that the aggregated production is corrected for periods when turbines (WTGs) are not available. The availability is however calculated in different ways, which creates uncertainty to the long-term energy yield.

Chapter 4 - Methods, post-construction long-term gross AEP

- Four different methods to long-term correct the measured production have been developed, two of these are index-based and two relies on derived historical power curves that are applied to the long-term reference dataset.
- Periods when WTGs are not running in full performance are identified. This includes periods that are classified as unavailable according to the technical specification IEC/TS 61400-26-1 but also periods when WTGs are running in partial performance.
- For Swedish climate conditions our recommendation is that it is preferable to only include the full-performance production when relating it to a wind-index (or production index). The reason being that it is common that a significant part of the total losses stems for icing on the blades, and it is not uncommon that the power production will continue with iced blades but with a reduced power output. Such situations will not be classified as unavailable according to IEC/TS 61400-26-1 since the WTG will be considered to be in partial performance.
- For the index-based months the aggregated full-performance production is corrected to 100 % full performance by adjusting the aggregated by the fraction of time the WTGs are identified to be in full-performance. Only week/months with full-performance record > 95 % is considered.

Chapter 5 - Methods, assessing losses from SCADA data

- Six different methods to assess the potential energy production (PEP) during episodes when the WTGs are identified not to be running in full performance are developed. Out of the six methods three are outlined in the technical specification IEC/TS 61400-26-2 and they can be grouped into “wind speed and specific power curve”-methods and “power based”-methods.
- Losses are derived from the PEP and the actual production during the episodes identified as non-full performance.

Chapter 6 - Cause of possible deviations between pre- and post-construction production estimates

- This chapter, in general terms, discuss possible reasons why there might discrepancy between the estimated pre- and post-construction energy yield.

Chapter 7 - Post-construction energy assessment

Production data from two wind farms (WFs) are included in this analysis. In terms of Swedish icing condition one of the WFs is representing relatively harsh condition, while the other WF is representing moderate conditions. Given that only two wind farms are included in the study, conclusions should not be considered general.

Long-term correction of production data

- The most adequate choice of method for long-term correcting the production data are site dependent.
- Most of the methods show sensitivity to biased seasonal sampling. To decrease uncertainty in the P50-value it is recommended to use full-years of operational data.
- The post-construction production estimate is sensitive to the choice of method. For the WF associated with harsh winter conditions, there is a 4 % spread with 24 month of operational data considered. This spread remains relatively unchanged up to the full length of the operational period (70 months).
- The large discrepancy between the methods is mainly attributed to the index-based methods, whose estimates are biased low. Only weeks/months when the WTG is identified to be running in full performance for > 95 % of the time is corrected and considered when relating aggregated production to the index. Likely due to icing, weeks/months that otherwise would increase the production estimate is discarded due to the 95 % threshold.
- Our results indicate that the index-based methods are less suitable for long-term correcting the production data if the WF is associated with substantial icing losses.
- Based on the two WFs analyzed, the estimated uncertainty associated with the choice of method for long-term correcting the production is about 8 %, slightly above/below 2 % for 6 months, 12/24 months of operational data, respectively.

Assessment of experienced losses

- The method most suitable to estimate the experienced losses varies from site to site.
- Our recommendation is not to use the power-based methods to estimate the experienced losses for wind farms for which icing is a significant issue. In the process of deriving the PEP of a WTG that is identified to not to be running in full performance it is required that at least one of the remaining WTGs are identified to be running in full performance. If not, no PEP can be determined for that timestamp. Typically when there is an icing event all WTGs in the WF are affected and thus, if the filtering procedure is working as it should, all WTGs are identified to not be running in full performance. A low success rate in determining the PEP can be adjusted for; however this adjustment is associated with considerable uncertainty.
- If the nacelle anemometry and a specific historical power curve are used to derive the PEP make sure the wind speed data is consistent during episodes when the WTG is running in full performance and during episodes when the WTG stands still or is not running in full performance.

- Whether the estimated experienced loss can be considered representative in a long-term perspective needs to be assessed for each site. For example, icing losses are known to have a large inter-annual variability; to base the long-term icing loss on the experienced icing loss during a 12-month period is uncertain.

Uncertainty assessment of post-construction long-term energy yield

- For the two WFs analyzed the uncertainty associated with P50 value in the post-construction assessment is approximately half the value of corresponding uncertainty in the pre-construction assessment. The relative uncertainty reduction is increasing somewhat with the number of months of measurements that go into the assessment.

Uncertainty reduction when using nacelle-mounted lidar measurements compared to nacelle-mounted anemometer measurements

- Our conclusion is that no major uncertainty reduction in the expected long-term production is expected when using a nacelle-mounted lidar compared to a nacelle-mounted anemometer.

9 References

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10 Appendix 1 – KVT Meso dataset

The Weather Research and Forecast (WRF) model is a state-of-the-art meso-scale numerical weather prediction system, aimed at both operational forecasting and atmospheric research needs. A description of the modelling system can be found at the home page http://www.wrfmodel.org/. The model version used in this work is v3.2.1 described in Skamarock et al. 2008[4]. Details about the modelling structure, numerical routines and physical packages available can be found in for example Klemp et al. (2000)[5] and Michalakes et al. (2001)[6]. The development of the WRF-model is supported by a strong scientific and administrative community in U.S.A. The number of users is large and it is growing rapidly. In addition the code is accessible for the public.

The most important input data are geographical data and meteorological data. The geographical data is from National Oceanic and Atmospheric Administration (NOAA). The data includes topography, surface data, albedo and vegetation. These parameters have large influence for the wind speed in the layers close to the ground. Global meteorological data with 1 degree resolution, available from the National Centres for Environmental Protection (NCEP) with 6 hours interval, is used as boundary data for the model. The data originates from the Final Global Data Assimilation System (FNL). FNL is an operational assimilation model that incorporates all available observation data globally, and uses this data to create a global analysis dataset, or a snapshot of the atmosphere, four times every day. The assimilation model incorporates data from several thousand ground based observation stations, vertical profiles from radiosondes, aircrafts, and satellites. See http://www.emc.ncep.noaa.gov/gmb/para/parabout.html for further description of the data. The global data analysis is based on observational data for the time-frames 00, 06, 12 and 18 UTC. Surface roughness and landuse have been updated from Landmäteriets GSD database in Sweden and from the N50 series from Kartverket in Norway.

The model setup used for this analysis is shown in Figure A-1. The model has been set up with 4 km x 4 km horizontal resolution. The model is run with 32 layers in the vertical with four layers in the lower 200 m. We have used the Thompson microphysics scheme and the YSU scheme for boundary layer mixing. The simulation outputs hourly data starting from 01.01.2000 and updated to current date on a monthly basis.

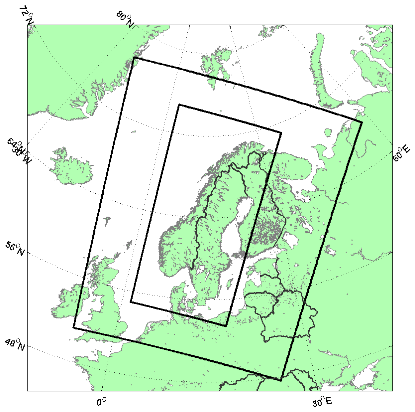

Figure A-1: Model set up for the WRF reference simulations of Scandinavia.

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POST-CONSTRUCTION PRODUCTION ASSESSMENT OF WIND FARMS

Focus in this report is on Developing methods for long-term adjustment of operational production data and Developing methods for estimation of losses using the potential energy production during periods when the turbine is in a non-full performance state.

Full performance is defined as "The WTG is operative and generating according to design specifications with no technical restrictions or limitations which affect generation". A post-construction production assessment is especially valuable in refinancing and sales processes. But a post-construction annual energy production (AEP) estimation can also be used to update the long term internal budget for the wind farm. The methods developed to estimate the losses can also be used in the daily monitoring of the wind farm performance.