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Project memo

Hourly wind and solar energy time series from Reanalysis dataset

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ABSTRACT
This document gives a brief description of a method to generate hourly time series for wind power and solar power production for a number specified locations, using publicly available numerical weather model reanalysis data covering the period from 1950 until today.

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1 Introduction

This document gives a brief description of a method to generate hourly time series for wind power and solar power production for a number specified locations, covering the 65 year time period from 1950 to 2014. The primary purpose of the time series is to be used in simulations using the EMPS multi-area power market simulator where long term statistics are important. The time series represent average values for large geographical areas corresponding to countries or regions within countries.

The data source is the NCEP Reanalysis data provided by the NOAA/OAR/ESRL PSD, Boulder, Colorado, USA, from their Web site at http://www.esrl.noaa.gov/psd/ [4]. Data used are near surface level (0.995 sigma level) U-wind and V-wind values, and solar irradiation (beam and diffuse downward flux). For solar power, an alternative data source is NASA (global irradiation and clearness index).

2 Wind energy

2.1 Locations

Selected locations for the generation of wind energy time series are shown in Figure 1. Blue circles indicate Reanalysis data points, which are separated by 2.5 degrees both in latitude and longitude. Red squares indicate the selected points representing the various areas of interest.

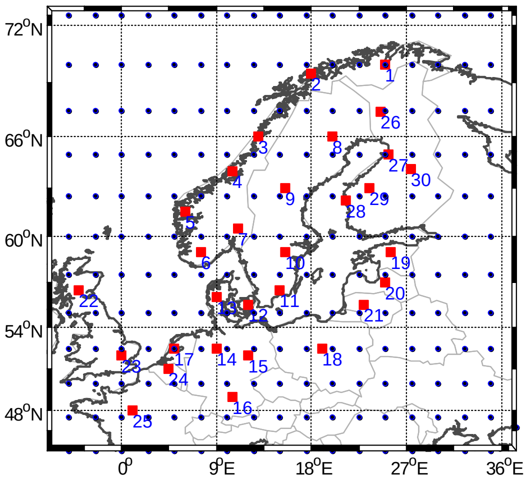


Figure 1: Locations selected for the generation of wind energy time series. Blue dots represent Reanalysis data points, and red squares represent selected points for power time series.

2.2 Method

2.2.1 Wind speeds

The Reanalysis dataset covers 1948–today, with a temporal resolution of 6 hours and a spatial resolution of 2.5 degrees in both latitude and longitude. To get wind speeds at the selected points (see Figure 1) a two-dimensional linear interpolation of neighbouring Reanalysis points has been applied. To get hourly time series for wind speed, a linear interpolation of the 6-hourly values has been applied. Wind speeds have further been adjusted with country specific tuning factors as explained below.

2.2.2 Wind power

Wind energy is computed from the wind speed using the same method as in the TradeWind project [2]. Since the wind speed is the average and smoothed out wind speed for a wide area, and because the wind energy output represents many wind turbines, a regional power curve is used for the computation of electric power. The regional power curve can be thought of as an average power curve for many wind turbines over a large geographical area. The power curve used in the computations is the average between the "present upland" and the "present lowland" curves used in TradeWind. The normalised power curve used is shown in Figure 2.

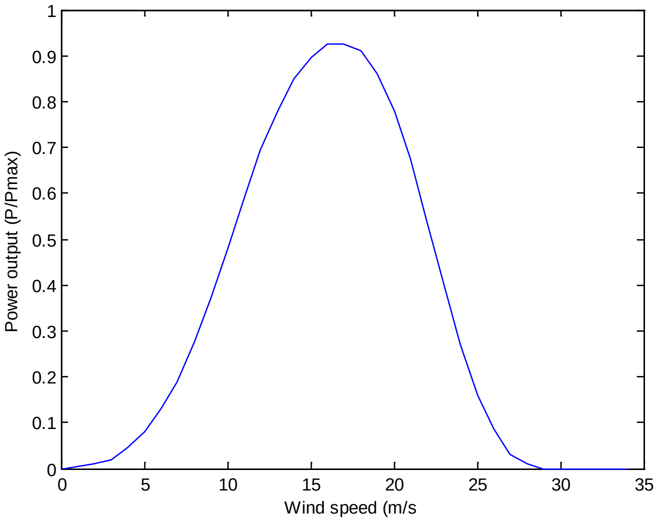
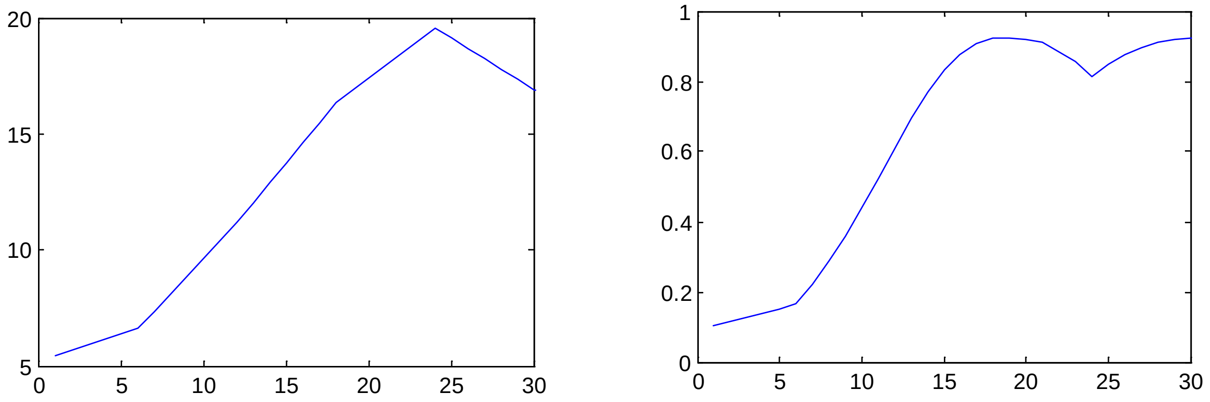


Figure 2: Regional power curve

Since a linear interpolation for wind speed is used to get hourly values from 6-hourly values, whereas the power has a non-linear relationship to wind speed, the wind power time series will vary non-linearly between the 6-hourly points. This is evident when inspecting the time series in detail (Figure 3). An alternative would be to compute the power for the 6-hourly points, and then interpolate power linearly. Linear interpolation of wind speeds was chosen since it preserves the average wind speed in the Reanalysis data set. However, in practice, the difference is minimal, especially since adjustment factors are used to scale the result. The effect is illustrated in Figure 3.



(a) Wind speed (b) Wind power

Figure 3: Extract of time series. Left plot shows wind speed (m/s), linearly interpolated from 6 hour to 1 hour time steps. Right plot shows normalised wind power computed using regional power curve.

2.2.3 Tuning

In most cases there is some deviation between the computed wind energy and the actual wind energy with this method. This is inevitable with such coarse data. More sophisticated methods to derive representative wind power series exist, but applying more refined methods is outside the scope of this work.

To correct for these discrepancies a constant scaling factor on the wind speed series has been used, such that historical capacity factors for 2011 were matched as close as possible. The capacity factor is the average generation divided by the rated capacity. Statistics for capacity factors have been found in [3]. The adjustment factors have been tuned in an iterative process, using 2011 as reference year. Table 1 shows the result of this process, with comparisons between historical values and computations. The match for 2011 is necessarily good, but the Table shows a good match in most cases also for 2010 and 2012, adding confidence to the approach.

Including these wind speed adjustment factors, the normalised power output from a wind region is given by

$$P = M(aU),$$

Where the function M is the power curve shown in Figure 2, U is the wind speed derived from the Reanalysis data, and a is the adjustment factor.

Table 1: Wind power capacity factors from EU statistics vs computation using Reanalysis data

		EU statistics			Calculation		
	adj_fac	2010	2011	2012	2010	2011	2012
BE	1.09	16.2	24.7	23.0	21.2	24.7	23.3
DE	1.20	15.9	19.2	18.5	17.5	19.2	18.5
DK	0.96	23.4	28.2	28.1	23.6	28.2	27.1
EE	1.21	29.3	23.3	18.6	18.6	23.3	21.4
FI	1.42	17.0	27.6	21.9	23.5	27.6	26.4
FR	1.10	18.9	20.6	22.6	20.8	20.6	22.2
LT	1.23	19.2	26.8	22.4	23.5	26.8	24.5
LV	1.13	18.6	22.5	22.0	17.4	22.5	20.0
NL	0.93	20.4	25.1	23.4	21.0	25.1	23.8
NO	1.07				22.1	30.0	27.0
PL	1.24	17.1	20.3	21.1	18.8	20.3	18.8
SE	1.12	19.8	25.0	22.7	20.3	25.0	22.6
UK	0.91	21.6	27.3	25.1	21.7	27.3	24.7

2.3 Characteristics of the results

The average capacity factors (power output relative to capacity) for the entire time series (1950 – 2014) is shown in Figure 4. If other capacity factors are desired, a simple approach is to scale the wind energy time series by the appropriate constant factors. The average wind speeds are given in Figure 5. The wind speed and power distributions for the different areas are shown in Figure 6. The correlation in wind speeds is shown in Figure 8. A value +1 means perfect correlation, zero means no correlation, and –1 means perfect anti-correlation.

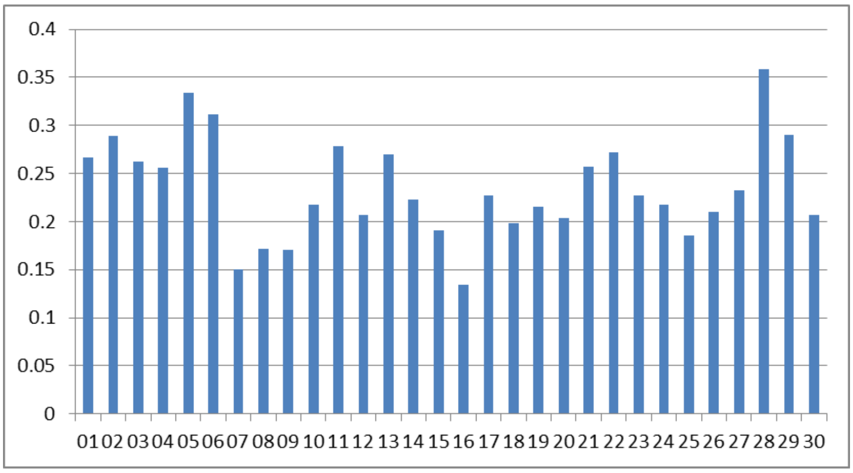


Figure 4: Computed capacity factors (average for entire time series) for all areas.

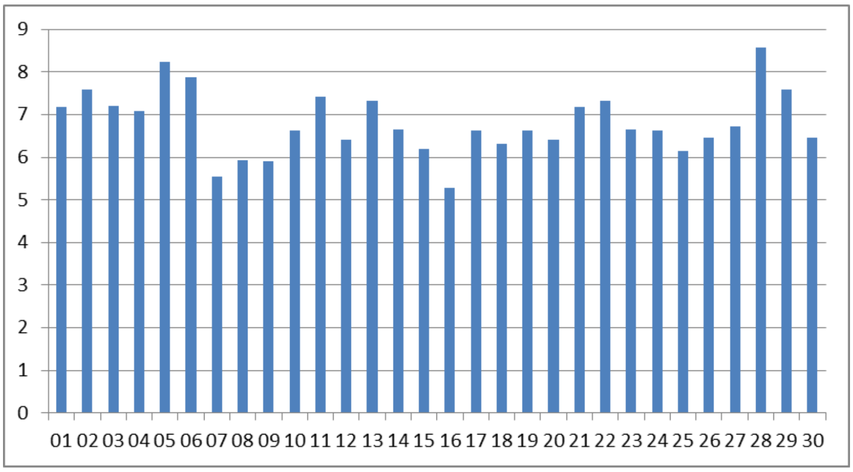


Figure 5: Average wind speeds (m/s) for all different areas

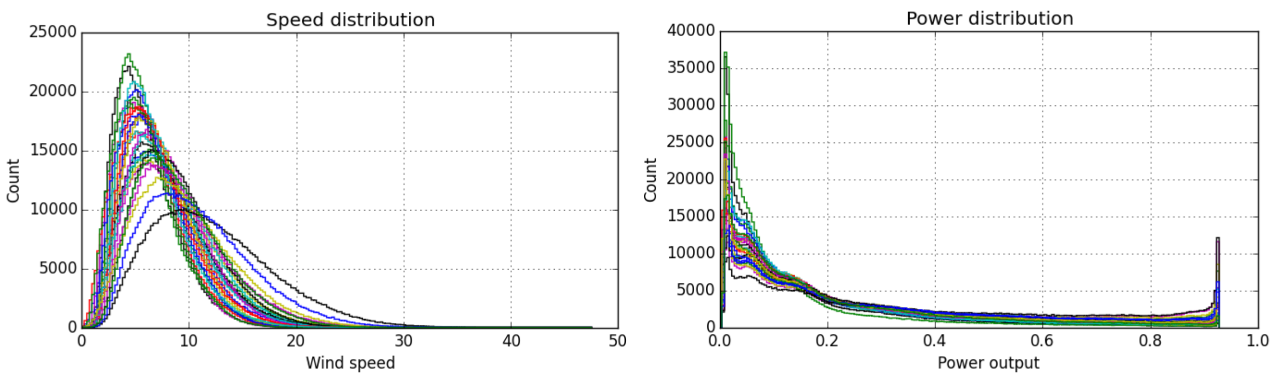


Figure 6: Wind speed (left) and power (right) distribution. Different curves per area.

	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
01	1	0.74	0.4	0.29	0.2	0.12	0.13	0.49	0.23	0.13	0.09	0.08	0.1	0.06	0.04	0.05	0.08	0.05	0.13	0.1	0.09	0.12	0.09	0.08	0.07	0.58	0.33	0.24	0.28	0.32
02	0.74	1	0.59	0.4	0.25	0.12	0.15	0.57	0.29	0.13	0.08	0.06	0.08	0.03	0.03	0.04	0.06	0.04	0.13	0.09	0.07	0.1	0.06	0.06	0.05	0.49	0.33	0.25	0.28	0.3
03	0.4	0.59	1	0.87	0.51	0.32	0.44	0.6	0.62	0.3	0.18	0.13	0.17	0.07	0.05	0.06	0.1	0.08	0.23	0.17	0.16	0.19	0.1	0.11	0.1	0.4	0.33	0.4	0.38	0.32
04	0.29	0.4	0.87	1	0.71	0.48	0.63	0.45	0.63	0.41	0.27	0.22	0.27	0.1	0.09	0.07	0.12	0.12	0.26	0.21	0.21	0.25	0.11	0.12	0.1	0.31	0.29	0.4	0.37	0.3
05	0.2	0.25	0.51	0.71	1	0.77	0.67	0.28	0.39	0.39	0.31	0.31	0.43	0.17	0.15	0.08	0.21	0.15	0.21	0.18	0.19	0.42	0.2	0.19	0.1	0.21	0.22	0.3	0.28	0.22
06	0.12	0.12	0.32	0.48	0.77	1	0.77	0.2	0.36	0.49	0.5	0.57	0.76	0.33	0.3	0.16	0.36	0.25	0.23	0.23	0.28	0.4	0.29	0.31	0.18	0.14	0.17	0.29	0.25	0.18
07	0.13	0.15	0.44	0.63	0.67	0.77	1	0.31	0.57	0.67	0.5	0.45	0.53	0.25	0.23	0.13	0.26	0.21	0.32	0.28	0.3	0.31	0.21	0.23	0.12	0.21	0.25	0.42	0.36	0.26
08	0.49	0.57	0.6	0.45	0.28	0.2	0.31	1	0.63	0.3	0.17	0.11	0.13	0.06	0.05	0.04	0.08	0.08	0.27	0.19	0.16	0.11	0.08	0.08	0.06	0.75	0.69	0.62	0.66	0.56
09	0.23	0.29	0.62	0.63	0.39	0.36	0.57	0.63	1	0.53	0.32	0.25	0.26	0.13	0.14	0.09	0.14	0.17	0.34	0.27	0.26	0.15	0.13	0.14	0.11	0.38	0.42	0.69	0.58	0.38
10	0.13	0.13	0.3	0.41	0.39	0.49	0.67	0.3	0.53	1	0.81	0.56	0.51	0.29	0.31	0.2	0.26	0.33	0.51	0.46	0.49	0.28	0.23	0.25	0.15	0.2	0.31	0.58	0.48	0.34
11	0.09	0.08	0.18	0.27	0.31	0.5	0.5	0.17	0.32	0.81	1	0.83	0.67	0.41	0.48	0.27	0.33	0.52	0.44	0.46	0.57	0.29	0.26	0.31	0.17	0.11	0.19	0.35	0.3	0.22
12	0.08	0.06	0.13	0.22	0.31	0.57	0.45	0.11	0.25	0.56	0.83	1	0.89	0.59	0.64	0.34	0.45	0.53	0.3	0.34	0.45	0.34	0.33	0.4	0.21	0.08	0.14	0.25	0.21	0.16
13	0.1	0.08	0.17	0.27	0.43	0.76	0.53	0.13	0.26	0.51	0.67	0.89	1	0.63	0.59	0.33	0.55	0.43	0.26	0.28	0.37	0.41	0.4	0.48	0.25	0.09	0.14	0.25	0.21	0.16
14	0.06	0.03	0.07	0.1	0.17	0.33	0.25	0.06	0.13	0.29	0.41	0.59	0.63	1	0.87	0.6	0.79	0.43	0.2	0.23	0.3	0.33	0.53	0.72	0.38	0.05	0.09	0.16	0.14	0.11
15	0.04	0.03	0.05	0.09	0.15	0.3	0.23	0.05	0.14	0.31	0.48	0.64	0.59	0.87	1	0.68	0.58	0.59	0.22	0.26	0.36	0.28	0.4	0.56	0.31	0.04	0.1	0.16	0.14	0.11
16	0.05	0.04	0.06	0.07	0.08	0.16	0.13	0.04	0.09	0.2	0.27	0.34	0.33	0.6	0.68	1	0.51	0.38	0.16	0.19	0.25	0.24	0.43	0.63	0.48	0.03	0.08	0.12	0.11	0.09
17	0.08	0.06	0.1	0.12	0.21	0.36	0.26	0.08	0.14	0.26	0.33	0.45	0.55	0.79	0.58	0.51	1	0.3	0.18	0.2	0.24	0.39	0.76	0.9	0.48	0.05	0.09	0.16	0.13	0.11
18	0.05	0.04	0.08	0.12	0.15	0.25	0.21	0.08	0.17	0.33	0.52	0.53	0.43	0.43	0.59	0.38	0.3	1	0.28	0.38	0.56	0.21	0.21	0.29	0.17	0.05	0.11	0.18	0.15	0.12
19	0.13	0.13	0.23	0.26	0.21	0.23	0.32	0.27	0.34	0.51	0.44	0.3	0.26	0.2	0.22	0.16	0.18	0.28	1	0.87	0.64	0.18	0.16	0.18	0.11	0.21	0.33	0.54	0.52	0.46
20	0.1	0.09	0.17	0.21	0.18	0.23	0.28	0.19	0.27	0.46	0.46	0.34	0.28	0.23	0.26	0.19	0.2	0.38	0.87	1	0.83	0.19	0.17	0.2	0.12	0.14	0.23	0.38	0.35	0.31
21	0.09	0.07	0.16	0.21	0.19	0.28	0.3	0.16	0.26	0.49	0.57	0.45	0.37	0.3	0.36	0.25	0.24	0.56	0.64	0.83	1	0.21	0.2	0.24	0.15	0.11	0.19	0.33	0.29	0.24
22	0.12	0.1	0.19	0.25	0.42	0.4	0.31	0.11	0.15	0.28	0.29	0.34	0.41	0.33	0.28	0.24	0.39	0.21	0.18	0.19	0.21	1	0.48	0.36	0.2	0.09	0.11	0.18	0.16	0.13
23	0.09	0.06	0.1	0.11	0.2	0.29	0.21	0.08	0.13	0.23	0.26	0.33	0.4	0.53	0.4	0.43	0.76	0.21	0.16	0.17	0.2	0.48	1	0.79	0.57	0.05	0.08	0.14	0.13	0.1
24	0.08	0.06	0.11	0.12	0.19	0.31	0.23	0.08	0.14	0.25	0.31	0.4	0.48	0.72	0.56	0.63	0.9	0.29	0.18	0.2	0.24	0.36	0.79	1	0.69	0.06	0.09	0.16	0.14	0.11
25	0.07	0.05	0.1	0.1	0.1	0.18	0.12	0.06	0.11	0.15	0.17	0.21	0.25	0.38	0.31	0.48	0.48	0.17	0.11	0.12	0.15	0.2	0.57	0.69	1	0.05	0.06	0.11	0.1	0.08
26	0.58	0.49	0.4	0.31	0.21	0.14	0.21	0.75	0.38	0.2	0.11	0.08	0.09	0.05	0.04	0.03	0.05	0.05	0.21	0.14	0.11	0.09	0.05	0.06	0.05	1	0.65	0.42	0.5	0.56
27	0.33	0.33	0.33	0.29	0.22	0.17	0.25	0.69	0.42	0.31	0.19	0.14	0.14	0.09	0.1	0.08	0.09	0.11	0.33	0.23	0.19	0.11	0.08	0.09	0.06	0.65	1	0.63	0.77	0.89
28	0.24	0.25	0.4	0.4	0.3	0.29	0.42	0.62	0.69	0.58	0.35	0.25	0.25	0.16	0.16	0.12	0.16	0.18	0.54	0.38	0.33	0.18	0.14	0.16	0.11	0.42	0.63	1	0.94	0.62
29	0.28	0.28	0.38	0.37	0.28	0.25	0.36	0.66	0.58	0.48	0.3	0.21	0.21	0.14	0.14	0.11	0.13	0.15	0.52	0.35	0.29	0.16	0.13	0.14	0.1	0.5	0.77	0.94	1	0.79
30	0.32	0.3	0.32	0.3	0.22	0.18	0.26	0.56	0.38	0.34	0.22	0.16	0.16	0.11	0.11	0.09	0.11	0.12	0.46	0.31	0.24	0.13	0.1	0.11	0.08	0.56	0.89	0.62	0.79	1

Figure 7: Correlation coefficients between wind speed time series for all locations

2.4 Output: Wind speed and energy time series

The wind speed and energy series are given as one text file each per area. Within each file, the first row corresponds to 1950-01-01 0000, the second row corresponds to 1950-01-01 0100, etc. The last row corresponds to 2014-12-31 2300. All years are considered to have 365 days (leap year days are discarded), that is, 8760 hours. Since the time series covers 65 years (1950-2014), there are therefore 65 × 8760 = 569 400 rows in the files.

The numbers give energy output in MWh/h per installed capacity in MW, and must therefore be scaled according to the correct numbers for installed capacity.

3 Solar energy

3.1 Locations

The locations selected for the generation of the solar energy time series are shown in Figure 1. Two-dimensional interpolation of the four neighbouring data points are used to get radiation data at specified locations. For the chosen points, this is equivalent to taking the average of the four neighbouring points.

3.2 Method

The computation of hourly solar energy time series presented here closely follows the method used by RETscreen and is described in detail in accompanying documentation [6].

Hourly values generated for this project give average values for the intervals 00:00–01:00, 01:00–02:00 etc. Time refers to UTC.

3.2.1 Geometry

The *declination* δ of the sun is the angular position of the sun at solar noon (i.e. maximum height) with respect to the plane defined by the equator (Figure 8). This angle (in radians) for a given day n of the year is approximately given by the following equation

$$\delta(n) = \frac{\pi}{180} 23.45 \ \sin\left(2\pi \frac{284 + n}{365}\right).$$

Here, $n = 1$ corresponds to 1st January. The declination is zero at vernal ($n = 81$) and autumnal ($n = 264$) equinox. See Figure 9.

The *solar zenith angle* (polar angle) θ_z is the angle of the sun from the zenith, and is given as

$$\cos\theta_z = \sin\psi \sin\delta + \cos\psi \cos\delta \cos\omega$$

where ψ is the latitude, and ω is the solar hour angle. Solar altitude $(90° - \theta_z)$ curves are plotted in Figure 7. The *solar hour angle* ω at a given hour h (measured in universal time) indicates the sun's azimuth position and is (Figure 8)

$$\omega(h) = \frac{\pi}{180}(15(h - 12) + \text{longitude}).$$

The hour angle increases 15 degrees per hour, and is zero at solar noon. The *sunset hour angle* ω_s at a given latitude ψ is the angle where the sun sets, which occurs when the solar zenith angle is 90 degrees, or equivalently, when $\cos\theta_z = 0$. Plugging this into the equation above gives

$$\cos\omega_s = -\tan\psi \tan\delta.$$

For high latitudes, it may be that the right hand side is more than one, which corresponds to midnight sun, or less than minus one, which corresponds to winter darkness. In these cases, the equation above cannot be solved and the sun is either always above or below the horizon.

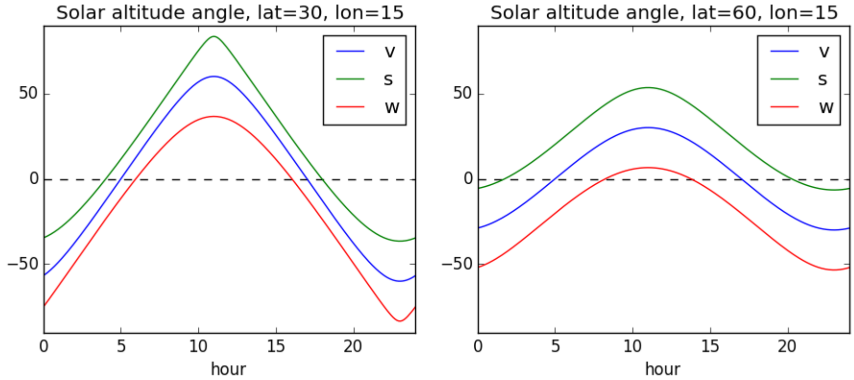


Figure 8: Solar altitude for different times of year and locations. Left: 30 degrees North, Right: 60 degrees North. v=vernal equinox, s=midsummer, w=midwinter.

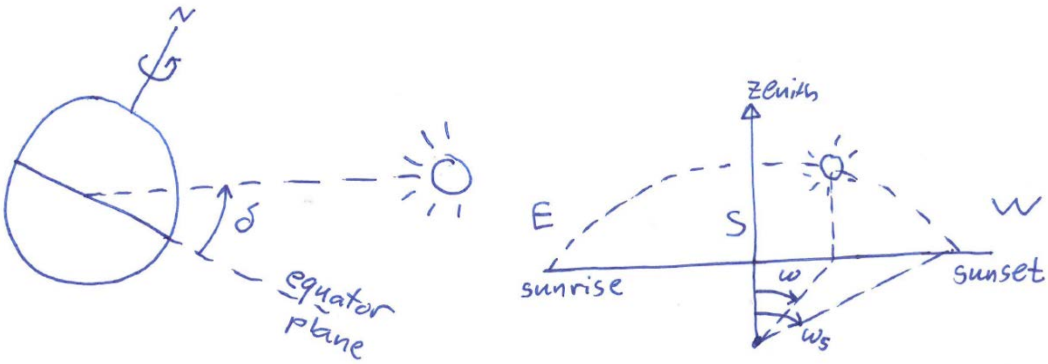


Figure 9: Declination angle (left) and solar hour angle (right)

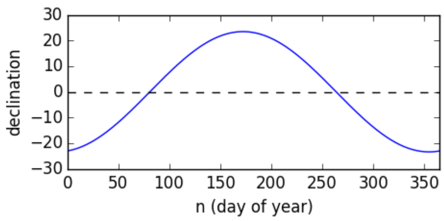


Figure 10: Declination change over the year

3.2.2 Daily solar irradiation data

Two sources providing daily radiation data may be used with this method. One is the Reanalysis dataset, and the other is a dataset from NASA.

3.2.2.1 Data from NCEP Reanalysis

Irradiation time series are based on NCEP Reanalysis data provided by the NOAA/OAR/ESRL PSD, Boulder, Colorado, USA, from their Web site at http://www.esrl.noaa.gov/psd/. [4] Variables used as input are the following daily average values:

- $\overline{H}_{b,v}$ = `vbdsf.sfc.gauss`: visible beam downward solar flux (W/m^2)
- $\overline{H}_{b,n}$ = `nbdsf.sfc.gauss`: near infrared beam downward solar flux (W/m^2)
- $\overline{H}_{d,v}$ = `vddsf.sfc.gauss`: visible diffuse downward solar flux (W/m^2)
- $\overline{H}_{d,n}$ = `nddsf.sfc.gauss`: near infrared diffuse downward solar flux (W/m^2)

The Reanalysis dataset covers 1948–today with a spatial resolution of 1.875° in longitude (0E to 358.125E) and approximately 1.904° in latitude (88.542N to 88.542S)[1]. In total, there are 192 x 94 data points. The coordinate system is based on Gaussian latitude, so the latitude points are not evenly spaced. The dataset provides average irradiation data (in units W/m^2) on a horizontal surface for each day. Days are separated according to midnight universal time (UTC).

Visible and near infrared irradiation is added and multiplied by 24 hours to give daily beam, diffuse, and global irradiation used in the subsequent calculations,

$$\overline{H}_b = 24\mathrm{h}\times(\overline{H}_{b,v} + \overline{H}_{b,n}),$$
$$\overline{H}_d = 24\mathrm{h}\times(\overline{H}_{d,v} + \overline{H}_{d,n}),$$
$$\overline{H} = \overline{H}_b + \overline{H}_d.$$

3.2.2.2 Data from NASA

An alternative set of input data is provided by NASA [5]. Instead of global and diffuse radiation, this dataset provides daily global irradiation and clearness index.

- Clearness index: the fraction of solar radiation at the top of the atmosphere that reaches the surface of the earth.
- $\overline{H}$ = global solar radiation on a horizontal surface at ground level (kWh/m^2/day)

These data series contain values from 1 January 1984 until 31 December 2005. The data series are based on a combination of measurements and meteorological models, and the given quantities refer to averaged values over an area of 1 degree in east-west direction and 1 degree in north-south direction. A given area is referred to by the southwest corner. E.g. data for 35°N / 10°E gives the averaged value for the area 35-36°N / 10-11°E. Moreover, the data are daily averages, using midnight local time to separate one day from the other.

The daily diffuse radiation is approximated using the *Erbs* factor ε:

$$\varepsilon = \begin{cases} 1.391 - 3.560k + 4.189k^2 - 2.137k^3, & \omega_s < 81.4° \\ 1.311 - 3.022k + 3.427k^2 - 1.821k^3, & \omega_s \geq 81.4° \end{cases}$$

Given the *Erbs* factor, the daily diffuse radiation is approximated as

$$\overline{H}_d = \varepsilon\overline{H}$$

If the clearness index is outside the interval [0.3, 0.8] then this approximation is poor.

3.2.3 From daily to hourly values

A daily profile is computed from the obtained daily average values, considering time of year, time of day, and latitude and longitude.

[1] For detailed information about the Reanalysis dataset variables, see http://rda.ucar.edu/datasets/ds090.0/#metadata/detailed.html.

Define the *Collares-Pereira-Rabl* (CPR) factor f_{cpr} and the parameters a and b as follows:

$$f_{cpr}(h) = \begin{cases} 0, & \omega > \omega_s \\ 0, & \omega < -\omega_s \\ \dfrac{\cos\omega - \cos\omega_s}{\sin\omega_s - \omega_s\cos\omega_s}, & \text{otherwise} \end{cases}$$

$$a = 0.409 + 0.5016\sin\left(\omega_s - \frac{\pi}{3}\right)$$
$$b = 0.6609 - 0.4767\sin\left(\omega_s - \frac{\pi}{3}\right)$$

The ratios of hourly to daily total global radiation r_t and hourly to daily total diffuse radiation r_d are then given by the empirical expressions [6][7]:

$$r_t(h) = \frac{\pi}{24}(a + b\cos\omega)f_{cpr}$$
$$r_d(h) = \frac{\pi}{24}f_{cpr}$$

Then the hourly global radiation H, diffuse irradiation H_d and beam radiation H_b at a particular hour of the day is

$$H(h) = r_t(h)\bar{H},$$
$$H_d(h) = r_d(h)\bar{H}_d,$$
$$H_b(h) = H - H_d.$$

This approximation may give negative beam radiation close to sunrise/sunset if diffuse radiation is large compared to beam radiation. To avoid this, negative values are afterwards replaced by zero, and the daily beam radiation profile is scaled up to give a daily sum equal to $\bar{H}_b$. Curves illustrating the daily variation of diffuse radiation are shown in Figure 10. The difference between summer and winter is bigger at high latitudes. The above approximate expression may in some cases close to sunrise/sunset give negative beam radiation H_b. If this happens, it is set to zero.

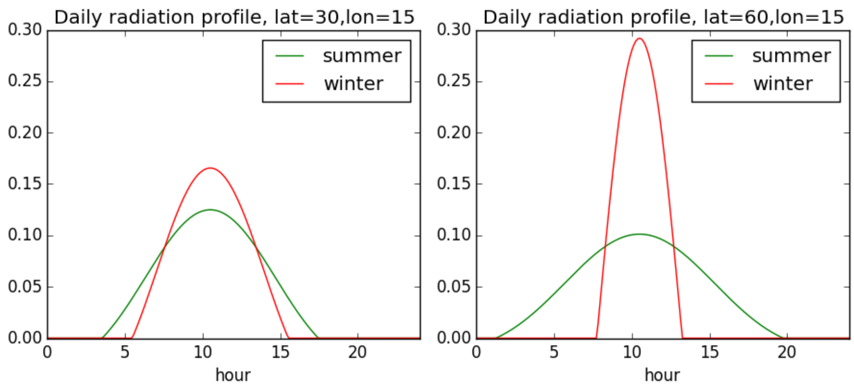


Figure 11: Daily radiation profile on horizontal surface for different latitudes and times of year. Note that these curves are normalised profiles and do not say anything about total radiation.

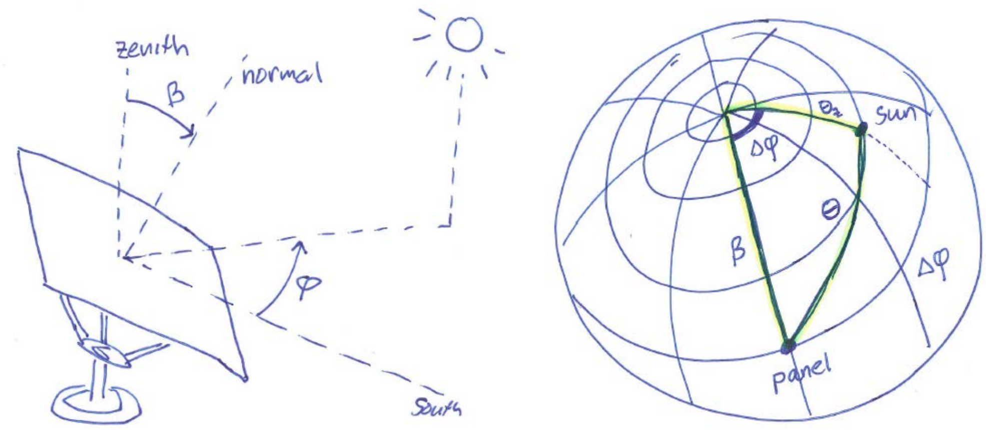


Figure 12: Slope and azimuth of tilted surface (left), and spherical coordinates (right)

3.2.4 Radiation on tilted surface

Assume that the PV panel is tilted with a certain slope β and pointing towards a certain azimuth angle φ, see Figure 11. The slope is defined as the angle between the panel's normal direction and the vertical line. The azimuth angle is the east–west angle with zero corresponding to the south. The difference between the azimuth angle of the panel and the azimuth angle of the sun (solar hour angle) is denoted $\Delta\varphi$.

Tracker system

- 2-axis tracking: $\beta = \theta_z$, $\Delta\varphi = 0$
- Azimuth tracking: $\beta = \text{fixed}$, $\Delta\varphi = 0$
- South-facing panel: $\beta = \text{fixed}$, $\Delta\varphi = \omega$

The incidence angle θ is the angle between the PV panel's normal direction and the direction towards the sun. Using the spherical cosine law (see Figure 11 right), it can be expressed in terms of slope, solar zenith angle and azimuth angles as

$$\cos\theta = \cos\theta_z \cos\beta + \sin\theta_z \sin\beta \cos\Delta\varphi$$

The ratio of beam radiation onto the PV panel relative to radiation on a horizontal surface is approximately given by the incidence angle and the solar zenith angle as

$$R_b = \begin{cases} 0, & \cos\theta < 0 \\ \dfrac{\cos\theta}{\cos\theta_z}, & \text{otherwise.} \end{cases}$$

Hourly irradiance (per area) on the tilted PV plane is approximated by an isotropic model that gives

$$H_{PV}(h) = R_b H_b + H_d \frac{(1+\cos\beta)}{2} + (H_b + H_d)\rho \frac{(1-\cos\beta)}{2},$$

where ρ is the ground albedo. The first term corresponds to direct radiation, the second to diffuse radiation, and the third to radiation reflected from the ground. Examples of daily radiation profiles on a tilted PV panel are shown in Figure 12, and the influence of different tracker systems is illustrated in Figure 13. Azimuth tracking (tracker1) allows better energy capture in the morning and evening, while two-axis tracking (tracker2) gives optimal energy capture at all times.

Because the computation of hourly radiation profile uses some approximations, a small error is introduced. This is corrected for by scaling the hourly radiation values such that the daily sum of radiation on a horizontal surface equals the value provided from the input dataset.

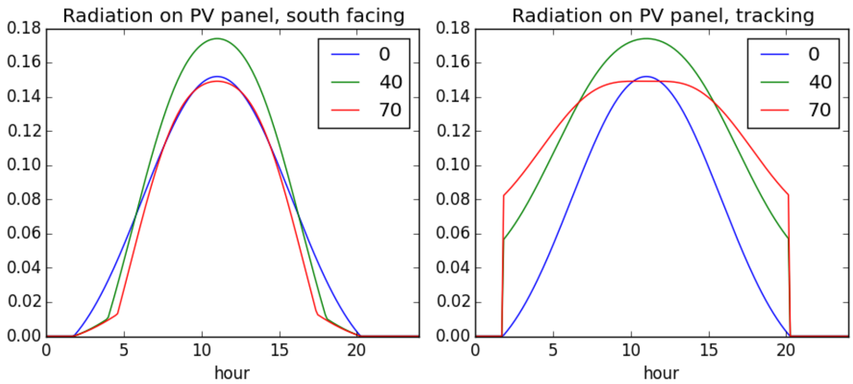


Figure 13: Daily radiation profile on south-facing panels (left) and azimuth-tracking panels (right) for different fixed panel slopes (zero corresponds to a horizontal panel). Parameters: lat=60, lon=15, albedo=0.2, Hb=1, Hd=0.5.

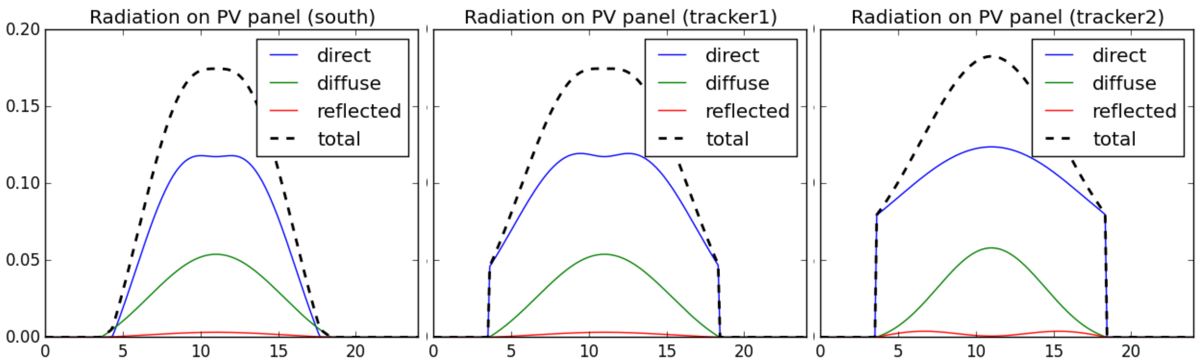


Figure 14: Radiation components on tilted PV surface for different tracker systems. Parameters: lat=40, lon=15, albedo=0.2, Hb=1, Hd=0.5, slope=35 degrees.

3.2.5 Power generation

The power generation per PV area is given as

$$p(h) = \eta_{PV}\eta_{el}H_{PV}(h)$$

where η_{PV} is the PV panel conversion efficiency from radiation to electrical power, and η_{el} is the efficiency of the electrical system. These factors depend on the properties of the PV panel and PV plant:

- *Photovoltaic conversion efficiency* (η_{PV}): this factor specifies how much of the solar radiation reaching the solar panel is converted to electric power (DC side). A value of e.g. 15 % means that at 1000 W/m2 solar radiation, the panel generates 150 W/m^2 of power.
- *Electrical efficiency factor* (η_{el}): this factor specifies how much of the generated power in the PV panel reaches the grid, i.e. is not lost in electrical cables, inverter and transformer.

The nominal capacity of a PV panel is defined based on standard test conditions, which is defined as 1000 W/m^2 at a temperature of 25 °C and air mass 1.5. As the actual solar radiation in very good sites may be larger than 1000 W/m^2, the generated power may therefore exceed the rated capacity. The PV panel conversion efficiency may therefore be written

$$\eta_{PV} = \frac{\text{capacity}}{1000\frac{\mathrm{W}}{\mathrm{m}^2}\times\text{area}}.$$

Instead of panel conversion efficiency and area, it is more convenient to use panel capacity as an input parameter, and express total PV panel electrical power output as

$$P(h) = \eta_{el} H_{PV}(h) \frac{\text{capacity}}{1000\frac{\mathrm{W}}{\mathrm{m}^2}}.$$

3.3 Solar energy time series

For the generation of time-series, the locations show in in Figure 1. Data from NCEP Reanalysis has been used. Ground albedo has been assumed to be $\rho = 0.2$. All PV panels are assumed south-facing with a fixed slope determined by the latitude as follows[2]:

$$\text{slope} = \begin{cases} 0.87\times\text{latitude}, & \text{latitude} < 25° \\ 0.76\times\text{latitude} + 3.1°, & \text{latitude} \geq 25° \end{cases}$$

The slope angle is defined such that zero slope corresponds to a horizontal panel, and 90 degrees slope corresponds to a vertical panel.

3.3.1 Tuning

As with the wind power time series, there may be a significant discrepancy between the computed solar energy and the actual solar energy produced in an area with this direct method. This is inevitable with such coarse data and simplified approach.

To correct for such discrepancies, the efficiency factors may be adjusted up or down to get a realistic relationship between installed capacity and annual energy production. This relationship is usually expressed in terms of the capacity factor, which is the ratio between average generation divided by the rated capacity.

In the present case, the efficiency factors have been adjusted using 2013 as reference year [8]. Table 1 shows the result of this process, with comparisons between historical values and computations. The match for 2013 is necessarily good, but the Table shows a good match in most cases also for 2012. In cases where statistical data is unavailable, an adjustment factor equal to the average of the other adjustment factors has been used. This average is 0.87.

Adjustment factors are in most cases significantly less than 1.0, indicating that the method overestimates PV power production. Note that system losses of 25.6 % have already been assumed according, so electrical losses in the PV array have been accounted for.

[2] The guidelines at http://www.solarpaneltilt.com/ for fixed tilt angle is used.

Table 2: Solar power capacity factors from EU statistics vs computation using Reanalysis data, after introducing adjustment factor to get a good match for 2013.

	adj factor	EU Statistics 2012	2013	Computed 2012	2013
AT	0.92	0.101	0.139	0.139	0.138
BE	0.78	0.121	0.108	0.105	0.108
CH	0.87			0.133	0.131
DE	0.74	0.104	0.103	0.101	0.102
DK	0.95	0.054	0.117	0.112	0.117
ES	1.21	0.226	0.212	0.218	0.213
FI	0.87			0.090	0.091
FR	0.82	0.135	0.125	0.127	0.125
HR	0.87	0.000	0.000	0.143	0.138
IT	0.89	0.148	0.142	0.145	0.141
LT	0.87			0.102	0.106
NO	0.87			0.098	0.100
PL	0.87			0.119	0.120
RO	0.74	0.000	0.112	0.115	0.112
SE	0.87			0.097	0.104
UK	0.77	0.117	0.101	0.097	0.101

3.3.2 Characteristics

The average capacity factors for the entire time series (1950 – 2014) are shown in Figure 4 for all locations. If other capacity factors are desired, a simple approach is to scale the energy time series by the appropriate constant factors. The average irradiation on a horizontal surface are given in Figure 5. Examples of computed daily power output are shown in Figure 16. Maximum output occurs at about 1100 UCT, which is as expected for a location in Central Europe.

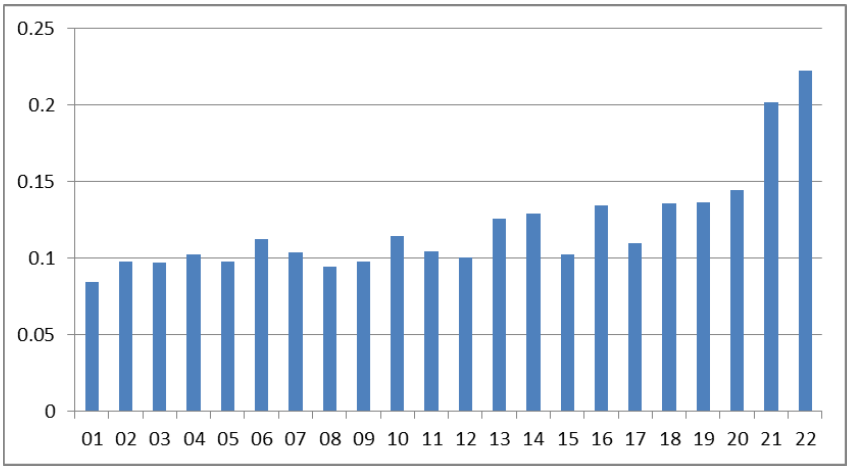


Figure 15: Computed capacity factors (average for entire time series) for all areas.

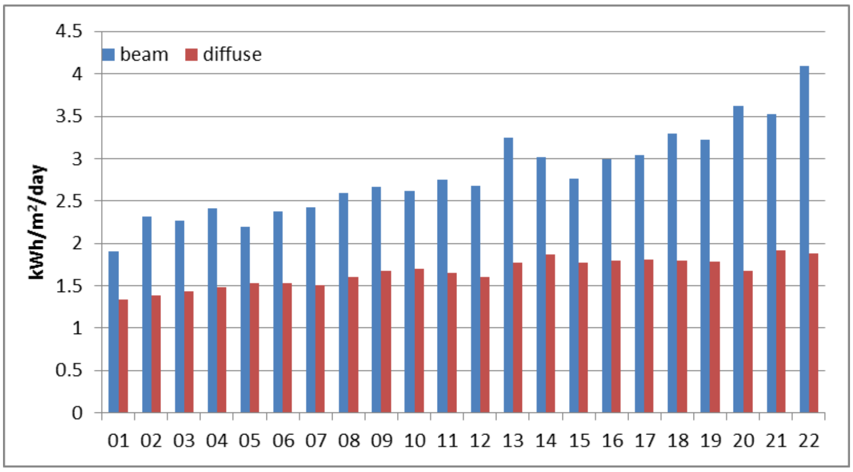


Figure 16: Average daily irradiation on horizontal surface for all areas

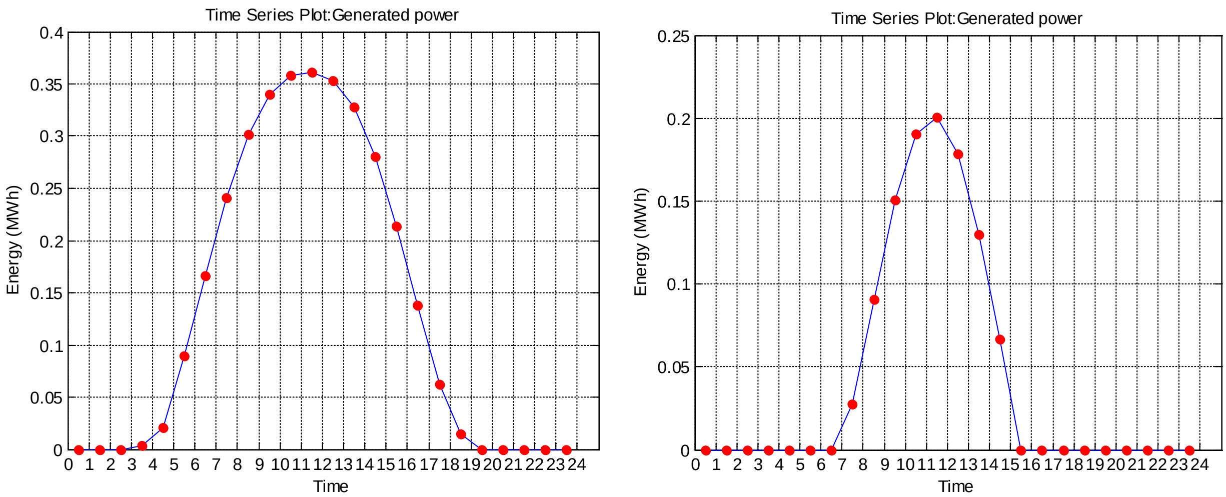


Figure 17: Two examples of power generation in area 15, on day 1 (winter) and day 172 (summer)

The correlation coefficients between solar power time series for the various locations is shown in Figure 17. A value of +1 means perfect correlation, zero means no correlation, and –1 means perfect anti-correlation. Because of the common diurnal variation, the timeseries are generally highly correlated.

	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	22
01	1	0.94	0.91	0.9	0.89	0.88	0.92	0.87	0.86	0.88	0.84	0.8	0.77	0.83	0.84	0.85	0.85	0.85	0.83	0.85	0.75	0.71
02	0.94	1	0.96	0.95	0.93	0.92	0.98	0.92	0.92	0.93	0.89	0.85	0.83	0.88	0.9	0.91	0.91	0.91	0.89	0.91	0.81	0.77
03	0.91	0.96	1	0.99	0.97	0.96	0.96	0.96	0.95	0.94	0.94	0.9	0.89	0.93	0.94	0.93	0.9	0.92	0.92	0.93	0.87	0.84
04	0.9	0.95	0.99	1	0.97	0.98	0.95	0.97	0.96	0.95	0.95	0.92	0.91	0.94	0.95	0.94	0.9	0.92	0.93	0.94	0.89	0.86
05	0.89	0.93	0.97	0.97	1	0.97	0.93	0.96	0.94	0.92	0.95	0.93	0.91	0.93	0.94	0.93	0.88	0.9	0.92	0.92	0.89	0.87
06	0.88	0.92	0.96	0.98	0.97	1	0.93	0.99	0.97	0.94	0.97	0.94	0.93	0.95	0.96	0.94	0.89	0.92	0.94	0.94	0.91	0.89
07	0.92	0.98	0.96	0.95	0.93	0.93	1	0.93	0.93	0.95	0.9	0.85	0.84	0.9	0.91	0.92	0.92	0.92	0.91	0.92	0.82	0.78
08	0.87	0.92	0.96	0.97	0.96	0.99	0.93	1	0.99	0.95	0.98	0.94	0.94	0.97	0.98	0.96	0.9	0.93	0.95	0.95	0.92	0.9
09	0.86	0.92	0.95	0.96	0.94	0.97	0.93	0.99	1	0.96	0.97	0.92	0.93	0.97	0.99	0.98	0.92	0.94	0.96	0.96	0.92	0.89
10	0.88	0.93	0.94	0.95	0.92	0.94	0.95	0.95	0.96	1	0.93	0.88	0.88	0.94	0.95	0.97	0.95	0.96	0.95	0.95	0.87	0.83
11	0.84	0.89	0.94	0.95	0.95	0.97	0.9	0.98	0.97	0.93	1	0.95	0.96	0.97	0.98	0.95	0.88	0.91	0.94	0.94	0.94	0.92
12	0.8	0.85	0.9	0.92	0.93	0.94	0.85	0.94	0.92	0.88	0.95	1	0.96	0.94	0.93	0.91	0.82	0.87	0.92	0.9	0.95	0.95
13	0.77	0.83	0.89	0.91	0.91	0.93	0.84	0.94	0.93	0.88	0.96	0.96	1	0.96	0.95	0.93	0.83	0.88	0.93	0.92	0.98	0.95
14	0.83	0.88	0.93	0.94	0.93	0.95	0.9	0.97	0.97	0.94	0.97	0.94	0.96	1	0.99	0.98	0.9	0.94	0.97	0.96	0.95	0.93
15	0.84	0.9	0.94	0.95	0.94	0.96	0.91	0.98	0.99	0.95	0.98	0.93	0.95	0.99	1	0.98	0.91	0.94	0.96	0.96	0.93	0.91
16	0.85	0.91	0.93	0.94	0.93	0.94	0.92	0.96	0.98	0.97	0.95	0.91	0.93	0.98	0.98	1	0.94	0.97	0.98	0.97	0.92	0.89
17	0.85	0.91	0.9	0.9	0.88	0.89	0.92	0.9	0.92	0.95	0.88	0.82	0.83	0.9	0.91	0.94	1	0.97	0.93	0.94	0.82	0.79
18	0.85	0.91	0.92	0.92	0.9	0.92	0.92	0.93	0.94	0.96	0.91	0.87	0.88	0.94	0.94	0.97	0.97	1	0.96	0.97	0.87	0.84
19	0.83	0.89	0.92	0.93	0.92	0.94	0.91	0.95	0.96	0.95	0.94	0.92	0.93	0.97	0.96	0.98	0.93	0.96	1	0.98	0.93	0.91
20	0.85	0.91	0.93	0.94	0.92	0.94	0.92	0.95	0.96	0.95	0.94	0.9	0.92	0.96	0.96	0.97	0.94	0.97	0.98	1	0.91	0.88
21	0.75	0.81	0.87	0.89	0.89	0.91	0.82	0.92	0.92	0.87	0.94	0.95	0.98	0.95	0.93	0.92	0.82	0.87	0.93	0.91	1	0.98
22	0.71	0.77	0.84	0.86	0.87	0.89	0.78	0.9	0.89	0.83	0.92	0.95	0.95	0.93	0.91	0.89	0.79	0.84	0.91	0.88	0.98	1

Figure 18: Correlation coefficients between solar power timeseries for different locations

3.4 Output: PV power production and irradiation timeseries

The solar power timeseries are provided as a single CSV file with one column per area. The first row indicates which area the column represents (01-22). The values give energy output per hour (MWh/h) relative to installed capacity (MW), and must therefore be scaled according to the correct numbers for installed capacity.

Irradiation on horizontal surface (beam and diffuse) are likewise provided as two CSV files with one column per area. One file is for diffuse irradiation and one is for beam radiation. These give irradiation in kWh/m^2/h.

The first data row (second line in the files) corresponds to 1950-01-01 0000-0100 UTC, the second row corresponds to 1950-01-01 0100-0200, etc. The last row corresponds to 2014-12-31 2300-2400. All years are considered to have 365 days (leap year days are removed), that is, 8760 hours. Since the time series covers 65 years (1950-2014), there are therefore 65 × 8760 = 569 400 rows in the files.

4 References

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