Comparative Study on Wind Power using Meteorological Data and Wind Turbine Output at Ashogoda Village, Northern Ethiopia

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Abstract: The power efficiency of a wind turbine may be influenced by several parameters such as wind speed and type and age of the turbine and its accessories. This study was conducted at Ashogoda village to compare the theoretically predicted power from the wind speed of Ashogoda area with electrical power generated from the wind turbines. Daily data of 10-minute intervals of six months were obtained from the company but data of two months were excluded because they were incomplete. The data were analyzed and comparisons of different parameters were made for fifteen turbines that had full data over the four months. Both wind and turbine powers showed diurnal variability that was difficult to predict. Variability between days over the four months showed some kind of cyclic patterns with one major peak and two minor peaks every 33±4 days but consecutive peaks occurred every 3-7 days. Both turbine power output and the power coefficient were nearly 25% (250 kW output for a 1 MW rated turbine) thereby limiting the rated power to 20-30%. The efficiency of the output power decreased with increasing wind speed possibly due to high friction loss at high wind speeds. The variability among the turbines was low and none of them revealed efficiency in excess of 27%. The efficiency of the turbines claimed by the company (38%) exceeded the average actual efficiency (~25%) by about 34%.

Keywords: Turbine Power; Wind Power; Wind Power Coefficient; Wind Power Variability

1. Introduction

Renewable energy currently is a minor contributor to the energy supply all over the world. In eastern and southern Africa it accounts for less than two percent of the total energy supply (Dalelo, 2009). However, its potential in relation to the decentralized energy needs of the rural population and its environmentally friendly nature makes it an attractive option for meeting the future energy needs of the region (Karekezi and Ranja, 1997).

Wind is one example of renewable energy sources. The use of wind as a source of power has a long history but it is only recently that the interest in wind power has revived (Goever, 1974) because of environmental concern and due to the gradual decline in the amount and hence the rise in prices of conventional energy sources (EWEA, 2009).

Wind turbines now are typically more powerful than early versions and employ sophisticated materials, electronics and aerodynamics. Costs have also declined, making it more competitive with other power generation options (Patel, 2006). But areas suitable for wind power generation depend on wind persistence, which is linked with a measure of the duration of wind speed to stay above a critical limit for an extended period of time (Blankenhorn and Resch, 2014).

Ethiopia has vast energy resources (Hydro, solar, wind, geothermal, biomass, etc.), some of which have not been fully developed. The country is also spending a substantial amount of foreign currency for the purchase of conventional energy sources particularly, petroleum oil (Birouke *et al.,* 2012). Hence, it is strongly recommended that the country should put emphasis on renewable energy resources to meet the challenge of the current as well as the future generations.

Today's power industry in Ethiopia has many challenges. Examples of such challenges include grid systems that are getting older, less efficient and thus are unreliable. The other challenge is the inability of grid systems to fully meet the power needs of the country and especially, their inability to reach the rural areas. These challenges necessitate the need for other sustainable energy sources among which wind energy is one that can meet the current technological and industrial needs.

Wind speed generally decreases as one move from higher latitudes towards the equator (Rai, 2007). The wind energy at higher altitude gets stronger as the latitude increases (i.e., as the area decreases flow of energy density increases). However, local effects like presence of geographic structures such as mountains, valleys and coastal areas can significantly enhance wind speed. Ethiopia being located close to the equator, has limited wind resource potential except for areas located close to the valleys especially the Rift Valleys that are identified as high wind resource areas. Ashogoda village in Tigray region is one such area that can potentially be influenced by the triple junction (Nubian, Arabian and Somali plates) or the Danakil depression (intersection

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of the Red Sea Rift and the East African Rift). Because of its location suitability for wind farm and its accessibility, it has attracted companies with the interest in wind farm. But, selecting sites for wind farm is far more than location suitability. It involves technical, physical, economic, social and environmental requirements (Woldeghiorgis, 1998). Persistence of the wind on hourly, daily and monthly bases has to be known to assure economic viability of this resource. The question of whether the theoretical wind power estimated from the wind speed of an area is close to the practically measured value of electrical energy generated from wind turbines is also a point of interest. The objective of this work is to assess daily and monthly performance of Ashogoda wind farm and to compare the actual electrical power generated from the wind turbines installed in the area, based on the actual efficiency of the electrical energy output, with the theoretical efficiency claimed or predicted by the company.

2. Materials and Methods

2.1. Description of the Study Area

Tigray is one of the National Regional States of Ethiopia, which is located in the north-eastern part of the country, between 12^{o} 15' N and 14^{o} 57' N latitude and 36^{o} 27'E and 39^{o} 59'E longitude and covers an area of 53,000 square kilometers (Solomon, 2005). The study was conducted in Enderta of Ashogoda village district (the wind farm site) of the Tigray region (Figure.1) located at 13^{o}28' North Latitude and 39^{o}29' East Longitude. The altitude of the district ranges between 1500 and 2300 meter above sea level. Similarly, the average annual rainfall and temperature of the district are 553 mm and 21^{o}C, respectively (EDARDO, 2011).

2.2. Data Source and Data Collection

The primary data used in this study were obtained from Ashogoda Wind Power Generation Company. Data types included day time and night time powers generated by the turbines during the study period (six months). However, data of the first two months were incomplete and not used in the study. Electricity powers generated every day were electronically recorded by the company every ten minutes over the study period. Hourly wind speeds of the corresponding data were also obtained from the meteorological station closest to the site, at the turbine height. Additional information such as turbine blade diameter, blade height, and company efficiency of the turbine, generator and other accessories, and the combined efficiency were obtained from the company (Table 1).

Table 1. Information obtained from the Wind Farm Company.

Company data on	Quantity
Turbine blade height	70 m
Blade diameter	62 m
Cut-in wind speed	3 m/s
Cut-out wind speed	25 m/s
Rated wind speed	15 m/s
Turbine efficiency	40-45%
Generator efficiency	97%
Mechanical efficiency	97%
Overall efficiency	38%

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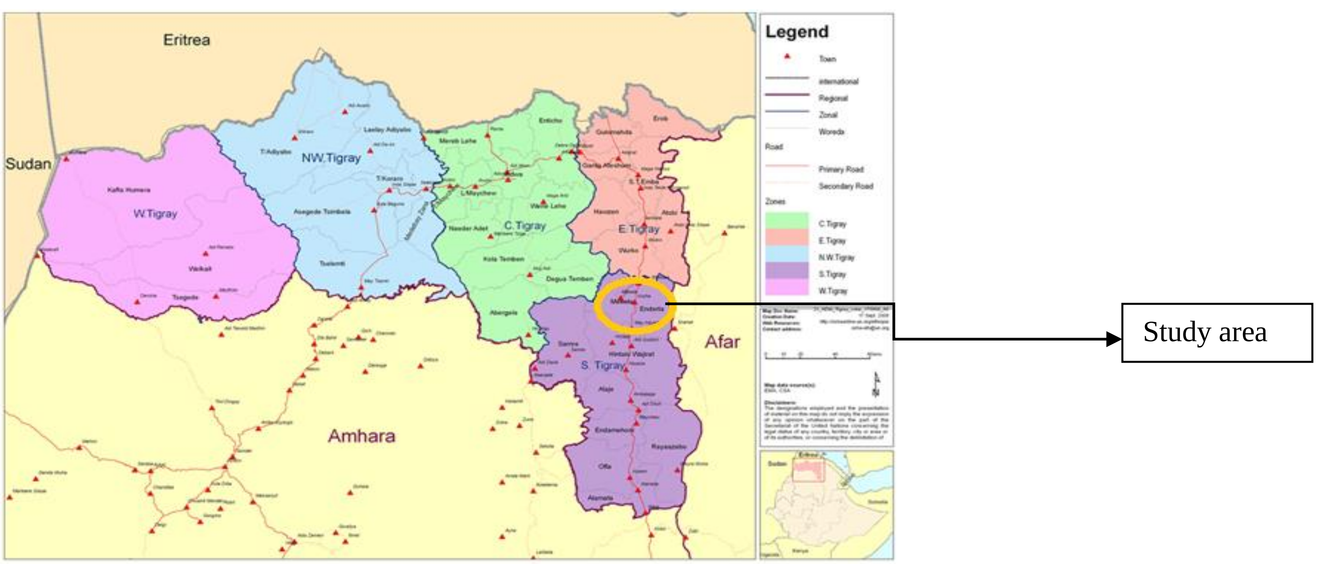

Figure 1. Map of the study site.
Source: OCHA, 2008

2.3. Method of Data Analysis

Under this sub-section, first, mathematical methods necessary to organize the data were explained. The data were then analyzed starting from hourly to daily wind patterns using smooth curve fitting. In order to find the link between calculated wind powers to the amount of electrical power produced, three polynomial (linear, quadratic and cubic) fits were used. The fits were compared using descriptive statistics, like mean, standard deviation, CV, RMSE, and R^2.

Wind velocity is the most prominent factor for deciding the power available in the wind due to its cubic relationship with power (Rai, 2007). Hence, selecting the right site plays a vital role in the success of wind power projects. Using the average annual wind speed alone in the power equation would not give the right results since such a calculation produces results that differ from the actual wind power by a factor of two or more (Ramos, 2005). The reason for this is that the average speed includes wind speeds above the cut-out as well as below the cut-in that do not result in energy production. It is the wind speed above the cut-in and below the cut-out that contributes to the power. Wind power is the rate of change of the kinetic energy of the wind calculated from wind speed as

$$P = \frac{dE}{dt} = \frac{1}{2} v^2 \frac{dm}{dt} \qquad .1$$

Where, $\frac{dm}{dt} =$ *wind mass flow rate*

The wind mass flow rate in turn is given by:

$$\frac{dm}{dt} = \rho A \frac{dx}{dt} = \rho A v \qquad .2$$

Where ρ is the air density, v is the wind speed and A, the cross- sectional area of the turbine through which the wind passes. Hence,

$$P = \frac{1}{2} \rho A v^3 \qquad 3$$

When this wind speed is converted into wind power, there is a theoretical limit above which wind power cannot be extracted. This limit first computed by Albert Betz is $\frac{16}{27}$ (59.3%) (Mathew, 2006). It implies that only roughly 60% of the kinetic energy of the wind can be converted into mechanical energy (useful work that is capable of rotating a rotor). This value is considered as the maximum efficiency of the turbine ($\eta_{t,max}$) in the conversion of wind power to mechanical power. The theory in general shows the maximum possible energy conversion efficiency by any device in any free-flowing fluid stream, under ideal conditions.

Wind turbines cannot operate at this maximum efficiency. The practical (η_t) value is much less and is unique to each turbine type and is also a function of wind speed that the turbine is operating at. Various engineering requirements of a wind turbine such as strength and durability are incorporated and the real world limit does not exceed 48% even in the best designed wind turbines (*netzeroguide.com, 2012/2013).* When other factors such as the gearbox, bearings, and generator and so on are taken into consideration, only 10-30% of the power of the wind is actually converted into usable electricity (Mathew, 2006). This value is called power coefficient or coefficient of performance (C_p) and has to be factored in equation (3) such that the extractable power from the wind is given by:

$$P_{avail} = \frac{1}{2} \rho A v^3 C_p \qquad 4$$

The swept area of the turbine (A) can be calculated from the diameter (D) of the turbine blades using equation

$$A = \pi \left(\frac{D}{2}\right)^2 \qquad 5$$

such that,

$$P_{avail} = \frac{1}{8} \rho \pi D^2 v^3 C_p \qquad 6$$

Hence, available wind power is directly proportional to the cube of wind speed and square of blade diameter. Air density is estimated using atmospheric parameters such as air temperature (T) measured in Kelvin (K) and atmospheric pressure (P) measured in Pascal (Pa) (Patel, 2006) as

$$\rho = \frac{P}{RT} \qquad 7$$

R is the gas constant and is equal to 287 N m kg^{-1} K^{-1}.

In equation (6) D and v are very important parameters, while the others including air density of a particular location at a specific time, are constant numbers. Hence, with the use of the constant values along with the values of the wind speed and blade diameter, it is easy to estimate and convert wind power to equivalent electrical energy provided that the coefficient of performance is known. Assuming, P_e = electric power generated from a turbine, $\eta_t =$ turbine efficiency, η_a = efficiency of other appliances between the turbine and the generator and η_g = generator efficiency, the electrical power *(P_e=IV)* can be given as

$$IV = P_e = \eta_t \eta_a \eta_g \, (P_{wind}) = \eta_t \eta_a \eta_g \left(\frac{1}{2} \rho A v^3\right) = P_{out} \qquad 8$$

$$P_e = \eta_t \eta_a \eta_g \left(\frac{1}{8} \rho \pi D^2\right) v^3 \qquad 9$$

Comparison between Equations 6 and 9 reveals that $\eta_t \eta_a \eta_g = C_p$ where C_p acts as a determining factor in the conversion of wind power to electrical power.

3. Results and Discussion

In the first part of this section, comparison is made between wind power and turbine power output. First, an attempt is made to see diurnal variability between power calculated from wind speed and electrical power obtained from the turbines. For this, the daily data collected every ten minutes were converted to hourly values by calculating hourly average and then using these hourly averaged values to find daily average wind speed and electrical power output. The second part of this analysis is finding the correlation of the average wind power and the average power output from the turbine. In the third part, comparison is made between the wind power and the output efficiency. Finally, the performance coefficient (C_p) is compared with the overall company efficiency given in Table 1.

Hourly averaged wind speed shown here for the month of December (2012) revealed daily fluctuations. The fluctuation was eminent because of the variability of land surface and atmospheric heating, which is responsible for air density gradient in the atmosphere and that in turn results in pressure gradient (i.e., responsible for wind).

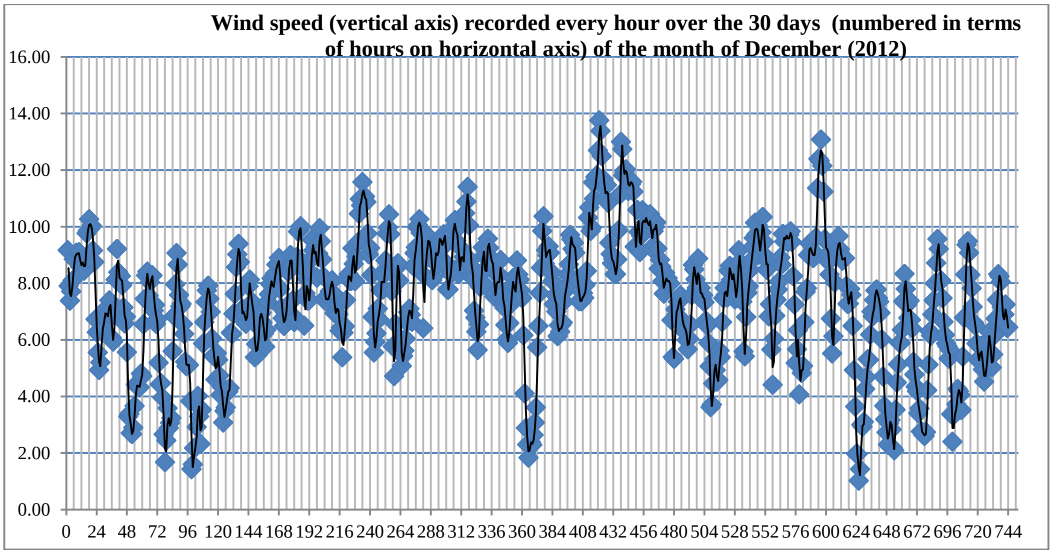

Figure 2. Hourly wind speed change for thirty days of the month of December 2012.

As is evident in Figure 2, there were times when there were bimodal wind speed fluctuations during a single day with small highs during early morning hours and the relatively larger highs during late afternoon hours (see for instance, the first six days – 0 to 144 hours). These are generally true on clear-sky days. The corresponding low wind speed hours during those days happened a little after midnight. Between 120 and 360 hours (nearly 10 days, which happened during the middle of the month), wind speeds at turbine height were in excess of 6 m/s. During those times it was difficult to discern the daily bimodal nature of the wind speed at least during this month. What we understand from the data of this particular month is that wind speed had high and low times not only on daily basis but also in weekly basis. Diurnal variability of wind speed is better illustrated using Figure 3 shown only for two specific days (Nov. 1 and Dec. 1, 2012) for the sake of illustration.

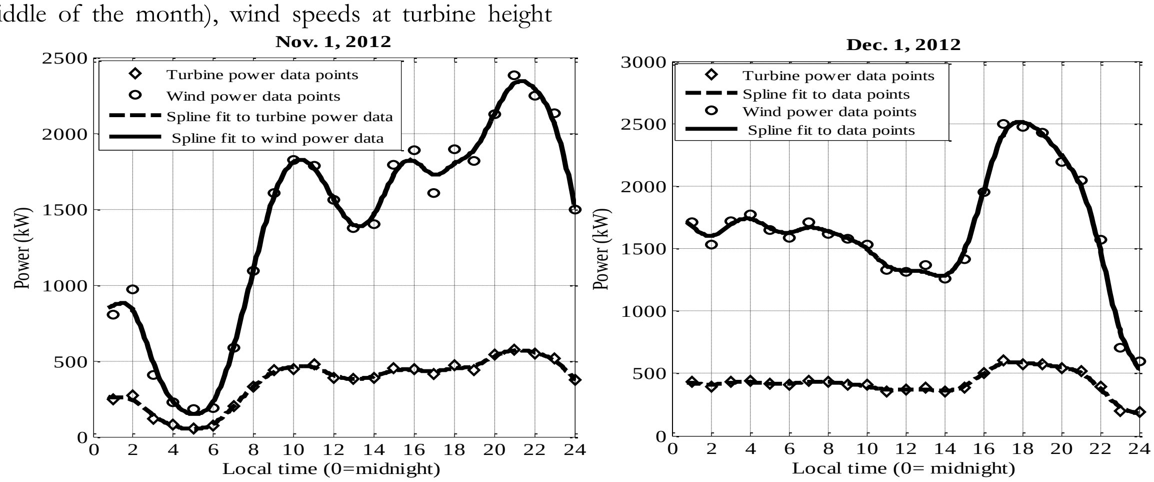

Figure 3. Diurnal variability of calculated wind power and measured turbine power shown as illustration for two days (Nov.1 and Dec.1, 2012).

Both wind power and turbine power changed during different hours of the day (Figure 3). Whenever wind power increased, the turbine power output also increased. On Nov.1, 2012, wind power picked up after 8:00 am reflecting the effect of solar radiation (thermal effect) on wind speed in creating density or pressure gradient on the surface of the earth. On this particular day wind speed remained high until about 21:00 hours. Generally, in tropical areas day-to-night variation of surface pressure shows bimodal nature (changes twice per day) due to thermally driven atmospheric tides (Covey *et al.,* 2011).

3.2. Variability of Wind and Turbine Powers over the Days of the Month

Figure 4 shows how wind and turbine powers changed over different days of each month.

Over the four months, turbine powers never exceeded 500 kW even though each turbine was rated at 1 MW (Figure 4). Average electrical output and wind powers calculated are shown with standard deviations and coefficient of variations (CVs) in Table 2. Wind powers were also generally less than 2500 kW. As indicated in the same table, the turbines operated within the limit of 20 - 30% of the rated power and the

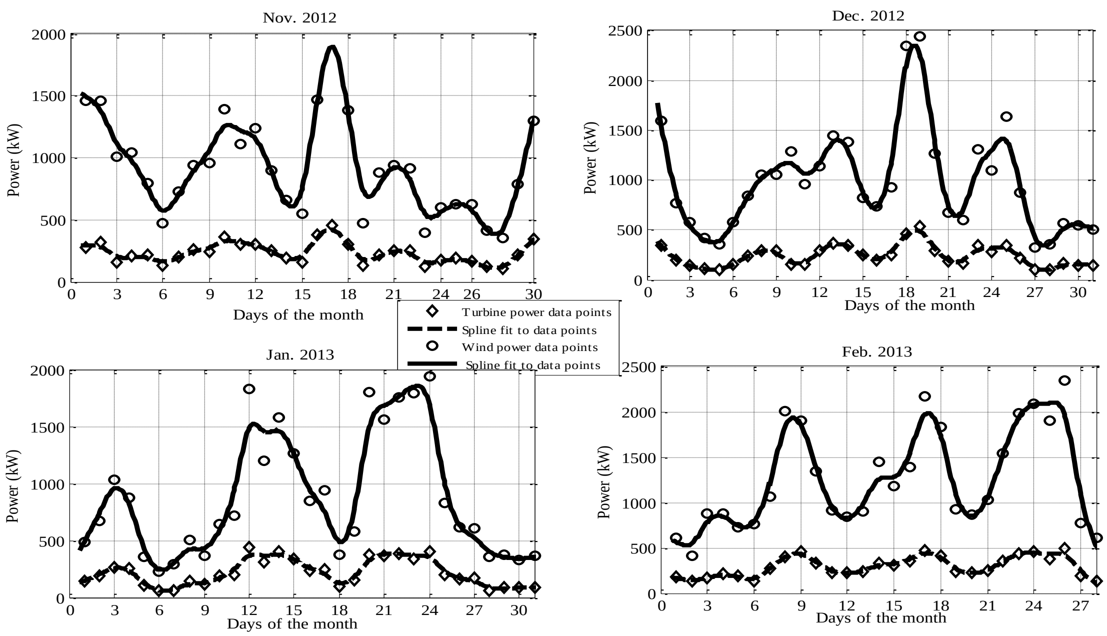

Figure 4. Comparison between daily measured and averaged turbine power and wind power, calculated from daily-averaged wind speeds of 15 turbines and shown independently for each of the four months (November, 2012 – February, 2013).

average of the four months approximately came to 25%. For most turbines the rated power is 30% or less (Watson, 2005) and the value obtained in this case also lies within this limit. The variability in electrical power output and wind powers was generally high as shown by the standard deviations and the CVs (Table 2). The two together indicate daily variability of wind speeds. The average C_p over all the four months was limited to within 25%.

Table 2. Changes in electrical output and wind powers over the four months.

Parameters	Month			
	Nov. 2012	Dec. 2012	Jan. 2013	Feb. 2013
Average energy output (kW)	234	240	219	293
(Percent of rated power)	(23.4%)	(24%)	(21.9%)	(29.3)
Standard deviation	85	109	118	114
CV	0.37	0.46	0.54	0.39
Avg. wind power (kW)	934	999	831	1260
Standard deviation	411	529	549	559
CV	0.44	0.53	0.62	0.44
C_p	0.25	0.24	0.25	0.23

Where, CV= Coefficient of variation; C_p =Power coefficient.

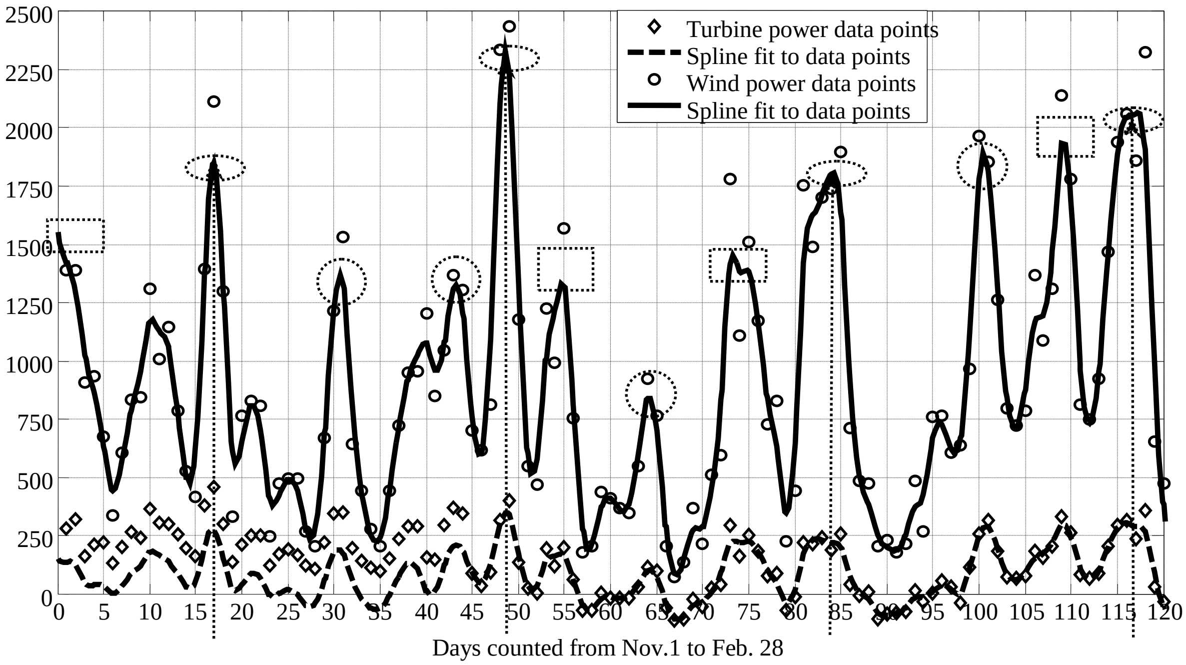

Figure 5. Combined figure of all the four months shown together. Both turbine powers and calculated wind powers were averages of fifteen turbines. The days are numbered as 1 for November 01/2012 and as 120 for February 28/2013.

In November and December each, the wind power experienced peaks four times (Figure 4).In January and February there were only three peaks each. However, it is sometimes difficult to make conclusions without looking at the four months together as shown in Fig. 5.

Generally, both wind power and turbine power varied during different days of the month as shown over all the four months (Figure 5). There seems to be some sort of cyclic pattern in the power produced because of the presence of high and low wind-power-days repeating roughly about four times in a month, three of them predominantly, over all the months. What is clearly visible are the three peaks observed every month (the highest peaks encircled by dotted ellipses, the moderate ones shown by dotted rectangles and the lowest ones shown by circles indicated by dotted lines). Each one of them showed cyclic patterns with time gaps averaging 33 $\pm$ 4 days. The minimum of 29 days may be linked with the lunar cycle whereas the maximum may be associated with the after (lagging) effect of the lunar cycle.

The moon has the capability of causing atmospheric tides similar to ocean tides (Covey *et al.,* 2011). This is bulging of the atmosphere creating areas in the atmosphere where there are high air densities, which also become responsible for high local atmospheric pressures (Covey *et al.,* 2011).

Such unbalanced local pressures create local wind (Covey *et al.,* 2011) and may be responsible for peaks in wind powers. Atmospheric tides are caused by global scale oscillation of the atmosphere by gravitational field (pull) of the moon, solar insolation of the atmosphere, nonlinear interaction between tides and planetary waves and large scale latent heat in areas where there are large water bodies releasing water due to deep convection in the tropics (Covey *et al.,* 2011). Planetary waves are giant waves that operate at high altitudes such as jet streams that are caused by the planet's rotation on its axis and atmospheric heating because of insolation that can influence weather including wind speed. Consistent with this postulation, at a place like Ashogoda, atmospheric tide due to gravitational force of the moon and solar insolation seem to be the predominant factors for the cyclic nature of the wind speed. Even in such windy area (Ashogoda), a maximum of two to three windy days are followed by three to seven relatively calmer days.

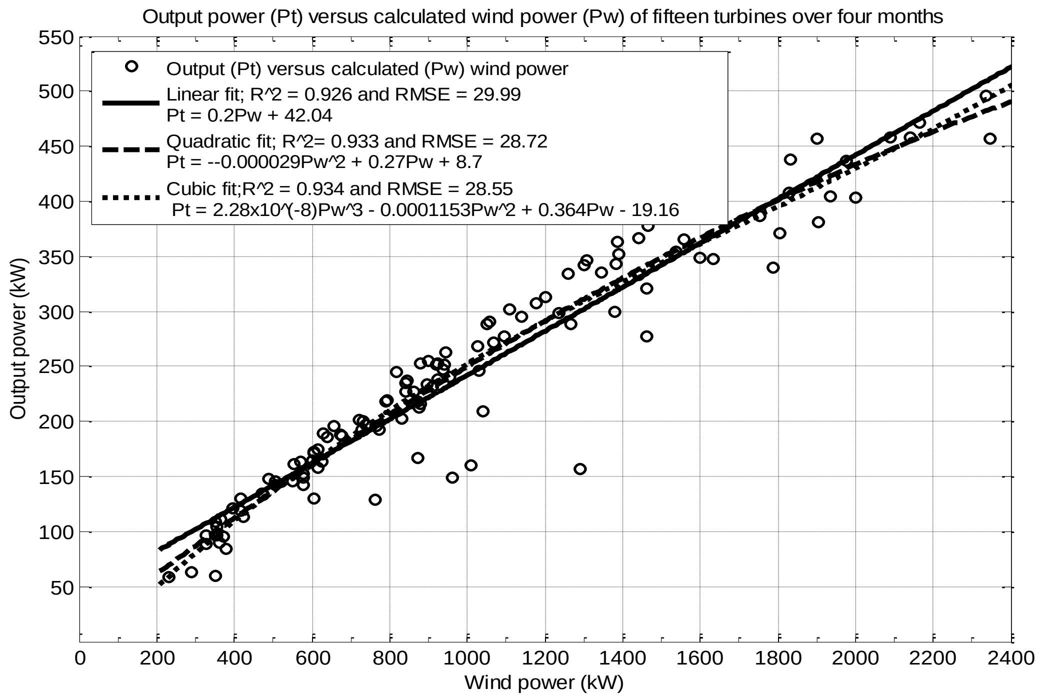

Figure 6. Calculated wind power against turbine power averaged for fifteen turbines over four months (November 2012 to February 2013).

3.3. Correlation between Wind Power and Turbine Power

Plots of turbine power versus wind power both averaged for 15 turbines for data points of four months are shown in Figure 6. In this figure three fit types are shown. The linear fit is important to estimate the combined efficiencies of the turbines and the other components linked to the turbine such as coupling and generators. Both quadratic and cubic fits did not show much improvement over the linear fit as indicated by their R^2 and RMSE values. The slope of the linear fit measures the overall efficiency. The overall efficiency (from Figure 6) averaged over the four months for the fifteen turbines (Table 3) gave the result of 0.2, which makes the overall efficiency of the turbine and its accessories to be 20%. The fact that there is very low standard deviation of the slope of 0.007 (Table 3) indicates that the efficiency change over the four months was very low. On the other hand, this efficiency was low compared to the other efficiency estimated earlier, which was close to 25%. This was due to the fact that plotting depends on the nature of the curve fitting equation selected, which in this case underestimated the efficiency. During the linear fit, the low efficiencies at lower and higher wind speeds tended to pull the efficiency down. However, the fact that the output versus calculated wind power fit curved slightly downward indicates higher efficiency at intermediate (between 200 and 400 kW) output powers. These values correspond to about 7.6 and 10.1 m s^{-1} wind speeds, respectively. Generally, optimum efficiencies of wind turbines do not occur at low or high wind speeds. Optimum efficiency is obtained at intermediate wind speeds roughly 6 to 9 m/s (Mujadi *et al.,* 1998l) at which power losses are modest (Ragheb and Ragheb, 2011). At low wind speeds efficiency loss occurs because of inertia. At high wind speeds efficiency loss is due to increased friction force, which positively relates to wind speed.

Table 3. Change in overall efficiency of the turbine power over the four months.

Month	Slope	Intercept	R^2	RMSE
Nov. 2012	0.1958	51.08	0.880	29.22
Dec. 2012	0.1940	45.80	0.878	39.00
Jan. 2013	0.2101	31.41	0.950	26.77
Feb. 2013	0.1991	41.92	0.953	25.11
Average	0.1998	42.55		
SD	0.007	8.32		

RMSE = root mean square error

The intercept is indicative of the cut-in wind speed. Averaged value of the intercept is 42.55 (Table 3) and 42.05 (Figure 6), which, when converted to wind speed using Eq. 6 and C_p value of 0.25 indicates the cut-in wind speed of about 3.03 m/s (Fig.6). The averaged cut-in wind speed for the fifteen turbines extrapolated using the linear equation also gave the same result. When the cubic fit equation is used, however, the cut-in wind speed rose to 3.5 m/s. The cubic fit slightly overestimated the cut-in wind speed. This shows the influence of the type of curve fitting used in giving accurate results.

As shown in Figure 6, turbine power did not show much increment after wind speed of 12 m/s (output power of about 540 kW). The curve fit improved in February (based on higher values of R^2 and relatively lower values of *RMSE* as shown in Table 3) and this perhaps can be attributed to self-adjustment of the turbines and their accessories after working for some time.

Looking at the linear fit in Figure. 6 it is very easy to observe the distribution of data points above the fitted line especially at moderate wind powers. This indicates that the conversion of wind power to turbine power is not strictly following linear relationships. At higher wind speeds, conversion of wind power to turbine power slightly decreased indicating low conversion efficiency. High wind speed is associated with high frictional loss (Tamura, 2012).

Table 4. Slopes and correlation coefficients obtained from calculated wind power plotted against turbine power shown for each of the fifteen turbines.

Turbine No	November		December		January		February		Average	Cp=η_{eff} = 1/slope
	Slope	R^2	**Slope**	R^2	**Slope**	R^2	**Slope**	R^2	**Slope**	
5	3.894	0.86	4.259	0.87	4.106	0.91	4.161	0.96	4.11	0.244
7	3.983	0.45	4.414	0.65	4.06	0.97	4.227	0.95	4.17	0.240
11	4.046	0.75	3.933	0.91	4.464	0.64	4.127	0.91	4.14	0.241
13	4.143	0.53	4.123	0.70	3.961	0.96	4.253	0.69	4.12	0.243
16	3.723	0.76	3.965	0.46	4.214	0.65	5.409	0.81	4.33	0.231
17	4.007	0.86	3.708	0.83	3.587	0.87	3.597	0.95	3.72	0.268
18	3.947	0.48	3.746	0.93	3.733	0.97	4.004	0.71	3.86	0.259
19	3.648	0.94	4.117	0.91	4.051	0.92	4.561	0.57	4.09	0.244
20	3.958	0.81	3.937	0.75	3.838	0.97	4.122	0.70	3.96	0.252
21	4.291	0.60	3.955	0.81	3.914	0.95	4.291	0.55	4.11	0.243
23	3.821	0.45	3.837	0.76	3.79	0.89	3.858	0.81	3.83	0.261
24	3.817	0.93	4.764	0.46	3.869	0.88	4.055	0.80	4.13	0.242
26	3.807	0.93	4.161	0.57	4.174	0.72	4.166	0.68	4.08	0.245
27	3.872	0.85	4.053	0.58	4.317	0.59	4.076	0.77	4.08	0.245
28	3.717	0.95	4.083	0.71	4.01	0.73	4.065	0.76	3.97	0.252
Mean	3.91	-----	4.07	-----	4.01	-----	4.20	-----	4.05	0.247
SD	0.17	-----	0.27	-----	0.23	-----	0.40	-----	-----	-----
CV	0.044	-----	0.066	-----	0.058	-----	0.094	-----	-----	-----

Since the slope indicates what fraction of the wind power is converted into turbine power, the value of the reciprocal of the average slope in Table 4 indicates that only about a quarter of the wind power is converted into turbine power. This is within the limit of 10-30 % as indicated in the literature (Mathew, 2006). Since the value of 0.25 represents a factor that relates wind power to output power (i.e., $\eta_{eff} = \eta_{turbine}\eta_{generator}\eta_{others} = C_p$; of equation 9) it indicates how net average efficiency of all the turbines compares to the efficiency value given by the company of 0.38 (Table 1). The value of 0.25 is lower by about 34% than the company efficiency. But compared to the practical high value of 30%, the 25% falls short by about 17%.

Coefficient of variation (*CV*) values of all the turbines for each month are less than 0.09 ($< 10\%$). Such low CV reveals uniformity among the performances of the turbines. This implies that the turbines have less variability (and it indicates better quality manufacturing).

3.4. Test to Check Interdependence between Overall Efficiency and Wind Power

In this part, an attempt is made to check if the overall efficiency is dependent on wind power (wind speed) and for this purpose plots of net efficiency against wind power were made as shown in Figure 7.

Correlation coefficient values and the slopes of the plots of each turbine were summarized in Table 4. As shown in Figure 7 and Table 5, there is a small negative correlation between wind power and efficiency and they indicate that there is dependence of net efficiency on power. It shows that efficiency slightly decreased as power increased since the slope is negative. This may be due to increase in frictional force as wind speed increases (Tamura, 2012). With increasing wind speed, the turbine and its accessories move with greater speeds and this in turn increases frictional loss.

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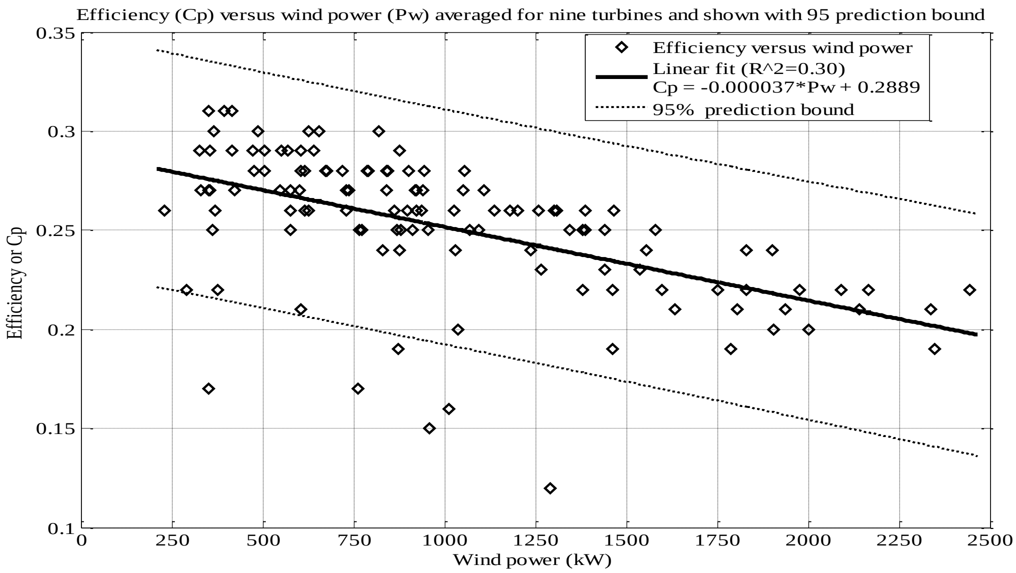

Figure 7. Interdependence between efficiency and wind power.

Table 5. Efficiency dependence of each turbine on wind power.

Turbine No	Slope	R^2
5	-0.00004	0.80
7	-0.0002	0.83
11	-0.00015	0.80
13	-0.00023	0.83
16	-0.00018	0.70
17	-0.00025	0.60
18	-0.0002	0.76
19	-0.0002	0.66
20	-0.0001	0.81
21	-0.0003	0.59
23	-0.00023	0.82
24	-0.0003	0.53
26	-0.0004	0.87
27	-0.00028	0.78
28	-0.0002	0.79
Avg.	**-2.18E-04**	**-----**
SD	**8.60E-05**	**-----**
CV	**0.39**	

Efficiencies of all the 15 turbines were less than company rated efficiency (as shown in Figure 7).

The efficiencies did not change much during the four months. This is not surprising since efficiency of a machine changes with age and four months is a short time to bring about this change.

4. Conclusion

As stated at the beginning, this research is a comparative study of wind power using metrological data and wind turbine output at Ashogoda village in northern Ethiopia. The results of the study have demonstrated that diurnal wind power showed higher wind power mostly in the afternoons. The correlation between calculated wind power and turbine power revealed that only 25% of the wind power translated into turbine power. The 25% efficiency is lower than the overall efficiency given by the company (38%) but is within the range of 10-30% given in the literature. All turbines revealed similar power outputs as revealed in their CVs ($< 10\%$). Efficiencies of the turbines decreased with increasing wind speed. Cut-in wind speed obtained from interpolation of the linear fit gave a value that is in good agreement with the company's value. But the cubic fit gave slightly higher cut-in wind speed of 3.5 m/s. In order to get more conclusive results, data of more months are required to see the effect of the rated wind speed of 15 m/s. In conclusion, this study covered data of only one third of the year, which may not be sufficient to give the general picture on the performance of the turbines. The authors recommend at least one-year data to get performance variability over a year. Hence, it is not appropriate to give any recommendations at this time.

5. Acknowledgements

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