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Subcontractor Report

WindPACT Turbine Rotor Design, Specific Rating Study

Period of Performance: June 29, 2000 – March 1, 2003

D.J. Malcolm
Global Energy Concepts, LLC
Kirkland, Washington

A.C. Hansen
Windward Engineering
Salt Lake City, Utah

National Renewable Energy Laboratory

1617 Cole Boulevard
Golden, Colorado 80401-3393

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NREL Technical Monitor: J.R. Cotrell

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1. Introduction

1.1 Background

The cost of wind energy has decreased significantly over the past two decades and is now close to being competitive with conventional fossil fuel sources, even without environmental credits. This drop in cost is partly a result of improved rotor designs with high aerodynamic efficiencies. It is also a result of more effective design of all the major components of a wind turbine, as well as the "balance-of-station" costs.

In 2000, the National Renewable Energy Laboratory (NREL) launched the Wind Partnerships for Advanced Component Technologies (WindPACT) program to examine ways in which the cost of wind energy could be reduced a further 30%. The purpose of this program was to explore advanced technologies for improving machine reliability and decreasing the overall cost of energy. One element of the WindPACT program has been a series of design studies aimed at each of the major subsystems of the wind turbine to study the effect of scale and of alternative design approaches.

The *WindPACT Turbine Rotor Design Study* was carried out by Global Energy Concepts, LLC, (GEC) on behalf of NREL, and the final report was delivered in June 2002 [1, 2]. The study examined what configuration and design changes in the rotor would reduce the overall cost of energy. The results, however, were valid only for the selected class of turbine rotors with a specific rating (ratio of rated power to swept area) of 0.39 kW/m^2. Although this ratio is representative of many current commercial machines, the effects on the optimum configuration of other specific ratings remained to be resolved.

This issue has become more relevant because several manufacturers now offer more than one specific rating for a certain machine, which is usually achieved by maintaining the rating but changing the blade length accompanied by necessary modifications to the gearbox and generator (the less energetic the wind regime, the lower the specific rating). At the same time, some researchers and authors have proposed that the specific rating should be increased to lower the cost of energy. To resolve this issue, NREL extended the WindPACT Rotor Design Study to examine the influence of specific rating on the overall cost of energy.

1.2 Objectives

The objectives of this report are as follows:

- Use the 1.5-MW baseline configuration from the earlier WindPACT Rotor Design Study to examine the effect of different power ratings and to identify an optimum specific rating
- Examine the effect of different maximum tip speeds on overall cost of energy (COE)
- Examine the role of different wind regimes on the optimum specific rating
- Examine how the optimum specific rating may be affected by introducing more advanced blade designs.

2. Present Industry Practice

The evolution of wind energy conversion systems over the past 2000 years has been one of increasing efficiency, improved reliability, and lower costs. Integral to this evolution has been more effective use of materials and a trend to extract the maximum amount of energy by increasing the swept area while restricting the materials and cost. The current state of the industry is summarized in Table 2-1, which lists the specific ratings of some selected current wind turbines. Figure 2-1 plots the specific rating of those machines listed in Table 2-1, as well as others.

In general, the larger-diameter machines are the most recent designs. There is no clear relationship between diameter and specific rating. Instead, the range of specific ratings may be governed by the target location and environment of each machine. This includes possible offshore application for some of the larger-diameter machines.

Table 2-1. Specific Rating of Selected Current Wind Turbines

Manufacturer	Model	Diameter (m)	Rated Power (kW)	Specific Rating (kW/m^2)
Vestas	V47	47	660	0.38
Tacke	TW1.5	65	1500	0.44
Enercon	E66	66	1500	0.45
GE Wind	TZ1.5	70.5	1500	0.38
Vestas	V80	80	2000	0.40
NEG Micon	NM80	80	2750	0.55
Nordex	N90	90	2300	0.36
Vestas	V90	90	3000	0.47
NEG Micon	NM92	92	2750	0.41
GE Wind	3.6	100	3600	0.46
GE Wind	3.25	104	3200	0.38
Enercon	E112	112	4500	0.46

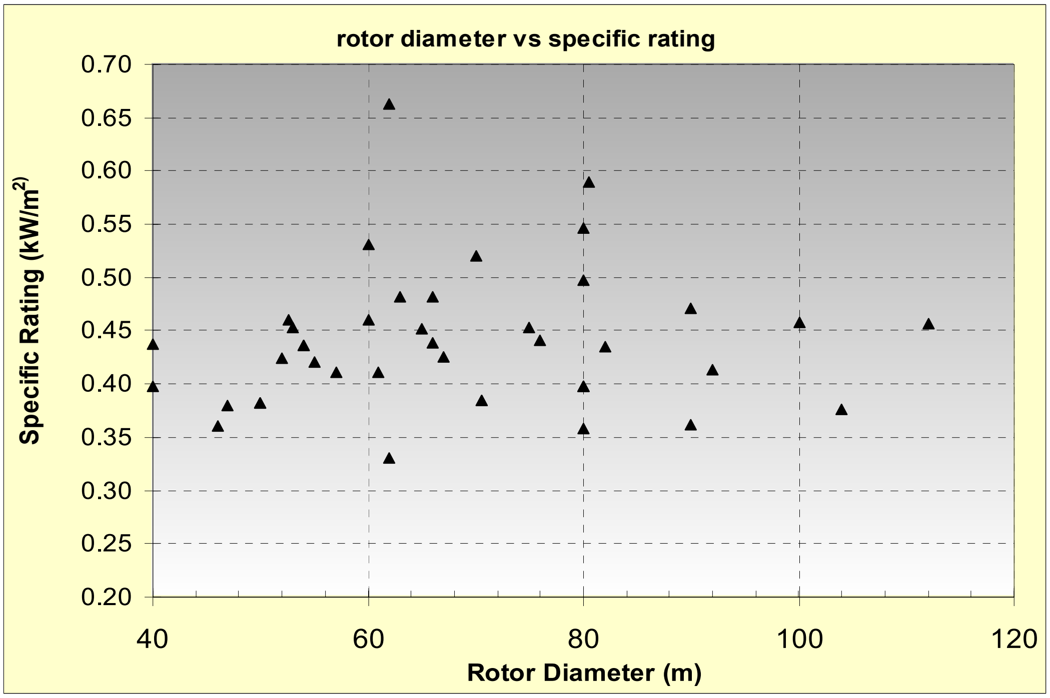

Figure 2-1. Specific rating of current and prototype rotors.

3. Approach

GEC worked closely with NREL personnel to determine how the objectives of the project could best be reached and how the work should be defined. Consequently, the project was divided into two phases, which allowed for a review and redefinition of the work following completion of the first phase.

3.1 Phase 1

The following principles and approach were adopted for Phase 1.

- The starting point was the baseline configuration for the 1.5-MW machine with a 70-m rotor from the Rotor Design Study [1].
- The procedures used for defining blades, input data, simulation cases, and design spreadsheets were developed in the Rotor Design Study [1].
- The rotor diameter was kept constant, while the rating was changed from 1500 kW to 1000 kW, 1900 kW, and 2300 kW. This allowed the use of the same costs for several balance-of-station components, such as roads and cables and the cost of assembly.
- Necessary modifications were made to the cost models (Section 3.3).
- The balance-of-station costs were calculated based on the assumption that the total number of wind turbines on the wind farm remained the same.
- The same control system that was developed for the baseline machines was used in Phase 1 (a variable-speed rotor at maximum aerodynamic efficiency followed by pitching to feather to maintain a constant rpm at rated power).
- The maximum tip speed for the 1500-kW configuration was adjusted from 75.0 to 77.5 m/s so that the design tip speed ratio (TSR) of 7.0 (corresponding to maximum power coefficient) was maintained until rated speed and power were reached simultaneously.

The Phase 1 work was divided into three tasks:

Task #11. The maximum tip speed was allowed to vary with the new ratings so that the design tip speed ratio was maintained until rated power was reached.

Task #12. The maximum tip speed was maintained at the same value used for the 1500-kW configuration (77.5 m/s).

Task #14. Using the configurations of Task #12, alternative wind regimes for energy production and for design were examined.

3.2 Phase 2

Following Phase 1, GEC and NREL staff held an interim meeting to review the findings of Phase 1 and to define the work for Phase 2. The final definitions of the Phase 2 tasks are given below.

Task #13. The design tip speed ratio was varied by changes to the blade planform, and the optimum value was determined while the rating was maintained at

1500 kW. That optimum design tip speed ratio was used to sweep the range of ratings, and the optimum rating for that tip speed ratio was determined.

Task #15. The baseline blade was replaced by the “advanced” blade design from Task #5 of the Rotor Design Study [1] (incorporating carbon fiber, flap twist coupling, and tower feedback). As in Task #13, the design tip speed ratio was varied while the rating was maintained at 1500 kW and the optimum tip speed ratio identified. Following this, the optimum rating was determined by using the optimum tip speed ratio to sweep all the ratings.

Task #16. Instead of varying the rating, the specific rating was modified by changing the diameter to determine whether the same results were obtained. This approach was applied to the baseline model of Task #12.

3.3 Cost Models

Table 3-1 lists the changes that were made to the cost models. Details of cost models that were left unchanged may be obtained from the Rotor Design Study [1].

The choice to maintain the same number of machines within the wind farm meant that the costs of roads and internal cabling were unaffected. However, the total rating of the wind farm changed as the rating of the individual machines changed. This affected the costs of electrical connection.

Discussions with the author of Reference [3] confirmed that the cost of the wind farm transformer was approximately proportional to the total rating, whereas the cost of the other substation components increased much more slowly. A reasonable model was, therefore, one in which the substation cost for the 1500-kW machines was shared equally between the transformer and the other components; the cost of the former was directly proportional to the rating, while the cost of the latter was held constant.

The objectives of the Rotor Design Study [1] were to examine alternative rotor configurations and to use a single, standard, drive-train design. This implied that the cost models for drive-train components were less sophisticated than for rotor components. The same approach was adopted in the current study.

3.4 Wind Regime

NREL specified a production wind regime for the WindPACT program with an annual mean of 5.8 m/s at a 10-m reference height and a vertical wind shear exponent of 0.143. This corresponds to a mean of 7.86 m/s at a hub height of 84 m. All COE calculations were done with this regime as a baseline. The design wind regime was that defined as Class 2a in the 1998 version of the International Electrotechnical Commission (IEC) design code [4]. Work in Task #14 investigated the effect of changing the wind regime for energy production and for design class.

Table 3-1. Cost Models Altered from Earlier WindPACT Rotor Study

Item	Previous Cost Model	Modified Cost Model	Comments
Substation, structural	Total substation cost from [6]	$71,880	This part assumed constant with rating
Substation, transformer	$/kW = 3.49E-6*Rating^2- 0.0221*Rating + 109.7	$35.16*Rating	This part proportional to machine rating
Long-term replacement	$15/kW/year	$0.00467/kWh See Section 4.1	The modified cost was used to examine the effect of this item on total COE in Tasks #11 and #12 only.

4. Results

4.1 Tasks #11 and #12: Rating Changes to Baseline Design

Table 4-1 summarizes some of the parameters used in the configurations of Tasks #11 and #12. Figure 4-1 shows the maximum rpm and rated torque of the various configurations.

The results of applying the cost models to the two sets of configurations and calculating an overall COE for each are shown in Figures 4-2 and 4-3.

Table 4-1. Specific Rating, Max RPM, and Torque for Tasks #11 and #12

Task	Electrical Rating (kW)	Diameter (m)	Specific Rating (kW/m^2)	Max rpm	Max Tip Speed (m/s)	Rated Shaft Torque (kN m)
	1000	70	0.260	18.55	68.0	557
Task #11	1500	70	0.390	21.15	77.5	732
	1900	70	0.494	22.92	84.0	856
	2300	70	0.598	24.56	90.0	967
Task #12	1000	70	0.260	21.15	77.5	489
	1500	70	0.390	21.15	77.5	732
	1900	70	0.494	21.15	77.5	927
	2300	70	0.598	21.15	77.5	1122

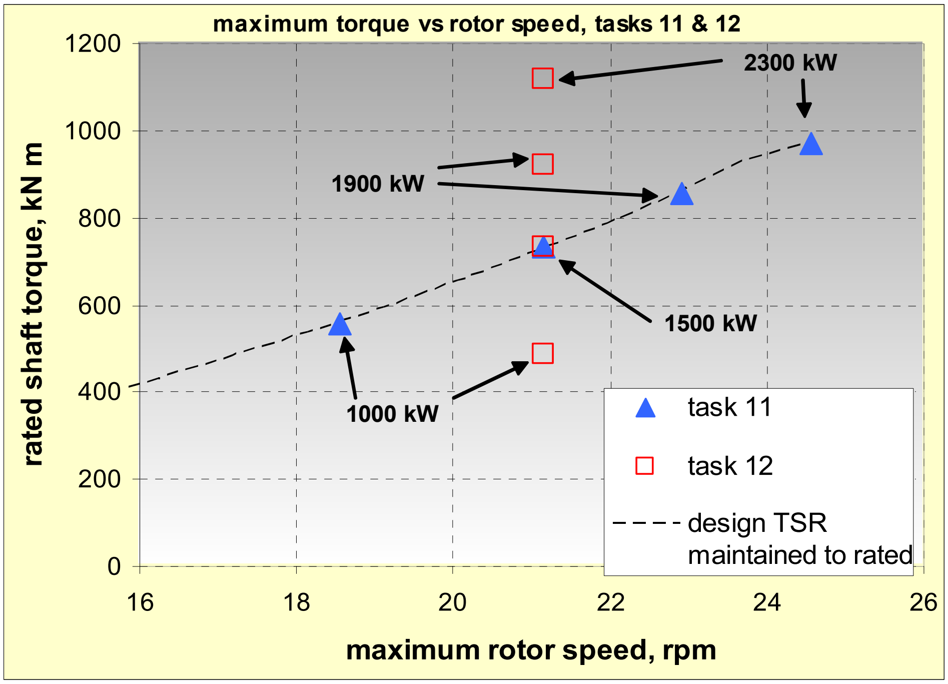

Figure 4-1. Maximum rpm and torques of configurations of Tasks #11 and #12.

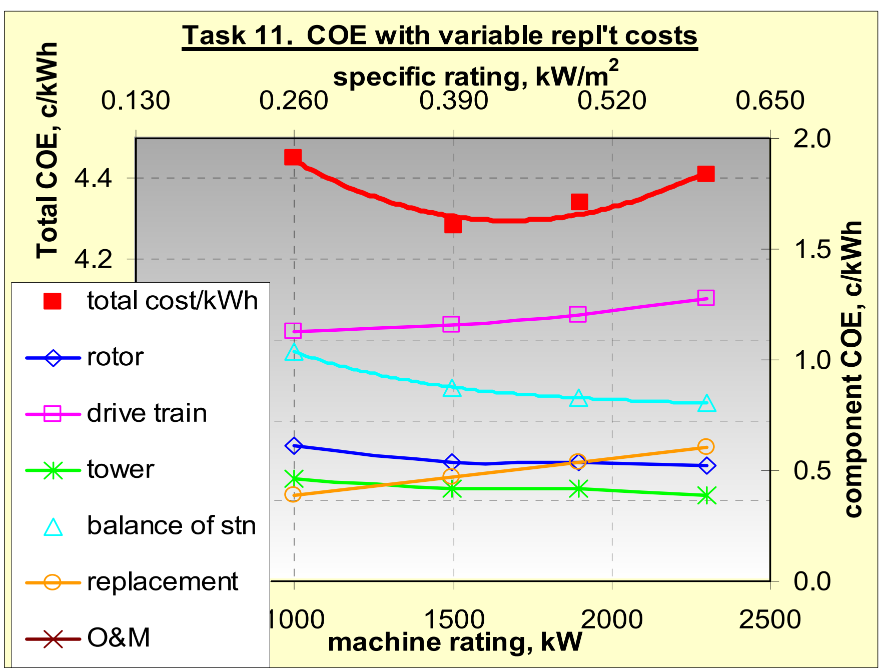

Figure 4-2. Total and component COE from Task #11 configurations. Vmean = 7.86 m/s; variable replacement cost.

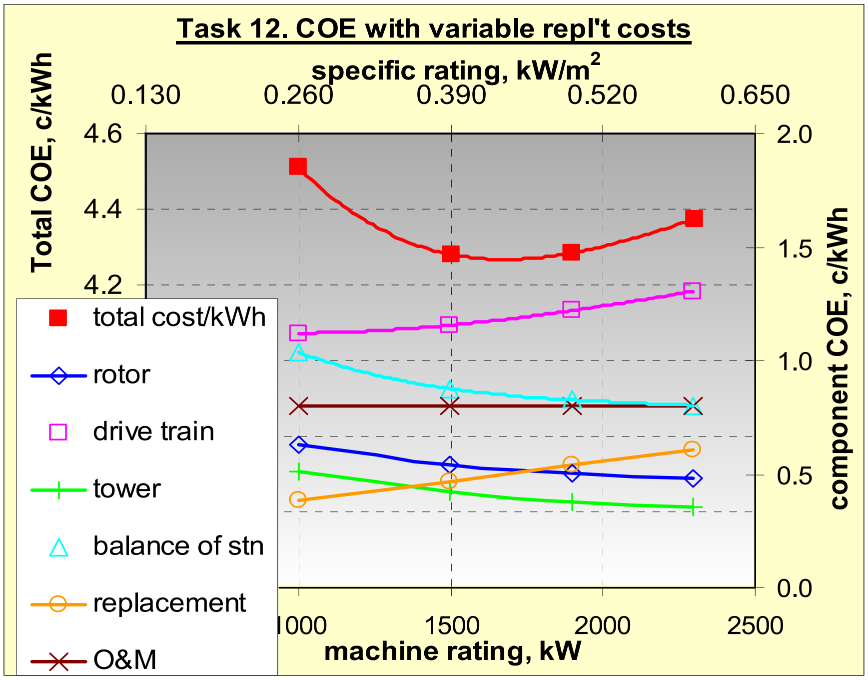

Figure 4-3. Total and component COE from Task #12 configurations. Vmean = 7.86 m/s; variable replacement cost.

It is apparent from Figures 4-2 and 4-3 that the shape of the total COE curve and the location of the optimum (the lowest) COE are strongly influenced by the manner in which the operations and maintenance (O&M) or the replacement costs are formulated. In the Rotor Study [1], the replacement costs were expressed as a dollar amount per year per kW rating. For much of that study, the rating did not vary and the replacement costs were unaltered. However, in this study the same model implies that the replacement costs of the 2300-kW configuration will be 2.3 times those costs for the seven 1000-kW configuration. This may be true for the generator replacement, but it is not true for the gearbox or for many other components.

To show how the results could be affected by the replacement cost model, the costs were reassessed using replacement costs that were proportional to energy output (similar to O&M costs). These results are shown in Figures 4-4 and 4-5. A comparison of the two sets of figures shows that the total costs of the higher ratings have been reduced by the change in the replacement cost model. This has moved the optimum rating higher. The modified replacement cost model (constant with annual energy production [AEP]) probably represents a lower bound for this item. The true cost model probably lies between the two models examined here.

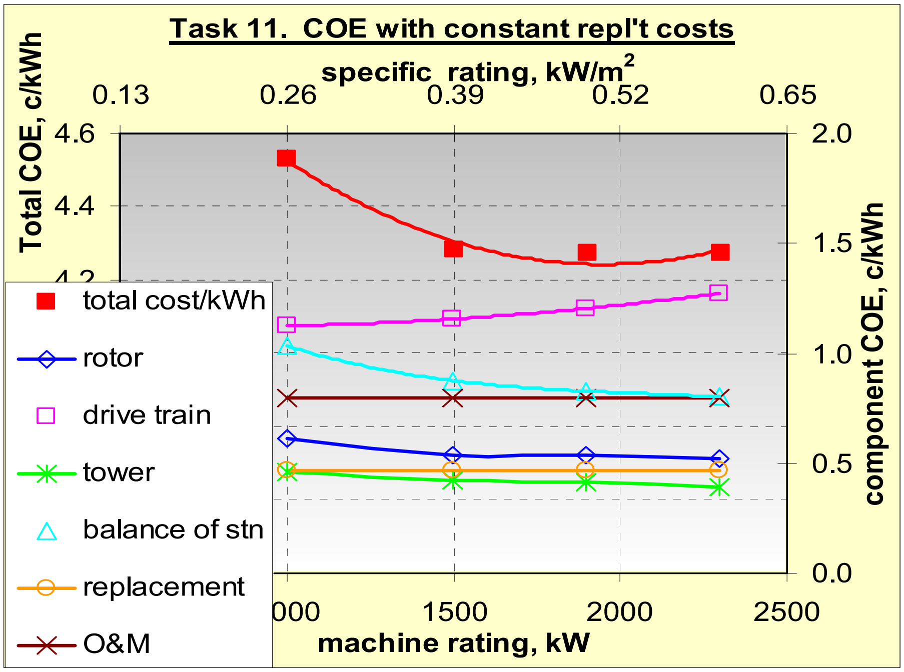

Figure 4-4. Total and component COE from Task #11 configurations. Vmean = 7.86 m/s; constant replacement cost.

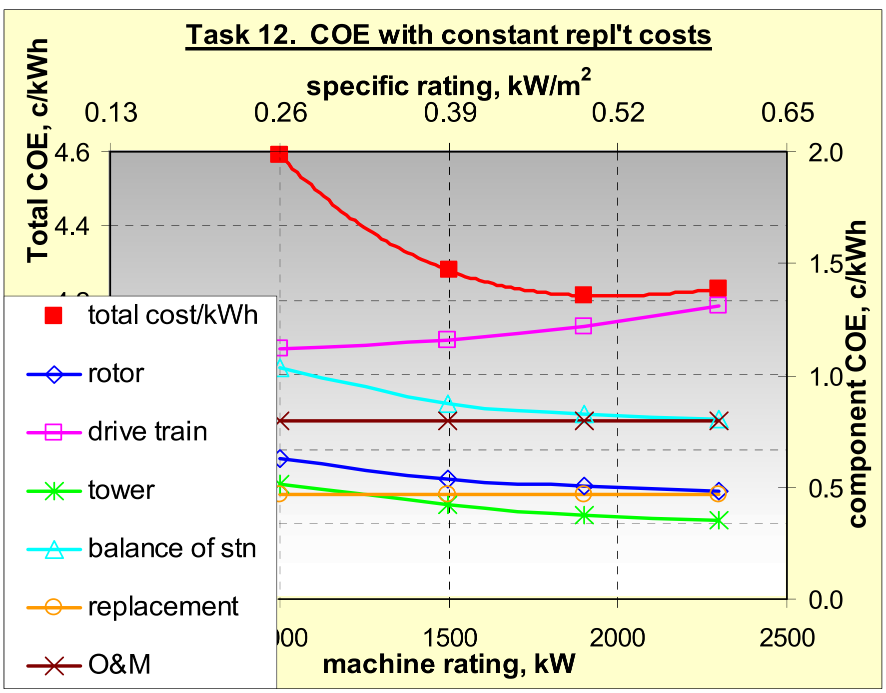

Figure 4-5. Total and component COE from Task #12 configurations. Vmean = 7.86 m/s; constant replacement cost.

The variation in annual energy production for the configurations of Task #11 and #12 are shown in Figure 4-6, which shows small differences between the two approaches. Figure 4-7 shows how the rating affects some selected fatigue loads and illustrates that the effect of increasing the maximum tip speed with rating (as in Task #11) is significant. It confirms that although higher tip speeds will lower drive train costs, it is balanced by higher costs for the rotor, bedplate, and tower, which is a result of the higher loads induced by any given gust [5].

4.2 Task #13: Effect of Optimum Tip Speed Ratio

A series of blades were designed so that their design tip speed ratios (tip speed ratios corresponding to maximum power coefficient) varied from the baseline value of 7.0 to a range of 6.0 to 8.5. These values and the corresponding changes in blade planform and AEP are shown in Table 4-2. The blade planforms, twist, etc., were selected by using the computer codes PROP or WTperf to obtain performance coefficients for new configurations and then using spreadsheets to calculate total AEP in the given wind regimes. For this task, the maximum tip speed was restrained to 77.5 m/s, the same as that used in Task #12. Figure 4-8 shows how these configurations change the component and total cost of energy.

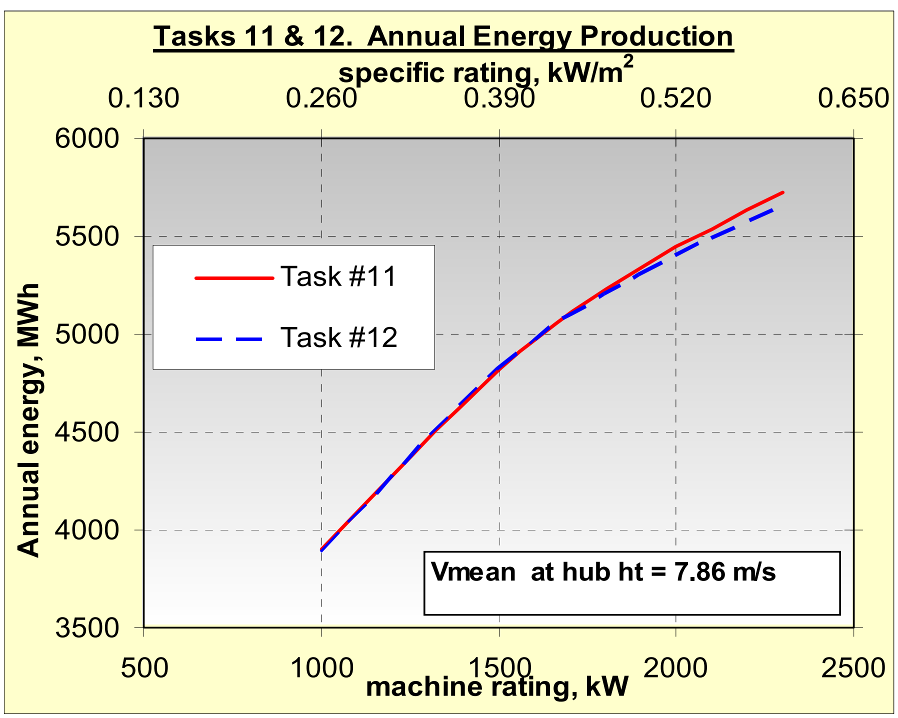

Figure 4-6. Annual energy production from Task #11 and #12 configurations. Vmean at hub height = 7.86 m/s.

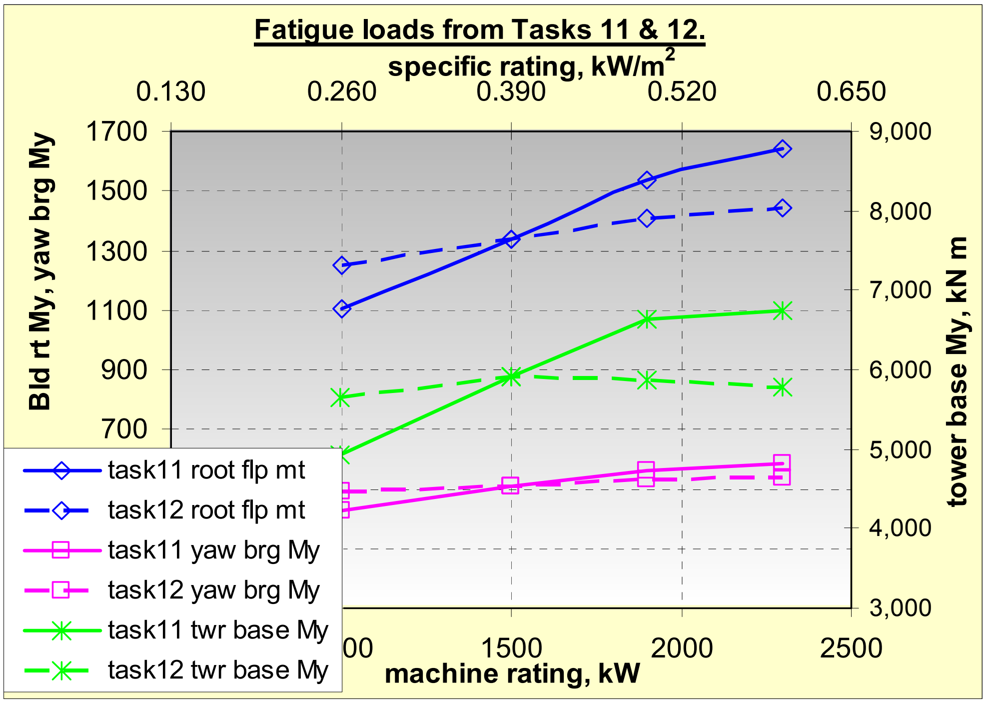

Figure 4-7. Equivalent fatigue loads from Tasks #11 and #12.

Table 4-2. Blade and Rotor Properties for Task #13 Tip Speed Ratio Study

	Design tip speed ratio			
Parameter	**6.0**	**7.0 (baseline)**	**8.0**	**8.5**
Maximum chord/radius	9.0%	8.0%	6.0%	5.0%
Maximum performance coefficient	0.507	0.506	0.506	0.507
Estimated AEP, (MWh/yr)	4829	4818	4786	4765

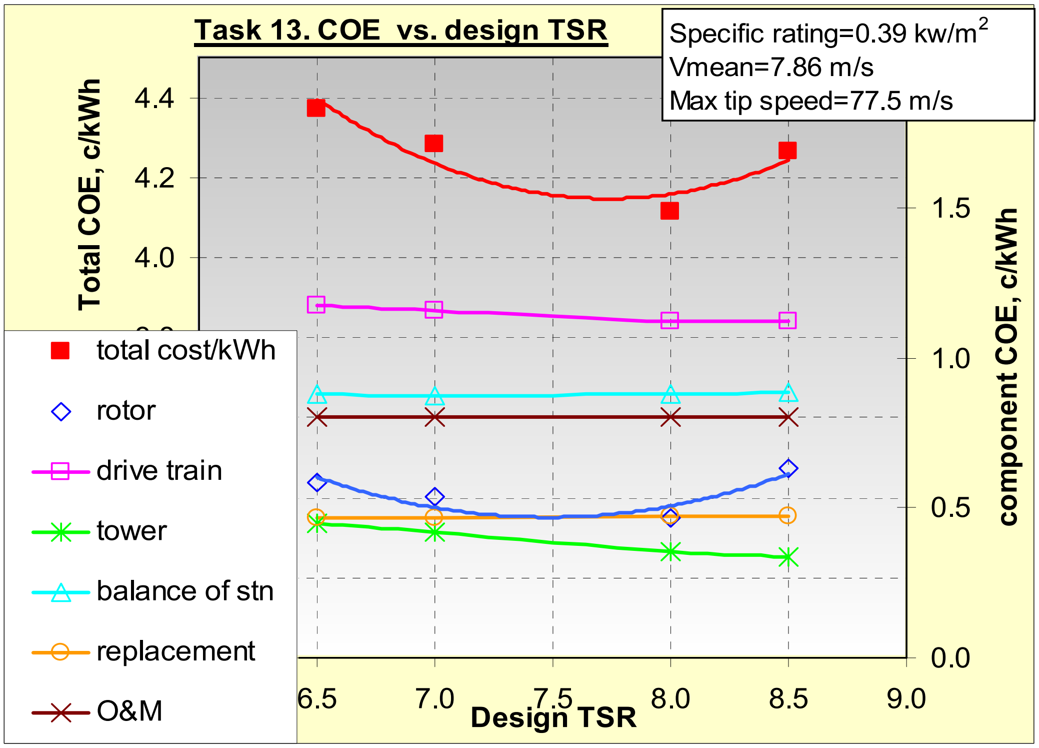

Figure 4-8. Effect of design tip speed ratio on cost of energy.

The optimum design tip speed ratio appears to be between 7.5 and 8.0. The shape of the curve is strongly influenced by the high COE value at the design TSR of 8.5. At that TSR value, the blade chord is much reduced from the corresponding baseline design, and it proved difficult to accommodate all of the required glass fiber into the limited cross section. This resulted in a very heavy and expensive blade and one in which inertial effects possibly added to the loads.

Based on the results shown in Figure 4-8, we decided that a design tip speed ratio of 8.0 represented the optimum value for the baseline-type blade. Therefore, that blade planform was selected for use in conjunction with the range of ratings from 1000 to 2300 kW. Those results are presented in Figure 4-9, which includes a comparison with the baseline design results. Not only has the COE been reduced, but the optimum rating has also been reduced from 1700 to 1600 kW. It is noticeable that the choice of a higher design tip speed ratio gives greatest benefit to systems with lower ratings.

The main reason for the reduction of COE with increasing design TSR is that the loads governing a number of major components are reduced. These governing loads are commonly the fatigue loads, and Figure 4-10 shows how some of the important fatigue loads are affected by design TSR. Figure 4-10 shows a dramatic decrease in the three loads with increasing tip speed ratio, except for the blade root flap moment between design TSRs of 8.0 and 8.5. This is probably a result of the excessive thickness of the blade spar necessitated by the limited chord and depth. If a material stronger in fatigue (such as carbon fibers) were used, this limitation might not be so onerous.

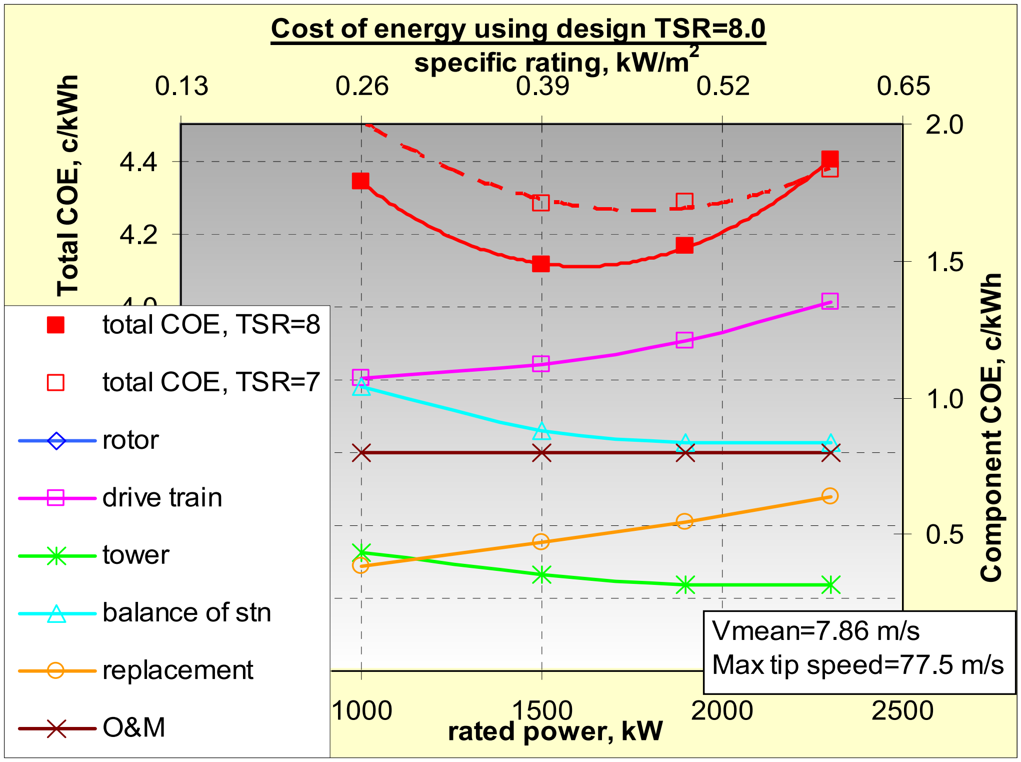

Figure 4-9. Effect on COE of specific rating using baseline blade with design TSR = 8.0.

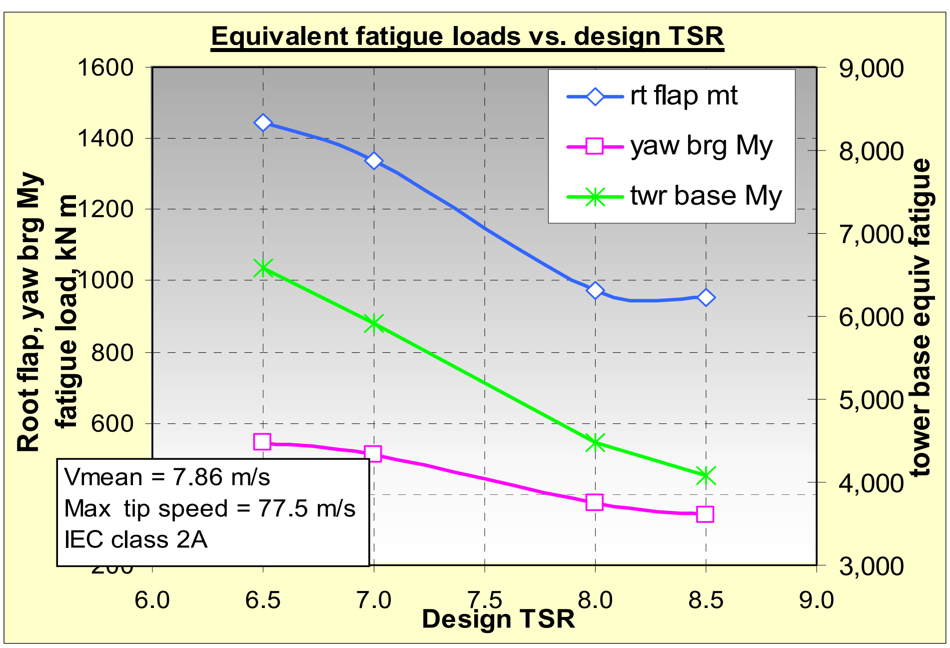

Figure 4-10. Effect of design TSR on selected equivalent fatigue loads.

4.3 Task #14: Effect of Wind Regime

This task, which investigated the effect on COE of changes in the wind regime, was divided into three parts.

1. The effect of changing the shape factor of the Weibull distribution
2. The effect of different mean wind speeds for energy production (maintaining a Rayleigh distribution)
3. The effect of changing the design class as well as the production wind regime.

4.3.1 Effect of Weibull Shape Factor

The increase in AEP with mean wind speed is an expected result, but the influence of machine-specific rating and the type of wind speed distribution is not always so intuitive. Figure 4-11 shows wind distributions for Weibull shape factors (k) of 1.6, 2.0, and 2.5 and includes power curves for three of the machines considered in this study.

The wind speed at which the machine reaches rated power clearly has an important role in determining which regime will generate the most total energy. In Figure 4-12, the wind distribution has been combined with power curves to produce plots of the distribution of energy production.

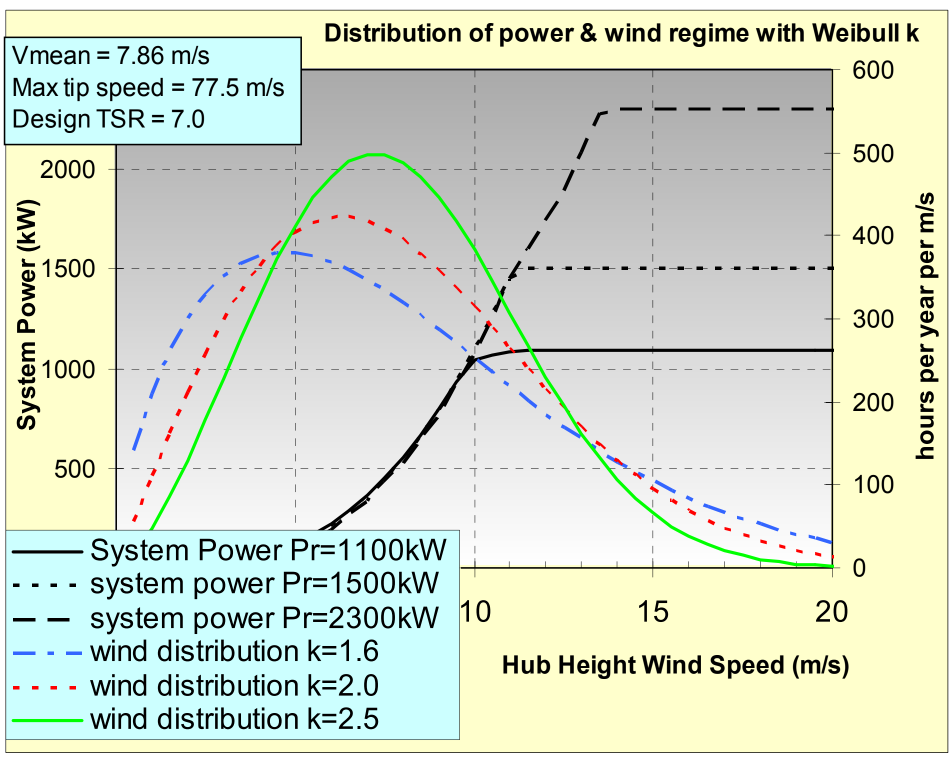

Figure 4-11. Effect of Weibull k on wind distribution and power generation curves.

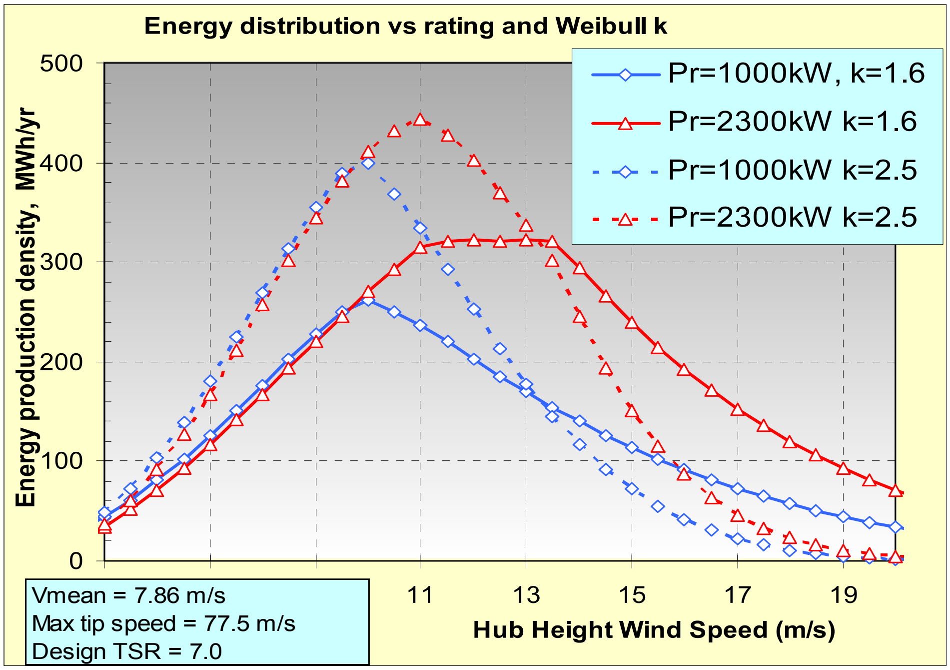

Figure 4-12. Effect of Weibull shape factor, k, on energy production.

The effect of the Weibull shape factor on total AEP and overall COE (while maintaining the mean wind speed at 7.86 m/s) is summarized in Figure 4-13. The effect on the annual energy is greatest at the lower ratings at which there is a penalty for low shape factors. This is because of a lack of compatibility between the power curve and the wind distribution curve. It is explained by reference to Figure 4-12, which shows that for a machine rating of 1000 kW, the shape factor of k = 2.5 is superior to the shape factor of k = 1.6 because there are more hours near peak power. On the other hand, for a rating of 2300 kW, a shape factor of 1.6 has more hours at peak power than a shape factor of 2.5. The implications on COE are that lower shape factors lead to higher optimum specific ratings and vice versa.

4.3.2 Effect of Mean Wind Speed and Design Class

Increases in the wind speed naturally lead to greater energy production and lower overall cost of energy. In addition, the sensitivity to machine rating changes so that the optimum specific rating can also change. Figure 4-14 summarizes these results and shows the effect of simultaneously changing the design class for the lower wind regimes.

Figure 4-14 shows that, as well as overall increases in the COE, the lower wind regimes are associated with lower optimum specific ratings. This supports the popular wisdom that lower specific ratings are suitable for lower wind regimes. For the lowest wind regime (Vmean = 6.0 m/s), the optimum rating may be below 1000 kW, implying a

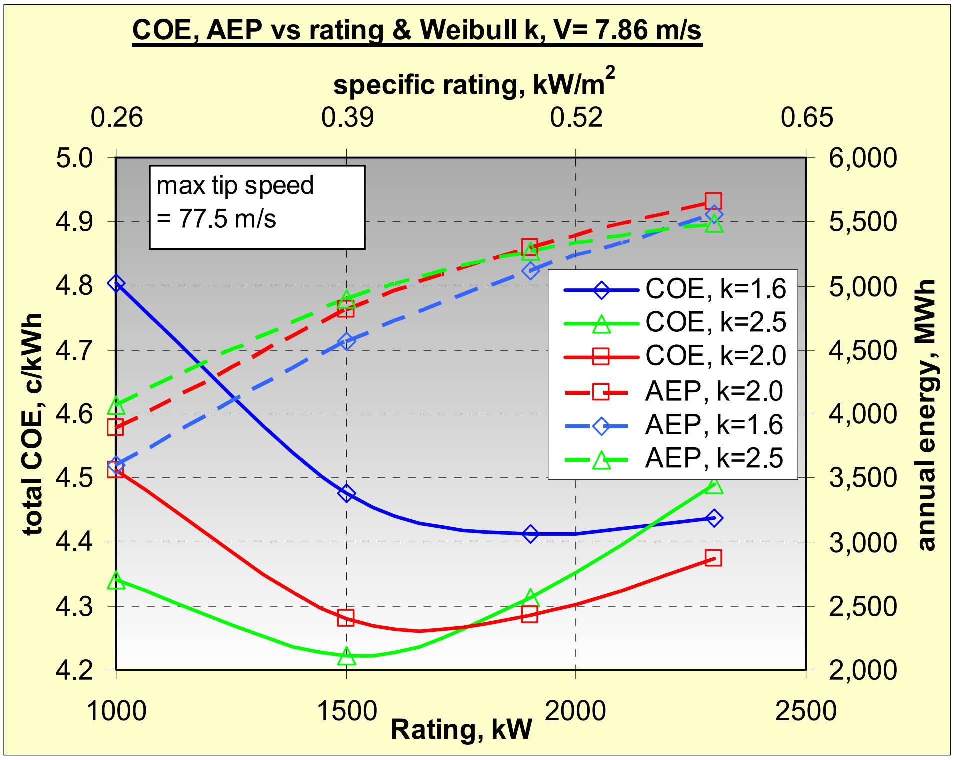

Figure 4-13. Effect of Weibull shape factor on AEP and COE.

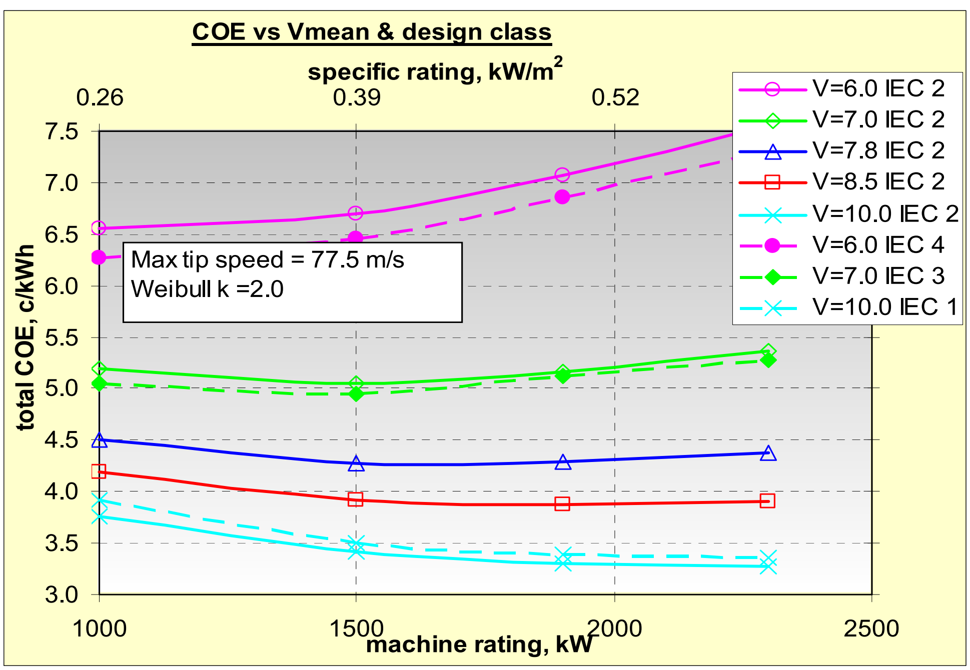

Figure 4-14. Effect on COE of mean wind speed and design class.

specific rating of less than 0.25. Figure 4-14 also shows that the effect of changing the design class while changing the production wind regime is significant only for the lowest of the wind regimes. The figure includes a line for a mean wind speed of 10.0 m/s while using an IEC design class 2; this implies a non-acceptable combination because IEC class 2 is limited to a mean wind speed of 8.5 m/s.

4.4 Task #15: Rating Changes Using Advanced Blade

The objective of Task #15 was to determine how the previous results, obtained using the baseline blade design, are affected by changing to the more advanced blade identified in Task #5 of the Rotor Design Study [1]. The main features of the advanced blade are:

- A design tip speed ratio of 8.0 and a maximum chord/radius ratio of 0.06
- Incorporation of a carbon fiber spar outboard of the 25% span section
- Incorporation of biased carbon plies in the skin to cause flap-twist coupling in the blade response.

In addition, the control system included feedback from the tower to ameliorate thrust and tower fatigue.

In a manner similar to that carried out in Task #13, the 1500-kW configuration was selected and modeled with a range of design tip speed ratios. The effect of these on the cost of energy is shown in Figure 4-15.

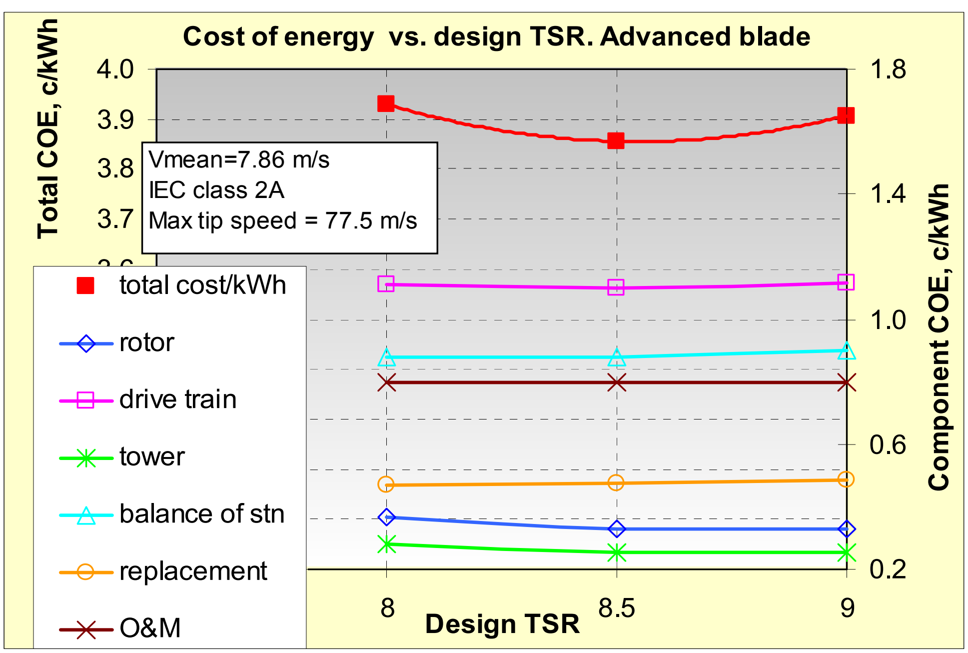

Figure 4-15. Effect of design TSR on the COE using the advanced blade design.

The design tip speed ratio of 8.5 was selected as the optimum and was used to study the effect of rating on the COE using this type of blade design. Those results are shown in Figure 4-16, which also includes the corresponding results from the baseline blade for comparison. The shapes of the two curves for total COE are similar, but the advanced blade has an optimum at a slightly lower rating. This is because the use of the advanced blade has reduced the cost of the lower rating design more than for the higher rating design. The costs of the rotor and the tower have been most strongly affected.

4.5 Task #16: Diameter Changes

The results obtained in the preceding tasks have involved changing the specific rating by changing the rating, while maintaining a rotor diameter of 70 m. The objective of Task #16 was to confirm that similar results can be obtained by adopting the reverse approach: maintaining a rating of 1500 kW while changing the diameter. In order to do this, some changes were made to the cost models and approach:

- The total wind farm rating and number of machines were unaltered.
- The blades were scaled from the baseline and the same ratio of chord to diameter, etc., was maintained. This allowed several other parameters to be kept constant although, in practice, manufacturers may add blade extenders to achieve greater diameters.
- The maximum tip speeds of the rotors were maintained at 77.5 m/s.
- The hub height was kept constant at 84.0 m for all configurations.
- The transportation costs were assumed to be shared equally between the tower and all other components. The costs for the tower were assumed constant, while the other half were assumed proportional to rating.
- The assembly costs were regarded as being most sensitive to hub height and were, therefore, kept constant.
- The spacing of the rotors was dependent on the rotor diameter so that the required length of roads and cables was affected.

The results of this approach are presented in Figure 4-17, which shows an optimum rotor diameter at about 69 m, corresponding to a specific rating of 0.40 kW/m^2. This is somewhat less than the optimum of 0.43 kW/m^2 obtained from Task #12, but it does indicate a similar pattern. The Task #12 results (Figure 4-17) demonstrated that the choice of abscissa scale can affect the apparent value of the optimum specific rating.

The range of specific ratings covered in Figure 4-17 has been chosen to be the same as the range of specific ratings in Figure 4-3 (Task #12), but the range of COE values is considerably greater. Changing the rotor diameter from 70 m to 56.5 m while maintaining the 1500-kW rating has a greater effect on COE than changing from 1500 kW to 2300 kW while maintaining a 70-m diameter.

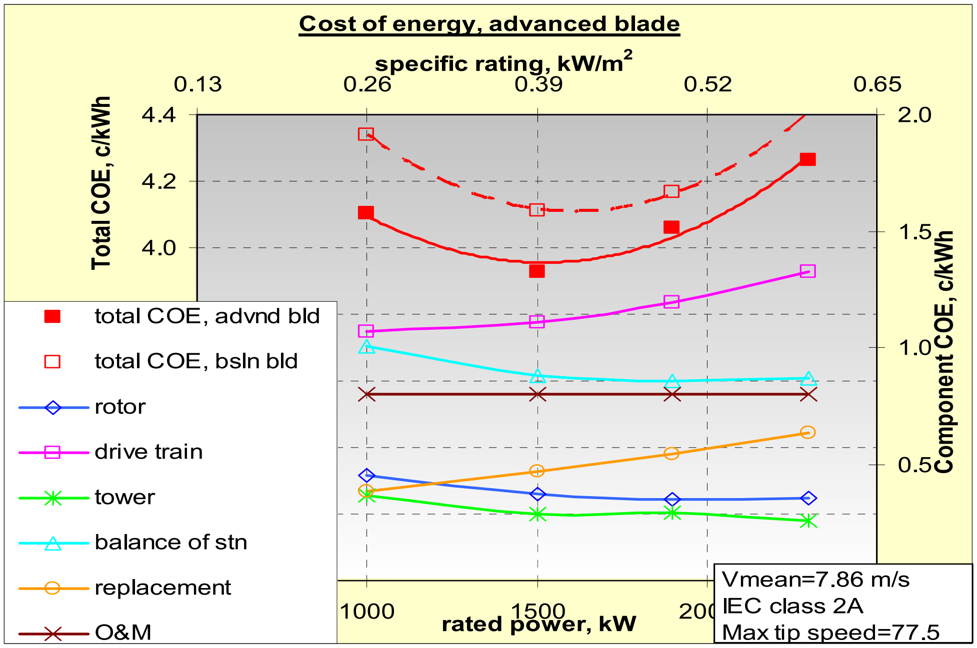

Figure 4-16. Effect of rating on COE using the advanced blade design.

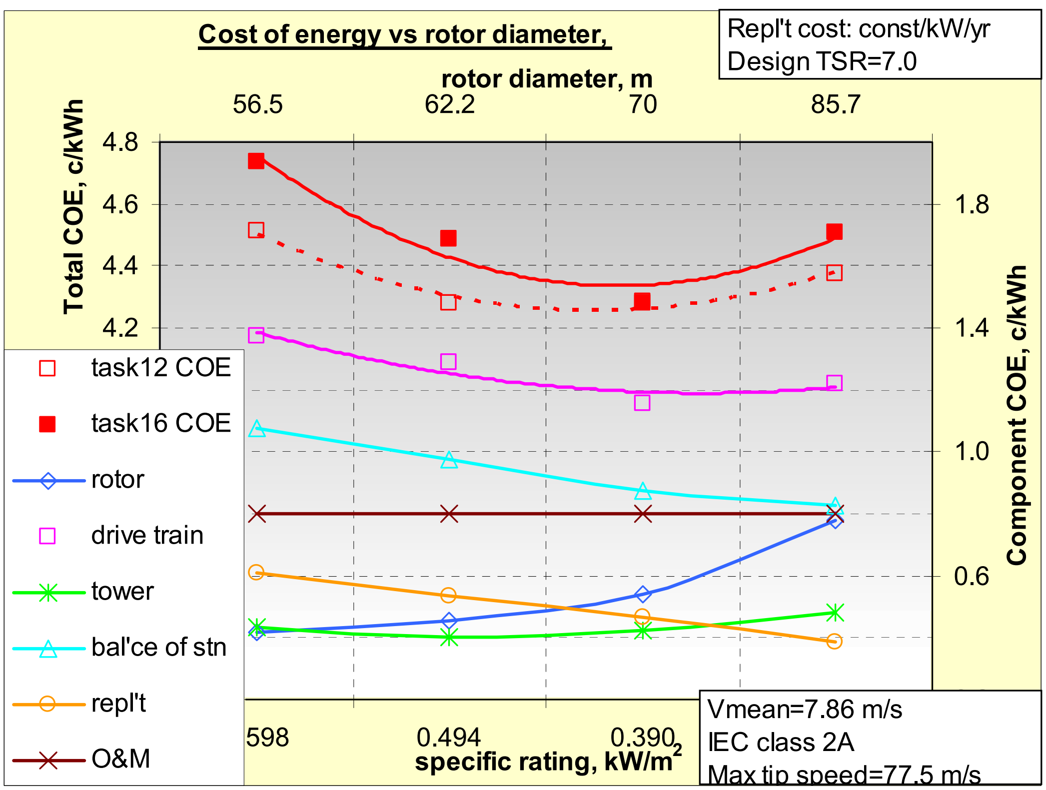

Figure 4-17. Effect of rotor diameter on COE, 1500-kW, baseline blade design.

There are several reasons for this. In changing the diameter from 70 m to 56.5 m in Task #16, the energy capture decreased by a factor of 1.30, but many of the costs decreased by much lesser amounts. While the rotor and drive-train costs were much reduced, the tower costs and balance-of-station costs decreased by lesser amounts. The tower cost is still high because the hub height is still 84 m (a height-to-diameter ratio of 1.50). The balance-of-station costs are still high because the foundations are for a tall tower, the assembly costs have been assumed the same, and the wind farm rating has not increased as it did for the 2300-kW machines.

One of our conclusions is that making machines of a certain specific rating will not, by itself, ensure a certain COE because there are other parameters, such as tower height and balance-of-station costs, that must also be equivalent.

5. Comparison with Other Sources

The presence of an optimum rating between 1500 and 2000 kW for the baseline configuration is compatible with the somewhat less rigorous exploration of the subject in the book by Burton, et al. [5]. In that text, the relationships between wind speed, blade chord, lift coefficient, power, blade weight, etc., are presented algebraically and conclusions are drawn for a 60-m-diameter rotor. The results from Table 6.3 of Burton [5] are compared with those from Section 4.1 for the baseline configuration in Figure 5-1.

The agreement is good in the range of mean wind speeds between 7.0 and 8.0 m/s (and below 7.0 m/s by extrapolation). At higher wind speeds, the approach by Burton, et al. points to higher optimum ratings; this would be compatible with the results obtained in the current study if, for example, the replacement costs were proportional to energy production rather than to rating.

In January 2001, Fingersh [6] presented results of work relating mean wind speed, rated power, rated wind speed, and AEP. This work did not include any costing or the influence of changes on the component costs. However, the relationships between rated wind speed, which can be used as a measure of rated power, and AEP are very close to those obtained in the present study (Figure 5-2).

Use of the rated wind speed can lead to some uncertainty because it is often difficult to identify this value precisely. The power curve in the region of the transition from variable speed to constant speed or rated power is usually a curve with a radius that depends on a number of control parameters. There is no agreement as to whether the rated wind speed corresponds to the intersection of the tangents to the two regions or whether it corresponds to where power begins to fall below rated.

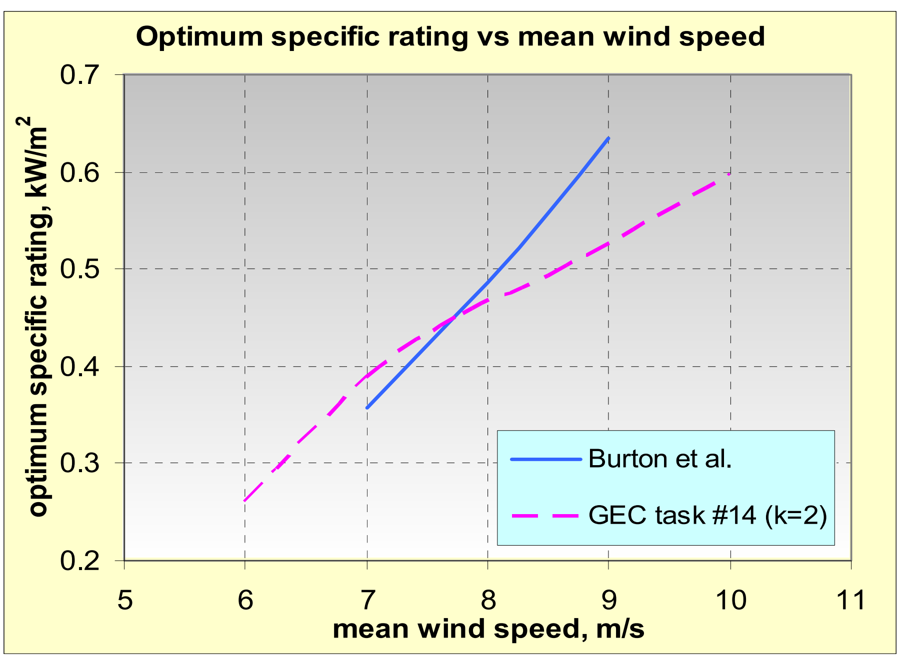

Figure 5-1. Comparison of optimum specific rating vs. annual wind speed.

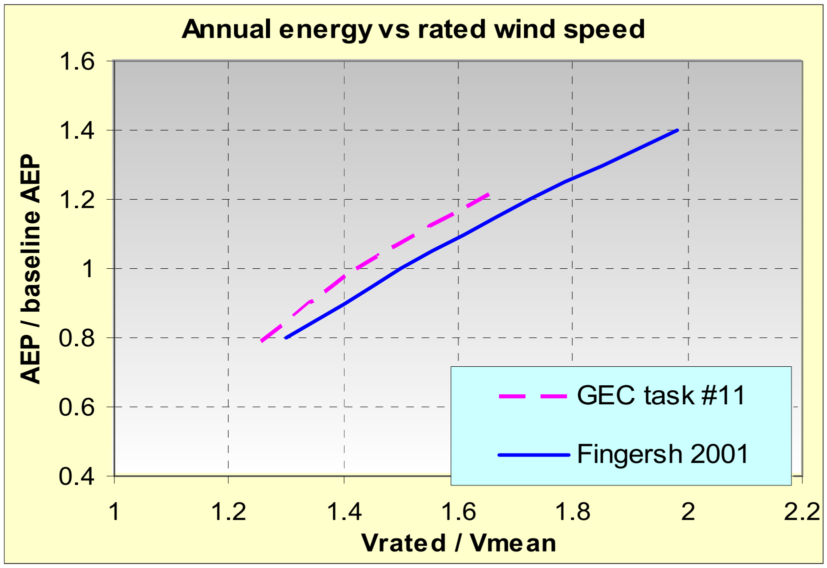

Figure 5-2. Comparison of rated wind speeds vs. annual energy production.

6. Summary

Several conclusions may be drawn from this study.

An optimum value of the specific rating (i.e., minimum overall COE) does exist in the range of 0.25 to 0.60 kW/m^2 for the types of wind turbines examined. This optimum is affected by many parameters, including:

- Maximum tip speed
- Design tip speed ratio
- Cost models for maintenance and for replacement costs
- Mean wind speed
- Weibull shape factor
- IEC design class.

These parameters and their effects on the optimum specific rating are summarized in Table 6-1.

While increasing the maximum tip speed increases the AEP, at all higher ratings it is accompanied by higher fatigue loads, which results in slightly higher COE. The effect on optimum specific rating is small, but at lower specific ratings, the effect on COE is considerable.

Increasing the design tip speed ratio of the blade can lower the COE for both the baseline design and the advanced blade design. In each case, the optimum specific rating was also lowered.

As expected, the optimum specific rating increases with increasing mean wind speed and with decreasing Weibull shape factor. The contribution to the total COE of items such as O&M and replacement costs are as great as or greater than those of the rotor or the tower. Therefore, it is not surprising that the influence of the cost models for the former can have a greater influence than the latter items on the optimum specific rating. Higher specific ratings will be favored when the costs of O&M and replacement costs are not proportional to the rating.

The use of more advanced carbon fiber blades with flap twist coupling and higher design tip speed ratios results in optimum values of specific rating similar to those for the baseline blade. However, the advanced blade benefits the COE more at lower specific ratings than at higher specific ratings. In addition, there is less certainty in the cost model for the advanced blade and whether the flap-twist coupling properties can be achieved in practice.

Changing the rotor diameter instead of changing the machine rating also results in an identifiable optimum specific rating but with a somewhat lower value. This is not surprising in view of the many steps involved in the derivation of the two sets of values. Although the specific ratings of the two sets of machines were identical, there were still many differences in other conditions, such as the tower/diameter ratio, the weighting of the balance-of-station costs, and the rating of the wind farm.

This study has largely confirmed the trends that have been presented elsewhere. However, the current report is accompanied by a consistent set of assumptions, cost models, and detailed cost results. This study has allowed a full investigation of several parameters that may affect the optimum specific rating.

The optimum specific ratings for both the baseline and the advanced blade designs are close to those used in the earlier Rotor Design Study [1]. The changes suggested in this study for optimum design tip speed ratios and specific rating are not likely to invalidate earlier findings.

This study has focused on wind turbines designed to the onshore IEC code [1], and all results are applicable to such locations. Offshore installations are typified by lower turbulence levels than would be found in onshore locations, which means that the rating of a given configuration can be safely increased if installed offshore. This, in turn, implies a higher specific rating.

A further restriction of this study has been the neglect of aeroacoustic effects. In practice, there may be a penalty for adopting the higher tip speeds advocated in Task #11. However, most of the configurations of this study have used a maximum tip speed of 77.5 m/s, and any penalties will be equally applied to all of those configurations.

Table 6-1. Summary of Features in Each Analysis and the Resulting Optimum Specific Ratings

Parameter	Task 11	Task 11	Task 12	Task 12	Task 13	Task 14	Task 14	Task 14	Task 14	Task 14	Task 14	Task 14	Task 14	Task 15	Task 16
Baseline configuration	x	x	x	x	x	x	x	x	x	x	x	x	x		
Advanced blade configuration														x	
Variable maximum tip speed	x	x													
Maximum tip speed = 77.5 m/s			x	x	x	x	x	x	x	x	x	x	x	x	
Repl’t costs α rating	x		x		x	x	x	x	x	x	x	x	x	x	
Repl’t costs α AEP		x		x											
Weibull k = 1.6						x									
Weibull k = 2.0	x	x	x	x	x		x		x	x	x	x	x	x	
Weibull k = 2.5								x							
Mean wind speed = 6.0m/s									x						
Mean wind speed = 7.0m/s										x					

Table 6-1. Summary of Features in Each Analysis and the Resulting Optimum Specific Ratings (continued)

Parameter	Task 11	Task 11	Task 12	Task 12	Task 13	Task 14	Task 14	Task 14	Task 14	Task 14	Task 14	Task 14	Task 14	Task 15	Task 16
Mean wind speed = 7.8m/s	x	x	x	x	x	x	x	x			x				
Mean wind speed = 8.5m/s												x		x	
Mean wind speed = 10 m/s													x		
IEC design class 1															
IEC design class 2	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
IEC design class 3															
Design tip speed ratio = 7.0	x	x	x	x		x	x	x	x	x	x	x	x		
Design tip speed ratio = 8.0					x										
Design tip speed ratio = 8.5														x	
Optimum rating, kW	1700	1950	1650	2000	1600	1900	1700	1500	1000	1500	1700	1900	2300	1500	1500
Rotor diameter, m	70	70	70	70	70	70	70	70	70	70	70	70	70	70	69
Optimum specific rating, kW/m^2	0.442	0.507	0.429	0.520	0.416	0.494	0.442	0.390	0.260	0.390	0.442	0.494	0.598	0.390	0.400

7. References

1. Malcolm, D.J.; Hansen, A.C. *WindPACT Turbine Rotor Design Study.* NREL/SR-500-32495. Work performed by Global Energy Concepts, Kirkland, WA. Golden, CO: National Renewable Energy Laboratory, August 2002.
2. Malcolm, D.J.; Hansen, A.C. (June 2002). "Lessons Learned from the WindPACT Rotor Design Study." *WindPower 2002 Proceedings*. Portland, OR: American Wind Energy Association.
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4. International Electrotechnical Commission. *Safety of Wind Turbine Conversion Systems*. IEC 61400-1, 1998.
5. Burton, T.; Sharpe, D.; Jenkins, N.; Bossanyi, E. *Wind Energy Handbook*, United Kingdom: Wiley Europe, 2001.
6. Fingersh, L.J. (January 2001). "An Investigation of the Effects of Wind Probability Density Functions and Wind Turbine Specific Power on Energy Capture." Oral presentation at *AIAA/ASME Wind Energy Symposium*, Reno, NV.

Appendix A: Detailed Costs and Loads for Tasks #11, #12, and #13

Detailed Costs for Tasks #11, #12, and #13

	units	task 11				task 12				task 13				task 13			
rating	kW	1000	1500	1900	2300	1000	1500	1900	2300	1500	1500	1500	1500	1000	1500	1900	2300
spec rating	kW/m^2	0.260	0.390	0.494	0.598	0.260	0.390	0.494	0.598	0.390	0.390	0.390	0.390	0.260	0.390	0.494	0.598
design tip speed ratio		7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	6.5	7.0	8.0	8.5	8.0	8.0	8.0	8.0
hub height mean wind speed	m/s	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86
design class		IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A
filename		1.0A01C01 V01	1.5A10C01 V00	1.9A01C01V 00	2.3A01C01 V00	1.0A02C01 V00	1.5A10C01 V00	1.9A01C02 V01	2.3A02C0 1V00	1.5A13C01 V01	1.5A10C0 1V00	1.5A12C01 V00	1.5A14C01 V01	1.0A03C01 V01	1.5A12C01 V00	1.9A03C01 V00	2.3A03C01 V01
Rotor	$1,000	**227**	**246**	**271**	**282**	**232**	**246**	**252**	**258**	**266**	**246**	**212**	**285**	**213**	**212**	**221**	**230**
blades	$1,000	146	159	176	183	146	159	163	167	166	159	149	226	150	149	155	164
hub	$1,000	44	52	60	65	49	52	55	56	56	52	38	37	37	38	40	40
pitch mechanism and bearings	$1,000	38	35	35	35	37	35	35	35	44	35	25	22	26	25	25	26
Drive train,nacelle	$1,000	**416**	**528**	**609**	**690**	**413**	**528**	**613**	**701**	**536**	**528**	**509**	**507**	**397**	**509**	**597**	**692**
low speed shaft	$1,000	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
bearings	$1,000	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
gearbox	$1,000	123	149	167	188	113	149	176	204	152	149	146	146	116	146	176	205
mechanical brake, HS coupling e	$1,000	2	3	4	5	2	3	4	5	3	3	3	3	2	3	4	5
generator	$1,000	52	78	99	120	52	78	99	120	78	78	78	78	52	78	99	120
variable speed electronics	$1,000	54	81	103	124	54	81	103	124	81	81	81	81	54	81	103	124
yaw drive & bearing	$1,000	12	12	12	12	12	12	12	12	13	12	8	8	8	8	8	9
main frame	$1,000	63	69	71	71	68	69	67	66	72	69	58	57	56	58	57	59
electrical connections	$1,000	40	60	76	92	40	60	76	92	60	60	60	60	40	60	76	92
hydraulic system	$1,000	5	7	9	10	5	7	9	10	7	7	7	7	5	7	9	10
nacelle cover	$1,000	34	36	37	37	36	36	36	35	38	36	35	35	32	35	35	36
Control, safety system	$1,000	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Tower	$1,000	**170**	**192**	**211**	**212**	**188**	**192**	**190**	**191**	**205**	**192**	**160**	**151**	**161**	**160**	**157**	**161**
Balance of station	$1,000	**382**	**400**	**418**	**435**	**382**	**400**	**415**	**430**	**403**	**400**	**398**	**398**	**385**	**398**	**413**	**429**
Foundations	$1,000	62	62	66	69	61	62	63	64	65	62	60	60	64	60	61	63
Transportation	$1,000	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Roads, civil works	$1,000	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
Assembly & installation	$1,000	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Electrical interface/connections	$1,000	107	125	139	153	107	125	139	153	125	125	125	125	107	125	139	153
Permits, engineering	$1,000	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
Initial capital cost (ICC)	$1,000	**1,205**	**1,375**	**1,519**	**1,629**	**1,224**	**1,375**	**1,480**	**1,589**	**1,421**	**1,375**	**1,288**	**1,351**	**1,166**	**1,288**	**1,397**	**1,522**
Net annual energy production	kWh	**3,898**	**4,818**	**5,339**	**5,725**	**3,886**	**4,818**	**5,303**	**5,661**	**4,829**	**4,818**	**4,786**	**4,765**	**3,900**	**4,786**	**5,230**	**5,421**
Rotor	$/kWh	0.61513	0.539	0.536	0.520	0.629	0.539	0.502	0.480	0.58233	0.539	0.467	0.632	0.578	0.467	0.445	0.447
Drive train	$/kWh	1.12633	1.156	1.205	1.273	1.121	1.156	1.220	1.307	1.17307	1.156	1.123	1.124	1.074	1.123	1.205	1.348
Controls	$/kWh	0.02763	0.022	0.020	0.019	0.028	0.022	0.020	0.019	0.02230	0.022	0.023	0.023	0.028	0.023	0.021	0.020
Tower	$/kWh	0.46159	0.421	0.417	0.391	0.510	0.421	0.378	0.355	0.44841	0.421	0.353	0.334	0.436	0.353	0.318	0.314
Balance of st'n	$/kWh	1.03503	0.876	0.828	0.803	1.037	0.876	0.827	0.802	0.88100	0.876	0.877	0.882	1.041	0.877	0.833	0.837
Replace't costs	$/kWh	0.38484	0.467	0.534	0.603	0.386	0.467	0.537	0.609	0.46593	0.467	0.470	0.472	0.385	0.470	0.545	0.636
O & M	$/kWh	0.80000	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.80000	0.800	0.800	0.800	0.800	0.800	0.800	0.800
Total COE	$/kWh	**4.45056**	**4.281**	**4.339**	**4.408**	**4.512**	**4.281**	**4.285**	**4.373**	**4.37304**	**4.281**	**4.113**	**4.266**	**4.341**	**4.113**	**4.167**	**4.402**

Detailed Loads for Tasks #11, #12, and #13

		units	SN expnt	task 11				task 12				task 13				task 13			
rating		kW		1000	1500	1900	2300	1000	1500	1900	2300	1500	1500	1500	1500	1000	1500	1900	2300
specific rating		kW/m^2		0.260	0.390	0.494	0.598	0.260	0.390	0.494	0.598	0.390	0.390	0.390	0.390	0.260	0.390	0.494	0.598
design tip speed ratio				7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	6.5	7.0	8.0	8.5	8.0	8.0	8.0	8.0
hub height mean wind speed		m/s		7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86
file name				1.0A01C01 V00	1.5A10C01 V00	1.9A01C01 V00	2.3A01C01 V00	1.0A02C01 V00	1.5A10C01 V00	1.9A01C02 V01	2.3A02C01 V00	1.5A13C01 V01	1.5A10C01 V00	1.5A12C01 V00	1.5A14C01 V01	1.0A03C01 V01	1.5A12C01 V00	1.9A03C01 V00	2.3A03C01 V01
tilt angle		deg		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
coning angle		deg		0	0	0	0	0	0	0	0	0	0	1	0	1	1	1	1
angle of first contact		deg		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
max tip out of plane displt	max abs	m		2.837	2.791	2.662	3.147	2.648	2.791	2.709	3.198	2.848	2.791	3.271	4.889	3.256	3.271	3.604	4.205
min tip out of plane displt	max abs	m		-2.366	-1.995	-1.748	-1.728	-2.395	-1.995	-1.639	-1.519	-2.132	-1.995	-2.905	-2.629	-3.531	-2.905	-2.645	-2.323
tip-tower clearance margin				0.160	0.145	0.180	-0.008	0.216	0.145	0.184	0.003	0.106	0.145	-0.025	-0.310	-0.023	-0.025	-0.101	-0.216
blade rt flap mt	max abs	kN m		3,466	3,261	3,232	3,223	3,419	3,261	3,232	3,230	3,931	3,261	2,459	2,208	2,544	2,459	2,490	2,511
	equiv fatigue	kN m	12	1,105	1,337	1,538	1,641	1,252	1,337	1,405	1,446	1,446	1,337	974	952	949	974	1,009	1,028
blade rt edge mt	max abs	kN m		802	1,007	1,239	1,322	993	1,007	1,124	1,203	1,165	1,007	860	999	757	860	874	961
	equiv fatigue	kN m	12	743	939	1,090	1,102	849	939	1,075	1,105	874	939	888	1,107	779	888	927	991
blade 25% flap mt	max abs	kN m		1,337	1,363	1,536	1,824	1,346	1,363	1,392	1,786	1,536	1,363	1,040	936	1,021	1,040	1,089	1,320
	equiv fatigue	kN m	12	657	784	900	968	735	784	821	853	869	784	538	501	531	538	564	581
blade 25% edge mt	max abs	kN m		408	438	540	655	427	438	480	519	491	438	401	406	385	401	404	440
	equiv fatigue	kN m	12	343	426	489	495	393	426	481	493	408	426	394	472	348	394	407	440
blade 50% flap mt	max abs	kN m		569	605	670	800	605	605	625	817	696	605	430	408	423	430	489	580
	equiv fatigue	kN m	12	305	360	409	439	338	360	373	387	410	360	237	207	236	237	246	259
blade 50% edge mt	max abs	kN m		138	161	183	206	151	161	169	198	164	161	134	156	129	134	139	190
	equiv fatigue	kN m	12	116	140	158	160	129	140	156	161	136	140	125	141	113	125	127	139
blade 75% flap mt	max abs	kN m		140	153	171	193	157	153	159	211	185	153	108	97	107	108	126	148
	equiv fatigue	kN m	12	79	94	106	112	88	94	96	100	109	94	63	57	63	63	64	70
blade 75% edge mt	max abs	kN m		33	35	41	44	35	35	36	50	40	35	28	28	27	28	30	42
	equiv fatigue	kN m	12	22	25	27	28	24	25	27	27	26	25	21	22	20	21	21	23
shaft/hub My	max abs	kN m		2,407	2,526	2,515	2,418	2,545	2,526	2,508	2,425	2,972	2,526	1,513	1,229	1,575	1,513	1,420	1,715
	equiv fatigue	kN m	3	532	624	684	707	608	624	646	645	673	624	451	417	439	451	451	446
shaft/hub Mz	max abs	kN m		2,379	2,412	2,390	2,327	2,439	2,412	2,368	2,390	2,736	2,412	1,672	1,460	1,696	1,672	1,591	2,106
	equiv fatigue	kN m	3	529	622	682	707	614	622	641	645	681	622	451	418	441	451	448	444
shaft thrust	max abs	kN		270	360	428	478	300	360	383	398	389	360	295	274	261	295	300	319
	equiv fatigue	kN	3	40	48	54	57	46	48	47	47	53	48	36	34	37	36	35	36
shaft Mx	max abs	kN m		3,456	3,579	3,561	3,594	3,468	3,579	3,561	3,582	3,952	3,579	2,666	2,762	2,859	2,666	2,714	2,801
	equiv fatigue	kN m	3	67	74	77	85	57	74	94	122	77	74	91	90	56	91	122	129
yaw brg My	max abs	kN m		2,993	3,099	3,127	3,005	2,974	3,099	3,146	3,079	3,341	3,099	2,204	2,128	2,210	2,204	2,111	2,389
	equiv fatigue	kN m	3	428	511	560	582	489	511	531	536	543	511	375	341	364	375	377	378
yaw btg Mz	max abs	kN m		1,808	1,817	1,726	1,759	1,754	1,817	1,726	1,810	1,960	1,817	1,558	1,262	1,597	1,558	1,423	1,644
	equiv fatigue	kN m	3	431	509	566	584	495	509	536	542	546	509	377	341	365	377	378	376
tower base Mx	max abs	kN m		30,009	29,566	31,489	32,629	29,677	29,566	31,489	32,447	33,028	29,566	27,848	28,419	32,850	27,848	28,958	31,791
	equiv fatigue	kN m	3	2,056	2,045	2,111	2,163	2,154	2,045	2,156	2,127	2,304	2,045	1,693	1,521	1,676	1,693	1,666	1,708
tower base My	max abs	kN m		22,316	30,079	35,136	38,378	26,116	30,079	31,544	31,863	33,532	30,079	24,896	22,642	22,250	24,896	25,505	29,280
	equiv fatigue	kN m	3	4,930	5,917	6,640	6,750	5,653	5,917	5,869	5,774	6,593	5,917	4,486	4,078	4,480	4,486	4,330	4,438

Appendix B: Detailed Costs for Task #14

Detailed Costs for Task #14

	units	task 14				task 14				task 14				task 14				task 14				task 14		
rating	kW	1000	1500	1900	2300	1000	1500	1900	2300	1500	1500	1500	1500	1000	1500	1900	2300	1000	1500	1900	2300	1500	1500	1500
spec rating	kW/m^2	0.260	0.390	0.494	0.598	0.260	0.390	0.494	0.598	0.390	0.390	0.390	0.390	0.260	0.390	0.494	0.598	0.260	0.390	0.494	0.598	0.390	0.390	0.390
design tip speed ratio		7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
hub height mean wind speed	m/s	6.00	6.00	6.00	6.00	7.00	7.00	7.00	7.00	10.00	10.00	10.00	10.00	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.00	6.00	6.00
Weibull shape factor, k		2.00	2.00	2.00	2.00	2.00	2.00	2.00		2.00	2.00	2.00	2.00	1.60	1.60	1.60	1.60	2.50	2.50	2.50	2.50	2.00	2.00	2.00
design class		IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC3A	IEC3A	IEC4A
filename		1.0A02C01 V00b	1.5A10C0 1V00b	1.9A02C01 V01b	2.3A02C01 V01b	1.0A02C0 1V00a	1.5A10C0 1V00a	1.9A02C0 1V01a	2.3A02C 01V01a	1.0A02C0 1V00g	1.5A10C 01V00g	1.9A02C0 1V01g	2.3A02C01 V01g	1.0A02C0 1V00c	1.5A10C0 1V00c	1.9A02C0 1V01c	2.3A02C0 1V01c	1.0A02C0 1V00d	1.5A10C01 V00d	1.9A02C0 1V01d	2.3A02C0 1V01d	1.5A10C01 V01e	1.5A10C01 V01f	1.5A10C01 V00f
Rotor	$k	**243**	**246**	**252**	**258**	**243**	**246**	**252**	**258**	**232**	**246**	**252**	**258**	**232**	**246**	**252**	**258**	**232**	**246**	**252**	**258**	**227**	**213**	**232**
blades	$k	157	159	163	167	157	159	163	167	146	159	163	167	146	159	163	167	146	159	163	167	151	145	159
hub	$k	49	52	55	56	49	52	55	56	49	52	55	56	49	52	55	56	49	52	55	56	50	45	47
pitch mechanism and bearings	$k	37	35	35	35	37	35	35	35	37	35	35	35	37	35	35	35	37	35	35	35	26	23	26
Drive train,nacelle	$k	**413**	**528**	**613**	**701**	**413**	**528**	**613**	**701**	**413**	**528**	**613**	**701**	**413**	**528**	**613**	**701**	**413**	**528**	**613**	**701**	**523**	**521**	**520**
low speed shaft	$k	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
bearings	$k	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
gearbox	$k	113	149	176	204	113	149	176	204	113	149	176	204	113	149	176	204	113	149	176	204	149	151	149
mechanical brake, HS coupling e	$k	2	3	4	5	2	3	4	5	2	3	4	5	2	3	4	5	2	3	4	5	3	3	3
generator	$k	52	78	99	120	52	78	99	120	52	78	99	120	52	78	99	120	52	78	99	120	78	78	78
variable speed electronics	$k	54	81	103	124	54	81	103	124	54	81	103	124	54	81	103	124	54	81	103	124	81	81	81
yaw drive & bearing	$k	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	11	12
main frame	$k	68	69	67	66	68	69	67	66	68	69	67	66	68	69	67	66	68	69	67	66	66	63	63
electrical connections	$k	40	60	76	92	40	60	76	92	40	60	76	92	40	60	76	92	40	60	76	92	60	60	60
hydraulic system	$k	5	7	9	10	5	7	9	10	5	7	9	10	5	7	9	10	5	7	9	10	7	7	7
nacelle cover	$k	36	36	36	35	36	36	36	35	36	36	36	35	36	36	36	35	36	36	36	35	36	36	36
Control, safety system	$k	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Tower	$k	**188**	**192**	**190**	**191**	**188**	**192**	**190**	**191**	**188**	**192**	**190**	**191**	**188**	**192**	**190**	**191**	**188**	**192**	**190**	**191**	**175**	**164**	**162**
Balance of station	$k	**382**	**400**	**415**	**430**	**382**	**400**	**415**	**430**	**382**	**400**	**415**	**430**	**382**	**400**	**415**	**430**	**382**	**400**	**415**	**430**	**400**	**401**	**400**
Foundations	$k	61	62	63	64	61	62	63	64	61	62	63	64	61	62	63	64	61	62	63	64	62	63	62
Transportation	$k	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Roads, civil works	$k	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
Assembly & installation	$k	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Electrical interface/connections	$k	107	125	139	153	107	125	139	153	107	125	139	153	107	125	139	153	107	125	139	153	125	125	125
Permits, engineering	$k	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
Initial capital cost (ICC)	$k	**1,235**	**1,375**	**1,480**	**1,589**	**1,235**	**1,375**	**1,480**	**1,589**	**1,224**	**1,375**	**1,480**	**1,589**	**1,224**	**1,375**	**1,480**	**1,589**	**1,224**	**1,375**	**1,480**	**1,589**	**1,334**	**1,309**	**1,324**
Net annual energy production	kWh	**2,527**	**2,843**	**2,948**	**2,993**	**3,307**	**3,944**	**4,235**	**4,425**	**4,874**	**6,430**	**7,376**	**8,172**	**3,601**	**4,564**	**5,116**	**5,561**	**4,076**	**4,902**	**5,262**	**5,484**	**3,944**	**2,843**	**2,843**
Rotor	$/kWh	1.014	0.914	0.903	0.909	0.775	0.659	0.629	0.615	0.502	0.404	0.361	0.333	0.679	0.569	0.521	0.489	0.600	0.530	0.506	0.496	0.607	0.791	0.862
Drive train	$/kWh	1.724	1.960	2.196	2.472	1.318	1.413	1.528	1.672	0.894	0.866	0.877	0.905	1.210	1.221	1.265	1.330	1.069	1.136	1.230	1.349	1.401	1.936	1.932
Controls	$/kWh	0.043	0.038	0.037	0.036	0.033	0.027	0.025	0.024	0.022	0.017	0.015	0.013	0.030	0.024	0.021	0.019	0.026	0.022	0.020	0.020	0.027	0.038	0.038
Tower	$/kWh	0.785	0.713	0.680	0.672	0.600	0.514	0.473	0.455	0.407	0.315	0.272	0.246	0.551	0.444	0.392	0.362	0.487	0.414	0.381	0.367	0.467	0.608	0.604
Balance of st'n	$/kWh	1.595	1.485	1.487	1.517	1.219	1.070	1.035	1.026	0.827	0.656	0.594	0.556	1.119	0.925	0.857	0.817	0.989	0.861	0.833	0.828	1.070	1.491	1.485
Replace't costs	$/kWh	0.594	0.792	0.967	1.153	0.454	0.571	0.673	0.780	0.308	0.350	0.386	0.422	0.416	0.493	0.557	0.620	0.368	0.459	0.542	0.629	0.571	0.792	0.792
O & M	$/kWh	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800
Total COE	$/kWh	**6.555**	**6.701**	**7.069**	**7.559**	**5.197**	**5.053**	**5.164**	**5.372**	**3.760**	**3.409**	**3.305**	**3.275**	**4.805**	**4.475**	**4.413**	**4.437**	**4.340**	**4.222**	**4.312**	**4.489**	**4.944**	**6.455**	**6.512**

Appendix C: Detailed Costs and Loads for Tasks #15 and #16

Detailed Costs for Tasks #15 and #16

	units	task 15				task 15			task 16			
rating	kW	1000	1500	1900	2300	1500	1500	1500	1500	1500	1500	1500
rotor diameter	m/s	70	70	70	70	70	70	70	56.5	62.2	70	85.7
spec rating	kW/m^2	0.260	0.390	0.494	0.598	0.390	0.390	0.390	0.598	0.494	0.390	0.260
design tip speed ratio		7.0	7.0	7.0	7.0	8.0	8.5	9.0	7.0	7.0	7.0	7.0
hub height mean wind speed	m/s	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86	7.86
Weibull shape factor, k		2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
design class		IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A
filename		1.0AA01C01V00	1.5AA17C01V00	1.9AA01C01V00	2.3AA01C01V00	1.5AA17C01V00	1.5AA18C01V00	1.5AA19C01V00	1.5A17C01V00	1.5A15C01V00	1.5A10C01V00	1.5A19C01V00
Rotor	$k	**167**	**168**	**173**	**183**	**168**	**149**	**145**	**147**	**181**	**246**	**429**
blades	$k	107	108	112	121	108	99	98	91	117	159	274
hub	$k	32	33	33	33	33	27	25	29	35	52	93
pitch mechanism and bearing	$k	28	28	28	28	28	22	22	28	29	35	62
Drive train,nacelle	$k	**394**	**505**	**593**	**679**	**505**	**496**	**492**	**482**	**513**	**528**	**673**
low speed shaft	$k	22	22	22	22	22	22	22	10	14	20	37
bearings	$k	12	12	12	12	12	12	12	6	8	12	25
gearbox	$k	116	151	180	209	151	151	149	122	134	149	185
mechanical brake, HS couplin	$k	2	3	4	5	3	3	3	3	3	3	3
generator	$k	52	78	99	120	78	78	78	98	98	78	98
variable speed electronics	$k	54	81	103	124	81	81	81	101	101	81	101
yaw drive & bearing	$k	7	6	6	6	6	5	5	8	8	12	23
main frame	$k	53	52	51	49	52	47	46	41	50	69	94
electrical connections	$k	40	60	76	92	60	60	60	60	60	60	60
hydraulic system	$k	5	7	9	10	7	7	7	7	7	7	7
nacelle cover	$k	32	32	31	30	32	29	29	27	30	36	41
Control, safety system	$k	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Tower	$k	**134**	**129**	**145**	**131**	**129**	**114**	**113**	**152**	**160**	**192**	**265**
Balance of station	$k	**372**	**401**	**424**	**447**	**401**	**397**	**398**	**378**	**388**	**400**	**454**
Foundations	$k	63	63	63	62	63	59	60	60	62	62	76
Transportation	$k	51	51	51	51	51	51	51	40	44	51	75
Roads, civil works	$k	79	79	79	79	79	79	79	68	72	79	93
Assembly & installation	$k	51	51	51	51	51	51	51	51	51	51	51
Electrical interface/connection	$k	107	125	139	153	125	125	125	127	127	125	127
Permits, engineering	$k	21	33	42	52	33	33	33	33	33	33	33
Initial capital cost (ICC)	$k	**1,078**	**1,213**	**1,345**	**1,451**	**1,213**	**1,166**	**1,157**	**1,169**	**1,252**	**1,375**	**1,831**
Net annual energy production	kWh	**3,900**	**4,811**	**5,230**	**5,421**	**4,811**	**4,765**	**4,658**	**3,706**	**4,199**	**4,818**	**5,821**
Rotor	$/kWh	0.451	0.369	0.349	0.356	0.369	0.329	0.329	0.420	0.455	0.539	0.778
Drive train	$/kWh	1.068	1.108	1.197	1.324	1.108	1.099	1.115	1.374	1.290	1.156	1.220
Controls	$/kWh	0.028	0.022	0.021	0.020	0.022	0.023	0.023	0.029	0.025	0.022	0.019
Tower	$/kWh	0.363	0.283	0.293	0.256	0.283	0.252	0.255	0.432	0.403	0.421	0.481
Balance of st'n	$/kWh	1.008	0.880	0.857	0.871	0.880	0.880	0.902	1.076	0.976	0.876	0.824
Replace't costs	$/kWh	0.385	0.468	0.545	0.636	0.468	0.472	0.483	0.607	0.536	0.467	0.387
O & M	$/kWh	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800	0.800
Total COE	$/kWh	**4.103**	**3.930**	**4.061**	**4.263**	**3.930**	**3.856**	**3.907**	**4.738**	**4.484**	**4.281**	**4.508**

Detailed Loads for Tasks #15 and #16

		units	SN expnt	task 15				task 15			task16			
rating		kW		1000	1500	1900	2300	1500	1500	1500	1500	1500	1500	1500
rotor diameter		m		70	70	70	70	70	70	70	56.5	62.2	70	85.7
specific rating		kW/m^2		0.260	0.390	0.494	0.598				0.598	0.494	0.390	0.260
design tip speed ratio				7.0	7.0	7.0	7.0	8.0	8.5	9.0	7.0	7.0	7.0	7.0
hub height mean wind speed		m/s		7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00	7.00
Weibull shape factor, k				2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Design class				IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A	IEC2A
file name				1.0AA01C01V00	1.5AA17C01V00	1.9AA01C01V00	2.3AA01C01V00	1.5AA17C01V	1.5AA18C01V	1.5AA19C01V	1.5A17C01V01	1.5A15C01V00	1.5A10C01V00	1.5A19C01V00
tilt angle		deg		5	5	5	5	5	5	5	5	5	5	5
coning angle		deg		1	1	1	1	1	1	1	0	0	0	0
angle of first contact		deg		0	0	0	0	0	0	0	0	0	0	0
max tip out of plane displt	max abs	m		2.246	2.388	2.746	3.167	2.388	3.158	3.202	1.837	2.819	2.791	2.835
min tip out of plane displt	max abs	m		-2.555	-2.299	-2.402	-2.402	-2.299	-2.778	-2.827	-1.174	-1.717	-1.995	-2.460
tip-tower clearance margin				0.390	0.283	0.146	0.022	0.283	0.093	0.084	0.364	0.012	0.145	0.367
blade rt flap mt	max abs	kN m		2,689	2,698	2,698	2,715	2,698	2,226	2,157	2,163	2,462	3,261	6,175
	equiv fatigue	kN m	12	835	847	865	892	847	706	658	738	908	1,337	2,415
blade rt edge mt	max abs	kN m		643	703	734	712	703	599	544	608	744	1,007	2,176
	equiv fatigue	kN m	12	477	469	474	489	469	425	409	498	603	939	1,990
blade 25% flap mt	max abs	kN m		1,069	1,071	1,090	1,242	1,071	887	833	871	1,024	1,363	2,527
	equiv fatigue	kN m	12	494	502	512	535	502	413	381	443	542	784	1,402
blade 25% edge mt	max abs	kN m		327	318	330	365	318	303	266	298	387	438	1,111
	equiv fatigue	kN m	12	221	208	209	221	208	181	170	227	275	426	898
blade 50% flap mt	max abs	kN m		399	407	449	511	407	358	317	381	445	605	1,073
	equiv fatigue	kN m	12	221	222	226	242	222	182	164	204	250	360	641
blade 50% edge mt	max abs	kN m		118	111	111	141	111	102	86	106	122	161	349
	equiv fatigue	kN m	12	75	72	75	83	72	63	57	76	91	140	290
blade 75% flap mt	max abs	kN m		85	88	102	115	88	78	65	92	109	153	278
	equiv fatigue	kN m	12	53	52	53	58	52	43	36	52	64	94	170
blade 75% edge mt	max abs	kN m		23	23	22	29	23	20	17	23	25	35	70
	equiv fatigue	kN m	12	15	14	14	15	14	12	10	14	17	25	50
shaft/hub My	max abs	kN m		1,594	1,455	1,354	1,310	1,455	1,121	1,056	1,465	1,742	2,526	4,515
	equiv fatigue	kN m	3	389	383	380	373	383	313	295	370	440	624	1,094
shaft/hub Mz	max abs	kN m		1,464	1,332	1,241	1,547	1,332	1,076	1,020	1,441	1,705	2,412	4,283
	equiv fatigue	kN m	3	391	383	380	375	383	315	294	372	441	622	1,098
shaft thrust	max abs	kN		236	260	281	298	260	241	233	301	320	360	485
	equiv fatigue	kN	3	35	32	31	32	32	26	25	33	37	48	76
shaft Mx	max abs	kN m		2,679	2,636	2,636	2,595	2,636	2,172	2,180	2,088	2,442	3,579	6,550
	equiv fatigue	kN m	3	67	103	133	141	103	104	110	78	74	74	112
yaw brg My	max abs	kN m		2,005	1,834	1,709	1,636	1,834	1,537	1,484	1,817	2,055	3,099	6,040
	equiv fatigue	kN m	3	317	312	310	308	312	254	240	317	363	511	878
yaw btg Mz	max abs	kN m		1,426	1,415	1,415	1,411	1,415	1,195	1,136	1,098	1,279	1,817	3,329
	equiv fatigue	kN m	3	328	327	324	320	327	268	252	320	363	509	886
tower base Mx	max abs	kN m		31,951	31,288	31,288	29,889	31,288	27,575	27,990	27,985	29,967	29,566	47,177
	equiv fatigue	kN m	3	1,552	1,617	1,594	1,702	1,617	1,388	1,304	1,595	1,614	2,045	3,101
tower base My	max abs	kN m		20,373	21,974	24,196	26,019	21,974	20,437	19,341	25,584	26,385	30,079	40,797
	equiv fatigue	kN m	3	3,298	3,081	3,024	3,222	3,081	2,563	2,469	4,116	4,567	5,917	9,675

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13. ABSTRACT *(Maximum 200 words)*

In 2000, the National Renewable Energy Laboratory (NREL) launched the Wind Partnerships for Advanced Component Technologies (WindPACT) program to examine ways in which the cost of wind energy could be reduced a further 30%. One element of the WindPACT program has been a series of design studies aimed at each of the major subsystems of the wind turbine to study the effect of scale and of alternative design approaches.

The *WindPACT Turbine Rotor Design Study* was carried out by Global Energy Concepts, LLC, (GEC) on behalf of NREL, and the final report was delivered in June 2002. The study examined what configuration and design changes in the rotor would reduce the overall cost of energy.

The objectives of this report are to use the 1.5-MW baseline configuration from the earlier WindPACT Rotor Design Study to examine the effect of different power ratings and to identify an optimum specific rating; to examine the effect of different maximum tip speeds on overall cost of energy (COE); to examine the role of different wind regimes on the optimum specific rating; and to examine how the optimum specific rating may be affected by introducing more advanced blade designs.

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