ADVANCED HORIZONTAL AXIS WIND TURBINES IN WINDFARMS

1.0 System Description

The system described here is a 50 turbine windfarm consisting of horizontal axis wind turbines for supplying bulk power to the grid. The turbine size changes over time, as described in section 4, causing the windfarm to increase from 25 MW in year 2000 to 50 MW in year 2005 and beyond. There are many different system designs for current commercial wind turbines. Figure 1 shows a generic horizontal axis wind turbine system. Although there is no standard system for classifying wind turbine subsystems, this document breaks the components shown in the figure into 4 basic subsystems: (1) a rotor, usually consisting of two or three blades, a hub through which the blades attach to the low speed drive shaft, and sometimes hydraulic or mechanically-driven linkage systems to pitch all or part of the blades; (2) a drive train, generally including a gearbox and generator, shafts and couplings, a nacelle cover for the entire drive train, and often a mechanical disk brake and/or yaw system including a motor and gears; (3) a tower and foundation that supports the rotor and drive train; and (4) electrical controls and cabling, and instrumentation for monitoring and control.

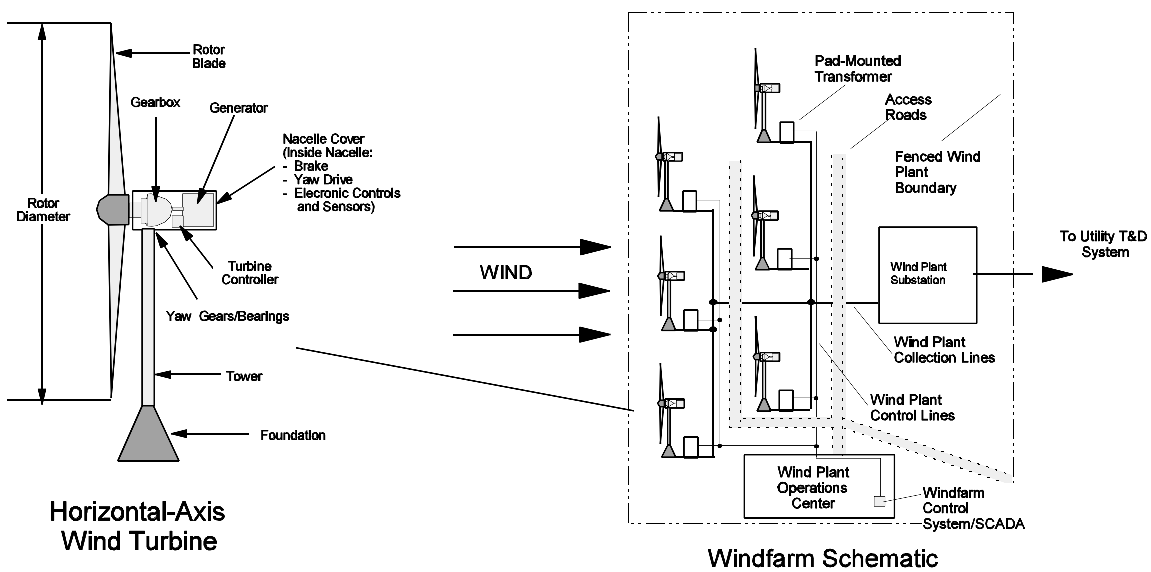

Figure 1. Horizontal axis wind turbine and windfarm system schematic.

The turbines characterized in this TC are composites that represent multiple, evolving design configurations for each 5-year time period. The generic turbine portrayed in Figure 1 can include any of these design features. For instance, one of several mechanisms may be employed to keep the rotor oriented properly in the wind stream. Some machines employ a non-motorized, or "passive" approach to control the turning, or yawing, motion while others have active motor-drive systems controlled by microprocessors. On most of the recently installed horizontal-axis machines, the blades are located on the upwind side of the tower; while a smaller number have been downwind. Some machines, called fixed-pitch turbines, have blades that are fixed to the hub in a single, stationary position, thereby reducing design complexity. Another design, called variable pitch, uses blades that can rotate (pitch) around their own axis in order to aid in starting, stopping, and regulating power output by changing the angle at which blades go through the air. Specific assumptions are made for each 5-year time period regarding the key design trends that are expected to drive cost and performance improvements. These are discussed in Section 4.

As shown in Figure 1, a windfarm is comprised of multiple turbines and various supporting balance of station (BOS) components exclusive of the turbines. These typically include roads, fences, ground support equipment for maintenance, operation and maintenance buildings, supplies and equipment, equipment for control of power flow and quality (e.g. switches, filters, and capacitors). Also included in BOS are electronics to control and monitor turbines in the windfarm (a microprocessor-based "Supervisory Control and Data Acquisition System," or SCADA), electrical wiring for power collection, and utility interconnection equipment such as transformers.

2.0 System Application, Benefits, and Impacts

Major Application: The major application for wind energy, in terms of potential for installed capacity, is the bulk power market. However, because of the changes underway due to utility restructuring, continuing low natural gas prices, and improving gas generation technology, the domestic market for wind energy is uncertain, especially in the near-term. Traditionally, the primary markets for windfarms were thought to be conventional utility and Independent Power Producer-owned projects. These markets may continue to provide opportunities. In the future, however, as utility restructuring accelerates, additional types of market opportunities may emerge, providing more near-term targets for wind energy.

Municipal or public utility-owned projects may be one such market. Other potential opportunities include ownership by cooperatives, power marketers, or aggregators, who package generation from several technologies, including renewables and (possibly) natural gas or hydroelectric, to add capacity value, and direct access customers. Smaller clusters of turbines owned by private land owners may be another near-term niche. High wind resources and favorable financing mechanisms will be typical for near-term projects. In addition, wind energy will be most competitive in applications where value beyond short-term avoided cost is recognized. Such applications could include distributed generation, or "green" power markets, whereby the energy is valued for its environmental benefits, or reduction of other impacts from fossil or nuclear power.

System Benefits: As the utility market shifts away from its recent structure, it will be increasingly important for sellers of wind energy to distinguish their product from other generation sources by emphasizing value that customers will recognize in the marketplace. The Introduction and Overview chapter of the TC compendium details benefits common to all renewable energy technologies. Specific sources of added value from wind energy include:

<u>Economic</u>: Wind turbines located in agricultural areas can enhance land values by boosting rents and prices, while leaving the majority of the land for continued agricultural use. Windfarms, because of their modularity, have the potential for distributed and/or strategic siting, which can help power providers optimize the use of existing transmission and distribution facilities or defer the need for equipment upgrades or line extensions. Such values are highly dependent on specific utility systems and wind sites.

<u>Risk Management</u>: Wind energy shares many of the positive risk management attributes as other renewables, as detailed in the Introduction and Overview. Wind energy may be uniquely positioned to add value in some instances, e.g., where coincidence of resource and load is high, or where the combination of economics and environmental impacts is the most favorable compared with the alternatives.

<u>Environmental</u>: Once installed, wind energy enjoys the advantages of zero air, water and solid waste emissions. In addition, total fuel-cycle emissions, including emissions experienced during construction, fuel extraction (zero for wind) and operations, are very low in comparison to fossil fuel combustion and other types of generating technologies. These

environmental advantages can help power companies meet environmental regulations and satisfy their customers' desire for clean power sources.

System Impacts: Several potential localized impacts that windfarm designers and developers pay close attention to include avian interactions, visual or aesthetic impacts, land erosion around turbine pads or roads, and acoustic impacts. Wind power plants can affect local habitat and wildlife as well as people. The degree of impacts from these issues can vary from non-existent to critical, depending on site-specific characteristics of each project, e.g., proximity to human and avian population, type and use of surrounding land, and local preferences for land use. Developers must carefully consider these characteristics when siting windfarms in order to mitigate potential impacts to acceptable levels.

Of the approximately 5 billion annual bird deaths reported in the United States, 200 million are a result of collisions with man-made objects [13]. Experience over the past decade has shown that the level of bird mortality from interaction with windfarms can vary from none in some areas to levels of concern in others, such as where windfarms are sighted in migratory pathways or in dense avian population centers, such as Altamont Pass, California. Bird collisions with wind energy structures are the leading cause of mortality reported. Electrocutions are the second leading cause, but solutions have been developed to mitigate this problem [14]. Other factors that influence the potential for avian collisions with wind energy facilities include land use, turbine design, turbine location, turbine orientation, operation methods, bird species, habitat use, and avian perching and flying behavior. Researchers performing studies at wind energy facilities in the United States and Europe report that mortalities are not considered biologically significant to overall populations [14], indicating that these impacts may be less than from many other man-made objects. However, regardless of the relative size of the impact from wind projects, minimizing the cumulative impacts on avian populations is still a critical requirement for wind energy growth domestically and abroad.

Windfarm developers and operators currently have the ability to mitigate a large portion of avian impacts by proper design, siting, and operation of wind turbines and windfarms. The ability to mitigate avian impacts is site-specific. In addition to employing design techniques such as using tubular towers to reduce perching or burying wires or covering connections to reduce electrocutions, developers may also have to avoid using all or parts of certain high risk areas. Research is ongoing to develop methods to minimize impacts from current installations and develop the ability to further mitigate impacts from developments yet to be installed.

Wind turbines are tall structures, often located on the tops of ridges and hills, and can be visible from relatively long distances. The visual impact of windfarms is often an important issue to the public. Experience shows that the layout of a wind power plant, type of tower, and color of the turbine and tower affect some people's aesthetic sensitivity. Finally, noise is caused by the air moving over the turbine blades (aerodynamic noise) and by the turbine's mechanical components. Engineers have reduced aerodynamic noise by design changes such as decreasing the thickness of the trailing edge of the blades and by orienting blades upwind of the tower. Since turbines still emit some noise, it is prudent for windfarm developers to consider proximity to residential areas when selecting development sites.

3.0 Technology Assumptions and Issues

Wind technology is currently commercially available, but limited production volume tends to raise current prices. he performance and cost indicators in this TC are composite numbers representing this commercially available technology. A high/low range is placed on this data to portray an envelope of cost/performance projections. A composite represents a combination of different design characteristics -- that is, it reflects different designs and design paths that may achieve similar results in terms of levelized cost of energy or other measures that combine cost, performance, and reliability. Because this characterization presents composite data, the specific cost and performance characteristics of any commercial system will be different from those presented here. The envelope of technology represented in this document includes worldwide technology. Estimates for current and future technology are based on U.S applications and market conditions. The projected technology path assumes robust R&D funding from public and private sources will continue.

The wind resource assumed in this TC analysis is characteristic of broad areas of land available in the U.S. As wind energy technology improves, abundant lower wind resource areas will become cost effective. This section provides annual energy projections for wind facilities located at Class 4 and Class 6 sites. Class 4 sites have annual wind speeds of 5.8 m/s (13 mph) and Class 6 sites have annual average wind speeds of 6.7 m/s (15 mph) at 10 meters above ground. A Rayleigh distribution is assumed for these annual average wind speeds and the 1/7 power law is used to account for wind shear effects when scaling wind speed to hub heights. More detailed information on wind energy resources may be found in [7]. Other useful references on resource assessment and turbine/windfarm siting include a handbook for conducting wind resource assessment, recently completed for the National Renewable Energy Laboratory [15], and the recently developed EPRI primer for utilities on planning windpower projects [12].

R&D Needs: Manufacturers are developing the next generation of wind turbines in the U.S and Europe. Government support of markets in Europe, India, and other developing countries, has been largely responsible for burgeoning sales, providing manufacturers with cash flow to conduct private development efforts. European manufacturers currently supply most of the world market for utility-scale wind turbines and therefore provide the majority of the private investment in R&D. Government-sponsored R&D, through national laboratories, also plays an essential role in developing new wind energy technology. The wind industry, as a whole, is still small enough, in terms of financial resources, to require shared research and testing in certain areas. Continuing applied R&D to develop the technical knowledge base necessary to design more cost effective and reliable turbines is critical to any company hoping to compete successfully in the marketplace five or more years from now: competition will not only be within the wind industry, but against improved fossil generating technologies. Research and testing of current advanced components and subsystems is also critical for manufacturers to compete in near-term markets.

This technology characterization does not address the specific and significant R&D advances that are implicit in the technology trajectory presented. However, this R&D will be essential to develop simpler, more efficient, lighter systems with larger rotors and taller towers, while maintaining high reliability and equipment lifetimes. Although it may appear simple in concept, achieving substantially improved cost effectiveness through larger rotor size and tower height is technically challenging. Research will be needed to enable industry to first understand damaging loads that increase with larger systems, and then to employ methods to reduce or control the impact of those loads in the context of improved overall system economics.

Research in other areas is essential to achieve the projected improvements. This includes developing a better understanding of (1) the characteristics of the wind "seen" by the turbine; (2) how turbines interact with the wind ("aerodynamics"); (3) how turbine structures and materials respond to such interactions and how manufacturers can use this knowledge to design stronger, less expensive components; (4) individual component advances and how they may be combined with other components into more cost effective systems; and (5) other ways of increasing the value of wind energy, such as improving the ability to forecast wind resource levels at longer time intervals into the future. The U.S DOE Wind Energy Program regularly publishes detailed descriptions of its current and planned R&D activities aimed at these and other R&D opportunities.

4.0 Performance and Cost

Table 1 summarizes the performance and cost indicators for advanced horizontal wind turbines in windfarms being characterized in this report. The following sections contain detailed discussion of each indicator.

4.1 Evolution Overview

Table 2 summarizes the projected composite technology path. It shows the progression of key turbine design characteristics between 1997 and 2030, and summarizes the basis for these changes. A detailed discussion of these and other characteristics is included later in this Section and in Section 4.2.

Table 2. Projected composite technology path.

Year	Turbine Rated Capacity (kW)	Turbine Diameter (m)	Hub Height (m)	Basis For Composite Technology Description
1997	500	38	40	Based on several commercial turbines.
2000	750	46	60	Based on several preliminary DOE Next Generation turbine designs, current prototypes, analysis from R&D activities, and manufacturer reports of next generation technology plans.
2005	1000	55	70	Advances are driven by an additional cycle of turbine research activities. Projections are based on internal laboratory analysis.
2010 2020 2030	1000 1000 1000	55 55 55	80 90 100	Post 2005 incorporates incremental technology advances. Modest cost reductions are primarily from manufacturing improvements and increased volume.

Figure 2 shows the associated major technical trends expected in wind turbine development. One of the concepts the figure illustrates is that while there may be major innovative advances in the technology which drive COE down, simultaneously, there will be an ongoing process of incremental optimization. Major innovation is reflected by "jumps" in both size and subsystem type from 1995 to 2000, and again from 2000 to 2005. The optimization process is shown as the bottom arrow "feeding" the major improvements above. The "jumps" in technology shown in the figure denote a broad technology development trend, but they do not indicate that a single design path is projected. The remainder of this Section and Section 4.2 detail the assumptions and rationale associated with this progression for each time period addressed by the TC.

Multiple designs will always be present in the market, with different design characteristics surviving or evolving from one time period to another. Depending on the market application and customer needs, turbines with different individual cost and performance characteristics have the ability to compete in the market. It is recognized that designs are not driven solely by economic and technical factors; manufacturer philosophy and the nature of the market also dictate the length of time that design features remain in the market. Additionally, designs are driven in part by the need to conform to certain design standards in order to receive certifications that enable sales in some

Table 1. Performance and cost indicators.

INDICATOR NAME	UNITS	Base Case 1997	+/- %	2000	+/- %	2005	+/- %	2010	+/- %	2020	+/- %	2030	+/- %
Plant (windfarm) Size	MW	25		37.5		50		50		50		50	
Turbine Size	kW	500		750		1,000		1,000		1,000		1,000	
Hub Height	m	40		60		70		80		90		100	
Rotor Diameter	m	38		46		55		55		55		55	
Swept Area	m^2	1,134		1,662		2,376		2,376		2,376		2,376	
Performance													
Net Annual Energy delivery			+5/-15		+10/-20		+10/-25		+10/-25		+10/-25		+10/-25
Class 4	GWh/yr	57		99		154		159		164		168	
Class 6	GWh/yr	78		133		199		203		210		213	
Net Annual Energy/Rotor Area			+5/-15		+10/-20		+10/-25		+10/-25		+10/-25		+10/-25
Class 4 (5.8 m/s @ 10 m)	kWh/m^2	1,011		1,192		1,294		1,334		1,385		1,412	
Class 6 (6.7 m/s @ 10 m)	kWh/m^2	1,372		1,596		1,671		1,711		1,765		1,797	
Capacity Factor			+5/-15		+10/-20		+10/-25		+10/-25		+10/-25		+10/-25
Class 4	%	26.2		30.2		35.1		36.2		37.6		38.3	
Class 6	%	35.5		40.4		45.3		46.4		47.9		48.7	
Annual Efficiency	% of												
Class 4	theoretical	65.0		71.8		75.3		75.4		76.4		76.2	
Class 6	maximum	70.4		78.9		80.2		80.3		81.3		81.4	
Annual Losses													
Class 4	% of gross	17.5		12.5		11.0		11.0		10.0		10.0	
Class 6	energy	12.5		7.5		6.5		6.5		5.5		5.5	
Availability	%	98	+1/-2	98	+1/-2	98	+1/-2	98	+1/-1	98	+1/-1	98	+1/-1

Notes:

1. The +/- range bounds a technology envelope that includes emerging/leading technology characteristics on the + side for performance and on the - side for cost. The range also includes uncertainty of achieving technical success and sales volume, and the natural variation in projects from normal market demands.
2. Net Annual Energy = Gross Annual Energy x (1- Annual Losses) x Availability

* Annual O&M is expressed as $/kWh and $/kW-yr. These are two expressions of the same cost and are therefore not additive.

Table 1. Performance and cost indicators. (cont.)

INDICATOR NAME	UNITS	Base Case 1997	+/- %	2000	+/- %	2005	+/- %	2010	+/- %	2020	+/- %	2030	+/- %
Capital Cost													
Rotor Assembly (including hub)	$/kW	185		180		190		160		150		140	
Tower	$/kW	145		145		185		195		215		235	
Generator	$/kW	50		45		55		50		45		40	
Electrical/Power Electronics, Controls, Instrumentation	$/kW	155		140		100		90		75		65	
Transmission/Drive Train, Shaft Brakes, Nacelle	$/kW	215		50		40		35		35		30	
Turbine FOB	$/kW	750		560		570		530		520		510	
Balance of Station (BOS)	$/kW	250	+5/-20	190		150		145		135		125	
Total Installed Cost	$/kW	1,000	+10/-20	750		720		675		655		635	
Total Installed Cost	$million	25.0	+10/-20	28.1	+20/-20	36.0	+20/-20	33.8	+20/-20	32.7	+20/-20	31.7	+20/-20
Cost per swept area	$/m^2	441	+10/-20	338	+20/-20	303	+20/-20	284	+20/-20	276	+20/-20	267	+20/-20
Operations and Maintenance Cost													
Annual O&M Cost*	$/kWh	0.01	+20/-30	0.008	+20/-30	0.005	+20/-30	0.005	+20/-30	0.005	+20/-30	0.005	+20/-30
	$/kW-yr	22.9-31.1	+20/-30	21.1-28.3	+20/-30	15.4-19.9	+20/-30	15.9-20.3	+20/-30	16.4-21.0	+20/-30	16.8-21.3	+20/-30
Levelized Overhaul and Replacement Cost	$/kW-yr	4.8	+20/-50	4.3	+20/-50	3.6	+15/-50	3.1	+15/-50	2.2	+15/-50	2.1	+15/-50
Annual Land Lease	% of revenue	3.0	+30/-30	3.0	+30/-30	2.5	+40/-30	2.5	+40/-30	2.5	+40/-40	2.5	+60/-40

Notes:

1. The +/- range bounds a technology envelope that includes emerging/leading technology characteristics on the + side for performance and on the - side for cost. The range also includes uncertainty of achieving technical success and sales volume, and the natural variation in projects from normal market demands.
2. Plant (windfarm) construction period is assumed to require 1 year.

* Annual O&M is expressed as $/kWh and $/kW-yr. These are two expressions of the same cost and are therefore not additive. Range for $/kW-yr bounds class 4 to class 6 sites.

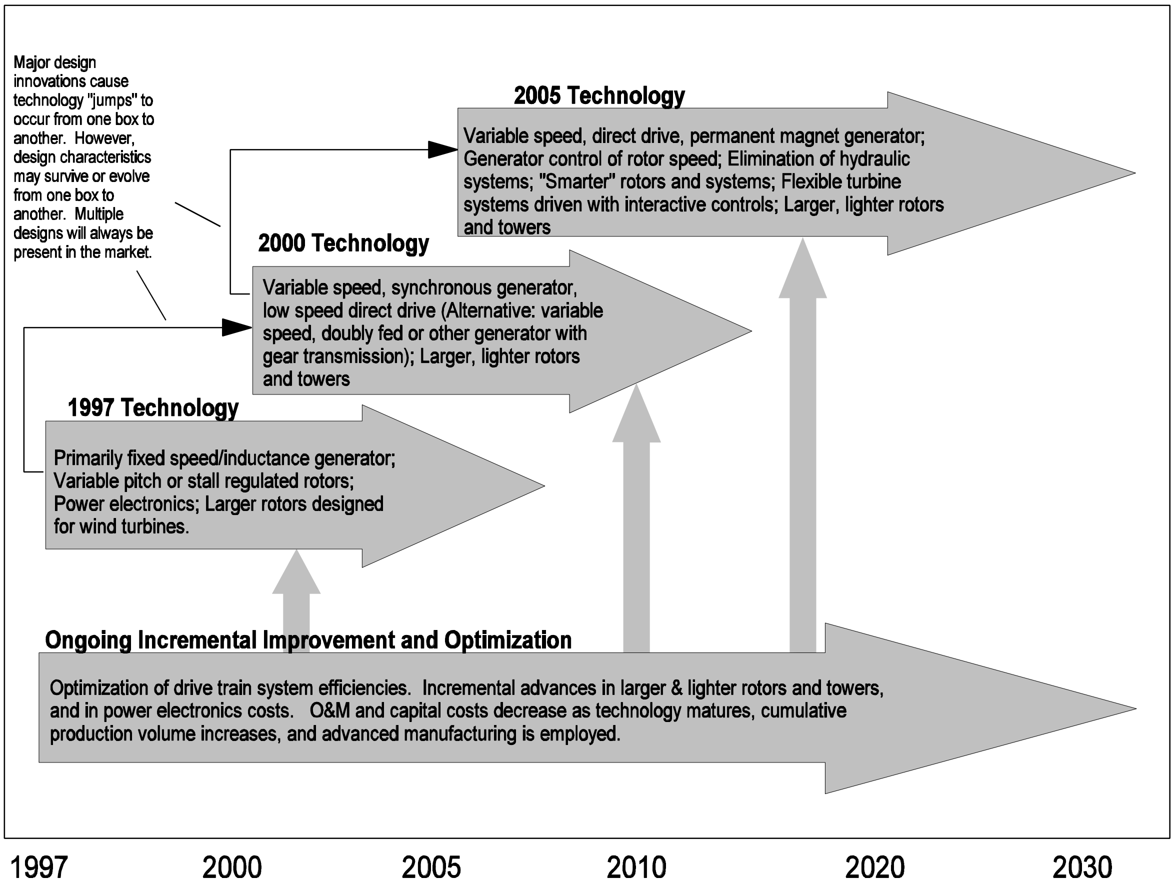

Figure 2. Wind energy technology evolution.

areas overseas. The diversity of design approaches currently being pursued by manufacturers increases the probability of successfully achieving the composite projections.

Baseline 1997 Wind Turbine

The TC baseline, 1997 turbine, described in the Overview of Wind Technologies, represents a composite of public data collected for several commercially available wind systems. Most of these wind systems include fixed-speed generating systems, usually coupled with a low-cost induction generator. Many systems use power electronics for power conversion and/or dynamic braking, and advanced airfoil designs. A few current designs utilize variable speed generation systems. The characterization includes turbines evolving along several design paths. The first may be termed advanced lightweight designs. This includes turbines such as Flowind's AWT-27 and Northern Power Systems North Wind 250, both developed under the DOE Near-Term Product Development Project, and by other manufacturers such as Cannon/Wind Eagle Corporation. The advanced lightweight design path continues to be pursued for the 2000

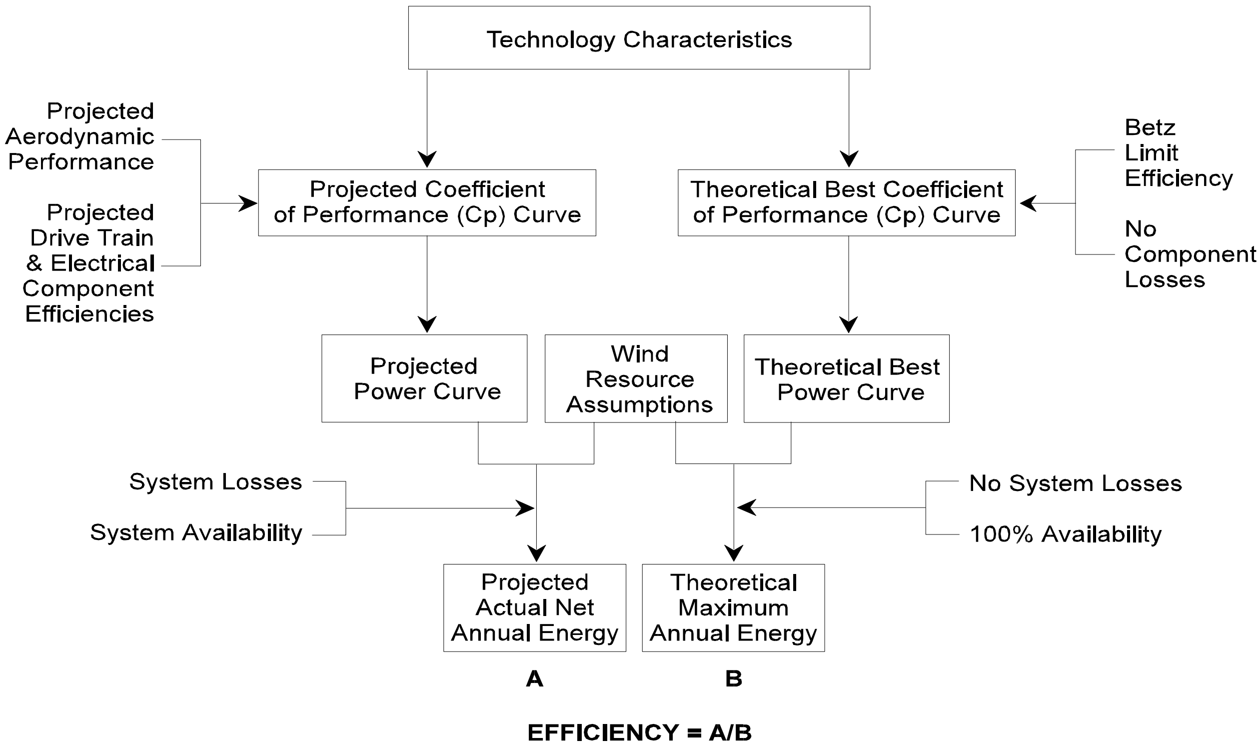

Figure 3. Methodology for estimating annual energy production.

time frame, including by manufacturers participating in DOE's Next Generation Turbine Development (NGTD) Project activity. Some technology in 2000 will also incorporate advanced components developed by industry, privately, and in conjunction with DOE's Innovative Subsystems activity. Lighter designs are also being developed or investigated by several manufacturers in Europe.

A second design path originates from the 3-bladed, rigid hub, fixed pitch design, sometimes referred to as the Danish-style turbine. This design approach continues to be advanced by U.S. and European manufacturers. A recently commercialized variable pitch design by Zond Energy Systems, Inc., in conjunction with DOE's Value Engineered Turbine activity, has achieved improved cost effectiveness, as measured by the levelized cost of energy. European manufacturers have also developed advanced subsystem features for this basic design approach, including full or partial variable pitch operation, and power electronics for rotor and generator control.

A third path, which may now be converging with the first two, can be described by the technology developed originally by Kenetech in the U.S. and by Enercon in Germany. This includes turbines utilizing power electronics to achieve variable speed generation. In 1993, Kenetech Windpower developed a 33-meter, 3-bladed, variable speed turbine with several industry partners. By 1996, Kenetech had also designed and tested a 45-meter turbine. Although Kenetech Windpower recently ceased operations, several of the design features envisioned for its next generation of technology were similar to those now being investigated or incorporated by others on the first two paths. Foremost among these include variable speed, variable pitch, and direct drive operation. Enercon produces commercial variable speed, direct-drive machines, but further R&D is required to bring down the cost of its electronic components and optimize its power conversion efficiency such that its cost effectiveness is in the competitive range of projections for 2000.

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2000 Wind Turbine

The 2000 composite turbine is expected to utilize a combination of tested and developmental subsystems. The direction of 2000 technology, as reflected in Figure 2, is generally toward larger generators and rotors; multiple speed or advanced variable speed generators, including increased use of power electronics; more sophisticated control electronics; advanced aerodynamic controls; tailored airfoils for specific wind regimes; taller towers; and early introduction of low-speed, direct-drive generators [16,17]. It will be possible to design turbines for greater reliability based on a better knowledge of wind inflow characteristics and how they impact structural design. It is expected that there will be improvements in turbine blades, particularly with respect to better integration of blade structural and aerodynamic design with appropriate manufacturing processes. In addition, developers will improve their ability to site turbines in order to optimize windfarm operation and energy production [16]. Figure 2 lists two alternative technology paths for 2000: 1) a variable-speed, synchronous generator with fully rated converter (electronics that allow elimination of the gear box), and 2) a doubly-fed generator, that is seen as an interim, low-cost, variable-speed generation option, with a geared transmission. These two alternatives hardly begin to cover the possible configurations that could emerge in the market, but they provide examples of potentially common technologies for the 2000+ time period.

2005 Wind Turbine

Advances in 2005 are expected to be driven in part by an additional cycle of government-industry financed turbine research projects. Based on the potential identified in internal laboratory analysis [18], the TC assumes that the move toward direct drive systems continues. Other improvements include lower cost power electronics, increasing sophistication in electronic control systems, and more responsive rotor power control and associated load reduction using ailerons, or pitch regulation, or other technologies. These advances are combined in the composite technology path with the last major size increase in rotor diameter and generator rating. Although opinions differ on what the ultimate optimum wind turbine size will be in the future, several industry scaling studies have indicated that sizes near 1 MW appear to yield the approximate optimal tradeoffs between cost, performance, and reliability for large windfarm applications. Permanent magnet generators start to become cost-effective for windfarm-size turbines in 2005. Finally, a trend towards incrementally higher towers is expected.

Post 2005 Wind Turbines

Turbine generator rating is not expected to increase significantly after 2005, because inverse economies of scale may hinder turbine development of machines larger than one megawatt [18]. Tower heights increase throughout the entire projection period. This reflects the belief that systems in the future will trend toward higher towers, with the optimal height determined on a project- and site-specific basis. Not all turbines sold in the market will have towers as tall, or as short, as the height specified in the wind TC. Improvements in design software and general reductions in turbine weight per unit output will permit this trend in the optimum design point for turbine towers. Technical advances after 2005 are also expected in the areas of lightweight materials, especially blade materials, and advanced techniques and components to enhance turbine load shedding.

4.2 Performance and Cost Discussion

Key Assumptions

Expected economic life (years): The expected economic life for the windfarm project is 30 years, based on manufacturers' field experience of nearly 15 years and stated design goals [19]. Periodic replacement or refurbishment of major subsystems such as rotor blades or generator windings are assumed to be necessary during the 30-year period, although not all manufacturers claim to require blade replacement in that period. Some researchers feel that sufficient data on component cycle loads, composite material performance prediction, and extended operation over a 30-year period do not currently exist to make accurate predictions of lifetime as long as 30 years.

Construction financing costs: These are not included in the $/kW capital cost estimates in Table 1. However, they should be incorporated into any COE calculation and they are included with COE's in the separate finance chapter. Capital cost estimates in Table 1 may therefore be termed "overnight" costs.

Profit: Turbine FOB (cost of turbine at manufacturer loading dock) costs include profit.

Windfarm Size: Fixing the number of turbines at 50 units allows cost trends to be examined more readily on the subsystem level in terms of absolute dollars as well as dollars per rated-kilowatt.

Capacity Factor: Capacity factor, as used in Table 1, is defined as the net amount of power produced annually by the turbine divided by the amount of energy that would be produced if the turbine operated at full rated capacity for the entire year. As such, it is a function of both wind resource (how often wind speeds are high enough for the turbine to cut-in) and turbine reliability (how often the turbine is available for operation when the wind is blowing versus how often it is unavailable due to scheduled and unscheduled maintenance).

Current Technology (1997)

Current Performance: Operational data for current technology is widely available from California windfarms and other locations around the world. Performance indicators for the base year are a composite of commercial technology available in 1997, including turbines from the DOE Near-Term Product Development Project [20-22] and from several other manufacturers [23]. These turbines include fixed and variable speed designs, most of which use one or more low cost, induction generators. The 1997 technology composite is distinguished from earlier technology, late 1980s/early 1990s, by the substantial use of power electronics for power conversion and/or dynamic braking, and by the use of advanced airfoil designs. Projects using these types of technology currently exist. Additionally, manufacturers have achieved high turbine availability with recent projects using these turbines or their direct predecessors [24].

As shown in Figure 3, the formulation of energy indicators for the 1997 base case and future years is based on the turbine size and subsystem characteristics for each time period. Specifically, a curve plotting the efficiency of power conversion from the wind through the rotor (which is known as the "coefficient of power" or C_p) was developed to be consistent with composite design characteristics of the turbines and includes the level of aerodynamic performance expected from improved wind turbine rotors for each time period. For example, the 1997 composite turbine was modeled as a fixed speed, fixed pitch machine. The rotor, generator, transmission and power electronics efficiencies were then incorporated directly into the C_p curves. For each time period, a curve of the net electrical power output, a "power curve," was then derived from the C_p curve. Finally, annual energy capture for each year was calculated using these power curves assuming a Rayleigh distribution for wind speed classes of 4 and 6 (5.8 m/s, and 6.7 m/s average wind speeds, respectively, measured at 10 meters above the ground). The sea level value for air density of

1.225 kg/cubic meter is used for all energy calculations. A wind shear exponent of 1/7 is also assumed. A modeling tool developed for NREL was used to perform these calculations [25].

To ensure that projections are sufficiently conservative, the energy production model was used to calculate a measure of efficiency for each year's turbine, relative to its theoretical maximum. The right side of Figure 3 illustrates this process. To perform this calculation, the power coefficients corresponding to each power curve are set at their theoretical maximum (0.593, known as the Betz limit) from a cut-in wind speed of 2 m/s, up to their rated power at 11 m/s. From 11 m/s, up to 30 m/s, the power output is held constant at rated power, while the power coefficients are adjusted downward, i.e., the rotor does not convert all of the power that it theoretically can from the wind above 11 m/s because the generator would have to be larger than is economically optimum. Turbine efficiency, as listed in Table 1, is thus defined as the projected net energy produced by the TC turbine system, including all losses, divided by the energy generated from the theoretical best system, assuming no system losses. A more detailed discussion of this method may be found in Reference 26.

Table 3 compares the 1997 wind TC energy indicator kWh per square meter of rotor area (kWh/m^2) against the calculated performance of 17 recent turbines from 11 manufacturers, including the Bonus 600/41, Cannon/Wind Eagle 300, Enercon E-40, Flowind AWT-27, Kenetech 33M-VS, Micon M1500-750/175, and M1500-600/150, Nedwind NW41, and NW44, Tacke TW-600, Vestas V39/500, V39-600, V42/600 and V44/600, Wind World W3700/50, and Zond Z-40 and Z-46. Publicly available power curves for these turbines are used to run the same energy model that was used to calculate the wind TC composite energy production estimates to produce comparable energy output estimates for class 4 and class 6 wind sites. For comparison, all turbines are normalized to 10 m hub height to eliminate the effect of tower height on the annual energy produced by the sample of commercial turbines.

Table 3. Comparison of current turbine performance with 1997 TC composite turbine.

	Turbine Rating (kW)	Rotor Diameter (m)	Annual energy (kWh/m^2, normalized to 10 m hub height, no losses, 100% availability)*	
			Class 4	Class 6
Minimum Value	275	26.8	519	790
Maximum Value	750	46.0	833	1,127
Mean Value	531	39.4	706	992
Stnd. Deviation	131	5.6	69	83
TC Value	500	38.0	777	1,088

*10 meters is height at which wind speeds are measured. Normalization eliminates effect of tower heights.

Table 3 shows that the 1997 TC turbine rotor diameter and rating are similar to the mean values of the 17 turbines. The 1997 annual energy estimates for the TC turbine are one standard deviation above the mean values for the 17 turbines for both the class 4 and class 6 calculations. Since the turbines in this data set are optimized for various wind regimes, the result of this statistical analysis tends to overstate the distance of the TC value from the mean. That is, the TC energy production would be closer to the mean of those turbines if they were all optimized for the TC wind resource assumptions. Thus, the composite performance estimate represents leading commercial technology, but is still under the maximum value for current machines. Individual turbines are not shown in the table because manufacturers were not given the chance to optimize their turbines for the TC wind resource assumptions. However, it is assumed that the large number of turbines included provides a reasonable range against which to benchmark the TC composite estimate for current technology. The uncertainty range for 1997 energy indicators in Table 1 is within the bounds created by the minimum and maximum values listed in Table 1.

Windfarm Losses - A breakdown of assumed losses is shown in Table 4.

- *Array Losses* - Large downwind spacing dimensions (2.5 diameters sideways x 20 diameters downwind) have been assumed for class 4 sites because land is most often found in flat plains areas and is abundant for this resource class. Based on judgement of DOE laboratory researchers, this relatively large spacing is the primary reason for reduction of array losses from levels currently reported in some large, densely-sited windfarms in California. Array losses are assumed to be zero for the higher class 5 and 6 sites because these resources are often found in ridge or mountainous terrain and turbines are typically situated large distances downwind from one another or in long, single rows.

- *Soiling losses* - 1997 values are based on (1) tests of airfoil designs developed by NREL and available commercially, that exhibit low sensitivity to soiling ("roughness") [27,28] and (2) the assumption that blade washing is conducted at economically optimal levels and the associated cost is included in the annual O&M. Introduction of variable pitch rotors in the 2000 TC design further reduces soiling losses; the pitch control is assumed to compensate for degradation of aerodynamic performance from soiling. Soiling losses decrease slightly after 2010, indicating that airfoil design and materials will not yet be fully optimized for roughness insensitivity until then.

Table 4. Windfarm loss assumptions (% of calculated gross energy).

	1997	2000	2005	2010	2010-2030
Array	5/0*	5/0	4.5/0	4.5/0	4/0
Rotor Soiling	7.5	2.5	2.5	2.5	2/0
Collection System†	2	2	2	2	2
Control & Misc.	3	3	2	2	2
Total	17.5/2.5	12.5/7.5	11/6.5	11/6.5	10/5.5

* Pairs indicate losses for wind (class 4 sites/classes 5 & 6 sites)

† Includes wire and transformer losses

Current Cost: Using public price quotes and engineering cost studies as the primary basis for the TC 1997 turbine FOB price estimate raises several issues. Foremost among these include:

- Differences may exist between advertised list prices, which are quoted by manufacturers for marketing purposes, and actual market prices, which are project-specific, depending on what the market will bear.

- Price estimates derived from engineering studies are based on production cost plus an assumed profit, which may not match current market conditions. A major source of uncertainty in turbine capital cost estimates comes from trying to infer turbine and windfarm costs from quoted prices. That is, competitive pricing strategies can make it difficult to determine true costs.

- Differences in, or lack of definition of, the volume of production associated with cost estimates and price quotes. This applies both to the cumulative volume, which determines how much cost reduction has been obtained through manufacturer "learning," and to the volume of the individual or annual production run associated with the cost, which affects the cost of purchased subcomponents, manufacturing materials, and distribution of fixed overhead costs. Normalizing estimates for these factors must often be attempted with imperfect information. Turbine costs in the TC for 1997 assume that the manufacturer has achieved a cumulative production volume of approximately 150 units prior to 1997 and that the size of the production run associated with the cost estimates is approximately 150 units.

- The differences between the U.S. market and other markets around the world, e.g. differences in subsidies, application size and type, ownership/financing, and exchange rate fluctuations and that most recent projects have been installed in countries other than the U.S., increase the difficulty of using recent market prices and quotes that are directed primarily at those markets.

- The difficulty in determining what costs are included in price quotes, e.g., substation costs or project management fees.

There is a large data set of current prices resulting from the substantial world-wide wind turbine industrial base. The 1997 TC cost composite draws from a combination of public information from manufacturers and published price quotes [24,29,30]. A statistical summary of this data from References 24 and 29 is shown in Table 5. Eleven turbines from eight manufacturers are included in this analysis. Assumptions concerning associated cumulative and annual production volume are not available from the data sources. European turbine list prices from [29] were reduced 15 percent due to the following reasons:

- Reference 29 is a document for general public information. Actual market prices will vary depending on many project-specific factors.

- It is assumed that manufacturers quoted prices for their primary current market, Europe, which is supported by various market subsidy programs, especially in Germany. It is further assumed that subsidies tend to support somewhat higher prices.

Table 5. Comparison of current turbine costs with 1997 TC composite turbine estimate.

	Turbine List Price ($/kW, Jan. 1997 $)	Total Installed Cost ($/kW, Jan. 1997 $)
Minimum Value	723	973
Maximum Value	841	1,091
Mean Value	758	1,007
Standard Deviation	35	36
Median Value	744	994
1997 TC Value	750	1,000
Number of Estimates	10	11
Mean Hub Height (m)	43.6	43.4

Total installed costs are calculated in Table 5 by increasing FOB cost by the 1997 wind TC value of $250/kW for BOS costs. Since the FOB cost was not available for the Zond Turbine, the installed project cost estimate was taken from a 1994 public briefing by the manufacturer and is assumed to be an estimate for general analytic purposes only [24]. The table shows that the 1997 wind TC composite cost estimate is close to the average value of this data set, after the 15% turbine price correction.

The 1997 TC cost does not include data points for two lightweight designs because they have not seen recent sales in the market. Nonetheless, costs associated with these designs appear to be significantly lower than those represented in Table 5. Reference 29 gives a list price for the Carter CWT-300 at $666/kW. This turbine was developed several years ago. In addition, current experience with the production of six prototypes of the later free tilt, free yaw Cannon Wind Eagle 300 design indicates that the 1997 TC figure could easily be met or surpassed with current technology [31]. In addition, a detailed engineering cost analysis performed under the DOE Near-Term Product Development Project estimated the on-site cost for 500 WC-86B turbines (the precursor to the AWT-27) including a 15% profit mark-up, to be $568/kW in 1992 dollars. Total project cost estimates depended on site-specific assumptions, but were approximately $800/kW [20].

This characterization assumes, as a baseline for calculating future cost reductions, that the nominal cumulative and annual production volume for 1997 technology is approximately 150 units. However, it is not possible to normalize the data in Table 5 for different cumulative or annual production volumes because it is not known what production volume assumptions are behind the prices.

A low range of uncertainty in 1997 costs is shown on Table 1, reflecting extensive commercial experience to date. The larger uncertainty on the low side of the cost indicators, reflects the lower costs reported for emerging technology such as the Cannon/Wind Eagle 300. Estimates for emerging technology are not considered validated until a sufficient number of turbines have proven themselves in the field. In addition, market prices may be higher or lower than the stated bounds, depending on project-specific details such as access to transmission lines, and competitive circumstances.

Technology Projections 2000 - 2030

Future Performance: Manufacturers are pursuing multiple design paths for year 2000 technology with the goal of achieving the system-level cost effectiveness represented by the 2000 wind TC characterization. Performance indicators for year 2000 technology are based in part on information from the DOE Next Generation Turbine Development (NGTD) Project. Data from that project is based on designs still in the pre-prototype stage.

The following two turbines are currently being investigated under the NGTD Project. The turbine descriptions are for current concepts, but do not now represent actual turbines.

- The Wind Turbine Company WTC 1000 is a downwind two-speed, variable-pitch turbine rated at 1000 kW. The rotor incorporates variable rotor coning to attenuate loads and the drive train employs multiple generators. The turbine employs a passive-yaw system to reduce mechanical complexity.

- The Zond Z-56 is an upwind, variable speed, variable-pitch turbine rated at approximately 1.1 MW. It employs 3 blades in an upwind configuration, an active yaw system, a variable-speed, doubly-fed generator, and advanced NREL airfoils.

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Table 6 details the projected performance gains for 2000 and each subsequent five-year interval up to 2030. The table lists gains as a percent of the 1997 baseline turbine and as a percent of the previous period's value. The table also shows the percent of incremental increases from the previous time period for each 5 year interval due to each driver. As shown in Table 6, the three largest drivers of increased energy in 2000 are taller towers, larger rotors, and reduced system losses from soiling. The energy estimate for the 2000 composite turbine assumes a variable speed generator system and a variable pitch rotor. However, because it is anticipated that variable speed systems will still be undergoing substantial development for wind turbine applications, it is assumed that the associated electronic power conversion system is not fully optimized. That is, due to limitations on individual component efficiencies, especially power-electronic conversion capabilities, it is assumed that introduction of variable speed operation will result in only modest net performance gains. A recent investigation concludes that realizing the benefits of increased energy output from variable speed operation requires advanced direct-drive architectures and more advanced power electronic conversion capabilities [32]. The table reflects these conclusions by showing zero-to-modest gains from variable speed in 2000, with substantial gains still possible in later years. This may be a conservative assumption, as industry is currently pursuing several different approaches to variable speed configurations and preliminary projections of the net performance/cost tradeoff for these vary.

A range of values is given in Table 6 for two primary reasons. The first is uncertainty related to technological development. The second, and larger, is that systems utilize an optimized combination of various subsystems involving tradeoffs between cost and performance of each subsystem. That is, subsystems are combined to maximize the cost effectiveness of the system as a whole. Since tradeoffs must be considered when employing various subsystems and design approaches, no single system can utilize every component or operational approach with the very highest individual performance characteristics.

Table 6. Performance improvement drivers.

	Increase in Net kWh/m^2 (percent) *		Percent of Incremental Increase from Previous Time Period (percent)†			
	From 1997 Baseline	From Previous Period	Taller Towers	Larger Rotors or Improved Aerodynamics	Lower Assumed Losses from Soiling	Variable Speed + Drive Train & Power Conversion Efficiency Optimization‡
2000	16-18	16-18	50-70	5-10	27-31	0-40
2005	22-28	6-10	30-50	5-10	11-20	30-60
2010	25-32	3-4	50-80	small#	small#	20-50
2020	29-37	4-5	70-90	small#	small#	10-30
2030	31-40	2-3	70-90	small#	small#	10-30

Notes:

* Range for increases in energy estimates is for class 4 to class 6 sites

† Range for contributions represents uncertainty and imprecision from using composite technology assumptions

‡ Opinions differ on the potential for variable speed to increase energy capture. NREL and others are currently investigating this topic [32]

\# Small incremental improvements are possible

The broader uncertainty range associated with year 2000 performance estimates, listed in Table 1, reflects increased technology-related uncertainty compared to the 1997 range. The low side is increased again in 2005 for the same reason.

Generally, progression in rotor performance, from 1997 into the future, is characterized less by increases in rotor aerodynamic efficiency (peak power, or C_p) and more by maintenance of a relatively high efficiency over a larger wind speed range. Additionally, a lower turbine cut-in speed, made possible by larger, variable pitch rotors, is assumed as an advance in 2000 and beyond (the impact of this latter assumption was not evaluated separately). Generator, transmission and power electronics performance, efficiency, are not explicitly modeled, i.e, explicit estimates for these efficiencies are not developed. Currently, these efficiencies are embedded in the curves used to estimate energy output.

Increasing hub height/tower height is shown in Table 6 to be a primary driver of performance gains in 2005. Other first order drivers in 2005 include more efficient variable-speed operation; larger rotors, including aerodynamic rotor control for clipping gusts, which allows larger rotors to be used economically with a given generator rating to capture lower wind speeds; and further reduction of system losses.

Performance gains are expected to level off after 2005, with further improvements assumed to be incremental. Increasing tower height is the primary driver of performance increases during this period. Progress is also expected in areas outside cost and performance. More accurate micrositing models are expected to be developed, which will contribute to a reduction in windfarm array losses. Improvements modeled into the energy estimate calculations for all years include cost/performance tradeoffs including increased tower heights (costs) for improved performance.
Future Cost: As seen in Table 7, the major cost changes in 2000 are driven by large increases in the rotor diameter and tower height, elimination of the transmission, and introduction of variable-pitch rotors and new, advanced power electronics for variable-speed operation and power control. Other low cost designs will be present in the market in 2000 -- a doubly-fed generator with a geared transmission is seen as one potential example. Lighter weight, more flexible systems are expected to appear, along with designs aimed at lower cost manufacturing techniques. Changes in specific subsystems include:

- *Transmission* - While many of the subsystem cost figures are composite values that describe trends, elimination of the geared transmission is a specific design feature that is explicitly assumed because it represents a large source of weight, and therefore offers a substantial cost reduction. This is the only subsystem that becomes a smaller fraction of the total cost for the 2000 system. The reduction from 22% represents a large source of weight, and therefore offers a substantial cost reduction. This is the only subsystem that becomes a smaller fraction of the total cost for the 2000 system. The reduction from 22% to 7% of total system cost from 1997 to 2000 is based on a recent design study [20] which estimated the transmission to account for 75% of the cost in the "Transmission/Drive Train, Shaft Brakes, Nacelle" category.
- *Towers* - Although savings in tower costs are possible from reduced loads, new tower designs, and advanced materials, total tower costs still increase significantly in 2000 in both per-kW and absolute dollars. This reflects the increase in height as well as increased thrust loads from the larger rotor. Tower cost is assumed to scale linearly with tower height and proportionately with the square of the rotor diameter [33]. However, calculation of the exact percentages of cost increase from each scaling effect, i.e., determination of coefficients in the scaling equation, is beyond the scope of this TC. Nonetheless, the costs in Table 7 are believed to reasonably reflect engineering scaling principles. Peak thrust loads from hurricane or maximum anticipated winds tend to drive tower costs. Since it is assumed that these loads will not be reduced by rotor designs in year 2000, no cost reduction is included to represent the potential

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Table 7. Cost breakdown for 50 turbine windfarms (January 1997 $).

Major Subsystems	1997	2000	2005	2010	2020	2030
	$/kW					
Rotor Assembly (including hub)	185	180	190	160	150	140
Tower	145	145	185	195	215	235
Generator	50	45	55	50	45	40
Electrical/Power Electronics, Controls, Instrumentation	155	140	100	90	75	65
Transmission/Drive Train, Shaft Brakes, Nacelle, Yaw System	215	50	40	35	35	30
Turbine FOB (including profit)	750	560	570	530	520	510
Balance of Station (BOS)	250	190	150	145	135	125
Total Installed Cost ($/kW)	1,000	750	720	675	655	635
	$/Turbine ($thousands)					
Rotor Assembly (including hub)	93	135	190	160	150	140
Tower	73	109	185	195	215	235
Generator	25	34	55	50	45	40
Electrical/Power Electronics, Controls, Instrumentation	78	105	100	90	75	65
Transmission/Drive Train, Shaft Brakes, Nacelle,Yaw System	108	38	40	35	35	30
Turbine FOB (including profit)	375	420	570	530	520	510
Balance of Station (BOS)	125	143	150	145	135	125
Total Installed Cost ($Thousands/Turbine)	500	563	720	675	655	635
	Percent of Total Initial Project Capital Cost					
Rotor Assembly (including hub)	19	24	26	23	22	22
Tower	15	19	26	28	32	36
Generator	5	6	8	7	7	6
Electrical/Power Electronics, Controls, Instrumentation	16	19	14	14	13	12
Transmission/Drive Train, Shaft Brakes,Nacelle, Yaw System	22	7	6	5	5	5
Turbine FOB (including profit)	75	75	79	78	79	80
Balance of Station (BOS)	25	25	21	22	21	20
Total	100	100	100	100	100	100

Note: "Controls" includes yaw drives and gears. Numbers may not add to 100% due to rounding error.

for load reduction that may be experienced during normal operation of new variable-speed, variable-geometry rotor systems emerging in year 2000.

- *Rotors* - Table 7 shows an absolute cost increase for the rotor subsystem from $93,000 to $135,000 per turbine, reflecting the diameter increase from 38 to 46 meters, and also a trend towards more complex, variable-pitch mechanisms. A percentage of rotor cost increases with the cube of the rotor diameter [33]. As was the case for estimated tower cost increases, scaling coefficients are not developed for this analysis. The trend towards lighter rotors also has a downward influence on costs. The rotor cost, as a percentage of the total system cost, is at the high end of the preliminary estimates from the DOE NGTD Project.
- *Electronics and Controls* - Power and control electronics and other electrical costs show a significant increase in year 2000, as more expensive or more complex electronics are required to implement variable speed, direct drive generation.
- *Generators* - *G*enerator costs are assumed to increase as a result of substituting higher performance technologies for off-the-shelf induction units. Sample technologies might be synchronous or doubly fed generators in 2000.
- *Reliability* - It is assumed that it will be possible to design turbines for incrementally greater reliability based on a better understanding of wind inflow characteristics and how these characteristics impact structural design, and appropriately improved modeling tools. It is expected that there will be improvements in turbine blades, particularly with respect to better integration of blade structural and aerodynamic design with appropriate manufacturing processes. Resulting improvements in reliability are reflected in the decreasing O&M and overhaul/replacement costs.

The uncertainty bounds on cost in Table 1 are doubled for 2000 and beyond, reflecting the relative difficulty of projecting turbine and project prices. The maximum upper bound for 2000 is assumed to be equal to the lower bound of 1997. This projection is conservative (higher) compared to preliminary estimates from the DOE NGTD Project. Project. The lower bound is also conservative (higher) compared to the lower bound of the NGTD Project estimates. The key 2005 cost changes are driven by the combined effects of the increase in rotor diameter and tower height. Changes in specific subsystems include:

- *Rotors* - Cost increases from significantly larger diameters in 2005 begin to be offset from improved manufacturing techniques resulting largely from the DOE/industry cost-shared Blade Manufacturing Project and to a lesser extent from increased production. The fact that the total rotor cost does not increase with the cube of the diameter also reflects the increasing use of lower cost paths such as 2-bladed designs, lighter, more flexible structures, or pultruded blades.
- *Electronics* - Cost decreases result primarily from R&D advances in power electronics for variable speed generation systems.
- *Generators* - As in year 2000, generator cost increases, per kW, as a result of a trend toward higher performance technologies such as permanent magnet generators, which may become cost effective in 2005.

Key cost drivers beyond 2005 include:

- *Rotors* - As production volume increases, it is assumed that industry will be able to support larger-scale advanced manufacturing improvements for rotor blades. Also, R&D is assumed to improve the ability to understand the connection between aerodynamic inputs and component fatigue loads, leading to use of lighter, more reliable components, and optimized control systems for lowest-cost approaches. These factors, combined with cost reductions from increased volume, account for the decrease in rotor costs in 2010 and beyond. Because blades are currently a custom-made subsystem, they have the potential to realize larger gains than mature technologies such as steel towers. Therefore, approximately a 10% cost reduction in the custom component of blade cost is expected for every doubling of cumulative production volume [34].

- Power *Electronics and Controls* - Power electronics and controls costs are projected to decrease significantly as a result of technical advances in components through R&D, wind turbine design advances, and increased volume.
- *Generators* - Incremental cost improvements from manufacturing, design, and volume effects are assumed to occur in permanent magnet generators after 2010.
- *Towers* - Cost per kW of towers increases at a rate lower than the tower height increases due to assumed advances in the ability to shed aerodynamic loads and design lighter towers.

The cost shown in Table 1 continues to decrease after 2000 because of three cost drivers: higher volume, advances in manufacturing resulting from R&D efforts, and technology advances from R&D. Therefore, the uncertainty percentage is kept fixed at +20% so that the absolute upper bound, i.e, the likely highest cost, is lower for each successive five-year period. The lower bound for 2005 is considered conservative because it is within the range of DOE NGTD Project estimates for 2000 technology cost. Table 8 summarizes the key qualitative subsystem cost drivers described above.

Table 8. Major wind turbine subsystem cost drivers.

	1997-2000	2000-2005	2005-2030
Rotor	Increase from larger size Decrease from trend toward lighter designs	Increase from size. Decrease from advanced manufacturing and lighter designs	Incremental reductions from volume, and R&D and manufacturing advances: lighter & smarter rotors
Tower	Largest increase from largest height and rotor size increase	2nd largest increase from height and rotor size increase. Decrease from lighter weight through R&D/design	Incremental increases with height, less than linear due to lighter weight from R&D
Generator	Synchronous or other intermediate, advanced approaches - higher cost than induction generators	First generation low speed permanent magnet - highest cost	Incremental reductions in permanent magnet generator costs from R&D and volume
Electrical	1st generation variable speed is expensive	Major cost drop as technology matures	Incremental improvements from R&D and volume.
Drive Train	Direct drive - no transmission.	Incremental refinements in design approaches	
BOS	Increases from larger turbines and higher power requirements		Incremental from volume

Effects of Volume on Cost

Although lower costs are not an automatic result of higher sales volume, there are several specific volume effects that can reasonably be expected to lower future turbine and windfarm costs. First, increasing sales may allow the industry to employ new manufacturing technologies that lower production costs. Second, there is an established learning effect in similar products that indicates product costs decrease as cumulative sales increase. Third, as annual production volume increases, there may be an opportunity for larger volume discounts for off-the-shelf turbine components. Reference 34 discusses these effects in more depth.

No assumptions were made in this wind TC concerning projected wind energy market penetration since such analysis is beyond the scope of the TC. Instead, this section investigates the level of increased cumulative and annual production volume that would be necessary to achieve the projected cost reductions, after accounting for cost reductions from R&D. The following discussion concludes that the necessary production increases are well within conservative assumptions for industry growth rates and market penetration levels.

Total installed cost per-unit-swept-area in Table 1 decreases 39% from 1997 to 2030. Since production volume will be lower as wind technology emerges in the near-term, the majority of the 23% cost reduction between 1997 and 2000 is assumed to be due to technology and manufacturing advances from R&D. Areas of expected cost reduction are listed in Table 8. After 2000, as wind technology market acceptance begins to increase, increasing production volume begins to have a larger impact on cost reductions. After 2005, as wind technology becomes more fully accepted and R&D focuses on incremental improvements, cost reduction is expected to occur largely from increased production volume. Given these expectations, the estimated range for the percentage of cost reduction due to R&D between 1997 and 2030 is 50-75%. Therefore, the remainder of the cost reduction between 1997 and 2030, 25-50%, is assumed to be due to volume effects. In absolute terms, this 25-50% reduction equates to approximately 10-20% total cost reduction from volume over the 1997-2030 time frame (i.e., 25-50% of 39% equals 10-20%).

According to Reference 34, cost-reduction rates will tend to be higher for turbines with higher percentages of custom-built components versus off-the-shelf components. Assuming future turbine designs contain more custom-built components than current technology, this reference indicates that a reasonable turbine cost reduction rate from volume effects is approximately 5% for each doubling of industry-wide cumulative production. In addition, manufacturers should expect to see volume discounts for non-customized components at a certain level of annual production (Reference 34 assumes a baseline estimate of a 10% discount at a level of 1000 units or higher). Finally, the majority of BOS cost reduction after 2005 is also assumed to be due to volume affects. Given these cost reduction effects from volume, approximately 2-3 doublings of industry-wide cumulative volume would be required to achieve the projected cost reduction between 1997 and 2030. This is a conservative level of required industry growth compared to private and government projections of market penetration by 2030.

Balance of Station Costs

Balance of Station (BOS) costs include foundations, control/electrical hardware, site preparation, electric collection system and transmission lines, substation, windfarm control and monitoring equipment, O&M facilities and equipment, initial spare parts, shipping, resource assessment, surveying, legal counsel, project management and administration, permits, construction insurance, and engineering services. Since land cost is listed on Table 1 as a percent of revenue and not an initial capital cost, it is discussed in the O&M section.

A range of approximately 25%-33% of total project costs was estimated for BOS costs in a recent design study based on a 50 MW windfarm using 275 kW wind turbines [20]. Other recent estimates are that BOS costs account for approximately 20 percent of the cost of energy from windfarms [19,35]. This indicates that BOS costs are approximately 25% of the total project cost. Therefore, using the TC 1997 FOB cost of $750/kW yields the BOS value of $250/kW (250 is 25% of 750+250). The range of +5/-20 shown on Table 1 reflects the possibility that developers may be able to reduce BOS costs for current projects well below the level of $250/kW [20].

The majority of BOS costs for utility scale windfarm projects are directly dependent on the number of turbines installed. While important, turbine rating has a smaller impact on BOS cost. Since the number of turbines is fixed for all years in this characterization, the primary drivers of BOS cost changes are increases in turbine size in years 2000 and 2005 (BOS cost increases 20% from 1997 to 2005), and from learning effects resulting from increasing cumulative volume after year 2005 (BOS cost decreases by 13% between 2005 and 2030). Learning effects apply to the design, construction and management of projects. The small increase in BOS cost per turbine in years 2000 and 2005 reflects a relatively small amount of additional capacity- and size-related costs, e.g., higher cost power transfer and conditioning equipment, heavier foundations, that are incurred for each turbine. That is, for a 50-turbine windfarm, the absolute cost increases per turbine are small relative to the increase in rated capacity. As expected, the tables show that costs decline significantly on a per-kW basis in both periods.

Project Size Impact on Cost - BOS cost estimates in Table 1 account for costs related to increasing turbine size, and associated increases in per-kW-related costs, for a fixed number of turbines. However, factors to adjust total windfarm project cost for increased numbers of same-size turbines are not included in Table 1. Wind turbines are a modular technology. A wide range of capacity may be installed within a short construction period simply by varying the number of turbines added to an installation. There are two primary sources of potential cost reduction resulting from increasing the number of turbines in a windfarm. First, the manufacturer may be willing to set a lower price for a larger number of turbines. Second, some windfarm costs are fixed or exhibit diminishing costs per turbine for each additional turbine. Examples of these include infrastructure-related costs for roads, grading, and fences, O&M facilities and equipment, project administration and permits, surveying, and legal fees. As a preliminary guide, Table 9 taken from the 1993 EPRI Technical Assessment Guide [36], may be used to scale project costs for various project sizes.

Table 9. Project size impact on cost.

Plant Size (MW)	Percent of 50 MW Cost
10	120
25	110
50	100
100	95
200	90

Operation and Maintenance Costs

Annual O&M Costs: Recent industry estimates of O&M cost, including overhauls and replacements, are typically near $0.01/kWh for turbines sizes similar to the 1997 TC turbine and windfarms in the 100 MW range [37]. This cost level is also consistent with an estimate for 275 kW turbines in a 50 MW windfarm made under the DOE Near-Term Product Development Project [20]. Annual O&M is often quoted in units of $/kWh and $/turbine. It is inaccurate to use a single $/kWh estimate for all turbines and resource sites because a large portion of the annual O&M is fixed for each turbine, and the cost per kWh therefore changes depending on the wind resource level and the output of each specific turbine [37,38]. Despite this, only one composite value is shown in Table 1 for both wind resource classes. This is because the conservative assumption is made that the downward trend of O&M cost per kWh due to the fixed O&M

cost component being divided by more annual kWh generated in class 6 sites will be offset by higher maintenance costs due to the more demanding loads seen by the turbine in that wind regime.

The majority of the O&M cost decrease portrayed in Table 1 is from economies of scale from larger turbines and taller towers. However, attaining these economies of scale are not automatic or simple -- R&D is required to design larger turbines with the same or improved levels of reliability and durability. Preliminary indications from the DOE Next Generation Turbine Development Project are that several manufacturers believe that the O&M cost per kW will be significantly reduced for turbines in the 750 kW-1000 kW size range, compared to 500 kW turbines. The 2000 and 2005 O&M estimates in Table 1 are consistent with these projections. In addition, beyond 2005, some O&M costs savings are expected to be realized through simplification of design, such as the elimination of hydraulic systems for brakes and/or blade pitch mechanisms, and through optimization of O&M practices.

The wind TC 1997 annual O&M cost estimate in dollars per kWh and dollars per kW is shown in Table 1 with a larger uncertainty on the low side, reflecting the fact that the estimate is on the high end of recent industry estimates. Note also that costs for periodic overhauls and replacement of components are included in some industry estimates, but are contained in a separate figure for the wind TC.

Actual O&M costs, as seen in the market, may not follow a smooth downward trend as shown in the TC. As new turbines are introduced, annual O&M costs may be higher than for previous designs until sufficient experience is developed in the field. Thus, although a downward trend is expected, the actual cost may be "saw-toothed" as new technology is deployed. This can be especially true with a technology in the earlier phases of commercial development, such as wind turbines, when significant improvements are realized with each new generation of technology. Because the uncertainty bounds are already relatively wide for the 1997 estimate in Table 1, no changes were made to those values through 2030.

<u>Overhauls and Replacement Costs</u>: These costs include periodic major component replacements and overhauls. For 1997, repairs include gearbox overhaul and generator bearing replacement in years 10 and 20 at a cost of 5% of total installed cost, and replacement of the blades in year 20 at a cost of 10% of total installed cost [20]. Major replacement/overhaul costs are estimated to be on the same schedule in year 2000 because uncertainty with scaled-up design is assumed to be offset by increased resistance to fatigue from composite rotor materials and/or improved design ability. As more experience is gained with these larger designs and newer materials, replacement costs fall to 5% and 10% of total cost in years 10 and 20, respectively, for the 2010 turbine (2005 assumes a linear interpolation between 2000 and 2010). Costs fall to 5% and 5% in years 10 and 20, respectively, for the 2020 and 2030 turbines. The impact of these costs on COE varies for different ownership/financing assumptions and wind resource levels. For investor-owned utility assumptions, the effect ranges from 0.3 to 0.5 ¢/kWh in 1997, and from 0.1 to 0.2 ¢/kWh in 2030.

These estimates are based on engineering judgement concerning the projected impact of improved design codes coupled with an improved understanding of fatigue-failure modes. Overhaul and replacement costs have a large uncertainty associated with them, reflecting a wide range of estimates, including detailed engineering cost studies [20] and manufacturer claims that turbines are designed to avoid major periodic repairs [19,37]. Compared to the average of these estimates, the value in Table 1 is judged to be conservative and therefore has a larger uncertainty on the negative side. This large uncertainty is carried through the time periods, reflecting the potential for lower costs (higher durability) than those portrayed in the table. In the actual market, a tradeoff exists between initial turbine cost and design lifetime of turbine components. This composite characterization is believed to reflect a middle ground relative to this tradeoff.

Land Costs: While costs for land lease or purchase will vary for individual projects, the value in Table 1 assumes land is leased using royalty payments and is on the high end of the range quoted for current projects [24,39,40]. Regional variations in land availability may alter land costs. Estimates of regional land cost variations have not been made for this analysis. There will be different influences on land lease values in the future. The dominant influence is that larger and more advanced turbines will produce more revenues per unit of land. Therefore, land owners will tend to realize much larger revenues from land leases, perhaps giving developers the ability to bargain the percentage down. The large uncertainties associated with land lease costs in Table 1 reflects the fact that it is unclear how costs will change over time, and that there is always a range of costs associated with different parcels of land.

Uncertainty

Uncertainty reflected in the +/- ranges in Table 1 comes from two sources. The first is the uncertainty associated with the accuracy of the value, e.g., uncertainty of outcome of R&D. The second is from the normal variation in data values for projects, such as the cost of land for different projects.

Reliability

Reliability and durability are reflected quantitatively in several ways in this characterization. First, availability is already at high levels for given current initial turbine cost, O&M cost, and system lifetime. Second, the decline of annual O&M costs after 2005 reflects increased reliability. The decline in per-kWh O&M costs between 1997 and 2005 is assumed to be due more to increased energy output per turbine than increased levels of reliability. This is a conservative assumption, since R&D is expected to result in more reliable systems in this time frame as well. Third, major overhauls and replacement costs decrease over time, reflecting an increase in durability and maintenance intervals for each period's stated initial capital cost level. Finally, the reductions in initial capital cost for the same size turbine and same assumed turbine lifetime after year 2005 reflect the expected trend towards increased lifetime/cost ratios made possible by R&D.

Other Areas of Value

In the long-term, progress is also expected in areas outside of cost and performance of the individual turbine and the windfarm as a whole. For example, better local weather forecasting, along with appropriate system operator training, is expected to raise the value of wind energy.

5.0 Land, Water, and Critical Materials Requirements

As demonstrated in Table 10, the amount of land required for windfarms depends on turbine size and number, turbine spacing (distance side-by-side and between rows), and the number of rows. The range of land use per MW of installed capacity in Table 10 covers two scenarios for turbine spacing: 2.5 rotor diameters (side-by-side) by 20 diameters between rows, and 5 diameters (side-by-side) by 10 diameters between rows. These ranges are shown for three array configurations of 5 rows of 10 turbines (more common in flat areas), 2 rows of 25 turbines, and a single row of 50 turbines (more common on ridged sites). A setback of 5 rotor diameters is assumed around the perimeter of the windfarm. While these scenarios represent a range of possible configurations for a 50 turbine windfarm, actual project configurations will be site specific, depending on terrain, local wind characteristics ("micrositing conditions"), turbine characteristics, environmental and aesthetic considerations, and cost and availability of land. The trend towards lower land use per unit of capacity in later years is due to the increasing rating of the composite turbines described in this characterization.

Table 10. Resource requirements.

Indicator Name	Units	Base Year 1997	2000	2005	2010	2020	2030
Windfarm Size	MW	25	37.5	50	50	50	50
Land (50 turbines)							
5 turbines x 10 rows	ha/MW	33-20	26-16	24-15	24-15	24-15	24-15
	ha	825-500	975-600	1200-750	1200-750	1200-750	1200-750
25 turbines x 2 rows	ha/MW	19-26	15-21	14-19	14-19	14-19	14-19
	ha	475-650	563-788	700-950	700-950	700-950	700-950
50 turbines x 1 row	ha/MW	29-46	23-37	21-33	21-33	21-33	21-33
	ha	725-1150	863-1388	1050-1650	1050-1650	1050-1650	1050-1650
Water	m^3	0	0	0	0	0	0

Note: Range is for 2.5 rotor diameters (side) by 20 diameters (deep), and 5 diameters (side) by 10 diameters (deep).

Land: Land does not have to be purchased/leased and dedicated exclusively for wind energy production. Approximately 5-10% of a windfarm's land area is actually utilized by wind turbines, leaving the majority free for other compatible uses. Leases are quite common where co-uses such as livestock grazing reduce the cost to the windfarm owner while increasing the land value to the land owner. Another possibility is to use former agricultural lands designated under the soil conservation program to enhance the fixed per-acre revenues allowed by the government.

Water: As shown in Table 10, windfarms have no water requirement for operation. This is advantageous in areas where competition for water is important.

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