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July 9, 2005 — July 8, 2006

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Technical Report
NREL/TP-500-41036
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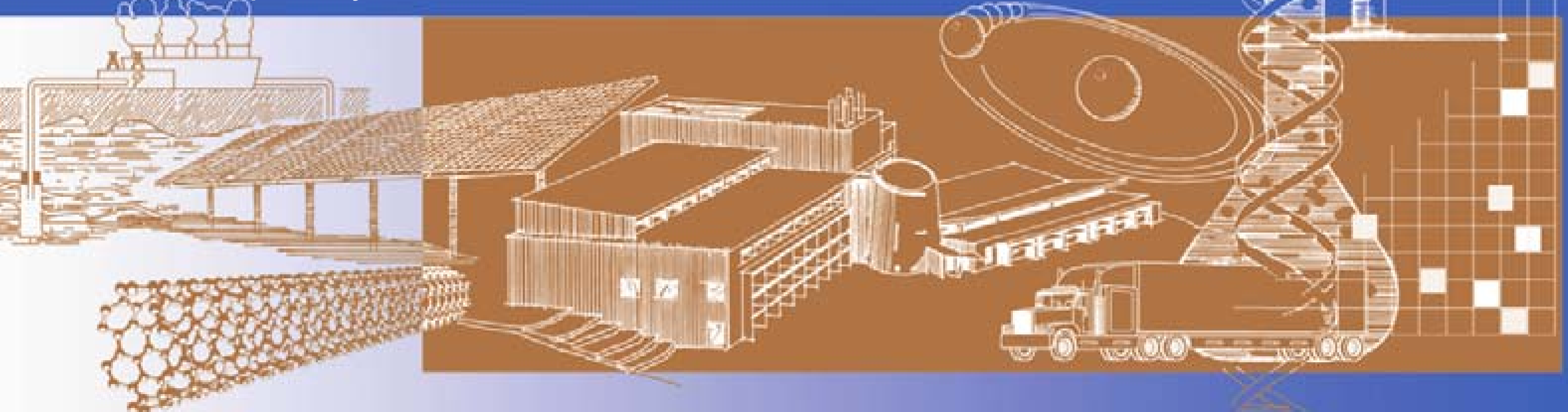

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Executive Summary

This report details an analytical approach for, and subsequent results of, an assessment of the potential for technological progress in Low Wind Speed Technology (LWST) under the U.S. Department of Energy's Wind Energy Program. The work was led by Princeton Energy Resources International, under subcontract to the National Renewable Energy Laboratory (NREL). Staff members from NREL's National Wind Technology Center and from Sandia National Laboratories contributed primary technical inputs to the analysis. The approach described herein evaluates wind energy technology status within the context of the marketplace in 2002, the first year of the LWST activity. Therefore, the assumptions concerning a reference from which progress is measured include technology cost and performance characteristics, and financial aspects of the market, corresponding to that first year. The overall metric used to assess technology status and progress is the levelized cost of energy, which combines the technology and financial characteristics just mentioned. To isolate technology-related developments, financial assumptions were frozen at their 2002 values for all years past 2002. Clearly, financial aspects such as interest rates and project financial structures have changed since 2002, as have commodity prices for steel and copper. Those changes are not incorporated into the analysis in this report, but they would certainly be included in the development of any new reference figures, i.e., a characterization of the actual costs and financial structures of current projects. This report describes the potential for technology advancements to reduce the cost and increase the performance of wind turbines.

Acronyms

AEP	annual energy production
BOS	balance of system
COE	cost of energy
FCR	fixed charge rate
ICC	initial capital cost
LRC	levelized replacement cost
LWST	Low Wind Speed Technology
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PE	power electronics
PERI	Princeton Energy Resources International
PMG	permanent magnet generator
TCC	total capital costs
TIO	technology improvement opportunity

1.0 Methodology Overview

The technology pathways analysis can be described as a five-step process, as shown in Figure 1. The overall metric used by the Program to set goals for technology improvements, and to track subsequent progress in R&D toward those goals is the levelized cost of energy (COE).

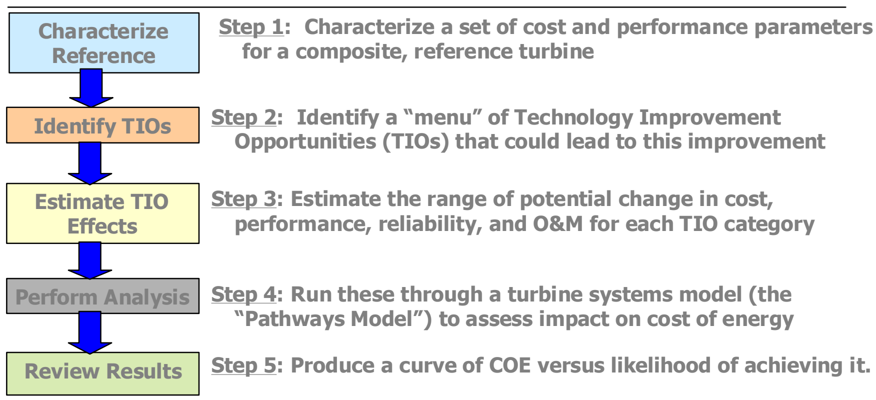

Figure 1. Technology pathways analysis process

COE depends partly on values for annual energy capture, and wind plant initial capital cost and annual expenses, including operations and maintenance (O&M) costs, sinking fund payments for periodic (long-term) replacements or major component overhauls, land lease payments, and other expenses such as taxes and insurance. The calculation of COE also involves assumptions for several financial factors such as the cost of money, required investor rates of return, project debt-to-equity ratios and other lender requirements, the assumed project operational life, and the annual wind energy available at the site.

To allow tracking of technology advances absent from changes in financial parameters and other assumptions, the following are treated as the only input variables in the COE equation for the Turbine Pathways analysis; all other inputs and assumptions are fixed:

- Net annual energy production (AEP)
- Turbine capital cost (TCC)
- Balance of station cost (BOS)
- Levelized replacement and overhaul cost (LRC)
- Annual O&M.

2.0 Reference Turbine Characterization

To project improvements in cost, performance, and reliability on wind turbine systems and wind plants using the pathways model, a baseline, or reference, set of cost and performance characteristics must first be developed. These characteristics serve as the inputs to a reference COE estimate from which all technical improvements are measured. The reference technology characteristics for DOE's ongoing low wind speed technology pathways analysis efforts were derived primarily from the baseline turbine design developed under the recent WindPACT (Wind Partnership for Advanced Component Technologies) project (Malcolm and Hansen 2002). That baseline represents a composite of the most advanced wind energy technology available in 2002. Nominally, it represents a three-bladed, upwind, variable-pitch, variable-speed turbine that uses a doubly fed generator rated at 1,500 kW. The rotor diameter is 70 meters and the tower height is 65 meters. The reference characteristics are also consistent with several leading commercial turbines from the major manufacturers in 2002. That date was selected as the reference because it was when the DOE Low Wind Speed Turbine Program was initiated.

Because the purpose of the pathways analysis is to examine leading edge technology, the reference turbine must represent the current status of such technology. The analysis characterizes costs assuming a 100-MW wind plant, to take advantage of economies of scale in procurement and installation. An analysis of 22 confidential power purchase agreements for projects installed over the past 6 years showed a strong correlation between project size and capital cost. Further, cost estimates assume favorable installation and maintenance conditions consistent with large areas of class 4 winds in the United States (relatively flat land, easy access, and soils conducive to foundations and large installation cranes). Together, these assumptions create a capital cost estimate toward the lower end of the range typically reported for commercial projects.

Table 1 summarizes estimated input data for the reference wind COE calculation. Data are shown as a range from minimum to maximum; the most likely value is in the middle column. Those three data points create a triangular distribution for each variable, as illustrated in Figure 2. (The most likely value in the triangular distribution is not necessarily the mean value or the median value.) The wind pathways analysis model uses a Monte Carlo sampling approach to randomly sample, and then combines the resulting values from each input distribution in the COE equation. The model performs this sampling exercise over numerous iterations to create a distribution of all possible resulting values. The model uses the inputs from Table 1 to calculate a reference wind turbine project with a mean (i.e., 50% chance) COE of $0.047/kWh, or $0.048/kWh at a 65% level of probability.

Table 1. Reference Wind Plant Input Data

Baseline and Path COE Inputs		Minimum	Most Likely	Maximum
TCC	TCC (2002 $)	920,000	1,000,000	1,100,000
	Low/High Range	–8%		10%
BOS	BOS Cost (2002 $)	368,600	388,000	446,200
	Low/High Range	–5%		15%
LRC	LRC ($)	9,750	15,000	22,500
	Low/High Range	–35%		50%
O&M	O&M Cost ($)	12,000	30,000	37,950
	Low/High Range	–60%		27%
Land	Land Lease Cost ($/kWh)	0.000648	0.00108	0.00140
	Low/High Range	–40%		30%
AEP	Net AEP (kWh/yr)	3,973,500	4,415,000	4,547,450
	Low/High Range	–10%		3%

Table 2 shows a breakout of project costs by component, total wind project costs, and the calculated COE.

Table 2. Reference Turbine Component, Plant, and O&M Costs, and Levelized COE*

Component	1500-kW Rating Baseline Component Costs $1000	1500-kW Rating Projected Component Costs $1000	Component Percent Improvement
Rotor	**248**	**248**	0.0%
Blades	148	148	0.0%
Hub	64	64	0.0%
Pitch Mechanism and Bearings	36	36	0.0%
Drivetrain, nacelle	**563**	**563**	0.0%
Low-speed shaft	20	20	0.0%
Bearings	12	12	0.0%
Gearbox	151	151	0.0%
Mechanical Brake, HS Coupling, etc.	3	3	0.0%
Generator	98	98	
Variable-Speed Electronics	101	101	0.0%
Yaw Drive and Bearing	12	12	0.0%
Mainframe	64	64	0.0%
Electrical Connections	60	60	0.0%
Hydraulic System	7	7	0.0%
Nacelle Cover	36	36	0.0%
Control, Safety System	**10**	**10**	0.0%
Tower	**101**	**101**	0.0%
TCC	**921**	**921**	0.0%
Foundations	49	49	0.0%
Transportation	51	51	0.0%
Roads, Civil Works	79	79	0.0%
Assembly and Installation	51	51	0.0%
Electrical Interface/Connection	127	127	0.0%
Permits, Engineering	33	33	0.0%
BOS	**388**	**388**	0.0%
Market price adjuster	**162**	**162**	0.0%
ICC	**1472**	**1472**	0.0%
Installed Cost ($)/kW for 1.5-MW Turbine	**981**	**981**	0.0%
Turbine Capital ($)/kW w/o BOS	**690**	**690**	0.0%
LRC ($10.70/kW)	**16**	**16**	0.0%
O&M $20/kW/yr	**30**	**30**	0.0%
Land ($/yr/turbine)	**5**	**5**	0.0%
Net 5.8 m/s AEP MWh	4439	4439	0.0%
Net 8 m/s AEP Energy MWh	5519	5519	0.0%
Fixed Charge Rate (FCR)	11.85%		0.0%
COE at 5.8 m/s $/kWh	**0.0480**	**0.0480**	0.0%
COE at 8.4 m/s $/kWH	**0.0386**	**0.0386**	0.0%

* Reference turbine: 1.5-MW, three-bladed upwind/pitch-controlled, 70-meter rotor. Improved turbine: 1.5-MW, three-bladed upwind/pitch-controlled, advanced power converter.

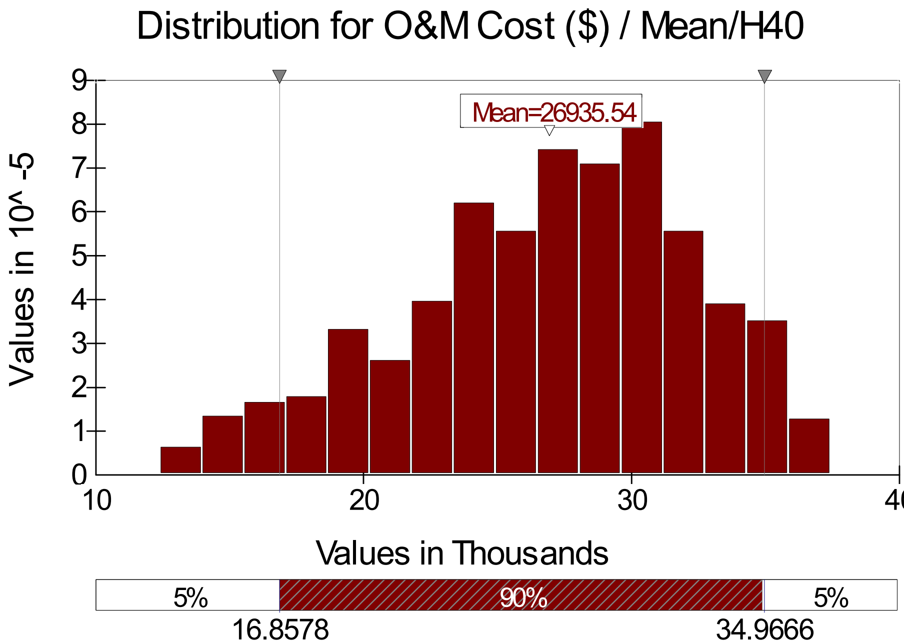

Figure 2. Triangular input distribution for reference turbine O&M cost

Table 3 describes the operating conditions and parameters used to establish the (2002) LWST reference turbine energy production estimates. These operating conditions and numbers are used for the validation of technology improvement opportunity (TIO) projections and for improvement forecasts for LWST subcontractor's wherever appropriate. Most of the detailed component numbers are based on the WindPACT study work performed by Global Energy Concepts, LLC (GEC) (Malcolm and Hansen 2002). There have been minor adjustments, as noted in the table, to match those numbers to the ones selected by program management for the Reference conditions. Where the conditions vary, they are noted below. A baseline AEP spreadsheet was created by Lee Fingersh at the NWTC and used for all AEP calculations. This calculator allows adjustments for wind speed, Weibull shape factor, shear, rotor diameter, hub height, air density, rotor Cp, net losses, availability, and various efficiencies. This spreadsheet was also used to analyze potential improvements in performance and operating conditions.

A COE spreadsheet was created, based on the COE formulation provided at the end of this section, and is consistent with the information details in Table 2. This spreadsheet was used when analyzing the impact of changes in component costs on overall COE. It includes cost elements for O&M, levelized replacement cost and land lease cost. Analogous to Table 3, Table 4 details the differences between the WindPACT cost assumptions and those used for this analysis. Adjustments to WindPACT cost data are somewhat more substantial compared to those for the performance conditions and parameters in Table 3. As detailed in Table 4, the adjustments were made to bring cost and financial conditions more closely in line with the 2002 market.

Table 3. Operating Conditions and Parameters

Condition	WindPACT (1989)	Baseline Turbine (2002)	Comments
Rotor Diameter	70 m	70 m	
Rating	1500 kW	1500 kW	
Hub Height	65 m	65 m	
Operating Wind Class 4	5.8 m/s @ 10 m	5.8 m/s @ 10 m	
Weibull K Factor	2	2	
Base Wind Shear	1/7 (.143)	1/7 (.143)	
Altitude	0 m	0 m	
Air Density	1225 kg/m^3	1225 kg/m^3	
Rotor Cp	0.5	.47*	*The Cp was reduced from the WindPACT study to more closely match the projected Cp of a machine this size in 2002, based on survey data.
Conversion Efficiency	.95	.95	This conversion efficiency is actually represented as an efficiency surface in the spreadsheet and matches the profile of the WindPACT studies.
Soiling Losses	2%	3.5%	Soiling losses were increased slightly to match the combined losses used to project the 2002 baseline.
Array Losses	5%	5%	The product of the conversion efficiency, soiling losses, and array losses is a reduction in AEP of 13%. This matches the losses for the 2002 baseline before availability is applied.
Availability	95%	98%	Availability was increased from the WindPACT 95% to the 98% used to project the 2002 baseline. This more closely matches reported project numbers for recent installations.

Table 4. Adjustments to Cost Elements

Cost Element	WindPACT (1989)	Baseline Turbine (2002)	Comments
Market Price Adjuster	0	$162,000	Although the capital cost estimates were derived with rigorous analysis in the WindPACT studies, various market sources and internal DOE Wind Program analysis of publicly available regulatory power purchase agreement filings for several recent projects indicate that the 2002 capital cost in the United States was closer to $1000/kW for large wind plants.
Tower Costs	$183,828	$101,000	The initial WindPACT tower was based on an 84-m hub height. For the baseline turbine this hub height was reduced to 65 m, consistent with most recent projects. This has reduced the baseline tower costs to $101,000 from the original estimate of $183,828.
O&M Costs	$0.008/kWh	$0.007/kWh	The WindPACT O&M cost number was fixed at $0.008/kWh. This was intended to limit O&M being varied during WindPACT studies, since these studies focused primarily on determining the impact of component design changes. For the baseline turbine the O&M number was reduced to $0.007/kWh (based on an estimate of $30,000 per turbine), to more closely match recent reports. O&M costs are tax deductible. In the final COE calculation on the spreadsheet, the O&M number is multiplied by 0.6 to take into account the tax-deductible nature of the expense.
LRC	$15/kW/ turbine	$10.70/kW/ turbine	Long-term replacement and overhaul costs from WindPACT were set at $15/kW. For the 2002 baseline this number was lowered to $10.70/kW.
FCR	10.6%	11.85%	The WindPACT FCR was set at 10.6%. This number was established at the beginning of the WindPACT project in late 1999. For the LWST project this number was adjusted to 11.85% to be more in line with data for projects at that time (2002). In addition, the FCR was updated as a result of efforts to more closely align the pro forma cash flow spreadsheet methodology with industry practices. The FCR is input from a standard case that uses the cash flow spreadsheet. The FCR reflects finance charges, cost of money, and other factors, and in reality would fluctuate over the years. But for comparing the competing technologies, this number must be frozen, as has been done for LWST.
Land Lease Cost	$0	$0.00108/kw/ turbine	In the WindPACT study the land lease cost, along with several other fixed costs, was included in the FCR. For the 2002 baseline, the land lease cost was entered as a separate item in the spreadsheet and set at $0.00108/kW/ turbine.

A factor called manufacturing uncertainty is added to the initial capital cost for the turbine. This number is set at $162,000. This number is included as an added markup to make WindPACT capital cost numbers consistent with a wide range of reported costs per kilowatt for large (100 MW and larger) projects reported in the 2002 timeframe. The WindPACT component cost data were developed based on quotes from vendors and cross-checks with other industry data, where available, on a component by component basis. The Wind Program believes, however, that due to less than optimum production conditions, the advent of newer equipment, starts and stops in production because of uncertainties in the Production Tax Credit, exchange rate risks, and less than ideal timing of project starts that manufacturer costs or mark-ups were higher, in this time frame, than those assumed in WindPACT studies.

The COE formula used for Table 2 includes those changes. The formula is:

$$COE = \frac{(FCR \times ICC) + AOE}{AEP_{net}}$$

where:

COE	$\equiv$	Levelized cost of energy ($/kWh) (constant dollar)
FCR	$\equiv$	Fixed charge rate (constant dollar) (1/yr) = (0.1158) Includes construction financing, financing fees, return on debt and equity, depreciation, income tax, property tax, and insurance.
ICC	$\equiv$	Initial capital cost ($)
AEP_{net}	$\equiv$	Net Annual Energy Production (kWh/yr)
AOE	$\equiv$	Annual operating expenses
	$\equiv$	$LL + \frac{(O\&M + LRC)}{AEP_{net}}$
LL	$\equiv$	Land lease ($/kWh)
$O\&M$	$\equiv$	Levelized O&M cost
LRC	=	Levelized replacement/overhaul cost

3.0 Technology Improvement Opportunities

The identification of TIOs is a central element to the pathways analysis. The process for identifying the most likely TIOs relies on the technical insights and judgments of the senior research staff at the National Wind Technology Center at the National Renewable Energy Laboratory (NREL) and Sandia National Laboratories.

Wind turbine design is a matter of constant tradeoff between the competing demands of lower cost, greater energy productivity, increased lifetime and durability, and maintenance cost. Achieving greater energy production may cost more, or it may cost less. Reducing materials to reduce capital investment may adversely affect O&M costs. These are the designers' tradeoffs, and they are captured in the model. However, the model does not currently perform detailed system tradeoffs. It can include any number of independent technology design paths, but tradeoffs between components within a system must currently be treated in the estimation of the input parameters.

Early attempts at developing TIOs, TIO descriptions, and estimates of TIO values were performed by a relatively limited group of the program research staff, primarily because the goal of the early effort was to develop the analytical framework and to test various aspects of the pathways model (Cohen 2004).

In mid-2004, NREL, Sandia and Princeton Energy Resources International (PERI) convened an expert group to finalize the details of the TIOs. The outcome of that effort is summarized in the remainder of this section. The estimates for all TIO values, including the data ranges, were made directly by the laboratory experts and did not result from Monte Carlo simulation. All estimates assume independence from each other. That is, there is no interdependency or correlation modeled between TIOs. This is obviously a simplification, but the detailed tradeoff systems analysis that would be required to accurately reflect such interactions was judged to be a major effort that was beyond the scope of this analysis. The other ground rules for TIO estimation included: (1) assume a level budget at the current level (nominally $40 to $44 million annually) up to the goal year of 2010; (2) evaluate the potential for advancement from each TIO by 2010; and (3) combine various possible separate pathways within each TIO into a single overall range of potential values for that TIO. Also included is the group's assessment of the likelihood that the expected TIO benefit will not be realized because of technical failure (Probability of Technical Failure). This was a subjective judgment made for all of the TIOs by the entire team, by comparing each TIO on a relative basis to each other, and on an absolute basis based on the stage of current R&D results, technology status, number of redundant pathways, and understanding of the number and nature of the remaining technical issues to be resolved, versus the assumed level of R&D under the level budget assumption.

TIO 1: Advanced (Enlarged) Rotors

This TIO uses the approach of enlarging the rotor to increase the energy capture in ways that do not increase structural loads or electrical power equipment requirements. The end result is a greater energy capture from the same infrastructure investment. Structural loads caused by turbulence are limited by using passive and active controls on the longer blades. However, since gravity loads grow with the length cubed, the blades must be lightened significantly as the blades grow. New materials and manufacturing processes are used simultaneously to reduce total blade weight. Numbers provided here are based on data extracted from reports and proposals and some of the detailed data are proprietary. The cost impacts are provided below. These incorporate and integrate the cost elements of all of the sub-TIOs, which are described later.

Several technological advances could (either separately or in combination) be used to create the ability to grow rotor diameter while maintaining or even reducing total system installed cost. The five identified areas are listed at the end of this section, followed by a more detailed explanation of how each might affect system costs and energy production. Because there are different and overlapping approaches, it is difficult to specify the final configuration that will result in the greatest COE reduction. However, the separate and complementary approaches lead to a very high probability of success; i.e., there is a very high likelihood that enlarged rotors in some configuration will produce a sizeable reduction in the system COE.

Although we cannot specify the exact scenario that will produce the optimal result, simple paths through the cluster of technology improvements can be created to illustrate how cost reductions will be realized. For example, passive controls might offer the ability to reduce loads by 20% to allow 10% rotor growth and 10% annual energy capture improvement. Active controls can make the same or greater claim. Since active and passive controls affect different loading contributions, the two improvements can add, perhaps with slight overlapping, to achieve a roughly 20% improvement in AEP. The combination of passive and active controls may avoid a penalty in O&M by passive effects that limit the increase in active pitch activation. Improved active speed and pitch control can increase energy capture by another 5%. Also, with quieter blade tips, higher rotor speeds, and reduced solidity, additional benefits are possible, and, as a result, the estimate of 25% is more likely to be achieved. Without lighter blades, there would be a substantial increase in capital cost because longer, heavier blades would increase gravity loads on the entire system. Therefore, the stiffer carbon-fiber materials are required to lighten the blade and reduce tip deflection so that the full benefit of the loads reduction can be realized on the entire system and the AEP can be increased without raising capital costs anywhere but in the blades. Finally, blade costs can be decreased with improved structural/aero design improvements that alone would cut blade costs by 10% to 20%, below a relevant baseline.

The specific advancements in the Advanced (Enlarged) Rotors TIO are based on the following five sub-TIOs:

- **Advanced materials**

  The availability of new materials and new material forms allows more flexibility in design concepts and fosters the development of enlarged rotors by using lighter, stronger blades that reduce or more efficiently resist loads. Carbon was suggested by several of the WindPACT studies for use in larger blades to overcome gravity constraints. It is also useful in passive bend-twist coupling. Carbon pre-preg has traditionally been too expensive for use in wind turbines, but costs have dropped with the recent introduction of larger tow fiber bundles. Other materials that may help in this area are new fabrics such as 3D weave and new matrix materials such as toughened resins. Other forms of materials that show promise are pultruded parts (such as pultruded rods in the spar-cap), use of pre-forms in areas of thick sections for resin infusion, and increased use forms with integrated glass/carbon hybrids. Carbon fibers, although more expensive than glass fibers, can reduce weight and tip deflections when used in select load bearing portions of the blade.

  Griffin (2002) estimates a 10% to 20% reduction in blade costs just going to carbon-hybrid materials. Reduced rotor mass results in reductions in the rest of the support structure, especially in the tower, on the order of 2%. With blades accounting for 10% to 15% of turbine costs, the net result is a 2% to 6% decrease in turbine capital cost.

- **Structural-aero design**

  This sub-TIO includes several methodologies:

  - An integrated design process looks to optimize the blade for structural load carrying capacity and manufacturing ease first with the aerodynamic design coming second. The integrated blade design process includes:
    - Design for simple structures before finalizing aerodynamic design.
    - Use constant spar cap thickness and constant spar cap width design on inboard half of the blade.
    - Inboard, use high thickness flatback airfoils.
    - Outboard, use high lift airfoils with modified thickness and shape for least complex and costly internal blade structure.
  - Thicker airfoils could be used primarily in the inboard section of the blade to provide more flapwise stiffness. These airfoils are much thicker than normal, ranging from 35% to 65% thick.
  - Slender blades refer to the reduction of the chord length used inboard. The effect is a reduction in mass (good) and edgewise stiffness (not necessarily good). One airfoil family that can provide the necessary aerodynamic and structural requirements is the flatbacks. Flatback airfoils are truncated at the trailing edge to provide enhanced flapwise stiffness and lower weights, and the trailing edge can be strengthened with a thicker flat panel perhaps with carbon fibers to maintain stiffness requirements.

The effect of truncated trailing edge, or "flatback," airfoils on AEP was estimated by TPI Composites (2003). The baseline turbine was assumed to be a 1.5-MW machine, with a 70-meter diameter rotor turning at 20 rpm. The increase in AEP produced by the flatback airfoil was estimated to be 1% to 4%. At the same time, the TCC was estimated to drop by 5% to 7% because of improved manufacturing efficiency and greater blade load carrying capability with substantially thinner and lighter material.

- **Active controls**

  The application of active controls has its main use in reducing rotor loads, enabling the growth of the rotor without increasing system costs. However, there are a number of quite distinct applications are enumerated here.

  - Advanced controls are being developed and tested to increase energy capture and reduce system loads. In isolation, advanced controls have the potential to significantly reduce turbine costs. Simulations and tests (in progress) have shown that blade root moments, drivetrain shaft torque loads, and tower bending moment fatigue loads can be significantly reduced (on the order of 20%) with rotor collective and independent blade pitch control. Energy capture in region 2 can be increased through the use of adaptive control algorithms, which can improve energy capture by up to 5%. The transition region between region 2 and region 3 is a cause of large thrust and blade root bending loads. If these could be mitigated, some driving fatigue loads may be reduced leading to a 2% to 5% decrease in rotor ICC.
  - Inserting the numbers into the cost analyses: If we assume a 20% reduction in component loads, we could assume a possible 10% reduction in component costs Here we have assumed reductions of 10% in the blades, hub, low-speed shaft, bearings, and gear box, as well as yaw drive and bearing. We have assumed 10% increases in the pitch mechanisms and bearings as well as the control and safety system (due to added complexity for advanced controls). We have assumed a 10% reduction in tower foundation costs. This leads to a 5.5% improvement in TCC and a 1.2% improvement in BOS. Much research must still be done to experimentally prove these possible improvements. We must design and test control algorithms for several turbine configurations.
  - Another way to look at this tradeoff is if component costs are kept constant, but the rotor is allowed to grow. A 20% rotor and drivetrain load reduction might allow rotor diameter to be increased by 10%. This results in an AEP increase of 11%.
  - Another advanced control consideration is mitigating driving loads in region 4 (high wind cutout). If control could be maintained with grid loss, substantial reductions in these loads could be had because many of the highest loads are caused by the assumed failure of the yaw drive to function. This results in rotor costs dropping by 5% and tower costs by 10%.

- **Passive controls**

  As blades become larger and we strive to lighten blades to reduce gravity loads, it becomes more important to reduce operating loads and at the same time enhance or maintain performance. This can be done passively or actively. To passively reduce loads, the blades can be designed in several ways. One is to sweep the blade along the span to create a moment that induces twist into the blade while operating, thus reducing loads. A second method is to align the primary load-carrying spanwise fibers in an off-axis manner by about 20 degrees, so as the blade bends due to flapwise loads, it twists more than usual allowing loads to be relieved. This same kind of "forced" twisting can be induced architecturally by designing the spar and shear webs in a box type of structure, such that the box has skewed structural properties that allow for the same twisting motion and this relieves loads. Studies have shown that this “bend-twist” coupling is maximized with the use of very stiff fibers, such as carbon.

The studies by Lobitz and Veers (2003) indicate that a 20% reduction in blade flap loads can be achieved with passive twist-flap coupling alone. If this is accompanied by a similar reduction in blade weight (as can be expected when switching from glass to carbon fiber for the load-bearing blade structure), the blades can be made 10% longer without increasing the cost of any of the blade loads. Blade costs are expected to, at best, remain constant, but even with a 10% to 20% increase in blade cost, the entire system will achieve a 20% larger swept area at a 2% to 4% increase in system cost (blades being 10% to 15% of system cost). Advances in manufacturing and materials at the same time will drive blade costs down, so the passive load attenuation could possibly be included without a concurrent increase in capital cost. The 20% increase in swept area results in only a 10% to 11% increase in AEP, because the fixed rated power limits the ability to make use of the increase power levels to the low wind speed region below rated power, which is normally about 12 to 13 m/s.

- **Higher tip speed ratios/lower acoustics**

  This sub-TIO is aimed at reducing the COE by increasing tip speed and simultaneously decreasing blade solidity and constraining blade aeroacoustic signature levels. In this approach, shrinking blade chord reduces blade aerodynamic loads and low speed shaft torque. Then, the blade rotation rate is correspondingly increased to maintain equivalent power levels. However, aeroacoustic emission originates principally at the blade tips and increases geometrically with tip speed. Thus, aeroacoustic emission could represent a key constraint on this COE reduction methodology. Because the capabilities for predicting and controlling blade aeroacoustic signature currently are not well developed, attenuation of aeroacoustic signature is not accounted for in these analyses. Instead, it is optimistically assumed that blade aeroacoustic can be maintained constant in conjunction with these modifications, or that amplified aeroacoustic signature will not impact the cost of energy (see Malcolm and Hansen 2006). In this study, the baseline turbine (Table 4-3, and Case A in Table A-3) was rated at 1.5 MW, had three blades with full-span, variable-pitch control, running upwind of the tower on a rigid hub, with zero cone angle, and comprising a 70-m diameter disk.

  The baseline configuration was modified (Case X in Table 5-2) by reducing the maximum chord to 6% of the rotor radius and increasing the tip speed to 85 m/s. These modifications significantly decreased loads in all components, but at the expense of a negative tower clearance margin (p. 38). This problem was remedied by using carbon-glass hybrid construction in conjunction with 5 degrees of blade cone angle and increased hub overhang (p. 38). The “Most Likely” reduction in TCC is extracted from Table A-3 is a 13% reduction with error bands of ± 25%, corresponding to model accuracy uncertainties. The aeroacoustic signature was assumed to be held constant, and thus had no impact on these analyses.

TIO 1: Advanced (Enlarged) Rotors

(% changes to reference value)	**Minimum**	**Most Likely**	**Maximum**
AEP	+10%	+25%	+35%
TCC	–6%	–3%	+3%
BOS Cost	–1%	0	+1%
LRC	0	0	0
O&M Cost	0	0	0
Probability of Technical Failure	5%		

TIO 2: Manufacturing

The Manufacturing TIO is based on potential developments of new manufacturing processes and improvements of processes that will provide reduced labor, reduced material use, and improved part quality. The advancements in the TIO are based on:

- **New or improved manufacturing processes**

  The automation of manufacturing will continue to become more widespread and is very important for large blades because of quality issues. For blades, the days of using primarily hand lay-up are gone. Resin infusion has become more common because it reduces labor costs and improves part quality compared to hand lay-up. Automated lay-up and incorporation of pre-forms (especially in areas of thick buildup) will become more prevalent. Pre-preg processes, which traditionally have been used in aerospace structures, tend to produce high-quality parts. The push to incorporate carbon is ongoing as we move to lighter blades. In addition, manufacturing process improvements for large blades are expected to include the optimization of the process around different material forms. For example, in the case of resin infusion, material-resin combinations will be chosen that infuse easily, achieve desired fiber content, and eliminate excess resin.

  Advanced manufacturing techniques may also apply to towers. Onsite forming techniques for tower sections may reduce fabrication and transportation costs. As diameters for tower base sections are limiting factors in taller towers, onsite manufacturing using these new techniques may be a major contributor to cost reductions, and help to realize advanced tower concepts discussed under TIO 4.

- **Lower margins**

  The partial safety factors designated in certification codes, such as IEC and Germanischer Lloyd, are high because of the uncertainty in loads, materials, and fabrication processes. Manufacturing processes that are more consistent and reliable, when backed up by testing, will allow for reduced safety factors.

- **Manufacturing markups**

  Estimates of turbine capital cost typically include assembly, shipping and manufacturing markups. For consistency in comparing COE from different proposals and subcontractor reports, we normally assume a markup of 20%. We assume that this manufacturing markup can be expected to decrease in the future. Several factors, including lower uncertainty and risk with mature products, contribute to this assumption. In addition, price pressure from competition and higher sales volume from larger, more expensive machines are expected to result in smaller margins. Therefore, this COE reduction element assumes a 15% markup instead of 20% used in the past. This would be representative of market conditions by 2010, when supply and demand are presumed to be more balanced than they currently are (in 2007), and competition creates downward pressure on pricing.

TIO 2: Manufacturing

(% changes to reference value)	**Minimum**	**Most Likely**	**Maximum**
AEP	0%	0%	0%
TCC	0	–5.0	–6.0
BOS Cost	0	0	0
LRC	–5	–2.5	0
O&M Cost	–2.5	–1.0	0
Probability of Technical Failure		5%	

TIO 3: Reduced Energy Losses and Improved Availability

Availability is a measure of how often a turbine is completely offline because of faulty conditions, repairs, or scheduled maintenance. Other energy losses are incurred when a turbine operates at less than the design output for a given wind speed. Possible causes include blade soiling, damaged sensors, and control errors, as well as a host of other possible operating difficulties. The baseline availability is assumed to be 95%, but significant improvements can be achieved by designing components that require less frequent maintenance visits. The more difficult challenge is to build the system with sufficient quality control and fault tolerance to reduce the number of times the machine is removed from operation by the safety system. A goal of 98% availability is not unrealistic. For example, using airfoils that are more tolerant to soiling or blade coatings that shed dirt can reduce some operating losses. Control systems can be designed to sense off-optimal operation and adaptively adjust to minimally affect power performance. Health monitoring systems can be used to inform a smart controller of needed operational changes or parameter adjustments. It can also alert operators of the need to schedule maintenance at the most opportune times. A warning about an incipient failure can warn the operators to replace or repair a component before it does significant damage to the system or leaves the machine inoperable for an extended period of time.

TIO 3: Reduced Energy Losses and Improved Availability

(% changes to reference value)	**Minimum**	**Most Likely**	**Maximum**
AEP	0%	5%	7%
TCC	0	0	0
BOS Cost	0	0	0
LRC	0	0	0
O&M Cost	–25%	–15%	0
Probability of Technical Failure		5%	

TIO 4: Advanced Tower Concepts

The Advanced Tower Concepts TIO is based on the use of new tower concepts that will enable taller towers to be erected in more difficult locations, without the use of high lift capacity cranes and may allow the tower to be assembled (and possibly even fabricated) on site, thereby reducing the cost of tower transport. The primary comparison is between the baseline tower and power production at 65 meters, and the cost of advanced towers and power production at 100 meters. The estimates on taller towers take into account reductions in cost from reductions in transportation, crane cost, and other associated infrastructure elements. The advancements in this TIO are based on:

- **New Materials** such as carbon fibers or e-glass
- **Innovation in structures** such as implementation of space frame designs (unique truss designs such as tensegrity) or fluted towers using unique plate forming techniques

- **Advanced foundations** such as tension anchors

- **Self-erection methods** that allow primary erection without high lift capacity cranes. These techniques may allow initial erection only, or may also allow de-installation for major servicing.

Estimates are based on data extracted from industry and a wide range of reports. In general, the cost numbers represent COE impacts that are break-even, that is, the overall impact on COE for each design is either very small or zero. This is caused by the additional capital cost of the tower offsetting the gain in AEP realized by going to 100 meters. This analysis is based on a wind shear of 1/7. However, this technology represents an enabling technology that allows very tall towers to be constructed cost effectively without high lift capacity cranes. This allows turbine installations to take advantage of sites with much higher shears. The COE impact of the higher shears is reflected in TIO 5 – Site-Specific Design. The cost impacts of the Advanced Tower Concepts TIO are provided below.

TIO 4: Advanced Tower Concepts

(% changes to reference value)	**Minimum**	**Most Likely**	**Maximum**
AEP	10.8%	10.8%	10.8%
TCC	+5	+12	+20
BOS Cost	–10	0	+17
LRC	–5	–2.5	0
O&M Cost	0	0	0
Probability of Technical Failure		20%	

TIO 5: Site-Specific Design/Reduced Design Margins

The reference turbine from which LWST improvements will be measured operates in a prescribed site with characteristics of typical open country; a Rayleigh distributed annual wind speed distribution and a standard wind shear profile. We are just now learning that many onshore locations with LWST average wind speeds have very high wind shears, and some have significantly different annual wind speed distributions. Opportunities exist for enhanced AEP where higher wind speeds are present. If wind shear alone was to change from a 1/7 to a 1/5 power law, the energy capture increase is about 20%. If the site wind distribution changes from a Rayleigh distribution to a slightly more favorable one, another 3% to 5% energy capture can be achieved.

With some additional tuning of the system design, COE can be driven down by making the most of particular site conditions. For example, a higher generator rating has a greater energy payoff with higher shears and taller towers than at the baseline LWST conditions. Using a larger rotor (TIO 1) at high elevation in a high shear site can increase the energy capture by another 20%. A low turbulence site might allow an expanded rotor to have a modest cost increase and keep the rate of fatigue damage equivalent to a high turbulence site. A site that is not likely to see the extreme winds specified in the standard could use a machine with reduced extreme design loads, which would reduce the cost of the machine. Also, local terrain perturbations might be exploited to maximize plant output. All these design improvements depend on a sophisticated understanding of the inflow characteristics and the way they will load the turbine structure.

The greater structural damage incurred by environments with high wind shear, an environment that is just now beginning to be understood, could offset the benefits of additional annual energy capture. The additional capital costs and maintenance expenses are unknown. Standards dictate design margins for all turbines, but these values are generally legislated by standards committees and could be much lower or higher than the actual margins. Site-specific conditions are hard to estimate because long-term records are usually needed to determine the 50-year design conditions for that site. Improved methods for site condition evaluations would greatly reduce the uncertainty of site-specific design. These might include long-term predictions that use meso-scale models tuned to the exact site terrain and atmospheric conditions, or it might include short records of atmospheric boundary layer conditions needed to tune the meso-scale models. Experiments such as the Low Level Jet and the Long Term Inflow and Structural test are beginning to characterize the nature of the loadings wind turbine structures will see in these environments.

The conditions specified in standards include extreme wind speeds, turbulence characteristics, wind shear, specific extreme events in discrete wind models, electricity grid conditions, and environmental conditions. If the turbines are optimized to a set of conditions that matched the intended site, the site-specific optimum design can be more economical. The ability to optimize a design for a specific site, and to optimize the placement of turbines on the site, is an opportunity with great upside on energy capture (about 20% in some sites), but with high uncertainty on the resulting capital costs and maintenance expenses.

TIO 5: Site-Specific Design/Reduced Design Margins

(% changes to reference value)	**Minimum**	**Most Likely**	**Maximum**
AEP	+10%	+20%	+30%
TCC	-5	0	+5
BOS Cost	0	0	0
LRC	-5	+5	+10
O&M Cost	-5	+5	+10
Probability of Technical Failure		50%	

TIO 6: Drivetrain Improvements

In general the drivetrain of a wind turbine is composed of any type of speed increaser (gear box), main shafts that support the rotor and their associated bearing, rotor brakes, and generators. These systems account for roughly 30% of turbine capital cost, excluding foundations and site infrastructure. A number of approaches have been suggested for significantly advancing the state of drivetrain technology.

- **Gear Boxes**
    - **Advanced Gear Profiles**

      This technology represents a fundamental change to the gear tooth geometry that may enable gear boxes to be made with less material for the same load-carrying capability and therefore at a lower ICC. These designs could lead to system capital cost reductions of 5% or more. If these advanced gear geometries are reliable, additional benefits may accrue from higher availability and reduced O&M. Projections are that O&M can be cut in half, or reduced by $.004/kWh. This would also carry over into higher availably and therefore increase AEP. Both lower O&M and higher reliability will be difficult to demonstrate at any early stage, and the arguments to support this must be demonstrated over time. Currently, gearboxes are limited by bearing failures, which are not addressed by this design. There may be some additional benefits if advanced geometries can be packaged more compactly, allowing some designs to be scaled up more easily. The overall assessment of this technology is that it carries a high risk with the potential to show significant COE reductions if successful. This technology, if successful, is potentially additive to most of the other gearing and drivetrain concepts.

- **Integrated gear/generator systems**

  Generally, cost reductions may be realized by integrating major drivetrain components such as the gearbox, generator, and bedplate. This forces adjacent structural components to carry additional loads and perform more than one function, which eliminates or significantly reduces the size and weight of the support structure. If integrated drivetrain systems can be designed and initially produced at or below the cost of modular systems, the potential for learning curve cost reductions is greater for the integrated system. This is true because the modular system is produced from more mature components with less initial customization. The challenge will be to demonstrate equivalent or better reliability and serviceability.

- **Single-Stage/Permanent Magnet Generators (PMGs)**

  A technology being explored both in the United States and Europe takes advantage of medium speed generators. These generators are larger in diameter and have many more generator pole pairs that allow them to produce close to 60 hertz power without spinning at the high speeds necessary for standard generators. These medium-speed generators spin at 150 rpm, compared to 1200 to 1800 rpm for normal induction generators. These generator designs are then coupled with a single-stage gearbox that is much more compact and less complex (fewer gears and bearings) than multi-stage gearboxes used in most wind turbines today. The permanent magnets in these generators, instead of copper wound rotors, further reduce their weight and size (Poore et al. 2002).

- **Compound Planetary**

  A gear box with a single compound planetary stage can deliver higher ratios that would normally require two stages. This could be advantageous for some of the medium-speed drives that have been proposed. There may be some advantage in a conventional gearbox to make it incrementally lighter, but this has not been fully demonstrated.

- **Multi-generator**

  An alternate approach to a wind turbine drivetrain would exchange a single generator for multiple generators. This design takes advantage of reductions in gearbox size and weight that can be realized by having multiple drive paths (extracting power from multiple points from a single bull gear). This approach effectively reduces the torque that each drive path must be designed for, reducing the size and load carrying capacity of the gearing. Such a design has been reduced to practice by Clipper Windpower in its Liberty Turbine. This design uses four parallel drive paths, each connected to a permanent magnet generator. This machine drive train and nacelle are significantly smaller and lighter than would be expected from other mainstream designs using multiple stage speed increasers and a single generator (Poore et al. 2002).

- **Direct Drive**

  An alternate drivetrain design approach eliminates the gearbox altogether. This approach uses a large diameter direct drive generator. Much as described in item 3, a generator with many poles is used to develop a low-speed generator. In this design, the generator turns at the speed of the rotor, and varying frequency output is conditioned by power electronics. This design can be implemented using either wound pole generators or permanent magnet generators, as described in item 3. However, as machines increase in size, direct drive generators can become very large, limiting their transportability. Permanent magnet designs help in this area to reduce the size and weight of such direct drive generators. But for much larger machines, in the 2 MW and larger size, unique and perhaps segmented design that can be assembled in the field may need to be explored to allow further growth.

- **Bearings**

  Current industry experience indicates that the single biggest cause of failure in wind turbine gearboxes is bearing failure. The failure of the bearings leads rapidly to a full system failure that is usually very costly. In order for wind turbine gearboxes to attain their design operating life, the bearings must last for the duration. In addition, there appears to be a significant challenge in scaling up the current line of gearboxes to the multimegawatt sizes. As turbine sizes increase, oil film thickness decreases, gear ratios increase, and bearings (especially planet bearings) must be compact to operate in increasingly limited space. Journal bearings, improved surface finishes, and improved analysis methods may enable the continued growth of wind turbines, and lower the cost of O&M.

- **Lubrication**

  Maintaining gearbox lubrication is essential to achieving gearbox design life and thus COE targets. Lubricant additives can be engineered to resist depletion and to guard against known failure modes in the gears and bearings. The lubricant also contains the best record of operation, and through its analysis the health of the gear system can be determined. Lubricant quality sensors alone, or in conjunction with other vibration and acoustic sensors, may provide early detection of gear or drivetrain failures.

- **Generator Configurations**

  Traditionally, high-speed generators have been coupled through speed increasers to the wind turbine rotor. The gearbox has been a primary cause of failure of the system as mentioned earlier. Many turbines smaller than 100 kW have used direct drive generators to simplify the system and make it more reliable. However they have not been less costly or more efficient. Efficiencies are heavily dependent on air gap, design choices of stator windings, pole configurations, magnetic paths and material choices. Configurations can also affect manufacturing costs, assembly costs, maintainability, hub and rotor configuration options, and structural load path efficiency. Even the size (diameter versus length of stator) of the generator can be altered to meet overall machine design criteria. Until the advent of new high flux density, lower cost permanent magnet material, these types of generators were generally thought to be too expensive. Also, they require power electronics (PE) to condition and convert the low frequency output to line frequency and allow variable speed and high fidelity torque control. PE have become much less expensive and less limited by power ratings. These facts make PMGs a more attractive option for wind turbines, which benefit from high reliability, variable speed, torque control, low speed/partial power efficiency improvements, load path efficiency, noise reduction (by eliminating gearing or high speed stages of gearing), and power conditioning for high power quality.

- **Assembly**

  Optimum diameters (from a single component cost standpoint) for large high-power direct drive generators can be very large compared to conventional nacelles. This means that assembly and simply transporting the assembled nacelle is costly. That fact makes field assembly of generator components attractive, especially if it allows simple tower top assembly. For offshore turbines the transportation challenge is relaxed, but shop assembly of large permanent magnet assemblies will require special tooling. This tooling or assembly procedure can drive the design, especially if repairs need to be done in the field. Assembly procedures can also affect the choice of flux paths and pole design, which can affect efficiency. Finally, if a very efficient assembly procedure for inserting the magnetized rotor into the winding is available the air gap can be minimized. This has a profound effect on efficiency. Structural stiffness also is an important factor in minimum air gap specifications.

- **Efficiency**

  Generator efficiency will directly affect AEP. Because wind turbines operate at partial power for most of their operational lives, the efficiency at power levels less than half their rated power is very important. Most traditional generators optimize efficiency at rated power because it allows them to minimize cost per rated power. PMGs enable designers to maximize efficiency at low power levels because there are no rotor losses. This gives generator designers the liberty to trade off efficiency for generator cost. In other industries, where efficiency is less important, this might be a high priority. For wind turbines the designer might choose to sacrifice efficiency at rated power for high efficiency at 40% to 50% of rated power. High-voltage designs might also offer even more options with possible savings in other components, such as reducing losses through cabling in the collection system and down the tower. However, these changes might affect the converter topology and component choice and cost.

- **Radial Flux versus Axial Flux**

  Most commercial generators have radial flux paths, i.e., the magnetic flux goes perpendicular to the axis of rotation. Axial flux paths, which parallel the rotational axis, have been proposed as alternative designs. These might have advantages in configuration, in helping to shrink generator size, and in assembly. They may also have disadvantages in stator winding tooling and automation. Axial flux generators present new challenges for structural stiffness to hold the air gap constant under all rotor loads.

- **Generator Cooling**

  All generators, including PMGs, need to be cooled. Smaller, higher current densities are possible in windings if more efficient methods for heat rejection can be developed. Smaller packages can save weight and hence cost. Also active cooling system such as water or hydrogen can be very effective but, in adding complexity to the system, may detract from simplicity and reliability goals. Air cooling options have not been fully explored for generators of this size either. Pole designs and winding design for optimum matching of converter/generator characteristics have not been fully explored. Each system tradeoff will affect the final optimal generator design and cost.

- **Superconductors**

  Superconducting generators would dramatically increase the conductivity of windings and wires by super cooling certain components of the machine. This might allow increased flux densities, which is also possible with the use of new magnetic materials. Although these concepts seem far off for standard generators, large generator designs could benefit from technology that is nearly commercial. This would obviously require a complete rethinking of the cooling system, winding, and pole configurations. The final benefit might be a much smaller and more efficient generator. A direct drive generator may someday be as small as a typical gear-driven, high-speed generator.

- **Medium-Voltage Designs**

  Most wind turbines in the United States currently operate lower than 600 volts, which is commonly termed low voltage. Medium-voltage generators and PE (600 to 35,000 volts) could lower electrical losses and reduce the cost of transformers. They could also have cost impacts on turbine-based breakers, conductors, converters, and controls. Generators in the rest of the power industry, of the power ratings of typical wind turbines today, are generally built in medium voltage. However, perceptions of increased maintenance costs and safety have generally kept the wind turbine industry from moving in this direction. As machine sizes increase more and more, the move to medium voltage may become more and more attractive. PMGs further complicate this choice. The benefits of medium voltage must be weighed in light of the wind turbine application with the possible benefit of increased efficiency.

- **Higher Energy Product Magnets**

  The flux density of magnets has been increasing steadily as manufacturing processes improve. High flux density magnets could change the internal rotor design and perhaps allow more compact designs that are more robust. By constructing the generator rotors so that the magnetic material is packed into more efficient flux paths, the flux can be focused and optimized to efficient pole designs. By using permanent magnets, it is expected that less total material will be needed. Slower rotor speeds may also be possible for a given torque. In general it is expected that the entire generator size will be reduced.

TIO 6: New Drivetrain Concepts

(% changes to reference value)	**Minimum**	**Most Likely**	**Maximum**
AEP	0%	+1%	2%
TCC	–3	0	+3
BOS Cost	–4	–2	0
LRC	–2	–1	0
O&M Cost	–5	–2	2
Probability of Technical Failure		0%	

TIO 7: Advanced Power Electronics

The Advanced Power Electronics TIO is based on the idea that PE will become an increasingly important part of modern wind turbines as wind turbine technology advances. Wind turbines largely began as constant-speed machines that were grid connected. Small PE converters were sometimes used as soft-starters for these machines. The next stage was to use PE to control the rotor currents of doubly fed induction machines. Such converters are usually rated at between one-quarter to one-half of the turbine rating. As more single-stage and direct-drive permanent magnet machines are developed, PE will be used to process all turbine power. New grid codes are requiring a greater range of grid compatibility to control such factors as low voltage ride through, reactive power, voltage, and ramp rate. Control of these kinds of parameters is usually reserved for synchronous generators, but with the advent of PE these types of requirements can be met more easily by wind turbine generators. Grid engineers have typically viewed wind turbines as grid destabilizing, but with these types of PE capabilities, grid engineers may eventually view wind turbines as a valuable ancillary asset. Finally, PE can be used to integrate energy storage and hydrogen production into the wind turbine or wind farm.

Advances in PE can usually be classified into one of four categories:

- **New circuit topologies or designs**

  New circuit topologies can be used for several purposes including power quality control, the ability to accept and produce higher voltages, to increase overall converter efficiency, and to more efficiently use the semiconductor switch area.

- **New ways of connecting devices together to increase power**

  No PE converter for wind turbine use would use a single switching device. In reality, most large converters contain hundreds or thousands of switching devices connected together in some way. Innovative ways of connecting these devices can yield higher utilization efficiency and the ability to handle larger voltage and currents.

- **New semiconductor devices**

  When insulated gate bipolar transistors were introduced, they revolutionized the medium power converter market. Other new devices, such as symmetrical gate commutating thyristors and metal-oxide semi-conductor controlled thyristors, are being investigated and may make inroads into the market.

- **New materials for the manufacture of semiconductor devices**

  Virtually all current semiconductor switches are made of silicon. However, new materials such as gallium-arsenide, silicon-carbide, and diamond are being investigated for producing semiconductor switching devices. In many cases they have superior qualities to silicon, particular in current handling and heat tolerance. How such devices will be incorporated into power conversion devices will be unknown for several years, as R&D continues, but they could easily lead to much smaller and more robust converters.

TIO 7: Advanced Power Electronics

(% changes to reference value)	**Minimum**	**Most Likely**	**Maximum**
AEP	0%	+3%	+6%
TCC	–8	–4	–2
BOS Cost	–5	–2	0
LRC	–8	–4	+1
O&M Cost	–10	–5	+3
Probability of Technical Failure		5%	

TIO 8: Learning Curve Effects

Although there is a standard mathematical formula for characterizing cost reductions in manufactured goods from “learning effects,” there is no standard definition of the term, i.e. what effects it includes, nor if there is an accepted single set of assumptions and overall methodological approach for calculating or predicting learning curve (sometimes referred to as “experience curve”) impacts. Indeed, the term is often used by different analysts to include different cost reduction mechanisms and market system boundaries (Junginger 2005). For this TIO, learning curve effects include cost reduction from learning that: (1) takes place in the early production stage after the product has been designed (learning by doing); (2) occurs during the early use of the technology as a result of feedback from the field (learning by using); and (3) occurs as more market stakeholders participate beyond the early production stage, share knowledge, and interact to improve various technical and market processes (learning by interacting).

Although some researchers include effects from economies of scale in learning curves, an analysis performed by PERI for NREL in 1995 differentiated two factors that affect wind turbine prices as production volumes increase: economies of scale and learning curves (Brock et al. 1995). Economies of scale are reductions in the average cost of a good attributable to increases in the scale of production of that good. Economies of scale covers many different aspects of production scale, but it can be most simply modeled as the relationship between per unit cost and the rate of production, typically measured as the number of units per year. The learning curve is defined as reductions in the average cost of a good due to reduced costs as workers and processes become more efficient. In contrast to economies of scale, the learning curve is a function of the cumulative production of the firm; the annual level of output is irrelevant (Brock et al. 1995).

TIO 8 input values assume that there is at least a chance that the annual level of wind turbine manufacturing output will increase over time, along with cumulative volume. Therefore, the analysis reflects the potential, on a probabilistic basis, for corresponding cost reductions that would result from economies of scale, including discounts for larger volume purchase of materials, parts, and components. Since there is no other TIO to account for economies of scale, it has been included in TIO 8.

The basic learning curve can be expressed as:

$$C_{cum} = C_0 Cum^b$$

$$\log C_{cum} = \log C_0 + b \log Cum$$

$$PR = 2b$$

$$LR = 1 - 2^b$$

C_{cum}: Cost per unit
Cum: Cumulative (unit) production
PR: Progress ratio
C_0: Cost of the first unit produced
b: experience index
LR: Learning rate

The progress ratio is a parameter that expresses the rate at which costs decline for every doubling of cumulative production. For example, a progress ratio of 0.8 (80%) equals a learning rate of 0.2 (20%) and thus a 20% cost decrease for each doubling of the cumulative capacity (Junginger 2005).

Among the parameters affecting the learning rate for a global technology are exchange rates, choice of inflators to correct for inflation, use of production costs versus market prices, choice of market boundaries and subsequent inclusion or exclusion of imports or exports from cumulative production levels, definition of production units (e.g., energy production, capacity or number of turbines) and cost or price (e.g., $/turbine, $/kW, $/wind plant, $/kWh produced). In addition, off-the-shelf components of wind energy plants that are already mass produced will tend to show much less cost decrease over time than lower volume, custom-designed and -built components (Brock et al. 1995). The assumed mix of these two types of components will affect the size of the projected progress ratio. There is also uncertainty about whether progress ratios remain constant over time or tend to increase, causing cost reductions to diminish as market diffusion increases. There are arguments to support the possibility of either case (Junginger 2005).

Although the application of learning curves to wind energy cost contains many uncertainties, there have been many recent attempts to construct such curves from the growing set of empirical market data. A recent review of 20 such studies, published between 1995 and 2003, shows a range of progress ratios from 75% to 117% (Junginger 2005). If the first two outliers on both sides of that range are eliminated, the new range becomes 83% to 96%. Most of these estimates used data from the German or Danish markets, but two used data from the United States, five used data from multiple countries, and one (the one yielding the 75% estimate) used data from the United Kingdom.

A recent analysis found that using data from the Wind Force 12 study (European Wind Energy Association and Greenpeace 2005), a progress ratio of 85% to 94% can be calculated, depending on which system boundaries are used to characterize cumulative production (progress) and costs (i.e., cumulative kilowatts, kilowatt-hours, or number of turbines; price of capacity; price of electricity) (Junginger 2005).

A study performed for NREL in 1995 found that a range of 85% to 95% was appropriate, based on historical experience in analogous industries (Brock et al. 1995).

Despite the difficulties in applying learning curve theory to projection of future costs, the relatively narrow range of results across these many studies can be used to develop a reasonable range of estimates for TIO 8 inputs. Accordingly, a range of 2% to 15% cost reduction was selected for overall capital cost reduction potential from TIO 8, with the expected value of 5% chosen to skew the distribution of values towards the conservative side. In addition, lower rates of cost reduction were chosen for BOS costs, O&M costs, and replacement costs, since a larger percentage of leaning from onshore experience is assumed to transfer in these areas than in the specialized platforms that contribute heavily to the initial capital cost.

Implicit in the choice of the values for the distribution defining the potential for cost reduction from learning curve effects for wind energy plants between 2002 and 2012 is the assumed increase in cumulative production. Figure 3 illustrates the tradeoffs between choice of progress ratio and assumed number of doublings of cumulative production. The box shown in the figure bounds the input values for cost reduction for TIO 8, as summarized in the table below. As is demonstrated in Figure 3, the TIO input values can result from a wide range of combinations of the progress ratios and market diffusion rates (i.e., doublings of production) of wind energy. Figure 3 also demonstrates that even the maximum level of cost reduction estimated for the TIO, 15%, can be met by quite conservative combinations of market activity and progress ratios.

TIO 8: Learning Curve Effects

(% changes to reference value)	**Minimum**	**Most Likely**	**Maximum**
AEP	0%	0%	0%
TCC	–15	–5	–2
BOS Cost	–12	–4	–1
LRC	–10	–4	–1
O&M Cost	–8	–2	–1
Probability of Technical Failure		Not applicable	

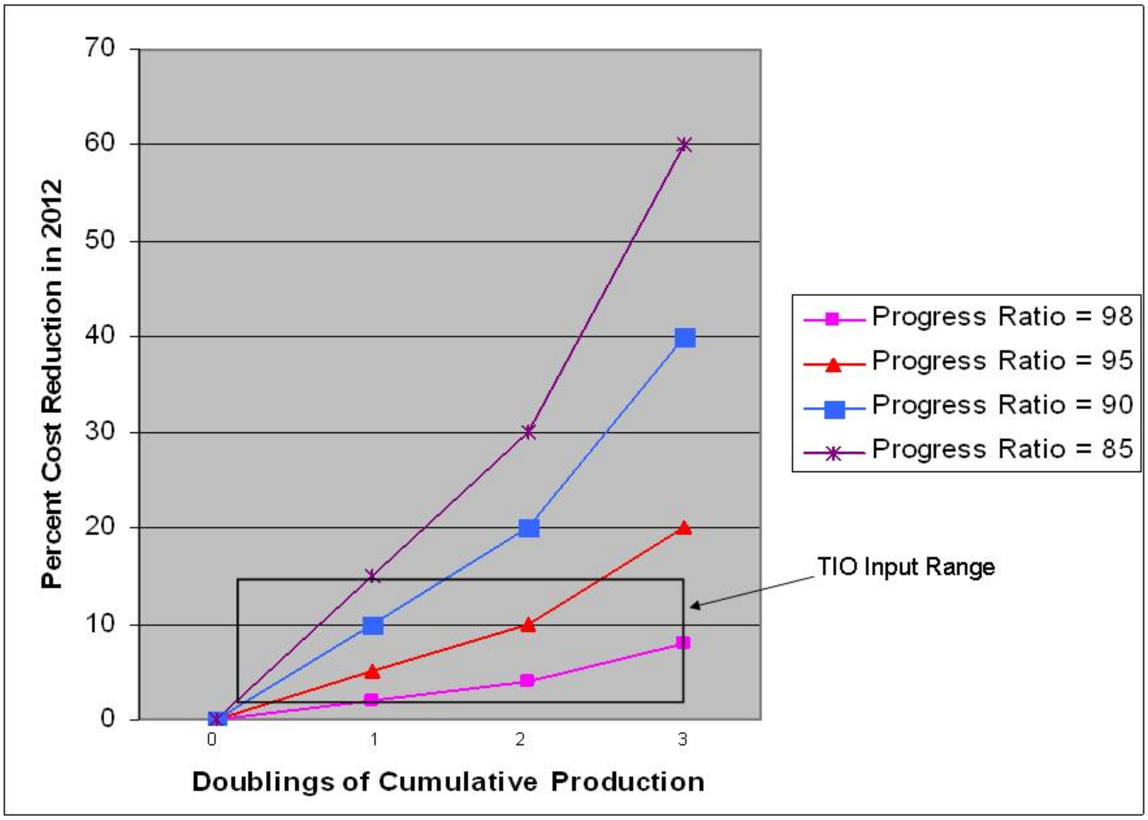

Figure 3. Cost reduction potential for various combinations of progress ratios and doublings of cumulative production

Figure 4 provides a graphical representation of the estimates of the potential contributions of the eight TIOs.

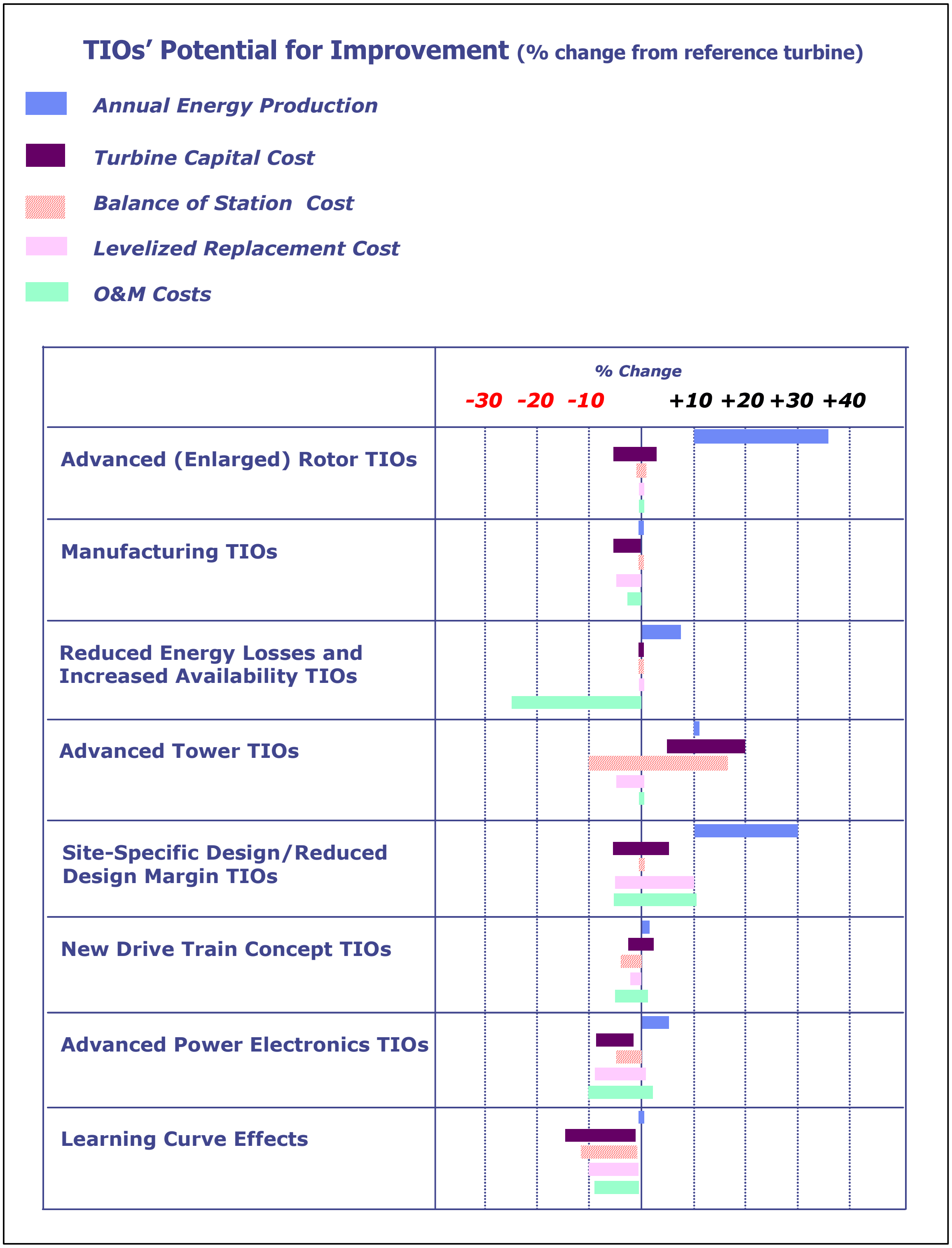

Figure 4. Potential contributions to COE reductions from all TIOs

Many TIOs have enhanced capability to drive down system costs when combined with the benefits of other TIOs. The one area where this is most likely is when advanced controls (within TIO 1) are combined with other features, both within TIO 1 and across other TIOs. These interactions are briefly described here, but the interplay is also indicative of other areas within enlarged rotors, especially as they interact with manufacturing, taller towers, and site-specific design,

Further improvements can be realized by combining the advanced controls with other categories in the advanced rotor TIO. For example, if we combined advanced controls with advanced materials and passive controls (all under advanced rotor) we can obtain further benefits. Improved materials may allow us to design blades with higher structural damping values (especially for the blade edgewise mode, which is easily destabilized by active control), resulting in decreased active control actuator duty requirements. Similarly, a combination of active and passive controls would also be of great benefit, because significant blade damping could be achieved through passive control (via twist-flap coupling in combination with advanced damped materials). This would further reduce actuator duty requirements because the active control objectives would be enhanced power capture and load mitigation, which are not possible with the passive control and advanced materials. In TIO 1 the costs of the pitch actuator, bearing, and control system are currently assumed to increase relative to the baseline. If the passive controls remove some of the burden from the active control system, perhaps these cost increases can be set to zero. If these cost increases are assumed zero, the resulting improvement in TCC would increase to 6.2% instead of the 5.5% currently assumed in the analysis.

One of the biggest areas deserving further research is the combination of active controls with increasing the height of the tower (Advanced Tower TIO) and Site-Specific Design TIO. The goal here is to place the rotor in optimal winds (site specific), which may mean placing the turbines on much taller towers. Increasing the tower height could lead to enormous increases in energy capture, on the order of 5% to 50%. Without controls or increased damping from advanced tower materials, the taller towers will result in increased tower motions and loads (with possible instabilities and resonances). Advanced controls and materials must be used to dampen these responses and mitigate these loads. It has been demonstrated (both through simulation and limited test results) that active controls can be used to mitigate tower motions and loads. Much research must still be done (and is planned) in the use of active controls to mitigate tower responses. We must be sure that active controls to mitigate tower responses do not destabilize other system modes. We must also be sure that these controls can be achieved without placing undue demands on the pitch actuator system (the control must be achievable within typical industry actuator duty limits).

4.0 Results

When the Pathways Monte-Carlo simulation is run, the TIOs described in Section 3 indicate that a reduction in COE of \$0.011/kWh (the baseline 4.8 – 3.7 = 1.1) to \$0.023/kWh (baseline 4.8 – 2.5 = 2.3) is possible at a 95% confidence level. The program goal of \$0.03/kWh for low wind speed turbines can be achieved with a 46% probability. Figure 5 shows the cumulative probability distribution for this analysis. Figure 6 is another way of showing the same data.

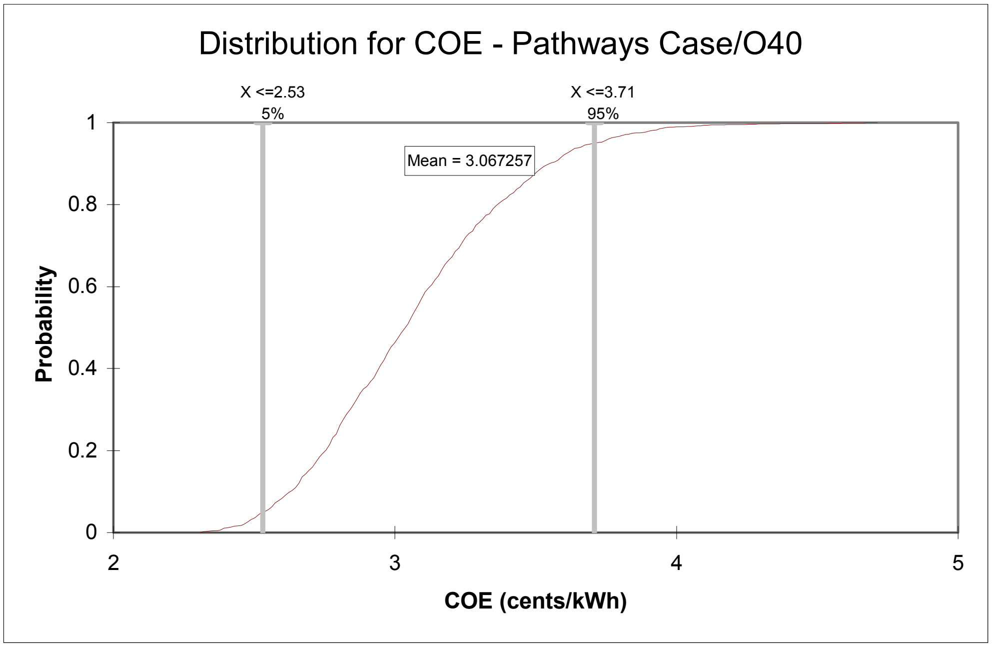

Figure 5. Cumulative probability distribution for COE resulting from all TIOs

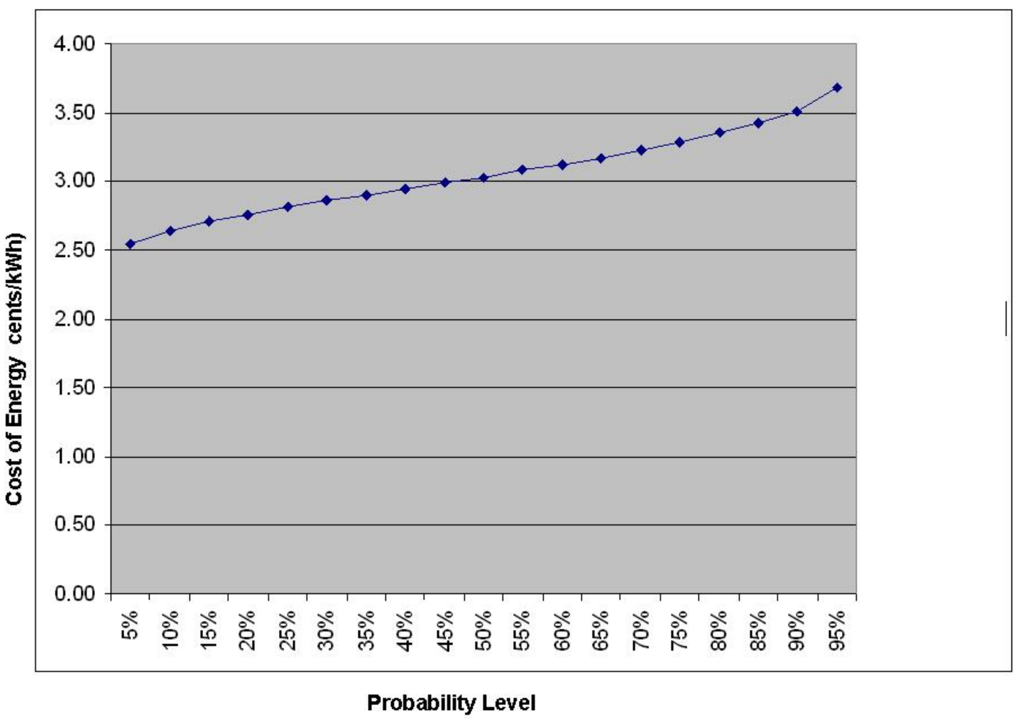

Figure 6. COE versus corresponding probability level

Figures 7 and 8 show that the primary contributions to this potential COE reduction come from TIO 1, Advanced (Enlarged) Rotors, and TIO 5, Site-Specific Design/Reduced Design Margins. Although the correlation of improvements between subsystems was explicitly addressed (e.g., reduced loading from TIO 1 resulted in estimated decreases in drivetrain costs), correlations were not explicitly included between TIOs in the actual model algorithms. Such correlations would require detailed system optimization modeling, using advanced design codes, which is a labor-intensive effort. Therefore, the reader is cautioned that, although the advances shown in Figures 7 and 8 are meaningful to a first order, their sum would not exactly match those of an optimized system that included the advances from all the TIOs.

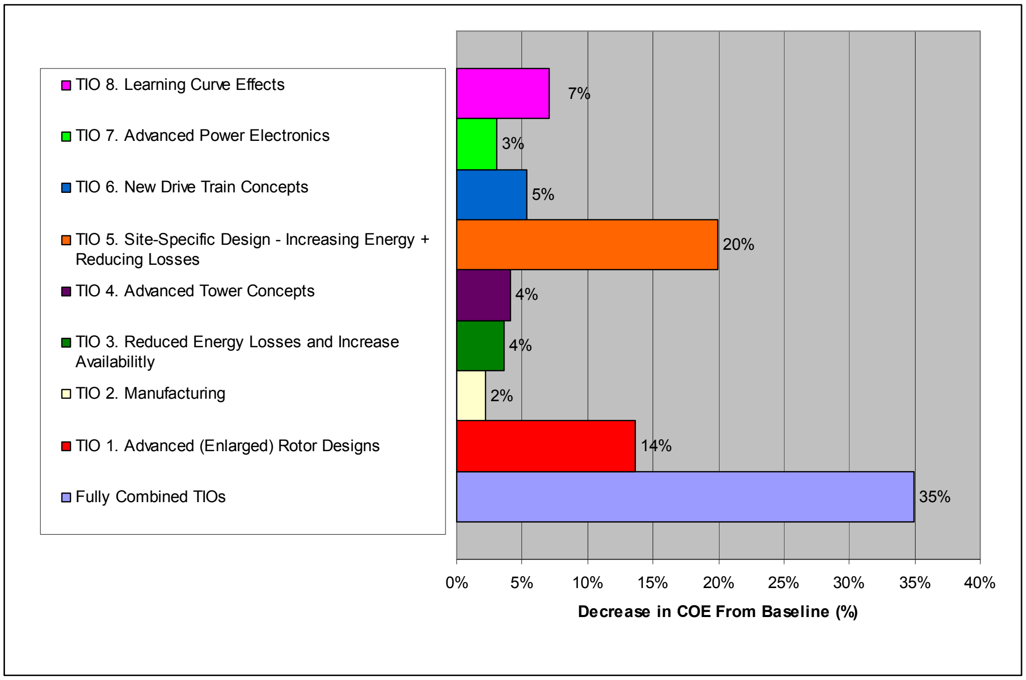

Figure 7. Percent decrease in COE from baseline from each TIO (using mean values)

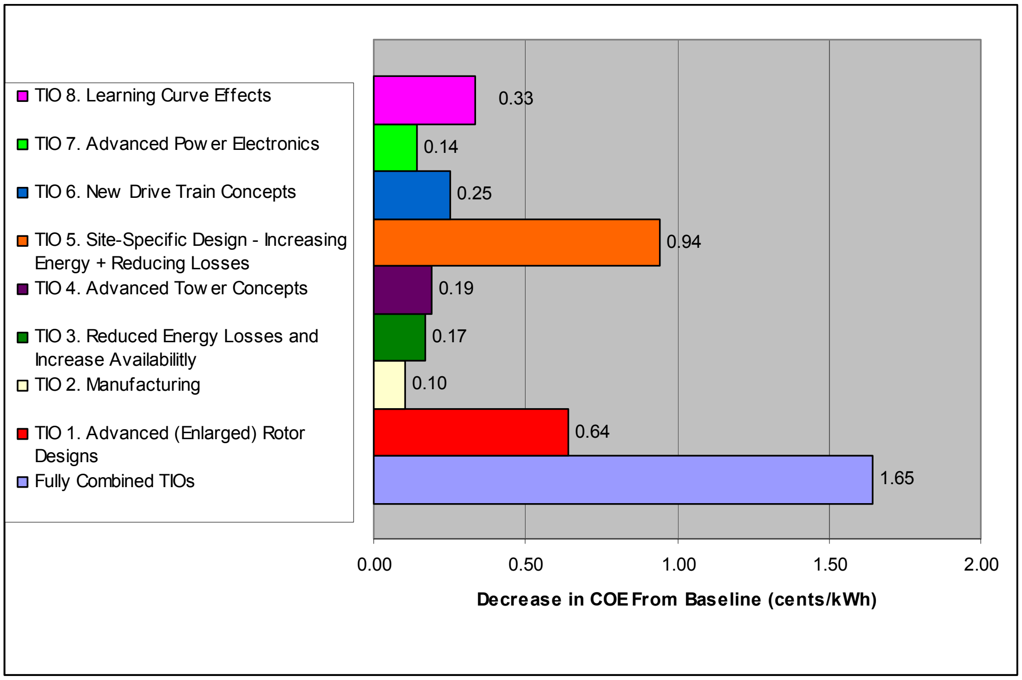

Figure 8. Decrease in COE from baseline from each TIO (using mean values)

5.0 References

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