NATIONAL RENEWABLE ENERGY LABORATORY






Data Collection for Current U.S. Wind Energy Projects: Component Costs, Financing, Operations, and Maintenance

January 2011 – September 2011

M. Martin-Tretton, M. Reha, M. Drunsic, and M. Keim
DNV Renewables (USA) Inc.
Seattle, Washington

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Subcontract Report
NREL/SR-5000-52707
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NREL Technical Monitors: Paul Schwabe and Suzanne Tegen

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National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401
303-275-3000 • www.nrel.gov

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Fax: 1-206-387-4201
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<tr><td>Prepared by:</td><td>Marina Martin-Tretton
Technical Consultant</td><td colspan="2">Signature</td></tr>
<tr><td>Prepared by:</td><td>Meghan Reha
Engineer</td><td colspan="2">Signature</td></tr>
<tr><td>Prepared by:</td><td>Michael W. Drunsic
Head of Section</td><td colspan="2">Signature</td></tr>
<tr><td>Verified & Approved by:</td><td>Michael Keim,
Head of Section</td><td colspan="2">Signature</td></tr>
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1 ABSTRACT

DNV Renewables (USA) Inc. (DNV) used an Operations and Maintenance (O&M) Cost Model to evaluate ten distinct cost scenarios encountered under variations in wind turbine component failure rates. The O&M Cost Model used in the analysis was developed for the National Renewable Energy Laboratory and is detailed in the 2008 report, *Development of an Operations and Maintenance Cost Model to Identify Cost of Energy Savings for Low Wind Speed Turbines* [1].

The analysis considers 1) a Reference Scenario using the default part failure rates within the O&M Cost Model, 2) High Failure Rate Scenarios that increase the failure rates of three major components (blades, gearboxes, and generators) individually, 3) 100% Replacement Scenarios that model full replacement of these components over a 20 year operating life, and 4) Serial Failure Scenarios that model full replacement of blades, gearboxes, and generators in years 4 to 6 of the wind project. DNV selected these scenarios to represent a broad range of possible operational experiences.

The three High Failure Scenarios showed relatively little change from the Reference Scenario. The 100% Replacement and Serial Failure Scenarios showed much larger increases in overall costs relative to the High Failure and Reference Scenarios. The magnitude of the increase varied by component; the largest increase resulted when the blade failure rate was modified and the smallest increase resulted when the generator failure rate was modified.

DNV updated the component cost data in the O&M Cost Model based on information from suppliers and actual receipts from recent component replacement work. A trend analysis comparing the 2010 component cost to data from 2005 shows no clear pattern of price changes and different changes by component type.

Also in this report, DNV summarizes the predominant financing arrangements used to develop wind energy projects over the past several years and provides summary data on various financial metrics describing those arrangements. The summary is based on projects developed in 2010 and 2011. The financial metric information reflects a significant increase in financed projects using term debt and the monetized version of the investment tax credit since 2009, when compared to the number of projects financed using tax equity investments in 2006 and 2007. The review of these metrics suggests a more consistent debt market, with largely equivalent terms across projects, compared to tax equity financing arrangements that vary widely from project to project.

2 INTRODUCTION

The National Renewable Energy Laboratory (NREL) retained DNV under Subcontract No. AGB-1-11427 to prepare an Excel workbook with wind energy component replacement data for U.S. wind energy projects. The inputs included component replacement costs, financing metrics, and O&M parameters. This report provides a narrative description of DNV's work under this agreement. It describes the model scenarios considered, the updated component costs from previous analyses, historical trends, and various aspects of project financing in 2010 and 2011.

3 O&M COST MODEL SCENARIOS

DNV created ten unique O&M scenarios to demonstrate the impact of various major component failure rates on O&M costs. The default rates and costs were based on data gathered from operating projects and industry component failure testing. The data is detailed in NREL's report, NREL/SR-500-40581, titled *Development of an Operations and Maintenance Cost Model to Identify Cost of Energy Savings for Low Wind Speed Turbines,* published in January 2008 (the O&M Model Report) [1]. This report accompanied the original model developed for NREL. It states, in part:

> "The model estimates parts use by applying two types of failure rates to selected components, or categories of components. The first type of failure event is random, and is represented by a constant failure rate. The model assumes by default that 5% of the blades and gearboxes, and 10% of the generators, will fail over the 20-year life of the project because of uncontrollable circumstances such as lightning strikes, manufacturer defects, operational errors, or servicing omissions and errors.
>
> The second type of failure event is wear out or deterioration, and is a two-parameter Weibull distribution. This distribution is commonly used in reliability studies as it allows for variation of the scale as well as the shape of the failure distribution. Weibull distributions are intended to describe failure rates for a given population of like components. Generally the most reliable data are obtained from exercising the components in actual or simulated conditions that are consistent over time. In an actual application, however, the parts that fail are replaced, so that the population eventually becomes a combination of components with varying periods of operation. At some point in time past the characteristic life, the instantaneous failure rate will oscillate about, and finally approach, a constant value."

3.1 Scenarios - Method and Assumptions

The O&M Cost Model requires input assumptions of project and turbine characteristics. In all scenarios, DNV assumed that the following inputs represent a typical project: 100 turbines, 36% net capacity factor, 1.5 MW turbine rating, 80 m hub height, electric pitch control, and partial power conversion.

Specifying these project and turbine characteristics, DNV used the default failure rates within the model to construct a Reference Scenario to represent the baseline O&M costs. From a design perspective, major components are certified to a 20 year design life. In practice, however, most turbine components experience failure before 20 years and the failure rate varies by component. Failure inputs to the O&M Cost Model can be modified by the user. The standard assumptions include a 5% catastrophic failure rate for blades and gearboxes and a 10% catastrophic failure rate for generators during the life of the turbine. Such catastrophic failures are considered to be the result of uncontrollable circumstances including, but not limited to, manufacturing defects and operational errors.

In addition to the baseline failure rate, DNV modeled the considerable uncertainty of actual O&M costs due to factors not easily accounted for, such as variations in O&M practices, site conditions, like icing, extreme temperatures and environments, variations in individual turbine inflow conditions relative to the turbine's International Electrotechnical Commission (IEC) classification, and price ranges in the component costs. These uncertainties are estimated by evaluating O&M costs using a 30% higher parts failure rate and a 30% lower parts failure rate.

DNV varied the blades, gearboxes, and generator failure rates from the default rates for three distinct scenarios. DNV selected these three components and scenarios based on proprietary wind industry data to represent a broad range of possible operational experiences. These permutations of components and scenarios resulted in nine additional cases. Once again, the uncertainty in O&M costs is represented with a 30% higher and lower component failure rate relative to the specific scenario discussed below.

High Failure Rate Scenarios: DNV increased the individual component failure rate to three times (3x) the reference failure rate of a specified component. For example, the default failure rate for blades in the model is 5%; therefore, the High Blade Failure Scenario used a 15% failure rate for blades and the default failure rate for all other components. Similarly, the High Gearbox Failure Scenario used a 15% failure rate for gearboxes, and default failure rates for all other components. The High Generator Failure Scenario used a 30% failure rate for the generator, and default failure rates for all other components.

100% Replacement Scenarios: DNV increased the failure rate to 100% for a specified component, distributing the failures evenly throughout the entire 20 year project life. In the 100% Failure Scenarios, the 30% uncertainty band represents failures at 130% and 70% over 20 years. For example, in the 100% Blade Replacement Scenario, the baseline represents 300 blade replacements, or 15 replacements per year. While the 30% Higher Parts Failure Scenario represents 390 blade replacements, and the 30% Lower Parts Failure Scenario represents 210 blade replacements. The components experiencing 100% replacement have a zero defect rate after the replacement.

Serial Defect Scenarios: DNV increased the component failure rate to 100%, distributing these failures throughout operating years 4 through 6. This scenario simulates how O&M costs are distributed in the event of a serial failure occurring outside of a warranty period. Components not experiencing serial failure use the default failure rates, which are applied over the entire project life. As with the 100% Replacement Scenarios, the components experiencing a serial defect have a zero defect rate after the serial defect remediation is complete. DNV assumed that the cost of serial replacements would be the cost of the components plus the cost of installation including a crane, labor, and other associated costs. These costs were distributed over a typical replacement period of three years with 33 or 34 turbines receiving replacements per year. Years 4 to 6 were selected as representative operating years because they occur after a typical original equipment manufacturers (OEM) warranty period.

The failure rate inputs to the O&M Cost Model for the scenarios described above are shown in Table 3-1.

Table 3-1. O&M Cost Model 20 Year Failure Rate Inputs for All Scenarios

	Blade Failure Rate (%)	Gearbox Failure Rate (%)	Generator Failure Rate (%)
Reference Scenario	5	5	10
High Blade Failure Scenario	15	5	10
High Gearbox Failure Scenario	5	15	10
High Generator Failure Scenario	5	5	30
100% Blade Failure Scenario	100	5	10
100% Gearbox Failure Scenario	5	100	10
100% Generator Failure Scenario	5	5	100
Serial Blade Failure Scenario*	100	5	10
Serial Gearbox Failure Scenario*	5	100	10
Serial Generator Failure Scenario*	5	5	100

* In the Serial Failure Scenarios, 100% component failures are modeled to occur in years 4 to 6 rather than evenly spread across the 20 year operating life (see description in text above).

Under all scenarios, DNV assumed that blades, gearboxes, and generators would be replaced as complete units. Rebuilt gearboxes and generators are common in the wind industry and the price of the replacement components in the O&M Cost Model is lower than the price of new components. Depending on the nature of the damage and when it is detected, gearbox maintenance ranges from repair or replacement of subcomponents to replacement of the entire gearbox. In many cases, subcomponents can be repaired prior to catastrophic failure, if the damage is identified in time. Such repairs often avoid the cost of crane deployment. Condition monitoring systems and inspections can help identify failures prior to a catastrophic event. It is uncommon to purchase refurbished blades; therefore, only new blade costs are considered in this analysis.

The O&M Cost Model does not explicitly include economies of scale cost savings for crane costs. However, the cost of a crane rental is a significant contributor to the replacement cost of most major components. One way project operators reduce their costs is by performing multiple repairs that require a crane at the same time [1]. Therefore, DNV has included some economies of scale savings in this analysis. The general scheme used for crane economies of scale is that mobilization and demobilization costs are reduced per replacement job since the crane remains on site and in operation for an extended period of time, allowing these costs to be distributed over multiple jobs. In this analysis, DNV assumed that if more than four major failures occurred in a given year, all subsequent crane events for that year would be discounted. Larger discounts result as the number of crane events increases, until a minimum per-event crane cost is reached. As outlined in the O&M Model Report, turbines with integrated cranes that are capable of replacing wind turbine generators (e.g., nacelle mounted lifts) are not considered in the current model [1].

DNV used the updated component costs described in Section 4 of this report as input cost assumptions in the ten scenarios. In these scenarios, failures of blades, gearboxes, and generators were considered to be the most relevant major components. Additional components that could be considered include the bed-frame and main bearings. However, replacement of these components is rare compared to the replacement of blades, gearboxes, and generators.

In addition to other components, two invariable cost items in the above scenarios are regularly scheduled maintenance (included through the labor budget and the consumables line items in the model) and a small budget for the maintenance of roads, meteorological equipment, and other facility maintenance. These items are held constant across the scenarios. Substation maintenance costs are not currently included in the model. These costs are highly variable from project to project and, in some cases, are borne by the off-taking utility instead of the project. There are various other costs when operating a wind project, such as insurance, taxes, and purchased electricity, that are not included in the model.

A full listing of all component failure rates and cost assumptions is in Appendix A.

3.2 Results: Reference Component Replacement Scenario

The results of the Reference Scenario are presented in Figure 3-1 as five year average O&M costs. As previously described, the uncertainty in the O&M costs is represented by the 30% higher and 30% lower parts failure rate band. The Reference Scenario results show increasing O&M costs over time. There is a slightly greater difference between the baseline and the 30% high case than between the baseline and the 30% low case due to the accelerated parts failures in the 30% high case which leads to a non-linear compounding effect in the total number of components replaced over 20 years.

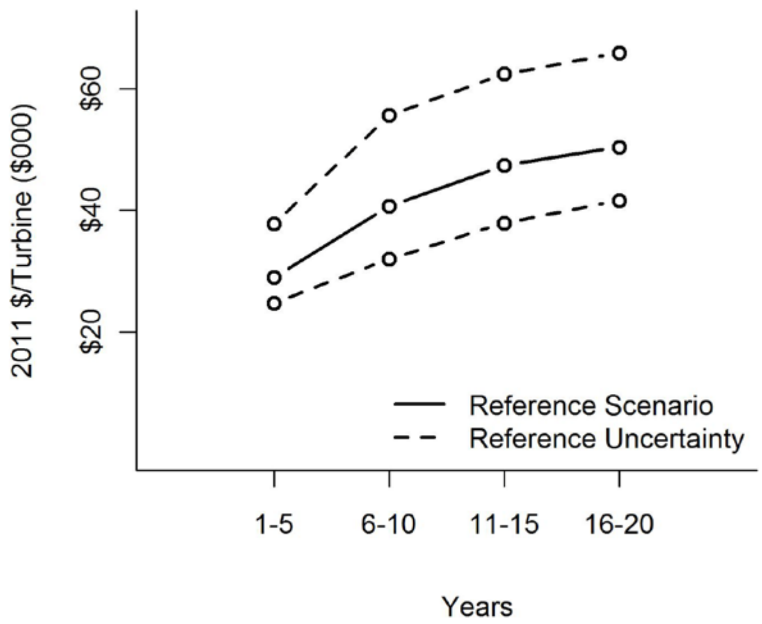

Figure 3-1. Reference Failure Rates, Five Year Average O&M Costs

3.3 Results: High Failure, 100% Replacement, and Serial Failure Scenarios

The results of the High Failure, 100% Replacement and Serial Failure Scenarios are shown in Table 3-2 and in Figure 3-2. In Figure 3-2, the High Failure, 100% Replacement and Serial Failure Scenarios are shown as solid black lines, while the 30% cost uncertainty band is shown with dashed black lines. For comparison purposes, the Reference Scenario is presented as solid grey lines while the uncertainties are shown as dashed grey lines. The Reference Scenario is identical in each plot.

Table 3-2. Cost Comparisons to Reference Costs for Each Scenario

Average Cost per Period (2011 $/Turbine)						
	Year 1-5	**Year 6-10**	**Year 11-15**	**Year 16-20**	**20-Year Average**	**Deviation from Reference Scenario (%)**
Reference Scenario	29,000	41,000	47,000	50,000	42,000	--
High Blade Failure Scenario	32,000	43,000	49,000	52,000	44,000	5%
High Gearbox Failure Scenario	31,000	43,000	48,000	52,000	43,000	3%
High Generator Failure Scenario	31,000	43,000	48,000	52,000	44,000	4%
100% Blade Failure Scenario	46,000	56,000	62,000	65,000	57,000	36%
100% Gearbox Failure Scenario	42,000	53,000	57,000	60,000	53,000	27%
100% Generator Failure Scenario	37,000	47,000	52,000	55,000	48,000	14%
Serial Blade Failure Scenario	69,000	60,000	47,000	50,000	56,000	34%
Serial Gearbox Failure Scenario	57,000	55,000	47,000	50,000	52,000	24%
Serial Generator Failure Scenario	43,000	48,000	47,000	50,000	48,000	13%

Note that costs are rounded to the nearest $1000 including the 20 year average; in some cases, the same 20 year average shows a slightly different percent deviation from the Reference Scenario due to minor differences in the underlying costs before rounding.

A full listing of all modeling results is in Appendix B.

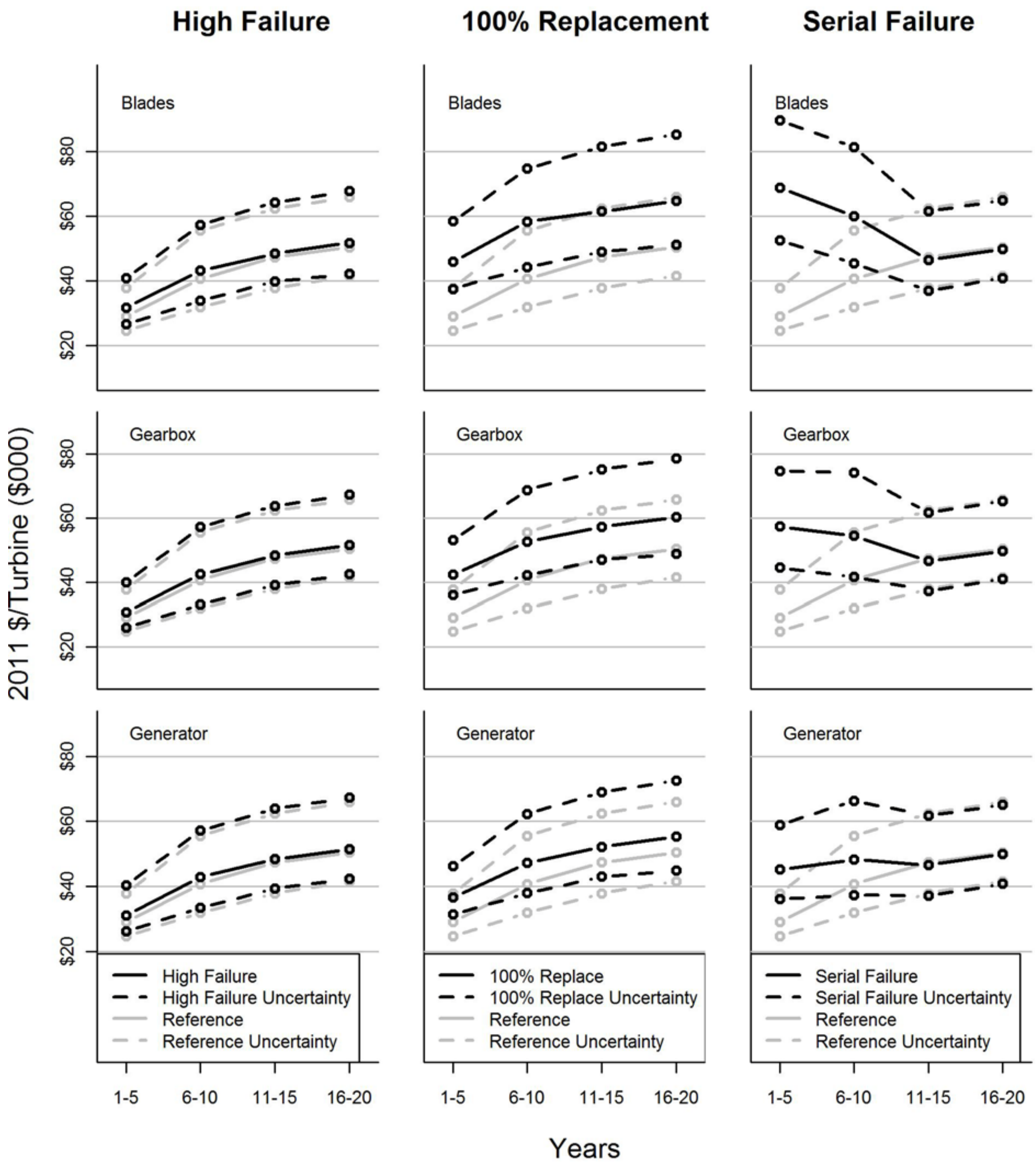

Figure 3-2. Scenario Results

Note that the High Failure Rate Scenario (left column), 100% Replacement Scenario (center column), and the Serial Failure Scenario (right column) are shown for three component types: blades (top row), gearboxes (center row), and generators (bottom row). All cases include high/low uncertainties (dashed lines) based on the 30% increase/decrease of underlying failure rates. Reference costs (grey lines) are shown for comparison and are identical in each plot.

Comparing across scenarios (i.e., columns in Figure 3-2), there is only a minor difference between the High Failure Scenarios and the Reference Scenario, while the 100% Replacement Scenarios and the Serial Failure Scenarios illustrate significant differences from the Reference Scenario. When compared to the 100% Failure Rate Scenario, the Serial Defect Scenario for each component shows slightly lower 20 year average costs. This is primarily driven by the significantly discounted crane costs in the Serial Defect Scenarios as compared to the 100% Failure Rate Scenarios.

The evolution of these costs over time is quite different between the 100% Replacement Scenarios, in which replacements are spread evenly across 20 years, and the Serial Failure Scenarios, in which replacements are concentrated in years 4 to 6. In the 100% Replacement Scenarios, costs increases from major component failures are incurred over all 20 years. In the Serial Failures Scenarios, the average O&M costs increases primarily in years 1 to 5 and years 6 to 10.

The shape of the cost distribution changes slightly depending on the component selected. For example, in the Serial Failure Scenario, the cost of blades sharply decreases in per turbine O&M cost from the first five years to the last five years. The 200 blades replaced in years 4 and 5 increases the average in years 1 to 5. The 100 blades replaced in year 6 increases the average for years 6 to 10, but replacements are lower than in the first five years. No blades were replaced in years 11 to 20, resulting in significantly lower costs relative to the first 10 years. By comparison, the Gearbox and Generator Serial Failure Scenarios show much shallower declines in O&M costs over the first 15 years. Replacing a set of blades is more expensive than replacing a single gearbox or generator and the default generator failure rate (10%) is higher than the default blade failure rate (5%).

There are only minor differences between the Reference Scenario and the High Failure Scenarios for each of the three components (on average less than 5% over 20 years). For the 100% Replacement Scenarios and Serial Failure Scenarios, the largest cost differences relative to the Reference Scenario are for blades, followed by gearboxes, followed by a relatively smaller difference for generators. Several factors contribute to the blade's higher O&M costs relative to the gearbox and generator. The modeled project has 300 blades, as compared to 100 gearboxes and 100 generators. A set of three blades costs more than a single gearbox or generator. This accounts for a significant portion of the higher O&M cost. Also, this scenario assumes the blades must be purchased new, and therefore, does not consider any savings associated with using refurbished components or possible discounts for buying multiple blade sets.

4 2010 COMPONENT COST UPDATE

DNV compiled annual component cost data in the form of price lists, from the years 2005 through 2010, from the leading turbine manufacturers in the U.S. market. DNV updated the component cost data to capture some of the changes in wind project costs since the original O&M Model Report was published in early 2008 [1]. These data, from O&M replacement part price lists, are used with the permission of the turbine operators. Due to confidentiality agreements with price list contributors, individual owners of the manufacturers' price lists are not disclosed. However, the component cost data analyzed in this report are representative of close to

90% of U.S. wind turbines installed in 2010 [2]. Wind turbine manufacturers' U.S. market share in 2010 is shown in Figure 4-1.

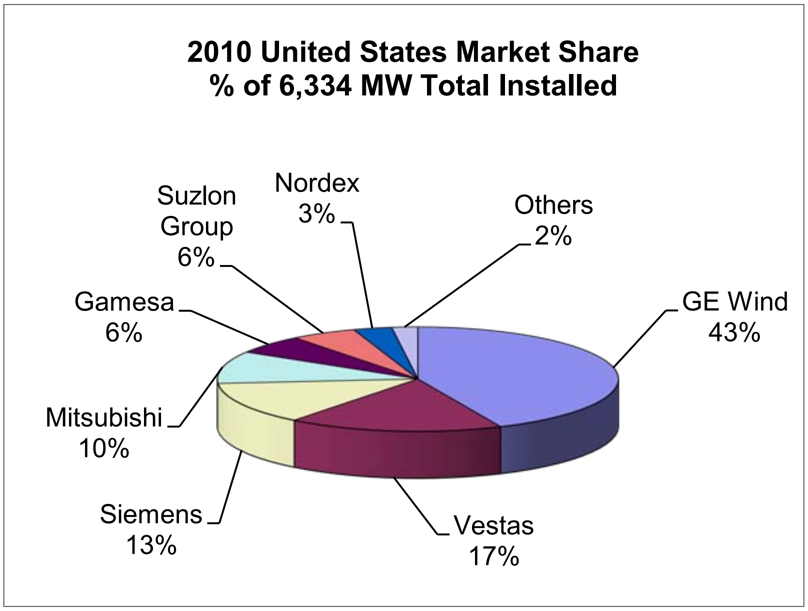

Figure 4-1. Wind Turbine Manufacturers' Share of 2010 U.S. Wind Power Installations

Source: *U.S. Wind Industry Annual Market Report Year Ending 2010* [2]

Using these replacement costs as data inputs, turbine characteristics, and the year when the pricelists were issued, DNV calculated average turbine component costs, component cost ranges, estimated labor costs, and crane costs.

The data are sorted into two main categories based on turbine rating:

- Wind turbine rating of 1.5 - 2.0 MW
- Wind turbine rating of 2.1 - 3.0 MW

The resulting component, labor, and crane costs were used to update the inputs to the O&M Cost Model. The same list of components that were part of the original O&M Cost Model were populated with updated inputs to generate 2010 cost values for the scenarios discussed earlier in this report. It is important to note that, due to the nature of the model and the use of replacement parts price lists, the component cost values should not be interpreted as a bottom up calculation of the initial capital cost of a wind turbine.

4.1 Component Costs – Methods and Assumptions

As shown in Table 4-1, the various replacement parts are categorized as the rotor, drive train, gearbox and lubrication, generator and cooling, brakes and hydraulics, yaw system, control system, electrical and grid, or miscellaneous. These categories are exclusive of consumables. Replacement parts (including mechanical, electrical, and hydraulic components) are those that wear or deteriorate during normal use. For example, gearboxes are a mechanical wear item, but the main shaft and bedplate are not.

Table 4-1. Parts Categories by System

Rotor	Blades, pitch bearings, pitch actuators
Drive train	Main bearing, seals, couplings
Gearbox and lubrication	Gearbox, lube pump, cooling system
Generator and cooling	Generator, power converter, cooling system
Brakes and hydraulics	Hydraulics, calipers, shoes
Yaw system	Calipers, wear pads
Control system	CPU, interface modules, sensors
Electrical and grid	Contactors, circuit breakers, relays, capacitors
Miscellaneous	Hardware, other small mechanical, hydraulic and electrical parts not identified specifically

The components included in the generic configuration represent the current state of the art for modern turbines currently being supplied. The assumptions for each component category are described below.

Rotor: The rotor is three-bladed and each blade has independent pitch. The pitch bearings are the rolling-element type, and are periodically lubricated with grease. The pitch mechanism may be one of two types: 1) a hydraulic pitch system, which includes a pitch cylinder, proportional valve, crank arm mechanism, accumulator, and displacement transducer for each blade; or (2) an electric pitch system, which includes a motor with a position encoder, gear reducer, electronic drive, and backup battery bank for each blade. The pump and position controller are common for all three mechanisms (i.e., one per blade).

Drive train: The drive train consists of a main shaft supported by two main bearings, coupled to the gearbox using a hydraulic shrink coupling. A composite tube, with flexure connections, is used to couple the gearbox to the generator.

Gearbox and lubrication: The gearbox is a combination planetary/helical unit, with an integral lubrication system and fluid cooler system. The gearbox is suspended from the bedplate with elastomeric bushings.

Generator and cooling: The generator is a single-speed, induction type. The variable-speed machine includes a wound rotor and slip-rings. Cooling is provided by an integral forced-air system.

Brakes and hydraulics: The brake is a caliper-type system located on the high-speed shaft of the gearbox. A dedicated hydraulic system provides pressure for the calipers. The brake is used only for parking, since the primary rotor brake is the blade pitch system.

Yaw system: The yaw bearing is a sliding-bearing type, with spring-applied calipers for stabilization. The surfaces are periodically lubricated with grease. The yaw drives are electric-motor driven in a multiple-reduction gearbox. The number and size of the yaw drives increases with turbine size.

Control system: The control and monitoring system consists of a main controller in the turbine base, a remote controller in the nacelle, and another in the hub. The base unit contains a user interface and display. Control sensors include wind measurement instruments, rotor speed control, and power/grid monitoring transducers. Sensors specific to monitoring component condition are included in that category.

Electrical and grid: The turbine switchgear consists of a main breaker/disconnect, a line contactor for the generator power, and smaller contactors and circuit breakers for ancillary systems and power factor correction capacitors. A soft-starter is included for connecting to the grid for constant-speed machines.

Miscellaneous: This category includes a value for miscellaneous parts not specifically identified elsewhere, such as hardware, small hydraulics, and small electrics.

Parts costs for each of the generic turbine sizes were estimated from machine cost data. In some cases, these data were drawn from manufacturers' price lists; in other cases, they were derived from actual receipts. The former data set is subject to an indeterminate mark-up; the latter may reflect a limited scope of supply.

In addition to the component categories above, the O&M Cost Model includes a labor cost category. It includes the staff dedicated to turbine maintenance including regularly scheduled, unscheduled, and major maintenance. The calculation assumes the hourly rates for site staff show in Table 4-2. These are representative of rates at operating projects. Technician rates usually vary by skill level and experience, and often a crew consists of a senior-level technician paired with a junior-level technician. The rates represent average values for a crew. Local rates can vary by 25% and depend on the local labor market. The impact of labor rates on overall O&M costs is a function of the time required for repairs.

Table 4-2. Annual Labor Rates

Category	Base	Burdened @ 35%
Junior Technician	$31	$48
Senior Technician	$49	$75

Source: DNV Update to Original O&M Cost Model [1]

Typically, the lead time to procure the crane and the components is longer than the time it takes to install a new major component. Total return-to-service time can be significantly longer than the time required for labor for the repair. As examples, a blade, gearbox, or generator can be replaced by experienced technicians in approximately 3-5 days, weather permitting, once the crane has arrived on site. Smaller components typically can be replaced in a few hours. Downtime for these components can be minimized by maintaining a good spare parts inventory.

Finally, the model assumes that the wind energy facility rents a crane for any major replacement, and that the replacements will occur on a per-unit basis. Crane rental costs are driven by crane capacity and mobilization time. Two common crane types—conventional crawler cranes and truck-mounted cranes—are appropriate for wind turbine component replacements. The cost for a crawler crane is driven by mobilization, as the crane and boom are shipped in pieces and require 10 to 20 truckloads, depending on height. Hydraulic truck-mounted cranes use a telescopic boom and require only one to three additional loads for counterweights. They are significantly cheaper to mobilize, but generally cost more per hour. Conventional cranes are sometimes available in a truck-mounted version, but still require multiple loads for the lattice boom and jibs.

4.2 Results: Component Cost

The results of the 2010 component cost data analysis are presented in Table 4-3 and 4-4. Average, maximum, and minimum costs are provided for each component, as well as the per event labor costs associated with the repair or replacement of the component, and the per event costs associated with crane mobilization and deployment (for components where crane use is required). Finally, the estimated total per event component replacement cost is provided; this is the combined average cost of the component, labor and, if applicable, crane costs. Amounts shown are rounded to represent reasonable levels of precision. In some cases, the rounded per-event totals do not equal the sum of the rounded parts, labor, and crane costs because the totals were rounded after summing the inputs.

Major component cost data on the two categories discussed in this report, 1.5-2.0 MW and 2.1-3.0 MW machines, are biased toward the predominant turbines in the U.S. market today. Typically, the cost of major components and mechanical equipment associated with them will scale up relative to size. In particular, crane costs are sensitive to hub height and component weight. However, the rotor diameter, the complexity of control systems, and the overall quality of components varies based on different manufacturers; thus, a linear cost relation cannot be established for all components.

Where no price list data inputs were available, such as the cost of the gearbox high speed section for turbines in the 2.0 MW to 3.0 MW range, the space was left blank to avoid providing misleading information.

Table 4-3. 2010 Component Cost Data 1.5 MW – 2.0 MW

	Rating	1.5 MW - 2.0 MW					
	Configuration	80 Meter Tower					
System	Component	Average	High	Low	Labor Cost	Crane Cost	Estimated Total
Rotor	Blade--struct. repair	$88,000	$109,000	$57,000	$23,000	$44,000	$154,000
	Blade--nonstruct. repair	$13,000	$19,000	$6,000	$4,000		$23,000
	Pitch cylinder & linkage	$13,000	$23,000	$3,000	$1,000		$14,000
	Pitch bearing	$13,000	$15,000	$11,000	$4,000	$44,000	$61,000
	Pump & hydraulics	$3,000	$4,000	$3,000	$1,000		$4,000
	Pitch position xdcr	$2,000	$3,000	$1,000	<$500		$2,000
	Pitch motor	$8,000	$14,000	$2,000	<$500		$9,000
	Pitch gear	$7,000	$15,000	$3,000	$2,000		$9,000
	Pitch controller	$9,000	$10,000	$8,000	<$500		$9,000
Drive Train	Main bearing	$24,000	$38,000	$9,000	$13,000	$144,000	$181,000
	High-speed coupling	$7,000	$11,000	$5,000	$1,000		$8,000
Gearbox and Lube	Gearbox--gears & brgs	$221,000	$445,000	$180,000	$18,000	$144,000	$383,000
	Gearbox--brgs, all	$194,000	$215,000	$180,000	$8,000	$144,000	$347,000
	Gearbox--high speed only	$183,000	$187,000	$180,000	$3,000		$186,000
	Lube pumps	$2,000	$6,000	$1,000	<$500		$3,000
	Cooling fan, gearbox cooling	$2,000	$4,000	$1,000	<$500		$3,000
Generator and Cooling	Generator--rot. & brgs	$131,000	$412,000	$52,000	$6,000	$59,000	$195,000
	Generator--brgs only	$2,000	$4,000	<$500	$1,000		$3,000
	Full converter	$36,000	$47,000	$25,000	$2,000		$38,000
	Motor, generator coolant fan	$2,000	$4,000	$1,000	<$500		$2,000
	Contactor, generator	$13,000	$20,000	$2,000	<$500		$14,000
	Partial converter (rotor side)	$17,000	$18,000	$16,000	$1,000		$18,000
Brakes & Hydraulics	Brake caliper	$7,000	$9,000	$6,000	$1,000		$8,000
	Brake Pads (set)	$6,000	$9,000	$2,000	<$500		$6,000
	Accumulator	$2,000	$4,000	<$500	<$500		$2,000
	Hydraulic pump	$5,000	$12,000	$1,000	<$500		$5,000
	Hydraulic valve	<$500	$1,000	<$500	<$500		$1,000
Yaw System	Yaw gear (drive+motor)	$9,000	$17,000	$3,000	$1,000		$9,000
	Yaw motor (with brake)	$2,000	$4,000	<$500	<$500		$3,000
	Yaw sliding pads	$1,000	$1,000	<$500	<$500		$1,000
	Yaw bearing (with gear)	$31,000	$40,000	$22,000	$8,000	$144,000	$183,000
	Yaw slew ring	$199,000	$229,000	$169,000	$21,000	$144,000	$364,000
Control System	Control board, top	$11,000	$18,000	$6,000	<$500		$11,000
	Control board, main	$17,000	$20,000	$16,000	<$500		$17,000
	Control module	$6,000	$8,000	$5,000	<$500		$6,000
	Sensor, static	$1,000	$1,000	<$500	<$500		$1,000
	Sensor, dynamic	$3,000	$5,000	$3,000	<$500		$4,000
Electrical and Grid	Main contactor	$13,000	$13,000	$13,000	<$500		$13,000
	Main circuit breaker	$15,000	$24,000	$10,000	<$500		$16,000
	Soft starter	$1,000	$1,000	$1,000	$1,000		$2,000
Miscellaneous	Miscellaneous parts	$101,000	$131,000	$71,000			$101,000

Source: DNV Review of Replacement Part Price Lists

Table 4-4. 2010 Component Cost Data 2.1 MW – 3.0 MW

	Rating	2.1MW - 3.0 MW					
	Configuration	90 Meter Tower					
System	Component	Average	High	Low	Labor Cost	Crane Cost	Estimated Total
Rotor	Blade--struct. repair	$223,000	$227,000	$218,000	$23,000	$72,000	$318,000
	Blade--nonstruct. repair	$12,000	$19,000	$6,000	$4,000		$16,000
	Pitch cylinder & linkage	$12,000	$21,000	$3,000	$1,000		$13,000
	Pitch bearing	$42,000	$54,000	$33,000	$4,000	$72,000	$118,000
	Pump & hydraulics	$9,000	$15,000	$2,000	$1,000		$10,000
	Pitch position xdcr	$1,000	$1,000	$1,000	<$500		$1,000
	Pitch motor	$11,000	$11,000	$11,000	<$500		$12,000
	Pitch gear	$5,000	$7,000	$4,000	$2,000		$7,000
	Pitch controller	$11,000	$14,000	$7,000	<$500		$11,000
Drive Train	Main bearing	$26,000	$34,000	$18,000	$13,000	$300,000	$339,000
	High-speed coupling	$11,000	$16,000	$4,000	$1,000		$12,000
Gearbox and Lube	Gearbox--gears & brgs	$445,000	$561,000	$405,000	$18,000	$300,000	$763,000
	Gearbox--brgs, all	$144,000	$187,000	$101,000	$8,000	$300,000	$452,000
	Gearbox--high speed only						
	Lube pumps	$4,000	$9,000	<$500	<$500		$4,000
	Cooling fan, gearbox cooling	$1,000	$1,000	$1,000	<$500		$1,000
Generator and Cooling	Generator--rot. & brgs	$145,000	$200,000	$117,000	$6,000	$107,000	$257,000
	Generator--brgs only	$3,000	$6,000	$1,000	$1,000		$4,000
	Full converter	$105,000	$141,000	$87,000	$1,000		$106,000
	Motor, generator coolant fan	$4,000	$5,000	$1,000	<$500		$4,000
	Contactor, generator	$3,000	$3,000	$2,000	<$500		$3,000
	Partial converter (rotor side)	$128,000	$166,000	$89,000	$1,000		$128,000
Brakes & Hydraulics	Brake caliper	$5,000	$8,000	$2,000	$1,000		$6,000
	Brake Pads (set)	$2,000	$3,000	$1,000	<$500		$2,000
	Accumulator	$3,000	$7,000	$1,000	<$500		$3,000
	Hydraulic pump	$6,000	$13,000	$2,000	<$500		$6,000
	Hydraulic valve	<$500	$1,000	<$500	<$500		$1,000
Yaw System	Yaw gear (drive+motor)	$7,000	$14,000	$4,000	$1,000		$7,000
	Yaw motor (with brake)	$3,000	$6,000	<$500	<$500		$3,000
	Yaw sliding pads	$1,000	$2,000	<$500	<$500		$2,000
	Yaw bearing (with gear)	$69,000	$89,000	$48,000	$8,000	$300,000	$377,000
	Yaw slew ring						
Control System	Control board, top	$8,000	$13,000	$3,000	<$500		$8,000
	Control board, main	$7,000	$13,000	$2,000	<$500		$7,000
	Control module	$2,000	$3,000	$1,000	<$500		$2,000
	Sensor, static	$1,000	$1,000	<$500	<$500		$1,000
	Sensor, dynamic	$2,000	$5,000	$1,000	<$500		$3,000
Electrical and Grid	Main contactor	$16,000	$21,000	$11,000	<$500		$16,000
	Main circuit breaker	$17,000	$31,000	$10,000	<$500		$18,000
	Soft starter						
Miscellaneous	Miscellaneous parts	$168,000	$219,000	$118,000			$168,000

Source: DNV Review of Replacement Part Price Lists

4.3 O&M Arrangements

The discussion above presents cost outputs for various component replacements that could be implemented under a range of O&M arrangements at any given wind energy project. Aspects that vary by O&M arrangement (and may or may not affect actual O&M costs) include:

Warranty Provisions: Warranty provisions affect who is responsible for replacement costs at a project. While specific warranty provisions vary, the original equipment manufacturer is typically responsible for replacing failed parts when failures occur during normal operations in the warranty period. There are four primary warranty scenarios:

1. A parts-only warranty is a warranty in which the OEM is only responsible for providing replacement parts; the owner is responsible for troubleshooting, labor, and significant additional expenses that can be incurred in the event a crane is required.
2. A full parts warranty provides parts and "in and out" service. This typically covers all costs associated with removing and replacing the parts.
3. A hybrid of these two options is a parts-only warranty with crane services. This is similar to the parts-only service except that any repairs that require a crane will be performed by the OEM.
4. The final option is when the OEM provides all O&M services in addition to the warranty services. In this case, the OEM will provide all scheduled and unscheduled maintenance, including troubleshooting and repair.

Regular maintenance: Typically, regular O&M consists of scheduled and unscheduled maintenance, including some provision for remote monitoring of the project. These services can be provided by the owner, the OEM, or a third-party operator. When provided by the OEM or a third-party operator, the contract may either cover only scheduled maintenance, with unscheduled maintenance provided on a time and materials basis, or the contract may include both scheduled and unscheduled maintenance for one fee. Parts may be included in the contract or they may be purchased by the owner for use by the operator. Some OEM contracts may include all parts and labor for a fixed fee, or charge an adjustable fee that is based on production.

Maintenance reserves: In cases where the project company responsible for the maintenance costs has obtained project-level debt, the terms of the credit agreement often stipulate certain reserve mechanisms to manage unplanned future costs not directly included in the annual O&M budget. The amount reserved will depend on the project history to date, expected issues relevant to the project equipment, and known equipment issues industry-wide. In the absence of project-level debt, owners typically have some planned provision for these maintenance costs, but the mechanism or approach varies widely in such cases.

4.4 Component Cost 2005 – 2010 Historical Trend

Using a collection of manufacturers' replacement part price lists, DNV analyzed main turbine component prices, when available, from 2005 through 2010, to determine historical cost trends. The analysis focused on the main turbine component prices, where they were available. Prices were selected from similar size turbines and equal capacity gearboxes, with comparable configurations and/or components. These were used to generate the data inputs for the following major wind turbine component assemblies:

- Blades
- Gearbox
- Generator
- Converter
- Yaw Gears

It is important to note that the cost trends of these components were analyzed individually, and do not represent a complete system or other combination of components, nor are they meant to reflect the historic cost trend of new wind turbines. DNV currently has insufficient historical trend information on balance of plant, foundation, tower, transportation, and installation to provide an accurate analysis of historical costs. These costs were excluded from the 2010 Component Cost section.

Wind turbine component costs remained relatively stable between 2005 and 2010, as seen in Table 4-5 below. The table also shows the cumulative inflation rate for the individual components during the same time period, relative to 2005.

Table 4-5. 2005 – 2010 Component Cost Trend

Component	Average Annual Cost Increase (%)	Cumulative Inflation Relative to 2005 (%)					
		2005	2006	2007	2008	2009	2010
Blade	2.0	0	4			6	10
Gearbox	3.5	0	0		13	21	19
Generator	-1.5	0	-11			-10	-7
Converter	2.3	0	0	0		4	12
Yaw Gear	3.2	0	0			4	17

The average annual cost increase rate for these turbine components during this period was approximately 2%. Gearboxes and yaw gears sustained annual inflation rates of 3.5% and 3.2%, respectively; blades and converters showed 2.0% to 2.3% annual inflation rates and generators experienced an annual deflation rate of -1.5%. The values in 2010 represent the cumulative inflation relative to 2005 as seen in Figure 4-2.

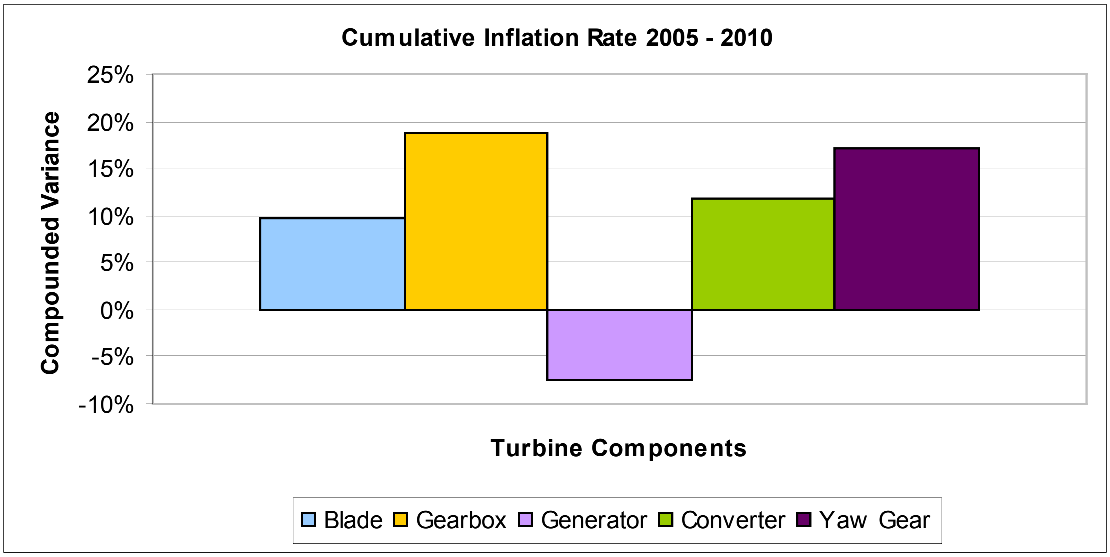

Figure 4-2. Cumulative Inflation Rate 2005 – 2010

5 PROJECT FINANCING

This section provides a high-level description of representative financing structures in 2010 and 2011 and relevant metrics for utility-scale wind power projects. Included is a qualitative outline of general wind development market conditions, including financing structures, capital availability, sources of funds (debt versus equity), and other information.

5.1 Financing Structures

Wind projects typically require higher capital costs and lower operating costs than fossil-fueled power plants. These result in the need for higher levels of capital earlier than for a similar-sized conventional power project. As a result of the high capital cost for commercial-scale wind energy projects, the wind industry may use any one of eight primary financing structures and leasing options to manage project risk.

The eight structures range in complexity and involve varying combinations of cash and tax equity capital from project developers and institutional investors, as well as commercial debt. These structures, outlined below, consider the differing financial capacities and business objectives of wind project developers, and the varying investment risk tolerances and objectives of the tax-oriented investors and debt providers.

The descriptions of the structures below are based on the report, *Wind Project Financing Structures: A Review & Comparative Analysis,* by Harper et al. [3]. DNV has updated the prevalence of the various structures based on our knowledge of 2010 and 2011 market activities, when possible.

Corporate Equity: In this structure, a single developer/investor (parent), with significant financial strength, will establish a special purpose entity to hold the assets of the project. Capital initially generated from other projects and activities is used to fund the project. The project's net cash flow and tax benefits flow back to the parent. While the parent performs sole management duties, other entities may take part in the day-to-day operational and maintenance responsibilities. [3]

The Corporate Equity Structure is the simplest financing arrangement considered here, and is prevalent among larger developers and utilities that have the capacity to self finance. All financial and management issues are solved in-house, without requiring the approval of outside investors and all benefits flow directly to the parent. The parent may gain competitive advantage due to the flexibility and time-efficiencies inherent to this structure [3]; however, there are relatively few organizations active in the wind industry in 2011 with the capital resources to adopt this approach.

Strategic Investor Flip: In the Strategic Investor Flip structure, an investor (known as a tax investor) interested in playing an active role in wind projects will negotiate a percentage ownership share with a project developer. This structure is similar to traditional joint ventures, but with three differentiating characteristics. [3]

First, in the Strategic Investor Flip structure, the tax investor provides almost all of the project equity and, in return, is allotted almost all of the distributable cash and tax benefits. For example, a tax investor may provide an undercapitalized developer with 99% of the project's total cost, leaving just 1% to be funded by the developer. In some cases, a tax investor has provided as much as 99.9% of the total project's costs. [3]

Second, at a point in time known as the flip point, the tax benefits and cash flow change typically in favor of the developer. The flip point occurs when a pre-negotiated internal rate of return (IRR) is met by the investor. It is often projected to be reached shortly after the tenth anniversary of the project's commercial operation date, coinciding with the expiration of production tax credits (PTC) for the project. This strategy is favored by developers who are unable to efficiently use tax benefits. It is even possible to incorporate a second flip point, having the inversion of percentage allocations staged across two flip points. [3]

Third, there is often an option included in the financial structure that allows the developer to purchase the tax investor's ownership share after the flip point. By this time, tax benefits have been realized by the tax investor and the investment is recorded as a true equity investment. [3]

The Strategic Investor Flip is less common today. This structure attracts third-parties who have equity to initiate projects to capture tax benefits, while allowing developers to retain some financial interest in the project.

Institutional Investor Flip: Similar to the Strategic Investor Flip structure, the Institutional Investor Flip structure has developers bring in a separate tax investor who receives the project's tax benefits. There is a flip point when the allocation of cash and tax benefits change. But there are important differences between these two flip structures. [3]

First, the Institutional Investor Flip structure tends to attract equity from more passive institutional investors that are not actively involved in the wind project. Second, the cash and tax benefit percentages received by the investor do not equal their initial investment percentage. This allows developers, who have a greater portion of initial equity capital invested in the project, to receive distributable cash from the project until they recover their investment, minus any tax benefits (which go to the institutional investor). The developer may receive what they have invested in the project, but not any returns on their investment, usually for the first four to six years of commercial operation. Once the developer has received 100% of their initial investment, 100% of the distributable cash plus tax benefits are allocated to the institutional investor until the flip point is reached. [3]

Under the Institutional Investor Flip structure, the developer maintains management control over project operations, but the institutional investor has voting rights and veto power on major decisions. Developers who have capital to invest, but lack the ability to use tax benefits, find this structure appealing. Investors who want developers more vested in the success of the project also find this structure appealing. [3] This structure was popular for most of the 2000s. Repeated use has made investors comfortable with the structure and has brought improved standardization of transaction documentation.

Pay-As-You-Go (PAYGO): Structurally, PAYGO is based on the Strategic Investor Flip, but with significant differences. Under PAYGO, the developer contributes roughly half of the initial capital required for the project, but the pre-"flip" cash and tax benefits do not match the percentage of equity contributions. In addition to their initial investment obligation, the tax investor makes annual payments based on the value of PTCs, allowing them to defer a portion of their equity investment over time. [3]

PAYGO is typically used as a refinancing strategy by developers who are also major investors. This structure allows developers to reduce their investment stake in projects or raise capital for other corporate purposes. Additionally, developers with capital to invest can maintain an ownership stake in projects for a longer term than some of the previous structures. Investors lacking a tax appetite and, when unsure about PTCs, they tend to choose PAYGO to acquire existing wind project assets and tap tax investor capital to finance a portion of the acquisition costs. PAYGO allows tax investors to offset some of the risk associated with potentially lower-than-expected wind resource, new turbine technologies, and other project risks. [3]

Cash Leveraged: In the Cash Leveraged structure, project-level loans are sized to be repaid from the cash flow generated by the project and secured by the project's assets. Initial funding contributions by investors and developers are similar to those in the Strategic Investor structure, but the amount of initial equity capital required is reduced based on the amount of debt incurred. As a result, loan principal and interest payments decrease the amount of distributable cash available to the project's investors. Debt can vary based on project requirements, but it is typically 40-60% of the total project costs. [3]

By seeking limited recourse project debt, equity returns can increase and required equity contributions can decrease. By adding debt to the project, equity returns go up because debt is usually cheaper than equity. In general, investors are not comfortable contending with a lender when the project encounters financial stress or if the project experiences foreclosure. As a result, more passive investors, like institutional investors not strategic investors, are usually sought out for this type of financial structure. The use of Cash Leveraged structures has increased significantly in 2010 and 2011 with the availability of the cash grant form of the Investment Tax Credit (ITC).

Cash and PTC Leveraged: The cash and PTC-leveraged structure adds an additional layer of debt based on the expected PTC at the project level, and lasts the full term of the PTC loan – ten years. Both PTC-based and cash-based loans are secured by project assets and assignments of contract rights. PTCs are used as a tax credit for project owners and do not generate cash that is used to repay project-level debt. As a result, additional debt may negatively impact (possibly exceed) cash flow created by the debt service coverage ratio for the cash-based loan. Consequently, tax investors usually need to commit periodic additional equity investments into the project to address lender concerns. This is capped at the amount the PTC generated during that same period. [3]

The same rationale for using debt to finance projects can be applied in this case. Lower costs associated with debt capital increase project equity returns while requiring less up-front investment. Developers favoring this structure are comfortable using debt to leverage their equity investment and believe the increase in IRR from incremental PTC debt justifies the added complexity. Maintaining control of projects also is attractive to developers and they usually already have experience in debt financing. By including the PTC, the number of tax investors may be limited because investors have to be willing to assume a contingent obligation around future capital contributions. [3]

Due to the uncertainty associated with the future cost of capital for up to ten years, and the increased risk presented by a senior debt's priority in receiving payments from the project, tax investors have been reluctant to participate in the Cash and PTC Leveraged structure and generally charge an associated premium when debt is used at the project level.

Back Leveraged: Similar to the Institutional Flip structure, the Back Leveraged structure adds a layer of debt for the developer outside of the project, specifically at the holding company level. The developer initially shows interest in the project by acquiring debt to fund capital contributions. The debt provider can impact returns at the developer level, demanding a pledge of the developer's equity interests, but the creditor has no recourse to the project company. Therefore, this structure does not affect project-level economics. The underlying allocations and structure remain the same as in the Institutional Investor Flip structure; however, loan terms are typically shorter (e.g., five years). [3]

The developer can increase IRR by securing lower cost capital to fund initial contributions under this structure. It also can increase an undercapitalized developer's equity participation. Since the financing is done at the developer level, tax investors are not impacted by this type of financial structure. The back leveraged structure is becoming more common because 1) it allows developers to increase their returns from projects through the use of leverage, and 2) tax investors are not exposed to project-level debt. [3]

Sale-Leaseback: The Sale-Leaseback is a recent innovation in wind project financing [4]. It became more viable when the PTCs were supplemented with the ITCs and cash grants; both can be used by a non-operating owner. The Sale-Leaseback provides benefits unavailable in the other structures and allows the borrower to obtain 100% financing. Equity investors have a starting tax basis equal to the acquisition price of the project, which can be beneficial in calculating tax benefits, including incentives and depreciation.

The Sale-Leaseback structure can provide access to capital from bank leasing companies, which may be unavailable in an Investor Flip structure. Either the lessee or the lessor has the option to apply for the grant. The lessee can apply for, and be the recipient of, the grant; the lessee places the property in service, sells the property to the lessor, and leases it back within three months of the project being placed in service.

5.2 Capital Availability and Cost of Capital

According to several discussions with equipment manufacturers, developers, and representatives of finance institutions, availability of project financing was one of the significant limiting factors in the U.S. wind energy market in 2009 and early in 2010, but the situation has since rebounded significantly. The primary reason for project financing limitations was the economic downturn that hit the U.S. and global economies in the fall of 2008, and led to a tightening of the financial markets.

The global credit crisis negatively affected wind project financing in two important ways:

- **Project-level debt** – In the aftermath of the credit crisis, lenders were sizing debt on more stringent terms compared to pre-crisis conditions. This resulted in increased borrowing costs and an overall reduction in the level of lending for new projects in 2009 and early 2010. The availability of project-level debt has since rebounded significantly.
- **Tax equity** – Historically, most projects relied largely on tax equity investment for project financing. The number of tax equity participants and the associated availability of tax equity were significantly reduced due to commensurate reductions in corporate profits and the resulting tax appetite. About 20 investors were active in the renewable energy tax equity market before the crisis, but this was reduced to a handful of organizations by the end of 2008. The number of investors active in the market rebounded, but as of 2010, it was still below the pre-crisis level at about 16 tax equity investors. All were not active in the U.S. wind market [5]. The need for tax equity was decreased by the use of the cash grant program instead of the ITC and PTC programs.

In an effort to counteract the impact of the global credit crisis on the wind industry, provisions were included in the American Reinvestment and Recovery Act (ARRA) passed in February 2009. This included the aforementioned cash grant in lieu of the ITC. This incentive provided financing for projects that otherwise would have had difficulty monetizing the tax benefits associated with the PTC or ITC due to the limited availability of tax appetite. The U.S. Treasury disbursed $1.4 billion in 2009 and $3.5 billion in 2010 to wind projects under this program [6].

Prior to the global credit crisis, the cost of project-level debt was trending upward. During this period, commonly referenced benchmark rates were relatively high, while bank margins were relatively low, ranging from about 125 to 175 basis points. As a result of the credit crisis, base rates dropped significantly, but margins increased to about 325 to 375 basis points. The combined result is that the overall interest rates for project-level debt have remained fairly steady in 2010 and 2011, with perhaps a slight reduction in interest rates relative to pre-crisis levels. Bank margins have come down recently from around 275 to 300 basis points. [7]

5.3 Empirical Findings on Financial Metrics

DNV conducted empirical research on various financial metrics including the following standard financial metrics:

- Cost of standard equity – defined as the 20 year after-tax internal rate of return (IRR) for the primary project owner.
- Cost of tax equity – defined as the 20 year after-tax IRR for a tax equity owner. In projects with a flip structure, this includes both pre- and post-flip cash flows.
- Cost of debt – defined as the before-tax all-in annual interest rate for a term loan. This does not include construction loans, which are typically short-term instruments.
- Debt fraction – defined as the percentage of the overall project cost that is funded by a term loan. This does not include any construction loan.
- Debt tenor – defined as the length of the term loan in years.
- Debt service coverage ratio (DSCR) – defined as the coverage ratio for sizing debt using a P50 production case. In practice, most term loans are also sized on the one year P99 production case, with a DSCR of 1.0. Lenders may offer the smaller of the loan sizes between the two cases. [8]

DNV reviewed project-level pro formas for 15 projects developed in 2010 and 2011. Most of these projects were funded using the cash-grant version of the ITC. DNV reviewed recent public presentations and reports from debt and equity institutions to gather information on target rates of return. DNV also interviewed six project participants, between June 2011 and July 2011, including project lenders, sponsors, and equity investors to discuss our empirical findings. The results below reflect both the empirical data from the evaluated pro formas and the results of interviews with project participants. Where appropriate, a range of results is presented. However, individual projects may vary materially from the ranges indicated below.

The cost of standard equity ranged from 8% to 13%, with a baseline of 10%. This was lower if an equity holder were buying into an equity stake in an operating portfolio as compared to early-stage, non-operating development portfolio.

The cost of tax equity ranged between 7% and 15%, with a baseline of 9% or 12% depending on the presence or absence of senior debt (e.g., a term loan). There were relatively fewer tax equity deals in years when the cash grant was in place. There was a premium of approximately 300 basis points (3%) on the cost of tax equity, if the project had senior term debt. This market was much more variable and project-specific than the debt market and was influenced by dynamics in the affordable housing market, which competes with renewable energy projects for tax equity investment funding. DNV's review of this metric relied more heavily on discussion with industry partners than our review of the debt-related metrics.

The cost of debt ranged between 6.75% and 8%, with a baseline of 7.125%. The typical bank margin over LIBOR was approximately 225-325 basis points. In 2010 and 2011, many term loans were fully amortized over longer periods (e.g., 15-18 years) as opposed to mini-perm structures that included a large balloon payment after 5 to 7 years. Mini-perm structures were more common in late 2008 and 2009 following the financial crisis of 2008. Other findings included the following:

- The debt fraction ranged between 40% and 55%, with a baseline of 45%, though some isolated cases were identified outside this range,
- The debt tenor ranged from 15 to 18 years, with a baseline of 17 years, though some isolated cases were identified outside this range, and
- The base case DSCR ranged from 1.4 to 1.55, with a baseline of 1.45.

Overall, the debt market appeared to be more consistent across projects than the tax equity market, which had more project-specific details. Our investigation converged quickly on the debt numbers and there were fewer comments on these in our discussions with industry partners.

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APPENDIX A – FAILURE RATE AND PARTS COST ASSUMPTIONS

Table A-1. Reference Scenario Failure Rates and Part Cost Assumptions

System	Component	Failure Prediction	Failures per 100 parts by Year 20	Weibull Curve Parameter – Alpha	Weibull Curve Parameter – Beta	Parts per Turbine	Parts Cost ($)	Crane?	Parts in Project	Failures in 20 Years
Rotor										
	Blade-struct. Repair	Constant Rate	5.0			3	87,500	YES	300	15
	Blade-nonstruct. Repair	Constant Rate	20.0			3	3,000	NO	300	60
	Pitch cylinder & linkage	Weibull Curve		10.0	3.5	3	3,800	NO	300	547
	Pitch bearing	Weibull Curve		50.0	3.5	3	13,100	YES	300	13
	Pump & hydraulics	Weibull Curve		12.0	3.5	1	2,200	NO	100	142
	Pitch position xdcr	Weibull Curve		12.0	2.0	3	1,800	NO	300	468
	Pitch motor	Weibull Curve		15.0	1.1	0	8,400	NO	0	
	Pitch gear	Weibull Curve		12.0	3.5	0	4,600	NO	0	
Drive Train										
	Main bearing	Weibull Curve		39.0	3.5	1	24,400	YES	100	10
	High-speed coupling	Weibull Curve		25.0	3.5	1	6,700	NO	100	39
Gearbox and Lube										
	Gearbox-gears & bearings	Constant Rate	5.0			1	154,700	YES	100	5
	Gearbox-bearings, all	Constant Rate	5.0	26.0	3.5	1	800	YES	100	35
	Gearbox-high speed only	Weibull Curve		26.0	3.5	1	36,700	NO	100	35
	Lube pumps	Weibull Curve		12.0	3.0	2	2,400	NO	200	294
	Gearbox cool. fan motor	Weibull Curve		19.0	1.1	2	2,000	NO	500	195
Generator and Cooling										
	Generator-rotor & bearings	Constant Rate	10.0			1	91,600	YES	100	10
	Generator--bearings only	Weibull Curve		17.0	3.5	2	2,100	NO	200	184
	Full converter	Weibull Curve		15.0	2.0	1	9,500	NO	100	117
	Gener. cooling fan motor	Weibull Curve		19.0	1.1	1	1,600	NO	100	98
	Contactor, generator	Weibull Curve		20.0	2.0	3	13,500	NO	300	235
	Partial converter	Weibull Curve		15.0	2.0	0	2,600	NO	-	-

System	Component	Failure Prediction	Failures per 100 parts by Year 20	Weibull Curve Parameter – Alpha	Weibull Curve Parameter – Beta	Parts per Turbine	Parts Cost ($)	Crane?	Parts in Project	Failures in 20 Years
Brakes and Hydraulics										
	Brake caliper	Weibull Curve		10.0	2.0	1	700	NO	100	194
	Brake pads	Constant Rate	200.0	10.0	2.0	1	5,900	NO	100	200
	Accumulator	Weibull Curve		6.0	3.0	4	1,500	NO	400	1,356
	Hydraulic pump	Weibull Curve		12.0	3.0	1	4,900	NO	100	146
Yaw System										
	Yaw gear (drive+motor)	Constant Rate	5.0			4	6,000	NO	400	20
	Yaw motor (with brake)	Weibull Curve		10.0	2.0	4	2,400	NO	400	776
	Yaw sliding pads	Weibull Curve		10.0	3.5	8	800	NO	800	1,462
Control System										
	Control board, top	Weibull Curve		15.0	2.0	1	5,500	NO	100	117
	Control board, main	Weibull Curve		15.0	2.0	1	8,600	NO	100	117
	Control module	Weibull Curve		15.0	2.0	13	6,100	NO	1300	1526
	Sensor, static	Weibull Curve		14.0	2.0	17	500	NO	1700	2184
Electrical and Grid										
	Main contactor	Weibull Curve		20.0	2.0	1	9,200	NO	100	77
	Main circuit breaker	Weibull Curve		30.0	2.0	1	10,800	NO	100	7737
	Soft starter	Weibull Curve		30.0	2.0	0	700	NO	-	-
Misc. (All others)										
	Miscellaneous parts	Constant Rate	5.0			1	100,900	NO	100	5

APPENDIX B – SCENARIO RESULTS

Table B-1. All Scenario Model Results – O&M Costs by Project Operating Year

	O&M Cost by Project Operating Year ($/turbine/year)																			
Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Reference Scenario	24,300	26,300	28,900	31,300	34,200	36,500	38,900	41,000	42,700	44,600	46,200	47,300	47,400	47,700	48,500	49,000	49,700	50,900	51,300	51,300
High Failure Rate Scenario – Blades	26,900	29,000	31,600	34,000	36,800	39,200	41,500	43,700	45,400	46,300	47,700	47,900	48,300	49,300	49,400	50,600	51,300	51,900	52,400	52,900
High Failure Rate Scenario – Generator	26,400	28,500	31,000	33,400	36,300	38,700	41,000	43,100	44,800	46,800	47,200	48,200	48,400	48,700	49,500	50,100	50,800	51,900	52,400	52,400
High Failure Rate Scenario – Gearbox	26,000	28,000	30,600	33,000	35,900	38,300	40,600	42,700	44,400	46,400	47,900	47,900	48,100	49,200	49,200	50,400	51,000	51,600	52,100	52,600
100% Replacement Scenario – Blades	41,200	43,300	45,800	48,200	50,800	53,100	54,900	56,700	58,100	59,400	60,400	60,900	61,500	62,100	62,400	63,300	64,100	64,800	65,600	65,800
100% Replacement Scenario – Gearboxes	37,900	40,000	42,500	44,900	46,800	49,200	51,300	53,200	54,100	55,700	56,300	57,100	57,300	57,700	58,300	58,900	59,600	60,600	61,100	61,200
100% Replacement Scenario – Generators	32,000	34,000	36,600	39,000	41,700	43,400	45,600	47,500	49,100	50,200	51,400	51,700	52,000	52,900	53,100	54,200	54,900	55,500	56,100	56,500
Serial Replacement Scenario – Blades	22,900	25,000	27,600	132,900	135,700	138,100	37,500	39,600	41,300	43,300	44,800	46,000	47,200	47,300	47,400	48,600	49,200	49,800	50,800	50,800
Serial Replacement – Gearboxes	23,400	25,500	28,000	103,700	106,600	109,000	38,000	40,100	41,800	43,800	45,300	46,400	46,600	46,900	47,800	48,300	49,000	50,200	50,600	50,700
Serial Replacement – Generators	23,200	25,200	27,800	73,500	76,300	78,700	37,800	39,900	41,600	43,600	45,100	46,200	46,400	47,600	47,600	48,900	49,500	50,000	50,500	51,000