Historical Trends in Wind Energy Operations Costs and Project Availability

September 2012—July 2013

DNV KEMA
Seattle, Washington

NREL Technical Monitor: Eric Lantz

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National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nrel.gov

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Preface

The work detailed herein was completed in 2013 and references both current and recent trends and data as of that date. Given the time elapsed between the completion of the work and this publication, readers should be aware that these references apply primarily to the period of time during and prior to 2013 and may no longer be considered either current or recent.

The work has been published at this delayed date as a reference volume for current and future research activities in wind power operations and maintenance.

Parallel work was undertaken by Garrad Hassan America, Inc. (GL GH) in the same time frame. Subsequently, DNV KEMA and GL GH merged to form the DNV GL Group. Certain analysis methodologies and assumptions may have changed since the original research was conducted. Recent thought leadership on related topics from DNV GL may be found at: https://www.dnvgl.com/energy/publications.

1 Introduction

The National Renewable Energy Laboratory (NREL) retained DNV KEMA Renewables, Inc. (DNV KEMA) to study the historical trends in wind energy operation and maintenance (O&M) costs, component replacement trends, and project availability. This scope of work is governed by the NREL Subcontract No. AFT-2-22435-02, dated September 27, 2012, under Prime Contract No. DE-AC36-08GO28308.

Gaining a greater understanding of the factors that impact cost, major component replacements, and availability of utility-scale wind projects is an important step in the effort to improve wind project operations. Once a project has been installed and the capital investment made, the primary variable operators have to control costs is in how efficiently and reliably they can run their projects. The three factors of operational expenditures (OpEx), replacements of major turbine components, and project availability are tightly interrelated. If a component fails, that puts a turbine out of service and availability suffers. If a condition monitoring system is implemented to improve preventative maintenance then operating expenses go up, but availability may also improve and thereby offset the cost increase with more energy production. Conversely, if an operator decides to reduce operating expenses by cutting corners on maintenance activities, then turbines may be less reliable, which can reduce availability and subsequently revenues. With more projects coming online, and many coming off warranty within the next several years, operators are increasingly interested in optimizing their processes, maximizing energy production, and minimizing downtime and equipment failures. One important step to aid this process is to gain insight into the historical trends in OpEx, component replacements, and wind project availability.

DNV KEMA's access to operating, cost, and availability data from a wide range of utility-scale wind projects provided the foundation for this study. Specifically, O&M cost, component replacement, and availability data for 5 gigawatts (GW) of installed capacity over a period of up to 14 years were extracted and organized. These data, which cover more than 50 North American projects were then used to establish a baseline database and analysis tool to begin analyzing trends. By definition, analysis of historical trends is backward looking and, as such, data reported include turbine types of an array of vintages (commissioned between 1999 and 2009), some of which may be more or less comparable to commercial technology being installed at the time of this study. Although the aggregate data used in this project, along with the accompanying data analysis tool, represent a significant step forward, it is DNV KEMA's opinion that this initial effort should be viewed as a foundation from which future work should continue and that additional data should be brought forth and analyzed as it becomes available.

To mitigate the limitations of a relatively small data set, DNV KEMA also reached out to industry owners/operators both to verify that the preliminary analysis and results were consistent with their experiences, and to survey them regarding their thinking on issues affecting operational costs.

The raw data used in this study were not made public because of confidentiality restrictions; however, an array of summary tables and figures are provided in this report. Summary statistics across a number of parameters are also presented.

The overall objectives of this study were to:

- Develop a historical OpEx baseline grounded in a representative sample of empirical data from North America
- Enhance the understanding of whether and how technological advancements have impacted project operational expenditures
- Serve as a starting point to inform modeling efforts designed to quantify the impact of future technological advancements on wind energy operational expenditures
- Provide NREL with a summary of empirical OpEx data from a large data set of operating wind power plants in the United States and provide significant insights into some of the variables that impact annual operational expenditures.

This report presents the assumptions, methodology, results, conclusions, and recommendations of DNV KEMA's work.

2 Project Data and Data Classification

2.1 General Description of Project Data

The primary objective of this study was to establish a baseline of historical operational expenditures, component replacements, and availability trends for wind projects, with the goal of better understanding the variables that impact these metrics. Executing this task required the extraction and organization of the relevant project level data from various sources. Project level statistics were captured for several parameters including:

- **Project Age**. Defined as the time elapsed since the commercial operation date (COD), in which the COD is the date that all turbines in a given project have been commissioned and are available to operate. Project age is computed monthly, and then annualized based on the COD. Thus, for a project with a June COD, the first year of operation is from June through July of the following year.
- **Turbine Size**. Turbines are classified by power rating, which gives an indication of a turbine's size. Turbine size generally scales with power rating, although rotor diameter can be and frequently is scaled independent of power rating. Turbine size is also roughly indicative of vintage, because larger turbines tend to be newer. To protect the confidentiality of project data, specific turbine models were not identified in this report.
- **Turbine Class**. Turbines are classified by the wind turbine class of each model as defined in International Electrotechnical Commission (IEC) standard 61400-1: Ed. 3. IEC Class provides an indication of the operating envelope (average and peak wind speed, turbulence intensity) for which a given turbine is designed. In general, turbines designed for lower average wind conditions, such as IEC Class III, tend to be newer, more advanced models than those designed for stronger winds (IEC Class I). Table 2-1 shows the basic parameters for each wind turbine class.

Table 2-1. Basic Parameters for Wind Turbine Classes

Wind Turbine Class	I	II	III	S
V_{ref} (m/s)	50	42.5	37.5	Values specified by the designer
V_{ave} (m/s)	10	8.5	7.5	
A I_{ref}	0.16			
B I_{ref}	0.14			
C I_{ref}	0.12			

where

V_{ref} is the reference wind speed average over 10 minutes Vave is the 10-minute average wind speed

A designates the category for higher turbulence characteristics

B designates the category for average turbulence characteristics

C designates the category for lower turbulence characteristics

I_{ref} is the expected (average) value of turbulence intensity at 15 m/s.

- **OpEx**. General OpEx cost accounting does not categorize overhead costs such as central control facilities and management in a consistent manner, and balance-of-plant (BOP) maintenance costs can be heavily influenced by who has responsibility for substation and transmission line maintenance. OpEx are not uniformly defined across all owners/operators, and in some cases, not even from year to year for the same owner/operator. Although the quantitative data DNV KEMA reviewed generally included itemized breakdowns of costs, the subcategories varied from project to project. After examining OpEx data from many projects, DNV KEMA determined that the only consistent categorization across all projects was the three broad categories: turbine O&M costs, BOP O&M costs, and "soft" costs. The items typically included in these broad OpEx categories are:
    - *Turbine O&M*. This category consists of annual costs related specifically to the turbines, including all components from the base of the tower and up, as well as the transformer. Turbine O&M comprises all aspects of maintenance, both scheduled and unscheduled. It may contain turbine warranty costs unless those are already included as part of a turbine supply agreement (TSA). TSA warranties typically cover parts and labor for unscheduled maintenance. Scheduled maintenance by the original equipment manufacturer (OEM) during the warranty period is typically covered under a service and maintenance agreement for an annual fee. Table 2-2 summarizes the cost categories related to turbine O&M, which vary depending on whether the turbine is under warranty, under an OEM or third-party service and maintenance agreement, or being maintained by the operator.

Table 2-2. Typical Turbine O&M Cost Categories

Category	Notes
Turbine warranty	Most projects include a warranty on all turbine-related maintenance for the first 2–5 years of operation. Scheduled maintenance is typically covered by an annual service maintenance fee. Unscheduled maintenance is typically covered under the warranty, which may be embedded in the original turbine supply contract, depending on specific terms and conditions negotiated at the time of sale.
Turbine operations/service and maintenance fee/management operations fee	Includes turbine-related maintenance, wages and salary, overtime, bonus, burdening, medical/life insurance, and other costs as well as scheduled and unscheduled maintenance.
Condition monitoring system repairs	May include equipment; may or may not be included in O&M service agreement
Manufacturer's incentive payment	Not included in warranty or O&M service agreement
Equipment rentals	Includes cranes and other heavy equipment
Supervisory control and data acquisition (SCADA) system maintenance	
Materials and supplies	
Small tools and equipment	
Turbine parts	

- *Balance-of-Plant O&M*. This category consists of costs related to maintaining facilities and infrastructure from the base of the towers down (including the turbine foundations), and from the grid side of the transformer up to and including the substation. For some projects, additional transmission line maintenance may also be included. Balance-of-plant O&M costs generally include the electrical collection system, maintenance of all equipment and equipment facilities, storage, maintenance and office buildings, and waste removal. Table 2-3 shows the typical balance-of-plant O&M costs.

Table 2-3. Typical Balance-of-Plant O&M Costs

Collection system maintenance
Equipment maintenance
Equipment purchase
Equipment rental
Facility expense
O&M building rent
O&M service
Road maintenance
Substation maintenance
T-Line maintenance
Waste management

- *Soft costs*. These costs represent other costs that are unrelated to the daily operations of a project, such as insurance, land leases and royalties, scheduling fees assessed by grid operators, legal fees, and environmental and community expenses and taxes. Table 2-4 provides a list of items included in the soft costs category.

Table 2-4. Typical Soft Costs

Audit compliance
Bank fees
Community involvement
Environmental expense
Fiscal management fees
Forecasting fees
Franchise tax
Insurance
Land lease and royalties
Legal fees
Miscellaneous expense
Payment in Lieu of Taxes (PILOT)
Project management fees
Property tax
Schedule imbalance charges
Scheduling fees
Tax compliance
Telecommunications expense
Transmission operator charges
Utility expense
Vehicle expense

- **Replacements**. Refers to replacement of five major turbine components that require a crane for removal and reinstallation. Major components, for the purposes of this study, include blades, gearbox, generator, main bearing, and an uptower transformer. Uptower or other minor repairs of those five components were not tracked, nor were any other replacements.
- **Availability**. Wind turbines can only produce electricity when they are able to operate. When they are unable to operate, they are considered "unavailable" and the lost electricity production associated with the downtime is called an availability loss. Lost production can be caused by issues with the turbine itself (such as routine maintenance downtime, fault downtime, or downtime caused by component failures) or with issues that go beyond the turbine, such as a facility's electrical infrastructure, the power grid, or weather-induced downtime. In this study, "turbine availability" is understood as the percentage of time the turbine is available to operate, regardless of the external conditions. Turbine availability is also known as OEM availability or contractual availability. Curtailment is not included in turbine availability calculations. "Overall availability" is the total percentage of time when

both the turbines and the facility are available to operate, regardless of the wind speed. Project downtime that is the result of curtailment will show up in overall availability.

The quality and resolution of the original data sources imposed some limitations on the database. For example, none of the OpEx data sets provided a distinction between fixed versus variable costs, or scheduled versus unscheduled maintenance; therefore, the database does not include that level of resolution. Whenever possible, DNV KEMA included the date (month and year) of warranty expiration, although for some projects such data were not available.

2.2 Classifying the Data

Several criteria that projects were required to meet to be included in this study were developed jointly by DNV KEMA and NREL. The criteria were selected to maximize the potential for achieving the objectives of the work while keeping the volume of data manageable within the scope of the study. At a minimum, each project data set in this study was required to include a project size of at least 20 turbines, a log of major component replacements and when those occurred, turbine and project availability, operational costs, as well as a minimum of 2 years in service. Among the projects that met these minimum criteria, DNV KEMA sought out data sets that also included: at least 1 year of data beyond the expiration of the turbine equipment warranty, a breakdown of downtime attributed to component failures (e.g., how long to remove/replace components, how long until the replacement parts were available, and so on), availability by turbine (not just aggregate project availability), and operating costs by component. In addition, DNV KEMA sought out high-quality data sets that exhibited consistency of data formatting and reporting. This latter criterion in particular was quite difficult to enforce, as the breakdown of cost by category for many of the operations reports varied from year to year and in some cases from month to month. Table 2-5 summarizes the criteria for selecting data sets for this study.

Table 2-5. Criteria for Selecting Data Sets for O&M Analysis

Project Criteria	Required	Preferred
Time in service	2 years	1 year after warranty
Project size	20 turbines	
Data Requirements		
Major component repair/replacement	X	Breakdown of downtime
Availability by manufacturer/balance of plant	X	Availability by turbine
Operation costs	X	Cost by component

To address the objectives of this study while preserving the confidentiality of the data sets, DNV KEMA categorized the data by several metrics, including project size, turbine size, number of years the project has been in operation, aspects of turbine technology, and IEC wind class. The researchers subsequently classified each project using turbine rating and number of turbines in the project as the sorting criteria. Each parameter was divided into three bins, as defined in Table 2-6.

Table 2-6. Classification Matrix

Metric	Bin 1	Bin 2	Bin 3
Project size	20–50 megawatt (MW)	50–100 MW	> 100 MW
Turbine rating	0.6–1.25 MW	1.26–1.8 MW	> 1.8 MW
Turbine IEC class	I	II	III
Years of operation	2–3	3–6	>6

The goal was to size each bin to ensure that the data remained anonymous yet retained meaningful and statistically significant results. Turbine size bins were set to include submegawatt turbines [0.6–1.25 megawatts (MW)], turbines in the 1.5-MW range (1.26–1.8 MW), and multimegawatt turbines (greater than 1.8 MW). Project size was binned based on "small" (less than 50 MW), "medium" (50–100 MW), and "large" (greater than 100 MW). Projects were also binned based on years of operation. For this case, Bin 1 was set at 2–3 years, which captures the end of the TSA warranty and the transition to a different service and maintenance arrangement. Bin 2 was set to 3–6 years, which is the period after the warranty has expired yet prior to the onset of most failures. The third bin under "years of operation" is for projects that have been in operation more than 6 years, when a project is considered mature. Final binning was established after evaluating all available data and in consultation with NREL.

DNV KEMA extracted the O&M data used for this analysis from over 50 projects representing more than 5 GW of installed capacity. All projects considered are located in North America. Of those total projects, 30 met the defined criteria laid out in Table 2-5. The data were in a variety of forms and formats including spreadsheets, monthly reports, and quarterly reports. Some reports changed the O&M cost category names and definitions multiple times over the course of a project. Changes in the categorization of turbine O&M occurred when:

- Owners changed service providers, transitioning from an OEM to a third-party service provider. In these instances cost categories often changed from a single service and maintenance fee for a comprehensive contract that covered all turbine O&M activities to itemized categories for service fees, unscheduled maintenance, and parts and crane costs.
- Projects transitioned from a third-party service provider to self-operated. In these situations, the O&M cost categories changed from service and maintenance fees and incentive payments to detailed lists of internal costs including wages and salaries, overtime, bonuses, burden, medical/life insurance, as well as a more detailed breakdown including equipment, tools, parts, and consumables.

Because of the lack of consistency in reporting turbine O&M when transitioning a project from OEM-operated to third-party-operated to self-operated, it was not possible to break turbine O&M costs into subcategories. Nor was it possible to assign OpEx costs to scheduled or unscheduled maintenance. The situation was similar with balance-of-plant OpEx when service and maintenance changed from a third-party provider to self-operated.

Additional challenges presented by the operating reports included:

- Switching from site-reported OpEx to centralized accounting systems. In a centralized accounting system, some costs were categorized only as "site maintenance" or "damage repairs," with no indication of whether costs were associated with turbine O&M or balance-of-plant OpEx. In these cases, DNV KEMA contacted the operator to clarify the nature of the expense so that they could properly categorize it in the database.
- Some project financials presented expenses in general categories, such as operation and maintenance, depreciation, amortization and accretion, general and administrative, and taxes other than income, with an accompanying report describing the significant contributors to each expense category. For these projects, DNV KEMA filtered the identified expenses into the turbine, BOP, and soft categories.
- Component replacements were generally logged on a monthly basis, whereas OpEx was typically provided annually. For some projects, turbine availability was recorded monthly on a per-turbine basis, whereas for others only annual availability for all turbines was provided.

2.3 Characterization of the Projects

DNV KEMA collated the data, which were compiled into a common format for input into a Microsoft Access custom database. Table 2-7 summarizes some general facts about the 30 projects, which amounts to 1,895 turbines with a total installed capacity of 2.5 GW. The turbines range in size from 600 kW to 3.0 MW and comprise 16 different turbine models from seven of the major turbine manufacturers.

Table 2-7. General Summary of Projects

Total number of projects	30
Total number of turbines	1,895
Total installed capacity	2,489 MW
Number of turbine models	16
Number of turbine manufacturers	7
Range of turbine ratings	600 KW to 3,000 KW
Range of rotor diameter	47 m–93 m
Earliest COD	January 1999
Latest COD	March 2009
Number of project years of data	150

Table 2-8 indicates the number of projects that fell into each of the different bins defined above in Table 2-6. DNV KEMA's goal was to have a minimum of five projects in each bin, which was achieved for project size, turbine operation, and years of operation, but not for IEC class. None of the 30 projects in this study included Class III turbines. In addition, because the latest COD in the database is March 2009, recent advanced turbine models that have been deployed since that time are not represented.

Table 2-8. Number of Projects Reporting in Each Classification Bin

Metric	Bin 1	Bin 2	Bin 3
Project size	10	13	7
Turbine rating	11	12	7
Turbine IEC class	7	23	0
Years of operation	20	16	7

The projects in this study had CODs dating as far back as 1999 and as recently as 2009, with project ages ranging from 2 to 14 years. DNV KEMA's operating data for these projects cover the period from January 2001 to July 2012, and vary from project to project. For 20 projects, DNV KEMA received operating data beginning from the COD. For the remainder, however, the data received did not cover project operations from inception. Most of the data in the database fell within the 10-year period from 2001 through 2011, and seven projects provided data through mid-2012.

Figure 2-1 shows the period of operation for each project, synchronized by operating year. This representation shows how many projects are reporting in each year of operation in the database. The dark yellow portions of the bars indicate the periods for which DNV KEMA received operating, OpEx, and availability data. In addition, the figure indicates the end of warranty (EOW) for most projects. Half of the projects in the database have 5-year warranties, whereas only four projects have 2-year warranties and the rest either have a different arrangement or EOW information was not available. Figure 2-1 also provides significant insight into the composition of the OpEx database. Notably, the database includes considerably more data for the first 6 years of project life, with relatively less data beyond 10 years.

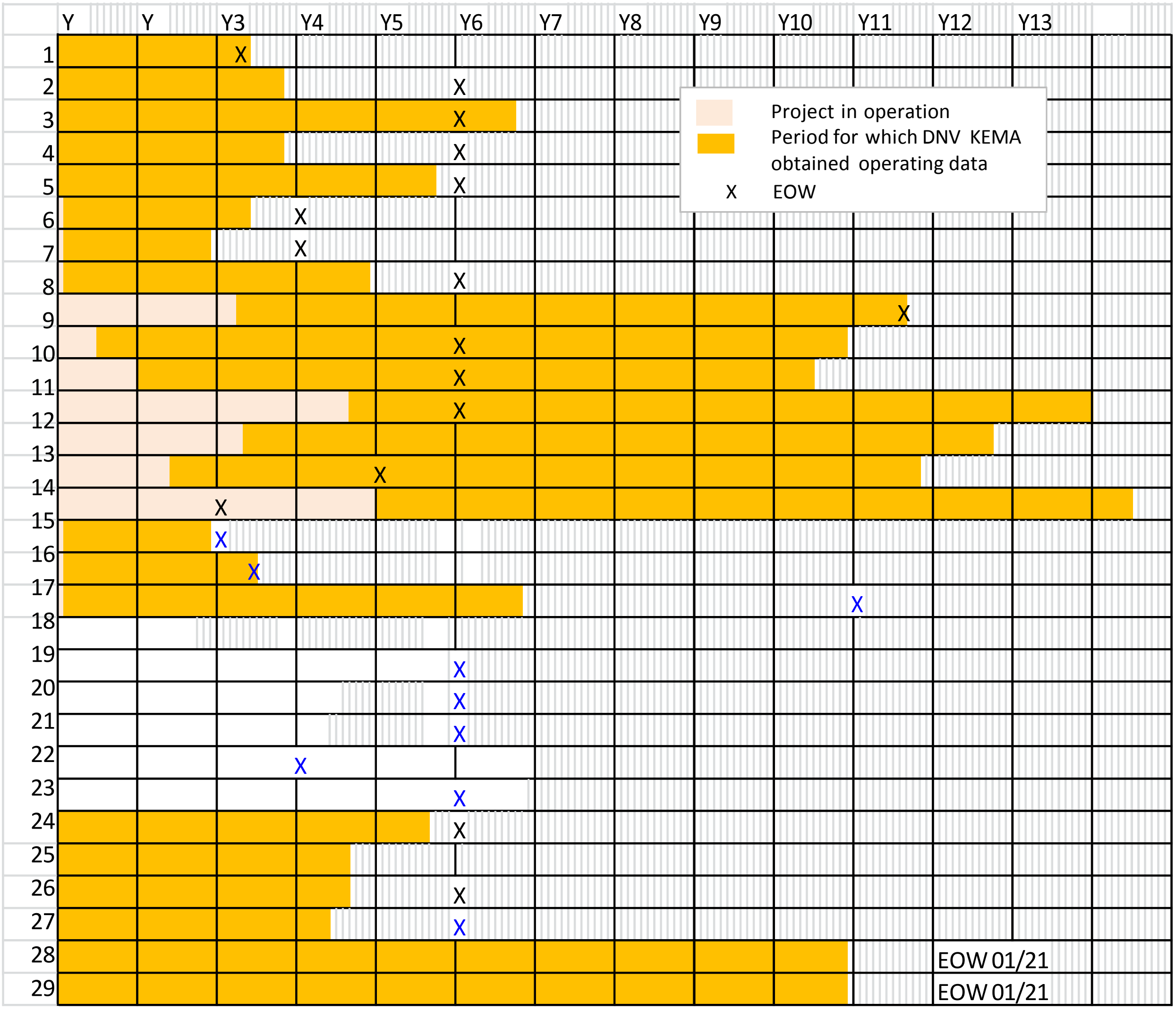

Figure 2-1. Operating data provided to DNV KEMA for each project, synchronized by operating year

2.4 Data Summary

In this study, it was challenging ensuring that data from different projects and time periods were handled in a consistent way. DNV KEMA analyzed the various data sources and applied their best judgment in assembling the data tables; however, the qualitative nature of the operating reports and the variations in the cost categories introduce some uncertainty into the database. This uncertainty could be reduced by: 1) expanding the number of projects in the database, 2) instituting uniform operating, OpEx, and availability data reporting within the wind industry, and 3) automating the reporting of operational data to facilitate data extraction.

3 Database Design and Implementation

The OpEx database was organized around three main factors: major component replacements (major interventions), operating expenses, and turbine availability. All data were synchronized by year of operation in a two-step process described below.

3.1 Step 1: Synchronizing Start Date

Each project had a different start date and so the data had to be synchronized in some way, organized either by year of operation or by calendar year. Because the COD does not always occur conveniently at the start of a new year (January 1), the database was set up to record data by year of operation, regardless of what month a project began operations. Examining the data by year of operation is useful for determining trends that tied to time in service, such as the impact of going out of warranty. DNV KEMA considered comparing project data by calendar year; however, this was complicated by the fact that the COD can occur at any time in the year, as a result, the first year of data may include fewer than 12 months of records. Furthermore, if partial-year records were excluded simply because the COD does not occur on January 1, then important O&M trends that occur early in a project's life (i.e., pre-EOW) would be missed. On the other hand, retaining partial-year records in the database presents its own problems. Most notably, it could lead to biased results because partial-year data would be treated the same as full-year data. For these reasons, DNV KEMA elected to synchronize all the data by year of operation.

3.2 Step 2: Allocating Annual Data by Year of Operation

To compare projects from different calendar years, time stamps were converted first to the number of months from the COD and then aggregated into each year of operation. For example, a project with a July COD that is in its fifth year of operation could experience some replacements that occur during the 7 months of calendar year five and others that occur during the 5 months of calendar year six. Similarly, the operating expenses, turbine output, and availability time stamps were grouped according to year of operation. Finally, with all three data sets grouped by operational year, they were joined by Project ID and year into one master query for further analysis (discussed below).

Figure 3-1 shows a schematic of the tables that comprise the OpEx database, as well as the associated interconnections among the tables.

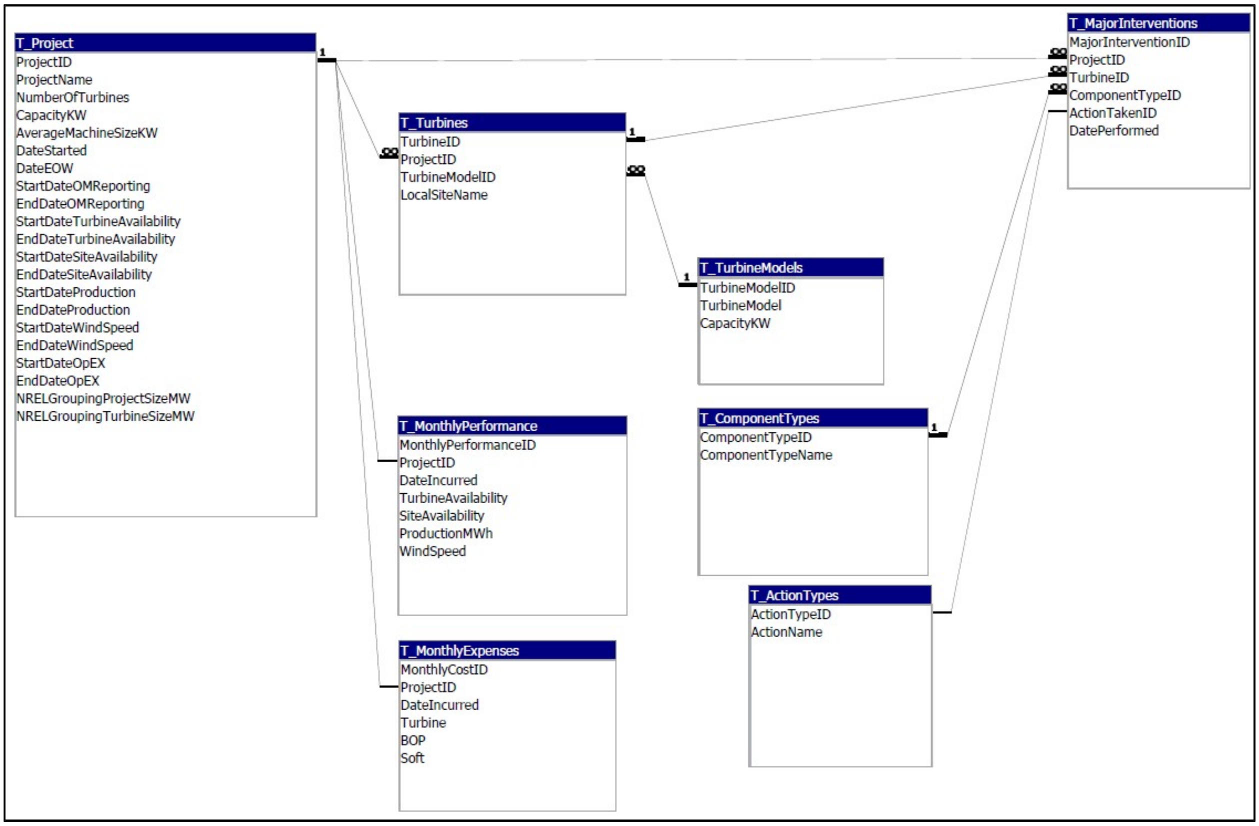

Figure 3-1. OpEx database schema

The OpEx database was developed to produce a master query table with the categories as defined in Table 3-1.

Table 3-1. Categories for the Master Query Table

Master Query from Access Parameters	Definitions
Project ID	Unique ID assigned to each project reporting
Year of operation	Operating year of the project, where year one begins on the COD
Blades	Number of blade replacements per year
Gearbox	Number of gearbox replacements per year
Generator	Number of generator replacements per year
Main bearing	Number of main bearing replacements per year
Transformer	Number of uptower transformer replacements per year
Production (megawatt hours [MWh])	Total annual net energy production
Average turbine availability	Annual average project-wide turbine availability, %; turbine availability generally includes all turbine-related downtime, component replacements, and scheduled maintenance
Average site availability	Annual average overall project availability, %; overall availability includes ALL downtime-related events at a project, such as collection-system maintenance or failures, weather-related incidents, and curtailment; in general, overall availability will be lower than turbine availability
Replacements and costs; number of months	Number of months in a given year of operation for which there is component replacement and OpEx data
Turbine	Turbine-related OpEx, $, referenced to year of operation
BOP	BOP-related OpEx, $, referenced to year of operation (e.g., roads, maintenance facilities, snow removal, electrical collection system)
Soft	"Soft" OpEx, $, referenced to Year of Operation (e.g., insurance, taxes, lease payments)
Operational year costs; number of months	Number of months in a given year of operation for which there is OpEx data
Project name	Commercial name of the project
Number of turbines	Total number of turbines installed at each project
Capacity (kilowatts [kW])	Total capacity of each project
Average machine size kW	Average turbine rating at each project; where there is more than one turbine model, the weighted average turbine rating is used
Calendar year of operation	Calendar year of project operation (always begins on January 1)
Project size (MW)	Category defining the project size classification (see Table 2-6)
Turbine size (MW)	Category defining the turbine rating classification (see Table 2-6)
Start date O&M reporting	Month/year of first O&M report
End date O&M reporting	Month/year of last O&M report

4 Data Analysis

DNV KEMA completed an initial analysis of the data to address issues and ensure an "apples to apples" comparison of data from different projects, as described previously. The MasterQueryFromAccess table derived from the OpEx database described earlier and shown in Figure 3-1 was imported into a Microsoft Excel workbook and further processed to derive the additional parameters listed in Table 4-1.

Table 4-1. Additional Derived Parameters for Data Analysis

Additional Derived Parameters	Definitions
Average turbine availability	Average turbine availability, in which overall (site) availability is used to fill missing records, where possible
Average site availability	Average overall (site) availability, in which turbine availability is used to fill missing records, where possible
Project size for availability (megawatts [MW])	Total MW of installed projects
# turbines for availability	Number of turbines for which the database has availability
Production per MW	Annual production divided by total project size (MWh/MW)
Installed capacity (MW)	Installed capacity
IEC class	Category defining the IEC class for which the turbine model was designed
Total operating cost per MW	Annual average total OpEx (sum of turbine+BOP+soft costs) divided by the project capacity
Total operating cost per turbine	Annual average total OpEx (sum of turbine+BOP+soft costs) divided by the number of turbines at a project
Total # of component replacements	Total annual major component replacements (blades+gearbox+generator+main bearing+transformer)
Cost per replacement	Total annual OpEx divided by total # of component replacements
Blades per 100 turbines	Number of blade replacements per 100 turbines
Gearboxes per 100 turbines	Number of gearbox replacements per 100 turbines
Generator per 100 turbines	Number of generator replacements per 100 turbines
Main bearing per 100 turbines	Number of main bearing replacements per 100 turbines
Total replacements per 100 turbines	Number of blade replacements per 100 turbines
Turbine O&M per MW	Annual turbine O&M divided by project rating
Turbine O&M per turbine	Annual turbine O&M divided by number of turbines in a project
BOP per MW	Annual BOP OpEx divided by project rating
BOP per turbine	Annual BOP OpEx divided by number of turbines in a project
Soft OpEx per MW	Annual Soft OpEx divided by project rating
Soft OpEx per turbine	Annual Soft OpEx divided by number of turbines in a project

From the master table and additional parameters, we developed a series of interactive tables and graphs showing trends in operations-related metrics throughout the lives of wind projects. The user can elect to bin the data according to project size, turbine rating, or IEC class.

Prior to deriving the results tables, the MasterQueryFromAccess table was filtered to remove partial years of data. Care was taken to ensure that in cases where OpEx or availability data were missing, or in other instances of partial records, the empty cells were ignored when calculating statistics.

The final results tables and charts were organized into the OpEx-Replacements-Availability-Trends (ORAT) workbook,[1] which consists of eight worksheets as follows:

- **Notes**. General notes about the ORAT workbook and how to use it.
- **MasterQueryTable-Definitions**. Tables listing definitions of all of the parameters used in the MasterQueryFromAccess table, as well as the additional derived parameters. Also includes a table defining the bin sizes for classifying the data.
- Three worksheets include tables and charts showing component replacements, OpEx, availability, and production data over a project's life:
  - QueryA-ProjSize–interactive tables, filtered by project size
  - QueryB-Rating–interactive tables, filtered by turbine rating
  - QueryC-IEC–interactive tables, filtered by IEC Class
- Three worksheets provide summary statistics (max, min, mean, and one-standard deviation error bars on the mean):
  - Stats-OpEx–statistics on turbine, BOP, soft and total OpEx
  - Stats-Replacements–statistics on blade, gearbox, generator, and main bearing replacements
  - Stats-Availability–statistics on turbine and overall availability.

[1] This workbook is available from NREL upon request.

5 Results

As described in Section 4, the ORAT workbook that accompanies this report (upon request) and is an additional deliverable for this project enables the user to interactively view trends in the data over time, as well as the statistical variability of the data set. The database, though somewhat limited in volume, is sufficient for making preliminary observations about the historical trends in project operations, costs, and availability. It provides tables and charts of aggregated OpEx, component replacement, and availability data that allow the user to examine trends over time based on project size, turbine size, IEC class, and project age as defined in the classification matrix shown in Table 2-6. The following sections present some initial results.

5.1 O&M Cost/Availability/Component Replacements Summary

Figure 5-1 and Figure 5-2 show the number of component replacements that occur each year per 100 MW and as a percentage of total units, respectively, for all projects in the database. Five major components were tracked in the database, and four are shown in the charts: blades, gearbox, generator, and main bearing. The fifth, uptower transformers, is not shown in the charts because the data set contained a negligible number of uptower transformer replacements. For each component, total replacements in each year of operation were tallied. The blue vertical bars in Figure 5-1 indicate the total installed megawatts for each year of operation. Data for years one through three are pulled from an annual average of 2 GW of installed capacity, which represents approximately 5% to 10% of the installed capacity in the United States over the data recording period from 2005 to 2010. In years 6-10, the data are sourced from an average installed capacity of 550 MW, also representing approximately 5% to 10% of the installed capacity in the United States for projects of that vintage.

Beyond year 10 the total installed capacity drops to 100 MW, which represents approximately 5% of the total installed capacity of projects with more than 10 years of operation. Although on a relative basis the percent of projects represented in this database is similar over time, the small absolute sample size beyond year 10 is insufficient to draw meaningful conclusions at this time. The green vertical lines in Figure 5-2 show the corresponding number of turbines represented in each year of project life, which ranges from approximately 1,600 turbines during operating years one through three down to 80 in year 13, again emphasizing that results from later years of operation (i.e., older projects) have a high degree of uncertainty. This uncertainty can only be mitigated by incorporating more long-term project data into the database. Each of the graphs presented below includes an indication of how much data was available for each operating year.

The graphs below include all the data in the ORAT (all projects). This report focuses on what the database is revealing as a whole in terms of general trends, and leaves further investigation into trends with project size or turbine rating for future reporting.

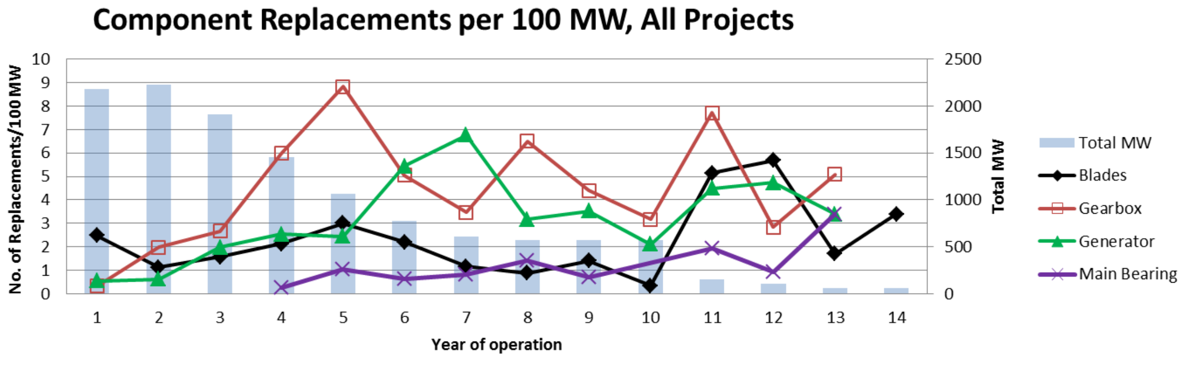

Figure 5-1. Total component replacements per 100 MW for all projects in the database

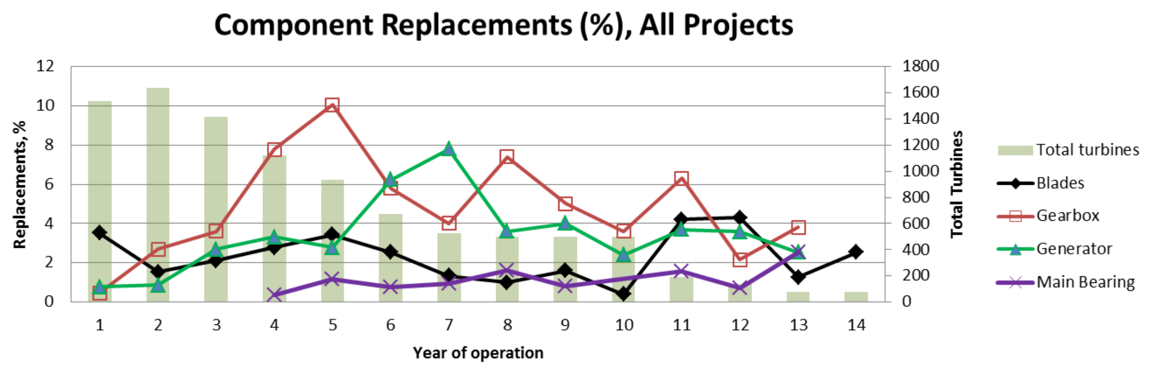

Figure 5-2. Total component replacements per 100 turbines (%) for all projects in the database

Because of the uncertainties resulting from the limited number of records beyond year 10, observations regarding trends in O&M costs, component replacements, and availability are limited to the first decade of operation. Figure 5-1 and Figure 5-2 show that gearbox replacements peak in years five and eight, after which they appear to decrease gradually over time (on a per-turbine basis). The peak in year five coincides with the EOW for many of the projects in the database, suggesting that peak gearbox replacement and the EOW are related. Generator replacements increase through year seven and then begin to decrease. When examined on a per-turbine basis, however, generator replacements are more or less constant from year eight. Figure 5-3 shows the average turbine rating in the database over time. The downward trend indicates that older projects in the database are equipped with smaller turbines, and because the average rating of the older turbines is less than 1 MW, the component replacement rate per turbine is lower than the replacement rate per MW. Over time, if more data from land-based wind projects are added to this database, the overall average turbine rating over the entire project life will increase, because turbine sizes have been increasing. Thus, relative trends per turbine would also shift.

Blade replacements shown in Figure 5-1 and Figure 5-2 indicate some initial replacement activity very early in life, then an increasing trend through year five to an average of four blade replacements per 100 turbines, then decreasing over the next 5 years to one replacement per 100 turbines. Blade replacements increase again in years 11 and 12. Main bearing replacements did not show up until year four, after which they gradually increased to two per 100 turbines per year by year 13.

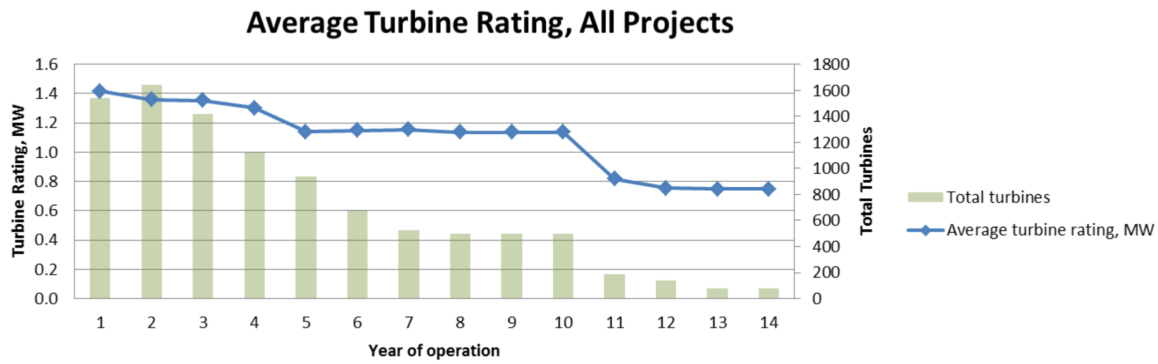

Figure 5-3. Average turbine rating, all projects

Looking at the component replacement data in aggregate in Figure 5-4 and Figure 5-5 we see similar trends. With the exception of blades, the percentage of major component replacements is relatively low in the first 2 years of project life (see Figure 5-4). Current owners/operators expressed some surprise at the low failure rates in the first 2 years of operation. The low replacement rates may be the result of new equipment, or it may reflect a lack of reporting by OEMs when turbines are under warranty. After year two replacements increase and peak to approximately 16% in year five, mainly driven by gearbox failures. Year five coincides also with the EOW for the majority of projects in the database. Project owners often hire an independent third party to conduct EOW inspections of the turbines 6 to 9 months prior to expiration. It is speculated that the high number of replacements near the EOW may be the result of EOW inspection findings resulting in warranty claims. Beyond year 10 there are insufficient data to identify a trend with any certainty.

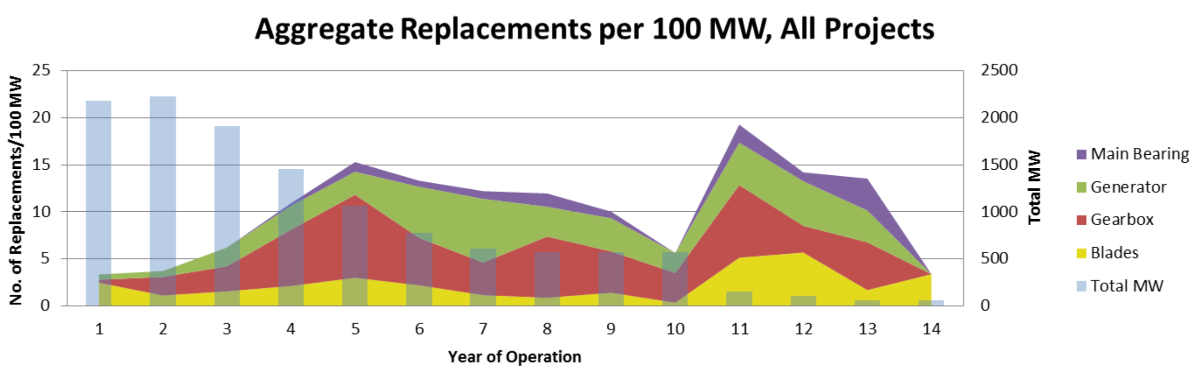

Figure 5-4. Aggregate replacements per 100 MW for all projects in the database

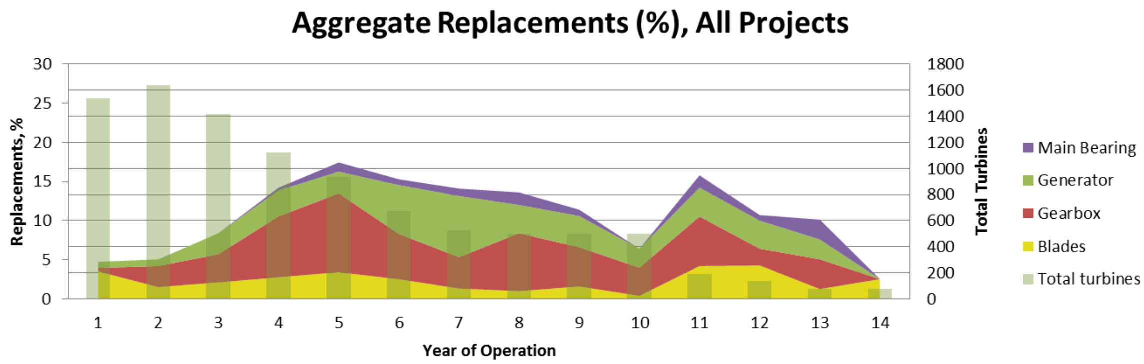

Figure 5-5. Aggregate replacements (%) for all projects in the database

The OpEx for each project is plotted in Figure 5-6 and Figure 5-7. The turbine and soft costs are generally of similar magnitude, and show a gradual increase over time when looked at on a per-MW basis, but remain constant or decrease slightly when looked at on a per-turbine basis because the average turbine rating decreases to below 1 MW after year 10. BOP costs are significantly below the turbine and soft costs, and show a decreasing trend over project life; however, given the lack of OpEx data beyond year nine, it is premature to conclude whether these lower costs are typical, or simply a function of the particular long-term data used in this study.

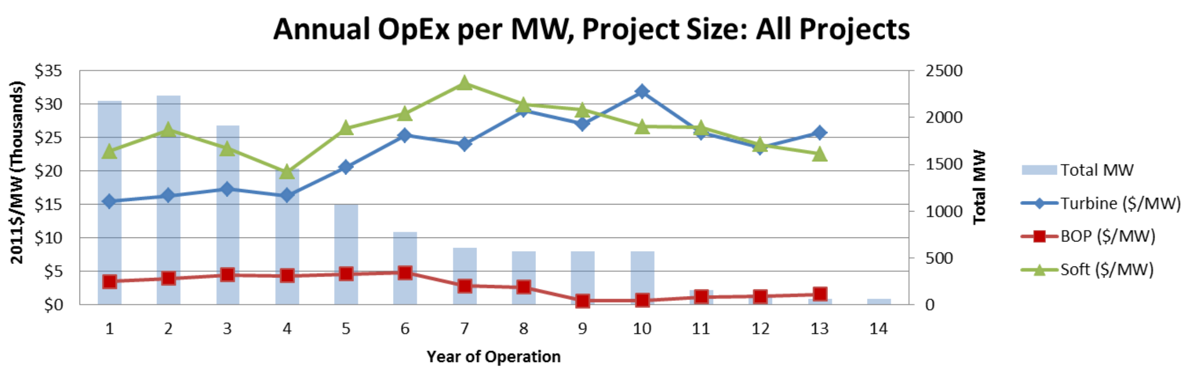

Figure 5-6. OpEx per MW for all projects

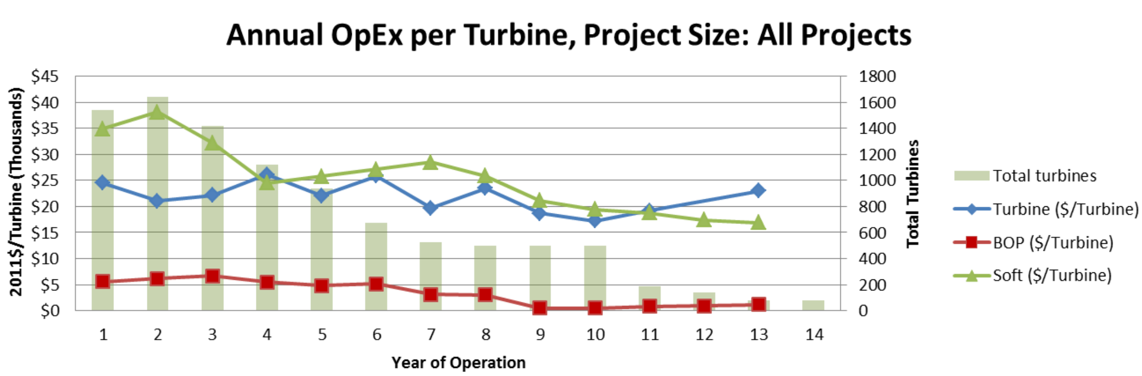

Figure 5-7. OpEx per turbine for all projects

The total OpEx per turbine is shown in Figure 5-8 and Figure 5-9. In Figure 5-8, total OpEx per MW is fairly constant at $40,000 per MW during the first 4 years of project life, increasing to $50,000 per MW by year six and remaining fairly constant through year 13, which is the oldest date for which we had data. When looked at on a per-turbine basis (Figure 5-9), total average OpEx starts at $60,000 per turbine during the first few years (which also corresponds to the warranty period) and appears to decrease over the turbine life. This apparent reduction does not suggest that for a given turbine model OpEx will decrease over the project life, but rather that in this database the projects that are the oldest also have considerably smaller turbine models with correspondingly lower OpEx per turbine. Taking both Figure 5-8 and Figure 5-9 together would suggest that OpEx costs for a specific turbine model are likely to rise somewhat over the life of the project.

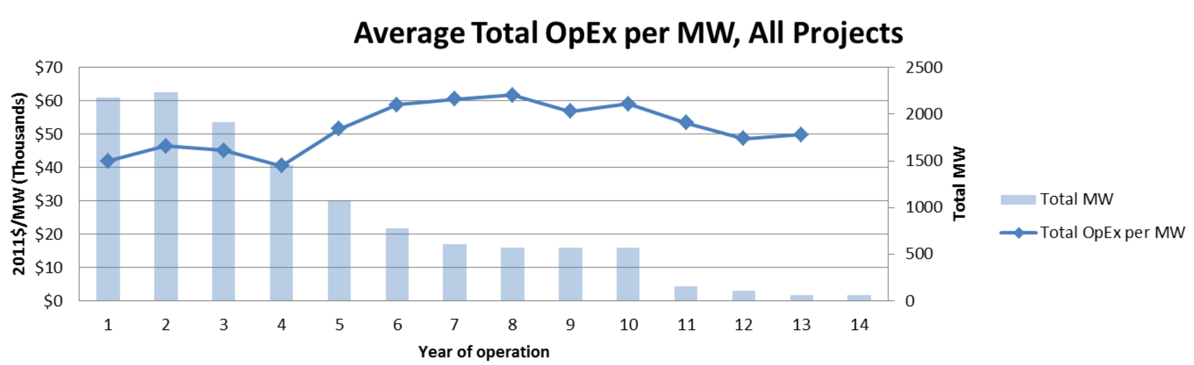

Figure 5-8. Average total OpEx per MW, all projects

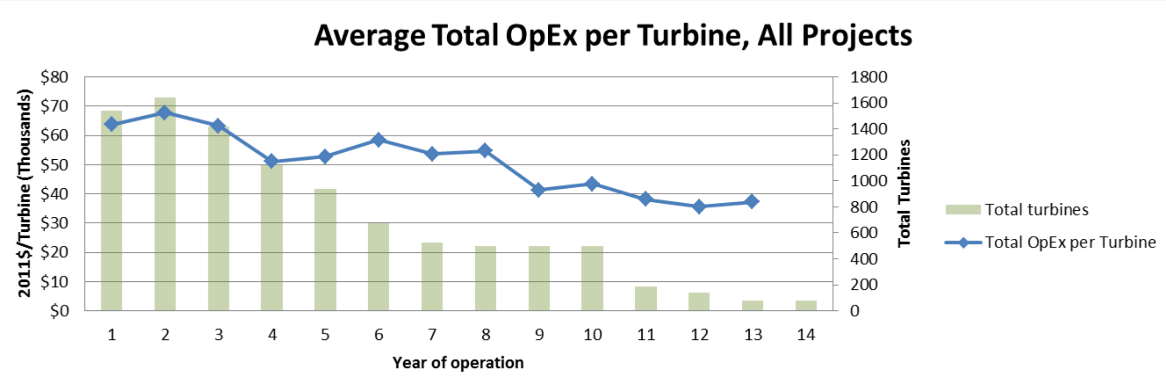

Figure 5-9. Average total OpEx per turbine, all projects

The OpEx data in the database do not specify explicit component replacement costs; however, by dividing turbine O&M per year by the total number of component replacements per year—for all five component types—we gained some insight into average (total) component replacement costs. The results are plotted in Figure 5-10. In years one and two, the turbine O&M per replacement averages $600,000, which is significantly more than in subsequent years where it drops to approximately $200,000 to $300,000 per replacement. The high average costs per event in years one and two evidently reflect the fact that new machines tend not to experience very many failures, with the exception of a serial failure or other "teething pains." In addition, many turbines are under warranty for at least the first 2 years of the project life, so the warranty fee or service maintenance fee is paid whether or not failures occur. Note that the average cost per replacement does not represent the actual cost to replace a particular component, but simply gives the average turbine O&M per replacement.

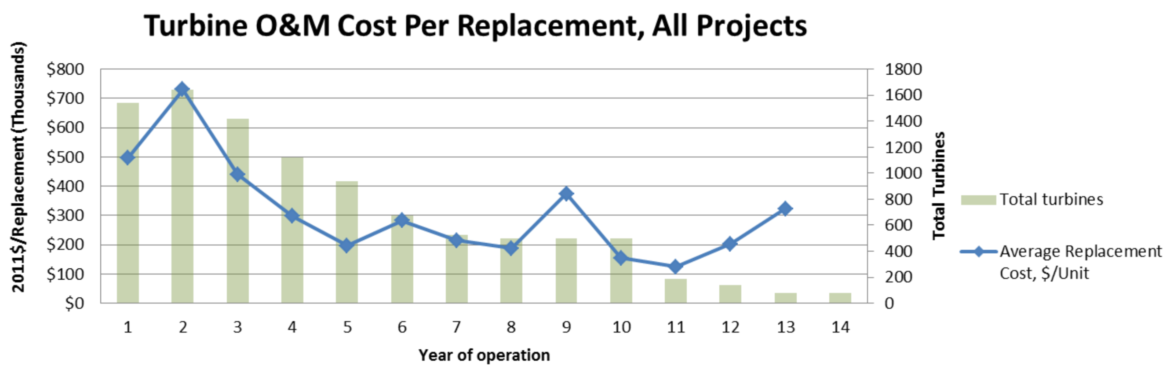

Figure 5-10. Average turbine O&M cost per replacement, all projects

In addition to examining OpEx as a function of operating year, we also looked at OpEx as a function of installation date to learn, for example, whether it is more or less expensive to maintain a project installed in 2007 compared to one installed in 2000. Figure 5-11 shows average OpEx per MW as a function of COD. The vertical bars show the number of project years of data reporting for each COD year. BOP costs have not changed significantly for more recent projects, and soft costs appear to have fallen in the early 2000s, but have risen since 2005. Turbine O&M, however, seems to have declined nearly every year from 1999 to 2008. Overall, average total OpEx has been more or less steady since 2003, but the distribution of cost seems to be shifting away from turbine O&M and toward soft costs. Figure 5-11 shows no data for 2002 because none of the projects in the database had a COD in that year.

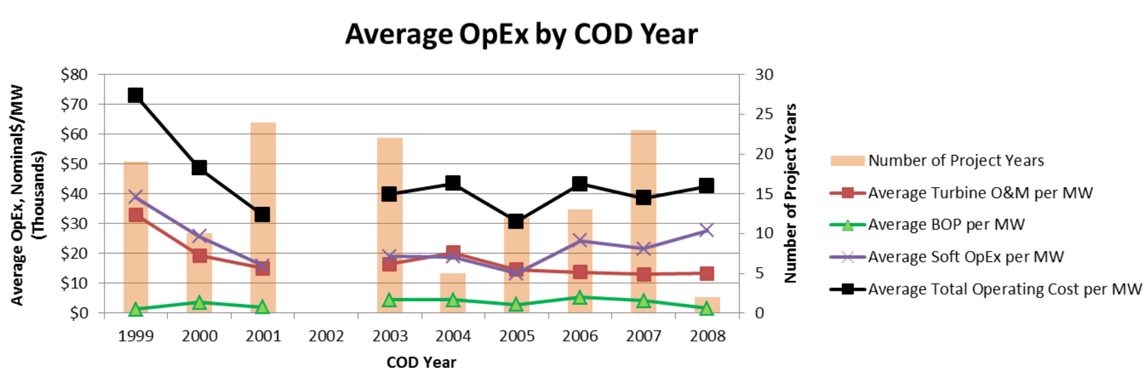

Figure 5-11. Average OpEx by COD

The trends in availability and production are shown in Figure 5-12 and Figure 5-13. Availability data in this study were limited to the 30 projects, for which we also had OpEx and component replacement data, and indicate somewhat lower turbine and overall availability during the first 11 years of operation than we have observed from wider availability studies. Beyond year 11 availability appears to jump considerably; however, as mentioned previously the small sample size is not representative. Some projects reported only turbine availability, and other projects reported only overall (site) availability. In those cases, the reported availability was used for both turbine and site availability. Consequently, turbine availability in Figure 5-12 is lower than the actual, whereas overall availability is higher than the actual. Adding more availability data to the database, where both turbine and overall availability are provided for each project, will improve the accuracy and decrease uncertainty in availability trends over project operating life.

Figure 5-12. Annual average project availability, all projects

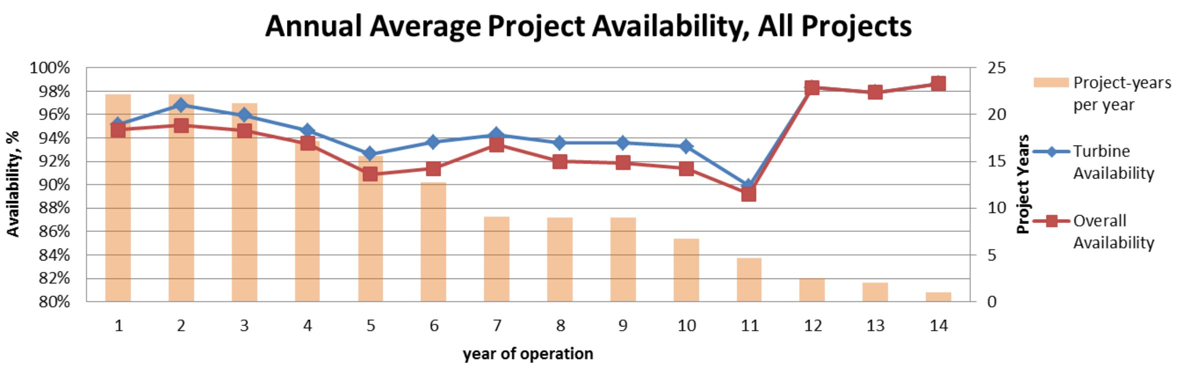

Figure 5-12. Annual average project availability, all projects

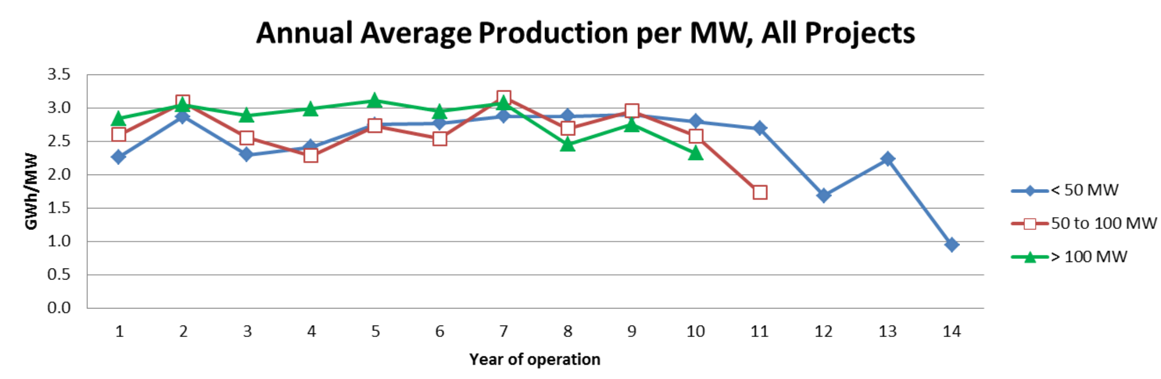

Figure 5-13. Annual average production per MW, all projects

Figure 5-13 shows annual average production per megawatt, where the data have been split out by project size. There is not a clear impact of project size on production per MW, but after year nine all project sizes evidently are trending less productive. This is generally in line with the decrease in availability through year 11 (shown in Figure 5-12).

Several trends can be gleaned from the results shown above. First, the component replacement data (Figure 5-4 through Figure 5-5) show two periods of increased activity, the first occurring around year five (corresponding to the EOW), driven by gearbox replacements, and the second occurring around year 11, driven by both gearbox and blade replacements. Second, the gradual downward trend in availability over the first decade of operation (Figure 5-12) corresponds approximately with the gradual decrease in average production over time, as seen in Figure 5-13. This trend also corresponds to a gradual increase in OpEx per MW over project life (shown in Figure 5-8). Taken together, these trends suggest that the cost of energy on average increases over the life of a project.

Looking at the total OpEx per turbine shown in Figure 5-9, along with turbine rating in Figure 5-3, we see that total OpEx costs correlate with average turbine rating.

5.2 Statistical Analysis Results

In addition to the summary graphs shown above, we also conducted a statistical analysis of several parameters (on a per project basis) to shed light on the variability and scatter in the data. Each plot below includes the mean (simple average), maximum, and minimum as well as error bars indicating ±1- standard deviation. Because it is not possible for any of the parameters to be less than zero, all minima and error bounds are truncated at zero.

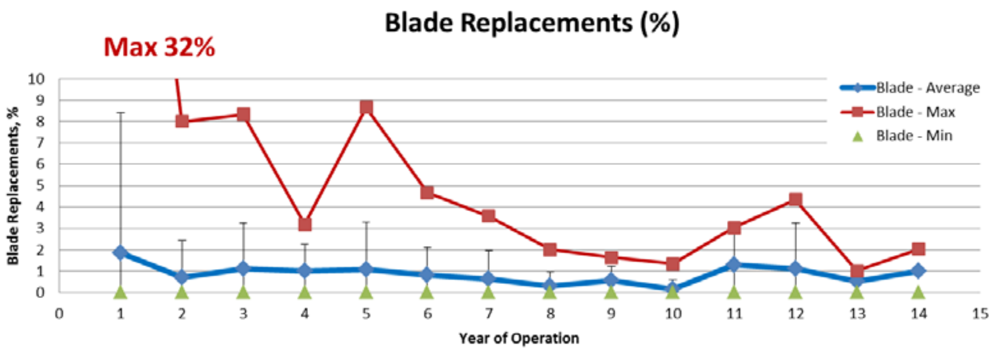

Figure 5-14. Blade replacements (%): maximum, mean, minimum, and one-standard deviation (error bars)[2]

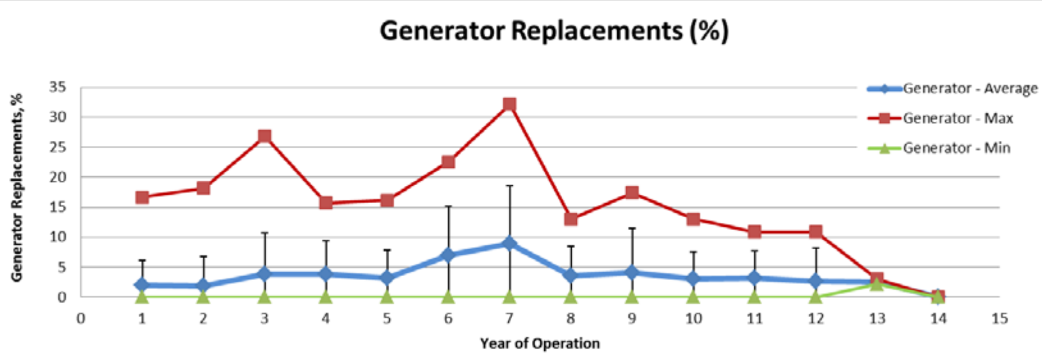

Figure 5-15. Generator replacements (%): maximum, mean, minimum, one-standard deviation (error bars)

[2] The max blade replacement percentage of 32% is reported for year one of operation; this value exceeds the 10% maximum set value for the y-axis to maintain visibility of blade replacement trends over the years of operation.

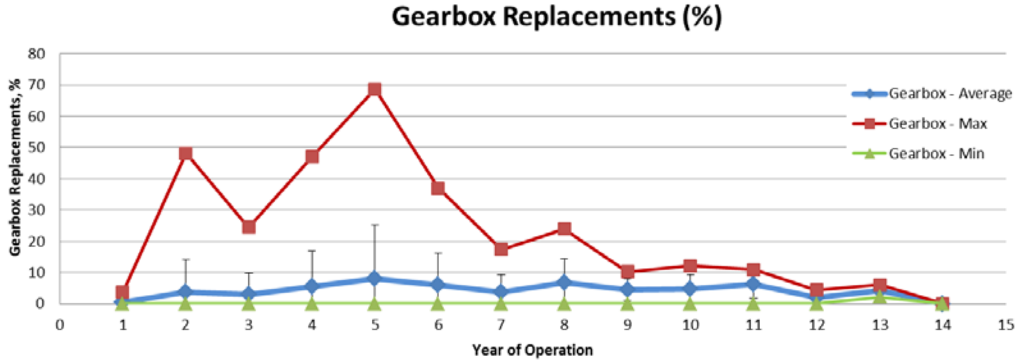

Figure 5-16. Gearbox replacements (%): maximum, mean, minimum, one-standard deviation (error bars)

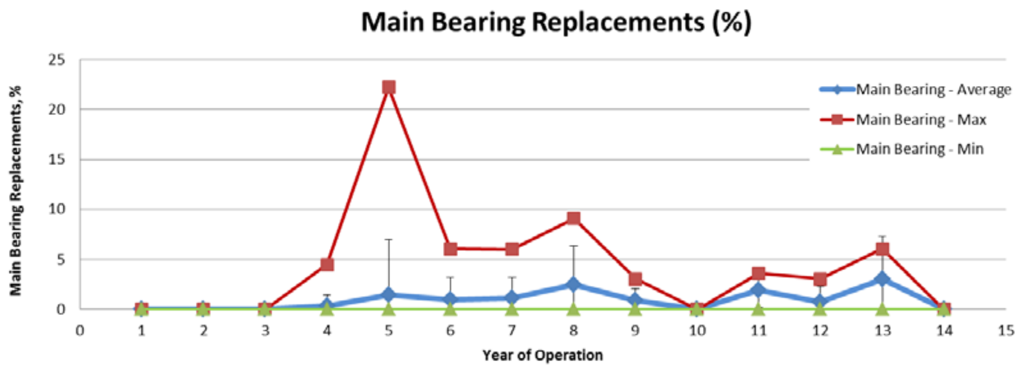

Figure 5-17. Main bearing replacements (%): maximum, mean, minimum, and one-standard deviation (error bars)

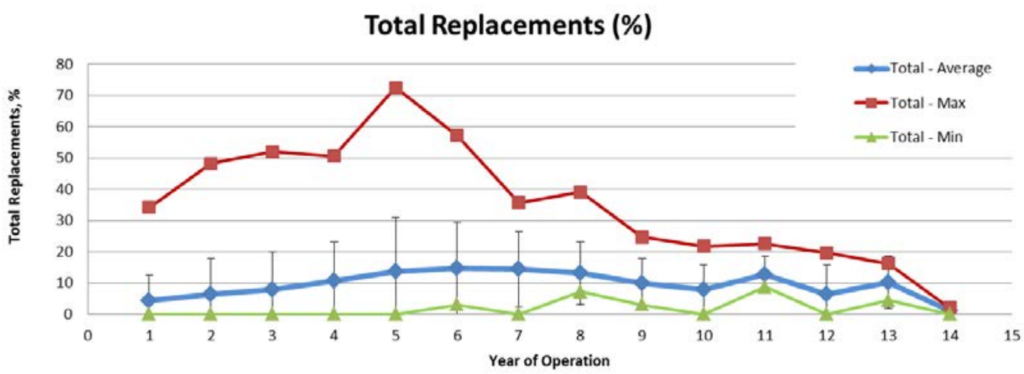

Figure 5-18. Total replacements (%): maximum, mean, minimum, one-standard deviation (error bars)

The statistics on blade replacements (Figure 5-14), generator replacements (Figure 5-15), gearbox replacements (Figure 5-16), and main bearing replacements (Figure 5-17) indicate considerable variability in failure rates from project to project. The standard deviation provides a measure of how anomalous the maximum/minimum values are. For example, the project with the maximum blade failures in year one replaced 32% of blades in just that single year, whereas in the average project 2% of blades were replaced in year one, with a standard deviation of about three times the average.

Figure 5-18 shows that variability of total component replacements appears to decrease with project life, but Figure 5-19 shows that the pool of data as project age increases was very small.

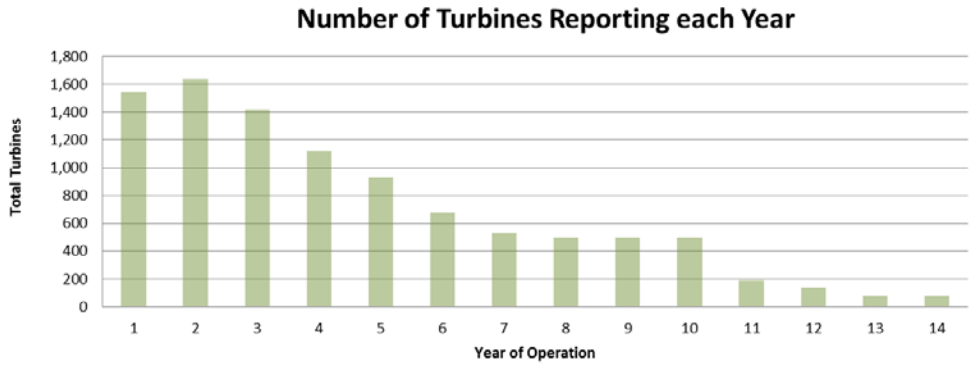

Figure 5-19. Number of turbines included in the statistical analysis of component replacements

Summary statistics of the operational expenses, including maximum, minimum, mean and error bars showing the one-standard deviation are presented in Figure 5-20 through Figure 5-23. Total OpEx costs are dominated by the turbine and soft costs. Figure 5-20 and Figure 5-23 show a bump in turbine O&M costs in years six, eight, and 10. The increase in year six may be a result of the high level of component replacement that occurs in year five, because costs may not accrue precisely at the time of replacement.

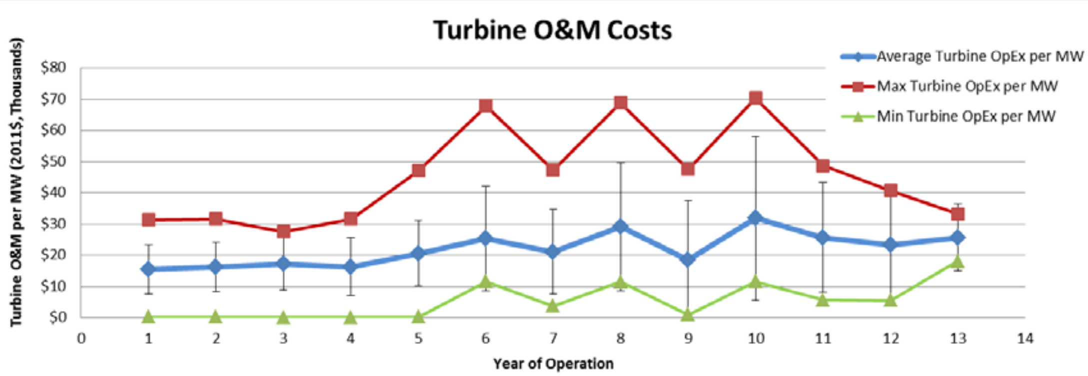

Figure 5-20. Turbine O&M costs per MW: maximum, mean, minimum, one-standard deviation (error bars)

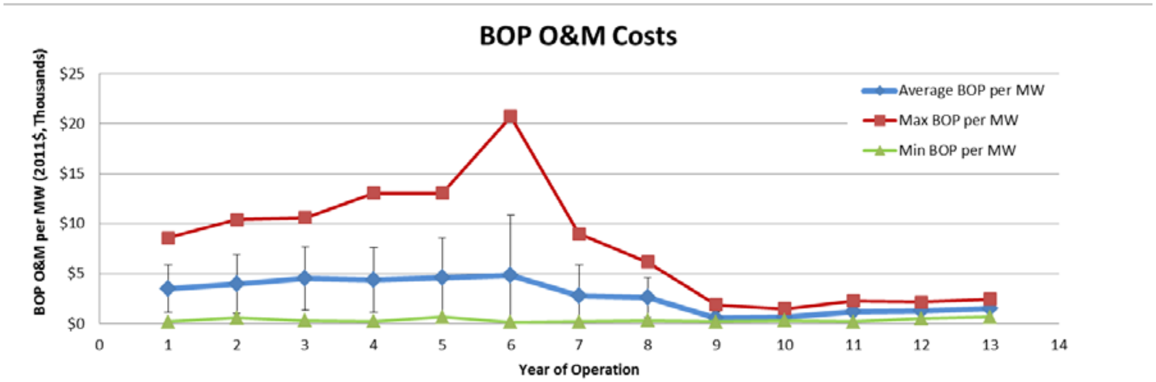

Figure 5-21. BOP O&M costs per MW: maximum, mean, minimum, one-standard deviation (error bars)

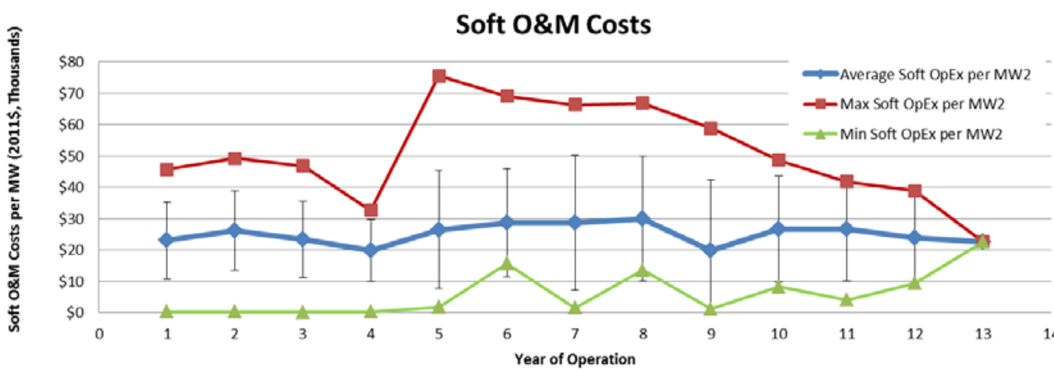

Figure 5-22. Soft O&M costs per MW: maximum, mean, minimum, one-standard deviation (error bars)

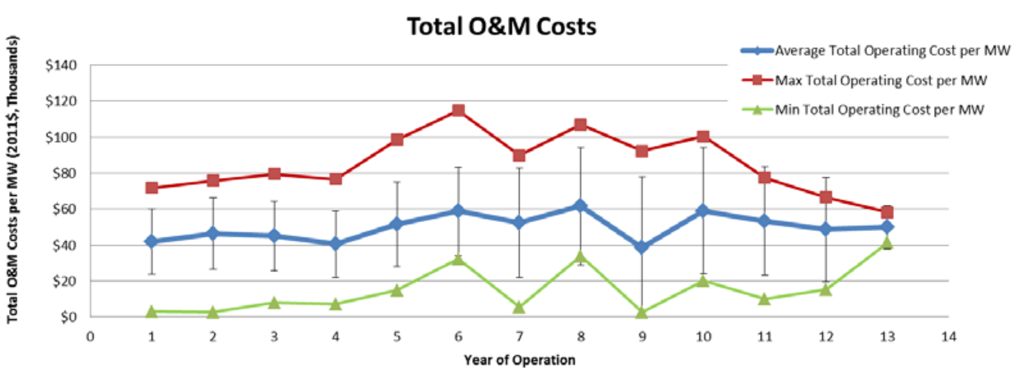

Figure 5-23. Total O&M costs per MW: maximum, mean, minimum, one-standard deviation (error bars)

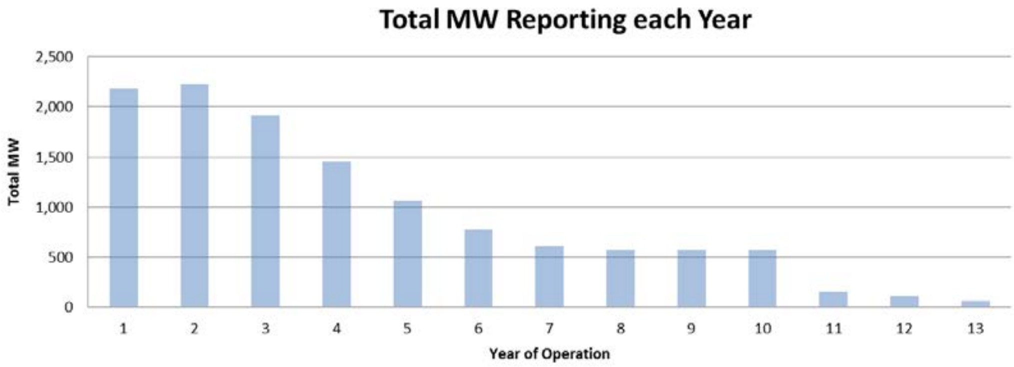

Figure 5-24. Total megawatts included in the statistical analysis of OpEx

Figure 5-25 and Figure 5-26 show summary statistics for turbine and overall availability. In this case, availability cannot exceed 100%, but of course performance can fall well below the mean. Interestingly, the biggest decreases in availability occur in years five and 11, which also correspond to the years with the greatest number of component replacements.

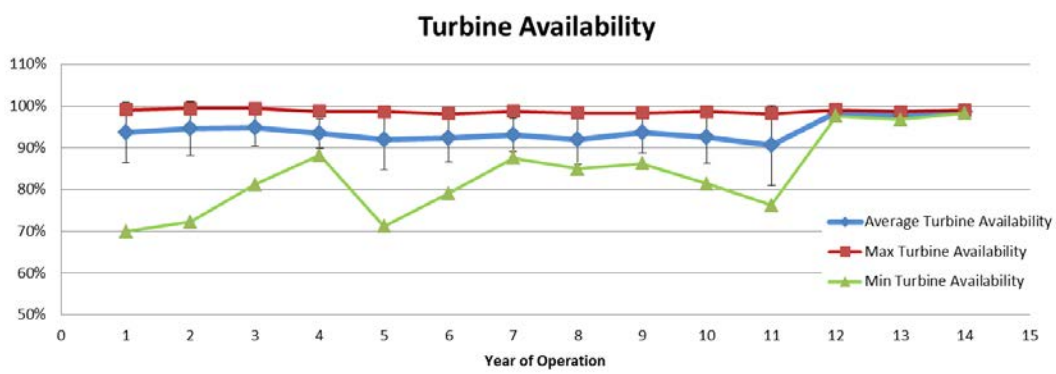

Figure 5-25. Turbine availability: maximum, mean, minimum, one-standard deviation (error bars)

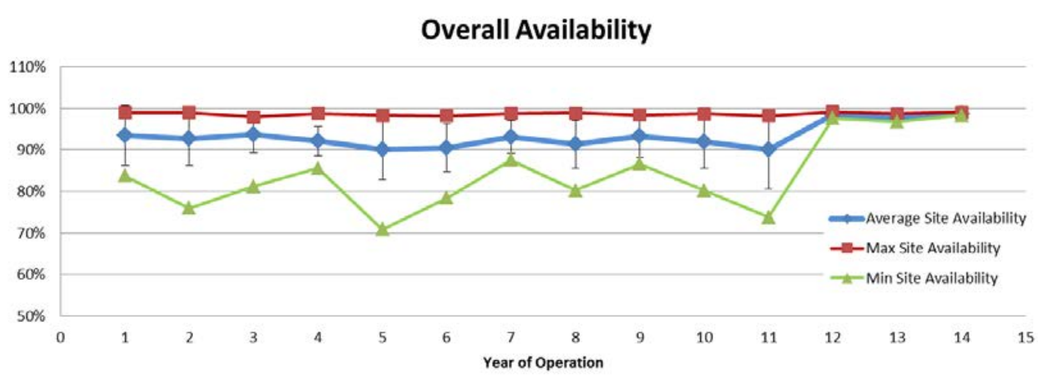

Figure 5-26. Overall availability: maximum, mean, minimum, one-standard deviation (error bars)

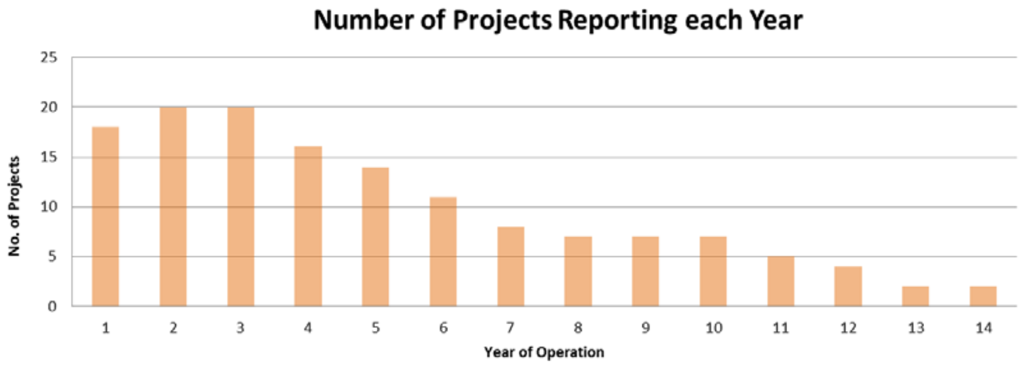

Figure 5-27. Total number of projects included in the statistical analysis of availability

In summary, although the database has known uncertainties and limitations, the statistical analysis reveals the potential for trends and correlations among the OpEx, replacement, and availability data for these projects.

5.3 Summary of Responses to Qualitative Questions

To gain insight into other factors that have or will influence OpEx in the future, DNV KEMA asked wind project owners/operators a series of questions regarding their experience with O&M and related costs. Surveys were distributed to operators controlling over 21 GW of installed wind power in North America, representing 30%–35% of the U.S. wind market share. Operators included both utilities and developers/owners/operators. Only 50% of those polled responded to the survey. Although this response was less than anticipated, DNV KEMA believes that the results from this survey provided some useful insights that helped evaluate the trends seen in the historical data, and whether these trends are consistent with the survey respondents' observations. Below is an aggregated summary of the responses.

1. How has condition monitoring (CM) impacted OpEx? How is CM expected to affect OpEx in the future? What does the initial evidence suggest with respect to new low wind speed technology?
    - The general consensus by all who took the survey was that CM is generally seen as beneficial, whether it actually reduces OpEx or not.
    - Some estimated a 2-year payback. Savings are primarily the result of doing uptower repairs versus having to do a complete retrofit or replacement that requires the use of a crane.
    - Other operators are skeptical that CM saves on repairs, and see the early detection of problems as leading to premature repairs/replacement. Also, many problems are detected by means of a good preventive maintenance (PM) program and so do not need to rely on CM monitoring.
    - CM facilitates better planned maintenance, thus avoiding unplanned maintenance.
    - Others say OpEx costs are driven more by logistics than CM—particularly the availability of parts.

- Some operators have retrofitted their fleet, or a portion of their fleet, with CM systems and are seeing sufficient benefits that they may install more.
- Average cost to retrofit has dropped to $5,000–$6,000 per turbine.
- Vibration and temperature (e.g., main bearing) are monitored.
- One suggestion was to pose this question again in 5 years, asking each project operator what they would have done differently without CM.

2. How have more advanced turbine designs impacted OpEx? For example, does initial evidence suggest that new low wind speed technology impacts OpEx, and if so, how?
    - Some operators see lower OpEx as a result of the more advanced (newer) turbine designs.
    - Newer turbines tend to be easier to maintain and have higher reliability.
    - The new technologies appear to have fewer gearbox failures and blade problems.
    - Operators are definitely seeing the results of improved design—different heat treatment of major components (such as the main shaft), the use of off-line filtration, and better lubrication.
    - On the other hand, machines are getting more complicated, particularly the control systems. Complexity leads to additional training requirements for technicians, which can increase OpEx costs. Also, increased complexity can result in reduced reliability.
    - For low-wind speeds, the turbine designs are improved but the overall impact on OpEx is not yet clear.
    - For low-wind turbines, operators adjust OpEx estimates for blades.
3. What has been the primary cause of missed OpEx estimates or forecasts? Why (or why not) have initial industry estimates changed over time?
    - For some owner/operators, budget forecasts are not an issue because their projects are either still under warranty or they have service maintenance contracts in place, so their costs are known.
    - Major cause of missed estimates is unexpected major maintenance, such as premature component failures.
    - Other causes include lack of useful data when developing the budget, or lack of meaningful failure data from OEMs when turbines are transitioning off of warranty.
    - For better budgeting, some operators use Weibull curves to establish failure rates.

4. In the post-warranty period, can discretionary OpEx be used to reduce downtime? (i.e., does higher OpEx yield less downtime and result in a cost of energy benefit)?
    - Some operators implement improvements that either expand the life of components or reduce downtime.
    - There is an inflection point, but some operators only offer one level of service, so they are not developing customized schemes to achieve certain outcomes.
    - Some operators have developed simple tools (Microsoft Excel) to assess issues and adjust criteria for when to call out a maintenance action, such as increasing blade maintenance and repairs; however, there is a point of diminishing returns on using OpEx to reduce downtime.
    - Setting up service agreements with incentives that drive maintenance strategy (e.g., timing of service actions) to improve energy production is very effective.
5. How do these trends vary regionally, and what are the primary drivers of regional variability (e.g., workforce, wind resource, surface cover)?
    - The labor force varies regionally. For example, it can be difficult to find workers in the southwestern United States.
    - Operators with projects in many regions notice higher OpEx in areas with high incidence of lightning, or coastal areas where corrosion is an issue. Mountainous regions have higher OpEx because of extreme wind shear and turbulence. Operators now include such regional factors in their O&M models.
    - Other operators do not see any significant regional impacts other than weather-related variables (e.g., snow).
    - Operators do not see regional impacts on OpEx resulting from crane or spare part availability.
6. What strategies are currently being used to minimize operating, maintenance, and replacement costs and/or maximize availability? How have OpEx strategies evolved over time (i.e., owner/operator services, third-party contractor services, OEM services, insurance providers)?
    - Strategies have evolved from run-to-failure (RTF) mode to preventative maintenance mode.
    - A key step has been to align goals between the project owner and the service provider.
    - One trend has been the move from time-based to energy/yield-based availability.
    - Now, all maintenance is proactive condition-based monitoring, including vibration/oil analysis, data-oriented system monitoring, and regular borescoping and other inspections.
    - CM program, performance monitoring, 24/7 monitoring of turbine status, remote reset of turbines—all these efforts to automate and monitor the turbines reduces operating costs.

- Advantages of self-operating are not completely obvious. During the transition from warranty to post-warranty there is a knowledge gap that takes time and training to fill.
- Lowering OpEx is not always the driving factor. For some operators, well-trained technicians who are familiar with the technology are preferable to a lower-cost third-party provider that may deliver fewer services.

7. Have perceptions of technology reliability or lack thereof been reflected in the weighted average cost of capital or the cost of debt and equity for more recent projects?
    - There is a cost premium for top-of-the-line turbine technology, but cost of capital is definitely reduced.
    - For less-reliable turbine models, lenders require a letter of credit and may impose higher costs for debt or equity financing.
    - Proven technology is easier to finance than unproven technology. For large owner/operators who have access to their own capital, this may be less of an issue.

8. Other observations?
    - Since 2008, independent service providers have been getting squeezed on cost, mainly because of increased competition.
    - OEMs are also experiencing more competition, which is driving them to lower their costs and provide longer terms for warranties and service contracts.
    - Service is becoming more of a commodity, where the lowest price wins. This can be good for an owner/operator, although in some cases you get what you pay for.
    - Taken together, these trends suggest that OpEx cost per kilowatt may be decreasing for newer projects.

6 Conclusions

DNV KEMA developed a database of operational expenditures, component replacements, and availability for a representative sample of empirical wind project data from 30 North American wind projects totaling 2.5 GW of installed power and ranging from 2 to 14 years old. A total of 16 different turbine models were represented, with rated power ranging from 600 kW to 3.0 MW. In all, the database includes over 1,800 months of O&M, cost, and availability data spanning 150 project years. In addition, DNV KEMA created ORAT, a database analysis tool, which can be used to explore the trends and correlations among OpEx, component replacements, and availability. The ORAT workbook contains no proprietary operating data.

The workbook has been designed to enhance the understanding of whether factors such as project size or technological advancements have impacted project OpEx. It has been set up to filter data by project size, turbine rating, and IEC class. In addition, the results show trends of evolving turbine technology over project life. Following the analysis of the data set used for this study DNV KEMA concluded the following:

- The database and ORAT workbook can serve as a useful starting point to inform modeling efforts designed to quantify the impact of future technological advancements on wind energy OpEx. The data set implemented during the course of this study does have limitations, however, they are a result of the lack of data for the second decade of operations.
- The ORAT workbook provides a means of exploring empirical OpEx data from a large data set of operating wind power plants in the United States and provides significant insights into some of the variables that impact annual OpEx. Some of those insights include:
    - In the first decade of operation, component replacements peak in operating year five, which coincides with the EOW for the majority of the projects in the database. The OpEx per-turbine data show a corresponding increase in OpEx in year five.
    - Availability as well as overall production display a gradual decline starting in year three and extending past the first decade of operation. Availability also dips in year five, which may be a consequence of the increased component replacements. Beyond year 10 the trend is uncertain because of limited data.
    - The summary statistics indicate considerable variability in OpEx among the different projects.
- Additional and more detailed empirical OpEx data tied to specific operating and maintenance events such as scheduled and unscheduled actions, fixed versus variable costs, and cost of major component replacement/repair, would help improve the accuracy and utility of the ORAT workbook. Such detailed OpEx data was either not consistently reported or not available for this project.
- The proprietary database is designed to receive and analyze additional data as it becomes available. More data beyond operating year 10 is needed to evaluate trends over the entire 20-year project life.

- The survey of current owners/operators revealed that they all find condition monitoring beneficial for improving their O&M monitoring, and many are seeing positive impacts on reducing OpEx.
- Most operators also see improvements in component reliability and lubrication schemes with new, more advanced turbine technology, which is reducing OpEx; however, increased complexity of control systems, which requires more highly-trained technicians, tends to drive OpEx up. Consequently, the impact of advanced turbine technology is not entirely clear.
- Regarding the OpEx database, operators were somewhat skeptical of the high component replacement rates seen in year five, and also of the low component replacement rates in years one and two.
- Those surveyed agreed that turbine O&M and soft costs are of similar magnitude, and both tend to increase over the project life.
- Survey respondents did see the gradual decrease in availability during the first decade of operation as reflective of their experience.

7 Recommendations

In the course of developing the OpEx, component replacement, and availability database and the ORAT workbook, we encountered the following issues that we recommend addressing in any future expansion of this work.

As mentioned several times in this report, DNV KEMA believes very strongly that the database and subsequent analysis capabilities and utility would be greatly improved by incorporating additional OpEx, component replacement, and availability data into the database. The data used in this pilot study covered a wide range of project sizes, turbine sizes, turbine technologies, and length of service of typical wind projects in North America; however, expanding the database would reduce uncertainty by adding many more data records to each data bin and provide insights specific to newer technology installed in more recent years.

DNV KEMA recommends incorporating higher-resolution data into the database, such as more detailed OpEx categories that clearly define scheduled versus unscheduled maintenance and tie costs to specific events like major component replacements.

Culling OpEx and component replacement data from monthly data reports can be an arduous task. Although some automated operations reporting is happening today, DNV KEMA suggests that the wind industry establish mandatory standards, primarily electronic reporting guidelines to facilitate further analysis of operating data.