AWEA Operations & Maintenance Recommended Practices

AMERICAN WIND ENERGY ASSOCIATION | Operations & Maintenance Working Group

AWEA Operation and Maintenance Recommended Practices

May 6, 2013

Produced by the
American Wind Energy Association
Operation and Maintenance Working Group

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ACKNOWLEDGEMENTS

These recommended practices represent decades of experience from the members of the AWEA Operations and Maintenance Working Group and should help bring that expertise, often gained from other industry sectors, to help inform, train and support wind energy technicians and managers in their efforts to improve reliability and project performance. These are, in general, the nuts and bolts of wind energy power plant maintenance and operations. As the industry matures, additional maintenance strategies and operations philosophies will certainly come to the fore, but these basics will always be required knowledge for new technicians and asset managers expanding their areas of responsibility.

The concept was initially developed by the O&M Working Group under the leadership of Michelle Graf of Lubrizol and facilitated by John Dunlop of AWEA. The efforts were kicked off in earnest in 2009 and what we have today is the result of hundreds of hours of volunteer time by many people and we, the current leadership of the working group, wish to thank all of the individuals who have participated so far as well as the companies that continue to allow those personal efforts as well as sharing their technical know-how. Over the years, Cynthia Breitkreuz of GE and Marty Crotty also helped guide the group to where we are today. Listed below is the current permutation of the working group. Again thanks to everyone for their continued support for development of these recommended practices. Please contact any of us if you have questions or comments regarding the working group or these documents. You can also reach out to technology@awea.org with any questions, or to join the Working Group.

AWEA appreciates the technical production assistance provided by AWEA member company O'Neil and Associates. (www.oneil.com).

Thanks again for the efforts and accomplishments,

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VERSION 1.0
AWEA Operation and Maintenance Recommended Practices

FORWARD

By 2013 there were over 45,000 wind turbines installed in the U.S. producing over 60GW of energy, and the prospects are strong that number will exceed 120,000 turbines by 2030. Each of those turbines requires monitoring, control, reporting, routine maintenance and possible repair operations. Many new firms and technicians will begin working in operation and maintenance of wind turbines to ensure they continue to produce clean, reliable, affordable electric power. The AWEA Operation and Maintenance Recommended Practices are intended to provide a baseline for providing those services.

The Operation and Maintenance Recommended Practices (O&M RPs) are not “best” practices nor the *only* procedures that should be followed. They represent the suggestions from experts in the field who have refined their procedures over time. And the preferred procedures in the future will no doubt change with improved communications, technology, materials and experience.

The O&M RPs were initiated and created by members of the AWEA Operation and Maintenance Working Group to ensure that the future wind industry benefits from the experience gained from the past. Individual members donated their time and expertise to document these procedures.

The O&M RPs are organized into eight “chapters” to address the major functions of a wind turbine (rotor, gearbox, generator, structure, overall facility) and its operation (monitoring, reporting and inspection). Individual recommended practices address specific procedures used in each of those areas.

Many other organizations have standards, recommended practices, best practices, etc. that also offer excellent supporting information for effective wind farm operations and maintenance. IEEE (Institute of Electrical and Electronic Engineers), NETA (International Electrical Testing Association), SMRP (Society for Maintenance and Reliability Professionals), AGMA (American Gear Manufacturer’s Association) just to name a few. All of these sources should be reviewed in developing sound maintenance strategies. The recommended practices developed by AWEA volunteers are just that – our best ideas collected to guide, educate and suggest proven methods and technologies to maximize the reliability, efficiency and profitable operation of this developing industry.

SAFETY

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RP 101

WIND TURBINE GEAR LUBRICANT FLUSHING PROCEDURES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

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PURPOSE AND SCOPE

This Recommended Practice discusses the proper methods of wind turbine gearbox flushing and oil conversion procedures to optimize oil change quality and prevent carryover of additives sludge and debris from used oil to new oil.

There are numerous wind turbine gear lubricant oil system types, however this paper will focus on a commonly used lubrication system. The general procedures can easily be adapted to other lubrication systems with similar results.

Base oil types associated with this Recommended Practice are Polyalphaolefin (PAO) and Petroleum oil (mineral oil). Other base oil types are not associated with this paper.

INTRODUCTION

Sludging on internal wind turbine gearbox components is common. If these components are not cleaned or flushed properly during an oil change, the quality of the new gear lubricant is compromised causing poor future performance.

Simply draining and filling a wind turbine gearbox may not be adequate. Doing so might leave deposits which could cause new oil foaming, increased wear such as micropitting, shortened oil life and making oil analysis difficult to interpret due to used gear lubricant additive carryover into the fresh gear lubricant. Specific flushing procedures are required to optimize oil change gear lubricant quality.

FLUSHING PROCEDURES

1. PREPARING THE GEARBOX FOR THE OIL CHANGE.

1.1. Take an oil sample of the current used gear lubricant from the gearbox at the recommended location, following established sampling procedures. All samples should be taken from the same location consistently. Purge the oil sample port to ensure respective sample is taken.

1.2. A cleaner may be added to loosen up dirty or sludgy gearbox deposits and assist in the flushing process. Consult with the oil supplier for direction as to the specific type and proper usage of cleaner.

2. DRAINING THE USED GEAR LUBRICANT FROM THE GEARBOX.

2.1. Take an oil sample.

2.2. Fabricate a drain plug with the correct fitting to adapt to a drain hose. *(See Figure A.)*

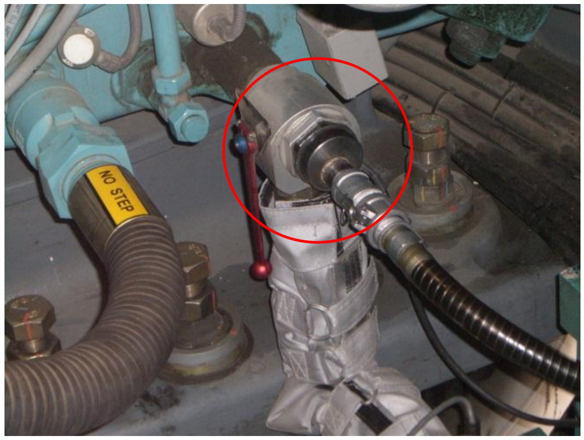

Figure A.

2.3. Connect the used oil hose to the reservoir drain valve.

2.4. Connect this hose to the waste oil tank at the lube truck.

2.5. Start draining the gearbox oil by opening the valve. Draining of used oil is aided by using a pump, vacuum, or both.

2.6. Open the oil filter housing, discard the used oil filter, and thoroughly drain the filter housing.

2.7. Clean the inside of the filter housing by hand. *(See Figure B.)*

Figure B.

2.8. Remove the by-pass pressure release valve and hose next to the gearbox heat exchanger/cooler and drain any oil in the hose*. (See Figure C.)*

Figure C.

2.9. Clean the by-pass pressure release valve by hand with spray cleaner (i.e. Brake Clean).

2.10. Re-install the by-pass pressure release valve and hose next to the gearbox heat exchanger.

2.11. Remove the thermostatic by-pass valve block which is found on the bottom of the filter housing and clean by hand*. (See Figure D.)* Then remove the thermostat assembly from the thermostat block and clean*. (See Figure E.)*

CAUTION: Do not remove the brass pin from the thermostat barrel.

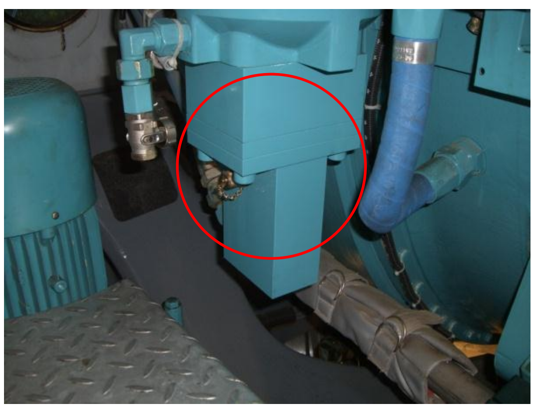

Figure D.

Figure E.

2.12. Re-install the thermostatic by-pass valve assembly and block.

2.13. Remove the hose from the system relief valve located between the filter housing and oil pump and drain any oil from the hose. *(See Figure F.)*

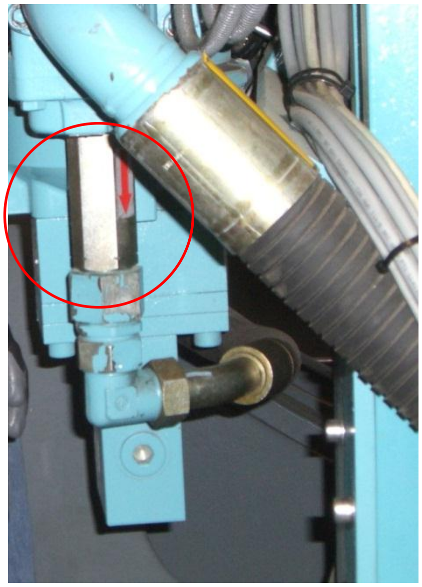

Figure F.

2.14. Remove the system relief valve and clean if needed.

2.15. Re-install the relief valve.

2.16. Remove the 2-inch plug at the top of the gearbox planetary *(See Figure G.)* Purge/spray the gearbox planetary with approximately 5 gallons of new gear lube.

Figure G.

2.17. Re-install the 2-inch plug at the top of the gearbox planetary.

2.18. Continue to drain the oil from the gearbox.

2.19. Through the gearbox inspection cover *(See Figure H)*, purge/spray the interior gearbox housing, gears, bearings and shafts using 5-gallons of new gear lubricant.

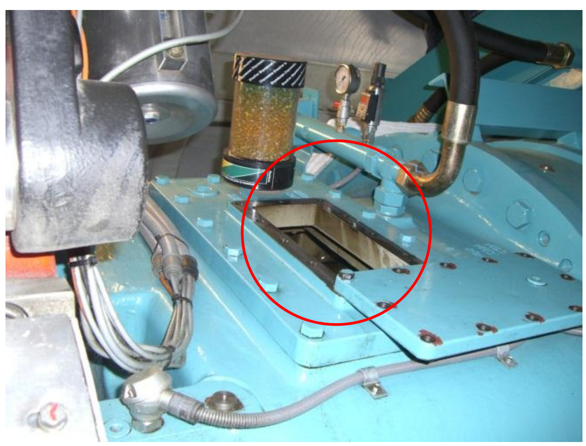

Figure H.

2.20. Continue to drain the oil from the gearbox.

2.21. Close the gearbox drain valve.

2.22. Place a drain pan under the gearbox drain valve and open the valve.

2.23. Use a magnet to swab into the gearbox through the drain port for any metallic wear debris.

2.24. Reconnect the hose to the drain port and open the drain valve.

2.25. Drain the external heater, if so equipped. *(See Figure I.)*

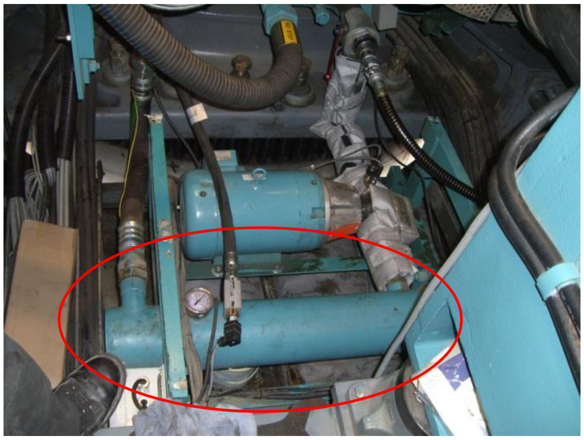

Figure I.

2.26. Disconnect the oil level sensor and clean.

2.27. Take the top of the oil float level housing off and clean out the sensor housing and oil float indicator by hand. *(See Figures J and K.)*

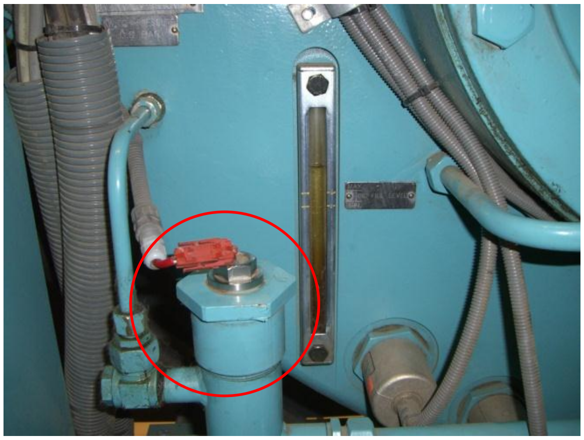

Figure J.

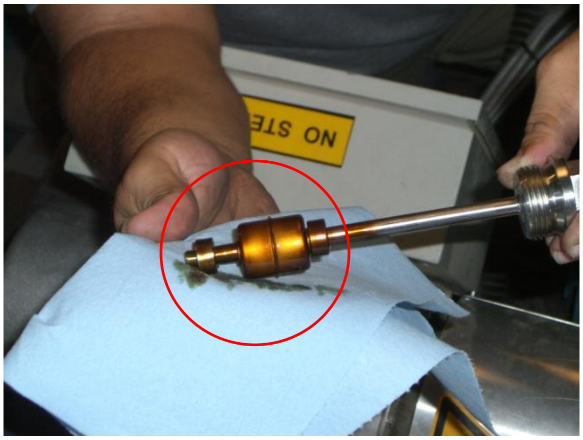

Figure K.

2.28. Install a new gasket for the oil sensor container.

2.29. Re-install the oil level sensor.

2.30. Install a dedicated flush filter. This flush filter can be reused for up to 5 turbine oil changes during the flush and rinse phases only.

2.31. Re-install the gearbox inspection cover.

3. FLUSHING PHASE

3.1. Prior to flushing the gearbox, all oils located on the oil change truck/trailer need to be filtered with a 5 micron filter to keep any possible debris from the lube truck tanks or oil transfer from entering the gearbox.

3.2. Close the gearbox drain valve.

3.3. Fill the gearbox to the recommended oil level with gear lubricant.

3.4. Turn on the heater pump to circulate the oil in the heater sump, if so equipped.

3.5. Turn on the gearbox lubrication pump and let the turbine pinwheel for up to 60 minutes at low speed. This is to be done with NO Load.

3.6. Take a one-quart sample of gear lubricant from the gearbox and label *Flush Sample*, and include turbine number and date on the bottle.

3.7. Repeat Steps 2.5 through 2.31 from *"Draining the Used Gear Lubricant in the Gearbox"* section of this document. Re-clean the bypass pressure release valve, the thermostatic bypass valve block, the system relief valve, and the oil level sensor only as required.

4. RINSING PHASE

4.1. Prior to rinsing the gearbox, all oils located on the oil change truck/trailer need to be filtered with a 5 micron filter to keep any possible debris from the lube truck tanks or oil transfer from entering the gearbox.

4.2. Close the gearbox drain valve.

4.3. Fill the gearbox to the recommended oil level with gear lubricant.

4.4. Turn on the heater pump to circulate the oil in the heater sump, if so equipped.

4.5. Turn on the gearbox lubrication pump and let the turbine pinwheel for up to 30 minutes at low speed. This is to be done with NO Load.

4.6. Take a one-quart sample of gear lubricant from the gearbox and label _Rinse Sample_, and include turbine number and date on the bottle.

4.6.1. Repeat Step 3.7. Close the gearbox drain valve.

4.6.2. _EXCEPTION FROM Step 2.29: Install new gear lubricant filter for final fill phase._ Retain flush filter for re-use up to 5 times.

5. FINAL FILL PHASE

5.1. Close the gearbox drain valve.

5.2. Pump up new, filtered gear lubricant until the gearbox sump reservoir is full as indicated by the gearbox sight glass.

5.3. Install a new desiccant filter/breather.

5.4. Inspect the gearbox inspection cover gasket, and replace if necessary.

5.5. Turn heater pump and lube oil pump on to circulate gear lubricant throughout the system. Turn off pumps and recheck the oil level to ensure oil level is between the low and high –level indicators. Top up as needed.

5.6. Turn on the gearbox lubrication pump and let the turbine pinwheel for 15 minutes at low speed, and with ***NO Load.***

5.7. Take a one-quart oil sample and label *Final Fill* and include turbine number and date on the bottle. Check for oil leaks at all fittings & connections.

5.8. Check the oil level 30 minutes after shutting the turbine down to ensure the gearbox oil is at full indicator.

5.9. Clean up and affix new oil label on the gearbox.

SUMMARY

Some wind turbine gearboxes are particularly dirty from deposits left by specific gear lubricant breakdown and/or outside contaminants. It is important to understand that a good flushing process includes draining the gearbox and all associated areas. These areas include: hoses, thermostat, oil float indicator, check valves, heater, and cooler. Neglecting to address all of these areas that are known to hold old contaminated gear lubricant will result in diminished new oil quality. It is also very important to manually clean all sludged surfaces such as: filter housing, check valves, oil float indicator and thermostat. This is to assure contaminants are not carried over to the new gear lubricant. By evaluating oil analysis comparisons between the used gear lubricants, flush, rinse and final fill gear lubricant samples, it is possible to determine final fill gear lubricant quality. The oil analysis used to properly evaluate the gear lubricant samples should include:

1 Viscosity
2 List of items
3 ICP Analysis
4 Water PPM
5 Particle Counting
6 Foam testing

Foaming is not normally tracked during regular oil analysis, however during the flushing procedures it is important to understand that residual components left from the used oil can cause foaming in the new gear lubricant. Although additive concentrations in the used gear lubricant are normally flushed adequately by the end of the Flush Phase, foam values may still remain and show up in oil analysis until after the Rinse Phase. This indicates that the Rinse Phase is necessary and provides a better final fill gear lubricant quality.

RP 102

WIND TURBINE GEARBOX OIL SAMPLING PROCEDURES

PREFACE

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AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

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PURPOSE AND SCOPE

This Recommended Practice discusses the methods for taking clean and respective wind turbine gearbox oil samples. Samples that are taken properly will provide the user with accurate data.

The general procedure applies to wind turbine lubrication systems. There are several different wind turbine gearboxes and lubrication systems. This paper will focus on two commonly used systems. These recommendations will give proper procedure for the handling of containers and oil before and after samples have been taken to ensure that data obtained from oil analysis is accurate.

INTRODUCTION

Standardizing oil analysis from a specific sampling port is important. Taking samples from different ports may result in providing skewed samples to the laboratory for analysis.

Taking respective oil analysis samples from the same port on each turbine can provide data to wind turbine personnel that will allow accurate comparisons between turbines. Establishing which turbines should be scheduled for maintenance can then be easily assessed.

GEARBOX OIL SAMPLING PROCEDURES

1. PREPARING FOR OIL SAMPLING

1.1. Normal samples are typically taken in 3.5oz bottles. If extra laboratory tests are required taking a 1-quart sample may be required.

1.2. Oil samples should be placed in a clean unbreakable container. Oil manufacturers and analysis laboratories carry special bottles available upon request.

1.3. Before sampling, bottles must be clearly marked by labeling with the following information:

1. Company/Site Name
2. Turbine Number
3. Gearbox Model/Type
4. Oil Manufacturer
5. Oil Name
6. Date Sampled
7. Time Sampled

Labeling ensures oil analysis is associated with the correct oil sample for data tracking purposes.

2. PRIOR TO TAKING THE GEARBOX OIL SAMPLE

2.1. If the turbine has been running, turn the oil pump on for 1-minute before taking an oil sample. If the turbine has not been running make sure to activate the oil pump for a minimum of 5 minutes before taking sample.

2.2. Make sure tubes, bottles, sample ports, and hoses are free of debris before taking the sample. This ensures no residual contaminants' enter your sample.

2.3. Oil samples must be taken from a port before the oil filter. Samples must be taken from the same location each time to create a solid comparison. On all systems, only take samples from the recommended locations*. (See Figures A & B)*

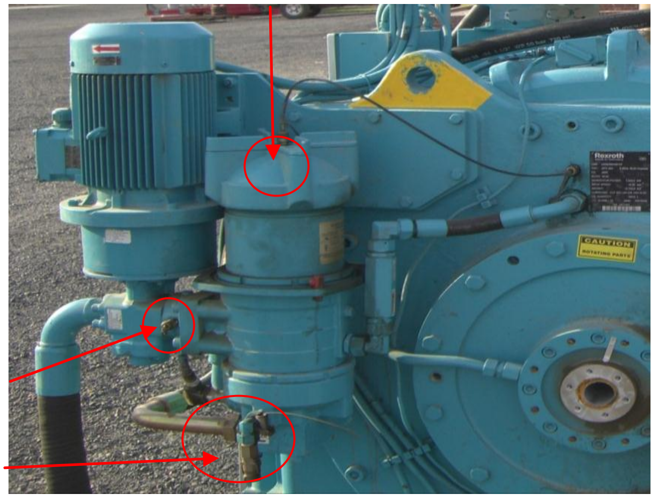

Figure A. System 1.

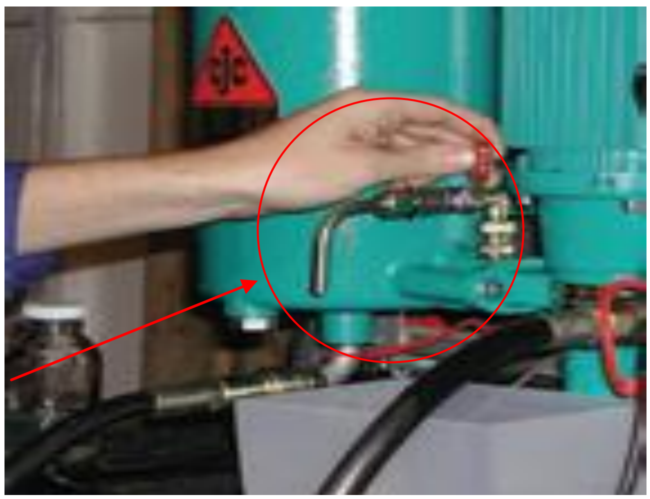

Figure B. System 2.

3. TAKING THE OIL SAMPLE (SYSTEM 1)

3.1. Purge with approximately the same amount of oil as the sample bottle size from a recommended **sampling** p**ort***. (See Figure A.)*

3.2. After purge sample is drawn seal the bottle immediately.

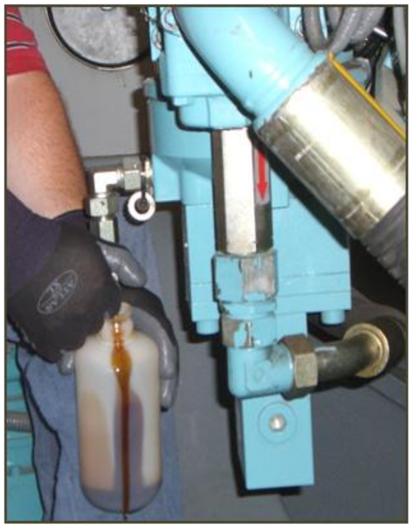

Figure 3. Example.

3.3. Open the clean sample bottle when ready to take the sample.

3.4. Open clean bottle and place under sample port. Make sure bottle is not touching the sample port.

3.5. Fill the 3.5oz clean bottle 80-90% full and place the cap on immediately.

3.6. Replace any hoses or caps on oiling system to ensure no leakage before exiting.

4. TAKING THE OIL SAMPLE (SYSTEM 2)

4.1. Open and close the recommended sampling port valve several times to purge the system, draining the purge oil into a container. Purge with approximately the same amount of oil as the sample bottle size*. (See Figure B.)*

4.2. After purge sample is drawn seal the bottle immediately.

Figure 3. Example.

4.3. Open the clean sample bottle when ready to take the sample.

4.4. Open clean sample bottle and place under the sample port. Make sure bottle is not touching the sample port.

4.5. Fill the 3.5oz clean bottle 80-90% full and place the cap on immediately.

4.6. Shut off valve and ensure there are no leaks before exiting.

SUMMARY

Proper gearbox oil sampling methods are crucial for comparing samples from one turbine to another or from sample to sample in the same turbine. This will assist in properly scheduling maintenance, as a good track record will be established. Many gearboxes have different filtration systems and sampling methods, however taking a clean sample from the same port will provide a good respective sample on a consistent basis.

RP 105

FACTORS INDICATING GEAR LUBE OIL CHANGE

PREFACE

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Committee Chair: Kevin Dinwiddie, AMSOIL
Principal Author: Kevin Dinwiddie, AMSOIL

PURPOSE AND SCOPE

This Recommended Practice discusses the determining factors that could indicate a gear lube oil change.

INTRODUCTION

There are many factors that could cause an oil change in a wind turbine gearbox. This paper will provide factors to consider that contribute to a condition-based gear oil change. The decision to perform a condition-based oil change is founded on the overall condition of the oil which is evaluated using turbine and gearbox manufacturer condemning limits and industry standards.

In some cases, filtration or dehydration corrective actions may be employed to extend the service life of the oil.

FACTORS INDICATING GEAR LUBE OIL CHANGE

1. CONTAMINATION

1.1. Externally Generated Contamination

External contamination particles can be derived from the environment or incompatible substances added to the oil. These include ingress of water due to weather conditions and natural aspiration through a breather, or salt spray, sand, dirt, dust, clay, silicates, and incompatible lubricants. Some contaminants may react adversely with oil additive packages in the lubricant, thus, damaging lubricant quality and may not be able to be remedied by filtration and may even require a system flush.

1.2. Internally Generated Contamination

In some cases internally generated contaminants have the same characteristics as the external type. Internally generated contamination consists of wear debris particles, decomposition sludge and oxidation by-products.

2. LUBRICANT DEGRADATION

Additive degradation, in some cases is known as additive depletion. Some lubricant types may have slightly reduced additives while staying within acceptable limits, and are still serviceable. Some other lubricant types may be characterized by the reduced ability of the oil's additive system to perform its intended function. Once depleted, organic acids may form, creating sediment, sludge or varnish particles that can cause deposits and increase the viscosity of the oil, makeup oil or even after an oil change if not flushed properly.

3. GENERAL GUIDELINES FOR LUBE OIL CHANGES

By necessity these guidelines are general in nature. These limits and/or rules can not cover every conceivable situation, but are meant to be a guide for you to make cost effective and reasonable corrective actions. These guidelines are consistent with

ANSI/AGMA/AWEA 6006-A03, Standard for Design and Specification of Gearboxes for Wind Turbines or *IEC ISO 61400-4-2012*.

3.1. WATER CONTAMINATION

Water is always present in some minute amount. There are different phases for water in oil:

1 In solution (not visible to the unaided eye).

2 Emulsified (causing the oil to appear hazy or milky).

3 Free (settling on the bottom of the gear case or sample bottle).

Different phases are dependent on several factors such as oil and additive types, amount of water present, and the temperature of the oil when it is observed.

AWEA 6006-A03 outlines water levels at 500 ppm (0.05%) as borderline and 1000 ppm (0.10%) as unsatisfactory [1], however water saturation levels change with temperature fluctuations i.e. warm oil holds more water than cold oil. This means that water in solution at hot temperature could cause some water to become free water when the oil cools from turbine down time. Water levels change with season and climate making it important to use the AWEA recommended ASTM test method, D6304-C outlined in the AWEA Recommended Practice *"Wind Turbine Gear Oil Analysis Test Methods".*

Water at elevated parts per million may contribute to [1]:

1 Accelerated additive depletion

2 Accelerated oxidation

3 Interfere with an active lubricant film formation

4 May react with additives to form residue on critical surfaces and plug filters or clog spray nozzles

5 May react with the base fluid or additives to promote the hardening of elastomers or premature failure of internal coatings such as paints.

6 May react with base fluid where additives can increase acidity.

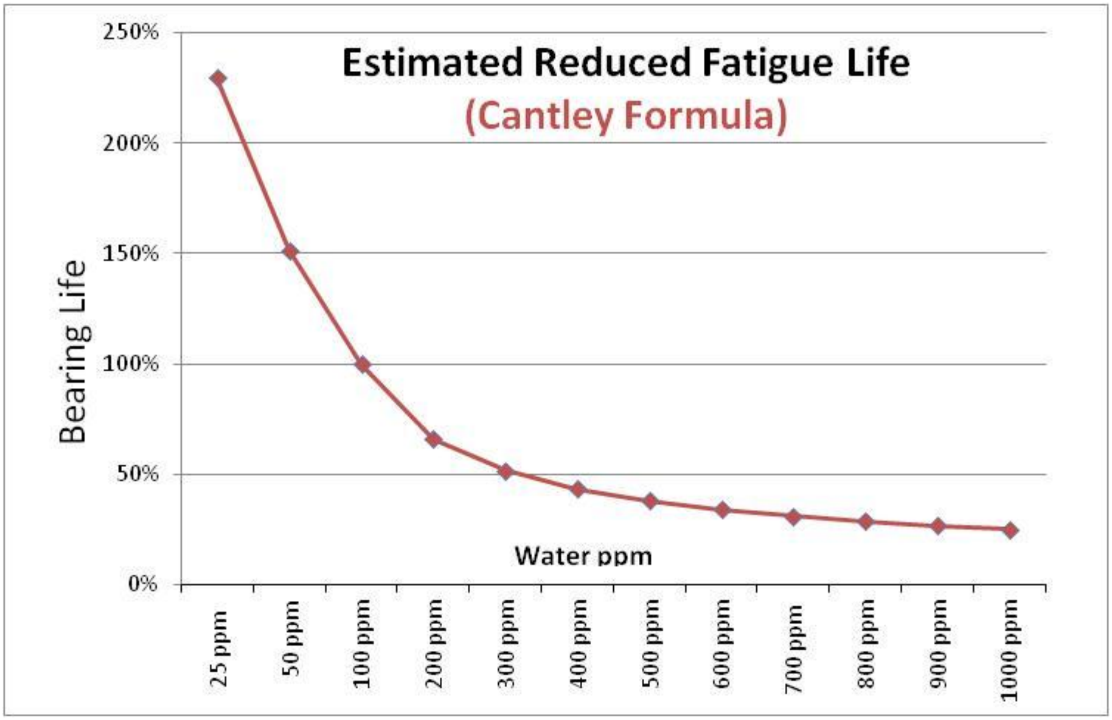
7 Direct contact with metal surfaces can produce rust particles that contribute to abrasive wear and act as an oxidation catalyst

8 Corrosion etch pits may initiate fatigue cracks

9 Under specific conditions, may lead to hydrogen embrittlement that promotes propagation of fatigue cracks

Bearing manufacturers and engineers have studied the effects of water in oil has on bearing fatigue and gear life and determined that increased water levels in wind turbine gear oil is related to increased gear wear and bearing fatigue life. A bearing manufacturer's research test provides data indicating water greater than 100 ppm (0.01%) will reduce bearing life significantly.[2] Another example of water in oil research is referred to as the Cantley Formula. [2, 3] *(See Chart A.)*

Chart A



Cantley Formula

L = (100/X)^0.6.

X = PPM Water

L = % of Rated Bearing Life

The Cantley Formula water chart indicates that 100 ppm water in gear oil will result in 100% bearing life. It is important to keep water levels down as low as possible to optimize bearing life.

Excessive water in wind turbine gear oil has been associated with gearbox problems such as sludging, micropitting, filter plugging and short oil and gearbox life [5]. The IEC/ISO committee in late 2012 published the newest wind turbine standards document *IEC 61400-4-2012* which indicates lower water limit guidelines, <300 acceptable, 300 to 600 caution level and >600 Alarm level [6] which are lower than AWEA 6006-A03 water limits.

3.2. Particulate Levels

Particle counting for gear oil in wind turbines gearboxes is performed at laboratories by *Solid Contamination Code, ISO 4406-1999*. Particles are counted in three ranges, >4, >6 and >14 micron particle sizes and the results are reported as x/x/x cleanliness code. Most turbine manufacturers consider that normal or the target cleanliness code is -/16/13 and borderline levels are -/17/14, while levels of -/18/15 or greater are considered unsatisfactory.

Filtration has much to do with particle count. The >4 micron particle count will be reduced if the filtration is switched from the standard 10 micron filter to a 5 micron filter.

If improved filtration or installation of a new filter does not control particle contamination to the target level, this would be a condemning limit for the gear oil.

3.3. Sediment, Sludge and Varnish Levels

Any visible sediment or discoloration is cause for unsatisfactory oil condition [1]. Verify that a clean sample is taken and visible sediment is not from the sampling process. If it is confirmed that the sample was taken without debris contamination then the source of the sediment could be from the gear oil. The source and type of contamination will determine what reasonable corrective action should take place.

3.4. Total Acid Number Values (TAN)

Although general limits for TAN level increase above new gear oil values vary by product chemistry type, lubricant suppliers should be able to give guidance regarding the level of TAN increase specific to their individual gear oil and at what point they consider recommending corrective action which could include changing the oil. General industry condemining limits are 2.0 over new oil value.

3.5. Viscosity Levels

The viscosity of the oil can change either up or down. The viscosity of wind turbine gear oil is normally 320 mm^2/sec, formerly centistokes (cSt) which is referred to as ISO VG 320. Per the standard, each viscosity grade ranges + or – 10%. Thus for an ISO 320 fluid, the range would be 288 to 352 cSt. Results that fall outside of this range either high or low would not meet turbine or gearbox manufacturer's viscosity requirements and could result in a recommendation for corrective actions or oil change.

3.6. Foam Tendency

One laboratory test not normally done on wind turbine gear oils during the regular 6-month oil sampling period is the ASTM D892 foam test. Foaming can cause many issues from filter plugging to reduced oil film thickness. In this test [3] air is blown into the test gear oil to create foam which builds up on top of the oil. It is measured at the end of the test and after a 10 minute settle time. If the foam bubbles break within the 10 minute settle time the fluid is considered to have good foaming resistance, however if there is any foam after the 10 minute settle time then the fluid may not be performing as designed and the oil may need to be targeted for an oil change.

4. OIL CHANGE CONDEMNING LIMITS

The factors indicating a gear oil change in Chart B are general and not necessarily specific to any one gear oil. *(See Chart B.)* It is important to contact the oil manufacturer and ask for their specific condemning limits. These condemning limits can be used as a guide in determining when an oil change is needed.

Chart B

Factors Indicating Gear Lube Oil Change				
	Method	**Measure**	**Monitor**	**Change or Reconditioning**
Water	ASTM D6304-C	ppm	300 to 600	600
Foam (@10 min settle)	ASTM D892	ml	<10	>10
Particulate Levels	Cleanliness Code	>4/>6/>14	-/17/14	-18/15
Total Acid Number	ASTM D664	mg/g KOH	1.5 over new	2.0 over new
Viscosity	ASTM D445	mm^2/sec (cSt)	<304 or >336	<288 or >352
Sediment	Visual in oil sample			Any
Sludge or Varnish	Visual	N/A	N/A	Early filter replacements
Additive	ICP or AES oil analysis ASTM		Subject to Oil Mfg	Subject to Oil Mfg

Factors Indicating Gear Lube Oil Change				
	Method	**Measure**	**Monitor**	**Change or Reconditioning**
Depletion	D5185 or ASTM D6595		Condemning limits	Condemning limits

SUMMARY

Increased contaminants, change in lubricant physicals and additive depletion are what to look for when evaluating whether or not gear oils need to be condemned and changed out. It is extremely important to obtain the condemning limits of the oil in use from the oil manufacturer. Applying the wrong condemning limit will cause inaccurate evaluation and skew the decision for condemning.

REFERENCES:

[1] ANSI/AGMA/AWEA 6006-A03 Standard for Design and Specification of Gearboxes for Wind Turbines, Page 74, Table F.4.

[2] Timken “Lubricating Your Bearings”, USA_chap_5.pdf, Contamination section, Page 125, 2. Water and Timken Products Catalog, A Engineering, Page 151 Lubrication and Seals section.

[3] R.E. Cantley, "The Effect of Water in Lubricating Oil on Bearing Fatigue Life." ASLE Transactions, 20 (3), 244-248, 1977

[4] ASTM Designation: D892-06, Standard Test Method for Foaming Characteristics of Lubrication Oils.

[5] ANSI/AGMA/AWEA 6006-A03 Standard for Design and Specification of Gearboxes for Wind Turbines, Page 67, Section F5.3.3.2, Effects of Water Contamination.

[6] International Standard ISO IEC 64100-4-2012, page 136 Table E.7 Guidelines for Lubricant Parameter limits..

RP 106

WIND TURBINE GEAR OIL FILTRATION PROCEDURES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

This Recommended Practice is for full-flow gear oil filters installed in wind turbine gearboxes. Flushing filters, and off-line (a.k.a. kidney loop) filters that may also be used with these gearboxes are defined but not discussed further in this Recommended Practice. Water and other types of contaminants are not discussed in this Practice.

INTRODUCTION

Full-flow filters are used to protect gearbox mechanical components from particle contamination suspended in gear oil. The major sources and types of particle contamination, along with associated wear mechanisms, are compiled in Table A. *(See Table A.)* The most contaminant sensitive gearbox components are bearings, followed by dynamic seals, pumps, and gears. One study by Timken established gear tooth wear debris as causing the greatest damage to rolling bearings [1]. In a second study, NASA found increases in rolling bearing life up to 6 times with increasing oil cleanliness maintained with highly efficient filters [2].

Table A: Damaging Contaminant Particles Found in Wind Turbine Gear Oil.

Sources/Ingression	Types	Wear Mechanisms
airborne mineral dusts	vents, ports, seals	sliding contact abrasion in gears, seals, pumps, retainers
metallic wear debris	gear tooth wear	rolling contact fatigue leading to pitting, spalling
manufacturing swarf: polishing/lapping grits; metallic chips	new installations, replacement parts	early failures of bearings, pumps, seals, gears
salt	marine sea spray followed by airborne ingression	corrosion

FULL-FLOW GEAR OIL FILTER PROCEDURES

1. TARGET PARTICLE CONTAMINATION LEVELS

In order to minimize damage to gearbox components, it is recommended gear oil be maintained at specified levels of cleanliness, or better. Quantities of particle contamination measured in oil samples are typically reported according to ISO 4406[3]. This format reports the number of particles per milliliter equal to or greater than a given size, in micrometers (µm). Particles per milliliter greater than 3 sizes are reported:

1 ≥ 4 µm

2 ≥ 6 µm

3 ≥ 14 µm

The number of particles for each size range is reported as an 'ISO Code'. For example, the number of particles in a particular sample of gear oil is reported as: ISO 19/17/15.

This translates to:

1 19: 2500-5000 particles/mL ≥ 4 µm in size

2 17: 640-1300 particles/mL ≥ 6 µm

3 15: 160-320 particles/mL ≥ 14 µm

An increase of one ISO Code equates to an increase in particle contamination by a factor of 2. As a second example, an oil sample with an ISO Code of 20/18/16 has in each size range two times more particles than the previous example. Maximum particle contamination levels are specified by gearbox or turbine manufacturer, or by in-house specification. Table 17 of ANSI/AGMA/AWEA 6006-A03[4] *(See Table B)* suggests a set of maximum allowable contamination levels for wind turbine gearboxes. Turbine or gearbox OEM, or in-house specifications, take precedence over this table.

Table B: Lubricant Cleanliness.

Source of Oil Sample	**Required Cleanliness Per ISO 4406**
Oil added into gearbox at any location	- / 14 / 11
Bulk oil from gearbox after factory test at the gearbox manufacturer's facility	- / 15 / 12
Bulk oil from gearbox after having been in service 24 to 72 hours after commissioning of the WTGS (pressure fed systems only)	- / 15 / 12
Bulk oil from gearbox sampled per the operating and maintenance manual (pressure fed systems only) *(See Step 6.7.)*	- / 16 / 13

Particle contamination in operating systems may be monitored by two alternative approaches:

This translates to:

1 Periodic oil samples are obtained from the gearbox then sent to a laboratory for analysis. This is the method currently used by a large majority of operators.

2 An on-line particle counting unit mounted on the gearbox. This has the advantage of providing real-time data. Disadvantages are unit and installation costs, and maintenance.

2. SELECTING FULL FLOW GEAR OIL FILTERS

2.1. Definitions

2.1.1. Full-flow filters receive the total flow of lubricant produced by the main lubrication system pump(s). All suspended particles in the oil reservoir are carried by the flowing gear oil into these filters. Depending on filter efficiency (filter rating), many to most damaging particles are removed from the gear oil by the full-flow filter before reaching loaded mechanical components, especially bearings and gears.

2.1.2. Off-line filtration systems are designed to operate independently of, or in addition to, the full flow filtration system. Off-line filtration may be used to supplement contaminant removal by full-flow filters, if deemed necessary to meet specified cleanliness levels.

2.1.3. Flushing filters are used to clean a gearbox during an oil change or after a system upset. These filters are temporarily plumbed into the gearbox lubricant system, and removed when the clean-up is completed. Flushing filter ratings should be as good as or greater than the full-flow filters installed on the gearbox.

2.2. Full-Flow Filter Ratings

The function of a full-flow filter is to remove damaging particles from the lubricant. For modern industrial filters, particle removal efficiency (a.k.a. filter efficiency) is reported as a 'filter rating'. Examples are filters rated at 5 µm or 10 µm. For particles this size and larger the filter is extremely efficient, as determined and quantified by laboratory testing. As illustrated in Figure 1, filter efficiency is determined by ISO 16889(5). *(See Figure 1.)*

2.2.1. The procedure is performed under controlled laboratory conditions.

2.2.2. A slurry of test dust (finely powered silica sand) in oil is flowed into the filter.

2.2.3. The number of particles entering and leaving the filter are sized and quantified throughout the test using electronic particle counters.

2.2.4. Filter ratings are reported as beta ratios:
ß10(C) = Number Particles Upstream ≥ X µm ÷ Number Particles Downstream ≥ X µm

2.2.5. For example, a filter rated at 10 µm has ß10(C) ≥ 1000.

2.2.6. Not all filters are equal. For example, a filter rated at 5 µm is 20 to 50 times more efficient at removing particles than a 10 µm filter, which in turn is 20 to 50 times more efficient than a filter rated at 20 µm.

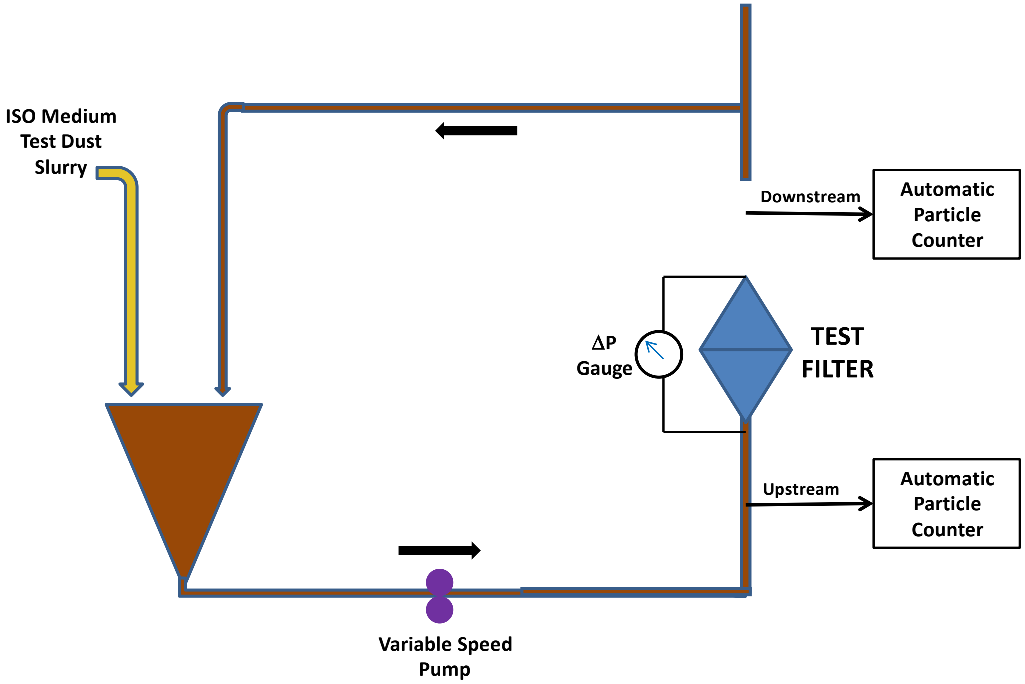

Figure 1. Multipass Test Per ISO 16899

2.3. Proper Filter Performance Parameters

Several additional parameters are required to ensure proper filter performance in a gearbox:

2.3.1. Differential Pressure (ΔP)

Filters present restrictions to flow. As gear oil flows through the filter, differential pressure (ΔP) develops across the filter. Differential pressure increases with increasing flow rate and oil viscosity. Cold gear oil flowing through a filter, such as during a system cold-start, often produces the greatest differential pressure experienced by full-flow filters. A maximum differential pressure may be specified by the gearbox or turbine OEM for unused filters at specific flow rates, oil types, and temperatures.

2.3.2. Compatibility and Integrity

The full-flow filter must be able to maintain integrity and withstand maximum differential pressure (including during cold-start) after contacting gear oil at highest system temperature. For additional information, see ISO 2941, *"Verification of Collapse Burst Pressure Rating"*, and ISO 2943, *"Filter Elements - Verification of Material Compatibility with Fluids"*.

2.3.3. Filter Service Life

As filters capture and retain particles, flow restriction and differential pressure increases. Full-flow filters are changed at or before a maximum differential pressure is reached. This ΔP value is specified by the gearbox or turbine manufacturer. The time interval between installation and removal is termed the filter service life. The ISO 16889 Multipass Test measures dirt holding capacity of silica sand under controlled conditions. However, because different types of contaminants load filters during field operation, this test method may not accurately predict the service life of full-flow filters in wind turbine gearboxes. It is recommended service life be established by field experience and evaluations.

2.4. Selecting a Full-Flow Filter

The full-flow filter should meet or exceed the specifications of the gearbox and/or turbine manufacturer. The filter rating should be sufficient to meet or exceed target cleanliness levels under real-world operating conditions. For concerns with possible removal of additives, confer with the oil supplier.

3. CHANGING SPENT GEAR OIL FILTERS

Two strategies are used for changing spent full-flow filters. The strategy used at a specific site may be specified by the gearbox or turbine manufacture, or by an in-house specification.

3.1. On-Time

This is the strategy used by the majority of wind turbine operators. Full-flow filters are changed at a convenient service interval. Currently, the most common service interval for land-based turbines is 6 months. Because filters are expected to last a minimum of 6 months, many are changed before dirt holding capacity has been depleted.

3.2. On-Condition

Full-flow filters are changed when a differential pressure indicator signals at pre-determined value of ΔP. This change-out ΔP is set below the differential pressure that activates the by-pass valve, avoiding unfiltered lubricant passing into the gearbox. Because the maximum dirt-holding capacity of the filter is used, this method tends to increase filter change-out intervals. However, tower climbs at irregular intervals to change these filters may be inconvenient and/or uneconomical.

4. FILTER CHANGE-OUT CHECK LIST

______ **1. Down Tower**

Inspect new filter. There should be no damage from handling/shipping.

______ **2. Bring Up Tower**

Plastic waste bag for used filter.

If changing spin-on filter, bring belt wrench.

2 gallons of pre-filtered make-up gear oil.

NOTE: The rating of the filter used for pre-filtering the gear oil should be a least as fine as the filter installed in the gearbox.

______ **3. If Changing a Cartridge Filter**

Remove cover from housing.

Partially remove used filter and let drain for several minutes.

Completely remove used filter and place in plastic waste bag.

Install new filter into housing.

Secure cover onto housing and tighten fittings.

Top up oil as needed.

______ **4.** **If Changing a Spin-On Filter**

Remove old spin-on; may need belt wrench.

Place old spin-on filter into plastic waste bag.

Spin new element onto filter head and tighten.

Top up oil as needed.

______ **5.** **When Back Down Tower**

Discard used element according to company policy.

SUMMARY

By protecting contaminant sensitive components from harmful particles, full-flow gear oil filters are indispensable for achieving acceptable uptime and life of wind turbine gearboxes, as well as for reducing maintenance costs. The full-flow filter installed on the gearbox should meet or exceed specifications. Specifications include, but are not limited to: filter rating (particle size where ß X(C) ≥ 1000), differential pressure (ΔP), compatibility, and integrity. The filter should also provide an acceptable service life, based on the needs of the site. A check-list is included to aid the proper change-out procedure when replacing spent filters with new filters.

REFERENCES

[1] Zaretsky, E.V., and Needelman, W.M., "Recalibrated Equations for Determining Effect of Oil Filtration on Roller Bearing Life", STLE Proceedings 64th Annual Meeting, Orlando, May 2009.

[2] Kotzalis, M., and Needelman, W.M., "Minimizing Oil Contamination and Using Debris Resistant Bearings to Enhance Wind Turbine Gearbox Performance", IJTC2009-15288, Proceedings International Joint Tribology Conference, Memphis, October 2009.

[3] ISO 4406:1999, "Hydraulic fluid power - Fluids - Method for coding the level of contamination by solid particles."

[4] ANSI/AGMA 6006-A03 "Standard for Design and Specification of Gearboxes for Wind Turbines", American Gear Manufacturers Association.

[5] ISO 16889:1999, "Hydraulic Fluid Power Filters - Multi-pass Method for Evaluating Filtration Performance of a Filter Element."

RP 201

GENERATOR COLLECTOR RING ASSEMBLY MAINTENANCE

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

This set of recommended practices addresses the common maintenance issues related to the collector ring assembly in double fed induction generators that are commonly used in many wind turbine designs. It is not machine specific and some variations may be required based on specific designs.

INTRODUCTION

In double fed induction generators, power is normally transferred to and from the wound rotor by the use of rotating collectors and brush assemblies. These are high wear items and should be included in any regularly scheduled maintenance inspection or process. The normal recommendation is to inspect and clean at least bi-annually, but longer maintenance cycles may be possible with improved materials and designs. Brush life is affected by carbon grade, ambient temperature and humidity as well as other operating environmental conditions. It is critical to the successful implementation of these procedures that good records are kept of generator maintenance and of any performance issues discovered between inspection intervals. Prior to any disassembly at each step, a careful visual inspection should be performed and any abnormal conditions should be documented, preferably including photographs.

COLLECTOR RING ASSEMBLY MAINTENANCE PROCEDURES

1. INSPECTING THE ASSEMBLY

Remove the generator collector ring cover(s). View the general condition of the assembly. Note any build-up of residue, leaking gaskets, broken or missing components, etc. A 1000 volt phase to phase and phase to ground insulation resistance test of the collector ring assembly is also suggested before and after cleaning. Values should conform to the generator manufacturer's specifications, but normally the minimum value should exceed 10 megohms during service and 100 megohms after cleaning. Leads should be disconnected before testing.

1.1. Brushes

1.1.1. Removal

To remove the brush for most designs, push forward on the spring to disengage the latch and lift the spring out of its slide. Other style of tension devices may be used. Consult the manufacturer's specifications for a specific generator design. Pull the brush out of its holder by its cables without disconnecting it. Note the orientation of the brush to the holder to ensure the brush will properly be reinstalled if it is not to be replaced.

1.1.2. Brush Body

Inspect the brush for minimum length requirement, any unusual wear-marks and free movement of the brush in the holder noting any restriction that maybe a sign of material swelling.

NOTE: This should also be a regular test for lightning protection brushes and grounding brushes.

Inspect for chipping or cracking. Assure that the terminals are secure and that shunts, micro switch tabs, etc. and rivet connection, if applicable, are in good working order and properly mounted and connected.

1.1.3. Shunt Wires

Discolored shunt wires can indicate uneven current sharing or overheating by insufficient air flow. It is recommended to replace the complete brush set, because single brushes can already be damaged. If the shunts are damaged or frayed by vibration, mechanical problems or too strong air flow, they should also be replaced and the condition corrected. Note any abnormal wear indicators. Verify terminal connections are secure on all brushes.

1.1.4. Vibration Markings

Smooth and shiny side surfaces are a clear indication of radial movement by the brushes in the brush box. That can be caused by out-of-roundness of the slip ring, too high friction also resulting in a shiny slip ring surface or external vibrations such as defective bearings, shafts, couplings etc. Markings of current transfer between brush holders and brush indicate that the connection between shunt and brush body is possibly damaged. Excessive brush dust in the slip ring compartment can also cause inappropriate current transfer. Frayed shunts or markings from the springs on the brush top also indicate abnormal vibration.

1.1.5. Brush Surface

Rough brush face surfaces may be cause by brush sparking from electrical or mechanical problems (e.g. vibrations). Rough surfaces on grounding brush faces can an indication of possible converter problems as well as ring surface issues.

Rule of thumb: If one of the brushes has to be replaced and the set is worn more than 25%, all the brushes should be replaced. If all brushes are to be replaced, disconnect them and remove them from the assembly. Loosen the terminal bolts until the brush terminal can be slid out from under it. If possible, do not fully remove the bolt to avoid dropping it and other hardware into the assembly.

1.2. Brush Holder

1.2.1. Holder Box

Inspect entire holder for any indications of arching or burning damage. Verify that all hardware and electrical connections are secure. Note any abnormal wear indicators.

1.2.2. Springs

Inspect tension devices for any indications of arching, burning or discoloration. The spring force should be checked every year with an appropriate spring scale device and springs should be replaced every 3 to 5 years depending on type of application. Springs with a deviation of more than 10% from the set value should be replaced.

1.2.3. Holder Distance

For a safe guidance of the brushes in the brush holder it is normally suggested that the distance between holder and slip ring surface is no more than 3mm (0.125")

1.3. Collector Rings

If possible the collector ring surface should also be checked regularly for grooving and other damage. Consult OEM specifications for tolerances. The collector ring assembly and the surrounding area should be checked for oil contamination. If oil or grease from the bearing comes into contact with the slip ring surface, an insulating film can be formed which hampers the current transfer. Increased brush wear could be the consequence. The brushes are porous and, in case of oil contamination, all brushes should be replaced after the collector ring is cleaned.

1.3.1. Signs of Brush Sparking

Extreme brush sparking may cause a serious flash over. Signs of sparking can be found on the brushes, the brush boxes, the rocker rings or other paths nearby the slip ring.

1.3.2. Brush Dust

Carbon brush dust is a good conductor. Excessive deposition of dust therefore may also create flash over and must be removed regularly during the inspection. Sufficient air flow is essential for successful removal of brush dust. Filters, air tubes etc. should therefore also regularly checked. The complete ventilation system should be cleaned and checked for proper operation.

2. CLEANING AND REASSEMBLY

2.1. Cleaning Collector Ring Assemblies

The collector ring assembly cover(s) should be completely removed and all components inspected as above before proceeding with cleaning. For these cleaning procedures, it is suggested that appropriate personal protection devices be worn, including a dust mask.

Use a small vacuum, preferably with a HEPA type filtration system, and a synthetic brush to remove all accumulated dust and other contaminants from the collector ring enclosure, the brush holder assemblies, any supporting rods or fixtures and the collector ring itself. Contact cleaner or other solvents should not be used directly on the collector ring as they may drive the carbon dust deeper into the insulated area reducing the dielectric properties of the assembly. If it is necessary to use a solvent, spray the solvent on a disposable towel or cloth and use the cloth to wipe the solvent on the unclean area. Do not use solvents on carbon brushes because they could affect the carbon material. The collector ring film (or patina) should not be cleaned with a solvent. If the collector ring surface does require cleaning, only use a mild abrasive tool such as use a non-conductive abrasive pad or a flexible rubber abrasive. Always clean from the top down to avoid re-contaminating components.

NOTE: If a brush is not to be replaced, it should remain connected during inspection and cleaning to assure return to its original location.

2.2. Installing Brushes

To install new brushes or to reinstall brushes after inspection, insert the brush into the holder ensuring the proper orientation, then slide the spring clip back into its slot and push it down onto the brush until the spring clip latch clips into the retaining notch. Connect new brushes and check that the connection is tight and the terminal is located correctly under the spring washer. As a final check to assure that the brush is free to move up and down in the brush holder and that the spring clip latch is correctly fitted, pull on the brush leads and lift the brush approximately 12mm (0.5”) and then lower it back onto the slip-ring a few times.

2.3. Seating New Brushes

Many new brushes are manufactured with a bottom radius. This radius is not the exact contour of the slip due to manufacturing tolerance, brush holder orientation and slip ring wear. In order to ensure adequate electrical contact to the collector ring, the brushes must be properly seated. Poor contact at startup can lead to major performance issues, shortened brush life and even component damage.

Garnet paper or any non-metal bearing abrasive paper is recommended and cloth backed abrasives are often easier to use in many circumstances. The abrasive size should be 80 to 120 grit. Fine sandpaper, such as 400 grit, will easily fill with carbon making the sanding process more difficult. It is important not to leave abrasive particles under the brushes when completed as these could damage the slip-ring surface.

Seat one brush at a time while all the other brushes are still connected but out of their holders.

Lift the brush by its shunts and slide a strip of the abrasive cloth under it with the abrasive side of the paper facing the brush. Lower the brush down onto the abrasive cloth and place the spring in its normal engaged position. The spring should apply the pressure to the brush. Slide the garnet paper back and forth under the brush in line with the brush path. After several of passes back and forth, remove the brush from its holder and check the face of the brush. The seating is complete when at least 80% of the brush face is abraded. Vacuum out all the accumulated carbon dust and sanding debris and reinstall the brush and spring-clips. Repeat with all the new brushes or used brushes with improper seating marks.

Once properly assembled, assure that all bolts are tightened and the brushes are properly connected.

Again, as a final check that the brush is free to move up and down in the brush holder and that the spring clip latch is correctly fitted, pull on the brush leads and lift the brush approximately 12mm (0.500”) and then lower it back onto the slip ring a few times.

Also make sure that all tools and cleaning materials are removed from the area and that the cover gaskets are functioning properly before replacing the cover.

SUMMARY

This recommended practice is designed to identify basic procedures and techniques for maintaining the collector ring assemblies in double fed induction generators. Careful cleaning, maintenance and proper brush replacement, when required, will assure long, trouble fee service life for these critical components.

RP 202

GREASE LUBRICATED BEARING MAINTENANCE

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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Contributing Author: Kevin Alewine, Shermco Industries
Committee Chair: Kevin Alewine, Shermco Industries

PURPOSE AND SCOPE

This set of recommended practices addresses the common maintenance issues related to lubrication of generator bearings and a basic trouble shooting guide to help with service/repair decisions.

INTRODUCTION

Conventional utility scale wind turbine generators range from 500kW to >3MW in production capabilities. Most of these units use grease lubricated anti-friction ball bearings that require some type of replenishment on a regular basis on both the drive and non-drive ends of the machine. Often, lubrication supply devices are utilized to partially automate the process, but monitoring and adjustments are required even with these automated systems. A few turbine designs have generators directly mounted to the gearbox and will only have one, non-drive end bearing to be maintained as the drive end bearing is integral to the gearbox lubrication system. Whereas alignment issues are simplified with these direct coupled machines, assuring proper lubrication is still a key element in good maintenance procedures. Alignment and vibration also contribute to premature bearing failures and those issues will be addressed in separate recommended practice documents. Regardless of design, it is critical that the proper amount of lubricant is used: both too little and too much grease will dramatically shorten the life of the bearing.

The proper choice of lubricant is normally specified by the generator manufacturer, but a general overview is included in this recommended practice for informational purposes only. Please refer to industry standard documents for more details.

Direct drive machines use generators that are integral to the main shaft of the wind turbine and the lubrication of those main bearings are discussed in other recommended practices.

GREASE LUBRICATED BEARING MAINTENANCE

1. OVERVIEW OF GREASE LUBRICATED BEARINGS

Lubricating greases usually consist of mineral or synthetic oil suspended in a thickener, with the oil typically making up 75% or more of the grease volume. Chemicals (additives) are added to the grease to achieve or enhance certain performance properties. As a result of having a thickener package, grease is more easily retained in the bearing arrangement, particularly where shafts are inclined or vertical. Grease also helps to seal bearings against solid particulate and moisture contamination. Excessive amounts of grease will cause the operating temperature in the bearing to rise rapidly, particularly when running at high speeds. As a general rule for grease lubricated bearings, the bearing should be completely filled with grease prior to start-up but the free space in the housing should only be partially filled. Before operating at full speed, the excess grease in the bearing should be allowed to settle or escape into the housing cavity during a running-in period. At the end of the running-in period, the operating temperature will drop considerably indicating that the grease has been distributed in the bearing arrangement. See the generator manufacturer’s specifications for more information on running in loads and speeds.

2. GREASE SELECTION

When selecting grease style and manufacturer for bearing lubrication, the base oil viscosity, consistency, operating temperature range, oil bleed rate, rust inhibiting properties and the load carrying ability are the most important factors to be considered. Please refer to the generator manufacturer's recommendations for the proper grease type for a specific machine.

3. LUBRICANT COMPATABILITY

If it becomes necessary to change from one grease to another, the compatibility of the greases should be considered.

CAUTION: If incompatible greases are mixed, the resulting consistency can change significantly and bearing damage due to lubricant leakage or lubricant hardening can result.

Greases having the same thickener and similar base oils can generally be mixed without any problems, e.g. a lithium thickener/ mineral oil grease can generally be mixed with another lithium thickener/mineral oil grease. Also, some greases with different thickeners, e.g. calcium complex and lithium complex greases can be mixed. However, it is generally good practice not to mix greases. The only way to be absolutely certain about the compatibility of two different greases is to perform a compatibility test with the two specific greases in question. Often the lubricant manufacturers for common industrial greases have already performed these tests and they can provide those results if requested. Most preservatives used to protect bearings are compatible with the majority of rolling bearing greases with the possible exception of older style polyurea greases. Again, always check with the generator manufacturer before changing or mixing grease types or manufacturers.

4. LUBRICATION

In order for a bearing to be properly lubricated with grease, oil must bleed from the grease. The oil then coats the bearing components, but is gradually broken down by oxidation or lost by evaporation, centrifugal force, etc. Over time, the remainder of the grease will oxidize or the oil in the grease near the bearing will be depleted. At this point, re-lubrication is necessary to keep the bearing operating properly for its designed life. There are two critical factors to proper lubrication: the quantity of grease supplied and the frequency at which it is supplied. Ideally, re-lubrication should occur when the condition of the existing lubricant is still satisfactory. The lubrication interval depends on many related factors. These include bearing type and size, speed, operating temperature, grease type, space around the bearing, and the bearing environment. Please refer to the generator manufacturer's documentation for lubrication rates and quantities.

4.1. Manual Lubrication Procedure

There is probably a manufacturer's recommendation regarding the hours of operation before lubrication. It is recommended that this be considered a maximum parameter since the periodic maintenance of wind turbines is normally minimized due to the difficulties of access. Make sure all fittings are clean and free from contamination. If the exit port becomes clogged or if the grease hardens within the bearing housing, the excess grease can be pushed out of the generator and onto the exterior or, more importantly, into the interior of the generator, contaminating the windings. Dispense only the amount required. Do not overfill. Refer to the generator manufacturer's specifications regarding the quantity and frequency rate for lubrication of the bearings.

4.2. Automated Lubrication

Automated lubrication devices work by adding a measured amount of grease to the bearing housing. The influx of new grease pushes out older material through an exit port. Again, if the port becomes clogged or if the grease hardens within the generator, the excess grease can be pushed out of the housing and onto the exterior or, more importantly, into the interior of the generator, contaminating the windings. Operation of these devices is critical and they should be checked carefully during periodic turbine inspections. Auxiliary power should be available for a test run of the device to assure proper operation. Also, any grease in the automated device storage container where the oil has separated should be replaced.

5. OPERATING TEMPERATURE

Since grease aging is accelerated with increasing temperature, it is recommended to shorten the intervals when in increased operating temperature environments. The alternate also applies for lower temperatures and the lubrication interval may be extended at temperatures below 158° F (70° C) if the temperature is not so low as to prevent the grease from bleeding oil. In general, specialty greases are required for bearing temperatures in excess of 210° F (100° C). Again, consult the generator manufacturer for grease recommendations for extreme temperature conditions.

6. VIBRATION

Moderate vibration should not have a negative effect on grease life. But high vibration and shock levels, such as those in found in wind turbines can cause the grease to separate more quickly, resulting in churning of the oils and thickener. In these cases the re-lubrication interval should be reduced. The overall importance of testing and controlling vibration is covered in another recommended practice.

7. CONTAMINATION

Contaminants have a very detrimental affect on the bearing surfaces. More frequent lubrication than indicated by the manufacturer's recommended interval will reduce the negative effects of foreign particles on the grease while reducing the mechanical damaging effects. Fluid contaminants (water, oil, hydraulic fluids, etc.) also call for a reduced interval. Since there are no formulas to determine the frequency of lubrication because of contamination, experience is the best indicator the appropriate interval.. It is generally accepted that the more frequent the lubrication the better. However, care should be taken to avoid over-greasing a bearing in an attempt to flush out contaminated grease. Using less grease on a more frequent basis rather than the full amount of grease each time is recommended. Excessive greasing without the ability to purge will cause higher operating temperatures because of churning.

SUMMARY

This recommended practice is designed to provide basic information and techniques for proper lubrication of generator bearings as well as a troubleshooting guide to aid with maintenance/repair decisions. Proper care and lubrication, when required, will assure long, trouble fee service life for these critical components.

TROUBLESHOOTING GUIDE

Bearings that are not operating properly usually exhibit identifiable symptoms. This section presents some useful hints to help identify the most common causes of these symptoms as well as practical solutions wherever possible. Depending on the degree of bearing damage, some symptoms may be misleading. To effectively troubleshoot bearing problems, it is necessary to analyze the symptoms according to those first observed in the applications. Symptoms of bearing trouble can usually be reduced to a few classifications, which are listed below. Note: Troubleshooting information shown on these pages should be used as guidelines only.

COMMON BEARING SYMPTOMS

- Excessive heat
- Excessive noise
- Excessive vibration
- Excessive shaft movement
- Excessive torque to rotate shaft

EXCESSIVE HEAT

- Lubrication
  - Wrong type of lubricant
  - Insufficient lubrication - Too little grease
  - Excessive lubrication - Too much grease without a chance to purge
- Insufficient bearing internal clearance
  - Wrong bearing internal clearance selection
  - Excessive shaft interference fit or oversized shaft diameter
  - Excessive housing interference fit or undersized housing bore diameter
  - Excessive out-of-round condition of shaft or housing
- Improper bearing loading
  - Skidding rolling elements as a result of insufficient load
  - Bearings are excessively preloaded as a result of adjustment
  - Out-of-balance condition creating increased loading on bearing
  - Linear misalignment of shaft relative to the housing
  - Angular misalignment of shaft relative to the housing

Sealing conditions

Housing seals are too tight

Multiple seals in housing

Misalignment of housing seals

Operating speed too high for contact seals in bearing

Seals not properly lubricated

Seals oriented in the wrong direction and not allowing grease purge

EXCESSIVE NOISE

Metal-to-metal contact

Oil film too thin for operating conditions

Temperature too high

Insufficient quantity of lubrication

Under lubricated bearing

Leakage from worn or improper seals

Leakage from incompatibility

Rolling elements skidding

Inadequate loading to properly seat rolling elements

Lubricant too stiff

Contamination

Solid particle contamination entering the bearing and denting the rolling surfaces

Solids left in the housing from manufacturing or previous bearing failures

Liquid contamination reducing the lubricant viscosity

Looseness

Inner ring turning on shaft because of undersized or worn shaft

Outer ring turning in housing because of oversized or worn housing bore

Locknut is loose on the shaft or tapered sleeve

Bearing not clamped securely against mating components

Too much radial / axial internal clearance in bearings

Surface damage

- Rolling surfaces are dented from impact or shock loading
- Rolling surfaces are false-brinelled from static vibration
- Rolling surfaces are spalled from fatigue
- Rolling surfaces are spalled from surface initiated damage
- Static etching of rolling surface from chemical/liquid contamination
- Particle denting of rolling surfaces from solid contamination
- Fluting of rolling surfaces from electric arcing
- Pitting of rolling surfaces from moisture or electric current
- Wear from ineffective lubrication
- Smearing damage from rolling element skidding

Excessive torque to rotate shaft

- Preloaded bearing
- Excessive shaft and housing fits
- Excessive out-of-round condition of shaft or housing
- Excessive out-of-round condition of shaft or housing
- Bearing is pinched in warped housing
- Wrong clearance selected for replacement bearing

Sealing Drag

- Housing seals are too tight or rubbing against another component
- Multiple seals in housing
- Misalignment of housing seals
- Seals not properly lubricated

Surface Damage

- Rolling surfaces are spalled from fatigue
- Rolling surfaces are spalled from surface initiated damage
- Fluting of rolling surfaces from electric arcing
- Shaft and/or housing shoulders are out of square
- Shaft shoulder too large and is rubbing against seals/shields

RP 203

GENERATOR OFF-LINE ELECTRICAL TESTING

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chair: Kevin Alewine, Shermco Industries
Principal Author: Kevin Alewine, Shermco Industries

PURPOSE AND SCOPE

This recommended practice provides an introduction to basic electrical tests for the periodic testing and troubleshooting of wind turbine generator electrical circuits. It is not intended to provide specific techniques or recommendations for corrections based on the test results.

INTRODUCTION

All generators, regardless of their design, contain at least one wound element where most or all of the energy is generated and made available to the system. They are often complicated windings with many opportunities for weakness as well as many connections where high resistance is a concern. When most electrical failures occur, a generator specialist is required for correction or repair, but normal operating conditions can often be verified by normal maintenance staff.

Some electrical tests are designed to merely provide a high level of confidence that the machine can be energized safely, but not as predictive tools regarding the longevity of the windings or even their performance under full load. Higher level testing can safely stress the winding insulating at or above normal operation levels and can help develop trends for predictive maintenance.

On-line electrical testing can provide a large amount of useful information, but specialized equipment and training is critical and the parameters for use on wind turbine generators is not yet available as standard testing. Future editions of this standard should address that technology as it develops.

This guide will provide an introduction to several of these tests, but only the insulation resistance testing is recommended for use by non-specialized personnel. Always remember the dangers associated with any electrical testing and follow proper safety procedures. Qualified and accredited companies and technicians should be utilized in most cases. Reference *NFPA 70B* and *NFPA 70E* as well as the interNational Electrical Testing Association (NETA)/ANSI testing protocols.

GENERATOR OFF-LINE ELECTRICAL TESTING

1. COMMON TEST METHODS

1.1. Insulation Resistance

Insulation resistance testing (sometimes referred to as IR testing, not to be confused with infrared testing) is one of the oldest maintenance procedures developed for the electrical industry and is covered in detail in *IEEE Standard 43-2000*. This test is fairly simple to perform and can provide information regarding the condition of the electrical insulation in the generator as well as contamination and moisture. This test is recommended before energizing a machine that has been out of service or where heating elements have failed to keep the winding temperature above the dew point which might have resulted in condensation on the windings. It is also useful whenever there is doubt as to the integrity of the windings and before any over voltage testing is performed. An accurate IR test requires a correction factor for the winding temperature to create useful data. The methods and expected result data for this test is listed in the standard document.

While the test results from IR testing are not normally trended, it is possible to do so to show a gross degradation of the insulation systems. It is, however, very important that the duration of the test, the temperature of the windings and relative humidity be consistent for the trend data to be meaningful.

1.2. Polarization Index

Another test described in *IEEE Standard 43-2000* is the polarization index (or P.I.) that is useful in some applications to identify contaminated and moist windings. In most modern machines, however, where the insulation resistance is above 5000 megohms, the test might not prove meaningful. There has also been a consideration of collecting de-polarization data. Refer to the standards document for additional applications and details.

1.3. Winding Resistance Testing

It is common to use a basic ohm meter in screening generator winding circuits, but the information gained is not a reliable diagnostic tool because of the many components in the circuit. The use of very low resistance test meters can provide good information, but these tests are very sensitive to temperature fluctuations and trending is difficult.

1.4. Ancillary Component Tests

Testing any auxiliary motors such as those in cooling systems or automated lubrication devices would follow the same basic procedures as the generator itself, but at the appropriate testing range. Other components such as resistance thermal devices (RTD), thermocouples, heater elements, micro switches, etc. are normally checked with an ohm meter. Consult the manufacturer’s literature for specifications.

2. HIGH VOLTAGE TESTS

Although these tests are not commonly used in general maintenance procedures, it is useful to have a basic understanding of what tests are available for predictive maintenance trending, troubleshooting and failure analysis. These tests are generally considered to be non-destructive in nature, but a weakness in the insulation system could and probably should fail during these tests so care should be taken when determining when these tests are advisable. It is recommended that only properly trained generator electrical test technicians should perform these tests.

2.1. High Potential Testing

The high potential test (sometimes referred to as an over potential test) is designed to stress the electrical insulation beyond its normal operating voltages to expose potential failures at a more convenient time. Both AC and DC tests are available, but should only be performed by a generator testing expert. The DC test methods are described in *IEEE Standard 95*. Trending is possible with this testing, but care should be taken as insulation weaknesses (cracking, contamination, carbon tracking, etc.) can be advanced to failure.

2.2. Step Over-Voltage Test

Using the same equipment as the high potential test, the step over voltage test stresses the insulation at rising levels of voltage over a set time scale. This is a very useful trending test and is also commonly used in periodic predictive maintenance testing. The same concerns exist as for high potential testing.

2.3. Surge Comparison Test

This type of test is the most common analysis tool for testing turn to turn insulation in motors and generators. In this test, a short pulse of high voltage energy at an appropriate stress level is sent through the windings and the results captured on a recording oscilloscope. The patterns of two identical circuits are then compared and the overlaying waves will highlight any differences which represent a potential failure point. A trained test technician can often identify winding failure types by the oscilloscope wave forms. This test is normally used in conjunction with a high potential test. This type of test is described in *IEEE Standard 522*.

Modern automated winding analysis equipment combines many of these tests into a concise report and is very useful for predictive maintenance practices. Again, these high voltage tests should only be performed by a trained generator test technician.

2.4. Partial Discharge Testing

Both periodic and continuous monitoring testing of partial discharge currents and/or corona are common for large high voltage machines for trending expected useful insulation life. Some techniques do exist for testing low voltage applications, but specialized equipment and training are necessary. It should be considered for long term predictive maintenance programs.

SUMMARY

Good maintenance practice calls for the periodic evaluation of generator electrical conditions and should always be part of a basic maintenance plan. Use of the proper testing protocols can assure safe operation of the generator and can help highlight corrective opportunities before catastrophic failure. True predictive high voltage tests offer much useful data for analysis and maintenance scheduling to avoid unplanned outages, but should only be performed by trained technicians.

USEFUL REFERENCES

[1] Electrical Apparatus Service Association Standard AR100-2010 Recommended Practice for the Repair of Rotating Electrical Apparatus

[2] Electrical Insulation for Rotating Machines: Design, Evaluation, Aging, Testing and Repair, Dr. Greg C. Stone, et.al., John Wiley & Sons, 2004

[3] IEEE Std. 4-1995 and Amendment 1-2001 Standard Techniques for High Voltage Testing

[4] IEEE Std. 43-2000 Standard Techniques for Testing Insulation Resistance of Rotating Machinery

[5] IEEE Std. 95-2002 Recommended Practice for Insulation Testing of AC Electric Machinery (2300 V and Above) with High Direct Voltage

[6] IEEE Std. 112-2004 Standard Test Procedure for Polyphase Induction Motors and Generators

[7] IEEE Std. 115-2009 Guide for Test Procedures for Synchronous Machines

[8] IEEE Std. 522-2004 Guide for Testing Turn Insulation of Form Wound Stator Coils for Alternating Current Electrical Machines

[9] National Electric Manufacturer's Association NEMA MG-1-2009, R1-2010 Motors and Generators

[10] NFPA 70B Recommended Practice for Electrical Equipment Maintenance

[11] NFPA 70E Standard for Electrical Safety in the Workplace

RP 208

SHAFT CURRENT MANAGEMENT

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chair: Kevin Alewine, Shermco Industries
Principal Author: Rob Hefner, Schunk Graphite
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Reviewing Committee: Benoit White, Mersen

PURPOSE AND SCOPE

This set of recommended practices addresses the common maintenance issues related to the grounding systems for generator and drive train shafts in various wind turbine designs. It is not machine specific and some adaptation may be required based on specific designs.

INTRODUCTION

A wind turbine generator shaft is usually protected by a grounding system to prevent currents from passing onto the generator and/or drive train bearings. The use of carbon brushes contacting the shaft rotating area and tied into the unit’s grounding is the most popular way of

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managing unwanted shaft currents. These brushes are wear items and should be included in any regularly scheduled maintenance inspection or process. The normal recommendation is to inspect and clean the brush and assembly at least bi-annually, but longer maintenance cycles may be possible with improved materials and designs. Brush life is affected by carbon grade, shaft speed, ambient temperature and humidity as well as other operating environmental conditions. During maintenance, a careful visual inspection should be performed and any abnormal conditions should be documented, preferably including photographs.

Understanding the Need for Shaft Grounding

Shaft voltages can be caused by:

- Asymmetry in the magnetic circuit of rotating electrical machines
- Build-up of static charges within the shaft
- Capacitative coupling of voltages into static exciting systems

If current does pass via the bearings of an electrical machine, high current densities may occur on the small contact points within the bearing, which can result in a local melting of the metal surfaces. The consequence is the formation of small craters and serrations. This typically increases the internal friction of the bearing and worsens over time causing increased temperature, contaminated lubrication and ultimately bearing failure.

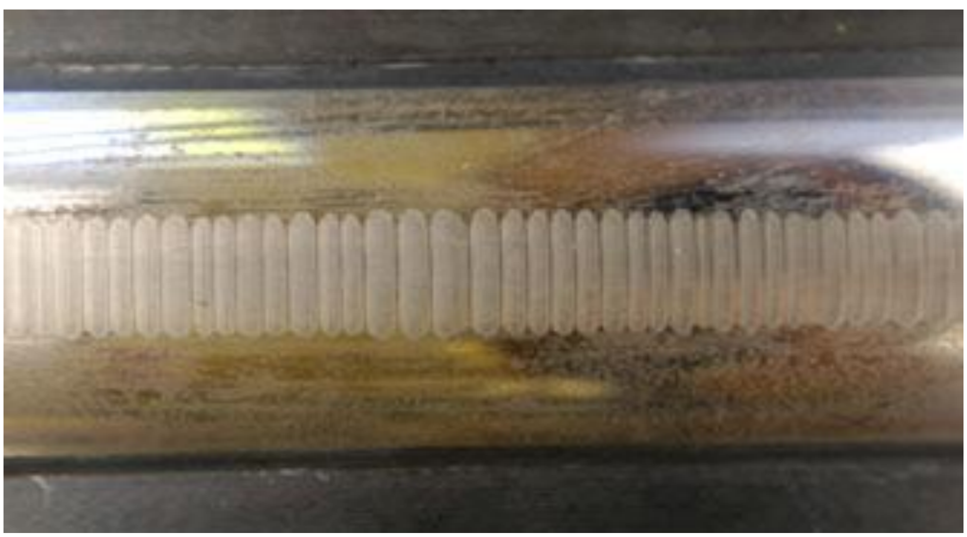

Figure A. Ripple formation on bearing race caused by voltage passing through bearing (fluting)

Electrical insulation of the bearings is a common practice, but is not always sufficient. Shaft grounding with carbon brushes helps to protect components by grounding out the majority of the voltage/current before making contact. This grounding is typically achieved by two brushes being mounted in a 90° angle on the shaft as seen in the images below. Varying grades may be recommended based on the operating conditions and the turbine manufacturer or a trusted carbon brush manufacturer can help with choosing the proper grade for the conditions.

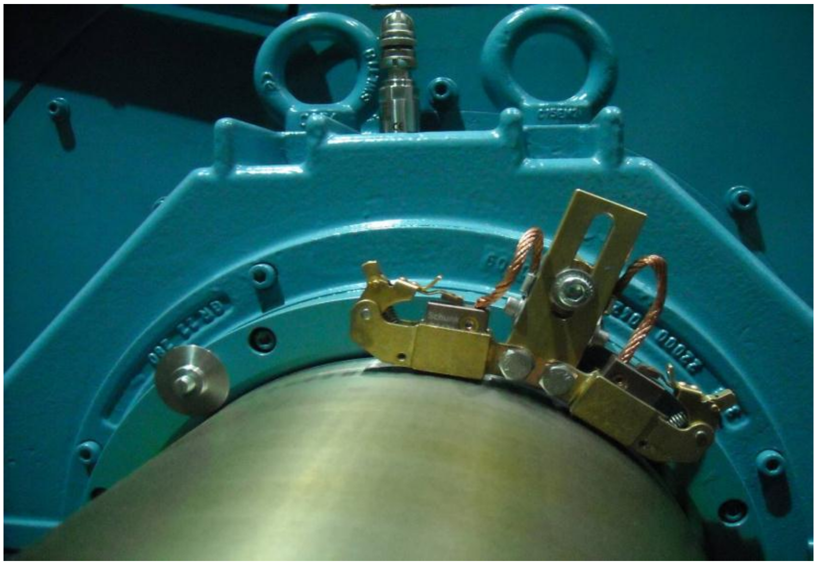

Figure B. Example of Main Shaft Grounding

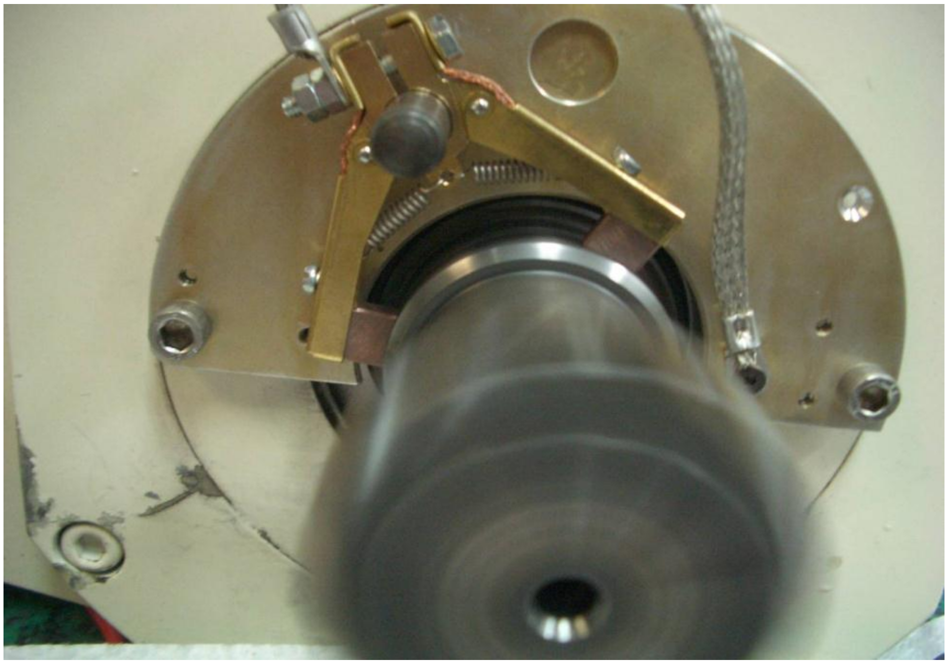

Figure C. Example of Generator Shaft Grounding

SHAFT GROUNDING MAINTENANCE PROCEDURES

1. INSPECTING THE ASSEMBLY

Remove the shaft cover if one exists. View the general condition of the assembly. Note any build-up of residue, leaking gaskets, broken or missing components, etc. It is always good to document the "as found" condition of the brush and assembly with an image.

1.1. Brushes

1.1.1. Removal

To remove the brush from most designs, pull back the spring loaded holder arm and loosen any connections to the holder assembly. Other styles of tension devices may in use. Consult the manufacturer's specifications for a specific generator design. Pull the brush out of its holder by its cables without disconnecting it. Note the orientation of the brush to the holder to ensure the brush will properly be reinstalled if it is not to be replaced.

1.1.2. Brush Body

Inspect the brush for minimum length requirement, any unusual wear-marks and free movement of the brush in the holder noting any restriction that maybe a sign of material swelling.

NOTE: This should also be a regular test for lightning protection brushes.

Inspect for chipping or cracking. Assure that the terminals are secure and that shunts, micro switch tabs, etc. and rivet connection, if applicable, are in good working order and properly mounted and connected.

1.1.3. Shunt Wires

Discolored shunt wires can indicate overheating or extreme current discharges. It is recommended to replace the complete brush set, because single brushes can already be damaged. If the shunts are damaged or frayed by vibration or mechanical problems they should also be replaced and the condition corrected. Note any abnormal wear indicators. Verify terminal connections are secure on all brushes. Additionally, shunt wires should still be pliable when moving, if the shunt wires are rigid they are susceptible to damage causing reduction in conductivity and the brushes should be changed.

1.1.4. Brush Surface

Rough brush face surfaces may be cause by brush sparking from electrical or mechanical problems.

Rule of thumb: If one of the brushes has to be replaced and the set is worn more than 25%, all the brushes should be replaced. If all brushes are to be replaced, disconnect them and remove them from the assembly. Loosen the terminal bolts until the brush terminal can be slid out from under it. If possible, do not fully remove the bolt to avoid dropping it and other hardware into the assembly.

1.2. Brush Holder

1.2.1. Holder Box

Inspect entire holder for any indications of arching or burning damage. Verify that all hardware and electrical connections are secure. Note any abnormal wear indicators.

1.2.2. Springs

Inspect tension devices for any indications of arching, burning or discoloration. The spring force should be checked every year with an appropriate spring scale device and springs should be replaced every 3 to 5 years depending on type of application. Springs with a deviation of more than 10% from the set value should be replaced.

1.2.3. Holder Distance

For a safe guidance of the brushes in the brush holder it is normally suggested that the distance between holder and shaft surface is no more than 3mm (0.125")

1.3. Counter Surface

Inspect the shaft surface where the brush makes contact. There should be a film (or patina) of on the shaft. LEAVE THE FILM AS IS! This helps with the wear and connectivity of the brush to shaft surface. If oil or grease comes into contact with the counter surface, an insulating film can be formed which hampers the current transfer. Increased brush wear could be the consequence. The brushes are porous and, in case of oil contamination, all brushes should be replaced after the shaft surface is cleaned.

2. CLEANING AND REASSEMBLY

2.1. Cleaning the Shaft Surface

Typically the generator shaft is clean area of a generator, but carbon dust may build up over time in this area. For these cleaning procedures, it is suggested that appropriate personal protection devices be worn, including a dust mask.

Use a small vacuum, preferably with a HEPA type filtration system, and a synthetic brush to remove all accumulated dust and other contaminants from the shaft, the brush holder assemblies, and any areas where the dust may have collected below the shaft. Contact cleaner or other solvents should not be used directly on the brushes or the shaft surface. If it is necessary to use a solvent, spray the solvent on a disposable towel or cloth and use the cloth to wipe the solvent on the unclean area. Do not use solvents on carbon brushes because they could affect the carbon material. The surface film (or patina) should not be cleaned with a solvent. Always clean from the top down to avoid re-contaminating components.

2.2. Installing Brushes

To install new brushes or to reinstall brushes after inspection, insert the brush into the holder ensuring the proper orientation, then affix the brush back to its operating position. Connect new brushes and check that the connection is tight and the terminal is located correctly under the spring washer. As a final check to assure that the brush is free to move up and down in the brush holder and that the spring is correctly fitted, pull on the brush leads and lift the brush approximately 12mm (0.5”) and then lower it back onto the shaft a few times. Assure that the bushes are oriented 90° to the shaft and that as much surface as possible is in contact with the shaft surface to avoid premature wear.

2.3. Seating New Brushes

In the event new brushes are manufactured with a bottom radius, seating may be needed to ensure the proper electrical continuity.

Garnet paper or any non-metal bearing abrasive paper is recommended and cloth backed abrasives are often easier to use in many circumstances.. The abrasive size should be 80 to 120 grit. Fine sandpaper, such as 400 grit, will easily fill with carbon making the sanding process more difficult. It is important not to leave abrasive particles under the brushes when completed as these could damage the counter surface.

Seat one brush at a time while all the other brushes are still connected but out of their holders.

Lift the brush by its shunts and slide a strip of the abrasive cloth under it with the abrasive side of the paper facing the brush. Lower the brush down onto the abrasive cloth and place the spring in its normal engaged position. The spring should apply the pressure to the brush. Slide the garnet paper back and forth under the brush in line with the brush path. After several of passes back and forth, remove the brush from its holder and check the face of the brush. The seating is complete when at least 80% of the brush face is abraded. Vacuum out all the accumulated carbon dust and sanding debris and reinstall the brush. Repeat with all the new brushes or used brushes with improper seating marks.

Once properly assembled, assure that all bolts are tightened and the brushes are properly connected.

Again, as a final check that the brush is free to move up and down in the brush holder and that the spring is correctly fitted, pull on the brush leads and lift the brush approximately 12mm (0.500") and then lower it back onto the shaft a few times.

Also, make sure that all tools and cleaning materials are removed from the area and that any cover gaskets are functioning properly before replacing the cove if applicable.

SUMMARY

This recommended practice is designed to identify basic procedures and techniques for maintaining the collector ring assemblies in double fed induction generators. Careful cleaning, maintenance and proper brush replacement, when required, will assure long, trouble fee service life for these critical components.

RP 301

WIND TURBINE BLADES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chairs: Jim Sadlo, 3M;
Gary Kanaby, Wind Energy Services
Principal Authors: Jim Sadlo, 3M
Robert Schmidt, M4 Wind Services

PURPOSE AND SCOPE

This Recommended Practice discusses proper purchase, transportation, maintenance, repairs and balancing of wind turbine blades.

INTRODUCTION

The purpose of this document is to provide turbine manufacturers, owner/operators and independent service providers in the wind energy industry with a description of the best maintenance, inspection and repair practices for the blades and nose cones employed on wind turbine rotors. These best practices are to serve as a guideline with the understanding that economics will drive the actual implementation decision at each individual wind farm.

WIND TURBINE BLADES

1. INSPECTIONS

1.1. Areas of inspection

Blades need to be checked in detail and their condition is to be documented. Irregularities and damages are to be detected and a recommended repair date specified. The blades need to be checked in detail by a reputable technical expert. Scope and type of inspection are taken from the following table. *(See Table A.)*

Table A. Areas of Inspection.

Component to be Checked	**Type of Inspection and Checkpoints**	**Minimum Inspection Frequency Every 2 Years***
Blade Body	visual evidence of cracks, air pockets, delamination, drainage, protective film and erosion of the leading edge, lightning protection system, spark gap documentation of blade pitch angle documentation of blade moment balance	*Selected inspections maybe needed after environmental incident events. Lightning storms, severe winds, hail, etc.*
Flow Elements	turbo rills, vortex generators, micro swirl prong bands, gurney flaps	
Visible Profile Accuracy	characteristics of the trailing edge, light reflection	
Blade Inner	If technically possible, the blade should be checked from the inside. It is important that the area is stable enough. delamination, bars : cracks, finish of web adhesion	
Blade Sealing To Hub	oil in the blade, lightning protection system within the blade	
Extender	corrosion, bolts, weld seams	
Wind Turbines Tip Stall Mechanism	play, grime, adjustment, crack, guide tube, damping plate, index pins, bolts and cross bolts, function	
Wind Turbines Blade Pitch Adjusting Device	bearings, grease condition, play in mechanism, leaks, gear tooth contact pattern, connecting rod, oil in the blade	
Wind Turbines Blade Pitch Adjusting Cylinder	leaks, mechanical stops, blade adjustment locking device	
Wind Turbines Pitch Return Element	function, tighten the accumulators	
Wind Turbines Pitch Electical Cabinet	tighten within hub	
Bolts, barrel nuts, bushings	Check torque, wear, corrosion	

1.2. Pre-Purchase Audit

In addition to the inspections listed above, documentation on the blade set should include the blade weights, the blade center of gravity's, manufacturing date, repairs made to the blade before delivery (this to include rework to bond lines, lamination defects {wrinkles} dry spots and leading edge reshaping). This information should be kept with the rotor set's O&M record for life of rotor.

1.3. Delivery/Commissioning Inspections

Assure all rotor sets are assembled as specified. Assure all surface defects since leaving OEM are resolved properly. Major pre-purchase repairs should require confirmation of balanced blade set. Confirm all rotors sets hung in proper/consistent order (eg A-B-C, etc).

1.4. Environmental Incident Inspection

Immediately following an environmental incident a ground based visual inspection for obvious blade damage should be conducted. Based on those observations, additional inspections from the list above should be conducted.

1.5. On-going Inspections

Part of a consistent O&M recommended practice is to have a documented on-going inspection plan where all turbines are inspected on a regular basis. Extra inspections on problematic blades are highly recommended as are higher inspection rates on previously repaired blades.

1.6. Pre-End of Warranty Inspection

Key to the end of warranty inspection is to plan well ahead of the end of warranty to plan out this inspection. As a single inspection may lead to a follow up inspection, prior to bringing any warranty issue to the OEM before the warranty period is completed.

2. TRANSPORTATION AND STORAGE

2.1. Transportation

All blades need to be shipped in compliance with the OEM transportation specification. Recommended practice would be to have this specification on site prior to the shipping of the blades to assure that all specifications are met as well if any conflicting issues would arise from this specification. Specific things to inspect are the bracing and support of the blades. Inspect for proper cushioning and support on the leading edge, proper side support on the shell body so as to not induce longitudinal cracking, proper cinching of cargo straps as to not damage trailing edge, proper bracing on the blade to prevent adverse flexing during transportation.

2.2. Storage

Storage of blades needs to be different for the intended length of storage. Short periods of storage, such as staging for installation, can be varied as long as the blade is not exposed to undue mechanical strain or an environment that would compromise the exterior structure of the blade. Long term storage needs to address the following:

- Protection from UV light
- Root bolts sealed from moisture
- Blade protected from rain, dust, foreign objects including small animals and insects from the interior of the blade
- Blade properly secured to the ground to prevent damage in high winds
- Blade properly supported to mitigate any mechanical stresses on the on the structure of the blade (leading edge, trailing edge, shell wall

3. MAINTENANCE

Preventive maintenance schedules have shown repeatedly to be more cost effective than responding to issues as they arise. There are many formats for maintenance schedules, but the key is to incorporate one that will be followed consistently by the site team. This may include having a third party conduct all PMs and repairs on a long term contractual agreement.

There are many visual and auditory inspections that can be used as part of the preventative maintenance plan, which require little effort and do not require interrupting the generation of power. High speed digital photography for identifying lightning strikes, trailing edge cracks, foreign object strikes can be conducted from the ground. Changes in the sound of the rotor set spinning can also be conducted on a regular basis.

Typical preventative maintenance plans will address the areas mentioned in Table A. Additionally, as the rotors age, a representative set of rotors should be physically inspected for defects, wear and damage by some form of blade access. The set of rotors physically inspected should change each year, so as to have each rotor set physically inspected on regular basis. This varies from farm to farm, but a 2 to 10 year rotation is common. Items identified with these inspections could alter the rate of inspection and should be used to plan repairs so as to minimize costs. (Bunching repairs to lower cost per turbine repaired.)

The maintenance data collected for each blade and rotor set needs to be retained with the rotor set for the life of the farm and it needs to be reviewed on a regular basis for potential predictions on power loss, potential failures, etc.

Blades and rotor sets that continuously have more issues, should have their PM scheduled more frequently to minimize reactive maintenance and to aid in understanding trends for the rotor set.

4. REPAIR

All repairs whether under warranty or past the warranty period should be conducted with OEM approved materials. The primary key to all repairs is to return the blade to the same physical strength, shape and weight as it was commissioned. Usually the exact same manufacturing process cannot be used to facilitate the repair. Thus the repair may be thicker or heavier in the repair location to obtain the same structural strength as in the original location, or it will be lighter or not as structurally strong to return the location to the same surface profile. Depending on the location and its critical performance function, the repair team will need to decide how best to complete the repair.

4.1. Safety

Repairing and maintaining rotors sets creates additional safety concerns beyond the concerns already presented on every wind farm. Safety needs to be first most in all maintenance and repair programs. This information below is meant to be adjunct to an existing site safety program. As noted above in the SAFETY NOTICE, this information is meant for awareness and all implementers of the processes are responsible for determining appropriate safety, security, environmental, and health practices or regulatory requirements.

4.1.1. Fall Protection and Rescue

All personnel that access the nacelle area of a wind turbine should be trained and certified to safely climb the tower and to perform self and others rescue. Personnel should be trained in the dangers of working at a height, how to use and maintain lanyards, fall arrest harnesses, positioning equipment and other climbing gear. In addition, personnel should be trained in the correct methods of dealing with emergencies including suspension trauma and rescue.

Testing and Certification should be obtained from a recognized third party organization such as ENSA to ANSI or NIOSH standards, which should include:

- Safety awareness.
- Equipment fitting.
- Care and inspection of equipment.
- Risk assessment.
- Restraint.
- Fall arrest.
- Work positioning.
- Rescue.
- Anchor selection.
- Evacuation

4.1.2. Aerial Platform Competent User, Safe Access and Rescue

External servicing of the turbine’s blades can be performed up-tower utilizing suspended platforms or crane man-baskets. It is critical that service personnel be trained and certified in the operation of vertical lifeline systems, rigging, safe operation of the platform; self-rescue and assisted recue using ANSI approved automatic control descent devices.

Specific areas to be trained and certified include:

- Safe use of Vertical Lifelines
- Establishing a safe work area
- Platform and Rigging Equipment inspection
- Rigging
- Pre-lift testing
- Platform components and assemblies
- Safe Operation of the Platform
- Tag Line operation
- Assisted Rescue
- Self Rescue
- Coworker Rescue
- Sling Angles
- Sling Ratings
- Anchor point requirements
- OSHA requirements

4.1.3. Rope Access

In addition to Fall Protection training, service personnel should be specifically trained and certified to SPRAT or IRATA standards for safe access strictly by rope suspension. Personnel should be trained and experienced in the evaluation of rope access equipment and systems, be able to perform access techniques and be competent in rescue procedures.

Specific areas of training and certification should include:

- Safety standards and documentation.
- Methods of access.
- Care, inspection, use and limitations of equipment.
- Knots.
- Rigging.
- Anchoring.
- Ascending and descending.
- Rope-to-rope transfer.
- Structure climbing.
- Assessing risks.
- Self and co-worker rescue.

4.1.4. 4.1.4 OSHA 30

The OSHA 30 program provides training in general safety practices for construction and industrial environments. Specific areas of training are:

- OSHA standards for hazardous conditions and practices
- OSHA’s general safety and health provisions
- Occupational health and environmental controls
- Personal Protective Equipment
- Fire protection and prevention
- Rigging

- Welding and Cutting
- Electrical standards and hazards
- Scaffolding
- Fall protection
- Excavations
- Concrete and Masonry
- Decommissioning and Demolition
- Ladders
- Hazards of confined spaces

4.1.5. First Aid / CPR

Due to the fact that most wind farm sites are in remote areas, it is critical that all field personnel be trained as first responders in applying first aid and CPR. OSHA or American Red Cross guidelines should be followed so that personnel can recognize and care for a variety of first aid emergencies and perform CPR and care for breathing and cardiac emergencies.

4.1.6. Confined Spaces and Respirators

Working within the rotor and especially inside of wind turbine blades require personnel to be trained in confined space access and the proper use of respiration gear. Training and certification for personnel should be done in accordance with OSHA 29 requirements and include areas such as:

- Confined space identification.
- Hazard evaluation.
- Behavior of gases.
- Oxygen deficiency.

- Equipment use and care.
- Respirator fit.
- Ingress and evacuation.

4.2. Skill Levels

Blade repairs tend to fall under two primary divisions; cosmetic repairs and structural repairs. Care is needed in assuring that appropriate training and skill levels are available for either type of repair. A simple cosmetic repair, if not performed correctly can result in a loss of generation power and potentially lead to additional repairs and failures. On site or independent service providers have varied skill levels for various types of repairs. This can include not only the type of repairs, but also the blade access techniques, scheduling availability, experience with various repair options and turbine platforms. Upfront discussion on these points will prevent issues after a repair is contracted and started. (An excellent team for changing our a pitch motor, may not be the best choice for repairing a lightning strike repair.)

Regardless of resources being used, accreditation through several programs and technical schools for composite repair should be part of the minimum acceptance level for skills to conduct on site composite repairs. Such programs include ACMA CCT program for Wind Blade Repair. AWEA maintains a list of the wind turbine technical training schools.

4.3. Blade Repair Steps

4.3.1. Have an agreed plan on what inspections for damage are to be reviewed. This should be in written form and signed by all parties.

4.3.2. Obtain all background information on the damaged area. This should include any drawings, ply orientation, type of resin/adhesive, laminate schedule and previous repairs.

4.3.3. Conduct a complete inspection of the damaged area. If appropriate, with the use of remote viewing equipment or another safe approach, inspect the interior at the damaged location. The intent is to determine the size of the damage and potential needed repair prior to starting the repair process.

4.3.4. Once completed, obtain an agreement with site owners, site operators and the repair team as to potential repair options needed to correct the damage. Obtain agreement to conduct further inspection to ascertain the extent of the damage.

4.3.5. After cleaning the damage location, remove the exterior gel coat or paint system to obtain a complete visual for the damaged area. This should be done only with a fine grain abrasive.

4.3.6. Once the entire area of repair has been exposed, the area should be marked, photographed and a detailed report on what steps and materials will be needed to complete the repair. This should include measurements as to the amount of scarf needed for each composite layer, the method of resin application to be used, the types of resin and even the types of tools and processing aids to be used.

4.3.7. The site team, owners and the repair team should have full agreement on the repairs, based on this report, prior to starting the repairs. This agreement may possibly be used as the basis for the repair costs and repair warranty.

4.3.8. The repair team should document all steps in the repairs with photos and citing the processing steps and materials used. The approximate weight of the materials used is also of value.

4.3.9. The finished report on the damage and the repairs should be kept as a permanent part of the blade's maintenance record.

4.3.10. For repairs where no composite needs to be replaced, such as replacing a pitch motor, replacing surface mounted devices or repairing a leading edge, the above mentioned steps of; inspecting the damage and recording with photos and a written report with proposal options for repair, obtaining agreement on the repair, its timing and costs, followed by conducting the repair, documenting all steps to remove and replace the damaged components, and retaining the documentation with the maintenance records for the blade/rotor set, should also be used.

5. ROTOR BALANCING

5.1. Expectation, Inspection, and Documentation

Most if not all blades are balanced and matched for a rotor set at the OEM location. Assuming that the set of blades remain a set on the turbine, the blades should be balanced.

Balanced rotor sets can lose balance by a change in material weight or by a change in material strength. It is recommended that inspections for rotor balance be made after a major composite repair, or after noting differences in blade deflections within the rotor set at a given wind speed. It is also possible to have a blade increase in weight due to moisture uptake from a porous gel coat, plugged drain hole, prolonged exposure of blade core material to the environment, etc. This should also warrant an inspection of the rotor balance.

Dynamic balancing should be required any time a substitute blade is needed to complete/repair a rotor set.

As with all maintenance inspections and repairs, the balance measurements should be kept with the rotor set records for the life of the turbine. This would include the blade number, the location on the blade where weight was added, the amount of material added as well as the final balance achieved.

5.2. Static and Dynamic Balancing

Static balancing should be a minimum with dynamic balancing desired. The blades arrive at the farm intended to be part of a balanced rotor set. Confirmation of this should be conducted prior to installing a rotor set. There are many views on balancing. A statically balanced rotor should be a balanced set but it does not mean that it is dynamically balanced. Only after being assembled and hung can the set be tested for its dynamic balance. There are varied ways to determine if the rotor set is out of balance, including auditory, "bumping" the set on a windless day, and correlating data as to which rotor sets are always last to spin up in light winds.

Upon finding a rotor set, which needs to be brought into balance, weight should be added to the lightest blade and weight should never be removed from the heaviest blade. Many OEMs build into the blades, "weight boxes". These confined spaces along the blade are intended to be used for the infusion of dense curable resins to adjust the balance as needed without having weights break free and rotate within the blade and/or reduce the structural strength of the blade.

6. THINGS TO AVOID

When inspections indicate the need for repair, do not unduly delay the repairs. Added costs to make repairs to blades as the need for repair grows may eliminate the ability of the blade to be repaired. (E.g., A blade in need of repair where moisture is allowed to egress into the blade core materials will make the blade repair costs potentially higher than the cost of total blade replacement.)

7. ADDITIONAL SUGGESTIONS

Conduct site visual inspections with high speed video/camera, telephoto lens and laser pointers. Lag measurement of blade tip can be indicator of trailing edge split. Tip offset from tower can indicate shear web weakness, stress cracking near root or pitch imbalance. Use such low cost internal audits to evaluate the scope of the need for external evaluations and repairs.

Require dynamic balance information on all new installs after the rotor set is installed. Confirm that the information is still within the specification limits.

Keep repair records for all forms of repairs to each blade.

Require of OEM all repair information on any post fabrication repairs. This should include the location and type of repair, method to repair and materials used to repair. This would include all repairs conducted as the results of transportation, storage and installation prior to commissioning. This would include all NCRs (Non conforming reports) from manufacturing.

Request lightning protection system readings recorded from manufacturing.

RP 302

ROTOR HUBS

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chairs: Jim Sadlo, 3M;
Gary Kanaby, Wind Energy Services
Principal Author: Jim Sadlo, 3M

PURPOSE AND SCOPE

This Recommended Practice discusses proper purchase, transportation, maintenance, repairs and balancing of wind turbine rotor hubs.

INTRODUCTION

The purpose of this document is to provide turbine manufacturers, owner/operators and independent service providers in the wind energy industry with a description of the best maintenance, inspection and repair practices for the rotor hubs employed on wind turbine rotors. These best practices are to serve as a guideline with the understanding that economics will drive the actual implementation decision at each individual wind farm.

WIND TURBINE HUBS

1. INSPECTIONS

1.1. Areas of inspection

Hubs need to be checked in detail and their condition is to be documented. Irregularities and damages are to be detected and a recommended repair date specified. The hubs need to be checked in detail by a reputable technical expert. Scope and type of inspection are taken from the following table. *(See Table A.)*

Table A. Areas of Inspection

Component to be Checked	Type of Inspection and Checkpoints	Minimum Inspection Frequency Every Year*
Hub	Visual for cracks, paintwork, corrosion	*Selected inspections maybe needed after environmental incident events. Lightning storms, severe winds, hail, etc.*
Drive Shaft Slow Side	cracks, paintwork, corrosion, slipping clamping ring	
Bolted Joint Shaft – Hub	corrosion, crack, mounting torque	
Spindle	cracks, paintwork	
Rotor Bearing	noise, leakage, greasing, sump pan, lightning protection system, shaft nut	

1.2. Pre-Purchase Audit

In addition to the inspections listed above, documentation on the hub should include conformity to the manufacturer's engineering drawings.

1.3. Environmental Incident Inspection

Immediately following an environmental incident a ground based visual inspection for obvious hub damage should be conducted. Based on those observations, additional inspections from the list above should be conducted.

1.4. On-going Inspections

Part of a consistent O&M recommended practice is to have a documented on-going inspection plan where all turbines are inspected on a regular basis. Extra inspections on problematic hubs are highly recommended as are higher inspection rates on previously repaired hubs.

1.5. Pre-End of Warranty Inspection

Key to the end of warranty inspection is to plan well ahead of the end of warranty to plan out this inspection. As a single inspection may lead to a follow up inspection, prior to bringing any warranty issue to the OEM before the warranty period is completed.

2. TRANSPORTATION AND STORAGE

2.1. Transportation

All hubs need to be shipped in compliance with the OEM transportation specification. Recommended practice would be to have this specification on site prior to the shipping of the blades to assure that all specifications are met as well if any conflicting issues would arise from this specification. Specific things to inspect are the bracing and support of the hub. Inspect for proper sealing and measures to assure rust prevention during the transportation.

2.2. Storage

Storage of hubs needs to be different for the intended length of storage. Short periods of storage, such as staging for installation, can be varied as long as the blade is not exposed to undue mechanical strain or an environment that would compromise the exterior structure of the hub. Long term storage needs to address the following:

- Protection from UV light

- Metal surfaces from moisture
- Hub protected from rain, dust, foreign objects including small animals and insects from the interior of the hub
- Hub properly secured to the ground to prevent damage in high winds
- Hub properly supported and allow for the periodic rotation and lubrication of the bearings within the hub

3. MAINTENANCE

As list in the table above, the inspections on the hub components should be part of the preventative maintenance schedule. The lubrication schedule should be based on the OEM recommendations.

4. REPAIR

All repairs where under warranty or past the warranty period should be conducted with OEM approved materials. The primary key to all repairs are to return the hub to the same physical strength, shape and weight as it was commissioned.

RP 304

ROTOR LIGHTNING PROTECTION SYSTEMS

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chairs: Jim Sadlo, 3M;
Gary Kanaby, Wind Energy Services

PURPOSE AND SCOPE

This Recommended Practice discusses proper maintenance and testing of wind turbine rotor/blades lightning protection equipment.

INTRODUCTION

This section contains recommendation in how to secure that a specific lightning protection system in a blade or in a complete rotor and hub system is maintained in a reasonable manor. The information in this section should give the reader an insight understanding on where to focus and what kind of documentation that gives the requested certainty in the provided system. The recommendations given in this section is based on general requirements given in the standard *'IEC 61400-24 Wind Turbine System - Part 24: Lightning Protection'* governing requirements for lightning protection of wind turbines and are based on the state-of-the art in the wind turbines industry.

WIND TURBINE ROTOR LIGHTNING PROTECTION SYSTEMS

1. INSPECTIONS

The standard IEC 61400-24 is requiring regular inspections during the lifetime process of the wind turbine to secure the following:

- The LP system conforms to its original design and functionality
- All part of the LP system is in good conditions and still capable of protecting the wind turbine with required performance until next scheduled maintenance

1.1. Inspection intervals/events

The inspections should as a minimum be performed on the following occasions:

- During production
- Before installation – on site before installation
- During installation
- After final commissioning of the wind turbine
- Scheduled Inspections
  - Yearly visual inspection
  - Bi-yearly full inspection
- After extensive repair situations
- After severe lightning strikes.

1.2. Pre-Purchase Audit

During the pre-purchase phase the buyer or an inspector representing the buyer must get a general understanding about the lightning protection philosophy covering the rotor and hub.

From the producer it must be presented how the overall lightning protection system is expected working from a functional point of view and how the lightning protection concept has been verified.

Detailed design documentation should be provided and this design must secure high efficiency in lightning interception and the rotor being able of withstanding the physical effects of lightning without consequential catastrophic failures.

The blade lightning protection system should comprise an adequate tip section protection including protection of internal conductive and semi-conductive parts. Test reports and other kinds of verification must be presented to document the desired protection performance. The down conductor system must be able to handle impulse current of at least 200kA@10/350µs (lightning protection level 1 in accordance with *IEC 61400-24*) without signs of internal arcing and temperatures exceeding critical levels in relation to conductor isolation and GFRP/CFRP materials in general. Is case of semi-conductive materials as carbon fibers or other conductive elements as sensors, heating elements, actuators etc. installed in the blade it must be secured that the presence of these systems and components are not compromising the safety and functionality of the blade.

Arc Entry tests must document the design lifetime of the air termination points (receptors).

In blades with a lightning current transfer system located in the root section to protect the pitch bearings and drive train against lightning current penetration, these transfer systems must be designed in a robust way to secure mechanical stability and good lightning current carrying capability. It must be documented that the designed solutions have the desired function and lifetime performance.

In or around the hub section the lightning current path must be defined and it must be secured that no mechanical, hydraulic or electrical components are exposed to direct or indirect lightning effect exceeding the withstand level of the component.

The inspector should audit the production facility to verify that the actual system is produced in accordance with the provided design. Lightning Protection Systems can be very different and the inspection points may be different from one system to another. It is important to define the inspection points as soon as the lightning protection concept is known.

For all blade lightning protection systems it is important that connections between different conductors are performed correctly. It is important that the right tooling and instructions are available in the production. In cases with bolted connections that are not visible for inspection during the blade lifetime, these connections must be locked in a way that secures a good connection during the entire lifetime.

All connections must be checked by measuring the resistance before the connection is covered by resin or the blade mold is closed. Resistance measurements must be performed with a calibrated '4-point measuring method' instruments and all individual sub-connections must demonstrate resistances below 1mΩ.

The entire lightning protection system must finally be checked by resistance measurement – and the threshold value for the entire system must be defined by the natural resistance in the down conductor system added with the resistances in the connections in the system.

A good rule of thumb is to have 0.5 mΩ per meter blade length in total resistance. If this cannot be demonstrated the reasons has to be sorted out and it must be decided by the inspector if the system can be accepted.

A diagram indicating the resistances in the system should be provided as a part of the blade documentation and all measurement data must be stored in the blade production file and made available for the inspector at any time.

1.3. During Production

During production, correct installation of all conductors and connections must be inspected. Resistance measurements must be taken regularly to secure that all connections are demonstrating low resistance values.

Attention should be on electrically isolating materials (resin, sealing compound etc.) used on electrical connections.

The lightning protection systems must be checked by measurement before the blade is closed or infused – depending on the production method. It is recommended that the resistances in the system are measured regularly during the production to make sure that no surprises occur.

Before the blade leaves production, the total resistance in the system must be measured and must still be within the tolerable range.

1.4. On Site – Prior to Installation

Before the blade is installed on site the total resistance in the system must be measured and must still be within the tolerable range. All connections must be inspected and the desired resistances in the system must be documented by measurement. Measurements are taken from the blade root termination point to all air termination points (receptors) in the system. *(See Figure A.)* All measurements must be stored in the blade file.

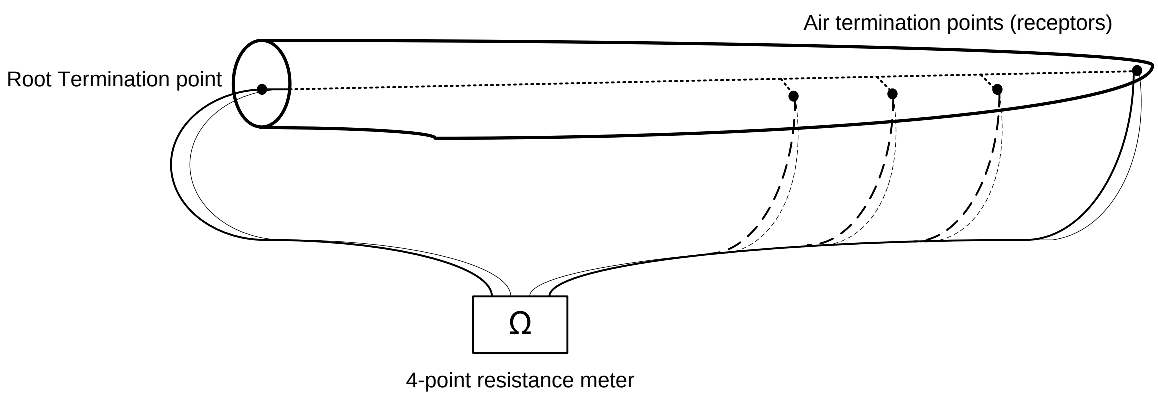

Figure A. 4-point resistance measurement from Root termination point to air termination points (receptors)

1.5. During Installation

SAFETY NOTE: Installation work cannot be carried out during thunderstorms. The risk of strikes to the turbine has to be considered by the site responsible person and no persons are allowed in the uncompleted turbine in the event of a lightning strike.

During installation of the rotor it is important to connect the lightning protection system to ground as early in the process as possible.

SAFETY NOTE: It has to be realized that even without thunderstorm activity, the blade can be static electric charged during the crane hoisting and installation; and the installation crew should be instructed how to approach the floating blade and un-grounded lightning protection system.

It is recommended to consider a solution to get the blade grounded without the installation crew touching the blade - eventually by use of an isolated ground stick.

When the turbine are erected and the blades are installed there is a risk of having lightning strikes even before the turbine is finally commissioned and put into operation. It has the be secured that the lightning protection system is completed as soon as possible in the erection process to avoid human injuries or system damages. It is important that the main lightning current path from the blade lightning protection system to the hub/nacelle/tower and further to the foundation grounding system is established.

By visual inspection and resistance measurements it must be checked that all intended lightning protection connections are full functional immediately after erection. All inspection instructions and checklists must be stated in the relevant erection manuals. Resistance measurement values must be noted in the turbine file.

During power and control cables installations in the hub, nacelle and tower it must be considered how cables are grounded in case of an approaching thunderstorms. Cables that are left unconnected and ungrounded can introduce a significant risk of flash-overs and damages to cables and equipment. Electrostatic discharges may occur and personnel may be injured.

1.6. After Final Commissioning of the Wind Turbine

After the turbine has been commissioned the lightning protection system must be checked finally before the turbine in put into operation. All connections must be inspected and the desired resistances in the system must be documented by measurement. Measurements are taken from the blade root termination point.

1.7. Scheduled Inspections

According to *IEC 61400-24* the lightning protection system must be inspected every one year of operation. Every year the lightning protection system must be inspected visually and every second year the inspection should be extended to cover a full inspection including continuity measurements and an indebt inspection.

1.8. Yearly Visual Inspection

During the yearly visual inspection the following points should be inspected:

- Root Termination Point - no broken/loosened parts.
- Connection to pitch bearing (if relevant) - cable connection - no broken/loosened parts.
- Lightning Current Transfer System (if installed)
  - Mechanical parts - no broken/loosened parts
  - Electrical parts - cables, brushes etc. - no broken/loosened/worn parts
- Lightning Registration Card changed (if installed)

1.9. Bi-yearly Full Inspection

During the yearly visual inspection the following points should be inspected:

- Root Termination Point - no broken/loosened parts.
- Connection to pitch bearing (if relevant) - cable connection - no broken/loosened parts.
- Lightning Current Transfer System (if installed)
  - Mechanical parts - no broken/loosened parts
  - Electrical parts - cables, brushes etc. - no broken/loosened/worn parts
- Lightning Registration Card changed (if installed)
- Measurement of resistance in the following connections
  - Root termination point to all air termination points (receptors)
  - Connection from root termination point to nacelle
  - External Grounding Systems to neutral (distant) Ground

1.10. After Extensive Repair Situations

After events with extensive repairs where the blade has been taken down the lightning protection systems must be inspected again. The same procedure as described in Steps 9.2.2, 9.2.3 and 9.2.4 must be followed before, during and after the blade re-installation.

1.11. After Severe Lightning Strikes

In the event of a severe lightning strike an inspection of the entire lightning protection system must be considered. If there is no defects observed the turbine operation should be continued, but it can be expected that delayed failures will show up in the weeks/months after the strike.

If the lightning strike causes a damage that is requiring a repair to the blade laminate, lightning protection system, the lightning current transfer system etc. the repair must be followed with a resistance measurement to secure that the tolerable resistance is maintained after the repair.

It is important to secure that the conductors and connections inside the blade are repaired in the right way to secure proper function.

In cases with regular damages caused by lightning strikes it should be considered to improve the lightning protection efficiency as a part of the repair.

In severe cases improvements should be installed proactively, but only improvements that are proven and verified having a higher performance should be installed.

2. MAINTENANCE

3. REPAIR

All repairs where under warranty or past the warranty period should be conducted with OEM approved materials. The primary key to all repairs are to return the lightening system to the same performance characteristics as it was commissioned.

4. ADDITIONAL SUGGESTIONS

Do request references from potential vendors verifying previous experience in performing the type of repairs needed.

Do investigate variances between the intended repair processes and those recommended by the component supplier or the OEM.

RP 401

FOUNDATION INSPECTIONS, MAINTENANCE AND BASE BOLT TENSIONING PROCEDURES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chair: Oliver Hirschfelder, Capital Safety
Principal Author: Jesse Tarr, Wind Secure

PURPOSE AND SCOPE

This set of recommended practices addresses the common maintenance issues related to foundation inspections, maintenance and base bolt tensioning procedures. It is not machine specific and some adaptation may be required based on specific designs.

INTRODUCTION

The operation of a wind turbine generator and the resulting stresses to the foundation make routine inspections and testing essential to maintaining the structural integrity of the turbine. The recommended practices for foundation maintenance contained in this section pertain to inverted

T spread footings with a peripheral arrangement of anchor bolts holding the tower to the foundation in tension. It should be noted that the vast majority of turbine foundations in North America are this type. For turbines supported by different foundations, similar inspection and maintenance procedures can be implemented with some alterations depending on the circumstances.

1. DEFINITIONS AND DIAGRAMS

1.1. Anchor Bolt

The steel stud which attaches the tower base to the foundation.

1.2. Anchor Nut/Hex Nut

The Anchor Nut holds the tension load of the anchor bolt to the tower base flange.

1.3. Kip

A unit of force that equals 1,000 pounds.

1.4. PSI

A unit of force equal to 1 pound per square inch.

1.5. Diagram of bolts/tower wall. *(See Figure A.)*

1.6. Anchor Bolt Numbering Example Diagram. *(See Figure B.)*

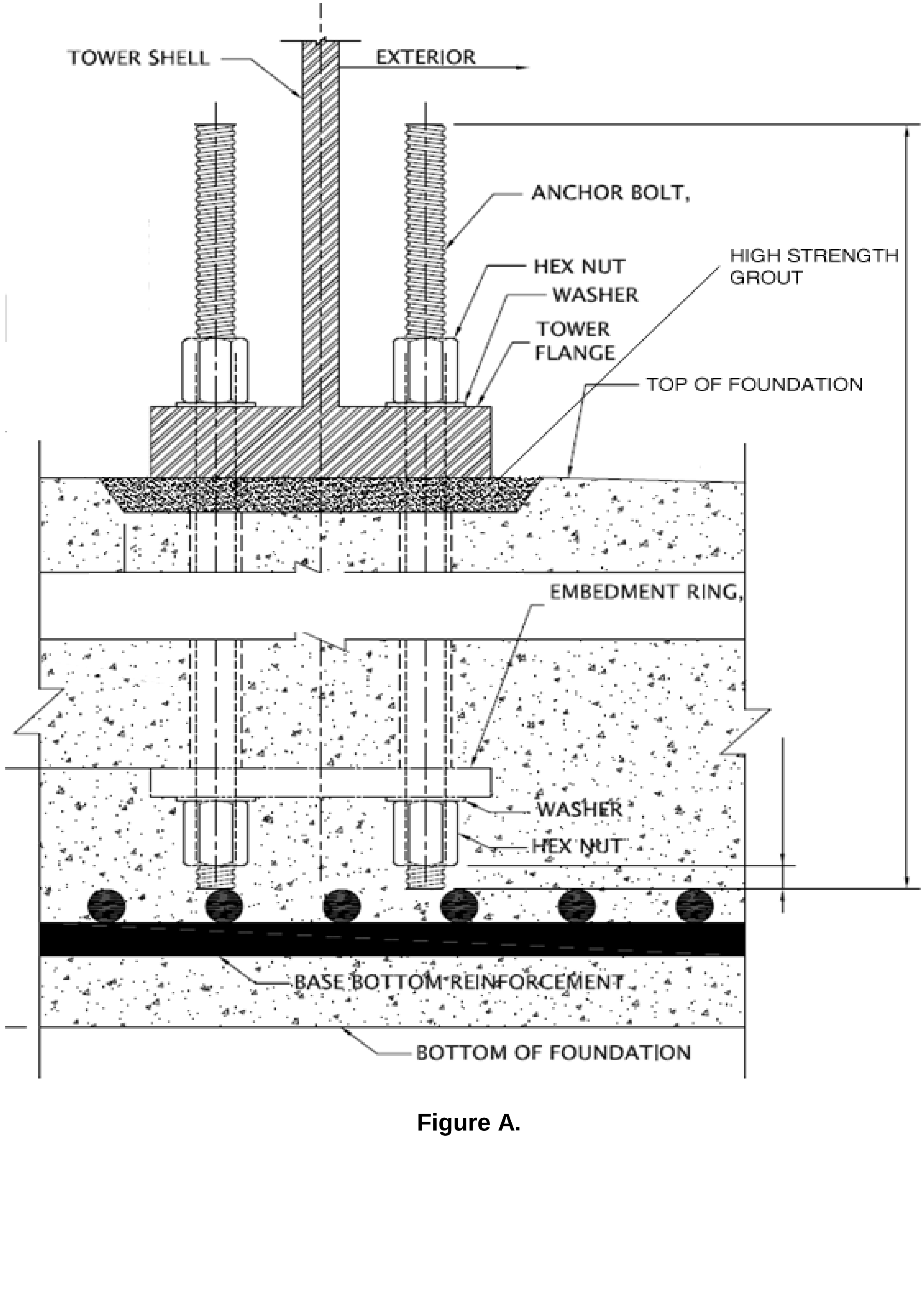
TOWER SHELL
EXTERIOR
ANCHOR BOLT,
HEX NUT
WASHER
HIGH STRENGTH GROUT
TOWER FLANGE
TOP OF FOUNDATION
EMBEDMENT RING,
WASHER
HEX NUT
BASE BOTTOM REINFORCEMENT
BOTTOM OF FOUNDATION

Figure A.

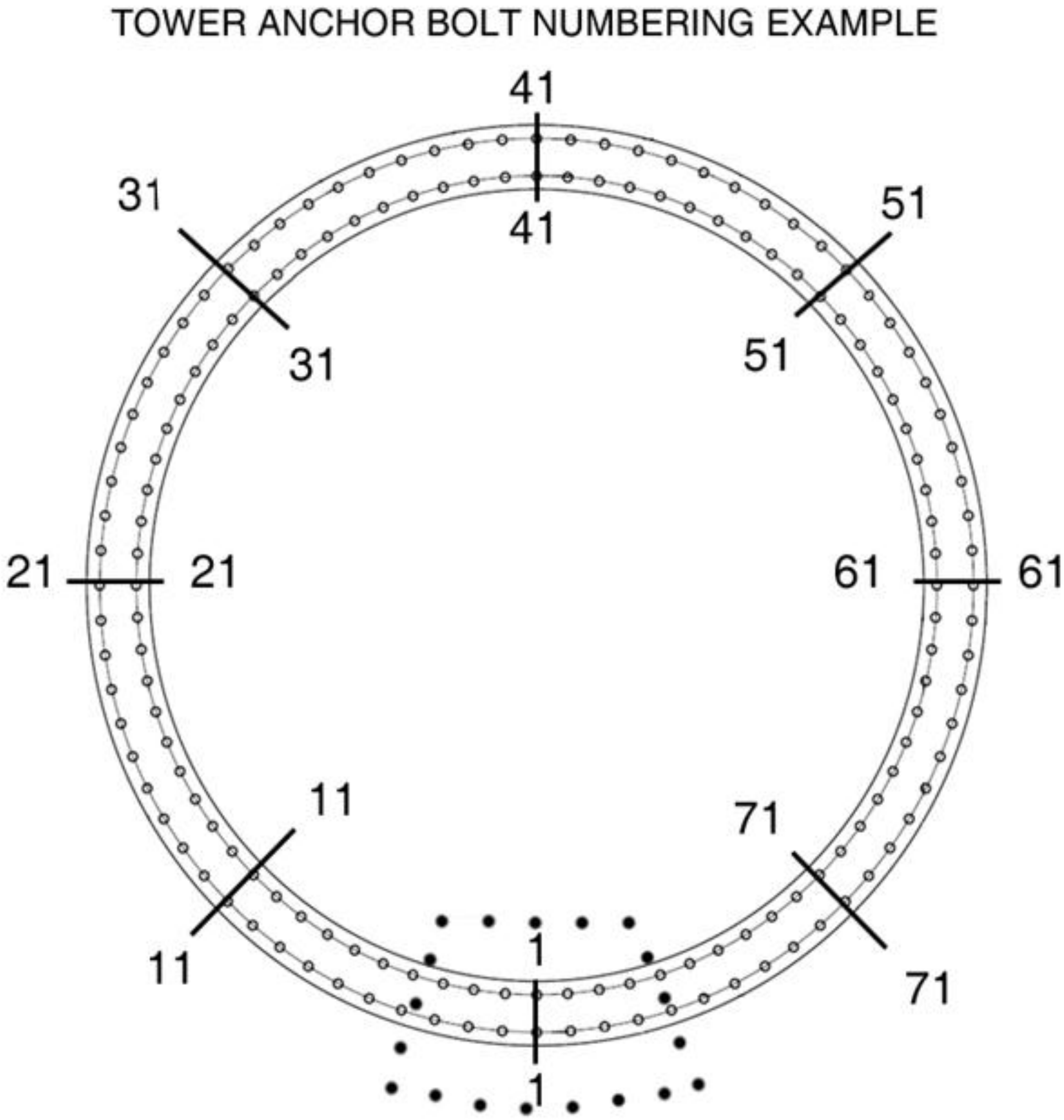

Figure B.

2. SAFETY

2.1. Personal Protective Equipment (PPE) must always be worn while performing tensioning work. This includes but is not limited to hard hats, shatter-proof safety glasses, EH protected steel-toed work boots, leather gloves and non-melting work clothing.

2.2. Equipment and tooling inspections should be performed before every shift. Run maximum daily pressure through tensioning system in controlled environment to check for leaks. Replace faulty components immediately if leaks are detected. Hydraulic oil injection into bloodstream is a major health and safety concern.

2.3. Follow OSHA guidelines for inspecting and marking all power tools, cords, ladders, etc.

2.4. If working conditions are classified as a confined space, all necessary measures must be followed to ensure a safe and proper work environment.

3. INSPECTIONS

3.1. 10% anchor bolt tension inspections

10% anchor bolt tension inspections are to be performed once a year for years 1-5 and every 5 years thereafter if all bolts pass final inspection. See section 6: *10% Tensioning Procedures* for full description of procedure.

3.2. Grout and concrete inspections

Grout and concrete inspections are to be performed yearly on 100% of the turbines for the first 5 years of the project. After the 5 year benchmark, 50% of the turbines should be inspected yearly for the remainder of the project. If issues are discovered on any turbines during the inspections, 100% of the turbines should be inspected at that time. If cracking or spalling is discovered, it must be tracked and documented. If repairs are necessary, perform them immediately or they will likely worsen. If inspections reveal cracking or spalling of the concrete or grout, seal them immediately with an approved sealant. Monitor and document every 4 months from then on to ensure issues do not worsen.

3.3. Anchor bolt corrosion inspections

Anchor bolt corrosion inspections should be performed in conjunction with grout and concrete inspections. Inspect for corrosion of interior and exterior anchor bolts, nuts and washers. If corrosion is present, note and rectify immediately with approved greases or anti-corrosive coatings. **Treat corrosion as a foundation indicator.** If anchor bolts are excessively corroded there is a high likelihood the nuts are seized to the bolt, and the bolts are not holding proper tension.

3.4. Complete approved inspection documents for each turbine. These documents must reflect all relevant findings and data. Being able to reference historical documents can become an invaluable tool as the project ages.

4. EQUIPMENT

4.1. Tensioning system calibrations are to be verified 3 times daily when performing 10% tests and before every tower on 100% tensioning. As ambient temperatures rise and fall, it is likely that the temperatures of the hydraulic oil will change as well, possibly resulting in varying PSI's of oil pressure needed to achieve the desired load. All calibrating machinery, including oil gauges, must have current certifications. If variations of more than 5% are detected during calibrations throughout the day, the previous tower completed should have 4 bolts tested at random to ensure they have been tensioned properly. If tests reveal loose anchor bolts, rectify as necessary.

4.2. Maintain pumps, jacks and hoses in controlled environment. Never store in freezing temperatures.

4.3. Keep working pumps in controlled environment if ambient temperatures are below freezing. A heated van, box truck or heated trailer all work fine for maintaining acceptable working temperatures of the pumps.

4.4. An oil pressure regulator should be utilized on the pump to assure that the desired PSI is being achieved each and every throw. Many pumps available today will push 20,000 PSI in as little as 3 seconds. At these speeds, discrepancies by the pump operator in fractions of seconds will result in thousands of pounds of differing tension. Setting the pressure regulator to a desired PSI, verified by the tensioning calibrator is the only way to ensure the proper tension is applied to each anchor bolt every time.

4.5. The tensioning system must allow for visibility of the anchor nut and washer on the bolt being tensioned. Being able to observe the nut and washer lifting under tension, and then being able to visually confirm that the nut has been properly tightened under tension is of utmost importance. Often times on operational projects nuts and washers corrode to each other and to the anchor bolt, thus requiring force to break them free. If anchor nuts are found to be sticky, two pancake jacks with a steel plate will allow for the throw of a large wrench. If nuts are moving freely, a single over-the-bolt tensioner will work fine, but it must allow for visibility of hardware for the reasons stated above. If the anchor nut and washer are not tight to the tower flange prior to releasing pressure from the tensioning system, the anchor bolt is not properly tensioned. Appropriate testing will reveal such issues.

5. 10% TENSIONING PROCEDURE

5.1. Approximately 1 year after the project has been 100% tensioned, 10% of the anchor bolts should be selected at random on 20% of the turbines. The testing value should be to the lowest specified engineered value. For example if the foundation drawings specify a tension of 75kips +5 -0 then all 10% testing is to be done at 75kips.

5.2. Anchor bolts should be numbered beginning with the bolt centered under the tower door being number 1 *(see Figure B)* with subsequent numbers in ascending order clockwise around the circumferences of the interior and exterior base flanges. The referenced bolt numbers should fall in the same position on every tower of the project.

5.3. Two exterior/interior anchor bolts will be selected at random as a starting point. From the starting point, tension every 10th bolt until a minimum of 10% of the bolts have been tested.

5.4. Every bolt tested must have visual confirmation from technicians that the anchor nut is tight to the flange prior to releasing tension from jack(s). If nuts are sticky from corrosion, necessary means must be employed to ensure the anchor nuts are tight to base flange prior to releasing pressure from the tensioning system.

5.5. Through performance documenting (outlined below) determine if the tower has passed or failed the tensioning check. If any singular anchor bolt is discovered to have an “as found” tension of less than 85% of the specified tension, it is to be deemed a failure and will require 100% of the anchor bolts to be tensioned on that tower following the procedure described in section 7.

5.6. If the population of tested anchor bolts has an average “as found” tension of less than 90% of the engineered specified value, that tower is to be deemed a failure, thus requiring 100% re-tensioning.

5.7. If any of the foundations fail the 10% test, then all of the foundations on the project must be 10% tested.

5.8. Repeat 10% tension check procedure as stated above on years 2 through 5 of the project. After year 5, when all of the foundations have been tested, and foundations have been properly tracked, revert to a 10% tension check on 20% of the project every 5 years for the remainder of the project, following the same pass/fail criteria. A different 20% of the foundations should be tested every year, so at year 5, all foundations will have been tested and documented.

5.9. Technician should sign interior tower basement wall under the doorway with initials, date and description of work; i.e. 10% tension @ 75 kips, and company abbreviations.

5.10. Sample 10% tension testing report. *(See Figure C.)*

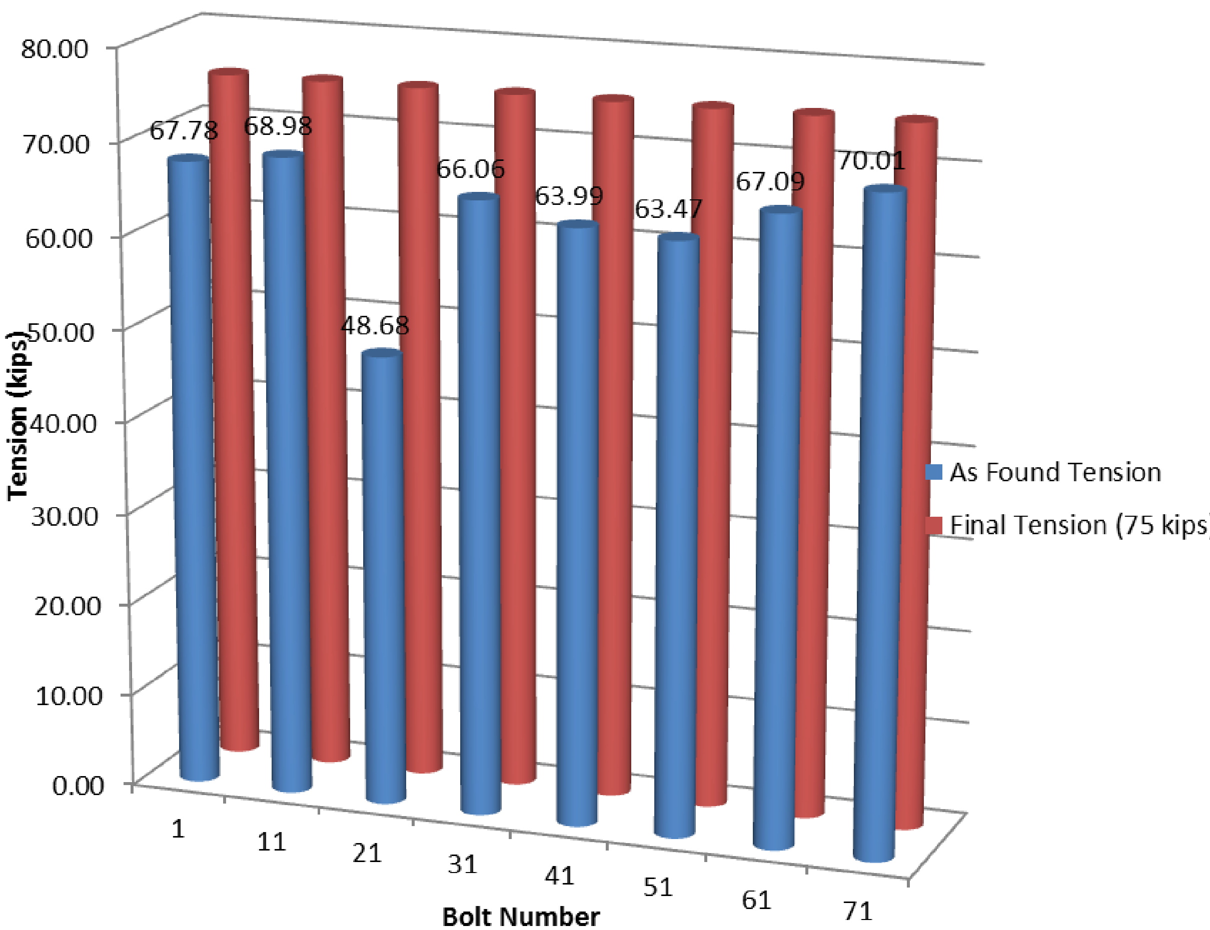

Figure C. As Found Tension (kips) vs. Final Tension (kips).

6. 100% TOWER TENSIONING

6.1. After construction has achieved final completion, a 100% anchor bolt tensioning should be completed within 6 months. It is important to record and document tension findings during this time.

6.2. Number foundation anchor bolts with permanent paint pen on top of bolt. Follow numbering sequence outlined in section 6.2 and illustrated by Figure B. *(See Figure B.)*

6.3. 100% tensioning should be completed to the highest engineered specified value. For example, if the foundation drawings specify a tension of 75kips +5, -0 then the 100% tensioning value is to be completed at 80kips. Verify proper system calibration every tower.

6.4. Beginning at bolt 1, tension all anchor bolts in ascending numerical order around circumference of tower to desired tension.

6.5. Repeat immediately on opposing flange.

6.6. Technicians should sign interior tower basement wall under doorway with their initials, date, description of work, i.e. 100% tension @ 80kips, and company abbreviations.

6.7. Accurately record and report findings for each anchor bolt tensioned. This condition monitoring information will be utilized for future evaluations of 10% checks, and offer historical data for monitoring performance and identifying future failures before they happen. Anchor bolts that continually lose tension are indications of larger issues that include but are not limited to grout failures, foundation failures, foundation settling, concrete shrinkage, chronic anchor bolt relaxation, poor previous workmanship, etc.

SUMMARY

The forces that wind turbines endure from harnessing the wind causes continual strain to their foundations. Construction builds a stationary structure; operations maintain the working structures. As the wind industry matures there is a growing understanding of the importance to properly maintaining the foundations. The earlier an owner can start monitoring a foundation's performance, the higher the likelihood of identifying warranty issues now, and preventing costly issues later.

RP 402

FALL PROTECTION, RESCUE SYSTEMS, CLIMB ASSIST AND HARNESS

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chair: Oliver Hirschfelder, Capital Safety
Principal Author: Oliver Hirschfelder, Capital Safety

PURPOSE AND SCOPE

This set of recommended practices addresses the common maintenance issues related to the grounding systems for generator and drive train shafts in various wind turbine designs. It is not machine specific and some adaptation may be required based on specific designs.

FALL PROTECTION, RESCUE SYSTEMS, CLIMB ASSIST AND HARNESS

1. FLEXIBLE CABLE LADDER SAFETY SYSTEM

1.1. Flexible cable ladder systems are designed to provide protection against falling for persons climbing vertical surfaces. These systems include installations on fixed ladders

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within the tower. The following inspection criteria is for user inspection and information purposes only. Formal inspections of ladder climbing systems must be conducted by personnel certified in their installation and inspection as required by the manufacturer.

2. CABLE SYSTEM INSPECTION

2.1. Inspect the top and bottom anchorage brackets for damage, corrosion, or rust. Look for cracks, bends or wear that could affect the strength and operation of the system. Inspect for loose or missing fasteners; retighten or replace them if necessary.

2.2. Inspect the cable guides. Ensure the cable guide is not worn or bent, and still locks on the cable. Inspect for loose or missing fasteners; retighten or replace them if necessary.

2.3. Inspect the carrier cable for damage. Look for worn or broken cable strands. Inspect for signs of abrasion against the ladder or structure. The cable must not contact the ladder or structure. Replace damaged cable if necessary. Check the carrier cable tension, ensuring there is no slack and re-tension the carrier cable if necessary.

2.4. Inspect the ladder structure for damage, rust or deterioration that could affect the strength of the ladder.

2.5. Inspect the installation and service label. The label should be securely held in place and fully legible. Record inspection dates on the system label.

3. LADDER SAFETY SLEEVE INSPECTION

3.1. Inspect the handle and cable shoe for bends, cracks and deformation. All fasteners must be securely attached. Operation of the handle and cable shoe must be free and smooth. Spring must be secure and of sufficient strength to pull the handle.

3.2. Inspect the locking lever for smooth operation, ensuring it springs back into its locked position when released.

3.3. Inspect the sleeve body for wear on the inside where the cable passes through.

3.4. Inspect the rollers and the upper roller extension. Ensure the rollers spin freely and the spring rotates the upper roller extension to the climbing position.

3.5. Inspect the gravity stop. Hold the sleeve upside-down and ensure the gravity stop rotates into the locking position. It should not be possible to open the sleeve far enough to insert the cable.

3.6. Inspect all labels and markings. Check that labels and markings are fully legible.

4. RESCUE DEVICE

4.1. Inspect for loose screws and bent or damaged parts.

4.2. Inspect the side plates for distortion, cracks or other damage.

4.3. Inspect the rope for cuts, severe abrasion, or wear. Check for contact with acids or other chemicals.

4.4. Inspect to make sure that the rope lies correctly in the pulley.

4.5. Inspect the contact surface of the drum for any sign of wearer strain. Check for distortion in the top loop.

4.6. Do not disassemble the Rescue block. It is not user serviceable.

4.7. With the unit properly mounted from any sturdy structure, test the functional load.

4.7.1. Make sure that the rope drum locks in the clockwise direction (reverse lock operative).

4.7.2. Make sure that the rope drum rotates freely in the counterclockwise direction (reverse lock not operative).

4.7.3. Make sure the stationary pulleys can be inserted and the locking bolt locked; that the locking pins in the locked state protrude about 5/32 in.

5. INSPECTION STEPS FOR PULLEYS

5.1. Inspect that the pulleys are clean and free from grease.

5.2. Inspect the contact surface of the pulleys for any sign of wear or strain. Check for distortion in connecting loops.

5.3. Inspect side plates for distortion, cracks, or other damage.

5.4. Make sure that the pulley can be rotated freely and without resistance.

If inspection or operation reveals a defective condition, remove the rescue unit from service immediately.

6. INSPECTION CABLE SLEEVE

6.1. Frequency

6.1.1. Before each use

Inspect the detachable cable sleeve according to Sections 5.2 and 5.3.

6.1.2. Formal inspection

A formal inspection of a detachable cable sleeve must be performed at least annually by a competent person other than the user. The frequency of formal inspections should be based on conditions of use or exposure. *(See Sections 5.2 and 5.3.)* Record the inspection results in an inspection and maintenance log.

6.1.3. After a fall

A formal inspection of a detachable cable sleeve must be performed by a competent person other than the user. Record the inspection results in an inspection and maintenance log.

6.2. Inspection Guidelines For Cable Sleeve

For identification of the example components described in the following guidelines, *see Figure A*.

6.2.1. Inspect the handle (1E) and cable shoe (1H) for bends, cracks, and deformities. All fasteners must be securely attached. Operation of handle and cable shoe must be free and smooth. Springs must be secure and of sufficient strength to pull handle down.

6.2.2. Inspect the locking lever (1J) for smooth operation, ensuring it springs back into its locked position when released.

6.2.3. Inspect the sleeve body (1M) for wear on the inside where the cable passes through.

6.2.4. Inspect the impact indicator pin (1L). If the indicator pin is missing or damaged, the sleeve should not be used until the pin is replaced.

6.3. Inspect the energy absorber (1K) to determine it has not been activated. The energy absorber cover should be secure and free of tears or damage.

A	Cable
B	Upper Roller
C	Upper Roller Extension
D	Label
E	Handle
F	Carabiner
G	Lower Roller
H	Cable Shoe
I	Gravity Stop
J	Locking Lever
K	Energy Absorber
L	Impact Indicator Pin
M	Sleeve Body

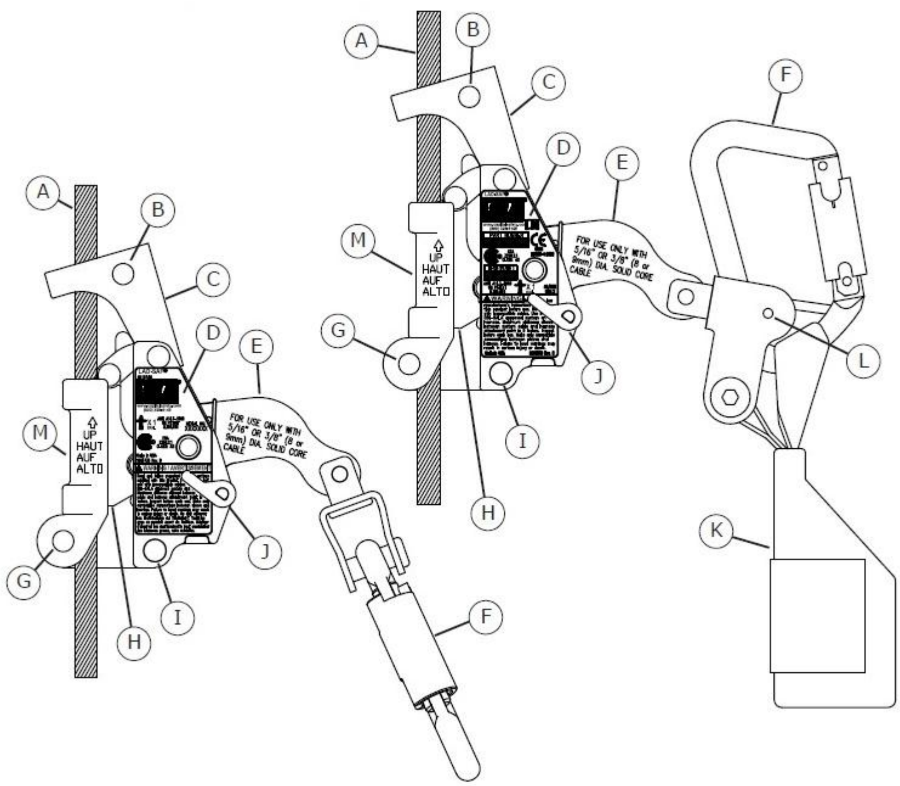

Figure A. Example of safety cable device (sleeve)

6.4. If inspection reveals an unsafe or defective condition remove the detachable cable Sleeve from service and destroy or contact an authorized service center for repair. Record the results in an inspection and maintenance log.

7. INSPECTION CLIMB ASSIST

7.1. Inspection Frequency

A portable motor control and cable grip must be inspected at the intervals defined by the manufacturer. Examples of inspection procedures are described in the example *Inspection and Maintenance Log (See Figure B.)* Inspect all other components of the Powered Climb Assist System per the frequencies and procedures defined by the manufacturer.

7.2. Defects

If inspection reveals an unsafe or defective condition, replace or repair the affected component(s) prior to further use of a powered climb assist system. Repairs must be performed by an authorized service center.

7.3. Product Life

The functional life of a powered climb assist system is determined by work conditions and maintenance. As long as the product passes inspection criteria, it may remain in service.

7.4. Cleaning

Cable grips may be cleaned using commercial parts cleaning solvents and rinsed with warm, soapy water. Light machine oil may be applied to moving parts if required. Do not use excessive oil, or allow oil to contact cable clamping surfaces. Clean attached lanyards with water and mild soap solution. Rinse and thoroughly air dry. Do not force dry with heat.

IMPORTANT: If the cable grip or attached lanyards contact acids or other caustic chemicals, remove from service and wash with water and a mild soap solution. Inspect per Table 2 before returning to service.

Serial Number(s):	**Date Purchased:**
Model Number:	**Date of First Use:**

Inspection Date:	**Inspected By:**		
Component:	**Inspection:** (See Section 1 for *Inspection Frequency*)	**User**	**Competent Person**
Cable Grip (Diagram 1)	Inspect the Cable Grip for cracks, bends, or other deformities that might affect performance. The Handle (A) should be securely attached to the Sleeve (B) but should pivot freely around the Rivet (C). Teeth (D) should be present on the end of the handle that contacts the Wire Rope Cable.	☐	☐
	Marking on the Cable Grip must be legible. See the back pages of this manual for required markings and their locations.	☐	☐
Cable Grip Lanyards (Diagram 2)	If so equipped, inspect attached web lanyards for concentrated wear, frayed strands, broken yarn, burns, cuts, and abrasions. The lanyard must be free of knots throughout its length. Inspect for excessive soiling, paint build-up, and rust staining. Inspect for chemical or heat damage indicated by brown, discolored, or brittle areas. Inspect for ultraviolet damage indicated by discoloration and the presence of splinters and slivers on the webbing.	☐	☐
Portable Motor Control Unit (Diagram 3)	The Motor Control Unit Enclosure should be clean and free of cracks or other deformities that might impact performance of internal components.	☐	☐
	The Motor Control Unit Power Cord should be free of cracks or holes in the outer casing and frayed, broken, or exposed wires. Plug ends should be free of defects and appropriate for the designated power source.	☐	☐
	Plug the Power Cord into the Motor Control Unit and appropriate power source. Pull out the Emergency Stop Button. The lights on the control panel will flash momentarily and then the yellow Power Button (⏻) light (A), first red Climb Assist Force light (B), and one of the green Motor Spin Direction lights (C) will stay lit. Verify that the correct Motor Spin light is lit for your Drive Bracket orientation. Press the Power Button (⏻) and the Power Button light will switch from yellow to green. If the control panel lights do not illuminate in the described manner, consult the Troubleshooting Chart in Section 3.4.	☐	☐
	All labels should be present on the Motor Control unit and should be fully legible. See the back pages of this manual for required labels and their locations.	☐	☐
Other Components	Inspect the PCAS Brackets, Wire Rope Cable Loop, and Wear Pads per instructions in the *"Installation and Maintenance Manual" (5903447)*. Inspect the Full Body Harness per the Manufacturer's instructions.	☐	☐

Figure 2. Example of Inspection and Maintenance Log.

7.5. Authorized Service

Additional maintenance and servicing procedures should be completed by a factory authorized service center. Authorization should be in writing. Do not attempt to disassemble and repair components of a powered climb assist system.

7.5.1. Storage

When not in use with a powered climb assist system, store motor control units and cable grips in a cool, dry, clean environment out of direct sunlight. Avoid areas where chemical vapors may exist. Thoroughly inspect components after extended storage.

8. INSPECTION of FULL BODY HARNESS

8.1. Frequency

Before each use inspect the full body harness according to manufacturer's guidelines. The harness must be inspected by a competent person, other than the user, at least annually. (A competent person is one who is capable of identifying existing and predictable hazards in the surroundings or working conditions which are unsanitary, hazardous, or dangerous to employees, and who has authorization to take prompt corrective measures to eliminate them.) Record the results of each formal inspection in an inspection and maintenance log.

IMPORTANT: If the full body harness has been subjected to fall arrest or impact forces it must be immediately removed from service and destroyed.

IMPORTANT: Extreme working conditions (harsh environments, prolonged use, etc.) may require increasing the frequency of inspections.

8.2. Inspection

8.2.1. Inspect harness hardware (buckles, D-rings, pads, loop keepers, vertical torso adjusters)

These items must not be damaged, broken, distorted, and must be free of sharp edges, burrs, cracks, worn parts, or corrosion. PVC coated hardware must be free of cuts, rips, tears, holes, etc. in the coating to ensure non-conductivity. Ensure that release tabs on buckles work freely and that a click is heard when the buckle engages. Inspect vertical torso adjusters for proper operation. Ratchet knobs should turn with ease in a clockwise direction and should only turn counterclockwise when the knob is pulled out.

8.2.2. Inspect webbing

Material must be free of frayed, cut, or broken fibers. Check for tears, abrasions, mold, burns, or discoloration. Inspect stitching; check for pulled or cut stitches. Broken stitches may be an indication that the harness has been impact loaded and must be removed from service. When performing the annual formal inspection, unsnap and open the back pad to facilitate inspection of the webbing.

8.2.3. Inspect the labels

All labels should be present and fully legible.

8.2.4. Inspect system components and subsystems

Inspect each system component or subsystem according to manufacturer’s instructions.

8.2.5. Record inspection data

Record the inspection date and results in an inspection and maintenance log.

8.2.6. Inspect the Stitched Impact Indicator

The stitched impact indicator is a section of webbing that is lapped back on itself and secured with a specific stitch pattern holding the lap. The stitch pattern is designed to release when the harness arrests a fall or has been subjected to an equivalent force If the impact indicator has been activated the harness must be removed from service and destroyed.

8.2.7. Inspect suspension trauma straps

Check the trauma strap pouches for damage and secure connection to the harness. Unzip the trauma strap pouch on each hip of the harness and inspect suspension trauma straps. Webbing and pouch material must be free of frayed, cut, or broken fibers. Check for tears, abrasions, mold, burns, discoloration, or knots.

IMPORTANT: If inspection reveals a defective condition, remove the unit from service immediately and destroy it.

NOTE: Only manufacturer or parties authorized in writing should make repairs to this equipment.

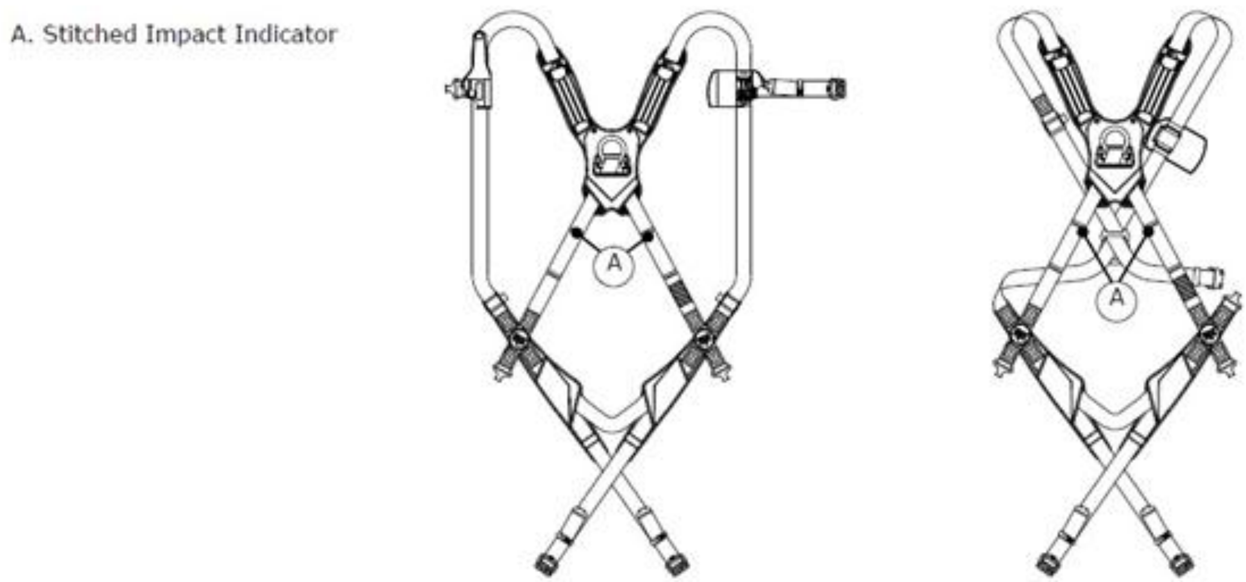

Figure C. Example of stitched impact indicators.

8.3. Washing Instructions

Washing procedures for the full body harness are as follows:

8.3.1. Spot clean the full body harness with water and a mild soap solution.

IMPORTANT: Use a bleach-free detergent when washing the harness and pads. Fabric softener or dryer sheets SHOULD NOT be used when laundering and drying the harness and pads.

8.3.2. Water temperature for wash and rinse must not exceed 160°F (70°C).

8.3.3. The harness and pads may be air dried or tumble dried on low heat not exceeding 200°F (90°C).

NOTE: More information on cleaning is available from the manufacturer. If you have questions concerning the condition of your harness, or have any doubt about putting it into service, contact the manufacturer.

8.4. Additional Maintenance And Servicing

Additional maintenance and servicing procedures should be completed by a factory authorized service center. Do not attempt to disassemble the unit.

8.5. Storage

Store the full body harness in a cool, dry, clean environment out of direct sunlight.

Avoid areas where chemical vapors may exist. Thoroughly inspect the full body harness after extended storage.

RP 404

WIND TURBINE ELEVATORS

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chair: Oliver Hirschfelder, Capital Safety
Principal Author: Carisa Barrett, Elevator Industry Work Preservation Fund

PURPOSE AND SCOPE

This set of recommended practices addresses the common maintenance issues related to the wind turbine elevator. It is not machine specific and some adaptation may be required based on specific designs.

INTRODUCTION

Before installing, maintaining, and or repairing any wind turbine elevators, check with the "Authority Having Jurisdiction" you are working in, for permitting and inspection requirements. If they are regulated, all work must be performed in accordance with the adopted codes, rules, and regulations. Currently a majority of jurisdictions require conformance to ASME A17.1/CSA B44, section 5.11. Companies should be cognizant that some jurisdictions do not have requirements and the elevators purchased may not conform to the new code requirements, care should be taken to consider risks associated with this lack of conformance.

<u>THESE REQUIREMENTS INCLUDE THE FOLLOWING EXCERPTS:</u>

1. Elevator, wind turbine tower

1.1. A hoisting and lowering mechanism equipped with a car installed in a wind turbine tower.

2. Part 5 applies to special application elevators as specified in the following requirements:

(k) Section 5.11 applies to elevators used in wind turbine towers

3. Scope:

Requirement 5.11 applies to elevators permanently installed inside an enclosed wind turbine tower to provide vertical transportation of authorized personnel, their tools and equipment for the purpose of servicing, maintaining, and inspection of wind turbine equipment.

Such elevators are typically subjected to extreme temperatures, humidity variations, and substantial horizontal motion where, by reason of their limited use and the types of construction of the structures served, full compliance with Part 2 is not practicable or necessary.

4. For more information on this standard or to order a copy of the *ASME A17.1-2013/CSA B44-13* please contact:

ASME Order Department
22 Law Drive
Box 2300
Fairfield, NJ 07007-2300
Tel: 800-843-2763
Fax: 973-882-1717
E-Mail: infocentral@asme.org
ASME Website: www.asme.org/catalog

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RP 501

GADS REPORTING PRACTICES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chair: David Zeglinski, OSIsoft, LLC
Principal Author: Michael Curley, North American Electrical Reliability Corporation (NERC)
Contributing Author: Scott Gronwold, Midwest Generation – Edison International

PURPOSE AND SCOPE

The purpose of this document is to describe best practices in reporting data to NERC's GADS system.

INTRODUCTION

NERC's Generating Availability Data System (GADS) is the industry standard for reporting Availability performance data. It was established in 1982.

The system has been invaluable to NERC in helping to assess Bulk Electrical System (BES) reliability issues and trends. In 2012, GADS became mandatory for conventional generating units over 50 MW in size. Before 2012, approximately 73% of the conventional generators reported their Availability data to GADS in 2010.

Benchmarking is the secondary use of GADS data. NERC and many consultants use GADS data to compare units' performance. For years, conventional generators have used GADS data to drive Continuous Improvement Programs by comparing their performance to industry performance. GADS allows an "apples to apples" comparison of data that is necessary to benchmarking programs.

Currently only around 4% of Wind generation is reporting data to GADS. Without a large jump in this percentage, benchmarking wind availability performance is not possible.

There has been discussion of having the reporting of Wind GADS data be mandatory, but that has not been approved by NERC as of now.

MAJOR SECTION - USE PROCEDURAL STEPS BELOW

1. PROCEDURES (DETAILED DESCRIPTIONS)

The GADS Data Reporting Instructions (DRI) are available on the NERC website:

http://www.nerc.com/page.php?cid=4|43|45.

In order to have proper benchmarking, it is necessary for generators to report GADS data. Reporting the following would be considered a best practice.

1.1. Design Data

This data is critical to be sure that GADS provides "apples to apples" benchmarking data to industry. Design Data is covered in Section 3 of the GADS DRI. This covers items such as:

1 Make and model of turbine

2 Wind class

3 Commissioning year

1.2. Performance Data

GADS uses consistent formulas developed by industry to calculate the key availability metrics. This data will allow wind generators to compare their performance to others, knowing that when they see a term it has a standard definition and has been calculated in a consistent manner.

In order to use the full power of GADS data, it is necessary that a best performer report the following (all of these items are defined in the GADS DRI):

1. Roll up data (generation, turbine outage hours, etc.)
2. Resource indicators (EAF, capacity factor, etc.)
3. Outage data by system and component (i.e. brake - high speed shaft brake)

This reporting will allow not only big picture availability comparisons among generators, but will also allow generators to see if their system and component failures are in line with the rest of industry. Currently we rely on word of mouth and general feeling when trying to determine is we have (for example) more generator failures on a specific turbine than others. GADS will allow for an objective answer to those questions.

NERC provides free software to allow for easy reporting. It is located at:

http://www.nerc.com/page.php?cid=4|43|46.

RP 502

SMART GRID DATA REPORTING

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

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This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chair: David Zeglinski, OSIsoft, LLC
Principal Author: David Zeglinski, OSIsoft, LLC
Contributing Author: Alistair Ogilvie, Sandia National Laboratories

PURPOSE AND SCOPE

This Recommended Practices section focuses on generating, collecting and serving up wind farm data for smart grid operation, power purchaser and owner/operator reporting as well as data sets for maintenance and reliability improvements. There are several key components – asset identification, the metadata system associated with those assets and the data collection system itself.

SMART GRID DATA REPORTING PROCEDURES

1. ASSET IDENTIFICATION, METADATA SYSTEM

1.1. Develop a Detailed Taxonomy

Developing a detailed equipment breakdown or taxonomy helps ensure that maintenance data is captured with enough detail to be useful. Using a breakdown of the equipment that provides a unique assessment opportunity for each component or part ensures greater insight in determining which assemblies, subassemblies, or components significantly affect reliability and availability performance (for example, "Drivetrain-Gearbox-Bearings-Planetary Bearing" provides much more information than just "Gearbox"). Fortunately with metadata software, this needs to be done only once for each equipment type. The elemental framework can then be copied for each turbine where only the turbine name or number is globally replaced as it is copied/duplicated.

1.2. Attend to the Details

With any data collection system, one of the biggest challenges is ensuring that data is entered for every applicable data field. In addition to entering all the relevant information, ensuring that standard and correct information is entered is also essential. There is often a trade-off to be made when weighing the value of data collected against the cost of collecting it. With the right hardware and smart software, it is possible for technicians to record data quickly and accurately without adding an unnecessary burden. A well-designed system can greatly reduce the amount of follow-up data entry and provide the quality assurance required.

1.3. Ease of Use

To have an accurate, consistent and useable system, it is important to limit the amount of time spent entering and updating records. This can be achieved by incorporating automated data collection and validation into maintenance processes. In addition to automated validation, use of handheld devices can decrease entry error and allow for automated capture of many data elements (for example, date, time, asset, technician, etc.). Typically, the manner that maintenance data will be used is not known at the time the system is implemented. Modern software systems can provide an interface that makes data entry easy and accurate, and they can also store information in a way that facilitates later use by the various groups who need to access the data. These software systems must allow for modification of the metadata frames that then port to all similar assets so the system can be realistic, dynamic and “future-proof”.

1.4. Root Cause Analysis – Down to the Bolt

To truly understand the impact each part has on overall reliability and availability, it is important to distinguish between parts that caused a failure (primary failures), parts that failed as a result of the primary failure (secondary failures), and other parts that need to be repaired/replaced in the process of performing maintenance on parts with primary and secondary failures (ancillary failures). For example, if a power spike from a power supply causes the power supply to fail and also shorts out a circuit board under a console panel, then the power supply has a primary failure, the circuit board has a secondary failure, and the console panel has an ancillary failure. If multiple parts are worked on for the same maintenance action, a Failed Part field could be used to identify parts with primary failures and distinguish them from those with secondary or ancillary failures. Additionally, parts are sometimes opportunistically replaced when other maintenance events are underway, thus significantly reducing their replacement time and/or cost compared to their usual replacement time and/or cost. These opportunistic replacement activities should also be captured. In some cases, the part with a primary failure may not be obvious at the time of the maintenance event. In these cases, returning to the maintenance record after the root cause is discovered will be important, to create an accurate and complete assessment of the maintenance event.

1.5. Cost Tracking – Labor and Replacement Parts

While availability and reliability are key metrics in assessing equipment performance, understanding what is driving maintenance costs can be just as valuable. Typically, the parts and personnel costs are stored outside the maintenance system, and the relevant information from the maintenance system (including parts replaced and man-hours) is used to calculate the total cost for each maintenance event. This information needs to be holistically integrated with the real-time data via connectors to the Enterprise Resource Planning (ERP) system(s). Only then can visibility from normal operation to fault to repair and all of the costs associated be coordinated. When this information is integrated and available to all personnel responsible for asset operation, then root cause analysis and a complete understanding of asset operation costs can be obtained and kept for future use.

1.6. Parts Source Identification

For relevant event types, the source of parts should be clearly captured. This includes parts cannibalized from other equipment, purchased outside the main supply system, and acquired by others means (including parts machined on site). Identifying the source of parts (including those exchanged between equipment) will allow for accurate cost calculations, in addition to setting the stage for advanced CMMS uses such as parts and inventory tracking; this can be accomplished through a "Parts Source" field. Integrating this information with real-time data (again) is critical to a complete asset management system for the wind plant.

2. DATA COLLECTON SYSTEM

The first step to information-rich decision making is accessible storage of the vast amounts of data generated by each turbine, substation and ancillary equipment (Balance of Plant – BOP). As with any storage solution, the initial step in the design process is the most important: deciding the type and use of information that needs to be extracted, analyzed and visualized. Designing a data collection infrastructure with the end use in mind allows for the eventual retrieval, analysis, reporting, and displaying of information in a far more efficient and effective manner.

2.1. Design, Install, Scale and Keep Evergreen Data Collection Systems

Wind plant operators want tools to drive their decisions with solid data. After determining what systems are most appropriate and the general type of data that should be captured, implementation is the next step. Yet implementation is not a trivial task, and requires committed and knowledgeable staff and executives both on the owner and vendor sides. Incomplete and ineffectual implementations result in high-cost systems with few benefits, often requiring replacement or upgrade before any return on investment can be achieved. Additionally, one of the most important aspects of a data architecture is that it needs to evolve. Many good systems are eventually tossed aside or misused because they do not evolve and grow as the business changes. For companies that own or operate multiple turbine technologies, the initial design stage also needs to include an assessment of the data available from each technology and a way to map these data points so that equal comparisons can be made.

The design of the data collection and storage systems can be approached from two directions: internal resources and external vendor and system integrator services. Often the use of internal skills and systems facilitates a custom approach that best suits the company and its existing infrastructure. However, realistic assessment of the skills available versus the skills required is an important first step. The use of an external vendor or system integrator can bring highly specialized professionals to develop a solution. However, customized options specific to internal business procedures and processes can often increase the price of development and extend the time needed to complete the project. A hybrid approach of using external contractors to fill any gaps in in-house knowledge is also an effective solution. Once it is established that the skills needed are available, a detailed cost assessment can then be performed.

Collecting data and collecting useful data are not the same, and this distinction is often the defining characteristic of a successful implementation versus an unsuccessful one. The vast amount of data available can paradoxically make collecting useful data more challenging. Wind plants produce staggering amounts of data – estimated annual storage of essential SCADA data from a plant with 100 modern wind turbines can exceed 150 Gigabytes of data annually and this figure increases dramatically if every SCADA tag is stored at the highest possible frequency. Collecting too many or too few pieces of data can both result in inefficient systems that do not produce the analysis results that are expected. Decisions need to be made in advance of collection to establish the types of analysis needed, thereby insuring the collection of the data needed to complete the analysis. Architecting the hardware properly at the sites to minimize data issues due to undersized hardware forcing future site upgrades (hardware and software) is key also. Management of the data system is also required during implementation to tune the data streams so that unnecessary data (instrument noise) is not collected. Proper tuning can dramatically reduce disk consumption and future storage requirements. Well managed data streams also allow rapid retrieval via the real-time data search systems.

While data collection for wind turbines is important, to fully understand plant reliability, data must be collected for turbines and other equipment in the Balance of Plant (BOP). Data from meteorological towers, the substation, and the electrical collection system are absolutely necessary to understand the reliability of the turbines and the whole plant. For example, turbine availability can be 100%, but if the substation is down the plant is not producing. Failing to capture such a situation will lead to large blind spots in any reliability analysis.

2.2. Data Collection and Storage

In any data storage scheme, the structure of the whole is as important as the structure of the individual parts. There are two common approaches to wind plant data storage;

relational databases and data historians. Relational database (RDB) products, offer storage of large data sets useful for non-real-time or instrument/equipment data. RDBs are very effective for storing asset information and other key textual data associated with the wind plant. This type of database is widely used in many implementations throughout many industries. Real-time data historian products are information technology systems that store time-series data, allowing the storage of large data streams at high speed while using compression to manage the hard drive storage space needed for these millions of pieces of information. Data historians are commonly found in manufacturing, pharmaceutical, and utility industries, including wind.

2.3. Supervisory Control and Data Acquisition (SCADA) – Timer Series Data

One of two main types of information captured by SCADA is time series data on turbine, BOP, and environmental conditions. For turbines, this time series data creates the “heartbeat” of the machine. It is collected almost continuously (typically once per second or more often) and is stored in regular intervals at the limit of the instrumentation and the data collection architecture. The various data streams that are captured are sometimes referred to as tags (for those familiar with traditional databases, a tag is like a database field). These data points record the operating conditions of the turbine and its parts, as well as the environmental conditions in which the turbine is operating. Many plants choose to archive their SCADA data in a real-time historian.

A multitude of time series data is available from a wind turbine SCADA system, enabling a great variety of analysis. As an example, the set of tags necessary for basic reliability analysis for a turbine is:

2.3.1. Turbine status or operating state

- Terminology can vary widely amongst owner operators or origina equipment manufacturers (OEMs), but some basic examples include: up and running, available but idle, down for repair, curtailed, manually stopped at turbine.

- This value can be stored as a text field (usually with abbreviated versions of the state descriptions), or as an integer (with a given number mapping to a specific description). Care should be taken that if this value is stored as an integer, that it is not translated to a real number in a historian or other database. If 1 means up and generating and 2 means down for maintenance, a value of 1.62 is not very useful.
- This value can be stored as a text field (usually with abbreviated versions of the state descriptions), or as an integer (with a given number mapping to a specific description). Care should be taken that if this value is stored as an integer, that it is not translated to a real number in a historian or other database. If 1 means up and generating and 2 means down for maintenance, a value of 1.62 is not very useful.
- For turbine status, high resolution data (data captured very frequently versus less often) is necessary to determine turbine status over the full course of a day, week, month, or year. When turbines are coming online and offline frequently, data that does not show the state changes does not provide enough visibility into the turbine's true condition. This limitation can be overcome either by collecting this data at a higher frequency, or by only capturing this data upon state change. Collecting upon change will yield the best data storage performance with respect to hard drive space consumption and retrieval speed.

2.3.2. Power generated

- Typically stored in kW for increased data fidelity, the power generated by the turbine is very useful for reporting on turbine production. It can also be a valuable "sanity check" when various data sources are in conflict regarding the turbine's actual status.
- Most SCADA systems offer more than one power metric (turbine, string, or park). It is important to be clear which is being reported. This is managed by careful meta-data and taxonomy design.

2.3.3. Wind Speed

- Typically, there will be at least two sources of wind speed data – the turbine's anemometry and the meteorological tower. Both sources can be useful to understand what is really happening at a turbine.
- All analyses of a wind plant's operations need to consider wind speed. Ideally, the actual wind speed (usually measured in meters per second) should be captured. When this data is plotted in a turbine power curve, a highly effective tool for combining wind speed and power output and determining (by the shape of the curve) how a turbine is performing is available to owner/operator and OEM staff.

NOTE: Beyond those listed above many of the other turbine, BOP and environmental tags in the SCADA time series data will be useful at some point for root cause reliability analysis. In particular, tags that are generally useful for root cause analysis include measures of temperature (including ambient air temperature and the temperature of components) and measures of other air conditions (including wind speed and direction, air pressure or density, and turbulence) as well as vibration modes from multiple contact points and rotational speeds of the components in the turbine. Transformer gas and condition monitors are also highly useful for preventing transformer failure as replacement lead times for these components are typically months to a year.

2.4. SCADA Alarms

The second type of SCADA data relates to alarms at the turbine. Events, alarms, and faults are collected when they occur (not continuously, as with the time series data, but are typically stored as a time series to correlate with the instrument and asset data streams). With this kind of data, information is only stored when something interesting happens - namely, events are recorded when the operating or environmental conditions of the turbine and its parts fall outside of specific boundaries. Combined with work orders, alarm information can help provide a complete set of downtime events for each turbine, BOP equipment, and the plant. Ideally, any alarm that requires human intervention will also have a work order associated with it. As an example, turbine alarms should contain the following information as a minimum:

2.4.1. Turbine Identifier

Recording the turbine ID links each alarm with a specific turbine.

2.4.2. Event Identifier

Most SCADA systems have a list of a few hundred alarm types (capturing an identifier for each alarm, then cross-referencing the meaning from a complete list of alarms and their attributes, provides much information about what was going wrong. Attributes can include useful information, such as whether an alarm can be automatically or remotely reset, and whether the alarm was triggered automatically or by human intervention. Cross-referencing can be done automatically through the construction of look-up tables and maintaining continuity between alarms, alarm codes, meta-data, real-time data and the overall plant and fleet taxonomy).

2.4.3. Alarm Set Date and Time

Date and time when the alarm begins.

2.4.4. Alarm End Date and Time

Date and time when the alarm ends.

2.5. Computerized Maintenance Management Systems – Work Orders

Beyond SCADA storage, many owner/operators have also implemented Computerized Maintenance Management Systems (CMMS) for their work orders. A CMMS enables access to work order data for trend analysis, detailed parts tracking, and root cause analysis. A CMMS is a crucial, but frequently overlooked, aspect of the data collection architecture; paper work orders and technician tribal knowledge are ineffective sources of information about turbine, BOP, single or multiple plant performance, especially over the life of the equipment and wind plant. One of the largest analysis challenges facing the wind industry is the current dependence on manual maintenance and repair documentation processes. These are not scalable and deprive owner/operators of the crucial corrective action information that is necessary for root cause analysis. Well-written work orders can provide a gold-mine of information for a company; poorly-written work orders can be a waste of valuable technician time.

One of the cardinal rules of a CMMS (or any other data entry system requiring human input) is that it needs to be as painless as possible to do data entry. Automating the data collection with handheld devices, bar coding and passive identification systems (Radio Frequency Identification - RFID) can mean the difference between capturing data or missing critical pieces of the operations and maintenance (O&M) puzzle. The people involved in work order data entry can vary widely, but often include technicians, administrative staff or management at the plant, and employees in an Operations Command Center (OCC). Other important aspects to keep in mind in designing data entry systems are that optional fields tend to remain blank and miscellaneous is a popular choice. Avoiding inaccurate and incomplete tracking and recording can mean the difference between understanding turbine, plant and fleet performance and multiple root cause unknowns. At a minimum, high-quality work orders for a turbine should contain:

2.5.1. Turbine Identifier

Recording a turbine ID links each maintenance event with a specific turbine. Events that do not tie to a specific turbine can still be captured, but this should be clearly specified. Ideally, there will be options to choose specific BOP equipment, in addition to specific turbines.

2.5.2. Event Type

- Event type captures at a high level what kind of work is being performed (e.g., component failure, preventative maintenance, inspection, etc.).
- All downtime and maintenance events should be recorded, including inspections and other scheduled maintenance events. Even inspections and scheduled maintenance that are relatively short in duration, relatively infrequent, and/or can occur while the system is running are crucial to understanding the availability, reliability, and financial performance of a system.

2.5.3. Afflicted Component

- Ideally, the affected component would be chosen from a standar breakdown of the turbine (e.g., taxonomy, meta-data framework or equipment breakdown structure). The affected component may not be initially known with certainty, so a good CMMS need to allow for updates, editing, and refinement as more knowledge is gained.

- In order to conduct real root-cause analysis, it is also useful to capture a brief description of the failure mechanism and/or the external event that caused the downtime or maintenance (e.g., chipped gear tooth, dirty oil, curtailment).
- For relevant event types, the source of parts is also a useful piece of information. This includes parts acquired through non-standard methods (e.g., swapped from another turbine, purchased outside the supply system, machined on site, etc.). Identifying the source of parts allows for more accurate cost calculations and will allow more advanced CMMS towards parts and inventory tracking.

2.5.4. Equipment Status

- Not all maintenance events will stop a turbine from generating, for example, some inspections are allowed when the turbine is running.
- Suggested choices for equipment status include Online, Offline/Fault, Planned Maintenance, Unplanned Maintenance, Degraded, etc. (it is very important to establish categories for up and down time and for operations management to ensure accuracy and consistency amongst the engineering and technician teams.

2.5.5. Event Start Date and Time

Date and time when the status of the turbine changes. Or, if the turbine status does not change due to the start of the event, the date and time the maintenance event begins.

2.5.6. Event End Date and Time

Date and time when the status of the turbine changes. Or, if the turbine status does not change due to the end of the event, the date and time the maintenance event ends.

2.5.7. Downtime

There are many ways to measure downtime. From the event start and end times, the total duration of the downtime or event can be captured. Other useful measures include:

- Active Maintenance Time - the total amount of time maintenance was being actively performed on the turbine.
- Person-Hours - the total number of person-hours required to complete the maintenance action. Note that this may be very different (greater than or less than) total downtime, and may be greater than the active maintenance time if more than one technician was needed.
- Waiting Time - ideally, this can be broken into time spent waiting for a technician to become available, waiting for a part from supply, waiting for a piece of support equipment to become available, or waiting on other administrative or supply delays.

2.5.8. Description/Components

Though free-text comments can be difficult to use in an automated way, allowing technicians to capture anything unexpected or unusual about a maintenance event can be quite useful when delving deeply into specific events or types of events. In addition, this field can be helpful to support the collection of additional data while the CMMS is being upgraded to capture it in a more appropriate field.

2.6. Other Systems

In addition to the data that is captured from SCADA and work orders, supplemental turbine and plant information is also needed. ERP systems containing cost and other financial and business information provide the supplemental information needed to support data-based decision making.

Ideally, cost information would include component-level repair costs, component-level replacement costs, consumables costs (for example, the price of a liter of gearbox oil), costs associated with technician time, and costs associated with overhead (such as administrative time) if such overhead is linked to maintenance or downtime. Additionally, some plants also look at lost revenue from generation or penalties assessed for not generating.

Information on turbine and BOP configuration is another essential aspect of cross-fleet analysis when performing analysis at system, sub-system, component-group and component levels, especially across multiple plants or turbine technologies. A hierarchical equipment breakdown structure or flow and the site taxonomy divide the turbines and BOP into their generalized parts in a parent-child relationship that allows sub-parts to be rolled up into sub-assemblies, sub-systems, and systems. Once a general taxonomy is developed, then each of the turbine technologies or plants can be mapped to it, creating a standard that allows comparison. Also, a detailed description of the equipment (make, model, manufacturer of major components, presence/absence of optional systems such as de-icing equipment or condition monitoring, etc.) is important for comparisons. Lastly, documented system knowledge, such as turbine specifications or substation fault trees, can provide the basis for more advanced reliability analysis.

2.7. Data Processes

In the wind industry, many multi-site and OEM companies have implemented operations command centers (OCCs) with real-time operating data flowing from plants to a centralized monitoring and control center. The real-time data is then stored in a single large enterprise-level database covering multiple plants. This approach requires a robust and reliable connection from each turbine and plant to the OCC or reliable data storage at each site so when connection to the OCC is restored, the buffered data is passed to the OCC. An alternative, seen at smaller operators and plants, is where a storage system is implemented on-site and stores a finite time period of SCADA data. Some of these implementations allow for sub-sets of the data to be sent to a central office for storage and analysis periodically or after events.

Those companies that do store their SCADA data consider it highly proprietary and treat it as intellectual property. This adds a requirement for encryption and security during the transfer of data from the plant, and access levels and controls that restrict who can view the stored data. If there is transfer of the data from a plant to OCC, a hardened high-bandwidth connection is most desirable. This creates a dedicated connection between the wind plant and the OCC, making it a good choice for carrying large amounts of data as it is both reliable and secure. Once data is stored at the OCC, the use of integrated security protocols can fulfill the needs for controlling access to the data.

After data is stored and accessible to those with the rights to see and use it, data protection becomes a primary task of the data administration staff. Design, implementation, and maintenance of a backup and recovery plan are essential to preventing the loss of data through accident, data corruption, hardware failure, or natural disaster. The plan should include levels of criticality for the data, projected recovery timeframes, scheduling and monitoring of backups, on-going validation testing of the backups, and the media choices on which the backups will be stored.

In addition to backups, with the amount of data being stored for each turbine and plant, an archiving strategy is necessary to manage the size of the database and maintain a high-functioning retrieval system. One approach is to archive the raw data but to retain calculated values. Another approach is to store the data using special compression techniques that reduce the number of data pieces stored without losing the meaning of the data. Data historians are especially designed with this type of compression in mind. With the cost of storage coming down over the prior decades, archiving strategies should be periodically re-evaluated to ensure that the correct levels of data are available for analysis.

When setting up transfer and storage protocols, the data to be stored must be determined. This concern is especially relevant when looking at the need to summarize the voluminous SCADA time series data. For monthly or yearly performance metrics balanced against the detail needed for root cause analysis, real-time data compression algorithms become critical to balance data storage needs against data completeness. Compression means reducing the number of electronic bits that represent a piece of data, thus reducing the number of bits that need to be transferred from the plant or stored. For example, only storing values when they change can save a great deal of space if that data does not change often. One of the other aspects of data integrity is addressing missing or illogical data, with data validation serving as an essential aspect of any data collection system. When there is only a single piece missing, it will likely have little to no impact on analysis, but when larger amounts of data are missing, perhaps covering hours, the loss may be important. The practice of data editing, or filling in the data with realistic values, can assist in creating a complete data set. For illogical data, values for a piece of data can be compared to previous values or sets/ranges of acceptable values, allowing an unrealistic value to be identified. Care must be taken with data editing, however as it can reduce confidence in the data as a whole. Among other challenges, important signals can be missed if unexpected, but accurate, values are overwritten. Also, filling in unknown values can mask a data communications problem.

For all of these data integrity concerns, their impact can be reduced by implementing good business processes and procedures, where all employees follow the same process when dealing with the data. Whether the employee is at the plant, or in the corporate IT department, or in the engineering/analysis group, business processes allow for the same methodology to be implemented, and for necessary improvements to be implemented systematically. Part of these remedies should be a standard approach to the use and interpretation of data. This creates an environment where comparisons between turbines and plants can easily be made, because the analysis is based on the same assumptions about the data.

2.8. Integrate Data

One of the greatest challenges in using CMMS and SCADA data to perform reliability analysis is in matching work orders, SCADA time series, and SCADA alarm data. This linking of symptom (for example, high SCADA temperature recordings followed by a gearbox over-temperature alarm) to corrective action (a work order to replace a lubrication oil pump) allows for the beginning stages of root cause analysis, parts tracking, and trending. An automated method for performing this linking will greatly improve the detail and accuracy of reliability analysis, but it is not an easy process. Challenges in linking data can include conflicts between CMMS and SCADA regarding turbine status, incomplete work orders, and missing SCADA data. Additionally, real situations that are difficult to interpret will appear, such as curtailment, overlapping work orders, and back-to-back alarms. While no systems emerge as the complete solution after a plant or fleet reaches Commercial Operation Date (COD), continuous investment and improvements to the operational and maintenance systems are crucial for assuring long asset live and the highest levels of production output.

3. ANALYSIS

The culmination of the above two sections, is analysis. Analysis incorporates the data generated, collected, and made available to improve the understanding of the current reliability and performance of the wind plant and its turbines. A staged approach is required to impact an O&M strategy through improved availability, increased reliability, and reduced O&M costs - first establish baseline performance to understand what the current situation is, then identify performance drivers and determine their root causes, and finally create action plans for addressing the those drivers with higher impact.

3.1. Understand Current Performance

Successfully answering questions such as “What is the current performance?” and “How good is it?” is the first step to making improvements. This will point toward problematic areas on which to focus. Examples of questions and analysis related to baseline performance include:

3.1.1. What is the Baseline Performance?

Calculate basic operations and reliability metrics, such as Availability, MTBE (Mean Time Between Events), Mean Downtime, and Capacity Factor for the plant and then each turbine.

3.1.2. How Does the Plant Performance Compare to the OEM or Financial Expectations?

- Identify and graph how a typical turbine spends its time (what percent of the time is it running, idle and available, down for scheduled maintenance, curtailed, etc.);
- Be sure to identify when the turbine state cannot be determined (such as when SCADA communication is lost or the historian briefly stops recording).

3.1.3. Are the Data Aspects of the Operations and Maintenance Processes Well Understood?

Make and document assumptions about the data being gathered, and how it is gathered, stored, and used for analysis. Institutionalize these assumptions so that all departments have the same meaning for particular pieces of data.

3.2. Identify Performance Drivers

Once baseline performance is understood, then performance drivers can be found. Methods for identifying these drivers can include exploring trends, outliers, good performance, and surprising results. Examples of questions that can be answered at this point and their related analyses include:

3.2.1. What is Driving Poor Performance?

- Identify key contributors to low generation, unavailability (downtime), etc. Exploring top contributors is a simple, but very powerful method for identifying areas for improvement.
- Compare multiple metrics, such as event frequency versus event duration or generation versus turbine wind speed. The outliers are especially interesting in these types of graphs.

3.2.2. Where is Performance Roughly the Same? Where is There Great Variability?

- Explore turbine-to-turbine performance and variability in all the basic aspects, including Availability, MTBE, Mean Downtime, and Capacity Factor.

- Explore trends (daily, weekly, monthly, and seasonal). Plot graphs of the metrics over time. Look at the whole plant, and also look at individual turbines or individual event types, especially those with very high or very low performance.

3.2.3. Where Are the Business Data Processes Different?

- Address any inconsistencies in data processes and assumptions including determining if there a valid reason for doing things differently.
- Understand limitations in the data systems, analysis/modeling, and reporting.

3.3. Determine Root Cause

After understanding baseline performance and identifying some of the key performance drivers, then root causes can be identified to solve problems. Examples of questions and analysis that can be addressed at this point include:

3.3.1. Why are Certain Aspects of Operations (e.g., Turbines or Groups of Turbines, Months or Days of the Week, Types of Scheduled Maintenance) Having Such a Negative Impact?

- Investigate de-rates and periods of unexplained performance.
- Interpret unexpected patterns.

3.3.2. What are the Root Causes of the Top Problems?

After identifying the operational aspects that have the most impact, conduct root cause investigations. Follow through on this activity. Simply identifying potential root causes is not enough. Real fixes should be developed, tested, implemented, and assessed.

REFERENCES:

"Wind Energy Computerized Maintenance Management System (CMMS): Data Collection Recommendations for Reliability Analysis", Valerie A. Peters, Paul S. Veers, Alistair Ogilvie, Sandia National Laboratories, Document ID: SAND2009-4184, Unlimited Release, September 2009.

"Using Wind Plant Data to Increase Reliability", Bridget L. McKenney, Alistair B. Ogilvie, Valerie A. Peters, Sandia National Laboratories, Document ID: SAND2010-8800, Unlimited Release, January 2011.

RP 503

WIND TURBINE RELIABILITY

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

This Recommended Practices section focuses data collection and the metrics for reporting and understanding overall plant reliability performance.

INTRODUCTION

The owner/operator bears the responsibility for collection of data and information for purposes of running the wind plant in a reliable and profitable manner. Reliability status reporting will be seen as failures, corrective and preventative maintenance, SCADA (time series) reporting, events, alarms, failures, MTBE, MTBF, downtime, maintenance costs, computerized maintenance management reporting (CMMS), condition monitoring functions.

The following discussion recommends practices for data collection and the metrics for reporting and understanding of the overall plant reliability performance. Reliability, Availability, and Maintainability (RAM) metrics will have a role in this. RAM metrics provide reliability and availability trends, causes, sources, reasons and impacts for plant downtime at the component level, and provide field performance

A subset of the data from every turbine's control system, as well as data collected at the metering, substation, and grid connection interface, is typically held in one or more of the plant-wide Supervisory Control and Data Acquisition (SCADA) systems.

The O&M function is focused on maintaining generation at high levels and conducting preventative and corrective maintenance of the turbines, their components and balance of plant. Production data by turbine should be maintained and analyzed for purposes of production engineering, an important to overall plant O&M function:

Table A.

kWh	Daily, weekly, quarterly, annually
Stop Hours	Daily, weekly, quarterly, and annually
Capacity Factor	Daily, weekly, quarterly, or annually
kWh/kW	

WIND TURBINE RELIABILITY

1. Event Data

Event data needed to answer the basic questions of **how often** something fails, **how long** is it out of operation, and **how much** the down time costs. In other words, the symptoms, cause, and corrective actions for any failure or maintenance activity is a need that must be determined.

A record of each downtime event should be made:

Table B

Turbine ID	Distinguishes individual turbines
Event Code	Unique identifier for type of downtime event
Fault Code	Automated SCADA code that initiated the event
Event Name	Descriptive label for type of downtime event
Event	Start date and time
Event Type	Type of downtime (e.g., failure, preventative maintenance)
Event Duration	Hours of downtimes/return to service

It is important to track these metrics to individual components so that O&M planning, parts inventory and orders, manpower and equipment, and maintenance scheduling can be done as efficiently as possible.

2. Computerized Maintenance Management System (CMMS)

Work orders are often generated by plant managers to capture the need for repairs or other types of maintenance. A work order may have multiple purposes. It may be used for tracking of human resources, or for tracking the time the turbine spent offline. For purposes of reliability tracking, work orders should document the investigation into the cause of outage and which component failed and/or was replaced i.e. the root cause. In this way, work orders may provide insight into turbine performance and document operator actions which indicate the root cause of failure.

Ideally, work order systems will be computerized in an automated maintenance management system. Sandia has published a report entitled Wind Energy Computerized Maintenance Management System (CMMS): Data Collection Recommendations for Reliability Analysis (SAND2009-4184). Combined SCADA and CMMS capabilities will enable reporting of recommended individual turbine metrics of:

Operational Availability

Wind Utilization

MTBE (operating hrs.)

Mean Downtime (hrs.)

Annual Cost (per Turbine)

Intrinsic Availability

MTBF (operating hrs.)

Mean Failure Downtime (hrs.)

Annual Failures

Failures Cost (per Turbine)

Mean Fault Downtime (hrs.)

Annual Fault Cost (per Turbine)

MTB Scheduled Maintenance (operating hrs.)

Mean Scheduled Downtime (hrs.)

Maintenance Schedule

Annual Scheduled Cost (per Turbine)

An ability to reconcile and harmonize SCADA and CMMS data is suggested as a recommended feature and capability for O&M and RAM functions in operating a wind plant. Getting organized to do this will provide tools to improve reliability and profits.

REFERENCES

[1] "Wind Turbine Reliability Database Update Appendix B: Report Template for individualized reports to partners.", R.R. Hill, V.A. Peters, J.A. Stinebaugh, P.S. Veers, SAND2009-1171.

[2] "Using Wind Plant Data to Increase Reliability", B.L McKenney, A.B. Ogilvie, V.A. Peters, SAND2010-8800.

[3] "Wind Energy Computerized Maintenance Management System (CMMS):Data Collection Recommendations for Reliability Analysis", V.A. Peters, P.S. Veers, A. Ogilvie, SAND09-4184.

[4] These and other reports available at http://windpower.sandia.gov/topical.htm#WPR.

RP 504

WIND FORECASTING DATA

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

The purpose of this document is to describe best practices for the data required for accurate, actionable wind forecasting.

INTRODUCTION

By its nature wind generation is variable, intermittent, and uncertain. Employing sophisticated, data-driven methods to increase forecast accuracy enables more efficient and reliable power system operations. Short-term forecasts can be used for turbine active control and dispatch. Mid-term forecasts and day ahead forecasts can be used for power system management and energy trading, unit commitment and economic dispatch (optimizing plant schedules). Long-term forecasts are often used for longer term scheduling and maintenance planning at a wind farm.

WIND FORECASTING DATA

1. PROCEDURES (DETAILED DESCRIPTIONS)

There is an ever growing volume of data points available to wind forecasters. While more data often means more accurate forecasts, one must weigh the cost and complexity of data-intensive methods against the results derived from simpler methods.

At its most basic level, there are two forms and sources of data necessary for any useable wind forecast: static data - latitude and longitude of the wind plant, and hub height, and dynamic data - the measurement of metered power output. Adding historical output increases the value of the forecast by allowing for an empirical relationship between forecasted wind speeds and power output.

Moving down a level in granularity, additional data sources can help a forecaster increase accuracy. Tracking current availability (i.e. the number of wind turbines available now and the power generation characteristics of those turbines) allows for a power conversion analysis to calculate lost generation resulting from planned maintenance at the wind farm. Forecast availability (the number of wind turbines expected to be available in the future, and the power generation characteristics of those turbines) can help in planning for power de-rates associated with a future maintenance schedule.

Curtailments, whether from system operator instructions or transmission issues, impact forecasts and should be integrated into the forecast analysis data, both for real time and historical purposes.

Data about the wind itself, both wind speed and direction can be leveraged to increase forecast accuracy. Depending on the forecast providers' methods, varying degrees of wind data will be required and the forecast user should consult with the vendor to determine how much and what type of data to collect. Often if wind data is used, it is considered after power, availability and curtailment data. Wind data can be collected directly from on-site MET towers or can be based on averaging nacelle wind speeds across the plant. Again, it is recommended that the end user consult with the forecast provider to understand the methods used.

At the lowest level of granularity, turbine-level data can be integrated into the final analysis. Turbine level data is often used to predict ramp forecasts (large changes in output). Both on-site and off-site temperature, humidity, air pressure, wind speed, wind direction and power make up this category of data.

While data collection and integration techniques can differ among forecasters, the next and most immediate challenge is in turning this data into usable, action-based knowledge for the wind operator. Intelligent and timely operator response to wind forecast data can result in very significant monetary benefit to the generator operator. Everything from effective unit commit and generation balancing, to understanding the economic impact of a curtailment, to efficient, cost-effective maintenance scheduling, can be positively impacted by timely, appropriate operator action in response to wind forecasts.

2. TOOLS

Tools that provide a common and easy-to-use interface to forecast data and that can help direct an operator to an appropriate action are critical to the future integration of cost-effective wind integration.

Tools are available today that allow end users to integrate third party vendor wind forecasts so that meteorologists and planners may visualize third party data, create and shape their own internal ensemble forecast, and integrate those with trading and market systems.

SUMMARY

In the near future, the ability to analyze wind forecasting models and provide insight into the best models under different weather conditions will provide end users insight into the forecast data they are buying. Inherently this will help produce more reliable wind forecasts and allow for scheduling and marketing of wind energy more aggressively to optimize revenue.

RP 506

WIND TURBINE KEY PERFORMANCE INDICATOR DATA REPORTING PROCEDURES

PREFACE

The following Recommended Practice is subject to the Disclaimer at the front of AWEA's Recommended Practices Manual. It is important that users read the Disclaimer before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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Principal Author: Dave Ippolito, Versify Solutions

SAFETY NOTICE

These process guides are not intended to assure safety, security, health, or environmental protection in all circumstances. Implementers of the processes are responsible for determining appropriate safety, security, environmental, and health practices or regulatory requirements.

PURPOSE AND SCOPE

The purpose of this document is to describe best practices in reporting Key Performance Indicators (KPI's) including recommended data granularity, frequency, methods for capturing and collecting data required to produce recommended KPI's.

INTRODUCTION

This document assumes the reader has working knowledge of SCADA, data capture, and data collection and historian technologies. While this document does not recommend specific technologies, it assumes that SCADA data may be captured and collected using some method of historian technology. Also, this document assumes that integrated values for any underlying data point that is captured may be extracted from the data historian at the described levels of frequency.

Presentation of Key Performance Metrics and any technologies associated with data reporting are also beyond the scope of this document, but is recommended that any reporting or presentation tool or application used allow for both high level "dashboard reporting" that may be tailored for senior management as well as the ability to drill down into granular details as needed by engineers, plant managers, and operators.

PROCEDURES (DETAILED DESCRIPTIONS)

Data should be collected from the plant at various levels of granularity and frequencies based on how the data is to be applied in calculating key performance indicators described below. As a best practice, data is should be read from a plant's SCADA system and collected in the data historian utilizing industry standard protocols such as OPC or MODBUS. Depending on the KPI, calculations may be completed as the data is read from SCADA, or may occur after integrated data has been collected over a period of time.

The following table lists operational data that must be collected in order to produce key performance indicators described within this document. *(See Table A.)*

Table A.

MW	BOP / Turbine	Hour / Minute
Turbine Available	BOP / Turbine	Hour / Minute
Turbine Online	BOP / Turbine	Hour / Minute
Turbine Fault Code	Turbine	Minute
Wind Speed	Turbine	Minute
Wind Direction	BOP	Minute
Curtailment Events	Turbine	Start / Stop

Key performance metrics may be calculated as data is collected, or may be tabulated periodically as needed. The following describes KPIs that should be collected for turbines and the balance of the plant.

1.1. Total MWh

Integrated MWh values for the plant and for each turbine describe plant output and are used for other metrics.

1.2. Available MW

Hourly metric based on each turbine's nameplate capacity and the total amount of time that the turbine is available

= Sum(turbine available * turbine capacity)

1.3. Availability

Percentage of plant or turbine that is available for given hour

= Available MW / Nameplate Capacity

1.4. Potential Energy

Turbine capability based on design curve and meteorological conditions

= Design Curve(wind speed, RH, BP, etc.)

1.5. Capacity Factor

Percent of plant or turbine capacity that is producing power

= Total MWh/Nameplate Capacity

1.6. Curtailment Hours or Minutes

The total number or minutes or part of an hour during which there has been a curtailment event

= Total minutes between curtailment event start and stop

1.7. Curtailment MWh

Total MWh lost during curtailment events. Note that it may be desirable to track curtailment MWh for different types of curtailment events. Curtailment MWh is estimated using minute level integrated Potential Energy - Actual MW for each minute of a curtailment event. This is best computed on a minute level basis, and totaled for any given hour.

1.8. Turbine Faults

The number of distinct turbine fault events should be tracked for each turbine as well as the total number of faults for the balance of the wind farm. A turbine fault event begins when a turbine fault code is recorded, and ends when the turbine is reset and fault status indicates the turbine is back online.

1.9. Turbine Fault Lost Energy

Lost energy due to turbine faults may be estimated by subtracting actual energy from potential energy during a given fault event. It may be desirable to track lost energy by fault code, category, and plant levels.

RP 507

WIND TURBINE CONDITION BASED MAINTENANCE SYSTEM OPEN ARCHITECTURE

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

The purpose of this document is to provide a recommended practice for condition based maintenance (CBM) system architecture for the wind plant, including wind turbine generator, balance of plant and other elements.

Condition based maintenance and condition monitoring has been shown in many industries to reduce the cost of ownership and increase the availability of assets for operations. Aviation and energy have multiple examples of implementing CBM with positive financial and operational results.

The goal of the best practice is to provide a common, scalable and open architecture to enable an interoperability and cooperation for CBM systems. The advantage to this approach is that the wind plant operator and owner will be able to leverage best in breed approaches for CBM through the implementation of an Open Architecture approach. Furthermore, future technology and capability will be easily integrated into the system, with little need for reconfiguration or modification.

INTRODUCTION

Implementation of a condition monitoring system can take many forms and processes and approaches. The general diagram of these systems is shown in Figure A. *(See Figure A.)* The description of each component is as follows:

- Wind Plant - The collection of wind turbine generators and balance of plant equipment needed to generate electricity.
- Wind Turbine Generator (WTG) - The electrical and mechanical system for converting wind energy into electrical energy, including tower, foundation and balance of plant. The control center for the WTG is not included.
- Balance of plant (BOP) - Remaining hardware in the plant, not including the WTG.
- Control Sensors & Hardware - The hardware and software system, typically the SCADA system, on the WTG which supports the control and operation.
- Condition Monitoring & Sensors - Data collection, processing anc sensors for the purposes of assessing the health and remaining life. This equipment is in addition to SCADA hardware.
- Data Storage - Standards-based storage of health and control data for the purpose of condition monitoring. Stored data can be local, centralized or both, depending on system architecture.
- Data Processing - Local or remote health management system processes collected real-time or off-line data either in time- or frequency-domain. Health metrics and indicators are restored in the database.

- Maintenance Interface - Alerts, health indicators and actions are communicated to appropriate stakeholders, ranging from local maintenance management to supply chain and engineering.

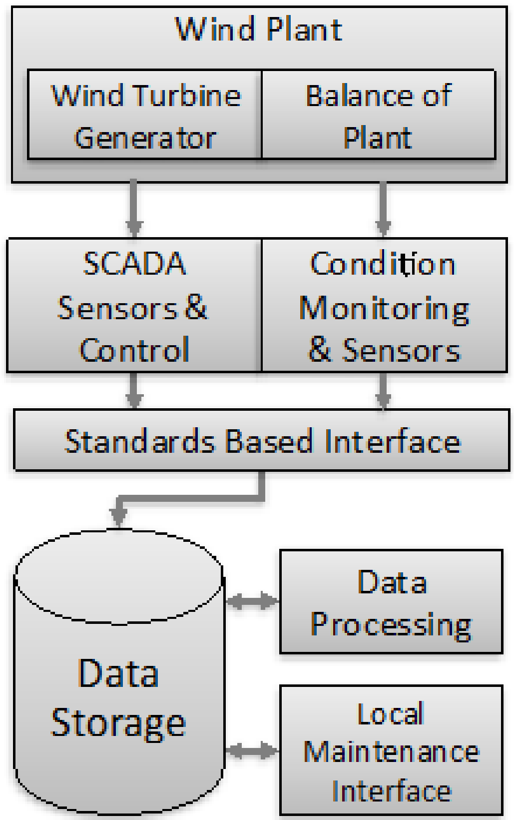

Figure A. Basic CBM System Architecture.

CBM OPEN ARCHITECTURE

1. CBM SYSTEM DEVELOPMENT

CBM system and data management strategy will be unique for each platform and plant, but follow a similar process. This process is outlined below:

1 Identify system failure modes, for both WTG and BOP through review of system supplier failure modes and effects (FMEA) analysis, industry data and interviews with Subject Matter Experts.

2 Determine CBM needs and strategy through analysis. Identify high priority components for CBM with careful consideration of failure rate, replacement cost, spare part lead-time and impact on operations.

3 For wind plant, determine required sensors, data collection, processing and storage equipment to meet strategy.

4 Leverage Open Architecture for CBM System and Data Management. Through application of Open Architecture, data collection, management and processing will have common interfaces to each development and integration. This architecture is created through apply Open Standards approached outlined in the sections below.

5 Implement CBM system, through procurement of hardware and software. Install systems and configure per manufacturer instructions.

2. OPEN STANDARDS _ MIMOSA

Once CBM needs have been defined for the system, Open Standards should be applied. MIMOSA publishes a well-accepted open standard for developing and implementing condition based maintenance systems. Both the OSA-CBM and OSA-EAI are data and communication architectures that define the interfaces between hardware and software. These common interface definitions enable the application of 3rd party capabilities built to the same interface definition and enable data, software and hardware to remain compatible well into the future, as along as the standards are adhered. The complete definitions are found at www.mimosa.org. These open standards are the basis of this recommended practice.

The OSA-CBM architecture is defined by a set of components (physical or virtual components in the system) and workflows (transportation of data from source to user). To achieve this, the architecture is composed of segments and agents. Segments correspond to Measurement Locations (sensors), and Agents (people or systems that analyze data).

The workflow for this system is conceptualized in Figure 2, below. *(See Figure 2.)* From the point of view of the CBM framework, each sensor would be a Measurement Location. To populate the Ports in the Module with Data Acquisition (DA) Data Events, the sensor interface would be wrapped in an Algorithm. These Ports and any DA Data Events they contain would then be available for the rest of the Configuration to make use of. By using the Ports of one or more Algorithms as inputs for other Algorithms, the Configuration specifies a workflow that processes the data as it flows through. Additional preprocessing for the Measurement Locations is done at the Data Manipulation and State Determination levels, producing corresponding Data Events. The end products of this workflow are Health Assessment, Prognostics Assessment and Advisory Generation Data Events. These high-level Data Events are created by Agents, interfaced to by Algorithms in the workflow, that provide interpretations of the health and prognosis, as well as recommendations on how to deal with them. The CBM process makes Data Events available to external processes via the interface types in the OSA-CBM specification.

For example:

Onboard the WTG, sensor data would be stored as Data Acquisition Events. During operation, the bandwidth usage would be minimized by limiting the Data Events sent to the ground station with Monitor Id Groups to pass on DA Events filtering out those with NumAlerts below a certain severity. Additional data may be requested by passing a Monitor Id Group to a CBM interface requesting a specific subset of data. They would be transferred in a serialized (XML, JSON, YAML, etc.) compressed format. Another possibility is to move some of the more critical or less processor intensive algorithms in the workflow onboard the WTG. Health and Prognostics Assessment Data Events produced by an onboard Digital Twin would take up much less bandwidth than the Data Acquisition Events consumed to produce them. This flexibility allows better balancing of the tradeoff between onboard processing and platform to ground station bandwidth. The network of Algorithms and Ports produce and consume the Data Manipulation, State

Detection, Health Assessment, Prognostics Assessment, and Advisory Generation Data Events. External applications may then request the Data Events from specific Ports provided by the CBM interface by using Monitor Id Groups. HA Events are used to provide the health level of components, PA Events report their remaining useful lives, and AG Events give Recommendations and optionally Requests For Work.

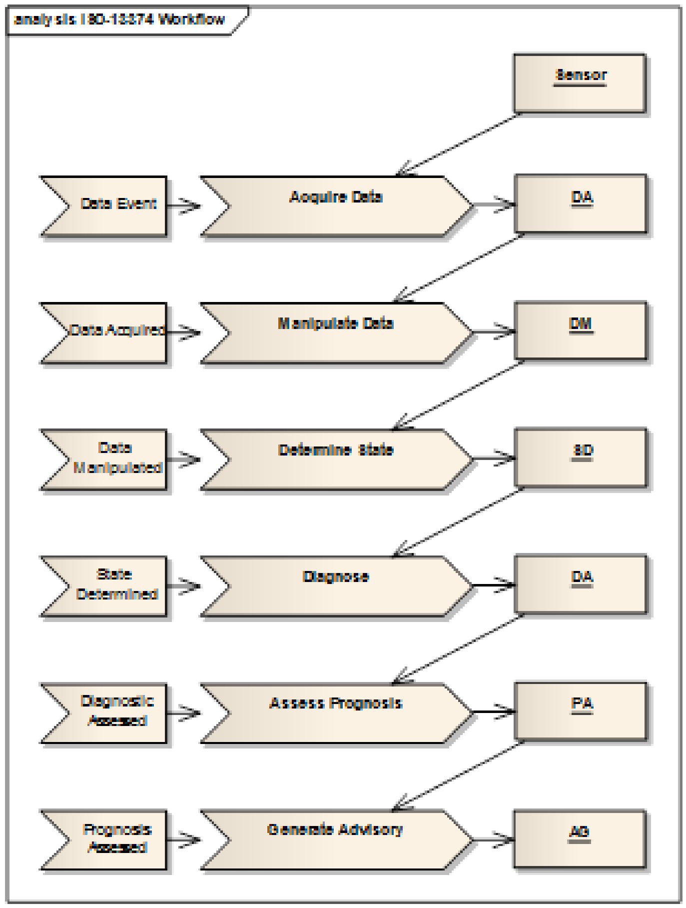

Figure B. OSA_CBM Workflow

3. INTERFACE DEFINITIONS

Condition Based Maintenance System elements will be implemented in the above architecture using the OSA-CBM interface definitions. OSA-CBM interface definition simplifies integrating a wide variety of software and hardware components as well as developing a framework for these components by specifying a standard architecture and framework for implementing condition-based maintenance systems. It describes the functional blocks of CBM systems, as well as the interfaces between those blocks. The standard provides a means to integrate many disparate components, including interfaces with sensors, data acquisition devices, software algorithms and eases the process by specifying the inputs and outputs between the components. In short, it describes a standardized information delivery system for condition based monitoring. It describes the information that is moved around and how to move it. It also has built in meta-data to describe the processing that is occurring.

OSA-CBM provides an interface standard and defines the interfaces between the functional blocks in a CBM system. Vendors can develop algorithms to fit inside of these blocks, separating the information processing from how it is presented. This separation allows proprietary code and algorithms to be kept hidden inside each of the functional blocks. It also creates a plug and play capability where vendors can easily insert updates or roll back to previous versions without affecting other modules or programs relying on the functional blocks. Figure C illustrates an example of proprietary algorithm in one OSA-CBM block. *(See Figure C.)*

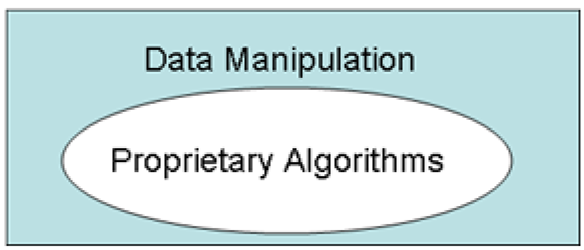

Figure C. Example of Proprietary Algorithm in One OSA-CBM Block.

The Algorithm Configuration and the Interface Implementation. Figure D illustrates the main part of algorithm configuration in OSA-CBM UML specification 3.3.0. *(See Figure D.)* Configuration provides information about Algorithm Input Data, descriptions of algorithms used for processing input data, a list of outputs, and various output specifics such as engineering units and thresholds for alerts.

Writers of Algorithms simply need to interact with this interface as it is provided to them in a CBM implementation. This can be accomplished simply in several ways, including inheritance from a base class in object oriented languages. The writer can then override a calling function that accepts an object providing method access to the outputs and any inputs. It is in this way that third-party code compiled into DLLs can be incorporated into the system transparently.

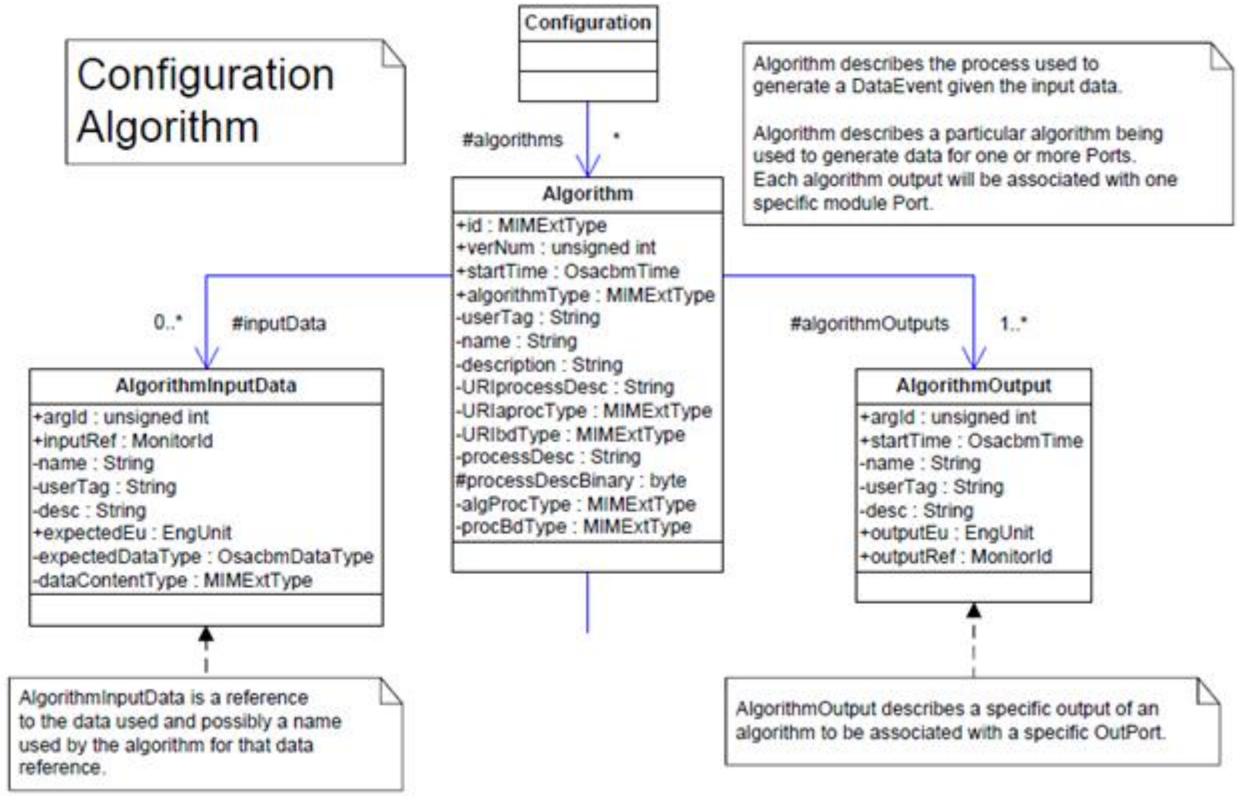

Figure D. Algorithm Configuration in OSA-CBM UML Specification 3.3.0.

SUMMARY

Implementation of the Open Architectures described herein is a recommended practice by AWEA. These architectures enable widespread and broad cooperation across the industry to enable improved capability and performance of wind turbine system.

REFERENCES

Open System Alliance, OSA-CBM Specification 3.3.0, February 2010, www.MIMOSA.org

ISO-13374 Condition monitoring and diagnostics of machines -- Data processing, communication and presentation, 2007.

RP 601

WIND ENERGY POWER PLANT COLLECTOR SYSTEM MAINTENANCE

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

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PURPOSE AND SCOPE

This AWEA balance of plant (BOP) operating and maintenance recommended practices document is intended to provide guidance to the wind industry regarding maintenance of a wind farm “balance of plant” collector system. The scope of this document includes electrical collection system components which are recommended for periodic testing or maintenance. The electrical collection system includes systems starting from the exit of the substation to the turbine connection terminals. This document is not intended to be an all-inclusive how-to manual but to provide general guidance to sound maintenance practices and references to applicable industry standards.

INTRODUCTION

Electrical power equipment and systems testing should be performed as specified by Manufacturer’s standards from organizations such as IEEE, IEC, ICEA or NFPA 70B. A summary of some of the applicable standards can be found in NETA standards. In most cases, the testing organization should be an independent, third party entity which can function as an unbiased testing authority, professionally independent of the manufacturers, suppliers, and installers of equipment or systems being evaluated. The organization and its technicians should be regularly engaged in the testing of electrical equipment devices, installations, and systems. An example of one such organization which has an accreditation program is the InterNational Electrical Testing Association (NETA).

The testing organization should submit appropriate documentation to demonstrate that it satisfactorily complies with these requirements. The testing organization should provide the following:

- All field technical services, tooling, equipment, instrumentation, and technical supervision to perform such tests and inspections.
- Specific power requirements for test equipment.
- Notification to the owner’s representative prior to commencemen of any testing.
- A timely notification of any system, material, or workmanship that is found deficient based on the results of the acceptance tests.
- A written record of all tests and a final report.

Safety and Precautions practices should be in accordance with NFPA 70E and other applicable standards including IEEE standards.

COLLECTOR SYSTEM MAINTENANCE

1. COLLECTOR GRID CONFIGURATION

The influence of the collector system voltage, reactive power flow and harmonics of the collector system can impact the performance, losses and life of the equipment. Periodically, it is recommended that the collector system operation be evaluated considering transformer tap settings, voltage set points, reactive power set points, wind turbine generator operational conditions and overall losses. Harmonic monitoring can be installed to determine conditions where the system can be contributing higher than normal harmonic currents. Overall, the collector system operation can be optimized to minimizes I2R losses and evaluated for conditions that may reduce the life of the system.

2. GROUNDING GRID

The purpose of a ground grid at a wind plant is to ensure the safety of personnel and property. During the commissioning process, the ground path impedance should be minimized, verified and documented according to *ASTM G57-95a* and *IEEE 81*. Measurement of the ground resistance and the potential gradients on the surface of the earth as a result of potential ground currents are necessary for:

1. Verifying the adequacy and detecting changes to the grounding system
2. Detecting potential hazardous step and touch voltages
3. Measuring ground potential rise (GPR) to determine adequacy for protection and communication circuits

Ground grid documentation should be readily available. If changes or repairs to the power system are made, operators should consider testing the associated ground grid to ensure that the alterations have not impacted its effectiveness. Frequent and/or extensive damage to turbine blades or other turbine equipment from lightning damage may indicate a potential issue with the grounding grid system.

3. CIRCUIT BREAKERS AND SWITCHGEAR

The power circuit breakers used with the pad mount transformers are used to protect the low voltage (LV) power cable and the equipment within the base of the wind turbine generator. These circuit breakers are typically between 400-2000 volts. The project preventative maintenance program should include these basic items to properly sustain the project. The following list of components should be inspected:

1 Thermal Imaging - Verify all terminal connections under high level of generation.

2 Housing/Frame - Verify the integrity of the breaker housing

3 Operating Mechanism - Check the physical operation by opening and closing the contacts.

4 Trip Unit - Verify the trip unit settings with manufacture testing techniques.

5 Terminals - Verify the line and load terminals for obvious visual degradation. Check the torque of the cable and bus terminations.

3.1. Inspection and Testing Frequencies

Switchgear circuit breakers and cubicles, should be mechanically-inspected and electrically-tested at the following intervals or events, and/or following manufacturers recommendations:

1 Periodically, at two to three year intervals.

2 Before placing new or modified breakers into service.

3 Before energizing breakers that have been out of service for over 12 months.

4 After an interruption of electrical short-circuits, other than a ground-fault in a resistance-grounded system.

5 After 1,000 close-open operations (or less, depending on manufacturer's recommendations) following the last inspection.

3.2. Cubicle Inspection

During the cubicle inspection process, the following items should be completed:

1 Examine the bottom of the cubicle for parts that may have fallen

from the breaker. The bottom of each cubicle should be maintained clean and free of any foreign objects to facilitate the detection of fallen parts.

2 Verify that the mechanical safety interlocks and stops are intact.

3 Check that the cubicle heaters (where applicable) are functioning properly.

4 Verify that the rack-in mechanism is aligned correctly.

5 Lubricate racking mechanism (jacking screws and bearings) according to station experience or manufacturers recommendations. Check brush length of associated motor (when applicable).

6 Perform an overall inspection looking for loose wiring or components and anomalies. Complete repairs as required.

7 Verify that the shutter mechanism functions properly.

8 The primary disconnects should be inspected for signs of over-heating, cracked insulation, cleanliness, and misalignment.

NOTE: Normally, the bus side will be energized; hence, the proper safety measures must be followed.

When the foregoing inspection process is satisfactory to the participating electrician, an adhesive label should be attached to the front of the breaker that indicates the date of inspection and the name of the responsible person.

4. PAD MOUNT AND GROUNDING TRANSFORMERS

The pad-mount and grounding transformer are typically tested over multiple stages during the commissioning process. The first phase is within the transformer manufacturer's facility prior to shipment. Generally, a prototype is constructed and rigorous acceptance testing is performed on the prototype unit to ensure operating compliance. Tests will vary depending on the manufacturer and specifications from the engineer (based on IEEE/ANSI guidelines). Successive tests are performed on the production units depending on the specifications.

4.1. Electrical Tests

Upon arriving at the site, the transformers are inspected for physical damage. After inspection the transformers are transported to their final resting place. Prior to connecting any external cable including the MV cables, secondary cables, and ground grid; the transformer should be tested. The recommended tests typically consist of the following:

4.1.1. Transformer Turns Ratio Test (TTR) On All Transformer Tap Positions (If Taps Are Present).

The TTR is performed to ensure that the turns ratio of the transformer is correct by verifying that none of the transformer windings are shorted. Generally, values should not exceed .5% as compared to the calculated value or the adjacent coils.

4.1.2. Winding Resistance Test (WTR):

- Primary winding to ground
- Primary winding to secondary winding
- Secondary winding to ground

4.1.3. Insulation Resistance Test:

The insulation resistance test is important for determining the condition of the transformer insulation. Resistance measurements are made between each set of windings and ground recording the readings at 30 seconds, 1 min and every minute afterwards for 10 minutes. The dielectric absorption rate (DAR) is the ratio of the 60 second resistance value to the 30 second resistance value. DAR readings below 1.25 indicate cause for investigation or repair of the transformer. The polarization index (PI) is the ratio of the 10 minute resistance value to the 1 minute resistance value. A PI value of less than 1 indicates possible deterioration and that the transformer is in need of repair.

4.1.4. Thermal Imagining:

For oil-filled transformers, use a thermal imager to look at medium and low-voltage external bushings, connections, cool fins, as well as the surfaces of critical transformers.

4.2. Non-electrical Testing

4.2.1. Dissolved Gas Analysis for Transformer Oil

The identity of gases generated in a transformer is useful information in a preventative maintenance program. Gases are created when the insulating mineral oil is subjected to any of the following electrical conditions: corona discharge, overheating or arcing. The gases result from the breakdown of mineral oil and conductor insulation materials. If gassing is extensive, the upper gas space may contain an lower explosive limit (LEL). Following are gases commonly found in a mineral oil DGA analysis:

Table A

Generated Gas		**ppm in Oil (DGA) That Results in Gas Space LEL**
Hydrogen	(H_2)	2232 ppm
Carbon Monoxide	(CO)	16,625 ppm
Methane	(CH_4)	23,214 ppm
Ethane	(C_2H_6)	77,700 ppm
Ethylene	(C_2H_4)	54,560 ppm
Acetylene	(C_2H_2)	30,500 ppm
Carbon Dioxide	(CO_2)	N/A

NOTE: N_2 and O_2 are also present in the oil but are the result of tank air leaks and the oil's exposure to atmosphere.

To be a potential explosion hazard,

1 The combustible gas concentration in the gas space must exceed the lower explosive limit

2 O_2 must be present in the gas space in sufficient concentration

3 An ignition source must be introduced

4.3. Normal Operations

Routine transformer operations (even if > LEL %) do not present a personnel hazard. The following evolutions can be safely performed on a transformer with a combustible gas concentration above LEL.

- Oil sampling
- 34kV disconnect switching operations
- Thermography and internal cabinet inspections
- Voltage measurements
- Medium voltage (MV) & LV elbow and cable terminating
- Insulation resistance testing of windings
- Bayonet fuse replacement/ inspection
- Crane and rigging of pad mount transformer (PMT) for movemen

4.4. Purge Guideline

The following procedure is applicable if a transformer's upper gas space will be opened or exposed for maintenance or inspection. If hot work is to be performed in any transformer compartment or on transformer components, a purge procedure must be completed. GSU's with an expansion tank (vice N_2 blanket) will not have a gas space in the main tank but could have accumulated gases in the expansion tank. Precautions should be observed if performing work on the expansion tank.

SAFETY NOTE: Explosive gases purged from a transformer gas space may be ignited if they settle or collect in a closed cabinet or stagnant compartment. Keep access doors open and insure adequate ventilation.

SAFETY NOTE: In addition to the explosion hazard, personnel need to insure that they recognize the dangers of introducing large amounts of N_2 for purging into a closed or ventilation limited space. Take precautions to maintain a supply of fresh air where personnel are working.

Transformer should be Locked Out- Tagged Out. Grounding may be required depending on system isolation and conditions. Always assume a transformer's upper gas space has a potentially explosive atmosphere that must be diluted and purged. Past DGA oil samples may not exhibit gas-in-oil concentrations high enough to create an LEL but even a recent DGA sample does not assure that gassing has not occurred in the recent past.

NOTE: It is assumed that personnel are using a 4 gas monitor capable of O_2 and LEL measurements. (For example a Honeywell Impact Pro Multi-gas Monitor.) Check your gas monitor manual to verify samples and responds to a variety of combustible gases (including H_2) when developing an LEL %.

Smoking, vehicle exhaust, open flame, welding, brazing, etc. in the vicinity of the open gas space is prohibited.

Select two appropriate ports with direct access to the transformer gas space (Gas pressure gauge, relief valve fitting, N_2 blanket fitting, gas fill port, access plate…). The purge will inject low pressure N_2 into the gas space while venting out the existing gases, thus diluting LEL concentration. Never use a port or access point that is below the transformer oil level (drain valve, Top Oil temp gauge, Level gauge.)

If N_2 purging through a port is impractical, a gas space access plate may be loosened and wedged open to allow free air venting. Check gases released from the tank. Insure no open flame or ignition source is present until LEL is <5%.

Check the transformer nameplate for maximum tank internal pressure (usually 7 -10 psi) to avoid damaging the main tank or fins.

Attach a nitrogen gas bottle to one fitting and purge nitrogen into the gas space (at low pressure). Verify gas flow into and exiting the transformer. **Do not pressurize the tank** as most can handle no more than 7-10 psi. If you don't feel gas escaping, STOP.

Monitor the gases escaping the upper gas space. Purge until LEL is < 5% and decreasing. Stop the purge and let the tank sit for 15 minutes to allow undisturbed gas pockets to re- mix with the N_2 in the upper gas space. Re-initiate the N_2 purge as above. Repeat as necessary until upper gas space is purged of explosive gases and safe to access.

Carefully expose or open the upper gas space or perform hot work. Every couple hours, if gas space has been not completely open and ventilated, re-purge to insure gases- in-oil have not been re-released into the space. Insure adequate ventilation of fresh air to the work area and cabinet interior.

Standard Chemical Properties for oil including:

- Dielectric Strength
- Interfacial Tension
- Power Factor at 25°C
- Neutralization Number
- Water Content
- Specific Gravity
- Dissolved Gas Analysis
- PCB

Check List for visual inspection of all components, and operation of gauges and controls.

NOTE: It is important to note and record the above results based on the Serial Number of the Transformer which is typical practice for any third party testing agency. Care should be taken to ensure that accurate readings are obtained and that the results are evaluated by a qualified individual to determine if there are any potential material issues. In the event the transformer is moved to a different location, it is recommended the above procedure is repeated prior to energization to ensure damage has not occurred during transport.

4.5. Operational Maintenance

Records of the above commissioning tests should be obtained and used as a baseline. In the case of a transformer failure, these tests should be repeated and documented. To ensure the performance of the pad mount transformer and grounding transformers continue to meet expectations visual and infrared camera inspections are recommend on a yearly basis. Oil sampling is recommended on one-third of the transformers on a yearly basis. In general transformers closer to the substation are more critical as disruptions to the collector system closer to the substation put the availability of the wind site at a higher risk.

5. PADMOUNT TRANSFORMER FOUNDATION

The padmount transformer are installed on concrete slabs or many time on prefabricated fiberglass or fibercrete box pads. These foundations should be visual inspected for cracking and periodically sealed to mitigate rodent and water access. The sealant should all be periodically inspected to minimize water ingress.

6. SECONDARY CABLE SYSTEMS

6.1. In many cases secondary cables are utilized between the Turbine Controller and the Collection System Pad Mount Transformer. The secondary cable insulation rating will range from 600V to 2000V depending on the cable design and the wind turbine generator (WTG) type. Typical installations will require multiple conductors per phase. Conductors should be properly labeled with phasing tape or colored cable jackets. After installation and prior termination to the transformer and controller, a DC insulation resistance test ("megger") is typically performed. The test voltage is dependent on the insulation value, but is usually in the range of within 500V to 2,500V. The intent of the installation tests are to:

- Ensure that the insulation was not shorted during the installation process. - A low voltage insulation resistance measurement of less than 100M-Ohm may indicate a problem.
- Verify the cable phasing from one end to the other.

Generally secondary cable systems are not retested as a maintenance practice unless there is reason to suspect a problem. An annual infrared inspection of the terminals is recommended especially on cables deemed critical.

7. FIBER OPTIC CABLE SYSTEMS

Upon installation and termination of the fiber optic cables from each WTG tests are performed to ensure the quality of the fiber optic cable and terminations. Typically one of the following two tests are performed:

1 Attenuation (dB) Loss Testing

2 Optical Time Domain Reflectometer (OTDR) Testing

Since the network is constantly used for data transmission it is in effect, constantly monitored. If there is a network problem, one of the tests above can generally help diagnose the problem. Other than a visual inspection of the connections, periodic maintenance is generally not necessary.

8. OVERHEAD CABLE SYSTEMS

9. MEDIUM VOLTAGE CABLE SYSTEMS

Medium voltage cable systems can be found as a part of the collector system and tower cables. During commissioning field tests range from legacy methods such as insulation resistance and withstand methods, which are only effective at detecting gross shorts (cable system failures), to sophisticated, predictive partial discharge (PD) tests which detect and locate gross and subtle insulation defects and provide a baseline for future use. The standardized electrical test requirement at the factory for all completed solid dielectric shielded cable insulation system components (including the cable, joints, and terminations) is a partial discharge test performed during a 50 or 60Hz over voltage. Ideally a partial discharge test comparable with the factory test can be repeated on installed cable systems to assure that they still meet these requirements. If this type of test is not available or deemed impractical for a specific application, a list of alternative tests can be found in the *IEEE 400* guide document.

Ideally, during commissioning the following step are completed on cable system and a baseline is established:

- Visual inspection for physical damage, bends at less-than-minimum bending radius, phase identification, fireproofing, proper shield grounding, cable supports and termination connections, along with required size and rating per design drawings and proper separation of power, control, instrumentation, and emergency circuits.
- Conductor phasing test
- Resistance of neutral wires and tapes, conductor resistance/ continuity
- Off-line 50 or 60Hz PD test on each individual span of cable (termination to termination point). This test can provide profile of the cable system which is comparable to factory standards listed below.

- DC Insulation resistance test (‘megger test’) or very low frequency AC test at the (operation voltage or less) on the entire cable system. This test is not intended to detect defects which may fail in the near future but rather, to detect pre-existing shorts.
- Infrared test of the accessories (terminations and accessible splices) under high current condition.

Table B. Cable System Insulation Test Standards

Cable Component	Thresholds
IEEE 48 Terminations	No PD >5pC up to 1.5Uo
IEEE 404 Joints	No PD >5pC up to 1.5Uo
IEEE 386 Separable Connectors	No PD >3pC up to 1.3Uo
ICEA S-94-649 MV Cable	No PD >5pC up to 2Uo*

*Actually 200V/mil in factory. Field tests are performed to a maximum voltage value equal to the level of system overvoltage protection which is typically 2 times the operating voltage for 35kV systems (line to ground, 1.0Uo).

9.1. After a Failure

A DC insulation resistance test at (operating voltage or less i.e. 10 or 20kV for a 35kV system) is recommend after any failure event to confirm the phase of the fault and to confirm that there is not a second fault before re-energizing. Arc reflection fault location technology should be used with a minimum of pulses to determine the location of the fault. To confirm dielectric integrity of the system after repair, an off-line 50 or 60Hz PD test is recommended.

9.2. Cable Fault Location Equipment / Thumpers

Fault locating methods use fault indicators, "thumpers," radars, acoustic detectors or combinations of this equipment. Research indicates that subjecting cable systems to unnecessary surges reduces their remaining life. The industry has developed less evasive fault locating methods that reduce the stress on cable insulation systems. The general approach is to reduce the amount of thumping necessary to locate a fault while simultaneously reducing the voltages required to perform the task.

9.3. Periodic Testing

Comparative infrared testing is recommend annually to check the condition of the mechanical connection of cable system joints and terminations. Off-line 50 or 60Hz PD testing is recommended every 5 years. In many cases operators will focus testing efforts on systems that are most critical (nearest the substation), that have components with a history of failure, or that have components with marginal performance during past tests.

10. SURGE ARRESTORS

Surge arrestor provide over voltage protection for dielectric components. During an overvoltage event the surge arrester will become more conductive and shunt the excessive voltage to ground. Arrestors can fail during excessive over-voltages or if there is moisture ingress. If arrestors are not functioning properly, the components they are designed to protect will likely fail prematurely. During commissioning, surge arrestors on the high and low side transformer and the beginning, midpoint and end of cable systems typically have the following tests and inspections performed:

- Verify that “station class” arrestors are installed at MV and HV underground to overhead structures.
- Verify nameplate ratings against owner’s specification
- Insulation resistance test and/or power factor testing should result in similar test results between similar units
- Test for low impedance path to ground grid with no sharp turns
- Check the lead length to assure that is it not longer than the manufacturer’s requirement. Long lead lengths cause the device to malfunction. In the absence of the manufacturer’s requirements, lead lengths should be maintained less than eighteen (18) inches for MV systems and three (3) feet or HV systems.

Deadfront (T-body type) surge arresters are typically installed at the last WTG in each turbine string for the purpose of protecting collector system equipment from transient overvoltage stresses. To ensure proper functioning, the surge arresters should be physically and infrared inspected after major event and during periodic inspections.

Surge arrestors are also used at cable system cross-bond points. These arrestors should be inspected and tested according to the manufacturers recommendations. Lead length should be less than a three (3) feet. Confirm proper lead length and arrestor sizing with your joint manufacturer.

Maintenance of arrestors is recommended. Arrestors should be visually inspected annually. And infrared inspection should be performed every 2 years or after system failures or per the manufacturer's recommendation.

11. ARC FLASH

The arc flash hazard analysis and safety program should be implemented at the early stages of a project. This safely program should be periodically updated while the arc flash hazard analysis should be revaluated, at a minimum of every 5 years or if the system or connecting electric grid has changed. A proper safety program with equipment should be applied per the NFPA 70E and all federal and local codes.

RP 602

WIND ENERGY POWER PLANT SUBSTATION AND TRANSMISSION LINE MAINTENANCE

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

This AWEA balance of plant (BOP) operating and maintenance recommended practices document is intended to provide guidance to the wind industry regarding maintenance of wind farm electrical substation components, including area substations and the final connection to the grid and their interconnecting transmission line. This document is not intended to be an all-inclusive how-to manual but to provide general guidance to sound maintenance practices and references to applicable industry standards.

INTRODUCTION

Electrical power equipment and systems testing should be performed as specified by Manufacturer's standards from organizations such as IEEE, IEC, ICEA or NFPA 70B. A summary of some of the applicable standards can be found in NETA standards. In most cases, the testing organization should be an independent, third party entity which can function as an unbiased testing authority, professionally independent of the manufacturers, suppliers, and installers of equipment or systems being evaluated. The organization and its technicians should be regularly engaged in the testing of electrical equipment devices, installations, and systems. An example of one such organization which has an accreditation program is the InterNational Electrical Testing Association (NETA).

The testing organization should submit appropriate documentation to demonstrate that it satisfactorily complies with these requirements. The testing organization should provide the following:

- All field technical services, tooling, equipment, instrumentation, and technical supervision to perform such tests and inspections.
- Specific power requirements for test equipment.
- Notification to the owner's representative prior to commencemen of any testing.
- A timely notification of any system, material, or workmanship that is found deficient based on the results of the acceptance tests.
- A written record of all tests and a final report.

Safety and Precautions practices should be in accordance with NFPA 70E and other applicable standards including IEEE standards.

SUBSTATION MAINTENANCE

1. MAIN POWER TRANSFORMER

The main power transformer should completely tested before energization commissioning documentation should include information included in following testing and energizing procedure.

1.1. Test Oil Dielectric From Bottom Drain Valve

Should be 40kV or higher.

1.2. Insulation Power Factor and Capacitance to Ground

Make the following test with a suitable power factor bridge. Measure only the power factor and capacitance on winding connections. Be sure to record the temperature of the insulation as accurately as possible. The temperature corrected values should not exceed 0.5%.

- Two winding transformers – HV to GRD with LV winding grounded (H-LG).
- LV–GRD. With HV winding grounded L-HG. HV connected to LV to GRD (HL-G).
- Autotransformers with tertiary winding – HV and LV to GRD with TV grounded (HL-TG).
- Tertiary to GRD with HV and LV ground (T-HLG).
- Autotransformers without tertiary windings HV and LV to FRD (HL-G).
- Three winding transformers:
    - HV to ground with LV and TV grounded (H-LTG).
    - LV to ground with HV and TV grounded (T-HLG).
    - TV to ground with HV and LV grounded (T-HLG).
    - All windings connected together to ground (HLT-G).

NOTE: Windings may be called by a different name than those given above but the above pattern should be used.

1.3. Check Alarm Circuits

- Fault pressure relay trip settings and outputs
- Pressure relief device
- Top oil temperature gauge indications
- Winding temperature gauge indications
- Gas detector relay

1.4. Test Fan Circuits For Continuity and Voltage

1.5. Check Heat Exchangers

If three phase motors are used and rotated the wrong way, reverse any two main winding wire connections at the motor circuit breaker in the main control cabinet.

NOTE: Copies of every test made on a transformer from time of arrival up to is present location should be included with the customer's permanent file.

1.6. Check The Following Before Energizing

- Transformer ground.
- Feeder cables bus for proper connection to transformer.terminals. There should be no strain on the porcelair insulators.
- Insulating oil for proper level in all bushings and compartments.
- Opening and joints for proper sealing.
- Pressure relief device for proper installation.
- Valve from the conservator to the main tank should be in open position.
- All winding neutrals should be properly grounded.

- Check the tightness of the packing nut on the de-energized tap charger handle.
- Check radiator valve stem packing nuts and tighten as required. Each valve may require 1/3 to 1/2 turn on the packing nut.
- All radiator valves and/or pump valves should be open and bolted.
- Lightning arresters for proper installation in accordance with specifications.
- Transformer finish for scratches. Any damage to the transformer finish during installation should be touched up with paint provided.
- Relay protection, CTs and relays, for proper connections and operation.
- Fan motor drain holes should be open.
- Terminal connection in control cabinet for tightness. Check to se that there are no loose connections.
- Conservator tank breather for proper operation. The dehydrating material should be dark blue.
- All temporary busing safety grounds should be removed.
- The gas detector relay should be bled.
- Heaters in the control cabinets should be energized.
- Shorting straps on winding temperature indicator (WTI) CT terminal block and line drop compensation (LDC) CT terminal block are removed. Shorting straps removed from all other CT's that have loads connected.

WARNING: High voltages may develop across open circuit secondary terminals of CT'S when energized. Shorting straps must be in place across the full CT winding for all CT's not connected to low impedance loads to prevent possible personnel hazard and damage to the CT and other equipment. All CT secondary circuits must be grounded, whether CT is in use or not, either in the transformer control cabinet or at the load.

- All drag hands on alarm gauges and the LTC position indicator should be reset.

- Lightning arresters on dual voltage units for proper connections.
- All personnel should be clear of the transformer.
- Valve between tank and pressure vacuum regulator should be open.
- Approximately 3 lbs. pressure should be on sealed tank units.
- All temporary shipping plugs and etc. should have been removec during installation. (Typically painted either red or yellow such as breather plugs in the LTC housing.)

1.7. Energizing The Transformer

- Apply full voltage and allow the transformer to operate for at leas one hour without load. Listen for unfamiliar noises. Check for excessive vibrations.
- Keep the transformer under observation for the first few hours. Watch gauges to see that specified limits are not exceeded.
- After several days of operation, check for any oil leaks that may have developed after energizing.
- Record time from first energization.
- Check metering or correct inputs and outputs.
- Check relays for proper inputs and outputs.

1.8. Renewal Parts

Should a transformer be damaged and new parts needed, contact manufacturer, giving full nameplate information and a description of the part required. If the proper name of the part is in doubt, a simple sketch will expedite prompt shipment to you.

1.9. Maintenance

1.9.1. Periodic Inspection

- External: Check the condition of the paint and finish periodically, especially when the transformer is exposed to inclement atmospheric conditions. If weathering takes place, clean the tank thoroughly and repaint with an ANSI-approved paint. Wipe off any insulating Fluid that might have spilled on surface. Occasionally inspect and tighten all bolted joints and check for leaks.

- Regularly inspect all gauges. The Fluid level must remain normal, considering the temperature effect. Refill when samples have been taken. Prolonged periods of zero pressure could indicate a gas leak and should be checked out. The Fluid temperature should not rise higher than the design value on the name plate, plus the ambient temperature. Check blanket nitrogen pressure and bottle pressure.
- Fluid samples should be taken periodically and analyzed as indicated under “Sampling”. It is recommended that you keep a log of the test values to determine when reconditioning or replenishing service is required.

1.9.2. Sampling Insulating Fluid

NOTE: A sample of Fluid should be taken when the unit is warmer than the surrounding air to avoid condensation of moisture on the Fluid. Fluid samples must be drawn from the sampling valve located at the bottom of the transformer tank.

- A clean and dry bottle is required. Rinse bottle three times with the Fluid being sampled. Make sure Fluid being sampled is representative of Fluid in the unit.
- Containers used for sampling Fluid should be large mouth glass bottles.
- Test samples should be taken only after the Fluid has settled for some time, varying from eight hours for a barrel to several days for a larger transformer. Cold insulating Fluid is much slower in settling. Fluid samples for the transformer should be taken from the sampling valve at the bottom of the tank.

- When sampling, a metal or non-rubber hose must be used because oil dissolves the sulfur found in rubber, and will prove harmful to the conductor material in the transformer. When drawing samples from the bottom of the transformer or large tank, sufficient Fluid must first be drawn off to ensure that the sample will be from the bottom of the tank, and no the Fluid stored in the sampling pipe.

1.9.3. Testing Insulating Fluid

For testing the dielectric strength of insulating Fluids, follow the technique as specified by the American Society for Testing Material in the method entitled, *"The Standard Method for Testing Electrical Insulating Oils", #D-877*.

If, at any time, the dielectric strength of the Fluid drops below 26kV, it should be filtered until it tests at 26kV or better.

1.9.4. Filtering Insulating Fluid

Mineral fluid can be filtered by means of a filter press. The filter press is effective for the removing all types of foreign matter, including finely divided carbon and small amounts of moisture. The purifier equipment consists of a specifically proportioned filter press, a positive volume gear pump, driving motor, combined drip pan, and mixing tank, necessary piping, valves, strainer, gauges and a drying oven.

The filtering procedure that will insure the best result is to draw the insulating Fluid from one tank, through the filter press and into a clean tank. Where this method is not practical, a circulation method is recommended. Fluid is drawn from the bottom of a tank, passed through the purifier ad discarded at the top of the tank.

Filtration should be continued until the dielectric test of the insulating fluid is 26kV or better.

1.10. Spare Parts and Services

Keep one set of gaskets for the hand hole and any gasket type bushings used. Other renewal parts may be ordered through manufacturer. When ordering, give a complete description of the part or problem and give the complete serial number as listed on the nameplate.

1.11. Applicable Standards

NEMA Publication TR-98 (Latest Issue) “Guide for Loading Fluid Immersed Power Transformers with 65 Degree C Average Winding Rise”.

ANSI Publication C57.93 (Latest Issue) “Guide for Installation and Maintenance of Fluid Immersed Transformers”.

IEEE Publication #64 (Latest Issue) “Guide for Acceptance and Maintenance of Insulating Fluid in Equipment”.

ASTM Specification #D-877, “The Standard Method of Testing Electrical Insulating Fluids”.

2. SURGE ARRESTORS

Surge arrestor provide over voltage protection for dielectric components. If arrestors are not functioning properly, the components they are designed to protect will likely fail prematurely. During commissioning, surge arrestors on the high and low side transformer and the beginning, midpoint and end of cable systems typically have the following tests and inspections performed:

- Verify that “station class” arrestors are installed at all overhead tc underground transitions.
- Verify nameplate ratings against owner’s specification.
- Insulation resistance test and/or power factor testing should result in similar test results between similar units.
- Test for low impedance path to ground grid with no sharp turns.
- Check the lead length to assure that is it not longer than the manufacturer’s requirement. Long lead lengths cause the devicє to malfunction.

Surge arrestors are also used at cable system cross-bond points. These arrestors should be inspected and tested according to the manufacturers recommendations. Lead length should be less than a few feet.

Maintenance of arrestors is recommended. Arrestors should be visually inspected annually. Electrical tests should be performed every 2 years and after system failures or per the manufacturer's recommendation.

3. ACTIVE AND PASSIVE COMPONENTS

Capacitors, reactors, VAR compensators and energy storage systems need to be inspected, maintained and monitored on a frequent basis. Real-time monitoring is recommended for these critical assets. See the Appendix for maintenance intervals.

4. RELAYS

The following describes a recommended approach to relay testing:

- Perform Comprehensive commissioning testing at the time of installation. Use thorough checklists, simulations, laboratory testing, and/or field checks to verify the performance of the protection system, including inputs, outputs, and settings.
- Monitor the relay self-test alarm contact in real time via supervisory control and data acquisition (SCADA) or other monitoring system. If an alarm contact asserts, take immediate steps to repair, replace, or take corrective action for the alarmed relay.
- Monitor potential relay failures not detected by self-tests. Specifically, these are logic inputs, contact outputs, and analog (voltage and current) inputs. Use continuous check of inputs (e.g., loss-of-potential logic) when available. If a secondary relay system is in place, compare the metering values between the primary and secondary systems.

5. BATTERIES AND BACKUP POWER

5.1. Battery Systems

Each battery system should be maintained and operated as guided by industry practice and manufacturer's recommendations. Following is generally accepted information for the major types of batteries:

5.1.1. Vented Lead

Vented Lead- acid (known also Wet or Flooded) cells make up the majority of DC battery cells in service at our sites. The internal lead and lead sulfate (Pb and $PbSO_4$) plates are formed with small amounts of antimony, tin, calcium or selenium alloyed in the plate material to add strength and simplify manufacture. The alloying element has a great effect on the life of the batteries. As water use can be high, electrolyte levels have to be monitored and adjusted as necessary. Equalization charges are necessary for some designs. 15- 20 year life is normal if well- maintained, however Amp- Hour capacity will drop to 80% toward end of life.

- **Vented lead- acid Antimony** batteries have a nominal specific gravity of 1.210 - 1.220. Cells have an average float charge of 2.19 (±.04) DC volts/cell.
- **Vented lead- acid Calcium** batteries have a nominal specific gravity of 1.210 - 1.220. Cells have an average float charge of 2.21 (±.04) DC volts/ cell.
- **Vented lead- acid Selenium** batteries have a nominal specific gravity of 1.235 - 1.250. Cells have an average float charge of 2.20 DC volts/ cell, but not more than 2.25.

Vented Lead - acid Plante cell have lead plates which are grooved to increase their surface area. Special fabrication techniques make this a mechanically/ electrically durable battery but also very costly. 25 year life expectancy is warranted along with the ability to deliver 100% designed capacity over full useful life. Watering requirements are minimal and the battery can operate at higher temperatures than non-Plante designs.

- **Vented lead- acid Plante** batteries have a nominal specific gravity of 1.210 - 1.220. Cells have an average float charge of 2.24 (±.01) DC volts/ cell at 20 - 25°C. A voltage of 2.25 DC volts/ cell will insure full capacity at all times with low water loss and will fully recharge the battery after a discharge.

5.1.2. Valve Regulated Lead - Acid (Gel cells)

Valve Regulated lead- acid (Gel cells) batteries are often referred to as maintenance free but this is a misnomer. These batteries remain under constant pressure (1-4 psi) which helps the Hydrogen and Oxygen gases generated during charging, turn back into water. As these cell casings are sealed and non-vented, excessive gas pressure build up is prevented with the installation of a regulating valve. Battery room ventilation requirements are minimal with these sealed cells. These batteries are approximately 60% of the cost of a Vented Lead –acid cell but can last 20 years if well maintained.

Two most common types are the Gel and Absorbed Glass Mat (AGM):

- **Gel batteries** have a gelling agent (fumed silica) in the electrolyte which immobilizes it in the cell.
- **AGM batteries** have a thin fiberglass that holds the electrolyte in place like a sponge. This style battery is preferred over the Gel cells.

It is important not to overcharge these batteries. Keeping the temperature of the negative post of the battery within spec will help prevent excessive gassing and thermal runaway. Excessive battery charger AC ripple can damage these cells. While electrolyte levels cannot be monitored as with a vented lead- acid battery, regular testing (impedance/ conductance) can detect a dry-out condition.

5.1.3. Valve Regulated Lead Acid (VRLA) Batteries

Valve regulated lead acid (VRLA) batteries have a nominal specific gravity of 1.300. Cells have an average float charge at 2.25 - 2.30 volts per cell at 20 - 25°C. VRLA batteries with a nominal specific gravity of 1.250, are to be kept on a float charge of 2.20 - 2.25 DC volts per cell at 20 - 25ºC. As the room temperature changes, it is necessary to adjust the float voltage proportionally (2.33 - 2.36 volts @ 0°C, 2.21 - 2.24 volts @ 40°C. Increasing the charge voltage to 2.40 volts per cell can reduce charge time of a discharged battery, however, the charge must be monitored and terminated when the charge current decreases to a constant value.

NOTE: Refer to the specific battery manufacturer's recommended float charging voltage for proper float voltage levels.

5.2. Recommended Inspections of Batteries and Backup Power

5.2.1. Physical Inspection

Battery cell casings/ jars are to be kept clean and dry. Necessary precautions are to be taken to prevent the intrusion of foreign matter into the cells. Cell caps and flame arrestors are to be in place. All cell connections should be kept tight and free from corrosion.

5.2.2. Room & Cell Temperature

Temperature affects batteries and may alter the set point of the charger voltage. When taking any measurements, always record the temperature of the battery room. As battery cell temperatures drop, so does stored energy capacity. Higher temperatures increase capacity, but lower life expectancy. EPRI recommends a battery room temperature range between 60°F (15.5ºC) and 90°F (32.2ºC), with an average of 77°F (25ºC).

5.2.3. Battery Room Ventilation

Battery rooms should be adequately ventilated, and exhausted outside the room to an open or outside area. Hydrogen gas concentrations in atmosphere greater than 4% are considered potentially explosive. Room air flow should be sufficient enough to prevent pockets of hydrogen from concentrating near the ceiling.

NOTE: If the ventilation system is out of service and work needs to be performed in the battery room, the area should be treated as hazardous, both for its oxygen deficiency and potentially explosive atmosphere. The room should be ventilated with portable/temporary air movers before proceeding with any work.

5.2.4. Electrolyte Levels

Only battery manufacturer's approved (distilled or de-mineralized) water shall be used to maintain the electrolyte level in the cell between the marked liquid level lines. Do not overfill the cell. Acid should never be added to or removed from a cell without specific instructions from the manufacturer.

5.2.5. Float Voltage

A battery's float voltage has an effect on the stored Ampere-hour capacity of the battery. In general, as the float voltage is reduced, so is the stored Ampere-hour capacity. However, maintaining a higher than suggested float voltage may cause an accelerated decrease of cell electrolyte levels as water is lost.

5.2.6. Inter-cell Connection Resistance

For a battery's inter-cell connection resistance, the measurements for each connection should be obtained and recorded to establish baseline data. A connection should be disassembled, cleaned, re-assembled, re-torqued and re-tested if any connection is:

Greater than 20% above the average resistance
or
Greater than 5 micro-ohms above average (if 5 > 20%)

The re-tested connection measurements should be used in the baseline dataset for future comparison and trending.

During routine testing of inter-cell resistances, an increase of 20% from the recorded baseline readings (for that individual connection, not the battery average) is cause for corrective action.

Sites shall maintain baseline resistance data (as applicable to their battery configuration) for use in determining SAT(< 20% over baseline)/ UNSAT (> 20% over baseline) results as measured during routine testing. This individual connection data shall be updated as necessary when connection work changes baseline data.

Note: Refer to *IEEE Std. 450, Annex F, Methods for Performing Resistance Measurements*. Refer *to IEEE Std. 450, Annex D.2* for discussion of baseline data

5.2.7. Internal Impedance / Conductance Testing

Internal resistive (conductive) measurements (BITE- Battery Impedance Test Evaluation) can be used to evaluate the electro-chemical characteristics of battery cells. The measurements can provide indication of individual cell problems and a degraded ability to provide Emergency DC power when required.

Baseline data should be recorded in the first six months (if possible) of placing a battery in service. The record datasheet should note the date of battery (bank or individual) installation and the date when baseline data was recorded. Note that baseline data will vary depending on manufacturer, battery model, Amp- hour capacity and the measuring equipment used.

Testing should be performed under similar conditions such as cell temperature, float voltage and charging current. Results will vary with the various models and styles of test equipment so it is preferable to always use the same equipment.

Significant changes (>100% for impedance, >50% for conductance) from baseline values should be investigated. Over the useful life of a battery, the average cell impedance will rise. Batteries whose impedance values differ from the current testing year bank average by ±20% should be considered for individual load test, equalize charging or replacement.

NOTE: Refer to *IEEE Std. 450, Annex J* for further information.

5.2.8. Negative Terminal Temperature (VRLA Batteries Only)

< 3°C (5°F) above room/ area ambient temperature.

This specification is linked to the requirement for battery charger current and voltage ripple be limited to the values listed below. Ripple above those limits drives chemical reactions at the negative post (internally) and will release heat into the cell.

5.2.9. Charger AC Ripple Voltage /Current (VRLA Batteries Only)

Max Voltage ripple - 0.5% of DC Float Voltage
Max Current ripple - 5A/ 100A-Hr rating of battery

6. GENERATOR LEAD LINE

CAUTION: Extreme caution should be used with inspecting transmission line systems.

6.1. Inspecting the Generator Lead Line.

6.1.1. The interconnect line will be inspected semi-annually for structural integrity and as part of the vegetation management program.

6.1.2. The inspection will be a ground-based inspection conducted by a qualified technician with a check list of items to inspect.

6.1.3. Detailed structural inspections will be conducted on an “as needed” basis.

6.1.4. Personnel assigned to conduct interconnect line inspections will be trained on proper inspection techniques, actions to take when vegetation conditions present an imminent threat of a transmission line outage, the requirements of this procedure, and the requirements for working in the vicinity of energized transmission lines. Documentation of this training should be maintained on site for a minimum of 5 years.

6.1.5. Any vegetation condition that presents an imminent threat of a transmission line outage will require immediate notification to the owner and an entry recorded in the facility log. An action plan, that may require switching the line out of service, will be implemented until the threat is removed.

6.1.6. Structural components will be visually inspected, utilizing binoculars where needed. If available, during periods of high generation loading, the inspection will include the use of an IR camera to identify high resistance connections. Discrepancies noted during the IR camera survey will be recorded and images will be archived for historical trending

6.1.7. Visual inspections shall be made to ensure no erosion is present from washouts and/or other means that could result in unstable structural conditions.

6.1.8. Significant discrepancies will be noted with follow up actions itemized. It is recommended that high resolution photographs accompany any discrepancy report.

6.1.9. The inspection results will be reviewed and signed by the owner.

6.1.10. The owner, or designee, is responsible for maintaining the status and remediation of all discrepancies.

6.2. Transmission Vegetation Management Program (TVMP)

6.2.1. The objective of the TVMP is to improve the reliability of the interconnect line by minimizing outages caused by vegetation on or adjacent to the interconnect right of way.

6.2.2. TVMP inspections will be conducted at the same time as the structural inspections.

6.2.3. Clearance 1 distance shall be a minimum of 50 feet on either side of transmission line centerline. Within those boundaries, all vegetation will be cut to less than 1 foot high. Danger trees beyond 50 feet will be adequately trimmed or removed. Vegetation management need only be conducted when routine inspections identify vegetation that has encroached or violated the Clearance 2 distance.

6.2.4. Clearance 2 distance shall be a minimum of 25 feet radial clearance between vegetation and all phase conductors under all rated electrical operating conditions. This distance is in excess of the IEEE recommended MAID distance of 4.4 feet, corrected for altitude (ref*. IEEE Standard 516-2009, Annex D, Table D.9,* where T = 3.0).

6.2.5. Inspection results identifying vegetation that has encroached upon the Clearance 2 distance will require vegetation management work to establish all vegetation back to Clearance 1 distances. Vegetation management work should be completed within 60 days of identifying encroachment beyond the Clearance 2 distance. This time requirement is based upon local conditions.

6.2.6. In the event that there are restrictions in attaining the Clearance 1 distance, monthly vegetation management work will be conducted to maintain all vegetation at the Clearance 2 distance. This monthly vegetation management requirement will stay in place until all restrictions are removed and the Clearance 1 distance is re-established.

6.2.7. Vegetation management work will only be conducted by contractors trained and qualified to perform vegetation management work in the vicinity of live transmission lines.

6.2.8. The vegetation management contractor will develop and submit a work plan that:

- Lists all areas noted during the interconnect line inspection wher Clearance 2 distance violations were identified. Specifies the scope of work to be completed including the vegetation management methods to be utilized.
- Lists all chemicals planned for use with MSDS sheets attached
- Provides an itemized check list for each area of work, with spots for completion signatures by contractor personnel after work quality is accepted by site managers.

- Documentation that all contractor personnel have been trained on the applicable sections of this procedure and the actions to take upon discovering any vegetation condition that presents an imminent threat of a transmission line outage.
- The completed work plan will be retained on site for a minimum of 5 years.

6.2.9. Vegetation management work may utilize manual clearing, mechanical clearing, herbicide treatment, or other industry approved methods as needed to establish the required distance of Clearance 1.Address any discrepancies identified during the interconnect line inspection.

6.2.10. Vegetation management work plans will comply with all local, state, and federal requirements.

6.2.11. Vegetation management work plans will require review and approval of the Environmental Program Manager prior to commencement of work.

6.2.12. The owner or designee will ensure compliance with all lease and easement requirements prior to commencing any vegetation management work.

7. SECONDARY CABLE SYSTEMS

7.1. In some cases secondary cables are utilized in substations. The secondary cable insulation rating will range from 600V to 2000V depending on the cable design and the wind turbine generator (WTG) type. Typical installations will require multiple conductors per phase. Conductors should be properly labeled with phasing tape or colored cable jackets. After installation and prior termination to the transformer and controller, a DC insulation resistance test ("megger") is typically performed. The test voltage is dependent on the insulation value, but is usually in the range of within 500V to 2,500V. The intent of the installation tests are to:

- Ensure that the insulation was not shorted during the installation process. A low voltage insulation resistance measurement of less than 100M-Ohm may indicate a problem.

- Verify the cable phasing from one end to the other.

Generally secondary cable systems are not retested as a maintenance practice unless there is reason to suspect a problem. An annual infrared inspection of the terminals is recommended especially on cables deemed critical.

8. FIBER OPTIC CABLE SYSTEMS

Upon installation and termination of the fiber optic cables from each WTG tests are performed to ensure the quality of the fiber optic cable and terminations. Typically one of the following two tests are performed:

- Attenuation (dB) Loss Testing
- Optical Time Domain Reflectometer (OTDR) Testing

Since the network is constantly used for data transmission it is in effect, constantly monitored. If there is a network problem, one of the tests above can generally help diagnose the problem. Other than a visual inspection of the connections, periodic maintenance is generally necessary.

9. MEDIUM VOLTAGE CABLE SYSTEMS

Medium voltage cable systems can be found as a part of the substation electrical system. During commissioning field tests range from legacy methods such as insulation resistance and withstand methods, which are only effective at detecting gross shorts (cable system failures), to sophisticated, predictive partial discharge (PD) tests which detect and locate gross and subtle insulation defects and provide a baseline for future use. The standardized electrical test requirement at the factory for all completed solid dielectric shielded cable insulation system components (including the cable, joints, and terminations) is a partial discharge test performed during a 50 or 60Hz over voltage. Ideally a partial discharge test comparable with the factory test can be repeated on installed cable systems to assure that they still meet these requirements. If this type of test is not available or deemed impractical for a specific application, a list of alternative tests can be found in the IEEE 400 guide document.

Ideally, during commissioning the following step are completed on cable system and a baseline is established:

- Visual inspection for physical damage, bends at less-than-minimum bending radius, phase identification, fireproofing, proper shield grounding, cable supports and termination connections, along with required size and rating per design drawings and proper separation of power, control, instrumentation, and emergency circuits.
- Conductor phasing test
- Resistance of neutral wires and tapes, conductor resistance/ continuity
- Off-line 50 or 60Hz PD test on each individual span of cable (termination to termination point). This test can provide profile of the cable system which is comparable to factory standards listed below
- DC Insulation resistance test ('megger test') or very low frequency AC test at the (operation voltage or less) on the entire cable system. This test is not intended to detect defects which may fail in the near future but rather, to detect pre-existing shorts
- Infrared test of the accessories (terminations and accessible splices) under high current condition.

Table A. Cable System Insulation Test Standards.

Cable Component	**Thresholds**
IEEE 48 Terminations	No PD >5pC up to 1.5Uo
IEEE 404 Joints	No PD >5pC up to 1.5Uo
IEEE 386 Separable Connectors	No PD >3pC up to 1.3Uo
ICEA S-94-649 MV Cable	No PD >5pC up to 2Uo*

*Actually 200V/mil in factory. Field tests are performed to a maximum voltage value equal to the level of system overvoltage protection which is typically 2 times the operating voltage for 35kV systems (line to ground, 1.0Uo).

9.1. After a failure

A DC insulation resistance test at (operating voltage or less i.e. 10 or 20kV for a 35kV system) is recommend after any failure event to confirm the phase of the fault and to confirm that there is not a second fault before re-energizing. Arc reflection fault location technology should be used with a minimum of pulses to determine the location of the fault. To confirm dielectric integrity of the system after repair, an off-line 50 or 60Hz PD test is recommended. In some cases relays can provide some information about the fault.

9.1.1. Cable Fault Location Equipment / Thumpers

Fault locating methods use fault indicators, "thumpers," radars, acoustic detectors or combinations of this equipment. Research indicates that subjecting cable systems to unnecessary surges reduces their remaining life. The industry has developed less evasive fault locating methods that reduce the stress on cable insulation systems. The general approach is to reduce the amount of thumping necessary to locate a fault while simultaneously reducing the voltages required to perform the task.

9.2. Periodic Testing

Comparative infrared testing is recommend annually to check the condition of the mechanical connection of cable system joints and terminations. Off-line 50 or 60Hz PD testing is recommended every 5 years.

APPENDIX OF MAINTENANCE CHECKLIST AND INTERVALS

Substation Inspection and Maintenance Intervals (Based on a 6-year maintenance cycle).

Table A.

Recommended - Substation Maintenance Tasks and Intervals	**Installation & Commissioning**	**5W (Monthly)**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Switchgear								
Inspect, clean, exercise.	X			X				
Grounding Transformers								
Testing should be similar to main power transformers (where applicable).	X			X				
Relay Panels								
Physically inspect lockout relays for mechanical and electrical integrity.	X				X			
Inspect panel wiring.	X				X			
Check As Found settings against past known settings.	X				X			
Perform a physical inspection of relay.	X				X			
Verify relay settings to RSO/Relay Database Information.	X				X			
Log any settings changes for testing.	X				X			
Check and record As Left settings values.	X				X			

Recommended - Substation Maintenance Tasks and Intervals	**Installation & Commissioning**	**5W (Monthly)**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Lamp and megger all CT Circuits.	X				X			
measure and record all three phase potential and currents inputs.	X				X			
Perform all control circuit operations including trip checks.	X				X			
Initiate communications devices.	X				X			
Check all external trips to the circuit breaker under test.	X				X			
Check any digital fault recorder points monitoring the relay package.	X				X			
Verify relay alarms.	X				X			
Replace DC and low voltage potential circuit fuses on transmission protection circuits.	X				X			
Check power supply lights, alarms, targets, etc. on relays, record results.	X	X						
Communications Panels								
Inspect panel wiring.	X					X		
Verify any auto AND/OR logic.	X					X		
Perform all control circuit operations including trip checks.	X					X		

Recommended - Substation Maintenance Tasks and Intervals	**Installation & Commissioning**	**5W (Monthly)**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Verify correct operation of Check Back Device or other auto test device.	X					X		
Verify operation and reset of communications alarms.	X					X		
Check power supply lights, alarms, status etc. on comm. equipment where applicable.	X	X						
Substation Grounding Systems								
Visual inspection (equipment, fence, gates).	X	X						
Motor Operated Disconnects								
Visual Inspection.	X	X						
Thermography.	X			X				
Operate / inspect / lubricate.	X				X			
Contact resistance (ductor) test.	X				X			
Blade and hinge assembly maintenance.	X						X	
Check cabinet heaters.	X	X						
Circuit Breakers - SF_6								
Check indicating lamps (red and green).	X	X						
Visual inspection.	X	X						
Thermography.	X			X				
Contact Resistance (Ductor) Test.	X				X			

Recommended - Substation Maintenance Tasks and Intervals	**Installation & Commissioning**	**5W (Monthly)**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Profile breaker operation.	X				X			
Power factor test.	X				X			
Travel test.	X				X			
SF_6 moisture test.	X			X				
Exercise mechanism.	X				X			
Mechanism lubrication / maintenance.	X				X			
Pressurized vessel inspection.	X				X			
Relief valve replacement.	X				X			
Internal inspection.	X						X	
Mechanism refurbishment.								X
Check control cabinet heaters.	X	X						
Check SF_6 tank heaters.	X	X						
Check of gauges and pressure switches.	X				X			
Functional alarm test.	X				X			
Substation Bus								
Visual inspection.	X	X						
Thermography.	X			X				
Verify torque of bolted connections.	X					X		
Substation Foundations								
Visual inspection.	X	X						

Recommended - Substation Maintenance Tasks and Intervals	**Installation & Commissioning**	**5W (Monthly)**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Substation Power Transformers								
Monitor nitrogen pressure (blanket and bottle).	X	X						
Monitor oil level.	X	X						
Monitor oil temperatures (top oil and LTC).	X	X						
Monitor oil flow indicator.	X	X						
Monitor winding temperature.	X	X						
Monitor gas accumulator as applicable.	X	X						
Oil dissolved gas analysis.	X		X					
Oil quality test.	X		X					
Thermography.	X		X					
Power factor test.	X				X			
Low voltage excitation test.	X				X			
Winding resistance (TTR on all taps).	X				X			
Frequency response analysis.	X				X			
Maintenance inspection.	X				X			
Power wash heat exchangers.	X				X			
Check cabinet heaters.	X	X						
Check bushing oil level.	X	X						
Visual inspection.	X	X						

Recommended - Substation Maintenance Tasks and Intervals	Installation & Commissioning	5W (Monthly)	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Functional test, cooling system, alternate lead / lag coolers [1].	X	X						
Record and reset top oil temperature.	X	X						
Record and reset top winding temperature range.	X	X						
Functional test LTC, run through 'neutral'.	X	X						
Functional alarm test (aux relay installations).	X		X					
Functional alarm test (direct wired).	X				X			
Inspect bushing potential tap.	X				X			
Check / verify gauges and alarms.	X				X			
Test sudden pressure relay.	X				X			
Check automated aux power throw-over switch.	X				X			
Transformer turns ratio test.	X				X			
Substation Yard								
Visual inspection.	X	X						
Oil / water separator check.	X			X				
Station summarization (cooling).	X			X				
Station winterization (heating).	X			X				

Recommended - Substation Maintenance Tasks and Intervals	**Installation & Commissioning**	**5W (Monthly)**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Surge Arrestors								
Thermography.	X			X				
Power factor test	X				X			
Visual inspection.	X	X						
Detailed visual report.	X				X			
MV Cable								
Thermography terminations (high load).	X			X				
Off-line 50/60Hz PD test.	X					X		
Visual inspection	X			X				
LV Cable								
Thermography terminations (high load).	X			X				
Insulation resistance.	X							

Additional notes to Maintenance Tasks and Intervals:
***Many of these tasks can be minimized or eliminated if real-time monitoring is provided for these assets.

TRANSMISSION LINE

These tasks should be done at the time of original installation and commissioning and then repeated at 1 year and every 3 years. Thermography should be done quarterly.

Table B. Transmission Line Tasks.

Transmission Pole and Frame Structure Inspections	**Installation & Commissioning**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Pole identification plates are present and fastened securely to the structure.	X				X	X	X
Cross Arm Inspection: Rainwater entrapment, moisture damage at connection points and hardware fastening points.	X				X	X	X
Oil coating inspection. Verify the wood surface is adequately soaked with oil.	X			X	X	X	X
Frame does not lean or list outside of intended structural design.	X			X	X	X	X
Insulators and Transmission Cable: Strong ties are securely fasten cable to insulator glass.	X				X	X	X
Insulators and Transmission Cable: Insulators are clean, no evidence of arcing.	X				X	X	X
Insulators and Transmission Cable: Insulators are not cracked.	X				X	X	X
Insulators and Transmission Cable: Insulators are mounted perpendicular to the frame/structure and cable is not causing undue stress at the attachment point.	X				X	X	X

Transmission Pole and Frame Structure Inspections	Installation & Commissioning	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Use clamp-on ammeter to identify any AC drain current flowing into the ground circuit.	X				X	X	X
Torque Checks and Verification							
Re-torque hardware at cross arm joints.	X				X	X	X
Re-torque hardware at all jointed connections of the frame.	X				X	X	X
Re-torque hardware at all arrestor and insulator attachment points.	X				X	X	X
Re-torque hardware at all auxiliary hardware attachment points (i.e. fiber).	X				X	X	X
Re-torque hardware at all guy wiring cable crimp hardware.	X				X	X	X
Arrestors							
Megger all arrestors on the transmission line circuit. Provide insulation results in final report.	X				X	X	X
Inspect ground connection points on arrestors are secure.	X				X	X	X
Inspect arrestor insulators for signs or arcing or tracking to ground.	X				X	X	X
Verify mounting hardware is present.	X				X	X	X
Riser Poles							
If applicable, inspect all disconnects for proper seating and no evidence of overheating or arcing at seated position.	X				X	X	X

Transmission Pole and Frame Structure Inspections	Installation & Commissioning	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Inspect cable for chafe marks at the point where cable exits the riser conduit stubs.	X				X	X	X
Verify mounting hardware of conduit riser stubs are all present and secure.	X				X	X	X
Verify conduit stubs are sealed. Foam seal if not sealed.	X				X	X	X
Torque check cable terminations.	X				X	X	X
Inspect cable terminations for signs of overheating, arcing, etc.	X				X	X	X
Inspect additionally mounted hardware and re-enforcement for signs of looseness.	X				X	X	X
T-Line and Fiber Inspections							
Inspect all splice points for fraying, slipping or failure.	X				X	X	X
Cable and fiber sag is uniform as compared phase to phase.	X				X	X	X
Cable and fiber sag is uniform from pole to pole.	X				X	X	X
Excess fiber coils are secured and not loose at coil locations.	X				X	X	X
Guy Wiring and Structural Re-enforcements							
Check tension on all guy wires. Tighten any found to be loose.	X				X	X	X
Check fastening hardware is present and torque marked.	X				X	X	X

Transmission Pole and Frame Structure Inspections	Installation & Commissioning	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Check guy wire marker sleeves are present and in good repair.	X				X	X	X
Torque check all fastening hardware.	X				X	X	X
Galvanized Frame Structures (If Applicable)							
Inspect protective coating, galvanized coating. Look for rust spots.	X				X	X	X
Perform inspections at welded joint locations, looking for cracks or rust in welded joints.	X				X	X	X
Inspect ground connection hardware is present and secure.	X				X	X	X
Inspect structure foundations for signs of stress cracking or water intrusion.	X				X	X	X
Vegetation Management / Inspection							
Fire boundary at the dirt / base exists and is acceptable.	X				X	X	X
Overhead vegetation is clear of poles, lines, etc. Vegetation boundary allowance, adjacent to cables, incorporates line sag and wind sway.	X				X	X	X
Thermography Inspection							
Perform thermographic inspection on all arrestors.	X	X			X	X	X
Perform thermographic inspection on all T-Line Termination.	X	X			X	X	X

Transmission Pole and Frame Structure Inspections	**Installation & Commissioning**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Perform thermographic inspection on all disconnects & fusing.	X	X			X	X	X
Perform thermographic inspection on all T-Line splices.	X	X			X	X	X
Perform thermographic inspection on all insulators.	X	X			X	X	X
Perform thermographic inspection on all ground wiring and jumpers.	X				X	X	X
Reporting - General							
Prepare report with all deficiencies identified from the above check lists.	X				X	X	X
Identify all deficiencies in the summary portion of the maintenance and inspection report.	X				X	X	X
Reporting - Thermography							
Description of equipment and or object; including phase if required.	X	X			X	X	X
Identify criticality of the equipment.	X	X			X	X	X
Date and time of inspection.	X	X			X	X	X
Visual photograph adjacent to infrared picture.	X	X			X	X	X
Thermograms.	X	X			X	X	X
Ambient temperature, wind speeds and weather conditions.	X	X			X	X	X
Thermographer name.	X	X			X	X	X

Transmission Pole and Frame Structure Inspections	**Installation & Commissioning**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Related operating parameters (equipment loading conditions).	X	X			X	X	X
Probable cause of failure indicated.	X	X			X	X	X
Recommendation.	X	X			X	X	X
Operational status.	X	X			X	X	X
Temperature rise.	X	X			X	X	X
Temperature reference.	X	X			X	X	X
Related past history of equipment.	X	X			X	X	X
Maximum operating temperature of equipment being thermal imaged (generally available on the name plate).	X						
All temperatures reported should be in Celsius scale.	X	X			X	X	X
Off-line power frequency PD Test	X				X		
Infrared inspection of terminations and splices (high load)	X				X		

Table C. Battery Charger Installation.

Battery Charger Installation	Installation	5W (Monthly)	3M (Quarterly)	1Y (Yearly)	3 Years	6 Years	12 Years	24 Years
Verify Charger Functions And Alarms	X	X						
Load Test	X			X				
Battery								
Visual Inspection	X	X						
Battery Cell Voltage Readings	X		X					
Annual Battery Inspection	X			X				
Internal Impedance Test	X			X				
Thermography	X			X				

Table D. Static VAR Compensators and Energy Storage.

Battery Charger **Installation**	**Installation**	**5W (Monthly)**	**3M (Quarterly)**	**1Y (Yearly)**	**3 Years**	**6 Years**	**12 Years**	**24 Years**
Inspect, Maintain And Monitor	X	X	X	X	X	X	X	X
Thermographic Inspections	X	X	X	X	X	X	X	X
Verify Correct Operation	X	X	X	X	X	X	X	X
Capacitor and Reactor Banks								
Inspect, Maintain And Monitor	X	X	X	X	X	X	X	X
Thermographic inspections	X	X	X	X	X	X	X	X
Verify correct operation	X	X	X	X	X	X	X	X

RP 701

WIND TURBINE END OF WARRANTY INSPECTIONS

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chair: Todd Wynn, Enel Green Power North America
Principal Author: Chris Hendersen, DNV KEMA

PURPOSE AND SCOPE

This Recommended Practice discusses preferred methods used to assess the condition of wind turbines prior to the expiration of the original equipment manufacturer (OEM) warranty, commonly referred to as End of Warranty (EOW) inspections.

The transition out of the warranty period is a critical milestone in the life of a wind project. Defects or damage due to design, manufacturing, shipping, installation, and maintenance practices are typically covered under warranty agreements and can often be repaired or replaced during this time so that turbines are in the best possible condition exiting the warranty. Scheduled maintenance inspections may not detect component failures and a more thorough inspection with specialized tools is recommended prior to warranty expiration. The priorities in an EOW inspection are to identify component failures (particularly on the critical and highest costs components) and any items which may pose hazards to equipment or the health and safety of site personnel, and to document the condition of the turbines and related equipment for future reference. Claims may result in component replacement or commercial changes to ensure the owner is protected (e.g., an extended warranty on a particular component). Some amount of normal wear and tear should be expected and will not necessarily impact the ability of a component to meet its design life or result in a successful warranty claim.

The purpose of this document is to describe the most appropriate techniques used in EOW inspections. These techniques, if properly applied, should lead to the submission of well-documented claims.

INTRODUCTION

The scope of an EOW inspection campaign can range from minimal to complex depending on the time and cost constraints and the interest of the project owner. A wide variety of inspection techniques are available and the project owner must decide which are appropriate for their situation. Known issues may exist with a particular component, warranting specific inspection techniques that may not be necessary in all cases. For large projects it can be beneficial to conduct a diverse range of inspection tasks on a sample population of turbines prior to the full scale inspection campaign. This can establish the most critical tasks and determine the scope of inspections to be conducted for the entire project. Individual inspection tasks during the complete EOW inspection campaign can be completed on 100% of turbines in a project or on a smaller sample population, depending on the criticality, cost, and time required for the particular task. Some inspection tasks may only be triggered if a problem is identified by other means. Evaluation of supervisory control and data acquisition (SCADA) data and review of parts usage at the project can also be beneficial for identifying problematic components that warrant additional attention during EOW inspections.

Inspections may be conducted by independent third party organizations, the project owner, or combinations of several groups with specialized skill sets. Representatives from the OEM and/or owner may accompany inspection teams, or teams can operate independently. Best practice is to involve site staff, owner’s engineers, and the OEM during the initial inspections so the processes can be reviewed and agreed upon by all parties at the onset of inspections.

WIND TURBINE END OF WARRANTY INSPECTIONS

1. COMMON INSPECTION TASKS

1.1. Gearbox Internal Inspections

Borescopes are commonly used to document the condition of gear teeth and bearings within the gearbox and is recommended for 100% of gearboxes. Borescope images should be taken in all accessible areas of the gearbox, regardless of whether or not damage exists, to document the condition. Images should include the gearbox nameplate and reference photo cards should be used to identify each section of the gearbox. Images of each component should be taken in a consistent order for all gearboxes. Areas of the gearbox that cannot be accessed should be noted and images of obstructions taken where appropriate, such as a bearing cage blocking inspection of bearing races.

Image quality should be the most important factor in borescope selection, as some borescopes are inadequate for wind turbine gearbox inspections. The rigidity of guide tubes, lens cleanliness, and the type and quality of light, and particularly technician training, all affect image quality.

The time required for a borescope inspection is highly variable depending on access, operator skill level, and the number of positions the gearbox will be stopped in to permit inspections.

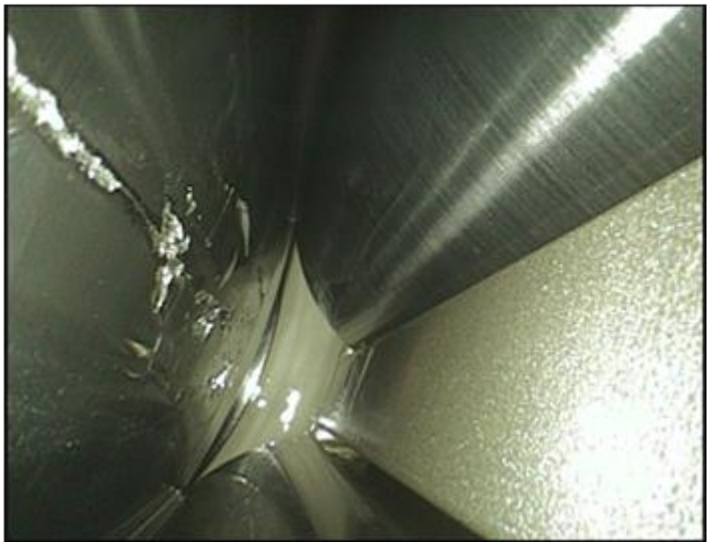

Figure A. Example of damage to the inner race of a high speed bearing documented with a borescope.

Additional elements of a gearbox inspection should include: visual inspection of the housing for cracks, leaks, and damaged ancillary equipment, oil level in the sight glass, and magnets. Any abnormal color, smell, or foam in the oil should also be noted at the time of inspection.

1.2. Blade Inspections

Visual inspection of the blade surface is commonly conducted from the ground and at the blade surface using various access techniques. 100% of turbine blades should be inspected from the ground using a digital single lens reflex (SLR) camera on a tripod with a telephoto lens. Each blade should be photographed with images covering the entire surface and from different angles so the leading edge, trailing edge, high and low pressure surfaces are all clearly visible. Using a camera is preferable to a spotting scope or binoculars, as a camera provides documentation that can be reviewed by others and in some cases damage may not be evident until post processing of the images is done.

Several (5-10) complete rotors can be completely documented by an experienced crew in a day. Inspection of all blades is recommended.

Figure B. Example of blade damage documented with ground-based digital photography.

Direct access inspections (e.g., ropes, platforms, boom trucks, etc.) can be used to detect damage that may not be visible in ground based images (e.g., small cracks). In some cases the extent of damage may not be clear in ground based images and can be clarified through direct access inspections. Non-destructive testing such as lightning protection system (LPS) resistance measurements or ultrasonic testing (UT) for voids in adhesive bonds can also be performed during direct access inspections. A single crew can typically inspect 1-2 rotors per day but these inspections impose greater limitations on safe working conditions (e.g., wind speed limits), so a sample of 10-20% of the project is often more feasible.

1.3. Visual Walk-down Inspection

A visual inspection of the complete turbine is recommended to document safety issues, the general turbine condition, and component failures. Visual inspection is recommended for 100% of turbines. A common checklist and rating system for findings to be used for all turbines on a project should be developed with input from the inspection team, owner, site managers, maintenance staff, and potentially even the OEM. Checklists provided by the OEM for regular maintenance are a useful starting point for development of the visual inspection checklist. Digital images of any observed damage should be collected in addition to the checklists. Inspection crews should have access to turbine controls to be able to test certain systems for function, such as yaw motors, fans, pumps, and brakes. Some areas of the turbine require specialized training or equipment to access, such as transformers located in nacelles.

1.4. Lubricant Sampling and Testing

Sampling and testing of gearbox oil and main bearing grease should be conducted as part of the EOW inspection, if this is not already being done as part of regular maintenance or if laboratory reports are not made available to the project owner. Laboratory testing can identify wear metals in the lubricant, the condition of the lubricant itself, and possibly indicate damage to the equipment. The presence of water, changes in viscosity, and additive breakdown can result in a failure of the lubricant, which is in itself a critical system. Hydraulic oil, blade bearing grease, and other lubricants may also be sampled and tested as needed. Detailed procedures for lubricant sampling and testing are described in RP 812 and RP 813.

1.5. Generator Testing and Inspection

Electrical testing of the generator can be done with specialized tools and may detect problems with winding insulation, although the ability of these tests to predict failure is limited. A description of specific tests can be found in RP 203. The condition of generator cable terminations may also be inspected and signs of previous arcing identified during testing.

In some cases it may be possible to inspect generator internals with a borescope, where evidence of arcing, dust generated from loose wedges, and excess grease or debris may be observed and documented.

1.6. Vibration Measurement

Vibration data (also called condition monitoring system data) can be valuable in detecting faults in parts of the drive train that may not be otherwise accessible. Data from a permanently installed system are preferable as they allow for long-term trending; however, portable vibration systems which can be installed temporarily for EOW inspections may still detect many faults. Vibration data alone will typically not be sufficient to make a warranty claim, but identification of faults though vibration may trigger additional focused borescoping or other inspection techniques which may be impractical to conduct site-wide, such as a partial bearing disassembly and cleaning. Additional information on vibration measurement can be found in RP204 and RP811.

2. EOW INSPECTION SCHEDULE

Inspections should be planned such that delivery of final inspection reports can be made well before the warranty expiration; however, warranty claims can be made at any time before the expiration if sufficient evidence is available. Warranty claims will need to be reviewed by the OEM and not all claims will be accepted, so including ample time for discussion after claims are made but before the warranty has expired is critical. Planning for delivery of inspection results six months prior to the warranty expiration is considered best practice.

Multiple teams with specialized inspection skills may be deployed across the site and the sequence of deployment is critical to ensure the initial teams provide information to subsequent teams. For example, ground-based blade inspections will inform the choice of turbines that receive direct-access blade inspections. Inspection teams should be given complete access to the turbines and trained to safely stop and control equipment as required for inspections

3. EOW REPORTING

Large amounts of data are generated during an inspection campaign and it is critical to distill the raw data into reports that can be used by project owners to make claims and provide sufficient information for the OEM review. A project-wide summary should be produced that identifies the most critical observations and patterns of abnormal wear or damage. The summary report should describe the inspection methods and tools used, nomenclature employed, criteria for classifying observations, and inspection coverage for all tasks.

Detailed individual turbine reports for each inspection task should also be generated which clearly document the observed conditions. These detailed reports should document the make, model, and serial number(s) of major components, date of inspection, tools used, and the names of the inspectors. For example, each turbine should have a unique borescope inspection report that includes representative images from each section of the gearbox and clearly identifies any damage.

All raw data should be retained and provided to the project owner. These data may be required during the claim process and can be used to benchmark the turbine condition for future reference.

SUMMARY

Properly conducted EOW inspections are effective for documenting the turbine condition in detail prior to warranty expiration and should be performed on all wind projects. A large number of inspection techniques can be deployed as part of an EOW inspection campaign and project owners must consider which are appropriate for their project.

RP 801

CONDITION BASED MAINTENANCE (CBM)

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Primary Author: Jim Turnbull, SKF
Committee Chairs: Bruce Hamilton, Navigant Consulting;
Jim Turnbull, SKF

PURPOSE AND SCOPE

This set of recommended practices addresses the common maintenance issues related to the grounding systems for generator and drive train shafts in various wind turbine designs. It is not machine specific and some adaptation may be required based on specific designs.

INTRODUCTION

The ability to plan how, where, what and when to maintain a wind turbine is essential to the management of a wind park. Establishing the right maintenance strategy and practices for your wind turbine can make the difference between a profitable operation versus one that runs in the red. One such maintenance strategy is Condition Based Maintenance (CBM). CBM is a philosophy that proactively assesses the health of an asset in order to optimize planning and scheduling of maintenance. RP801 focuses on some the key Predictive Maintenance (PdM)) technologies of a Condition Based Maintenance program.

The fundamental concept behind CBM is the establishment of a practice that enables the measurement, monitoring and diagnosis of the equipment's health. Maintenance decisions are then made to either:

1 Continue to monitor.
2 Take additional measurements.
3 Schedule an inspection.
4 Schedule a repair.
5 Schedule a replacement.
6 Do nothing.
7 Run to failure.

Any one or more of these decisions may be acceptable, however having the insight to the condition of your equipment enables you to make a more informed decision and reduce the financial and operational risks of the unknown.

There are a variety of technologies and techniques that are used to assess the condition of equipment in the field. In this RP we will focus on the more commonly used Predictive Maintenance (PdM) technologies. There are emerging hardware and software technologies being developed that will be incorporated in future RP versions.

The first edition of RP 801 focuses on PdM technologies for:

1 The drive train.
2 Blades.
3 Electrical controls/systems.

The monitoring and analysis technologies employed on these components can be easily correlated to the some of the tests that are taken to measure and diagnose a human's health.

CONDITION BASED MAINTENANCE

1. VIBRATION ANALYSIS

Similar to an EKG, in that it measures the "pulse" of a machine. Evaluating the signature of the pulse can help determine the severity and source of a pending component failure. Reference: *RP811 - Drive Train Vibration Analysis, RP821 - Blade Condition Monitoring.*

2. OIL ANALYSIS AND OIL DEBRIS MONITORING

Oil Analysis measures the health of a machine's "blood". Is the oil or grease retaining its properties and is it sufficiently clean to properly serve its original lubrication function? Oil and grease debris monitoring does not measure the health of the oil or grease itself, but rather identifies and trends metallic particles carried within the lubricant that are produced as a result of early damage. Reference: *RP 813a-c Grease Sampling, RP 814 Grease Analysis, RP817 Oil Debris Monitoring, and RP818 On-line Oil Condition Monitoring.*

3. TEMPERATURE MEASUREMENT

Is your machine running outside its "normal body temperature of 98.6°F?" Higher temperature measurements on bearings, control panels, generators, etc. are a reliable indication that equipment is in an early to late stage of failure. Reference: *RP 815 - Temperature Measurement*.

4. NACELLE PROCESS PARAMETERS

Combine a brain scan with your records of your medical history. This data is taken from process variables from the control system. Whether real time or data stored in a plant historian, this data provides valuable insight into the holistic condition of the turbine. Reference: *RP816 - Nacelle Process Parameters*.

5. ELECTRIC CURRENT ANALYSIS

Also similar to an EKG, however the focus is more on electrical versus mechanical derived signal analysis. Reference: *RP831 - Electrical and Electronic Components*.

The use of these technologies allows for round-the-clock monitoring of key turbine components. Monitoring can be done by taking measurements periodically or continuously. Measurements can be taken through portable, temporary or permanently installed instrumentation. The frequency and amount of measurements are influenced by a combination of factors, such as the potential severity of the failure, when is the failure expected to occur, and/or what personnel and financial resources are available. These factors are determined as part of the overall maintenance strategy.

By tracking component performance, maintenance activities can be coordinated across the wind farm; service calls can be better planned and combined; and operators can take advantage of planned shutdowns to service several turbines at the same time, since machinery conditions are known from the monitoring. All contribute economies and efficiencies for the wind farm operation.

The monitoring process for a wind turbine can effectively reduce lifecycle costs and extend service life. Implementing necessary repairs when problems begin to surface, for example, proves easier and much less expensive than running a turbine to catastrophic failure.

Today's monitoring systems can handle any number of turbines and multiple data points. Using vibration sensors mounted on a turbine's main shaft bearings, gearbox and generator, systems (in tandem with software) will continuously monitor and track a wide range of operating conditions for analysis. Wireless capabilities allow operators to review data from any location with a computer or hand-held device with Internet access (which can shorten lead-time from alarm to solution). The collected data also can be figured into root cause failure analysis, which can then be applied to eliminate recurring failure.

Monitoring systems can play vital roles in highly reliable maintenance forecasting, which is an essential requirement for improving turbine reliability and availability. This is made possible by continuously recalculating fault frequencies and delivering accurate values based on reliable trends, which facilitates alarms at various speeds and loads, including very low main shaft speeds.

CONCLUSION

Ultimately, a CBM program can assist wind farm operators in performing appropriate maintenance at the right time. It can set the stage for more time and cost efficient maintenance activities, whereby maintenance, inspection and overhaul of plant machinery are scheduled largely on the basis of machine condition. In this approach, rollout of maintenance relies upon equipment condition data instead of the calendar. As a result, wind farm operators can extend maintenance intervals, consolidate maintenance initiatives, cut total operating costs and costs per kWh, reduce the risk of unplanned shutdowns, prevent lost energy production due to breakdowns, and predict remaining service life for each turbine. When considering the implementation of CBM, a detailed cost/benefit analysis is recommended.

RP 811

VIBRATION ANALYSIS FOR WIND TURBINES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Committee Chair: Bruce Hamilton, Navigant Consulting
Primary Author(s): Jim Turnbull, SKF;
Greg Ziegler, SKF

PURPOSE AND SCOPE

This guide introduces wind turbine personnel to vibration analysis methods used to detect and analyze machine component failures. This guide does not intend to make the reader an analysis expert. It merely informs the reader about common vibration analysis strategies and methods, and lays the foundation for understanding vibration analysis concepts for the primary rotating components on the drive train of a wind turbine.

This RP focuses specifically on the use of vibration analysis and encourages the consideration of additional condition monitoring technologies as part of a comprehensive pro-active maintenance strategy.

PURPOSE AND SCOPE

This set of recommended practices addresses the common maintenance issues related to the grounding systems for generator and drive train shafts in various wind turbine designs. It is not machine specific and some adaptation may be required based on specific designs.

INTRODUCTION

All machines will deteriorate over time and fail. It is just a question of when and to what degree the failure impacts operations and/or project financials. Vibration analysis is one of many common condition monitoring technologies (oil analysis, borescope, temperature measurements, acoustics, etc.), that can provide insight into deteriorating components and the trend toward their ultimate failure.

The fundamental premise for vibration analysis is that each machine has a baseline (healthy) vibration signature. Changes in the health, or condition, of a machine often produce corresponding changes in the machine's vibration signature. To detect these sometimes subtle variations, specialized sensors or transducers are attached to the machine and vibration measurements are collected with portable or on-line instrumentation. These measurements can then be analyzed to determine the severity of changes to the baseline vibration signature, and their source.

Successful on-line surveillance based condition monitoring and evaluation of intricate industrial machinery, such as wind turbine drive trains, relies on the ability to successfully compartmentalize signals from multiple vibration sources that are all collected simultaneously at the measurement transducer. Most industrial machines are relatively simple to monitor, as transducers are easily placed to monitor direct vibration transmission paths from the moving elements. In nearly all of these machines, transducers are positioned to "see through" a direct path to a single constrained rotating component, such as a shaft held in place by a bearing. This transducer is thus focused on the shaft and local bearing. In most cases, sufficient external surface area is available to dedicate needed transducers to monitor specific internal components.

In a traditional wind turbine drive train (non-direct drive); the following are the primary components for which condition may be monitored through vibration analysis:

- Main Shaft Bearing(s)
    - Axial Movement

    - Radial Vibration
- Generator Bearings
    - Drive End Radial
    - Non-Drive End Radial
- Gear Box Bearings
    - Low Speed Shaft Radial
    - Intermediate Speed Shaft Radial
    - High Speed Shaft Radial

DRIVE TRAIN MEASUREMENTS

1. MAIN BEARING

A single radial first main bearing sensor will predominantly identify a rotor imbalance condition, mechanical looseness, bearing defects and lubrication issues. Including a second sensor on the axial direction can provide additional insight into main shaft coupling misalignment. In addition, an axial sensor located at the first main bearing also enables detection of rotor blade defects/aerodynamic unbalance and yaw misalignment, provided the sensor has adequate low frequency response and corresponding shaft rotational position (phase) and speed data.

2. GENERATOR

One accelerometer is typically placed on a radial location near the drive end bearing, and a second is placed on a radial location near the non-drive end bearing.

A speed probe may also be added to the non-drive end of the generator to better differentiate and understand variances in vibration signals.

Figure A: Speed Probe and Generator DE Sensor

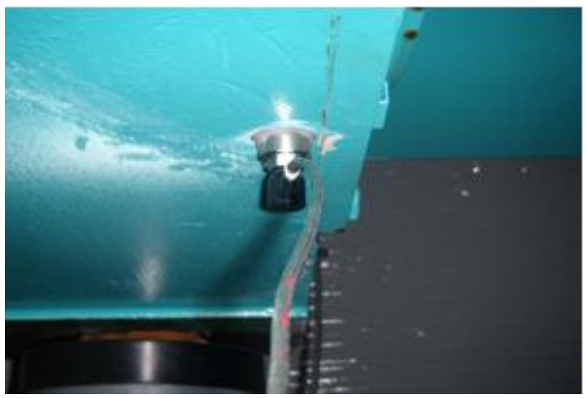

Figure B: Generator NDE Sensor

3. GEARBOX

A majority of conventional wind turbines, in the 500 kW to 2.5 MW class, are equipped with three-stage gearboxes. The first high torque stage is often a planetary gearing system. The remaining two stages are typically parallel shaft drives with either spur or helical gears, as shown in Figure A. *(See Figure A.)* There are usually a dozen or so bearings, four gear wheels and a planetary gearing set including a sun gear, several planet gears, and a ring gear. Any of these components could be a candidate for mechanical failure.

To accurately identify the source of developing problems in such a complicated mechanical system presents quite a challenge. This is particularly true where the components are located internally, away from accessible bearing housings where sensors are ideally mounted.

Unlike other rotating machinery, wind turbines operate in a constantly changing environment. With a variable speed machine, as the inflow field changes, the load and speed of the drive train vary accordingly. Variations of turbulence intensity in the incoming wind interacts with turbine rotor systems, generating dynamic loading that greatly complicates the operating condition of the drive train, and that affects the vibration signal in such a way that a signal validation process or operating condition-based alarm may be necessary.

3.1. Structurally Induced Variability

In addition to the difficulties mentioned so far, the turbine bedplate on which the gearbox is mounted is not likely to be as rigid as concrete pads common to ground-based installations. Dynamic deformation of the bedplate can cause gearbox casing deformation, resulting in bearing housing deformation and shaft misalignment. Consequently, bearing overloading caused by deformation stress could result in an apparent damage signature that is not necessarily from existing damage, but may cause damage at some future time.

3.2. Structural Resonance

Field experiences also indicate that in variable speed drive train designs, gearbox structural resonance frequencies can be excited under normal operating conditions. This may result in gear mesh frequencies being much higher than expected at a given shaft rotating speed. As the rotor gradually changes speed in response to increasing or decreasing wind, gear mesh frequencies can sweep across a very large frequency band, exciting gearbox resonances in the process. This sudden dramatic increase in vibration levels due to structural resonance may cause a conventional alarm setting strategy to produce false alarms.

3.3. Large Vibration Dynamic Range

Very low rotational speeds at a gearbox input shaft, ranging from ten to twenty revolutions per minute, result in very large structural vibration signals from the blades and the tower (blade and tower resonance signals), which usually dominate the vibration spectrum when they appear. Careful measurement and alarm setup is needed to separate these strong structural vibration signals from the significantly more subtle bearing and gear vibration signals.

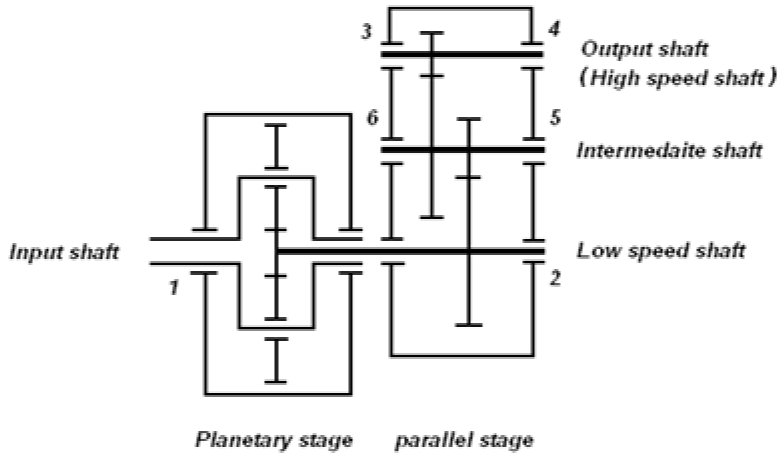

Figure C: Typical Wind Turbine Gearbox Configuration with Transducer Locations

3.4. Sensor Location

Establishing a consistent monitoring strategy for intricate mechanisms that are subject to any or all of these challenges includes proper sensor selection and location; and determining the types of measurements needed, including their setup and appropriate alarm criteria. A gearbox (typical of many applications) with a planetary first stage and parallel shaft second and third stages, as illustrated in Figure C, requires a minimum of four accelerometers with constant frequency response up to 10 KHz. *(See Figure C.)*

The locations of these sensors are indicated in Figure D, at the input shaft bearing housing (1), low speed shaft bearing housing (2), and on the output shaft bearing housings (3, 4). *(See Figure D.)* Additional sensors at the intermediate shaft bearing housings (5, 6) should also be used, but may not be practical to install. A tachometer may be installed on the high-speed shaft (3 or 4). Shaft speeds for each individual shaft in a gearbox may also be obtained using gear ratio information. This information is entered into the on-line software for automatic speed computation each time a measurement is performed.

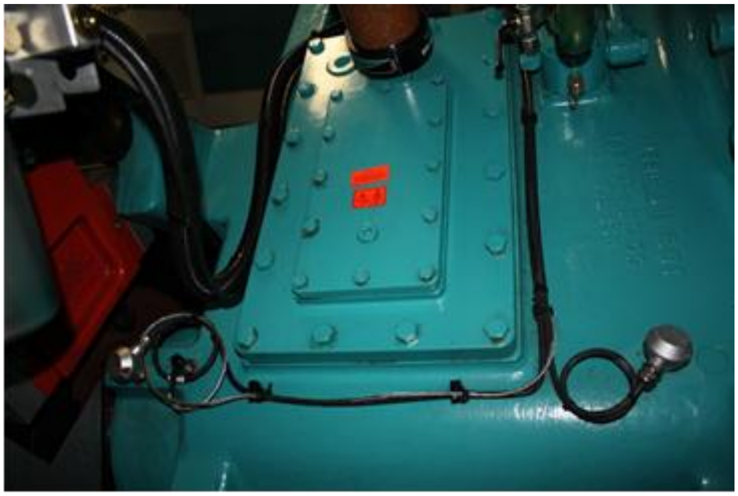

Figure D: Gearbox High Speed Shaft Cable Routing

4. PROCEDURES

Multiple measurements need to be made with each sensor. Each measurement focuses on specific frequency bands and has a specific use in determining the condition of the internal components, as the following describes:

Velocity

- Monitors low frequency rotational faults (imbalance, alignment, etc.).
- Helps detect / confirm bearing damage in later failure stages.

Acceleration

- Monitors high frequency faults (gear mesh, fluid induced vibration, etc.).
- Detects high frequency structure resonance.
- Helps detect / confirm bearing damage in later failure stages.

Demodulation or Enveloping

- A process that enhances repetitive impact signals vibration, etc.
- Early bearing damage detection.
- Gear tooth damage detection.
- Impact detection.

Measurement Setup Includes Defining The Following Measurement Parameters:

- Number of spectral lines.
- Order tracking.
- Analysis frequency range, i.e. fmax and low cutoff frequency.
- Band pass filter selection.
- Tachometer setting.
- With or without averages, number of averages, if needed.
- Detection method (peak, peak-to-peak, true peak, RMS).

4.1. Effective Monitoring Results

To achieve effective monitoring results, measurement settings are based on the individual component's parameters. In general, it is recommended that the acceleration measurement fmax should be higher than three times the focused gear mesh frequency and the acceleration enveloping fmax should be higher than five times the targeted bearing damage frequency. Data acquisition duration should be long enough to ensure at least ten to fifteen shaft rotations are acquired. Since the number of spectral lines together with the fmax setting determine the data acquisition duration, it may be difficult, in some cases, to satisfy both requirements with a single measurement (data acquisition duration and spectral line resolution).

Measurements for gearbox intermediate or output shafts should use a low cutoff frequency higher than structural resonance frequencies (blades and tower natural frequencies) to eliminate the influence of these components, which tend to reduce the measurement's amplitude resolution due to low frequency saturation.

To use band trend and alarms, a speed reference is associated for each shaft and correctly calculates each shaft speed according to the speed ratio of each shaft with reference to the shaft that has the tachometer installed. Additionally, all bearing frequencies are then calculated from this known speed ratio.

The general rule for selecting the filter band is to ensure the high pass filter cutoff frequency is at least five times higher than shaft rotation speed. Peak-to-peak detection is recommended. Using averaging, or using higher numbers of spectral lines, has a similar effect in reducing random noise. For larger frequency ranges signals, a higher number of lines tend to produce better measurement results.

Note: Signal averaging is not recommended for a variable speed machine. Not only will random noise be reduced, signals related to the speed, such as defect frequencies, will be affected.

4.2. Alarm Setting Methodology

Setting alarms for gearbox measurements is not a simple task. Vibration analysis software provides excellent secondary diagnostic alarming capability, focused on specific component failure patterns. Analysis and investigation of the data collected suggests that both Overall and Band vibration measures should be considered in order to have an effective alarm strategy. In terms of determining alarm levels, a statistical tool is very useful in calculating alarm levels from real data. Vibration standards and recommendations from ISO or other organizations, such as gearbox manufacturers, condition monitoring organizations, etc., and past experiences can be used as references.

SUMMARY

A multiple measurement / multiple parameter approach is critical to detecting problems that a typical mechanical drive system may develop. Knowing the characteristic structural resonant frequencies, bearing damage frequencies, and gear mesh frequencies is essential in developing an effective measurement and alarm setting strategy.

ADDITIONAL INFORMATION

Guideline for the Certification of Condition Monitoring Systems for Wind Turbines, Edition 2007

Requirements for Condition Monitoring Systems for Wind Turbines, AZT-Report 03.01.068 dated 27-03-2003, Allianz Zentrum für Technik GmbH.

Condition monitoring and diagnostics of machines - General guidelines BS ISO 17359:2011

Introduction Guide to Vibration Analysis, SKF Publication JM02001, October 2012

RP 812

WIND TURBINE MAIN BEARING GREASE SAMPLING PROCEDURES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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Jim Turnbull, SKF

PURPOSE AND SCOPE

This Recommended Practice discusses the methods for taking uncontaminated and trendable grease samples from wind turbine main bearings. Samples that are taken properly can provide the user with accurate data for maintenance decision making.

The general procedure applies to wind turbine lubrication systems. There are several different wind turbine main bearing types. This paper will focus on two common main bearing types, those with drain purge plugs and those without. Following methods laid out in *ASTM D7718-Standard Practice for Obtaining In-Service Samples of Lubricating Grease*.

These recommendations will give proper procedures for the handling of sampling devices and grease before and after samples have been taken to ensure that data obtained from grease analysis is accurate.

INTRODUCTION

Performing grease analysis from a specific sampling location is important in ensuring repeatability and accuracy. Unlike oil samples, which can more thoroughly mix and circulate through a gearbox or other location, greases are semi-solids and their flow behavior is quite different. Known as a "non-Newtonian" fluid, their movement and circulation in a bearing is dependent on the grease consistency, temperature, and force applied by nearby moving components, among other factors. Published studies demonstrate that greases in wind turbine main bearings do indeed move and circulate, but only in an area very close to the moving parts of the bearing. Therefore it is critical that any sampling methods provide effective means to obtain grease close to these moving zones, or otherwise ensure that grease samples are not compromised by contaminating or diluting influences as they travel away from these flow zones. The methods outlined in this recommended practice provide several approaches to achieve this goal.

WIND TURBINE MAIN BEARING GREASE SAMPLING PROCEDURES

1. MAIN BEARING GREASE SAMPLING PROCEDURES (WITH DRAIN ACCESS PLUG)

NOTE: In this section, "grease sampler" refers to the "Passive Grease Sampling Device" described in *ASTM D 7718, Section 8..* The "T-Handle" describes a tool used to reach the grease sampler into the bearing, and actuate the sampler at the proper point in the machine. This method ensures that the sample obtained is taken from the area of the bearing where grease circulates due to the action of the bearing.

1.1. Place a catch basin below the drain plug to catch any dripping grease.

1.2. Remove the drain plug, clean it, and set in a safe place for later re-insertion.

1.3. If necessary, remove the grease sampler from packaging used to keep it clean until ready for use. Ensure that the open end of the grease sampler is clear of any cap, and that the internal piston is positioned to close off the sampling tube.

1.4. Attach the grease sampler piston handle to the T-handle tool by inserting the end of the handle into the internal rod.

Figure A.

1.5. Insert the internal rod into the pusher tube, with the grease sampler facing forward. *(See Figure A.)*

1.6. Thread the base of the grease sampler into the female threads in the pusher tube, and make adjustments to set the depth at which the sample will be taken. This should be made based on a measurement or print of the bearing, and set such that the fully extended position of the sampler will be very close to, but not touching, the face of the bearing rolling elements.

Figure B.

1.7. Position the pusher tube so that the internal piston is flush with the end of the grease sampler. *(See Figure B.)*

1.8. Fully insert the grease sampler and T-handle into the drain hole until the positioning guides of the T-handle contact the bearing housing face, positively positioning the grease sampler at the desired set depth.

1.9. Slide the pusher tube forward, while holding the T-handle firmly against the housing face, to core a grease sample close to the bearing.

1.10. When the pusher rod has been slid completely forward, hold it in that position as the T-handle and grease sampler are withdrawn from the housing and access hole.

1.11. Using a clean rag, wipe the excess grease from the T-handle parts and the OUTSIDE of the grease sampler body, being careful not to contact the grease inside.

1.12. Release the internal rod so that it spins freely, and unthread the grease sampler from the pusher tube.

1.13. If there is insufficient grease to sample using the T-handle, utilize a disposable spatula to gather grease from within the drain area, and pack into the opened syringe. The syringe is opened by removing the plunger.

The grease selected in this manner should, wherever possible, be taken from the far end of the access hole. If necessary, drag out most of the grease in the hole and set aside to access the grease closest to the moving parts of the bearing.

Figure C.

1.14. Additional grease can be put into the grease sampler by reinserting the plunger in the syringe, and pushing grease into the grease sampler to achieve maximum fill. *(See Figure C.)*

1.15. The open end of the grease sampler should be secured by placing a cap over the end prior to shipment. It may be necessary to purge a small portion of the grease from the sampler into the cap to avoid an air pocket being pushed into the sampler, displacing some of the sample through the far end of the sampler.

1.16. Once a small portion of the grease is in the cap, slide the cap on the grease sampler just far enough to engage the end of the sampler as a friction fit.

1.17. Place the filled and capped grease sampler into a suitable shipping tube to prevent leakage from the grease sampler and protect it during shipping.

1.18. Affix a sample label on the shipping tube, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab. Ensure all samples are clearly identified and promptly submitted to the lab for analysis.

2. MAIN BEARING GREASE SAMPLING PROCEDURES (WITH DRAIN ACCESS PLUG)-ALTERNATIVE METHOD

NOTE: This method follows guidance provided in *ASTM D7718 Section 10*.

2.1. Remove the drain plug and allow any grease near the plug to drain out.

2.2. Using a clean spatula or straw, remove all grease from the inside of the drain area, up to a point within about 1" of the moving parts of the bearing. Ensure that in this purging step, a sufficient amount of grease remains to obtain the required sample amount.

2.3. Utilize a new, clean spatula or straw to gather grease from that area directly adjacent to the moving bearing parts, and pack into an opened syringe. The syringe is opened by removing the plunger. In place of a syringe, a similarly suitable clean, closeable container can be used to gather the sample. If the analysis to be performed is a small-volume method as outlined in *RP-814*, it may be necessary to use the syringe to inject grease into the *"Passive Grease Sampling Device"* described in *ASTM D7718*. Instructions for properly filling that device are described in the previous section, steps 14-17.

2.4. Affix a sample label on the sample container, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab.

2.5. Place the sampling container inside the shipping envelope or box and promptly send to the lab for analysis.

3. MAIN BEARING GREASE SAMPLING PROCEDURES (WITHOUT DRAIN ACCESS PLUG)

NOTE: Some bearings do not have a drain access plug, or this plug does not provide sufficient access to grease close to the bearing moving parts. In those cases, grease may need to be taken from the face of the bearing, where excess grease is purged in the natural course of the addition of new grease. Samples taken in this manner are much less protected from environmental contaminants, which can skew results. Effort is required to ensure the influence of these external contaminants are kept to a minimum, and analysis of these samples should consider the potential influence of these factors when making evaluation and recommendations.

3.1. Obtain a disposable spatula or straw, that will allow both movement and displacement of external contaminated grease, and capturing of the protected underlying grease closer to the exit area. Opposing ends of this straw or spatula can be designated for these two purposes. A syringe or suitable container should be available to place the sampled grease, and these sampling devices should be kept clean in protective packaging up to the time of sampling.

3.2. Using a clean rag, wipe the excess grease from the face of the bearing, being careful not to wipe away representative grease just exiting the bearing.

3.3. Select an accessible location on the face of the bearing, close to the bottom of the bearing roller travel, near the shield gap where excess grease exits the bearing. *(See Figure D.)*

Figure D.

3.4. Open the protective packaging, and remove the disposable spatula/straw and sample container. Using one end of the spatula/straw, wipe away the outermost grease in the area to be sampled, to remove ambient dirt and expose underlying recently purged grease.

3.5. Turn the spatula/straw around, and utilize the other end to gather grease exiting the bearing face, and pack into the sampling container. If a syringe is used, it is opened by removing the plunger.

3.6. If the analysis to be performed is a small-volume method as outlined in *RP-814*, it may be necessary to use the syringe to inject grease into the "Passive Grease Sampling Device" described in ASTM D7718. Instructions for properly filling that device are described in the first section, steps 14-17.

3.7. Affix a sample label on the sample container, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab.

3.8. Place the sampling container inside the shipping envelope or box and promptly send to the lab for analysis.

SUMMARY

Proper grease sampling methods are crucial for comparing samples from one turbine to another or for trending samples from the same turbine. If the proper methods are not employed, grease samples can be obtained that do not represent the condition of the bearing wear, contamination levels, or the physical properties of the grease actively involved in lubricating the bearing. Any analysis from such inadequate samples will be misleading and result in improper maintenance actions being taken. Properly obtained samples ensure that analysis results represent current bearing conditions and provide the basis for sound maintenance decisions to provide reliable main bearing operation.

RP 813

WIND TURBINE GENERATOR BEARING GREASE SAMPLING PROCEDURES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

Primary Author: Rich Wurzbach, MRG
Committee Chairs: Bruce Hamilton, Navigant Consulting;
Jim Turnbull, SKF

PURPOSE AND SCOPE

This Recommended Practice discusses the methods for taking uncontaminated and trendable grease samples from wind generator bearings. Samples that are taken properly can provide the user with accurate data for maintenance decision making.

The general procedure applies to wind turbine lubrication systems. There are several different manufacturers of generators, and each may have a slightly different configuration, which could require slight modifications of this procedure. This paper will address one of the more commonly seen configurations in a wind turbine generator: a bearing bottom exit hole, and a mating chute to direct purged grease to a catch tray. Following methods laid out in *ASTM D7718- Standard Practice for Obtaining In-Service Samples of Lubricating Grease,* these recommendations will give proper procedures for dealing with the chute and gathering grease samples and the use of sampling devices to ensure that data obtained from grease analysis is accurate.

INTRODUCTION

Performing grease analysis from a specific sampling location is important in ensuring repeatability and accuracy. Unlike oil samples, which can more thoroughly mix and circulate through a gearbox or other location, greases are semi-solids and their flow behavior is quite different. Known as a “non-Newtonian” fluid, their movement and circulation in a bearing is dependent on the grease consistency, temperature, and force applied by nearby moving components, among other factors. Published studies demonstrate that greases in wind turbine bearings do indeed move and circulate, but only in an area very close to the moving parts of the bearing. Therefore it is critical that any sampling methods provide effective means to obtain grease close to these moving zones, or otherwise ensure that grease samples are not compromised by contaminating or diluting influences as they travel away from these flow zones. The methods outlined in this recommended practice provide several approaches to achieve this goal.

1. METHOD 1: GENERATOR BEARING GREASE SAMPLING PROCEDURES (SAMPLING FROM BEARING DRAIN OPENING WITH CHUTE OR DEFLECTOR)

NOTE: In this section, “grease sampler” refers to the *”Passive Grease Sampling Device”* described in *ASTM D 7718, Section 8*. The “T-Handle” describes a tool used to reach the grease sampler into the drain chute or bearing exit slot. This method ensures that the sample obtained is taken from the grease which has most recently exited the bearing. This method references the style of drain chute shown in Figure A, common to certain Nordex units, with similar chute designs in other units. *(See Figure A.)*

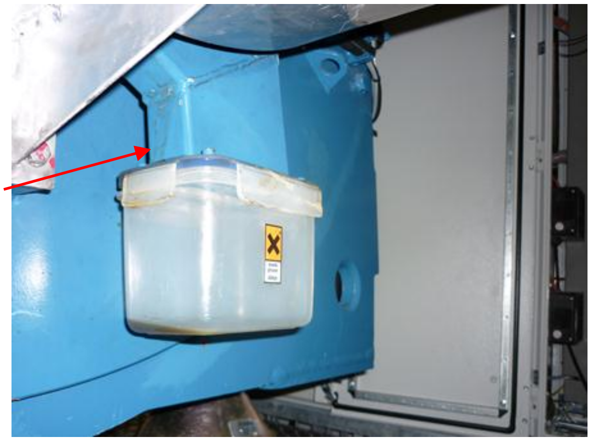

Figure A.

1.1. Remove the purge container (if so equipped) from the generator bearing grease exit chute *(See red arrow, Figure A)* and place the container in a clean area.

1.2. Note the condition of the material in the container. If the grease is excessively runny, hard, discolored or contains shiny or dark particulate, note this on the sampling label.

1.3. Determine if there is sufficient clearance for a T-handle tool or similar sampling tool to insert the tool with a grease sampler into the drain chute. If not, the chute must be removed to obtain the sample.

1.4. If necessary, remove the grease sampler from packaging used to keep it clean until ready for use. Ensure that the open end of the grease sampler is clear of any cap, and that the internal piston is positioned to close off the sampling tube.

1.5. Attach the grease sampler piston handle to the T-handle tool by inserting the end of the handle into the internal rod. *(See Figure B.)*

Figure B.

1.6. Insert the internal rod into the pusher tube, with the grease sampler facing forward. *(See Figure C.)*

Figure C.

1.7. Thread the base of the grease sampler into the female threads in the pusher tube, and make adjustments to set the depth at which the sample will be taken. Position the T-Handle so that the extended position of the open end of the grease sampler will be inside the bearing housing, adjacent to the area of travel of the bearing within the housing. This is often a few inches longer than the position that would be flush with the surface of the generator housing.

Figure D.

1.8. Position the pusher tube so that the internal piston is flush with the end of the grease sampler. By looking up into the chute or bearing drain, verify that there is sufficient accumulation of grease that it presents a solid area of grease for coring. If there is not sufficient grease to permit the coring process described here, go to Method 2 to obtain this sample.

1.9. Insert the grease sampler and T-handle into the chute or bearing drain, until the positioning guides of the T-handle contact the outside edge or the chute or drain hole in the generator housing.

1.10. Slide the pusher tube forward, while holding the T-handle firmly against the purge container lip, to core a grease sample close to the lower entry hole.

1.11. When the pusher rod has been slid completely forward, hold it in that position as the T-handle and grease sampler are withdrawn from the container.

1.12. Using a clean rag, wipe the excess grease from the T-handle parts and the OUTSIDE of the grease sampler body, being careful not to contact the grease inside.

1.13. Release the internal rod so that it spins freely, and unthread the grease sampler from the pusher tube.

1.14. If there is insufficient grease to sample using the T-handle, refer to Method 2 to manually extract grease from the lower entry hole area.

1.15. The open end of the grease sampler should be secured by placing a cap over the end prior to shipment. It may be necessary to purge a small portion of the grease from the sampler into the cap to avoid an air pocket being pushed into the sampler, displacing some of the sample through the far end of the sampler.

1.16. Once a small portion of the grease is in the cap, slide the cap on the grease sampler just far enough to engage the end of the sampler as a friction fit.

1.17. Place the filled and capped grease sampler into a suitable shipping tube to prevent leakage from the grease sampler and protect it during shipping.

1.18. Affix a sample label on the shipping tube, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab. Ensure all samples are clearly identified and promptly submitted to the lab for analysis.

2. METHOD 2: GENERATOR BEARING GREASE SAMPLING PROCEDURES (SAMPLING FROM BEARING DRAIN WITH A SPATULA/STRAW)

NOTE: This method follows guidance provided in *ASTM D7718 Section 10.* This method assumes that the purge container opening is too small to allow the insertion of a grease sampler inside the container, and the grease is to be manually extracted using a disposable spatula.

2.1. Using a clean, lint-free rag, wipe the outside of the grease purge container and surrounding area of the pitch bearing to avoid any of this external contamination from getting into the grease sample to be taken.

2.2. Remove the purge container (if so equipped) from the generator bearing grease exit chute *(See red arrow, Figure A)* and place the container in a clean area.

2.3. Inspect the exit chute or drain opening in the bearing and determine if there is sufficient grease accessible in this area for the required sample size.

2.4. Using a clean spatula or straw, remove grease from the inside of the drain area, up to a point within about 1" of the moving parts of the bearing, if possible. Ensure that in this purging step, a sufficient amount of grease remains to obtain the required sample amount.

2.5. Utilize a new, clean spatula or straw to gather grease from that area directly adjacent to the moving bearing parts, and pack into an opened syringe. The syringe is opened by removing the plunger. In place of a syringe, a similarly suitable clean, closeable container can be used to gather the sample. If the analysis to be performed is a small-volume method as outlined in RP-814, it may be necessary to use the syringe to inject grease into the *"Passive Grease Sampling Device"* described in *ASTM D7718*.

Figure E.

2.6. Additional grease can be put into the grease sampler by reinserting the plunger in the syringe, and pushing grease into the grease sampler to achieve maximum fill.

2.7. If there is insufficient grease in the drain path to fill the grease sampler, the remaining amount can be obtained from the chute, at the end closest to the bearing, or from the purge container. The grease closest to the opening is the most recently purged grease, and the most representative of the current condition of the bearing. If a sample is obtained from these alternate areas, note this on the sample label so the analyst can take this into consideration.

2.8. The open end of the grease sampler should be secured by placing a cap over the end prior to shipment. It may be necessary to purge a small portion of the grease from the sampler into the cap to avoid an air pocket being pushed into the sampler, displacing some of the sample through the far end of the sampler.

2.9. Once a small portion of the grease is in the cap, slide the cap on the grease sampler just far enough to engage the end of the sampler as a friction fit.

2.10. Place the filled and capped grease sampler into a suitable shipping tube to prevent leakage from the grease sampler and protect it during shipping.

2.11. Affix a sample label on the sample container, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab.

2.12. Place the sampling container inside the shipping envelope or box and promptly send to the lab for analysis.

SUMMARY

Proper grease sampling methods are crucial for comparing samples from one turbine to another or for trending samples from the same turbine. If the proper methods are not employed, grease samples can be obtained that do not represent the condition of the bearing wear, contamination levels, or the physical properties of the grease actively involved in lubricating the bearing. Any analysis from such inadequate samples will be misleading and result in improper maintenance actions being taken. Properly obtained samples ensure that analysis results represent current bearing conditions and provide the basis for sound maintenance decisions to provide reliable generator operation.

RP 814

WIND TURBINE PITCH BEARING GREASE SAMPLING PROCEDURES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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Committee Chair: Gearbox - Kevin Dinwiddie, AMSOIL; Erik Smith, Moventas
CM - Bruce Hamilton, Navigant Consulting

PURPOSE AND SCOPE

This Recommended Practice discusses the methods for taking uncontaminated and trendable grease samples from wind turbine pitch (blade) bearings. Samples that are taken properly can provide the user with accurate data for maintenance decision making.

The general procedure applies to wind turbine lubrication systems. There are several different wind turbine pitch bearing styles and purge recovery systems. This paper will address two such pitch bearing purge recovery styles, and can apply to both automatic and manual grease lubrication systems. Following methods laid out in *ASTM D7718- Standard Practice for*

Obtaining In-Service Samples of Lubricating Grease, these recommendations will give proper procedures for the handling of purge recovery containers, sampling devices and grease before and after samples have been taken to ensure that data obtained from grease analysis is accurate.

INTRODUCTION

Performing grease analysis from a specific sampling location is important in ensuring repeatability and accuracy. Unlike oil samples, which can more thoroughly mix and circulate through a gearbox or other location, greases are semi-solids and their flow behavior is quite different. Known as a "non-Newtonian" fluid, their movement and circulation in a bearing is dependent on the grease consistency, temperature, and force applied by nearby moving components, among other factors. Published studies demonstrate that greases in wind turbine bearings do indeed move and circulate, but only in an area very close to the moving parts of the bearing. Therefore it is critical that any sampling methods provide effective means to obtain grease close to these moving zones, or otherwise ensure that grease samples are not compromised by contaminating or diluting influences as they travel away from these flow zones. The methods outlined in this recommended practice provide several approaches to achieve this goal.

1. METHOD 1: PITCH BEARING GREASE SAMPLING PROCEDURES (RECOVERY FROM PURGE CONTAINER WITH REMOVABLE LID)

NOTE: In this section, "grease sampler" refers to the *"Passive Grease Sampling Device"* described in *ASTM D 7718, Section 8.* The "T-Handle" describes a tool used to reach the grease sampler into purge container. This method ensures that the sample obtained is taken from the grease which has most recently exited the bearing. This Method 1 references the style of purge container shown in Figure A, common to certain Vestas units.

Figure A.

1.1. Remove the purge container from the blade bearing, and place the container on a level surface, with the removable lid facing up.

1.2. Remove the lid and set aside.

1.3. Verify that there is sufficient accumulation of grease that it presents a solid glob adjacent to the lower entry hole, larger than the length of the grease sampler. If there is not sufficient grease to permit the coring process described here, go to Method 2 to obtain this sample.

1.4. If necessary, remove the grease sampler from packaging used to keep it clean until ready for use. Ensure that the open end of the grease sampler is clear of any cap, and that the internal piston is positioned to close off the sampling tube.

1.5. Attach the grease sampler piston handle to the T-handle tool by inserting the end of the handle into the internal rod.

Figure B.

1.6. Insert the internal rod into the pusher tube, with the grease sampler facing forward.

Figure C.

1.7. Thread the base of the grease sampler into the female threads in the pusher tube, and make adjustments to set the depth at which the sample will be taken. Position the T-Handle so that the extended position of the open end of the grease sampler will be slightly past the lower entry hole in the side of the container.

Figure D.

1.8. Position the pusher tube so that the internal piston is flush with the end of the grease sampler.

1.9. Insert the grease sampler and T-handle into the top of the purge container, keeping close to the wall where the entry holes are located, until the positioning guides of the T-handle contact the top lip of the container, positioning the grease sampler at the lower entry hole.

1.10. Slide the pusher tube forward, while holding the T-handle firmly against the purge container lip, to core a grease sample close to the lower entry hole.

1.11. When the pusher rod has been slid completely forward, hold it in that position as the T-handle and grease sampler are withdrawn from the container.

1.12. Using a clean rag, wipe the excess grease from the T-handle parts and the OUTSIDE of the grease sampler body, being careful not to contact the grease inside.

1.13. Release the internal rod so that it spins freely, and unthread the grease sampler from the pusher tube.

1.14. If there is insufficient grease to sample using the T-handle, refer to Method 2 to manually extract grease from the lower entry hole area.

1.15. The open end of the grease sampler should be secured by placing a cap over the end prior to shipment. It may be necessary to purge a small portion of the grease from the sampler into the cap to avoid an air pocket being pushed into the sampler, displacing some of the sample through the far end of the sampler.

1.16. Once a small portion of the grease is in the cap, slide the cap on the grease sampler just far enough to engage the end of the sampler as a friction fit.

1.17. Place the filled and capped grease sampler into a suitable shipping tube to prevent leakage from the grease sampler and protect it during shipping.

1.18. Affix a sample label on the shipping tube, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab. Ensure all samples are clearly identified and promptly submitted to the lab for analysis.

2. METHOD 2: PITCH BEARING GREASE SAMPLING PROCEDURES (RECOVERY FROM PURGE CONTAINER WITHOUT A LID)

NOTE: This method follows guidance provided in *ASTM D7718 Section 10*. This method assumes that the purge container opening is too small to allow the insertion of a grease sampler inside the container, and the grease is to be manually extracted using a disposable spatula.

2.1. Using a clean, lint-free rag, wipe the outside of the grease purge container and surrounding area of the pitch bearing to avoid any of this external contamination from getting into the grease sample to be taken.

2.2. Remove the purge container *(see Figure E)* from the pitch bearing, and set on a level surface with the open end facing up. Other styles of purge container can also be used in this manner.

Figure E.

2.3. Inspect the exit hole in the bearing and determine if there is sufficient grease accessible in this area for the required sample size.

2.4. Using a clean spatula or straw, remove grease from the inside of the drain area, up to a point within about 1” of the moving parts of the bearing, if possible. Ensure that in this purging step, a sufficient amount of grease remains to obtain the required sample amount.

2.5. Utilize a new, clean spatula or straw to gather grease from that area directly adjacent to the moving bearing parts, and pack into an opened syringe. The syringe is opened by removing the plunger. In place of a syringe, a similarly suitable clean, closeable container can be used to gather the sample. If the analysis to be performed is a small-volume method as outlined in *RP-814*, it may be necessary to use the syringe to inject grease into the *“Passive Grease Sampling Device”* described in *ASTM D7718.*

Figure F.

2.6. Additional grease can be put into the grease sampler by reinserting the plunger in the syringe, and pushing grease into the grease sampler to achieve maximum fill.

2.7. If there is insufficient grease in the drain path to fill the grease sampler, the remaining amount can be obtained from the area near the opening inside the purge container. The grease closest to the opening is the most recently purged grease, and the most representative of the current condition of the bearing.

2.8. The open end of the grease sampler should be secured by placing a cap over the end prior to shipment. It may be necessary to purge a small portion of the grease from the sampler into the cap to avoid an air pocket being pushed into the sampler, displacing some of the sample through the far end of the sampler.

2.9. Once a small portion of the grease is in the cap, slide the cap on the grease sampler just far enough to engage the end of the sampler as a friction fit.

2.10. Place the filled and capped grease sampler into a suitable shipping tube to prevent leakage from the grease sampler and protect it during shipping.

2.11. Affix a sample label on the sample container, filling out all necessary information clearly and legibly, including equipment identification, sample date and time, sampler's name, and any notes or observations for the lab.

2.12. Place the sampling container inside the shipping envelope or box and promptly send to the lab for analysis.

SUMMARY

Proper grease sampling methods are crucial for comparing samples from one turbine to another or for trending samples from the same turbine. If the proper methods are not employed, grease samples can be obtained that do not represent the condition of the bearing wear, contamination levels, or the physical properties of the grease actively involved in lubricating the bearing. Any analysis from such inadequate samples will be misleading and result in improper maintenance actions being taken. Properly obtained samples ensure that analysis results represent current bearing conditions and provide the basis for sound maintenance decisions to provide reliable pitch bearing operation.

RP 815

WIND TURBINE GREASE ANALYSIS TEST METHODS

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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Secondary Author: Ryan Brewer, Poseidon Consulting
Committee Chairs: Bruce Hamilton, Navigant Consulting;
Jim Turnbull, SKF

PURPOSE AND SCOPE

This RP will focus on specific test methods which should be applied for accurate grease testing and analysis.

INTRODUCTION

Accurate grease analysis results are critical to the success of the diagnosis of wear rates, contamination levels, oxidation levels and consistency of the grease. Inaccuracies can be due to improper test methods selected for the particular application, inadequate quality control of test methods or poor sampling techniques. This practice is intended to assist in proper test selection specific to wind turbine grease samples, thus allowing for proper diagnosis and reasonable corrective action based on sound limits and warnings.

Test methods specific to wind turbine main bearing grease should provide accurate oil test results for which to base good maintenance decisions and reduce operating costs.

Effectiveness of grease analysis test methods is directly and completely dependent on the accuracy of the samples obtained for this purpose. Consult AWEA guidance on grease sampling methods, developed in compliance with *ASTM D7718, Standard Practice for Obtaining In-Service Samples of Lubricating Grease*.

WIND TURBINE GREASE ANALYSIS TEST METHODS

1. PROCEDURES

Prior to sending grease samples to your laboratory, it is important to establish with your laboratory which tests are to be performed on the used in-service grease, the grease volume needed to run these tests, and the condemning limits that should be applied. Some methods exist that enable an in-service grease analysis basic test slate including measurement of wear, consistency, contamination and oxidation with as little as 1 gram of grease. Some tests require greater quantities of grease. In all cases, the grease submitted for sampling must be representative of the condition of the grease actively lubricating the bearing and receiving wear particles by nature of proximity to the wearing surfaces

2. GREASE ANALYSIS METHODS

OEM’s may require grease analysis more often during initial startup on new turbines. Grease analysis can be performed every 6-months or annually, depending on component age, history or other factors. Samples can typically be taken while up tower performing other routine maintenance tasks. A typical test slate for grease analysis may include the following tests (These methods listed in this section are recommended for use with wind turbine grease):

1 Ferrous debris quantification.*

2 Consistency testing (such as Cone penetration, Rheometry, or Die Extrusion Test*).

3 Infrared Spectroscopy (FT-IR).

4 Anti-Oxidant Additive quantification (such as Linear Sweep Voltammetry (ASTM D7527) or short-path FTIR).

5 Elemental Spectroscopy (such as RDE or ICP).

6 Visible Appearance (manually or Grease Colorimetry*).

7 Water PPM (D6304, Oven Method).

NOTE: These tests marked with asterisk are a pending ASTM Work Practice in review for ASTM standard in CS96 committee as of the writing of this procedure.

2.1. Ferrous Debris Quantification

This test determines the amount of ferromagnetic material present in the sample. Because the metallurgy of wind turbine drivetrain components are primarily ferrous, this test is effective at monitoring ferrous wear debris generation rate. Several methods exist that measure the change in voltage as it is dropped through an electromagnetic field. (The Hall Effect refers to the voltage induced in a conductor in the presence of magnetic flux.) One method must be selected an applied consistently, as there are differences in values produced by different ferrous debris monitoring technologies.

The values derived from such analyses are used as a general flagging mechanism for the lab to detect high wear levels. An action level should be developed based on the method used and statistical analysis or evaluation of historical values against observed conditions. When the sample has exceeded the action level, analytical ferrography is recommended to characterize the nature and severity of the wear. It should be noted that wear debris in grease is cumulative until flushed out by introduction of new grease, and replenishment rate must be factored into the development of action criteria.

2.2. Consistency Test

The consistency of grease is a function of the base oil and thickener, and their types and ratios. The consistency is important in ensuring that the grease will stay in place in the intended lubrication point, and affects the ability of the grease matrix to supply liquid oil to maintain a lubricant film to separate surfaces in relative motion. After some time in service, the consistency can change due to variables such as grease mixing, aging, overheating, excessive working or contamination. In new grease, consistency is measured by Cone Penetration, and an NLGI number is assigned to the grease on a scale from 000 to 6. In-service greases usually cannot be tested per Cone Penetration method due to the large quantities required, so either a Rheometer or Die Extrusion methods are typically used.

In Die Extrusion, the consistency is determined by measuring the load required to force the grease through an orifice of know dimensions at varying speeds. The consistency of the grease is compared to the new baseline grease. Drastic increases or decreases in the consistency correspond to severe thickening or thinning of the grease, which could indicate abnormal operating conditions and/or compromise reliability.

For Rheometry, the grease is placed between opposing plates that are rotated and oscillated while measuring the resulting force, which is a function of the consistency and flow characteristics of the grease. Parameters measured include storage modulus (grease flow), oscillation stress (oil content and shear from thickener), and recoverable compliance (tendency to tunnel or channel in the bearing or gearbox).

In either test, results are compared to new, fresh grease, and criteria is developed to flag samples that deviate significantly in service from the new grease. Due to the geometry and loads in wind turbine main bearings, consistency reductions of as much as 40-50 percent may be considered typical for in-service greases, and it is necessary to establish action criteria based on statistical analysis or comparative operating histories.

2.3. FT-IR Infrared Spectroscopy

Infrared (IR) Spectroscopy or Fourier Transform Infrared Spectroscopy (FTIR) have been used for many years to provide rapid, low cost, offline analyses of oil samples. The technology passes and infrared light source through a lubricant sample to an infrared detector. The light that passes through the oil is influence by the fluid properties as oil contaminants and additives absorb infrared radiation at varying frequencies. By comparing the frequency spectrum of new and used oil samples it is possible to determine the lubricant properties such as water, soot, oxidation, nitration, and glycol levels.

Through advances in electronics manufacturing techniques, IR technology is beginning to make its way into online sensing devices. Current technology does not have the refined measurement capabilities of laboratory devices; however, they do offer multi-parameter trending capabilities which can provide valuable, real-time insight into fluid condition.

FT-IR is used to fingerprint the molecular bonds in the grease. An IR beam is passed through a thin grease film, of known dimension, and the resulting absorbance spectrum is used to characterize the organic components of the grease. Alternatively, other sample introduction methods can be used, such as Attenuated Total Reflectance (ATR) or Photoacoustic Spectroscopy. By comparing the in-service sample to the baseline, oxidation, grease mixing, and organic contamination (including water) can be detected.

2.4. Linear Sweep Voltammetry

Linear Sweep Voltammetry, know commercially as “RULER”, measures the Remaining Useful Life of the anti-oxidant additive package. A voltage sweep is applied to the sample as the current is measured. The graph of current and time will contain peaks which correspond to different anti-oxidants and the concentration remaining in the sample is proportional to the area under the curve for these peaks. The results are reported as a percentage of the concentration found in the baseline grease.

2.5. Atomic Emission Spectroscopy

The quantification of metallic elements in grease can be accomplished by Rotating Disc Electrode (RDE), Inductively Coupled Plasma (ICP) or Xray Fluorescence (XRF). While atomic emission spectroscopy is routine for oil analysis, sample preparation is unique for greases. The grease must either be dissolved by a clean, filtered solvent and analyzed, or use a uniform preparation method to introduce the solid grease to the analyzer. For ICP, the sample must be fully dissolved, and the selection of the solvent system for each grease type is important to the effectiveness of the method. ASTM D7303 governs the ICP method. For the XRF and RDE methods, direct application (without dissolving sample) sample preparation methods are used in industry, and standards are under development.

For the solvent methods, the grease is dissolved in reagent grade organic solvent and vaporized in the sample chamber. The atoms are excited with an electric arc and the light patterns emitted are compared with the known patterns of 19 different metals. The spectrometer detects most wear particles such Iron and Babbitt, as well certain additive elements that could indicate grease mixing. All results are recorded in parts per million (ppm). The limitation of this technology is the instrument is not sensitive to particles larger than about 6 microns because they do not vaporize in the AC arc.

2.6. Grease Colorimetry

Grease Colorimetry measures light absorbance in the visible light range (400 nm - 700 nm) under controlled repeatable conditions. The resulting spectrum has peaks which differentiate colors at a much higher sensitivity than the human eye. Because some grease products contain unique dyes, this method can be used to detect grease mixing when the true baseline is known. This method can validate observed appearance changes in greases, trend darkening due to aging or overheating, characterize dye formulations of new grease, and be used to approximate the concentration of certain particulate contaminants, such as coal dust, soot, or other solids accumulating in the grease. As an alternative method, subjective visual analysis of the grease and comparison to the appearance of new or typical used greases can be made.

2.7. Water PPM

The presence of moisture in lubricating greases lead to corrosion, wear, and an increase in debris load which contributes to bearing and gear fatigue. While FTIR can identify gross levels of water in greases, it is typically not accurate in assessing quantitative values.

A quantitative test is Karl Fischer titration by oven method, *ASTM D6304*. This test method detects the presence of water by thermal mass transfer of the grease to a dry gas, which is then titrated to determine parts per million of water in the grease. Action criteria can be determined from statistical analysis of a given population of similar wind turbine drivetrain components in a certain environmental application, or comparative operating histories.

3. INTERPRETING GREASE ANALYSIS RESULTS

1 Consult your specific laboratory for help with interpreting results and with understanding the lab reports.

2 Appropriate alarms, (min./max., percent change, deviation), will

vary based on machine and population of sample data.

3 Any opportunity to evaluate and inspect a removed wind turbine drivetrain component should be made to correlate as-found conditions to the preceding grease analysis trends, and expand the knowledge base for developing more precise and accurate action criteria

SUMMARY

A comprehensive, disciplined approach to grease sample collection, specific analysis methods, trend monitoring and proper condemning limits can help identify grease, bearing and gear issues. This enables wind farm operators to make cost-effective servicing and maintenance decisions, and predict bearing and gear failures so that pre-emptive action can be taken. Overall, the objective supported by this recommended practice is to accumulate solid data in order to reduce guesswork and improve uptime and availability, and ultimately to reduce O&M costs.

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Operation and Maintenance
Recommended Practices

RP 816

WIND TURBINE TEMPERATURE MEASUREMENT PROCEDURES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

This Recommended Practice discusses the methods and procedures to facilitate temperature based condition monitoring. Temperature is available from most supervisory control and data acquisition systems (SCADA) and provides a low cost, late warning indicator for bearing, generators and motor components in the turbine.

INTRODUCTION

Temperature is age old indicator of component health. Bearing manufacturers have long been aware of the relationship between bearing temperature and bearing life. Because of this relationship, temperature can be used to monitor bearing condition or other temperature sensitive components, such as motors and generators.

If temperature is a reliable method for component life prediction, why is its use not sited more often as an indicator of fault? While there are subtle changes in temperature due to wear, there are many other environmental factors that affect bearing temperatures, such as: load, speed, and ambient temperature.

The key to successfully use temperature is to remove the environmental factors so that differences in temperature between the same components on similar turbines reflect actual bearing faults or other components where temperature can signify failures.

Potential areas where temperature can be used for condition monitoring include and is not limited to:

1 Main Bearing.
2 Generator Bearings.
3 Generator Windings
4 Gearbox Oil Sump
5 Gearbox Bearings
6 Yaw Motors.
7 Pitch Motors.
8 Slip Ring.
9 Hydraulic Pumps.

TEMPERATURE CONDITION MONITORING PROCEDURES

In general, the temperature sensor must be attached in close proximity to the bearing/component under analysis.

1. SIMPLE TROUBLE SHOOTING RULES FOR BEARINGS

No more than 82°C on the bearing housing. The bearing outer ring can be up to 11°C hotter than the housing. Note that lubricants are typically selected to run at lower temperatures and a temperature rise of 28°C may cause oil viscosity to drop by 50% or more.

2. SIMPLE TROUBLE SHOOTING RULES FOR ELECTRIC MOTORS AND GENERATORS

The National Electrical Manufactures Association (NEMA) has defined temperature rise for electric motors and generators in MG 1-1998. This standard outlines the normal maximum temperature rise based on a maximum ambient temperature or 40°C, power/load, service factor rating, and insulation class. For example, for a 1.5 MW generators with service factor of 1.15 and insulation class B, the maximum allowable temperature rise would be 95°C. Thus, the machine should alert a warning condition when the winding temperature is greater than 135°C.

3. THE USE OF SCADA FOR TEMPERATURE CONDITION MONITORING

SCADA systems can be used to alert for high temperature conditions on bearings, generator and motors. As noted, successful temperature diagnostics will requires reducing the effect of environmental factors.

3.1. Define a component temperature rise (CTR) which is the difference of the sensor temperature and ambient temperature.

3.2. Define a threshold for CTR. Since the operating temperature can be a function of load/power output, consider developing threshold bins by wind speed/power output to reduce variation. Additionally, threshold should be set for similar machine configuration (e.g. model, gearbox and generator represent one type of machine configuration).

1. Use a minimum of 6 nominal machines, with a minimum of 21 acquisitions per machine, to generate test statistics (mean and standard deviation).
2. Assuming near Gaussian distributions, set the threshold for each power bin as MeanCTR + 3*Standard DeviationCTR, which will give an approximate probability of false of 1e-3.

3.3. Set Alarm Alerts for Hot Bearings at 82°C.

3.4. Set Generator/Motor Alerts based on NEMA MG 1-1998 as appropriate.

SUMMARY

Temperature can be a powerful indicator of component health. That said, temperature of components is also affected by environmental factors such as ambient temperature, load and speed. By reducing the effect of these environmental factors (monitoring temperature rise, binning by power), temperature can be used to diagnose component wear. For bearings, the absolute temperature should not exceed 82°C. For motors/generators *NEMA MG 1-1998* should be consulted for absolute temperature limits.

RP 817

WIND TURBINE NACELLE PROCESS PARAMETER MONITORING

PREFACE

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AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

This Recommended Practice discusses the methods and procedures to facilitate nacelle process parameter modeling for condition based monitoring. The process parameters are available from the OEM controls system (SCADA) and provide an early warning indicator for degraded operation of bearings, gearboxes, blade controls, generators, motors, and control components in the turbine.

INTRODUCTION

There are many methods in which to monitor and utilize the SCADA data collected around the processes within a wind turbine and wind plant. The issue is the high variability in the data and getting a sense of the data compared to the plant and historical operations. One proven method is using empirical nonparametric modeling of process parameters to complement traditional condition based maintenance techniques. The Process Parameters provide drivers and responses for modeling methodologies to detect “normalized” departures from historical behavior that could be early indicators of degraded conditions around the equipment in the Nacelle.

The industry description of this methodology is referred to as Advanced Pattern Recognition (APR) and has been used successfully in the Wind industry over all manufactures and designs of wind turbine generators. The understating of relationships between performance and mechanical systems has been known since the origins of Condition Base Maintenance. When a bearing temperature increases, the technician looks at trends in the data for the variable of concern: local ambient temperatures, oil supply temperatures, speed of the rotating system, load changes, cooling system operations etc… These correlations were (and are) performed manually and by some simple data extractions and X, Y plots or simply visual comparison of trends against the one in question. This “validation” is performed in relationship to hard alarms, with little or no warning which placed the technician at disadvantage having to reacting to the equipment alarm conditions. By the end of the 1990’s computer hardware and software systems had advanced sufficiently in order to perform statistical modeling using standalone computer systems. The advanced pattern recognition algorithms were commercialized to take advantage of “online data mining” that is running advanced statistical models in real-time on process parameters.

The key to successfully using process parameters in Condition Based Maintenance is ensuring that there is known good historical reference data set to use for compression with current process parameters.

The APR methodologies are very robust and accurate in determining the behavior of an asset. They are very sensitive to changes in single instrument behavior that are clear indicators of degradation i.e. small deviation in bearing metal temperature (<10% of normal span of operation) while taking into many other environmental factors affecting the bearing temperature, such as: load, speed, and ambient temperature.

Statistical models are used to compare the same components, for similar assets, across a wind plant, detecting changes in the components behavior as compared to the other assets. This analysis, which can be automated, identifies the outliers and focuses resources where and when they are needed.

Areas where statistical models and APR can be used for condition monitoring include and are not limited to:

Asset components:

1. Hub System.
    a. Main Bearing.
    b. Blades.
2. Gearbox
    a. Bearings.
    b. Oil Sump.
    c. Gears.
    d. Oil System.
        - Online Oil Particulates.
        - Oil Cooler.
3. Generator.
    a. Bearings.
    b. Windings.
    c. Slip Rings.
    d. Controls.
    e. Cooling Systems
4. Transformers.
5. Converters.
6. Yaw.
    a. Controls.
    b. Position

7 Wind.

a. Power.

b. Efficiency.

c. Direction.

d. Speed

The different assets include all physical measurements and calculations associated with these assets:

1 Pressures.

2 Temperatures.

3 Vibrations; including deterministic characteristic: Kurtosis, Crest Factor, Spike Energy, Stress Wave, Etc…

4 Voltage.

5 Current.

6 Torque.

7 Strain.

8 Moment.

9 Particle Count.

10 Wind Direction.

11 Wind Speed.

12 Wind Deviation.

13 Blade Tip Speed Ratio.

14 Ambient Temperatures.

15 Ambient Pressures.

16 Power.

17 Position.

18 Set Points.

19 Control Demand Signals.

20 Etc… the more parameters around a component the better the detection of potential effects from degradation.

Fleet comparison of parameters for a component – localized models looking at all similar gearbox parameters, typically a correlation matrix verses statistical modeling.

ADVANCE PATTERN RECOGNITION AND STATISTICAL ANALYSIS CONDITION MONITORING PROCEDURES

In general, the greater the number of parameters monitoring a process, the better the modeling; for most APR models there needs to be (at a minimum) three (3) drivers (independent parameters) - ambient temperature, rotor speed, power output and five (5) or more response (dependent parameters) bearing vibration, bearing temperatures, oil temperatures, etc… typically the OEM installed sensor are enough to get started. A rule of thumb is: the more sensors around a process the better the detection of an abnormal behavior.

1. Where Advance Pattern Recognition (APR) Fits Into Condition Monitoring for Wind Turbines

APR is an "early" detection methodology for changes in equipment asset behavior using statistical techniques. They are typically early warning systems that gives time for the analyst to run fleet comparisons and analyze the behavior. With early detection there is some ambiguity in the actionability of the advisories that APR systems report.

These system have a low false reporting rates as compared to standard alarming system since they use models based on each turbines unique historical behavior to determine when there has been a change that needs investigating.

APR systems increase the coverage for Failure Modes and Effects Analysis beyond traditional Predictive Maintenance Techniques. APR correlates all the behaviors which results in early notification in equipment degradation without having to deploy resources in the field.

This helps optimize time base Predictive Maintenance and Preventive Maintenance work for up tower activities.

2. How Statistical Models fit into Condition Monitoring for Wind Turbines

Most wind plants have many "identical" turbines in a similar environment with the same operating profile. This enhances the ability to compare like assets across a large population.

Statistical models are used to compare the behavior of each asset's parameters on a wind turbine to the local populations of the wind plants similar wind turbines parameters. This allows for detection of an outlier on one turbine in comparison to the local population of wind turbines and classifies the severity of the change in behavior.

In addition, the power profile for one turbine is compared to the plant, and degraded performance is classified compare to the overall plants performance which could identify control system degradation or equipment degradation that would be missed in monitoring a turbine in isolation.

3. The Use of SCADA for time series data trending and analysis

SCADA systems can be used to provide data for all the parameters measured within the nacelle. Successful diagnostics requires eliminating the effect of operational and environmental influences. This is accomplished by statistical / APR modeling and asset model comparisons across the wind plant.

3.1. Since statistical and APR models are based on empirical data, the range of operation of the parameters is used to set the actionability of a change in behavior.

3.2. Define a threshold for APR. Since the operating parameters can be a function of load/power output, engineering and technical understanding of the normal behavior of each asset is used to set the threshold criteria. Some of the APR and statistical products allow a service threshold to be set for similar machine configurations (e.g. motor, gearbox and generator represent one type of machine configuration).

1 To build the thresholds, the user will use engineering judgment on how far from normal range of operations that the modeled parameter can be for abnormal behavior. This can be done statistically or with engineering 1st principle knowledge of the wind turbines:

For example: a five (5) degrees difference between actual value and the statistical normal behavior (modeled) for the metal bearing temperature of a high speed bearing on the generator that is operating well below its OEM recommended temperature. Since the model takes into account all "known" behavior, this is an abnormal behavior that could be indicative of low oil level in the bearing cavity.

2 Suppliers of the different statistical and APR technologies have specific methodologies to determine the thresholds for each asset within a nacelle.

3.3. Alarm Alerts are determined by the model, thresholds, and persistence.

3.4. To date, there are no industry standards of setting advisory notifications.

SUMMARY

SCADA statistical models and APR models are the best solution of process parameters modeling for determining component health. Since these methods remove the normal behavior and emphasizes the abnormal behavior across the process parameters associated with the assets within the nacelle (self-normalizing), these solutions focuses attention to actual changes in behavior that is an early indicator of a possible failure mode.

Care should be taken in that the modeled behavior does not allow a parameter to exceed the OEM, or best practices, thresholds that have been established to protect the equipment and for personal safety.

Statistical and APR theories have been around for approximately one hundred years. Since the late 1990's, the hardware and software in the industrial networks have evolved to a point where development and deploying of these solutions on real time data feeds is acceptable. They are used extensively in the Power Industries, Oil and Gas, and Mining. In the power sector, they are deployed on many thousands of wind turbines throughout the world.

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RP 818

WIND TURBINE ON-LINE GEARBOX DEBRIS CONDITION MONITORING

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

This Recommended Practice discusses the use of oil debris monitoring to assess and monitor the health of a wind turbine gearbox as part of a comprehensive condition monitoring program.

Experience has shown that premature gearbox failures are a leading maintenance cost driver of a wind turbine operation. Premature gearbox failures reduce turbine availability, result in lost production and downtime, and can add significantly to project lifecycle cost of operation.

Oil debris monitoring used in conjunction with Prognostics and Health Management (PHM) techniques offers the potential of detecting early gearbox damage, tracking the severity of such damage, estimating the time to reach pre-defined damage limits, and providing key information for proactive maintenance decisions. Experience has shown that major damage modes in wind turbine gearboxes are typically bearing spall and gear teeth pitting, both of which release metallic debris particles into the oil lubrication system.[1, 2, & 3] Oil debris monitoring is well suited to provide an early indication and quantification of surface damage to bearings and gears of a wind turbine gearbox.

An oil debris sensor is used to detect and count metallic debris particles in the lube oil as it flows through the bore of the sensor. The amount of debris detected and the trend in particle counts can be used as an indication of component wear and damage. These sensors may employ inductive coils to detect debris resulting from early gearbox damage, and are capable of detecting both ferromagnetic and non-ferromagnetic metallic debris.

INTRODUCTION

The arrangement of a wind turbine gearbox typically consists of 3 stages of gearing - a high-speed stage, an intermediate stage, and a planetary stage. *(See Figure A.)* The majority of the wind turbine gearbox problems that cause outages are due to bearing spall and/or gear pitting.[1, 2, & 3]

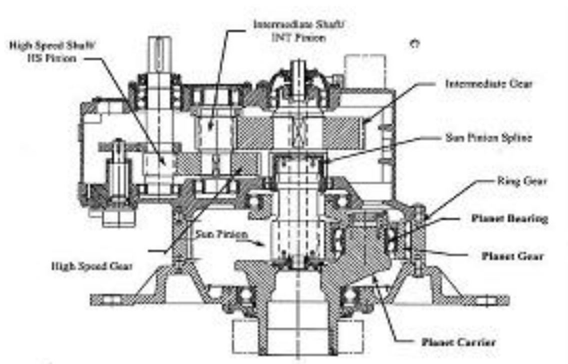

Figure A.

Employing an oil debris sensor installed in the gearbox lube oil system provides the capability of detecting bearing and gear damage at an early stage and giving insight into the extent of the damage and its impact on the remaining life of the gearbox. Increasing particle counts have been successfully used as a notification to perform additional boroscope inspection of the gearbox to better localize and assess the progression of damage.

Inductive oil debris sensors can be installed in either a full-flow or partial-flow configuration. In the full-flow configuration 100% of the oil flow is passed through the sensor along with 100% of the debris particles. In a partial-flow configuration, the oil flow is divided and a portion of the flow is passed through the oil debris sensor while the rest is diverted. *(See Figure B.)* In a partial-flow configuration, a number of factors can influence the amount of oil debris passing through the sensor. These factors include flow rate, sensor location, and sensor plumbing arrangement. It is recommended that some tests be performed to correlate the fraction of oil debris passing through the sensor as a function of oil flow rate for a given type of partial flow sensor configuration.

Either a full-flow or partial-flow configuration is suitable for wind turbine gearbox condition monitoring as both provide comparable data trends.

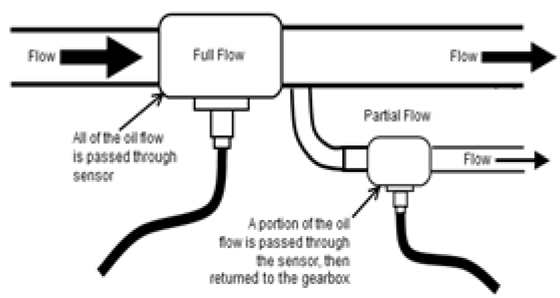

Figure B.

Whether a full-flow or partial-flow configuration is used, the oil debris sensor is installed in the lube system at a point downstream of the gearbox oil return port and prior to the filtration system. Typically only a single sensor is used, and it can be installed in either a return line or a supply line as long as it is upstream of the filtration system.

<u>ON-LINE CONDITION MONITORING (DEBRIS MONITORING) PROCEDURES</u>

1. SITE SURVEY AND INSTALLATION PLANNING

1.1. Review the lube oil system to determine the most suitable location to install the debris monitoring sensor. The sensor must be located at a point downstream of the gearbox oil return port and prior to the filtration system and can be installed either before or after the pump. *(See Figure C.)*

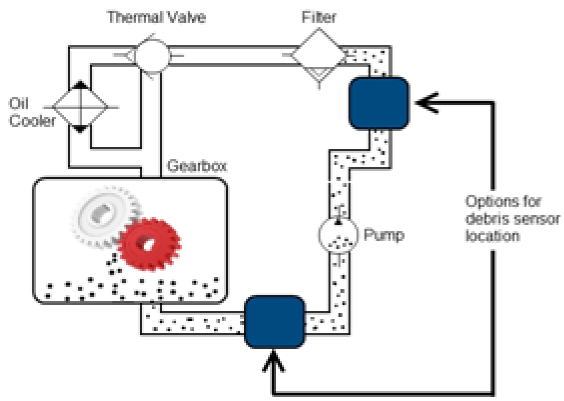

Figure C.

1.2. If using a full-flow sensor, select a sensor bore that matches the lube oil line bore as closely as possible. This will ensure that the pressure drop across the sensor is minimized. If there is a difference between the oil debris sensor bore and the lube oil line bore, then a pressure drop analysis should be conducted prior to the sensor installation in order to confirm that the pressure drop across the sensor is acceptable.

If using a partial-flow sensor, select or install bypass flow stream that supports the sensor manufacturer's recommended flow rate. Bypass filtration systems and oil sampling ports are typical install points; consult with the sensor manufacturer for specific instructions. Ensure the bypass configuration maintains a suitable oil flow in the supply line to the gearbox lubrication points.

1.3. Ensure that there are no interferences and/or conflicts of space between the oil debris sensor and existing components.

1.4. Locate and mark the position where the sensor will be installed, as well as any bolts, brackets, and tubes that need to be replaced or repositioned.

1.5. Ensure that there is suitable power available for the oil debris sensor. Ensure that the power source has a switch or circuit breaker that can be turned off during sensor installation.

1.6. Ensure that all required tools and consumable materials are available and are on-site.

2. SENSOR ELECTRICAL INSTALLATION

2.1. Connect the oil debris sensor to the SCADA or Control/Monitoring System (CMS) according to the instructions from the sensor manufacturer.

2.2. Ensure the switch or circuit breaker from the sensor power supply source is turned off.

2.3. Connect the oil debris sensor to the power supply according to the instructions from the sensor manufacturer.

2.4. Switch the power to the sensor on.

2.5. Perform a signal check by passing a metal particle through the sensor bore. Ensure that the sensor detects the particle and conveys this information to the SCADA / CMS. When available, perform a sensor self-test to verify functionality and communications; consult with the manufacturer for specific instructions.

3. SENSOR INSTALLATION IN FLUID LINE

3.1. Ensure the switch or circuit breaker from the sensor power supply source is turned off.

3.2. Install the sensor in the lube oil line location that was marked during the site survey. Replace hoses, bolts, brackets, tubes, etc. as required.

3.3. Perform a leak-check for all installed lube system components including sensor, hoses, and fittings/adapters.

3.4. Perform a physical mounting integrity check to ensure that the sensor and all installed lube system components will remain secure without leaking, becoming damaged, or suffer degraded service life or performance.

4. WARNING & ALARM LIMIT CONFIGURATION

Although all stages of gearing have experienced bearing problems, it is noteworthy that feedback from field experience suggests that high speed shaft bearings and planet gear bearings are especially problematic. The former can be repaired in-situ whereas the latter requires gearbox replacement. This suggests that damaged high speed shaft bearings should be replaced early in the damage cycle while damaged planet gear bearings should be run to the damage limit that maximizes production and minimizes secondary damage in the gearbox. Hence, gearbox damage inspection limits will be set on the basis of bearing damage. These same limits will also provide valid inspection points for gearing, since surface fatigue phenomena for bearings and gears progress in a similar manner.

The recommended parameters for indicating severity of bearing damage are:

1. The total accumulated particle counts detected by the oil debris monitoring sensor.
2. An increasing rate of particle generation.

A correlation can be defined between the accumulated particles counts detected by the sensor and the spall size on a damaged rolling element bearing.

Thus, the maximum severity of damage can be defined as an ALARM limit.

SUMMARY

Condition monitoring is an effective technique for managing gearbox failures. Oil debris sensors, when installed within the gearbox lube system provide reliable information regarding the health of the gearbox. Sensor data can be interpreted easily as a condition indicator that provides an early warning of bearing spall and gear pitting damage and quantifies the severity and rate of damage progression towards failure.

Oil debris sensors are a proven technology and have been in operation since the early 1990s. There are now thousands of these devices operating in a wide variety of machinery applications accruing millions of operational hours.

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RP 819

ONLINE OIL CONDITION MONITORING

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

This Recommended Practice discusses the utilization of online oil condition monitoring to assess the health of a wind turbine gearbox lubricant.

Gearbox lubricants are designed to provide a protective layer between contact surfaces, thereby significantly reducing friction and wear. They also transfer heat, contaminants, and debris out of the gearbox. Due to the extreme conditions wind turbines operate under (temperature swings, high torque, frequent start/stops, humidity swings), gearbox lubricants are specially formulated with additives such as, oxidation inhibitors, corrosion inhibitors, extreme pressure protection, and anti-foam agents.

Maintaining a healthy lubricant is of critical importance to maximizing the operating life of a wind turbine gearbox. Over time and as a lubricant is exposed to debris or contamination, temperature swings, and extreme loads, its ability to provide the expected level of protection degrades. Ineffective or improper lubrication can lead to highly accelerated wear rates, development of corrosion, reduced efficiency, and ultimately functional failure.

In addition to traditional offline sampling and analysis, many online oil condition monitoring technologies exist which can provide users early warning of lubricant degradation. This RP provides a summary of available technologies and their use for effective lubricant health monitoring.

INTRODUCTION

Traditionally, the condition of lubricating oils has been determined through periodic oil sampling and laboratory testing. The methods for collecting gearbox oil samples and recommended analyses are discussed in detail in RP 102 and 104. A full laboratory oil analysis of an oil sample provides a detailed report of a lubricant's physical properties, quantitative analysis of key contaminants, and an indication of its remaining useful life. However, with a limited number of oil samples from a given component and the significant time between sampling (typically 6 months or more), combined with variability in lab analysis techniques and contaminants which can rapidly fluctuate in concentration such as wear debris and water, offline analysis methods provide limited early warning of lubricant degradation.

Online oil condition sensors help to fill these information gaps and provide improved situational awareness when used with conventional offline methods. The real-time data provided by online sensing devices allows operators to identify and correct lubrication issues early, leading to improved long-term reliability and reduced lifecycle cost.

ONLINE OIL CONDITION MONITORING

1. ONLINE OIL MONITORING METHODS

A multitude of online oil condition sensors are available from several different manufacturers. The sensing technologies used can be grouped into the following categories:

1 Impedance Spectroscopy.

2 Conductivity Sensing.

3 Infrared Spectroscopy.

4 Moisture Sensing.

5 Viscosity.

The following sections describe the principles of operation of these devices and how they can be applied for wind turbine oil condition monitoring. Operators are encouraged to seek specific equipment recommendation and instructions from their selected device manufacturers.

1.1. Impedance Spectroscopy

Impedance Spectroscopy methods utilize a set of electrodes immersed in the lubricant to measure the fluid's impedance over a range of frequencies. Impedance measurements consist of a magnitude and phase angle and are frequency dependent. Contaminants, additives, and oxidation byproducts influence portions of the impedance spectrum. Properties such as anti-wear additive health, detergent/dispersant additive health, and dissolved/free water contamination can be detected and trended using impedance spectroscopy based devices.

Impedance based devices can provide the following fluid condition monitoring benefits:

- **Trend Analysis** - Monitor impedance measurements to detect abnormal levels or patterns indicative of contamination or poor health.
- **Contamination and Remaining Useful Life Estimation** - Some manufacturers provide data interpretation algorithms capable of providing remaining useful life estimates (estimate of time until oi

properties reach unacceptable levels) and alarms for specific contaminations.

- **Additive Depletion Monitoring** - Impedance-based devices are particularly sensitive to changes in additive levels in a lubricant. Some devices can even distinguish between surface protection additive loss and detergent/dispersant loss.

1.2. Conductivity

Conductivity-based devices operate on a similar measurement principle to impedance-based devices, using a set of electrodes immersed in the lubricant and measuring the electrical properties of the fluid between the electrodes. Conductivity measurements are performed at a fixed frequency and represent the inverse of the measured resistance at that frequency.

The measurement capabilities of a conductivity sensor are dependent upon the frequency at which conductivity is measured. They provide value in trending and alarming, but are limited in their capability by only measuring a single property of the fluid.

1.3. Infrared Spectroscopy

Infrared (IR) Spectroscopy or Fourier Transform Infrared Spectroscopy (FTIR) have been used for many years to provide rapid, low cost, offline analyses of oil samples. The technology passes an infrared light source through a lubricant sample to an infrared detector. The light passing through the oil is influenced by oil contaminants and additives which absorb infrared radiation at specific frequencies. By comparing the frequency spectrum of new and used oil samples, it is possible to determine the lubricant properties such as water, oxidation, glycol levels, and other breakdown products.

Through advances in electronics manufacturing techniques, IR technology is beginning to make its way into online sensing devices. Current technology does not have the refined measurement capabilities of laboratory devices; however, they do offer multi-parameter trending capabilities which can provide valuable, real-time insight into fluid condition.

1.4. Moisture Sensors

Water contamination has many detrimental effects on the performance of a lubricant, including accelerating oxidation, promoting corrosion, decreasing film strength, and increasing foaming. Water is also a difficult contaminant to control, particularly in gearbox applications which endure frequent temperature cycling, changes in atmospheric humidity, and do not experience high enough temperatures to evaporate water contamination. Online moisture sensors, often referred to as oil Relative Humidity (RH) or Water Activity sensors, can detect and trend water contamination in an oil lubrication system.

Nearly all online moisture sensors utilize a capacitive sensing element with a hydrophilic dielectric. As moisture is absorbed and desorbed by the lubricant and sensor, the measured capacitance value will change. These devices track moisture while it is present in its dissolved state and will not continue increasing as free water forms in a system.

Benefits of this technology to wind turbine gearbox lubricant monitoring include:

- Real-time tracking of dissolved water contamination during temperature and humidity swings that are missed by periodic offline analyses.
- Identifying turbines that have faulty desiccants.
- Identifying turbines that show potential for free water formation tc prompt corrective actions.

1.5. Viscosity

Through monitoring the viscosity of the oil in a lubrication system, mechanical shear as well as contamination can be indicated. Reduced viscosity results in reduced film strength and increases the likelihood of excessive friction, wear, and heat generation. Elevated viscosity can result in reduced cold-start lubrication and oil filtration performance, and decreased efficiency due to increased fluid friction.

There are several types of online viscosity sensing techniques including rotational, vibrational, and displacement based sensors. Each method has its own advantages and disadvantages which should be discussed with the respective monitoring equipment manufacturers. Due to the very high temperature sensitivity of viscosity measurements and the temperature swings experienced by wind turbine oils, devices capable of providing a temperature compensated output or trending measurements from a specific operating temperature are recommended.

2. INSTALLATION CONSIDERATIONS

Proper installation of an online oil sensing device is critical to insuring reliable operation and expected sensor performance. The following sections detail the considerations required when selecting an installation location and plumbing the unit into the system. Always consult with the device manufacturer before installing a device.

2.1. Location Selection

The following considerations should be used to determine the optimal location for device:

1. The device should be place in a section of the lubrication system with sufficient flow to insure a representative fluid sample is observed by the device.
2. Insure the flow rate in the installation location does not exceed manufacturer recommendations.
3. The device should not be placed at the bottom of a fluid reservoir or low point of a kidney loop as sludge and deposits may prevent accurate readings.
4. For many online condition monitors, post filtration installation locations are preferred to prevent electrode shorting or damage to moving parts. Wear debris monitors should be installed pre-filter
5. Insure the device's maximum ambient temperature will not be exceeded.
6. Orient the device and/or design the device manifold in a manner that avoids entrapment of air bubbles or debris.

2.2. Plumbing

When installing the device into a system, consider the following:

1. If using a manifold, ensure it is free of machining chips and any burrs have been removed.
2. Lubricate any threads and/or o-rings prior to installation.
3. Tighten all fittings per the recommended torque specification.
4. After installation, engage the lubrication system and check for leaks.

SUMMARY

Online condition monitoring enhances lubrication maintenance practices to help maintain healthy lubricant and ultimately extend gearbox life. Many online sensing devices are available which offer insight into a variety of oil condition parameters. The selection of an appropriate device depends on the monitoring objective, historical lubrication issues, site location, and the operator's budget. Regardless of the sensing method chosen, these technologies provide significant enhancement to a standalone offline sampling and analysis program by providing continuous data between the typical 6-month sampling intervals.

RP 821

WIND TURBINE BLADE CONDITION MONITORING

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

Blade condition monitoring systems may be capable of detecting and predicting failures and conditions that would otherwise be difficult to undetectable in megawatt class wind turbines (this is not accurate, almost all are detectable with visual inspection). Several technologies have been tried or adapted from other markets with varying ability to detect emerging failure modes. While a mature system is currently not yet commercially available, this Recommended Practice will provide insight into the technologies and discuss common failure modes of wind turbine blades.

Condition monitoring of blades may be required in the future as wind turbines and blades increase in size or complexity, new insurance or lender requirements emphasize predictable reliability, and offshore wind turbines increase in number.

INTRODUCTION

There are six major failure modes that can be monitored by a blade condition monitoring system. To date, no commercially available system is available capable of detecting all major failure modes, although several approaches have been tested in the recent decade.

Historically, there have been many attempts at adapting technologies from other industries to this application with limited operational or commercial success. In order to gain market acceptance, any blade condition monitoring system must be able to detect (unknown failures, trend damage progression and confirm) known failure modes, be easily installed in existing towers, be sufficiently robust to withstand operational and environmental conditions, and provide reliable cost-effective data on blade condition.

WIND TURBINE BLADE CONDITION MONITORING

1. ISSUES

- The first issue is if the technology or product detects the likely encountered failure modes.
- The second issue is if the system is a retrofit to existing towers.
- The third issue is if the system is cost effective.

There is a new patent which does show promise in addressing all three of these issues.

2. FAILURE MODES

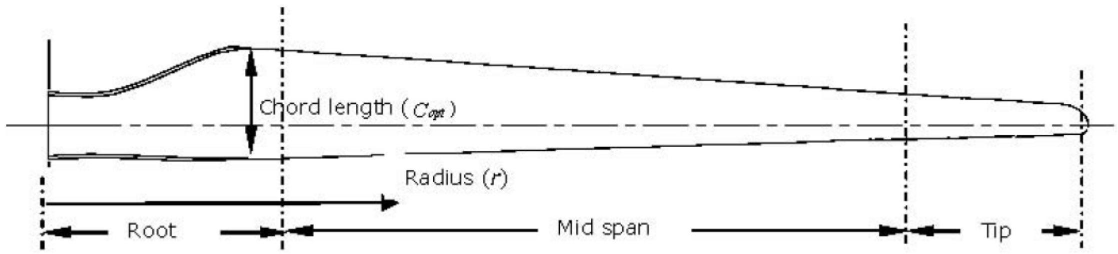

Figure A. A Typical Blade Plan and Region Classification.

2.1. Cracks

The ability to detect and provide early warning of cracks that typically occur at four common locations is critical feature of blade condition monitoring. These crack locations include the root, leading edge, trailing edge, and tip. *(See Figure A.)* While there is some uncertainty as to where a crack might occur in these locations due to variables from one blade manufacturer to the next, these four locations are generally consistent.

2.2. Delamination

Delamination predominately occurs at the trailing edge location and is caused by separation of the layers of composites and laminations. Separation may be caused by poor structural design, resin-rich areas with inadequate reinforcing matrix, poor quality control in manufacturing, accumulated stress-fatigue damage, and other factors.

2.3. Icing

An accumulation of ice on the blade surface is not conducive to safe or reliable wind turbine operation. Performance is degraded and the extra loading of ice on blades creates uneven stresses which can be measured. A blade monitoring system should be able to measure this accumulation of ice on the blades and provide the operator with a warning if loads exceed an established action threshold (under operating conditions).

2.4. Imbalance (Either Aerodynamic or Static)

While blades are balanced from the factory within a tight tolerance, the operating environment and in-service wear or damage (e.g., leading edge erosion) may contribute to static imbalance in the field. In addition, aerodynamic imbalance may be result from variations in pitch index or sweep, improper placement of vortex generators or other aerodynamic aids, and variations in a blade's aeroelastic behavior.

There may also be uneven loading issues caused by wind shear, pitch deviation, tip in/out, and yaw deviation. All of these conditions can be monitored and will return improved performance, reliability, and production. If not monitored correctly, these operational conditions may appear as imbalance, but a best practices blade condition monitor and a trained analyst should be able to discern between these differences. (This is actually a function of a legitimate analyst.)

2.5. Lightning Strikes

A blade condition monitoring system should be able to detect lightning strikes which contribute to one of the acknowledged failure modes. Since lightning is very common in certain geographical locations (like icing), best monitoring practices would dictate a system capable of detecting its occurrence.

3. TECHNOLOGY APPROACHES

While no single product or technology today can measure or detect all of the possible failure modes common in a wind turbine blade, many (only one actually) there are current efforts that show promise for future applications. Below are the different technologies that may be applied:

3.1. Fiber Optic

Fiber optic sensors provide fast high resolution strain data from structures. They are light weight and would not affect performance. However, they are also difficult to install outside of initial blade manufacture, are expensive, and do not detect all failure modes. This is likely why fiber optic technology has had limited success and adoption in the wind industry, although is quite common in the aerospace industry. Installation usually involves cutting a shallow slot into the perimeter of the blade where the fiber optic strand is then laid and epoxied in place.

3.2. Strain Gauges

Strain gauges are inexpensive, easy to install/retrofit to existing turbines, but have proven to be troublesome in the field having a lifetime as short as 6-9 months. Like fiberoptic sensors, strain gages do not detect all blade failure modes, and their deployment has had limited success.

3.3. Acoustic

One wind turbine manufacturer has experimented with acoustic monitoring technology to detect blade cracks on a small number of towers. A focused microphone was placed on the top of the nacelle pointing forward towards the hub in an attempt to detect high frequency acoustic signatures emitted by surface blade cracks. The detection capability of acoustic technology is limited to surface cracks, and it will not necessarily identify sub-surface delamination, or uneven stress loading. While easy to install/retrofit, and relatively cost effective, acoustic technology has not been successful in the wind industry for the same reasons as fiber optic.

3.4. Vibration Sensors

This approach has been used with the sensors mounted near the hub, not on the blades. There is good measurement ability in some failure modes such as icing, imbalance, and less than optimal operational conditions. Again, there is limited detection capability for all common failure modes, but ease of installation or retrofit and cost-effectiveness are good. As a secondary benefit, vibration sensors for blade monitoring are usually applied at the main shaft bearing which is also monitored. While main bearings are the least frequent failure (in most drive trains), they are expensive to repair. Main bearing monitoring is an added benefit of this technology.

3.5. Laser Reference

This method utilizes a laser and prism system which compares the spatial differences and changes between known reference points within a wind turbine blade. This is done by aiming the laser at the prism and then redirecting the laser to internal locations. This technology would provide an excellent system for quality control of blades to measure manufacturing deviations in substrates and composites. Once again, the inability to detect all common failure modes, complexity of retrofit, and system cost all contribute to a lack of widespread acceptance.

4. A PERFECT SYSTEM SUMMARY

As a note to system designers and integrators, the perfect wind turbine blade condition monitoring system would have the following features:

- Be able to detect all 6 common failure modes.
- Have robust sensors.
- Provide blade and blade position identification.
- Provide sensor identification.
- Be cost-effective for either retrofit to existing turbines or installation at original manufacture.
- Use wireless and self-powered sensors to facilitate installation and data collection.

5. ANALYSIS AND SOFTWARE

Like any good condition monitoring system, they are only as effective as the analyst who configures the alarms, monitors the data and performs the analysis. So even with a perfect blade CMS hardware, you still need a certified and experienced vibration analyst with familiarity in wind turbine blade defect analysis to set-up and monitor the CMS for results.

Software should be able to configure appropriate measurements, alarming and display of blade data in a familiar condition monitoring format consistent with industry standard vibration analysis practices and norms. This means industry standard measurements, units of measurements, labeling, measurement set-ups, alarming, charting and reporting.

With the blade CBM data streaming (off of the blades, tower, farm and fleet), special considerations need to be made for appropriate data transportation, data storage and resulting data analysis with the aforementioned software and appropriate analysist.

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RP 831

CONDITION MONITORING OF ELECTRICAL AND ELECTRONIC COMPONENTS OF WIND TURBINES

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

This recommended practice was prepared by a committee of the AWEA Operations and Maintenance Working Group.

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PURPOSE AND SCOPE

This Recommended Practice discusses the condition monitoring techniques used for detecting emergent failures occurring in the electrical and electronic components of wind turbines. It will cover the condition monitoring of wind turbine generator, power electronics, transformer, and cables.

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INTRODUCTION

Wind industry practice shows that for onshore wind turbines, 75% of faults cause 5% of downtime, and 25% of faults cause 95% of downtime. The majority of those 25% of faults are due to the failures of electrical and electronic components of wind turbines [1]. Considering the wet and corrosive environment of offshore sites and the difficulties of accessing offshore equipment, it is believed that above figure will be more undesirable offshore. Therefore, the reliability and availability of wind turbine electrical and electronic components are critical to minimize life-cycle energy cost and benefit project financials [2]. This highlights the importance of condition monitoring for electrical and electronic components of wind turbines either onshore or offshore. In the following sections, condition monitoring techniques for detecting emergent failures in wind turbine generators, power electronics, turbine and substation transformers, and cables will be discussed.

CONDITION MONITORING OF ELECTRICAL AND ELECTRONIC COMPONENTS OF WIND TURBINES

1. CONDITION MONITORING OF WIND TURBINE GENERATORS

Since Doubly-Fed Induction Generators (DFIG) are the most common type in the wind turbine fleet, this section will focus on condition monitoring techniques for DFIG. The failure modes of permanent magnet generators, which are getting increasing market share, are different from those of DFIG, but still have many similarities.

The failure modes of DFIG include:

- **Mechanical** - bearing failure; rotor mechanical integrity failure; stator mechanical integrity failure, cooling system failure.
- **Electrical** - core insulation failure; rotor winding or insulation failure; stator winding or insulation failure; brush gear failure; slip ring failure; commutator failure; electrical trip.

The root causes of these failures are various, such as defective design or manufacture, poor installation, inadequate maintenance, heavy cyclic operation, severe ambient conditions, overload, over speed, low cycle fatigue, shock loading, high cycle fatigue, component failure, excessive temperature in windings, excessive temperature in bearings, steady or transient excessive dielectric stress, debris, dirt, corrosion and so on.

Electrical current, flux, and power monitoring techniques have been well developed and are now successfully applied to the condition monitoring of wind turbine generators. Many characteristic frequencies have been identified from stator current signals for diagnosing those electrical failures occurring in the stator and rotor. The relevant information can be found from many openly published literatures.

1.1. Bearing

Since bearings account for over 40% of failures in generators, condition monitoring practice should concentrate on generator bearings. This can be achieved by onboard vibration monitoring and analysis, often in combination with temperature measurement. As the relevant techniques and monitoring procedures have already been introduced in AWEA O&M RP 811 and RP 815, they will not be repeated again in this section. Nonetheless, bearing faults may also be detectable from an analysis of generator electrical current and power signals. Bearings approaching failure contribute to changes to air-gap eccentricity, resulting in measureable effects on magnetic field.

1.2. Earth/Ground Fault Detection

While generator rotors, stators, and bearings are responsible for over 80% of failures of the generator (usually, stators exhibit more problems than rotors) [3], detection of other electrical faults in the generator cannot be ignored. For example, a single earth/ground leakage fault in a generator rotor winding is not serious in itself because the leakage current is relatively limited and cannot cause significant damage. But if multiple earth/ground leakage faults occur, higher current flows may eventually lead to the damage of winding, insulation and even the rotor forging. To early detect this type of fault, a rotor earth/ground fault detector is required, which applies a DC bias voltage to the rotor winding and monitors the current flowing to the rotor body via an alarm relay. Should an alarm occur, it is essential to shut down the generator for further investigation and to prevent additional damage.

1.3. Electrical Discharge Monitoring

Electrical discharge monitoring is another important technique that is often adopted in the condition monitoring practice of wind turbine generators. The discharge behavior of a generator is complex, but can be categorized in an ascending order of energy and potential damage as corona discharge, partial discharge, spark discharge, and arc discharge. Electrical discharge is an early indicator of many electrical faults occurring in the generator that are usually related to integrity and the residual life of insulation.

Today, many commercial on-line discharge monitoring systems have been developed and are extensively used in the condition monitoring of wind turbine generators.

1.4. Other Practices

Besides the aforementioned techniques, some others are often adopted in practice as well for various condition monitoring purposes. For example, turn-to-turn faults in rotor or stator windings may lead to local overheating thereby increasing the temperature of the stator and rotor. Stator and rotor temperature is often measured as an indicator of overall condition.

In addition, the deteriorating performance of the brush gear in the generator can be detected by measuring brush or brush-holder temperature. A more advanced technique involves detecting the radio frequency energy generated by brush sparking, but this technique has not been commercially used in practice.

2. CONDITION MONITORING OF THE POWER ELECTRONICS OF WIND TURBINES

Power electronics have been identified as the components that are most prone to fail, particularly in the wet, salty and corrosive environment experienced offshore. However, condition monitoring techniques for power electronics have not been fully developed. The reasons are various, but the major ones include:

- The failures of power electronics develop quickly, not allowing sufficient time to implement condition monitoring.
- Power electronic systems have a compact structural design, not leaving enough space to install condition monitoring transducers.
- The power electronic components are relatively cheap in price and easy to replace, no need to monitor their health condition online if the system can be easily accessed.

However, power electronics have a wide range of failure modes, which can be caused by excessive temperature, excessive current and voltage, corrosion, thermal fatigue, ionizing radiation, mechanical shock, stress or impact, etc. A recent survey based on 200 power electronics products from 80 companies shows that failures in the converter are 30% due to capacitors, 26% due to PCBs, 21% due to semiconductors (e.g. Insulated Gate Bipolar Transistor - IGBT), and 13% due to poorly soldered connections[4]. Clearly, semiconductors and DC link capacitors are the most fragile components in wind turbine power electronics.

2.1. IGBTs

Temperature measurement is commonly used for monitoring the operation and health of wind turbine power electronic converters and inverters, but more advanced techniques are being researched today. The latest generation of IGBT products has been equipped with built-in thermocouples, so that variations in IGBT temperature can be readily tracked. However, measured temperature is reliant on many factors (such as ambient temperature and load), thus, diagnosis of an IGBT high temperature condition still requires further investigation.

2.2. Capacitors

Two kinds of capacitors are being used in the wind industry as DC link capacitors in power electronic converters - the aluminum electrolytic capacitor, and the metallized polypropylene film capacitor. The former is characterized by a high power density at a relatively low price, but is prone to fail in practical application. By contrast, the latter is more reliable and is able to withstand higher voltages and currents, with a tradeoff of comparatively lower power density. The condition of electrolytic capacitors can be approximated by trending three characteristic aging indicators - capacitance, equivalent series resistance, and the dissipation factor - and comparing the measured values of these parameters with recommended service thresholds. Although film capacitors are generally more reliable than electrolytic capacitors due to their self-healing capability, they are not free from failures. In contrast to the three aging indicators of an electrolytic capacitor, the film capacitor has only one ageing indicator - capacitance. Online condition monitoring of the capacitance of the film capacitor is exactly same as that used for monitoring the electrolytic capacitor. Since temperature is the main ageing accelerator of capacitors, temperature measurement is also applied to condition monitoring for capacitors, though the result derived from temperature monitoring could be less reliable.

3. CONDITION MONITORING OF WIND TURBINE AND SUBSTATION TRANSFORMERS

Wind turbine and substation transformers are critical to the operation of wind farms. Their safety and reliability is critical to profitable power generation, transmission, and distribution. As the transformers are subject to very high mechanical, electrical, and thermal stresses during operation, failures and aging issues often occur in their windings, bushings, tap changers, insulation, and auxiliary equipment. Although consistent failure rates for these components have not been established in surveys conducted by different organizations, winding, bushing, and insulation systems have been identified as the three most fragile components in transformers. Moreover, these components are responsible for over 50% of plant downtime [5].

Bushing – Modern transformer bushings are generally designed with closely stepped capacitive stress control layers. The basic insulating systems of capacitive stress controlled high voltage bushings are classified as Resin-bonded paper bushing, Resin-impregnated paper bushing, and Oil-impregnated paper bushing. Despite the different types of bushings, bushing capacitance and dielectric dissipation factor are two key indicators of their operational condition. This is because both indicators are dependent on ageing, although they are also affected by the external environment (e.g., moisture, dirt, etc.). Dielectric dissipation factor is a function of bushing capacitance. An increase in bushing capacitance for all bushing types indicates partial breakdowns between the control layers. A short-circuit between two control layers could have little influence on the general health condition of a bushing. But the increasing number of defective control layers can result in a complete breakdown of the insulation. Storm conditions (lightning, high winds, etc.) and/or routine switching actions may cause a transient overvoltage condition that could damage the insulating layer of the bushing. Tracking and reporting of transient overvoltage conditions in transformers is recommended as an additional tool in the evaluation of transformer and bushing condition.

3.1. Other Practices

Besides monitoring bushing capacitance, dielectric dissipation factor and transient overvoltage, the following techniques are often useful for condition monitoring of wind turbine and substation transformers:

- **Dissolved Gas Analysis** - High electrical and thermal stresses in the transformer will cause breakdown over time of insulating materials and release gases due to localized overheating, corona and arcing. Different concentrations of gases will appear depending on the intensities of energy dissipated by various faults and the analysis of dissolved gases is very helpful for the identification of the root causes of the faults.

- **Partial Discharge Monitoring** - PD is also an important means for detecting the deterioration of the insulation system of a transformer. Once a defect has developed on the insulator, partial discharge pulses will be generated at its point of origin. Hence, the initiation and development of an insulation defect can be identified if partial discharge pulses are detectable.
- **Temperature** - Temperature measurement is used as an indicator of the operational and health/aging condition of transformer windings. Now, several approaches have been adopted for the measurement of transformer temperature. Among them, the most promising device is an optical fiber transmitter connected to a crystal sensor. The sensor converts an incoming light beam into an optical signal that can be correlated to sensor temperature. Currently, these devices have been tested, but are not widely in service.
- **Vibration Analysis** - Vibration sensors magnetically attached to the sides and top of the transformer tank may help detect changes in the mechanical integrity of transformer windings (e.g. winding looseness) and the tap changer. But the practice has shown that vibration analysis of transformers is quite complicated due to the many vibration sources such as primary excitation, leakage flux, mechanical interaction, switching operations, etc.
- **Leakage Flux** - This is a traditional method popularly used for detecting changes in winding geometry. It is known that any mechanical displacement of the windings can result in changes to the radial component of leakage flux. By using search coils that are installed in the transformer, these changes can be readily detected.
- **Analysis Of Current Signals** - This is a very popular approach used in the condition monitoring practice of transformers. This method can be used to detect the undesirable conditions in single phase or three phase transformers. Usually, all three phases of current signals are used together for either comparison or comprehensive analysis (e.g., Park's vector pattern analysis)

to detect the early malfunction of transformers.

- **Monitoring of Bushing Oil Pressure** - For oil-filled bushings, it is possible to measure bushing oil pressure, thereby checking for possible oil leaks. Since changes to bushing oil pressure can also be affected by the thermal overload or partial discharges, it is recommended that careful onsite investigation be conducted once a significant drop in bushing oil pressure is observed.

4. CONDITION MONITORING OF ELECTRIC CABLES

Power cables used on wind farms represent a large capital investment. They are usually reliable, but are critical to the overall performance of the facility. Failures not only affect the power generation of individual wind turbines, but the production of the whole wind farm could be impacted. For this reason, monitoring and maintaining the condition of electric cables is of great significance to assure the profitable production of wind farms, particularly for those where cable installation and repair are difficult to carry out.

Different types of electric cables (e.g., paper/oil and extruded cables) are produced for different purposes. Cable systems used on wind farms are predominately insulated with solid dielectric insulation (e.g. plastic and rubber based materials). Electric cable systems can fail for a number of reasons [6]. The most common reason for failure on wind farms is poor installation technique. Low voltage cable systems, less than 1kV, commonly fail at the connectors due to overheating. One of the most effective tests for low voltage cable systems is the infrared assessment (see RP 601 and 602 Secondary Cables for more information). Medium and high voltage cable systems can fail due to overheating at the connection points but the predominant issue is insulation failure. Failure occurs when the local electric stress exceeds the insulation strength (e.g. a sharp metal protrusion in the insulation), a gas or air void is introduced where solid insulation should be (e.g. a lack of dielectric grease on a joint interface), or, as is most common, a more subtle mixture of the two cases. In either case partial discharge arises and begins erosion process. The erosion process only advances during voltage stresses which are sufficiently high enough to turn on the PD ionization process. Voltage transients, which are very common at wind farms, intermittently turn on PD sites and cause sporadic erosion. Manufacturer standards of modern solid dielectric components require the components to be PD free at stress levels well over the operating voltage, as they will not last long under continuous PD activity. Thus, IEEE, IEC and ICEA standards require and off-line 50/60Hz PD test with better than 5pC sensitivity to determine whether or not components are in or out of specification. Since this standardized test can only be performed off-line it is typically performed during construction and then periodically during plant shutdowns (see RP 601 and 602 MV Cable Systems for more information).

Wind farm cable systems are presented with some extreme and unusual requirements. For example, the cable systems are typically designed for 100% loading; they can cycle from 100% to virtually zero load; they operate at more than two times the stress of typical medium voltage cable systems; and they often have relatively long cable runs (longer than 1 mile). This combination of challenges is unusual for other types of power plants and utility distribution applications that use similar cable system components. These noted challenges are usually only seen in transmission class cable systems. For this reason, many owners have specified stringent commissioning test requirements, such as the off-line 50/60Hz PD test. In some cases owners have installed thermocouples to spot check cable systems. While it is possible to run an optical fiber in parallel with the cable system for distributed temperature sensing (DTS), it is not a common practice.

A more common practice is to minimize the number of underground joints and use above ground junction boxes. The junction boxes can be serviced using an infrared (IR) camera and the most common overheating point, the cable accessory, can be checked for overheating during high load conditions and prevent damage to the cable insulation. IR cameras and off-line 50/60Hz PD tests are complementary. There is virtually no IR signature associated with PD activity and there isn’t any PD activity at overheating connection points until the insulation is slightly damaged. In addition, junction boxes are convenient points for fault indicators, sectionalization during failure locating and predictive off-line insulation testing.

An important issue in partial discharge testing is the level of test voltage. Using an excessive test voltage will initiate partial discharge pulses that would not exist at normal operating voltages, and may cause other damage that would not occur under normal operation. Therefore, it is recommended that system test voltage not be greater than 1.5 to 2 times the operation voltage.

SUMMARY

Condition monitoring of electrical and power electronic components of wind turbines has long been overlooked in previous wind industry practice. It is now being recognized as equally important to the condition monitoring of wind turbine drive trains, particularly with the increasing deployment of the wind turbines offshore or in remote locations.

In contrast to condition monitoring of wind turbine drive trains, condition monitoring of wind turbine electrical and power electronic components requires dedicated techniques or methods. While some methods come from traditional ideas (e.g., temperature measurement), they have been applied using more advanced technologies in order to meet special needs of wind facilities. This motivates the invention and development of even more innovative techniques in this young industry.

In this recommended practice section, a number of commercially available condition monitoring techniques for generator, power electronics, transformer and cables are briefly discussed in order to sketch an outline of the condition monitoring of the electrical and power electronics of wind turbines. However, the selection and practical application of these techniques is still reliant on the actual situations and physical requirements at site. Moreover, care should be taken in the application of some techniques (such as partial discharge testing) to assure they will not introduce negative effects or additional damage to the assets being monitored.

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RP 832

LIGHTNING PROTECTION SYSTEM CONDITION BASED MONITORING (CBM)

PREFACE

The following Recommended Practice is subject to the Safety Disclaimer and usage restrictions set forth at the front of AWEA's Recommended Practices Manual. It is important that users read the Safety Disclaimer and usage restrictions before considering adoption of any portion of this Recommended Practice.

AWEA OPERATIONS AND MAINTENANCE WORKING GROUP

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PURPOSE AND SCOPE

This recommended practice provides suggested methods for condition based monitoring of the lightning protection system. Specific methods of monitoring are not provided but the requirements for monitoring are described.

INTRODUCTION

The main purpose of the lightning protection system is to provide sufficient protection for the wind turbine to avoid damages in the event of a lightning strike. The lightning protection system can prevent or reduce damage that results in forced production outages and long-term degradation of components.

LIGNTNING PROTECTION SYSTEM CBM

1. MONITORING DIRECT ATTACHMENT

1.1. Online Triggering CBM

As a minimum, it is recommended to monitor lightning strikes to the wind turbine by a simple trigger circuit that provides a digital signal in the event of a lightning strike. The trigger signal should be monitored by the controller of the wind turbine and this triggering may be correlated with other CBM signals/data so eventually incidents can be compared to the occurrence of lightning strike.

1.2. Parameter Measuring CBM

The online triggering CBM can be extended to also measure the typical relevant parameters of the lightning. By measuring such parameters, the chance of success in predicting and evaluating damage is further enhanced. These parameters are stored as values in the wind turbine data log and can be correlated with other events, trends or developments that might originate from the specific time of triggering.

- **Peak Current** - This parameter is the easiest to measure. It will tell if there is risk of damage for connection components and risk of magnetic field coupling (i.e., damage to other parallel electrica components).
- **Energy** - This parameter provides information of overheating risk of conduction materials.
- **Charge** - The charge will indicate the wear erosion on lightning attachment points and on rotational transfer systems/bearings.
- **Current Rate-of-Change -** The steepness of di/dt in a lightning strike will indicate whether there is risk of coupled transients or

failing insulation.

1.3. Wave Shape Logging CBM

As a supplement to the online triggering and parameter logging the CBM can be extended to log the actual wave shapes of the lightning. The system logs and stores the curves. The curves can be used for further analysis of the lightning attachment.

1.4. Location Logging CBM

Each of the suggested systems can be expanded to either measure at several points or to do one detailed measurement. This will provide knowledge of where the lightning has attached and specific areas can be targeted for subsequent investigation or monitoring.

2. MONITORING INDIRECT EFFECTS

2.1. Surge Protective Devices (SPD) Failure Monitoring

If the SPD system provides feedback, this feedback should be monitored. Furthermore, several systems use an upstream fuse that also needs to be monitored, if present. This monitoring may be done online, and any fault will require a service visit to the wind turbine to replace the defective component.

2.2. CBM of Surge Protective Devices

It is suggested that the operation of SPDs be monitored. By continuous monitoring and counting of transients, the SPD can be predictably maintained.

3. INSPECTING THE LIGHTNING PROTECTION SYSTEM

On an annual basis, it is recommended that a full inspection is performed on all wear parts of the lightning protection system. The system should be inspected for excessive wear or defects. All adjustable systems should be inspected for correct adjustment and corrected if needed.

USEFUL REFERENCES:

IEC 61400-24