orbit

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A Technical Publication for Advancing the Practice of Operating Asset Condition Monitoring, Diagnostics, and Performance Optimization

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Editor's Notepad

Editor | Orbit Magazine

I will probably never make it to the International Space Station, so it gives me great pleasure to be able to legitimately say, "Greetings, and welcome to *Orbit!*"

Our previous issue featured condition monitoring software, and a future issue will focus on transducers. This particular issue includes updated information for several of our monitor systems.

One advantage of being middle-aged is that I can remember the way things used to be. And they were NOT always the "good old days..." When I was a plant operator in the 1980s, my plant used Bently Nevada* 7200 series protection systems on our reactor coolant pumps, feedwater pump turbines, and as part of the Turbine Supervisory Instrumentation (TSI) system for our main turbo-generators.

These analog instruments provided very reliable "hardware alarms" and automatic machine trips for parameters such as high radial vibration, high axial thrust displacement and overspeed. But the only way that we could use most of them for condition monitoring was to walk to the monitors (sometimes several times per day) and write down the readings on paper log sheets on a clipboard. Even the most critical TSI-related signals were only captured as paper hardcopy on various strip chart recorders. Needless to say, those old-fashioned methods of trending were much more time-consuming than modern digital methods.

All of the monitor systems described in this issue use digital communications to store data samples, and software to facilitate condition monitoring and diagnostic analysis. Several of the articles show graphic examples of how our various data plots contributed to the successful diagnosis and resolution of developing machinery problems.

I must admit that I felt a brief moment of horror the first time that I saw the "interesting" Average Shaft Centerline plot on page 74. Hopefully, you will never experience such a moment with one of your own machines. But if you do, I hope that you will take appropriate action and enjoy a happy outcome similar to the example in our case history.

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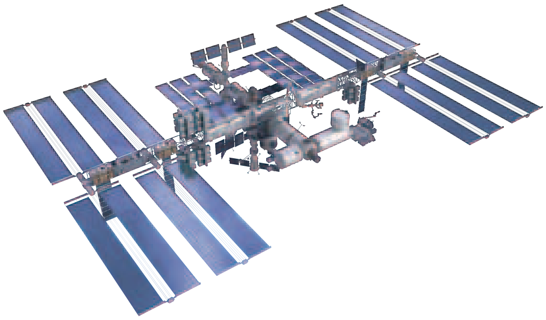

Cheers!
Gary

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Changing of the Guard

In keeping with local tradition, the Bently Nevada team gathered in Minden's Ferris Park to bid farewell to **Jeff Schnitzer**, who has served as our General Manager for the past six years, and to welcome his replacement, **Art Eunson**.

Schnitzer, with his family, will be relocating to Plano, Texas to be the new President and CEO for GE's newly-acquired Lineage Power business. "I have learned a lot during my time with the Bently Nevada team," he said, "and I will always remember my time here with great fondness."

"JEFF'S PASSION AND LEADERSHIP WILL TRULY BE MISSED," SAID MCS CEO, BRIAN PALMER. "HE HAS BEEN KEY TO THE PROFITABLE GROWTH OF BENTLY NEVADA AND A STRONG LEADER IN THE MINDEN COMMUNITY."

Eunson comes to us from GE's Energy Services, where he was responsible for delivering customer value in the US North Region. "Jeff and the Bently team have created a legacy of great products, great people, and a customer first attitude," he said, "and my goal is to build on that as we take Bently forward into the future – all while enjoying some great mountain biking, skiing, and other outdoor activities with my family here in the west."

"ART BRINGS TO THIS ROLE A KEEN EXPERTISE IN THE ENERGY INDUSTRY, FROM BOTH AN ENGINEERING AND A SERVICES PERSPECTIVE," ADDED PALMER. "WE ARE LOOKING FORWARD TO GREAT THINGS FROM HIM."

[We send Jeff on his way with the familiar mariners' blessing, "Fair winds and following seas." And we extend a hearty "Welcome aboard!" to Art. Watch for an interview with Art in the next issue of ORBIT – Editor]

"Sealing the deal" with a handshake, Jeff Schnitzer (left) welcomes Art Eunson to Minden.

Commtest* Joins Bently Nevada* Product Line

Recently, GE announced the purchase of certain assets of Commtest, a provider and designer of machinery health information systems. GE Energy's Bently Nevada product line will incorporate Commtest products into its portfolio and enhance an already robust lineup. Bently Nevada provides machinery protection and condition monitoring for refineries, petrochemical plants, power plants and wind farms. With more than 50 years of experience, Bently Nevada has built a reputation for improving the reliability and performance of critical production assets like turbines, compressors, motors and generators.

As a major component of predictive maintenance, condition monitoring is essential to increase asset longevity. Through condition monitoring, plant managers constantly receive data that provides input about the health of their machinery. For example, by knowing the vibration behavior and temperature of certain assets, managers can make strategic decisions about preventative maintenance to avoid asset fatigue, breakdown and failure. This is especially important in critical applications where failed assets potentially cost hundreds of thousands of dollars a day in lost production revenue and increased operating and maintenance costs.

"The acquisition of certain Commtest products allows us to significantly upgrade our portable vibration data collection and analysis capabilities," explained Art Eunson, general manager for GE's Bently Nevada product line. "Bently has an extensive portfolio of continuous monitoring solutions, sensors and transducers, software and supporting diagnostic & installation services, but the Commtest acquisition will help us bring our customers a more integrated offering that takes into account the health of the entire plant."

Commtest is based in Christchurch, New Zealand, and primarily focuses on producing vibration analysis and monitoring equipment – including portable vibration monitoring products that offer ease-of-use, cost-effectiveness and up-to-the-minute data collection. The acquisition of Commtest provides GE customers the benefits of highly reliable and accurate machinery condition monitoring for the total plant.

"With any acquisition, we look for companies and products that have a natural fit and will enhance the solutions we are currently offering," Eunson noted. "The vibration and monitoring equipment provided by Commtest elevates the Bently offering."

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Reference: [Press Release] GE Acquires Commtest, Enhances Bently Nevada Condition Monitoring Portfolio. MINDEN, NEVADA, USA —August 19, 2011.

[We will be providing updates on the Commtest products – and how they integrate with the Bently Nevada Asset Condition Monitoring product line – in future issues of Orbit. –Editor]

ADRE* Goes to School

GE Donates ADRE system to Virginia Tech

John G. Winterton, North Region Bently Nevada Technical Leader, recently travelled to Blacksburg, Virginia to deliver an ADRE 408 Digital Signal Processing instrument (DSPi) and associated Sxp software that GE donated to Virginia Polytechnic Institute and State University. The university, also known as Virginia Tech, is one of the premier educational institutions in the United States teaching rotordynamics related curricula.

The 408 DSPi will specifically be used in the Engineering School Mechanical Engineering Department by Dr. Gordon Kirk, who has been at the institution since 1985 and a full Professor since 1991. Dr. Kirk teaches courses in Dynamic Systems, Vibrations, Engineering Design & Projects, and Introduction to Rotor Dynamics.

His undergraduate and graduate students are heavily involved in both analytical and experimental research of rotating machinery. To date, he has supervised 22 Master Degree students and 6 PhD students. Their major research work continues to be Computational Fluid Dynamics (CFD) Analysis of Labyrinth Seals, Experimental Evaluation of Turbocharger Stability (Figure 2) and Thermal Instability Design Analysis involving the Morton Effect.

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Figure 1: The new ADRE system is an upgrade from two old Bently Nevada* Digital Vector Filter 3 units (blue boxes on the top shelf), and an ADRE 208 Data Acquisition Interface Unit (DAIU) at the left end of the lower shelf.

Figure 2: Overhung turbocharger rotor is instrumented with XY proximity transducers and a phase reference/speed sensor.

It's a very **EXCITING TIME** to be leading the Bently Nevada Monitors business. Looking back at the work we've done, the **MILESTONES** we've achieved and the **PROBLEMS WE'VE SOLVED** over the last few years it's hard to imagine that there is still so much work to do to get to what we at Bently would consider complete **"ASSET CONDITION MONITORING."**

In this issue, we've asked each member of my team to author an article about some current developments in their respective product lines. We'd like to give the readers a chance to see how we use our 300 Design Engineers at Bently Nevada to use technology and innovation to solve real customer problems and then build that knowledge into our Monitoring platforms.

For instance, today as I write this article, Bently Nevada 3500 series Monitoring systems are monitoring over 1 million points worldwide. As this product line continues to evolve over the years, how many of you knew that we have redesigned the internal hardware and embedded firmware? If we've done our jobs correctly as Engineers, then most people should not have realized it. This is because of our commitment to our customer and the investment they made in our business. Our redesigns on flagship products are meant to be as painless to those of you who count on our products as possible. In this example, our 3500 system redesign was backwards compatible. With very few exceptions, cards bought today with the latest technology built in, can be placed in any 3500 rack.

Bently Nevada invests tens of millions of dollars every year in Engineering and Research to make sure that most innovative technology is delivered directly from our factory in Minden, NV, USA to each and every customer.

I hope you enjoy a look into our products from the people directly responsible for them.

Landon Boyer
Product Line Manager
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THE 3500 SERIES Machinery Protection System

Landon Boyer
Acting Product Manager
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At Bently Nevada, our philosophy is to continually enhance our flagship products without punishing our valued customers. One example of how we are doing this is by keeping the same form factor in our 3500 system and making sure that new monitors are backwards compatible with the 3500 chassis. In this way, our customers can extend the life of the investment they made in the 3500 product line and continue to take advantage of the most advanced technology the industry has to offer. In other words, if a customer only wants the increased functionality in a single card, they can replace only that card. In many cases, they can upgrade the monitor simply by installing the latest firmware.

We are continuously improving the 3500 system. Last year, we invested over 5 million dollars in this product line alone. As technology has evolved, we have completely reworked the product circuitry to take advantage of the advancements. So even though the system looks the same on the outside, it has recently progressed to its third generation on the inside (Figure 1). Along with hardware upgrades, firmware enhancements are also a very regular occurrence.

There are more than 100,000 Bently Nevada protection racks in the world today, and each one of the associated customers has unique needs and requests. We take all of them very seriously and we learn more from every inquiry. As we continue to learn and grow in our knowledge of machinery, it is our duty to take what we know and update our products to reflect our new understanding.

Our ongoing investment in technology and the subtle way that we have introduced these improvements into the market has presented some unique challenges. Many industry professionals don't realize that the 3500 monitor they purchased in 1996 is internally different from what is shipping today. It becomes a marketing and sales task to individually explain each and every function and improvement as it is developed.

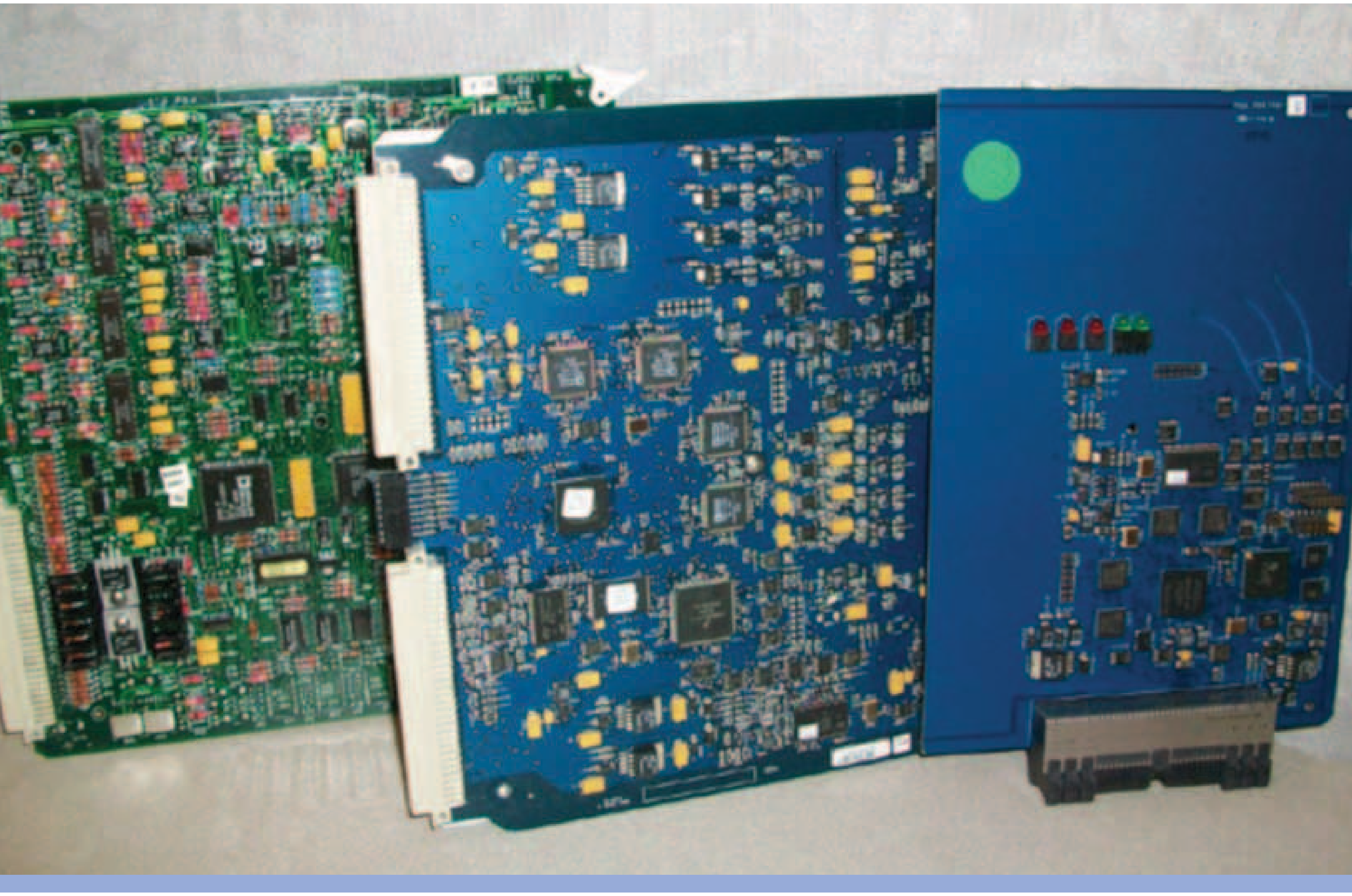
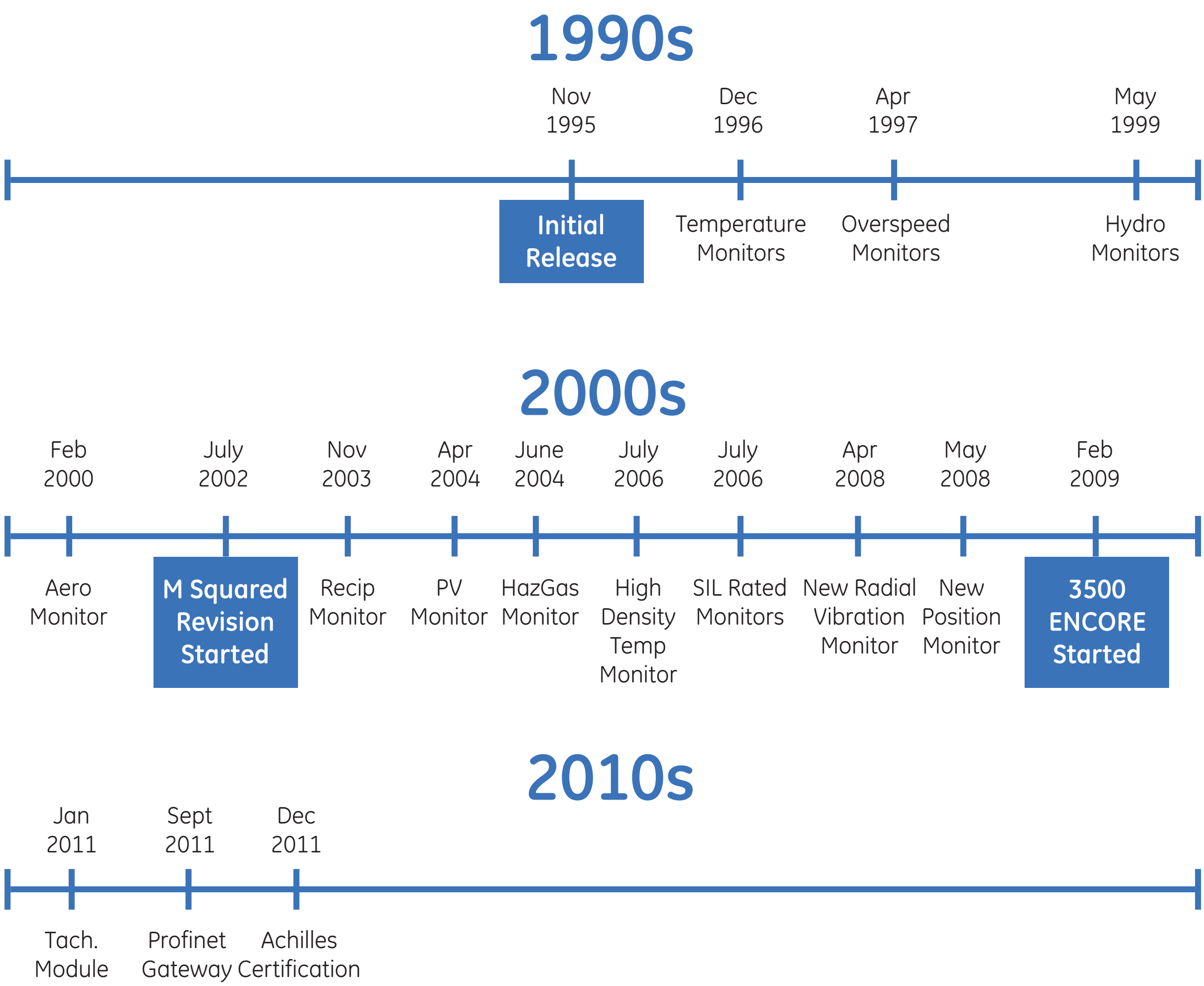


Figure 1: This photo shows the progression of 3500 circuit boards from the 1995 vintage board (green board on the left) to the 2002 vintage board (center) and finally to the equivalent board that we are manufacturing today (right). Due to the very small dimensions of modern electronic components, the third generation circuitry takes up much less space than the original design. Note: The blue color of the second and third generation circuit boards indicates that they were manufactured to comply with the Restriction of Hazardous Substances (RoHS) Directive. The solder that we use for these boards is completely lead-free.

To give you an idea of how this evolution occurred in the past, I've enclosed a timeline of the features as they were developed and included some things we are currently working on for the near term.

The three generations of electrical boards in these timelines are indicated with highlighted blocks. These three revisions are the most intensive as they result in the internal cards being extensively "renovated" with the most current technology available. In this way we can assure our customers that when they purchase a 3500 System, they are always investing in the technology that will deliver value for years to come.



"Many industry professionals **don't realize** that the 3500 monitor they purchased in 1996 is **internally different** from what is shipping today."

Historical Timeline

The M-Squared revision updated the monitor backplane to accommodate the internal Transient Data Interface (TDI) card, which took the place of the external TDXnet* communication processor. The 3500 ENCORE* project created next-generation monitors for retrofit into existing 3300 racks. The technology upgrades that we developed for the ENCORE modules are now being implemented in the standard 3500 system.

Current Timeline

Without giving away any "trade secrets," I can mention a few things that we are working on currently, that you will see on the market very shortly.

- **Tachometer Module:** The 3500 tachometer module is currently being enhanced with the latest technology, as shown in Figure 1.
- **PROFINET® Gateway:** Allows a 3500 system to communicate via PROFINET, which is an open industrial Ethernet standard that is used very widely in process automation systems.
- **Achilles Certification:** Implements standards for industrial cyber security to improve the reliability of critical processes.

Although I am not showing the current timeline beyond 2011, our Multi-Generational Product Plan (MGPP) and corresponding developments currently continue into 2015. In other words, we already know the features we'd like to add in 2015 and have estimated the components we'd like to use to make those plans a reality. As we learn more, the MGPP will continue to grow.

3500 ENCORE

This is the third generation shown in the timeline. Many of you have heard of the new 3500 ENCORE series monitors that we developed in the past year. The concept was developed from the same vision that we have for our standard 3500 product line. That is, "How do we make it painless for existing customers to take advantage of new technology?"

The 3500 ENCORE product is a 3500 board based on the newest technology highlighted above, but in a form factor that allows it to be used in a 3300 chassis. With the larger form factor we were able to include an integral color display for local indication of bargraphs and alarms. This allows customers to extend the life of their investment in the Bently Nevada 3300 system while obtaining the benefits of the latest digital technology. For more information on the 3500 ENCORE product, please visit www.3500ENCORE.com.

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ADAPT*.wind

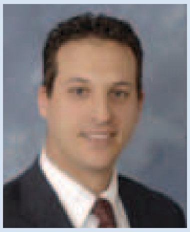
The ADAPT.wind platform was first developed in 2008 with the goal of providing powerful condition monitoring capabilities for all types of wind turbines. Since the initial release, and over the past three years, we focused on the basics: data and fundamental scientific analysis. Through Failure Modes and Effects Analyses (FMEAs), we have gathered data from hundreds of turbines, refined our existing algorithms, patented several new ones, and put that knowledge back into the product. The result is Release 1.3 of the ADAPT.wind system. This article talks about the ADAPT.wind solution at a high level, discussing several of its unique features.

Synchronous Sampling

In Release 1.3 of the ADAPT.wind software and 3701 firmware, all waveform sampling is done synchronous to shaft rotation. A wind turbine is a spectrally rich environment, and the use of synchronous sampling without tracking anti-aliasing filtering can lead to unwanted frequency components aliasing into the passband. For this reason, the ADAPT.wind solution tracks all shaft speeds and applies anti-aliasing filters to reduce the likelihood of irrelevant spectral components. The synchronous sampling rate varies, depending on the required span and spectral resolution. It can vary from 8X to 256X.

Another added benefit of synchronous sampling on low- and variable-speed machines is improved spectral frequency resolution and accuracy. Figure 1 details a spectrum from an accelerometer on the planetary stage of a gearbox. This spectrum was processed from a waveform record that was sampled asynchronously.

Driven by the turbine rotor, the planetary carrier has a typical rotational speed of about 18 rpm, and can vary between 0 rpm and roughly 20 rpm. Spectral waveforms in ADAPT.wind are typically 8192 samples. This spectrum was acquired in 320ms at a sample rate of 25,600 samples per second. With a turbine speed of 18 rpm, it takes



Adam Weiss
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Release 1.3

approximately 3.33 seconds for the carrier to make one full revolution. The 320ms waveform represents only a tenth of a full revolution, making the likelihood of detecting a gear or bearing issue with this sampling scheme very low.

The mathematics of sampling theory dictate that spectral resolution is proportional to sample time. That means the longer you sample, the better the spectral resolution you can achieve. Since wind turbines are extremely low-speed, you must sample for a long time to get enough spectral resolution to resolve all possible faults.

However, due to the variable speed nature of the turbine, it is nearly impossible to sample for a time long enough to allow the required spectral resolution without having the wind speed change. When the speed changes during an asynchronous acquisition, frequency smearing in the spectrum is the result.

To minimize the amount of spectral smearing, you can decrease the sample time (to reduce the likelihood of a change in shaft speed) as in Figure 1, or you can sample synchronously as shown in Figure 2.

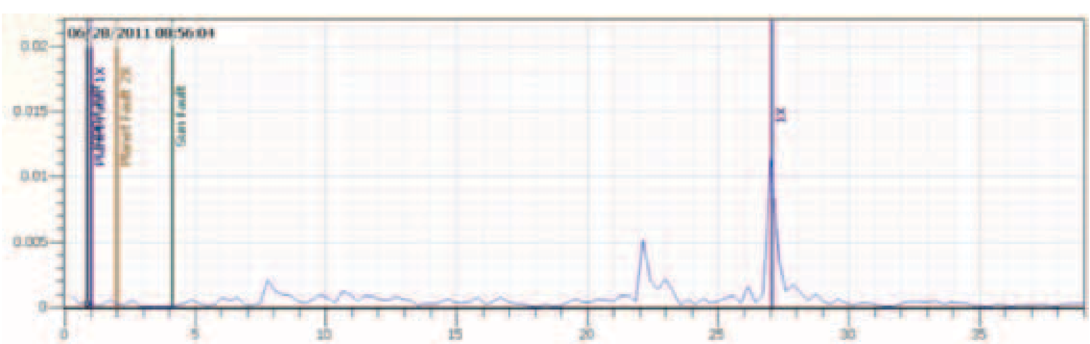

Figure 1: Asynchronously-Sampled Spectrum.

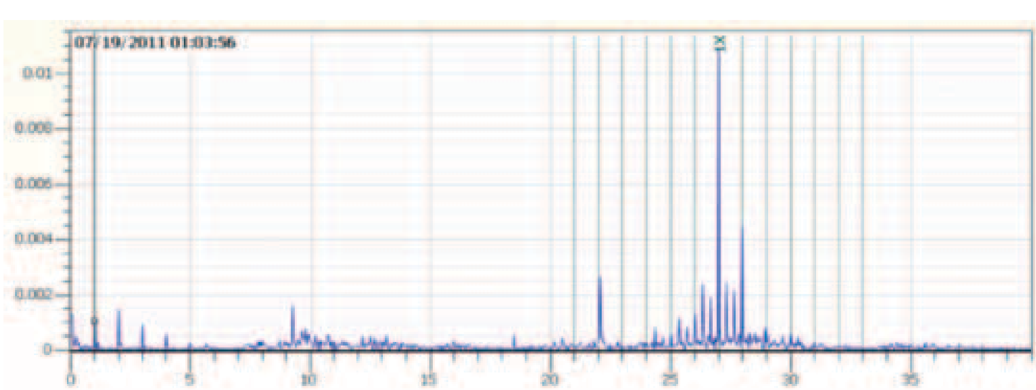

Figure 2: Synchronously-Sampled Spectrum for same machine conditions as in Figure 1.

The waveform used to generate the spectrum in Figure 2 is also an 8192 sample waveform. However, it was sampled with 1024 samples per revolution over 8 revolutions. At 18 rpm, this means the sample time is over 26 seconds, or over 80 times as long as in Figure 1. You can immediately notice the increase in spectral resolution and the decrease in smearing. Features that were not previously visible are now clear. This is the advantage of synchronous sampling, and this is how the ADAPT.wind system acquires waveform data used in its algorithms.

Sideband Energy Ratio

A new measurement in Release 1.3 is the Sideband Energy Ratio (SER). This is a patent-pending algorithm used for gear mesh fault detection. It relies heavily on the improved spectral resolution as previously described.

Every gear mesh produces a fundamental mesh frequency that corresponds to the number of teeth and the shaft speeds. In the simple case of a parallel helical stage, it can be expressed as in Equation 1:

$$f_{mesh} = \left| \frac{\text{pinion\_shaft\_speed} \times N_{pinion}}{60} \right| \qquad (1)$$

where Npinion is the number of teeth on the pinion, and pinion shaft speed is in units of rpm.

Note: In typical wind turbine gearboxes, three separate speed-increasing stages are used. This means that three separate gear mesh frequencies may be detectable for the gearbox.

This gear mesh frequency, as well as several of its harmonics, are visible in the spectrum of both healthy and faulty gearboxes. As a fault develops, say a cracked tooth, that fault engages in the gear mesh and will modulate the amplitude of the gear mesh frequency. This modulation results in sidebands in the frequency domain. The spacing of the sidebands is equal to the modulation frequency, which in turn, is equal to the rotating speed of the shaft on which the fault occurs.

For example, if a gear pinion develops a broken tooth, then the spectrum will show the mesh frequency with sidebands spaced at 1X of the pinion shaft speed. The sidebands will have multiple harmonics as well, both above and below the center frequency.

SER is a simple ratio of the sum of the sideband energy to the energy of the mesh frequency. When the gear mesh is healthy, there will be little amplitude modulation, and an absence of sideband energy. The numerator of the ratio will be small, and the resulting ratio will be small. As a fault develops, sidebands will increase in energy, increasing the value of the ratio. The calculated SER variable can be trended, as in Figure 3, and alarm setpoints can be established to warn of increasing values of SER.

Figure 4 shows a synchronous spectrum, with orders of rotation for the high speed shaft on the x-axis, from 0 to 100X. Overlaid on the spectrum are the fault frequencies associated with three SER measurements: one for each of the first three harmonics of the gear mesh associated with the High Speed Stage.

From this spectrum, and particularly the fault frequencies shown by the colored overlays, the SER is calculated as in Equation 2.

$$SER = \left| \frac{\sum_{i=1}^{6} \text{Sideband Amplitude}_i}{\text{Center mesh frequency amplitude}} \right| \qquad (2)$$

Figure 5 zooms in on the area of the spectrum around the fundamental gear mesh fault frequency. It shows the mesh frequency and sidebands (gear sidebands of a parallel mesh) for a single SER fault frequency group. As the energy in the sidebands (at the overlaid sets of sideband lines) increases relative to the 1X line, the calculated SER will increase.

Sideband Energy Ratio has been used successfully to detect several gear faults to date. For a more complete description of SER and some case history examples, watch for more in-depth articles in upcoming issues of ORBIT magazine.

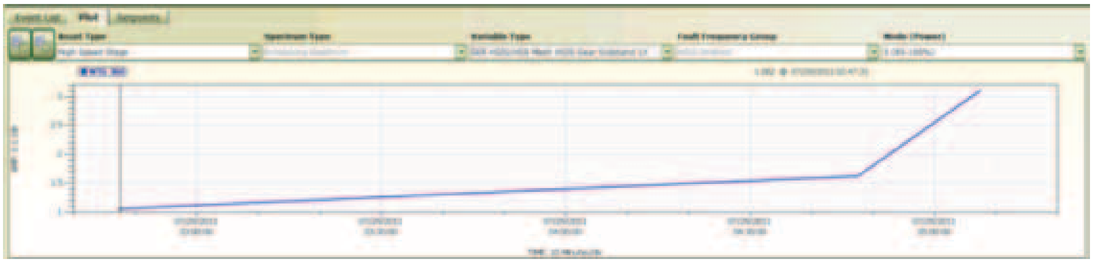

Figure 3: Trend of an SER variable. Alarm setpoints can be configured for SER.

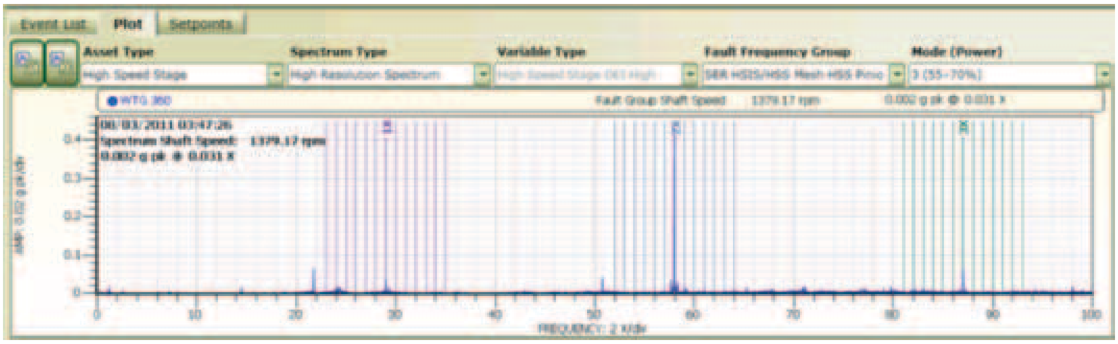

Figure 4: This high resolution spectrum shows SER "Fault Frequency Groups" for the first three harmonics of gear mesh frequency for the High Speed Stage.

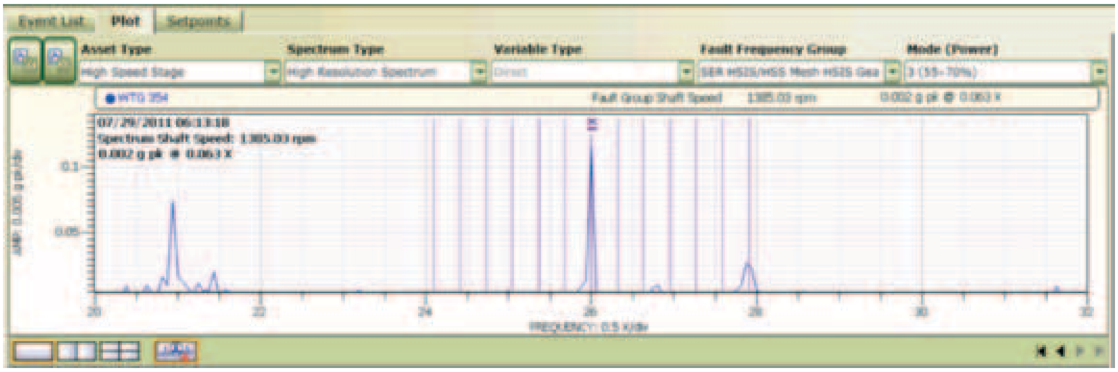

Figure 5: This example shows a Gear Mesh Frequency component at 26X (since the gear in question has 26 teeth). Observe that there is also a small sideband at about 27.9X.

OPC DA and A&E

With Release 1.3, ADAPT.wind is fully compliant with the OPC Foundation® specifications for Data Access (DA) version 3.00 and Alarms & Events (A&E) version 1.02. This allows users access to all static data and alarms generated by the ADAPT.wind system. Dynamic (waveform) data is available for export via CSV (comma separated value) format.

The typical use for exporting the static data via OPC is to store it in a site historian, so that it can be viewed and evaluated along with other process parameters such as wind speed, generator electrical load, etc. The non-proprietary CSV format for exported waveform records allows them to be studied in additional detail by using various spreadsheet and mathematical analysis programs.

Summary

Release 1.3 of ADAPT.wind offers several improvements over previous versions. The most notable features in this release include synchronous sampling, Sideband Energy Ratio (SER) calculation, and OPC data export. Bently Nevada is committed to exploring the science of vibration on wind turbines, and continues to invest in Research & Development (R&D). As our monitored fleet expands, we use this wealth of data to feed our R&D and provide continuous improvement to the ADAPT.wind offering. As mentioned, watch for case histories in upcoming ORBIT articles. ■

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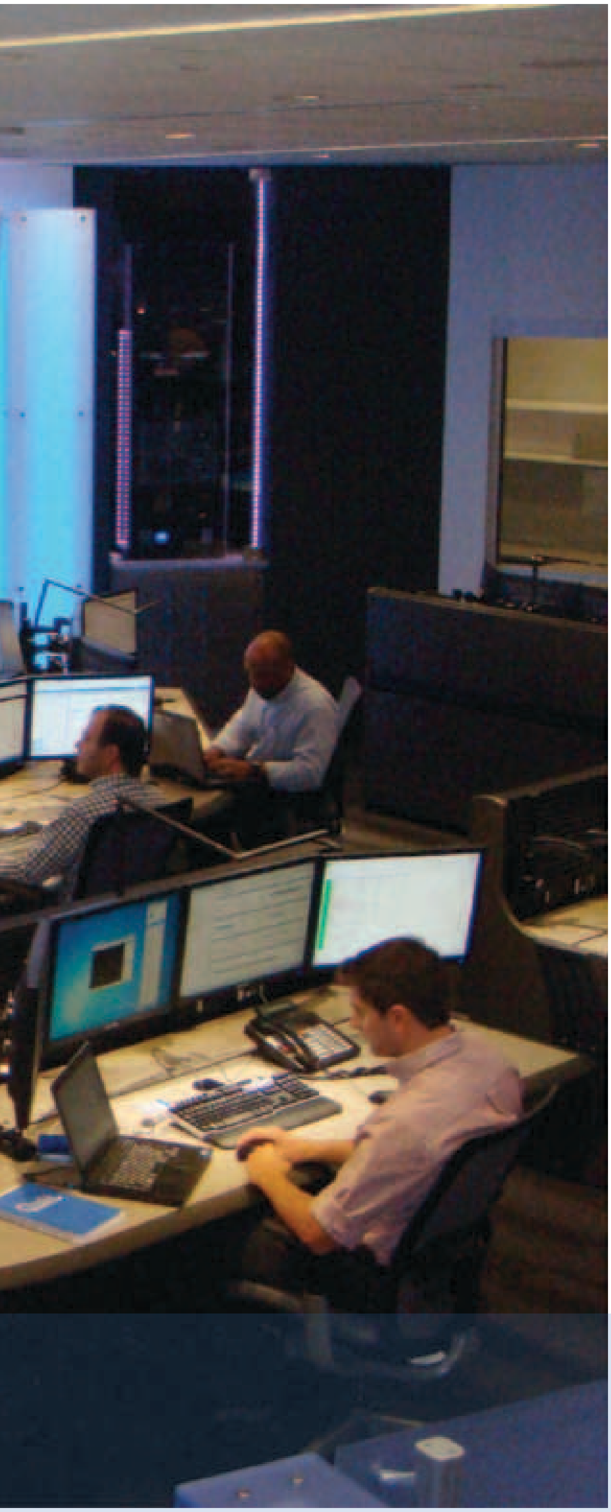
OPC Foundation is a registered trademark owned by OPC Foundation, and used for computer software interoperability Accreditation Services.

> "The ADAPT.wind solution is critical to monitoring our drivetrain health. The ability to detect defects at an early stage gives us options. Often, we can continue to run the turbine and replace the part when convenient, either during the next maintenance cycle or during low winds. It has become an integral tool in the effective operation of our wind parks."
>
> **— Chris Dannehy**
>
> **GE Wind RMC Team Leader**

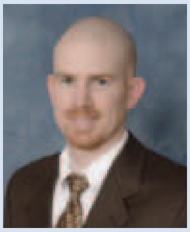
Figure 1: Dedicated M&D Engineers monitor our power generation customers' machines around the clock.



GE Energy Monitoring & Diagnostics

Heavy Duty Power Generation

The goal of the GE Monitoring and Diagnostics (M&D) Center (Figure 1) is to maximize the availability and performance of our customer's power generation assets. The M&D system incorporates an intelligent architecture with powerful local and central capabilities to accomplish these goals. Complementing the system, the M&D team holds strong experience in the operation of the equipment being monitored. Through experiential learning, a suite of targeted algorithms have been developed to enable exception-based monitoring and address dozens of unique equipment failure modes.



Craig Foster
Engineering Manager
M&D Operations
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In collecting over 20,000 turbine operating hours of data every day across a huge variety of operating conditions the M&D Center provides a wealth of data not only for immediate response to operating issues, but for product development as well. This data is also being used to provide our customers with fleet benchmarking capabilities enabling better decision making when it comes to maintenance and performance improvements for their plants.

These benchmarking capabilities are available on a variety of parameters from the simple counters such as running hours and number of unit starts, to the more complex calculations such as ISO corrected output and heat rate. A simple example of fleet benchmarking capability is provided in Figure 2, showing how two units for a particular customer (bold blue dots) compare to the overall fleet (light-colored dots) in terms of fired hours and fired starts.

The primary focus of the M&D Center in Atlanta, Georgia, USA is on GE heavy duty power generation equipment. Considering the coupled driver (turbine) and driven machine (generator) as an individual unit, the M&D Center monitors over 1400 units around the world, with over 1150 gas turbine generator sets and over 250 steam turbine generator sets…that's over 200 GW of capacity!

To accomplish this monitoring, the operations team is broken into two levels of support. The first tier of support is the frontline which is made up of three shifts working 24 hours a day, 7 days a week in the center and acting quickly as first responders to any issues. The second tier of support is a group of lead engineers with greater depth in the various disciplines across gas turbine, steam turbine and generator operations.

These lead engineers issue the specific recommendations back to the customer for fastest remediation of operating issues. The group of lead engineers is made up of a core team in the USA as well as regional resources in Europe and India with plans to add additional regional resources in the near future. The operations team is also supported by sustaining, analytics, applications and product development engineering teams to provide complete monitoring and diagnostics support for our customers. Refer to Figure 3 to see how the M&D center has grown since inception in 1996.

The M&D system is comprised of three high level components. First, the local sub-system (also referred to as the On-site Monitor or OSM) at plant level collects and archives site data from the turbine control system as well as other instrumentation – including the Bently Nevada* 3300, 3500 or 3701 (ADAPT*) platforms.

Note: Bently Nevada 3300, 3500 and ADAPT systems have been used widely to provide functions such as machinery protection trips for the monitored gas turbine generator units, as well as to collect condition monitoring data for trending. By correlating vibration data collected by the Bently Nevada instrumentation with data collected through the unit control systems, the M&D Center Engineers are able to perform more accurate diagnoses, and to make them with higher certainty than otherwise possible.

The second high level component is a secure network which transmits data to the central sub-system. And finally the central sub-system which hosts the fleet data historian, the central calculation engine, the asset model, and the data visualization tool sets. The central sub-system is anchored by Proficy® Historian from GE Intelligent Platforms and is capable of archival and distribution of large volumes of data. Refer to Figure 4 for a high level architecture diagram.

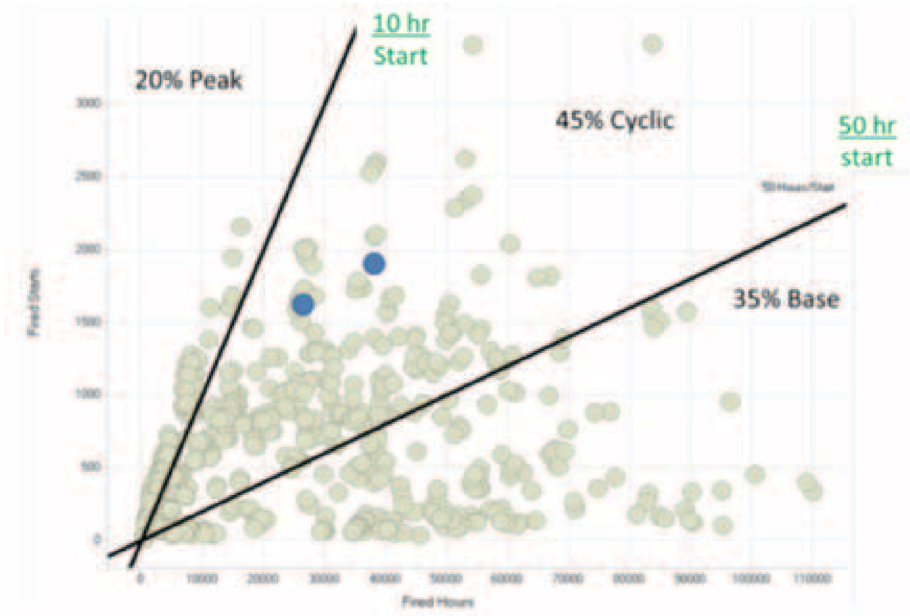

Figure 2: 2010 GE 7FA Gas Turbine Fleet Data

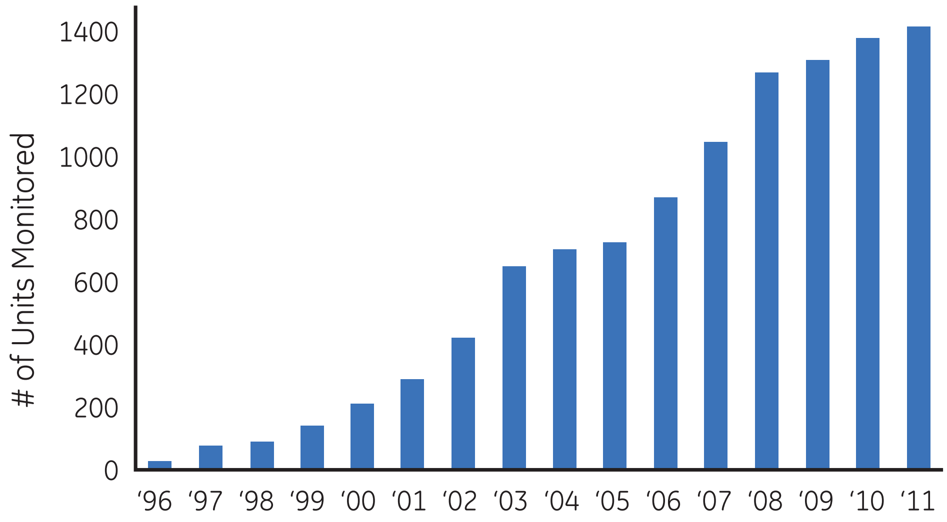

Figure 3: The M&D Center now monitors 1,419 Units in 57 countries.

Historically speaking, the M&D Center has always had a strong focus on asset availability, and this focus continues today. Over the past year, the M&D center addressed over 20,000 operational alarms and responded to over 4500 gas turbine trips helping our customers stay on-line. More than 25 detailed work-instruction covering more than 50 unique failure mechanisms have been developed over the past several years. Refer to Figure 5 to get a sense of how the M&D Center uses the detailed maps to address customer issues.

In order to help quantify how the M&D Center impacts customers in resolving issues, the term "save" has been defined as an event which contains the following characteristics:

1) data signature available in M&D collected data

2) analysis complete to verify operational issue

3) specific action recommended to site for remediation

4) site action implemented

5) connection to financial benefit for customer (typically reduction in hardware damage or subsequent trips avoided)

Anomaly Detection

A nice example of a save is outlined in Figures 6 and 7. In this example, the detected failure mode was the presence of liquid distillates in the gas fuel of a GE 7FA gas turbine operating in North America during the winter of 2010-2011.

Early signatures were present in the combustion dynamics data as well as the exhaust thermocouple data. The M&D center quickly identified this signature and recommended a specific action plan for the site to clean the liquid distillates from the fuel system and return the unit to service. ■

*Denotes a trademark of Bently Nevada, Inc., a wholly owned subsidiary of General Electric Company.

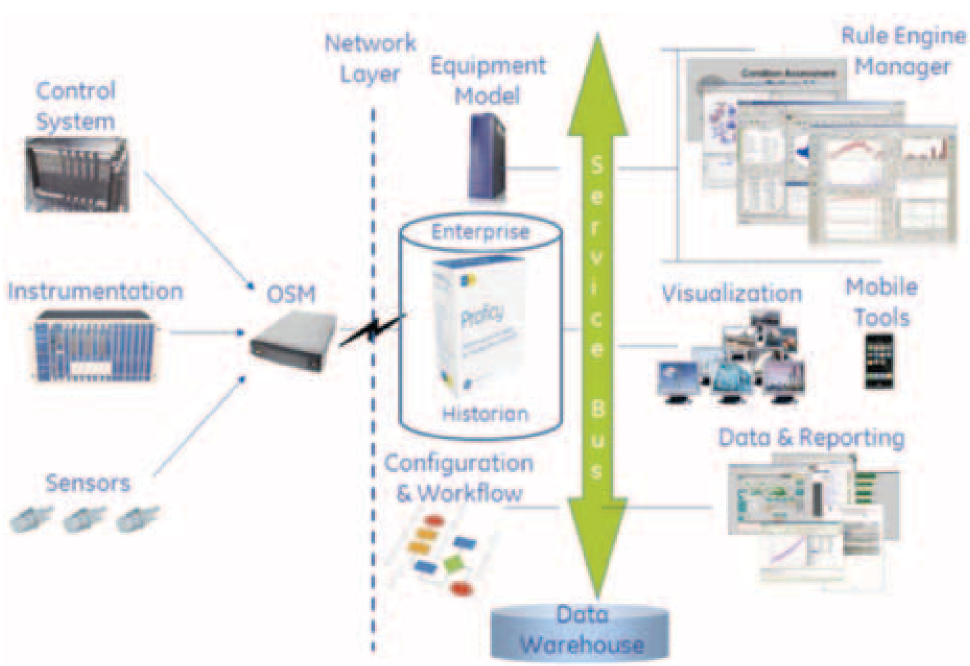

Figure 4: M&D Center high-level architecture diagram. Plant process and vibration information is collected by the OnSite Monitor (OSM) and then communicated to the M&D Center.

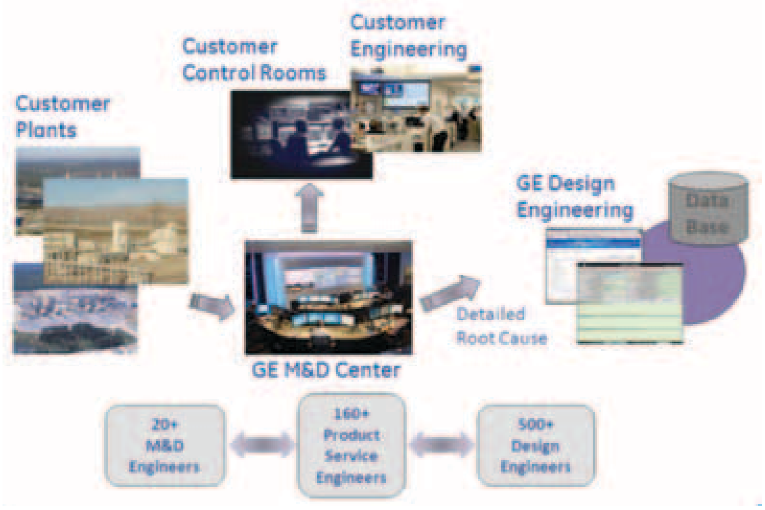

Figure 5: This graphic maps out how information flows through the established processes.

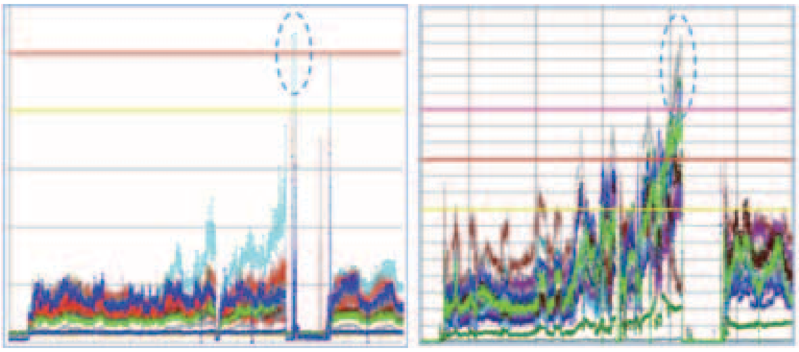

Figure 6: Trend plot of dynamic pressure signals in the "Blow-out" frequency band (left) and Medium frequency band (right) for upper combustor cans. The y-axis is signal amplitude, and the x-axis is time, while the different colors represent data from different sensors. The time scale for both plots is the same, and it is roughly 11 days.

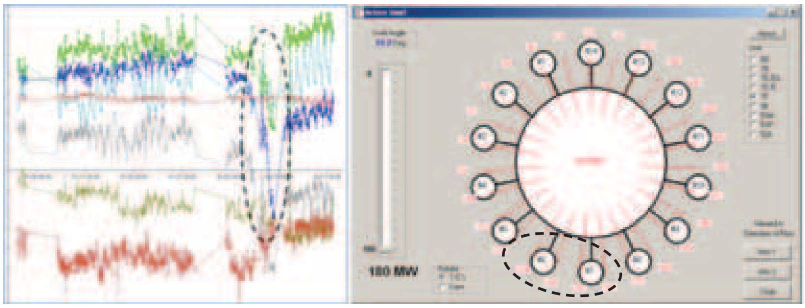

Figure 7: Formation of a "cold spot" was observed at the lower combustion cans. The left plot shows trends of exhaust gas temperature (EGT) over time, indicating the difference or "delta" from the mean temperature. The right screen shows the location of EGT sensors relative to the combustor cans.

WHAT'S NEW WITH ADRE*?

INTRODUCED

in the early 1980s as part of the Bently Nevada product line, ADRE is an acronym meaning "Automated Diagnostics for Rotating Equipment." The original system automated the labor-intensive task of processing vibration data through analog tracking filters to plot diagnostic data from live transducer signals or prerecorded magnetic tape.

The ADRE family has evolved through the decades, culminating in the ADRE 408 DSPi (Digital Signal Processing Instrument) and ADRE Sxp software, which are still continuously being improved and updated. Our most recent ADRE update was published in the First Quarter 2007 Orbit issue, where we introduced the Transducer Power Supply Module. Since then, we have made several significant updates, a few of which are summarized on the following pages.


the Orbit
Premier Edition
published by Bently Nevada Corporation
summer 1980
BENTLY NEVADA INTRODUCES ADRE

The first version of ADRE was the headline of the first issue of ORBIT, more than 31 years ago!

Don Marshall
Product Manager
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Impact Testing

This enhancement provides the ability to perform structural analysis. Impact Testing is used to determine the dynamic behavior of mechanical structures by striking the structure with an instrumented hammer and collecting response information from transducers mounted on the structure.

The integration of response information from multiple accelerometers at various points of interest allows for modal analysis (velocity compliance, impedance, and mobility). ADRE SXp software has been upgraded to accommodate the data collection and signal processing required support forced-response frequency analysis. This includes the capability to process Coherence and Transfer Function information, as well as Cross Spectrum and Phase data.

Time Synchronous Averaging (TSA)

With this signal processing technique, instead of averaging a series of spectrum plots together, we average a series of synchronously-sampled time waveform records together before processing them into the frequency domain by using Fast Fourier Transform (FFT) algorithms.

The advantage of this technique is that any vibration components that are not coherent with the Keyphasor* triggering signal are essentially eliminated due to their random characteristics. The TSA process is very useful when analyzing the vibration of a gearbox or other machine that has rotor shafts operating at different speeds from each other.

The averaging process combines up to 512 synchronously-sampled waveform records. Synchronous components that are associated with the shaft that has the Keyphasor transducer are kept, while synchronous components that are associated with the other shaft are attenuated significantly by the averaging process. This process greatly increases the clarity of the resulting spectrum by removing vibration components from the shaft that is not triggering the synchronous collection

One common technique is to collect TSA samples using a temporarily-installed Keyphasor transducer. Such a transducer can be moved from one shaft to another between sampling, in order to collect vibration samples specific to any rotor shaft of interest.

Analog Output Replay Card

The ADRE 408 system has the ability to record raw waveform data as it is processed through the input cards. The digitized data is then stored on the ADRE 408's hard drives. You can play back the data using the internal replay card, and resample it using various data collection and signal processing settings, just as if it were "live" data.

The new analog output replay card allows you to play back recorded data and to export the analog signals to outboard devices through multi-conductor cables (Figure 2). This card does not allow you to recondition the signal. It simply restores the original offset and gain and sends the signal out a buffered output. It continuously outputs all 32 channels of recorded data, through 4 Display Port connectors (corresponding to the data cards) for the signal outputs. Each Display Port has 8 channels.

MODBUS® Data Export

This new feature allows you to export static values (not waveform samples) using industry-standard MODBUS protocol. Any system that communicates over MODBUS can now request specified data from an ADRE system using a standard "registry." One common application is to use an existing System 1* platform to collect additional data from a special test that is being captured by an ADRE system. The test data is then available for correlation with historical data from the existing online condition monitoring system. ADRE data for the following variables can be exported using this method:

- Direct: Unfiltered vibration amplitude
- Average Gap Voltage: DC voltage for proximity transducer signals
- 1X amplitude & phase (filtered vibration)
- 2X amplitude & phase (filtered vibration)
- nX amplitude & phase (filtered vibration)
- Bandpass: Amplitude for specified frequency range

Figure 1: The impact test kit includes the options of impulse hammers of different sizes, several different accelerometers, cables, and various adaptors.

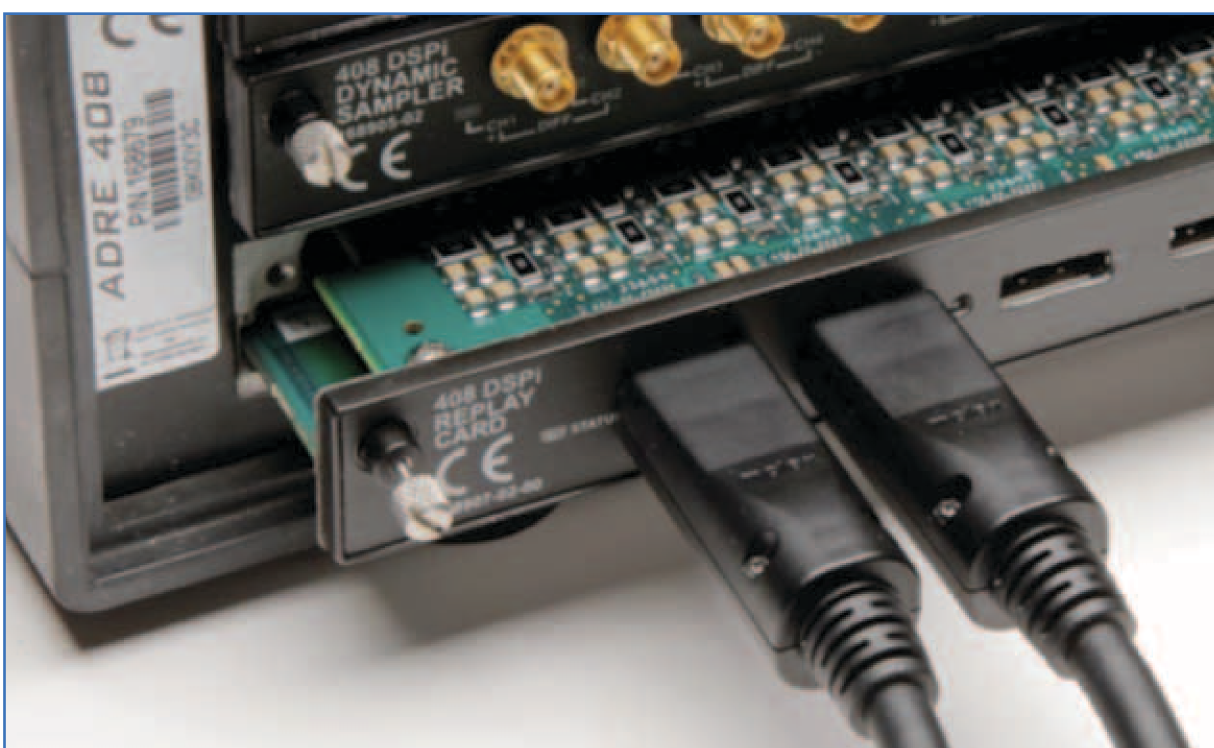


Figure 2: This photo shows the new analog output replay card with two of four cables connected.

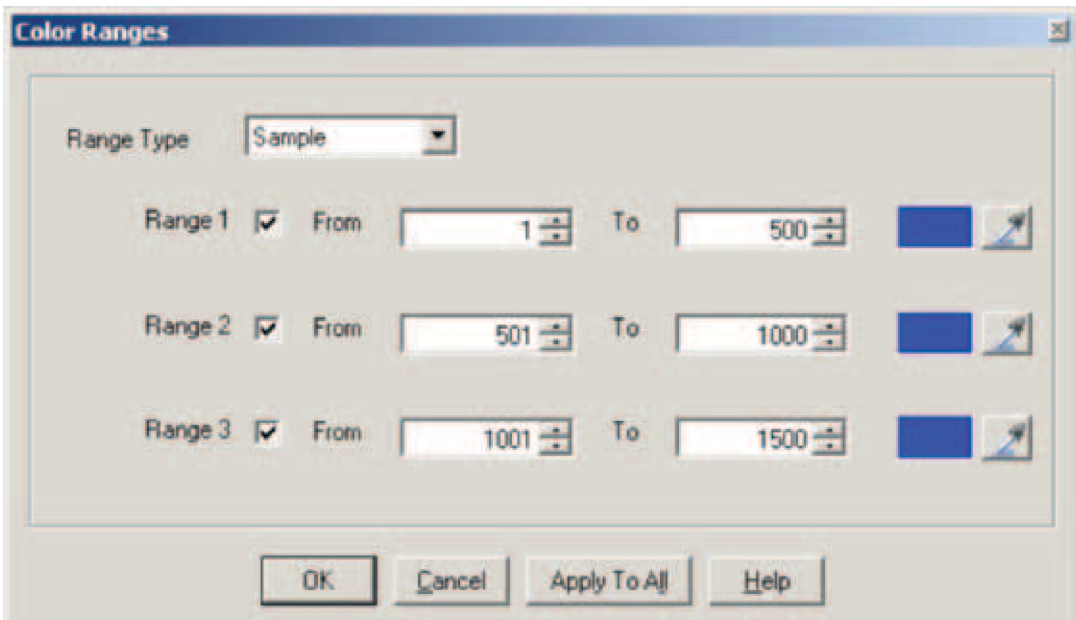


Figure 3: Color Ranges dialog box from Release 2.6. Observe that the From and To boxes only allowed selecting sample ranges by sample number.

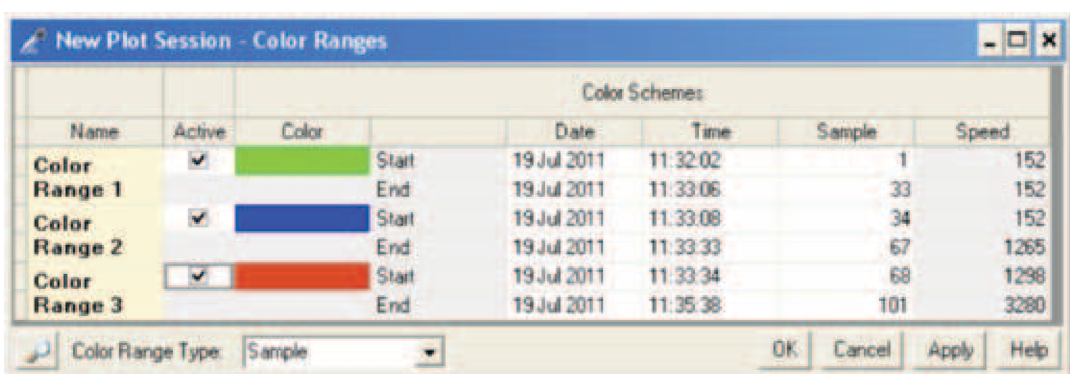


Figure 4: With Release 2.7, it is much simpler to select sample ranges, as dates, times, machine speeds and sample numbers are available within the Color Ranges dialog itself.

- RPM: Machine running speed.
- Time Tag: Year, month, day, hour, minute, second

Enhanced Color Ranges Dialog

The Color Ranges dialog has been updated to make it much easier to use. With the previous software, it was necessary to find data samples in a separate dialog in order to know which sample numbers to select in the Color Ranges dialog (Figure 3).

The new dialog (Figure 4) is "modeless." This means that you can still work with the rest of the Sxp program while you are configuring the color ranges. You no longer need to close the dialog to perform other tasks, and then open it again to adjust color ranges. There are also some easy new ways to access the dialog – from a new button on the plot session window, and from the plot session tree.

Wireless Condition Monitoring Update

The last time we mentioned our wireless monitoring system in ORBIT was back in 2007. Since then, the system has undergone several significant improvements in functionality and capability. The basic goal is still the same – to augment hardwired monitoring systems and portable collection programs with a flexible wireless solution. Release 1.1 includes updates in the following categories, which we will summarize in this short article.

- **External Power**
- **Mounting Options**
- **Signal Processing**
- **Data Collection**
- **Transducer Cables**

Figure 1: Left to Right: Repeater, Wireless Signal Input Module (wSIM), Wireless Gateway, wSIM* with new External Power Module rather than a battery pack.

Figure 2: This photos shows an External Power Module before it is connected to a wSIM or repeater unit.

Figure 3: This photo shows a Vibration Energy Harvester (VEH) with cable for connecting to the optional External Power Module of a wSIM or repeater unit.

External Power

The original wireless system relied on an internal battery pack in the mounting base of each wSIM and repeater unit. Although this design allows extreme flexibility of mounting location, it also includes some potential drawbacks, summarized here:

- **Available Battery Power:** Because the energy stored in a battery is finite, every battery eventually needs to be replaced. There is a tradeoff between maximizing battery life and increasing wireless data rates and signal processing. Also, battery life is shortened by temperature extremes.
- **Hazardous Material:** Lithium thionyl chloride batteries are regulated as "hazardous material" and create a potential disposal issue when they become depleted. Also, these batteries cannot be transported on passenger airplanes. This restriction can introduce shipping delays and additional logistical issues, for new batteries as well as for depleted ones.
- **Maintenance Cost:** There is a labor cost associated with replacing batteries in wSIM and repeater units throughout the plant, as well as a replacement cost for the new batteries and disposal cost for the old ones.

To address these issues, Release 1.1 includes an optional External Power Module, which can be used in the place of the normal battery pack base on a wSIM or repeater module (Figure 2). This module allows the use of an external power supply providing 5 VDC at 0.5 mA.

Another option for external power is the Vibration Energy Harvester (VEH), which is essentially a small linear generator. The VEH uses a resonantly-tuned assembly similar to a moving coil velocity sensor. The VEH generates electrical power when the unit is stimulated by mechanical vibration along the vertical axis at a frequency that is compatible with its tuned design (Figure 3).

Mounting Options

In addition to the stud mount and magnetic mount options that were available with the initial release, the wireless system now includes optional fasteners that are compatible with the widely used Unistrut® mounting system (Figure 4).

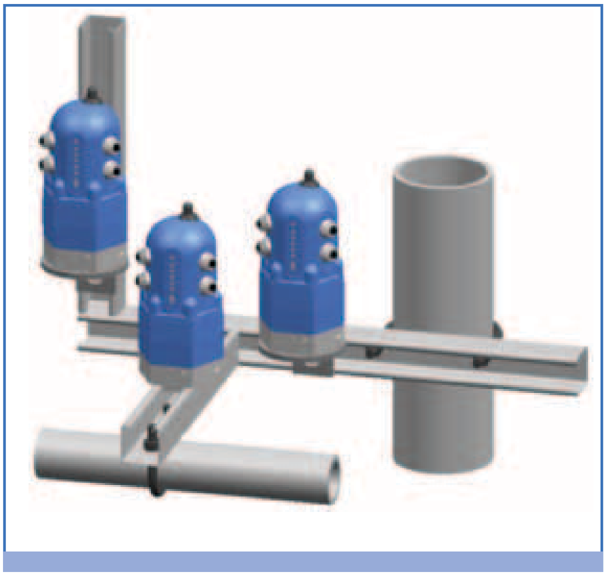


Figure 4: This illustration shows some of the various orientations that wSIM or repeater units can be mounted using standard Unistrut installations.

Signal Processing

Our wireless system now has the capability to perform enveloping processing of acceleration signals. This process demodulates the original high frequency signal to extract meaningful characteristic frequencies that represent symptoms of various machine faults. The demodulation process is widely used to provide early warning of deteriorating condition of rolling element bearings.

[Note: We will describe the Enveloping process in more depth in future Orbit issues —Editor]

Data Collection

Previously, data was only collected based on the selected settings in the System 1* Configuration database. With Release 1.1, you can also manually trigger the collection of a sample whenever you want to take a specific measurement. This feature is very useful if you suspect that an asset may be experiencing unusual conditions, or demonstrating abnormal symptoms.

Release 1.1 also adds the capability to establish data collection intervals shorter than 15 minutes. It is important to remember that the data collection rate configured for a battery-operated wSIM affects the battery life and can cause delayed data collection. Consider the following factors before establishing data collection intervals shorter than 15 minutes:

- **Battery Life:** If the data collection interval is set to less than 15 minutes, it will significantly impact the battery life. If you require fast data collection and the battery maintenance is an issue, consider using an external power source. The software includes a Battery Life Estimates worksheet that will estimate the battery life depending on data collection interval, signal processing configuration, and operating temperature.
- **Available Communication Bandwidth:** A wSIM can be configured in such a way that it exceeds the available bandwidth allocated to transfer the collected data to System 1 DAQ. While configuring a wSIM, consider the collection interval, number of enabled variables, and number of lines on asynchronous waveforms to utilize the available bandwidth. For instance, selecting one minute collection interval for static data with all 4 static variables enabled will disturb any other data collection. To resolve this issue, increase the collection interval to 5 minutes or reduce the number of variables enabled on each channel. The Data Collection worksheet will help you select a valid configuration.
- **Delayed or Skipped Data Collection:** For battery-operated wSIMs, short sample intervals (less than 15 minutes) can lead to delayed data collection cycles and in some cases a scheduled data collection cycle may be skipped altogether. This condition is worsened when the wSIM is used at temperatures below 20 °C. You can use an external power supply to completely avoid this issue. If an external power supply is not a practical option, increase the time between data collection cycles.

Transducer Cables

Before Release 1.1, transducer cables were only available in 2, 4 and 6 meter lengths, without armor. Now, these same cables are available with an armored option. For more installation flexibility, longer cables (10, 15 and 25 meters) are also available, in either armored or unarmored configuration.

*Denotes a trademark of Bently Nevada, Inc., a wholly owned subsidiary of General Electric Company.

The Importance of Setting Gearbox Tooth Combination as Opposed to Nameplate Ratio

At the time John wrote this article, he had been with the Bently Nevada team for 25 years, and was our Senior Technical Manager in the northeast USA. He volunteered to write this particular ADRE* Tip before he retired – which is very appropriate, given his extensive gearbox experience. –Editor

Typically, gearboxes either increase or decrease the speed of the driver output shaft in order to match the requirements of the driven machine. In some instances, one of these two machines will have accommodations for a Keyphasor* transducer, but the other will not. In such a situation, the 408 DSPi can use the gearbox ratio to generate a "derived" Keyphasor signal for the machine that does not have its own Keyphasor transducer.

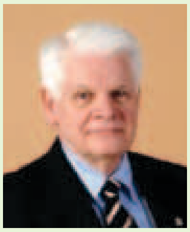
In our example, (Figure 1) the gas turbine – generator machine train had a speed-reducing gearbox with a nameplate ratio of 1.426:1. A physical notch was available on the generator shaft, and a Keyphasor transducer was applied to provide a one event per turn phase reference (and machine speed) signal for the generator. However, the gas turbine driver did not have provisions for triggering a Keyphasor transducer.

Keyphasor Channel Configuration

In order for the 408 DSPi to synthesize a "derived" Keyphasor signal for the gas turbine, it needs to have the ratio of the gear train. In this example, the nameplate ratio was entered in the Events Ratio box in the Keyphasor Channel Configuration dialog (Figure 2).

This procedure seems simple enough, but does it provide useful data for diagnostics? Let us observe some of the gas turbine vibration data associated with the derived Keyphasor signal and see for ourselves.

Our first example is the Bode plot for the vibration measurement from Bearing 2, at the turbine inlet of the gas turbine (Figure 3). At first glance the data may appear reasonable – but more careful examination indicates a strange appearance to the data. One might conclude that the speed was hunting – causing a "smearing" of the data points during the coast-down of the gas turbine.



John Winterton

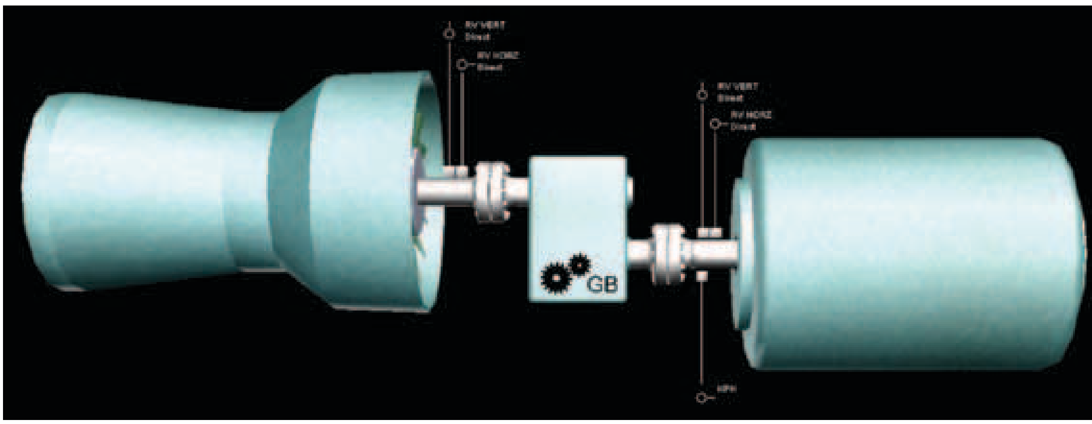


Figure 1: Machine train illustration, showing gas turbine driver (left), speed-reducing gearbox (center) and generator (right). In this example, the generator has a Keyphasor transducer, but the gas turbine does not.

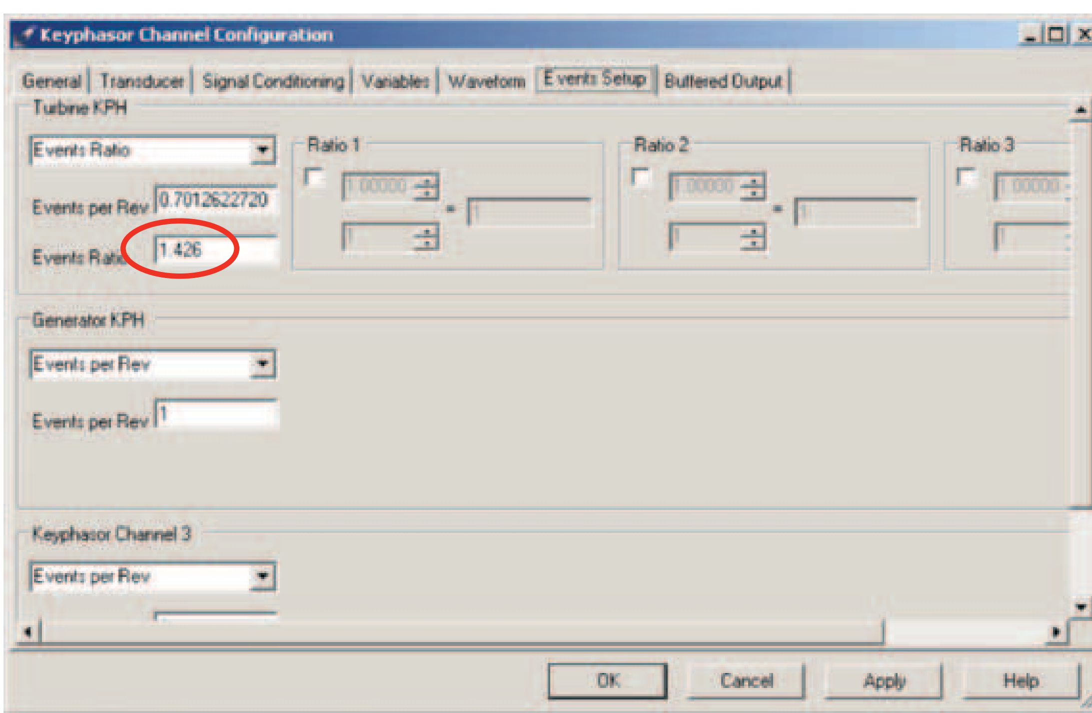


Figure 2: Keyphasor Channel Configuration dialog box in Sxp software, with entry for events ratio of 1.426 (circled). The 408 DSPi will use this ratio – together with the Keyphasor signal from the generator – to produce a derived Keyphasor signal for the gas turbine.

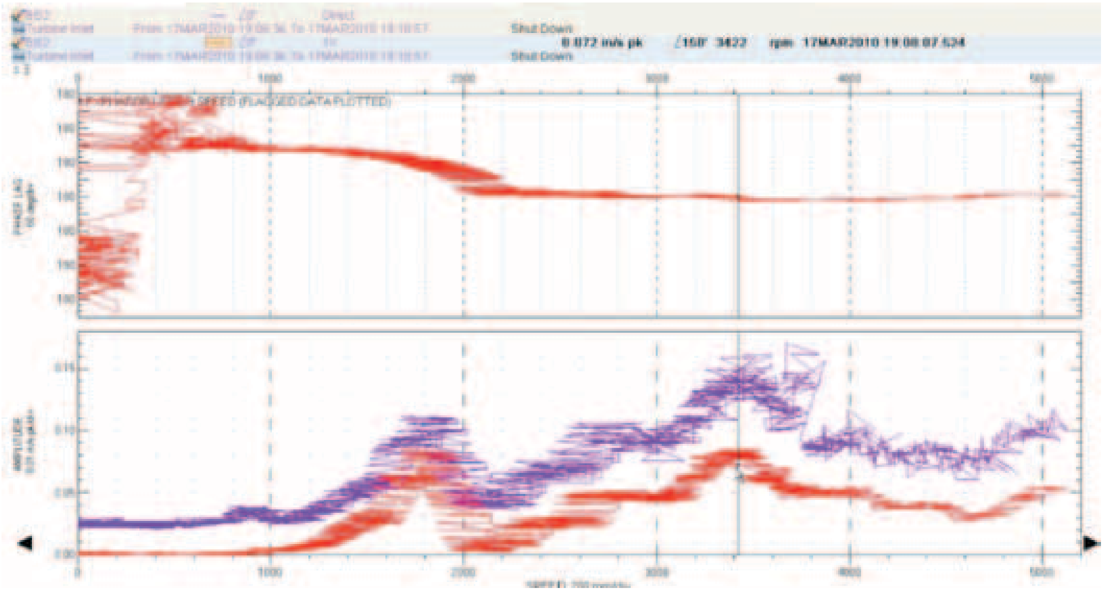


Figure 3: Bode plot. The upper plot shows phase lag, and the lower plot shows vibration amplitude collected during a coast-down of the gas turbine.

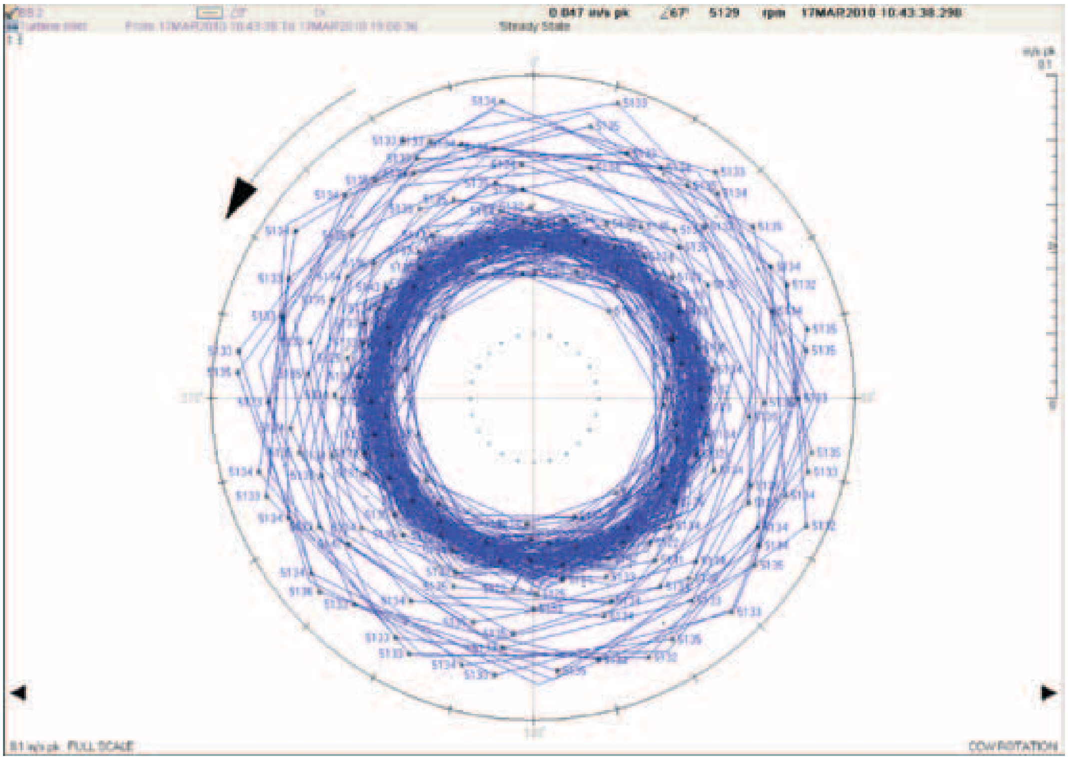


Figure 4: This polar plot shows vibration data from the gas turbine coast-down.

Wow! What have we got going on in Figure 4? Is this a light rub causing a thermal bow in the rotor? Perhaps a "Morton Effect" is at play, with its constantly-changing vibration phase angles? (Reference 1)

It turns out that the strange appearance of this data is a direct result of the truncated nameplate ratio that we typed into the Events Ratio field in the Sxp Keyphasor Channel Configuration dialog box (Figure 2). The nameplate ratio was stated as 1.426. But in actuality, this gearbox had gears with a tooth combination of 77 and 54.

77/54 is a rational number (able to be expressed as a ratio of two integers), with a decimal equivalent of approximately 1.4259259259... (the "259" group repeats forever). The rounded nameplate value of 1.426 only has four significant figures, so it is obviously an imperfect representation of the actual physical ratio. Because of the small error inherent in the nameplate ratio, each vibration vector data point in Figure 4 has a different phase angle.

The ADRE system allows us to avoid this problem by calculating the ratio much more accurately than the truncated value on the nameplate. If the actual number of teeth is known, these values can be entered directly (Figure 5). In this example, the ADRE system takes the Keyphasor signal from the generator, multiplies it by 77, and then divides it by 54, to create a derived signal that is essentially phase-locked to the rotation of the gas turbine.

Unfortunately, comparable data was not collected using the actual numbers of gear teeth for this machine train. However, if it had been, it would be expected to show a normal "clean" Bode plot and a non-spiraling Polar plot.

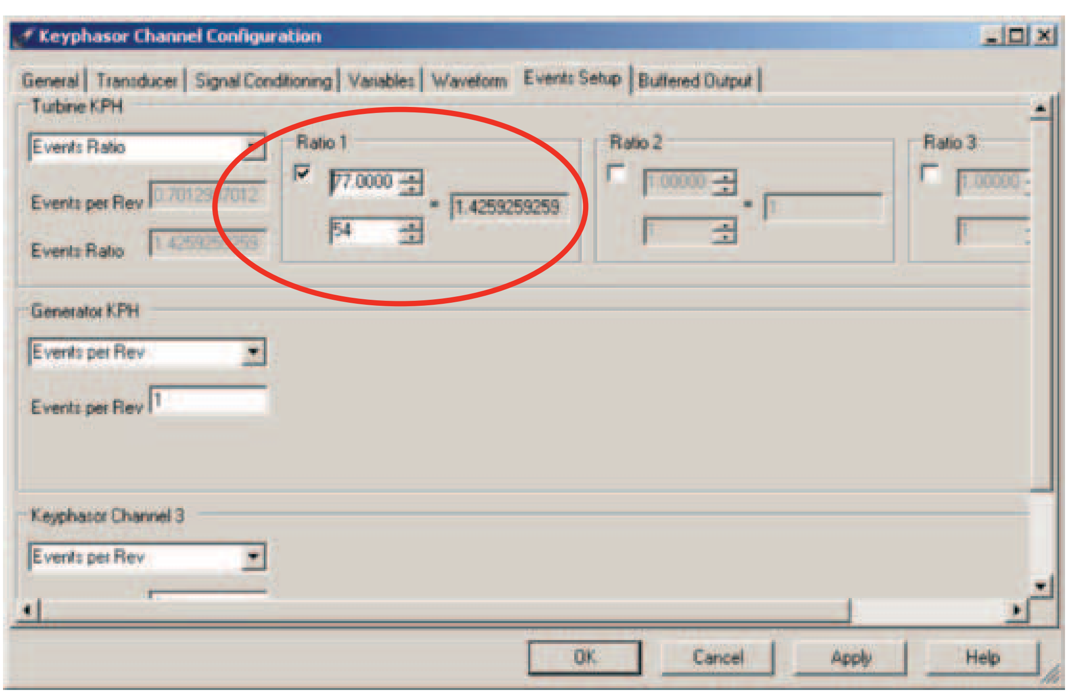


Figure 5: Sxp software allows us to enter actual numbers of gear teeth. This results in a much more accurate derived Keyphasor signal than using the truncated nameplate ratio.

Note: The indicated phase for the shaft with the derived Keyphasor signal should not be inferred to be absolute, since it will vary from run to run. In other words, it is useless for balancing, run to run phase comparison, etc. However, it will prove very useful for identification of balance resonances.

The Importance of Tooth Count

In virtually all instances of working with gearbox diagnostics, it will be essential to know the exact tooth combination. In his book, *Machinery Malfunction Diagnosis and Correction*, Robert C. Eisenmann, Sr., former Global Director of our Machinery Diagnostic Services (MDS) organization, makes the statement. "If at all possible, the diagnostician should obtain an exact tooth count on both elements. This must be an exact number (± 0 allowable error)." (Reference 2)

API Standard 613, Special Purpose Gear Units for Petroleum, Chemical and Gas Industry Services, requires that gearboxes should be designed to have a "hunting tooth" combination. This design concept requires that the number of teeth in each gear should not be integral multiples of the other. With such a design, each tooth on the gear engages a maximum number of teeth on the pinion, equalizing wear patterns, and reducing any damage caused by a single tooth imperfection. In the ideal case where there is only one unique "assembly phase," the number of teeth on the two wheels do not share any common prime factors, and every tooth on the gear engages every tooth on the pinion at some point in time (Reference 3).

Finding Tooth Count

By definition, a hunting tooth combination cannot be expressed exactly except in the form of a ratio (N1/N2), for example, 77/54. The optimum manner in which to obtain the tooth combination is to physically count the number of teeth. In most instances this can be done through an inspection opening in the gearbox casing (Figure 6). Another method is to research the Technical Manual for the tooth combination, or seek out a drawing (often termed the Mass Elastic Drawing) that shows this type of information. Lacking drawings, you can call the OEM and seek out this information, but often this is time consuming – resulting in not knowing the tooth combination when you are ready to start data acquisition.

If tooth count information is not available, Bently Nevada Technical Leaders have a ratio finder spreadsheet tool that calculates probable tooth combinations to satisfy specified values of nameplate ratio and ratio boundary conditions. Unfortunately, this is an iterative trial and error process, but the automated calculations provided by the spreadsheet can minimize the number of errors over performing this process manually.

The representative output of the spreadsheet for the nominal ratio of 1.426 is shown in Figure 7, which shows a small excerpt from the full worksheet. It can be seen that the tooth combination of 77/54 is very near the desired 1.426.

IF AT ALL POSSIBLE...

THE DIAGNOSTICIAN SHOULD OBTAIN AN EXACT TOOTH COUNT ON BOTH ELEMENTS.

THIS MUST BE AN EXACT NUMBER (± 0 ALLOWABLE ERROR).

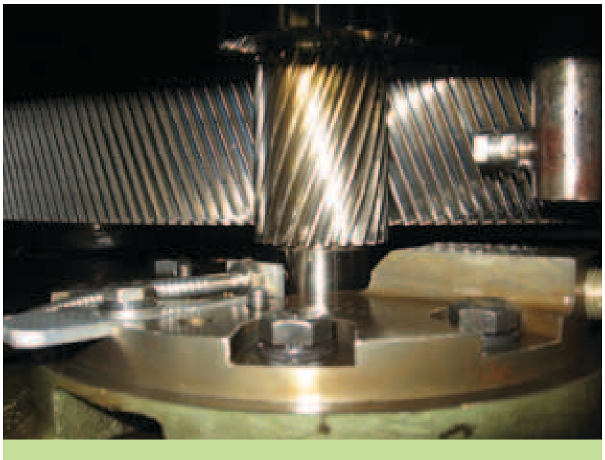


Figure 6: This example shows a speed-increasing gearbox for an integral-gear compressor.

1.4260	←	Exact ratio required		
1.4160	←	Lowest ratio acceptable		
1.4360	←	Highest ratio acceptable		
20	114	←	Min./Max. tooth combination	
N1	N2	N3	N4	Ratio
77	54			1.42593

Figure 7: This example shows the output from the ratio finder spreadsheet for the gearbox described in this article.

Important: When using a calculated tooth combination, remember that in observing the orbit of the shaft with the derived Keyphasor signal, an incorrect tooth combination will show a travelling Keyphasor dot, while the correct tooth combination will lock the Keyphasor dot in place. In addition, the polar plot will show the spiraling effect seen in Figure 4 if the incorrect tooth combination is used. Once the correct tooth combination is entered, the Keyphasor dot will remain stationary and the phase of the 1X vector will display properly in the Polar format.

If you are ever working with gearbox diagnostics, be aware that the Bently Nevada MDS team has access to the ratio finder spreadsheet tool (Figure 6) and can use it to assist with finding tooth count even it if is not available via other means.

References

1. Arthit Phuttipongsit, "The Morton Effect and Light Rubs in Rotating Machinery," Orbit, Vol 27 No 1, 2007, pp. 44-51.

2. Robert C. Eisenmann, Sr., Machinery Malfunction Diagnosis and Correction, Prentice-Hall, Upper Saddle River, N.J., Inc., 1998, p. 464.

3. John G. Winterton, "Component identification of gear-generated spectra," Orbit, Vol. 12, No. 2 (June 1991), pp 11-14.

ADRE* 408 DSPi Signal Processing

It has been a long time since analog oscilloscopes and spectrum analyzers were widely used to diagnose machinery problems. These functions have been taken over by computers – which have become increasingly powerful, and have been used more frequently as diagnostic tools. However, when using computers, an important fact has to be considered – they work in a digital world. For this reason, the analog signals coming from the transducers must be transformed into a digital format before they can be used for diagnosing machinery problems.

The term "analog" means that the signal is continuous in nature; it contains an infinite number of amplitude levels, separated by infinitesimal time intervals. A digital signal, on the other hand, is not continuous. It is formed by a finite number of amplitude levels, separated by finite time intervals. The process through which an analog signal is transformed into digital is usually referred to as "sampling". Figure 1 shows an example of an original analog signal, while Figure 2 shows a digitized version of the same signal.

The quality of the digitalized signal depends on two factors: resolution in amplitude (vertical axis) and resolution in time (horizontal axis). Amplitude resolution is controlled by the design of the Analog to Digital Converter (ADC) of the data acquisition instrument, and time resolution is controlled by the sampling rate.

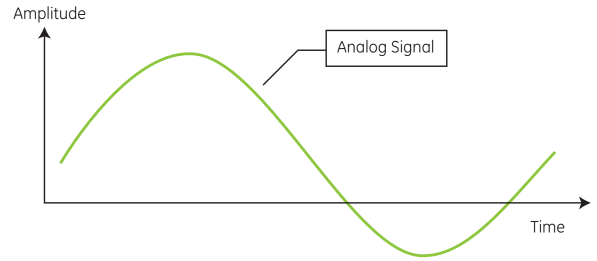


Figure 1: This example shows a typical analog signal as a "timebase" waveform. The amplitude of the signal is plotted on the y-axis, while the passage of time is plotted on the x-axis.

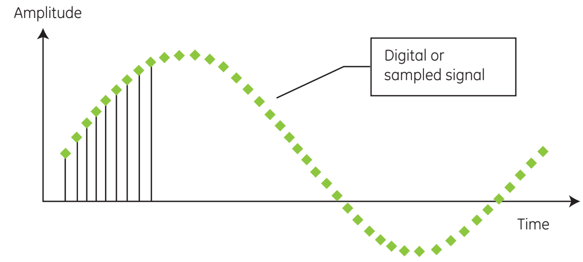


Figure 2: This example shows the same analog signal after it has been converted to a series of instantaneous digital samples (small red diamonds) that represent unique values of amplitude and time. If enough instantaneous values are sampled, they can be combined to recreate the original analog signal very accurately.

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The ADC converts the continuously changing amplitude of the analog signal into a digital sample containing a series of discrete values, represented by binary numbers. Each of these binary numbers is formed by a certain number of bits, the basic unit of information in the digital world. The resolution of an ADC, i.e. the smallest available difference between two consecutive values of amplitude for a given full scale range, is determined by the number of bits of each digital sample, which is based on powers of two (4, 8, 16, 32, 64, etc.).

Considering that a bit can have only two states (0 or 1), a particular full scale range will be divided into 2^n separate amplitude levels, where n is the number of bits in the sample. The following example shows how amplitude resolution increases when the number of bits is increased, for a given full scale analog signal range of 10 volts (10,000 mV). Dividing the full scale range (10 V) by the number of available discrete amplitude values (number of bits in the sample) gives us the minimum incremental change that can be captured by the ADC:

- Resolution for 8-bit A/D: 10 V / 2^8 = 10V / 256 = 39.1 mV
- Resolution for 12-bit A/D: 10 V / 2^{12} = 10 V / 4096 = 2.44 mV
- Resolution for 16-bit A/D: 10 V / 2^{16} = 10 V / 65,536 = 0.153 mV
- Resolution for 24-bit A/D: 10 V / 2^{24} = 10 V / 16,777,216 = 0.000596 mV

The higher the number of bits in the sample, the higher will be the resolution that is provided by the ADC. The tradeoff of using digital samples with more bits is that they require more storage space (memory) and processing time. It is important to observe that the number of bits in each instantaneous value captured by the ADC is not user-configurable, as it is based on the design of the data acquisition device. For the 408 Digital Signal Processing instrument (DSPi), the number of bits in each instantaneous value sampled by the ADC is 24.

The second parameter affecting the quality of the sampled signal is the sample rate, which controls the separation between two consecutive samples in time. Unlike the number of bits processed by the ADC, the sample rate is highly configurable. As such, a certain level of knowledge is required to select appropriate sampling parameters, so that important information can be captured and not lost. We will discuss this parameter in more detail in the next section of this article.

Signal Sampling in the 408 DSPi

Why should we be concerned about carefully configuring our 408 DSPi unit before collecting vibration data? Some valid reasons are listed here:

- The quality of the collected vibration data affects the quality of the vibration analysis that is performed using the data.
- When vibration data has not been appropriately sampled, even the best analysis may have no value at all.
- It is important to know that every acquisition instrument has limitations, and to know what these limitations are for the particular instrument being used.
- In most cases, opportunities for data acquisition are limited due to machine availability. The sampling settings must be correct the first time – otherwise, there may not be another opportunity to collect important data.

Because this new piece of equipment is far more versatile than its predecessor, the Data Acquisition Interface Unit (DAIU) 208P, the configuration of sampling parameters has become more complex than it used to be. This requires the user to be quite knowledgeable on signal processing concepts.

Synchronous & Asynchronous Sampling

Now that we have discussed amplitude resolution, we will move on to sample rate, which is one of the most important configuration parameter that is available with the 408 DSPI. Two types of sampling are available on the 408 DSPI: Synchronous and Asynchronous. Several important differences exist between the two, so we will explain them separately. However, before getting into more detail on sampling, let us talk briefly about how data is actually stored in the 408 DSPI hard drives.

The process of digitalizing an analog signal in the 408 is not continuous – not only because the analog signal is divided into discrete parts – but also because these parts are grouped in packages, called waveform records, or waveform samples (Figure 3). Typically, the number of instantaneous values included in these packages may vary between 256 and 16384. Both the specific number of instantaneous samples and the way in which these waveform files are filled up with data, depends on whether the sampling process is Synchronous or Asynchronous.

Before getting into more detail on these two types of sampling, it is important to make a clarification. Throughout this article, we will be dealing with the process of digitizing a signal, both synchronously and asynchronously. However, it is not the purpose of this article to describe the data collection settings of the 408, which control when the samples are taken (sampling events such as delta RPM or delta time, triggering events, the ratio of static samples to waveform samples to be collected, etc.).

Application Example

In this example, we will consider using a synchronous sample rate of 256 samples per revolution (256/8). This parameter will be used in two different machines – one running at 1800 rpm, and the other running at 6000 rpm. In both cases, the data acquisition device will collect 256 samples during each of the required 8 revolutions, in order to fill up a waveform record, or "package" with the required 2048 digital values.

Though the synchronous sample rate is the same in both cases (256 samples per rev), the time required to complete one revolution is very different for the two machines. In our example, the rotor will take 0.033 s to complete one revolution for the machine running at 1800 rpm and only 0.01 s for the machine running at 6000 rpm. A direct consequence is that the time interval between two consecutive samples (Figure 5) will differ from one machine to the other.

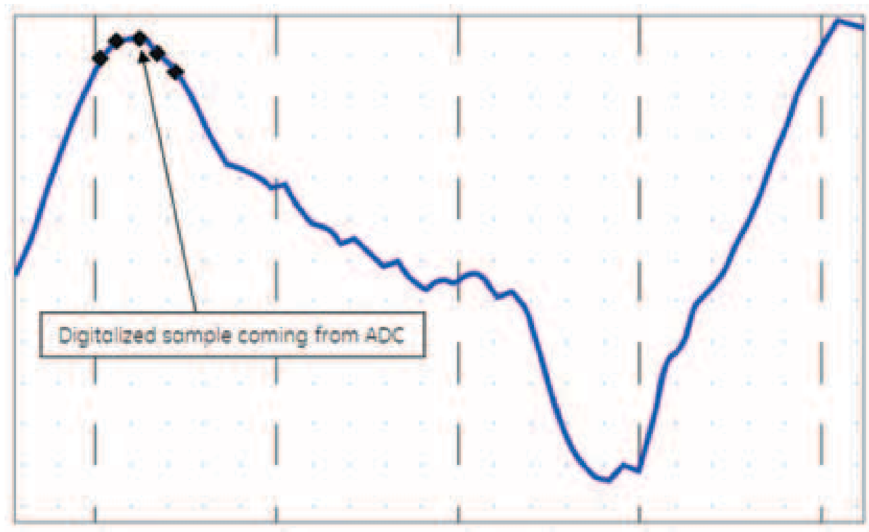

Figure 3: This example shows just a few of the digitized values (black diamonds) that would be included in a typical ADRE waveform sample.

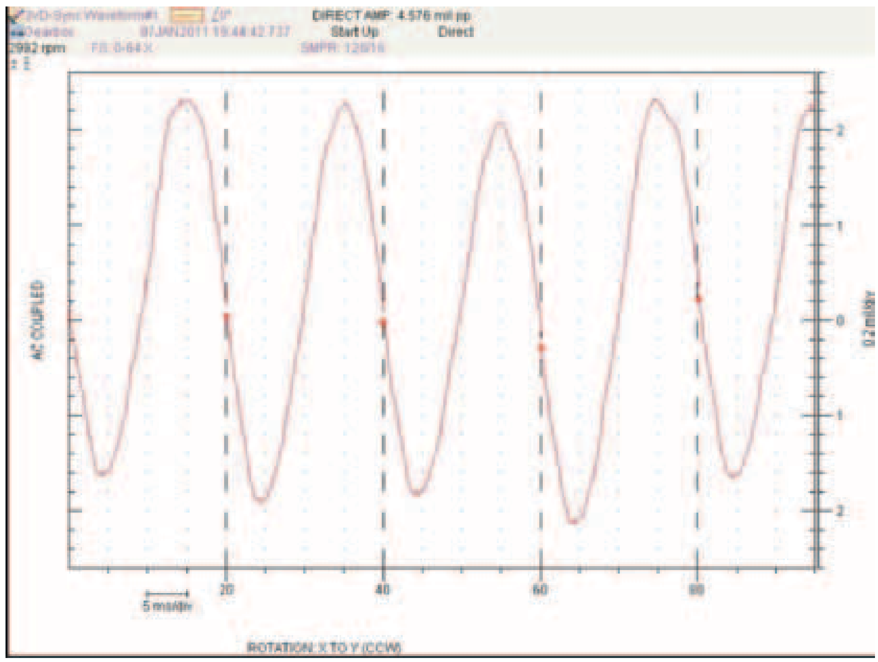

Figure 4A: Timebase plot generated for a synchronous waveform.

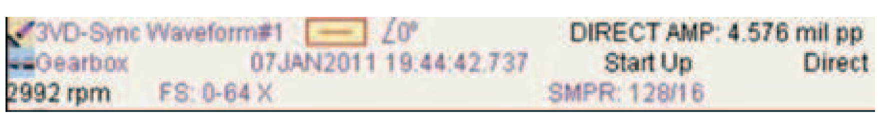

Figure 4B: A closer view of the plot header in Figure 4 shows various pieces of important information for the plot. "SMPR; 128/16" means that the sample rate is 128 samples per revolution, collected over a total of 16 revolutions. (128x16=2048). The "Direct" (unfiltered) amplitude value in the upper right corner was derived by a peak-to-peak measurement of the digital waveform.

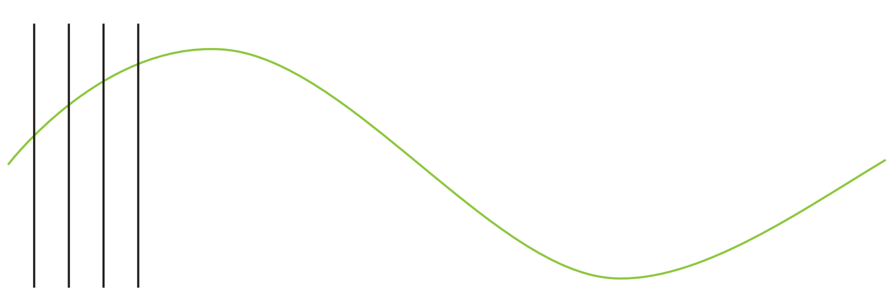

Figure 5: For both machines, each full revolution will include 256 evenly-spaced digital samples (represented by the vertical lines in this illustration. However, the time intervals will be different because of the difference in machine speed.

1800 RPM EXAMPLE

One full revolution (0.033 s) is split into 256 equal parts. The time interval between samples will therefore be 0.033 s / 256 = 0.00013 s. To find the sampling frequency, we divide 1 by the sample interval. 1 / 0.00013 s = 7692 samples per second.

6000 RPM EXAMPLE

One full revolution (0.01 s) is split into 256 equal parts. The time interval between samples will therefore be 0.01 s / 256 = 0.000039 s. To find the sampling frequency, we divide 1 by the sample interval.
1 / 0.000039 s = 25641 samples per second.

From Figure 5, it is evident that the sampling frequency, measured in samples per second (Hz), will depend upon running speed of the machine. The faster the machine runs, the higher will be the sampling frequency used by the 408, in order to satisfy the selected synchronous sampling rate (128/16, 256/8, etc.). Also, the higher the synchronous sampling rate, the more accurately the digitized waveform record will represent the original analog signal.

However, it is important to realize that there is an upper limit on how fast the digital samples can physically be collected. In the 408, the maximum frequency for synchronous sampling is 32 kHz. Using the configured Keyphasor maximum speed, ADRE SXP software calculates and displays the maximum available synchronous sampling rate that can be selected without exceeding the 32000 Hz capability of the ADC.

The result of the synchronous sampling that we have described up to this point is a collection of synchronous waveform samples, each containing 2048 digitized values. These waveform samples represent the raw material that is used in two main groups of plots. These are time domain plots (orbit and timebase), and frequency domain plots (spectrum, cascade and waterfall).

Note: a “full” spectrum, cascade or waterfall plot is an enhanced plot that is produced by using the timebase waveforms from XY transducers. It displays the amplitudes of the forward (same direction as shaft rotation) and reverse (opposite direction to shaft rotation) frequency components of the vibration signal.

Time domain plots constitute a direct representation of the digitized signal, either as a single waveform or as an orbit, which is a combination of two signals coming from a pair of orthogonal XY transducers. In other words, no further processing, other than digitizing the analog signals, is performed when generating these type of plots. In contrast, the frequency domain representation requires additional manipulation of the original waveform files to extract the various frequency components from the signal.

Frequency Domain Analysis

For now, we will take a quick look at the basics of frequency domain analysis as it is used for machinery diagnostics This will help with understanding the limitations of synchronous sampling, as well as some advantages that asynchronous sampling has for frequency domain analysis. Later, when we talk about asynchronous sampling, we will come back to the frequency domain considerations in more detail.

Once the analog signal has been sampled (transformed into digital format) the Fourier Transform is applied to the sample, through a computational algorithm called Fast Fourier Transform or “FFT”. The main purpose of this transformation is to go from a time domain (waveform) representation of the signal, to the frequency domain representation of that signal, in order to display a conventional spectrum plot (a representation of all the frequency components that exist in the original complex signal, along with their respective amplitudes).

One of the properties associated with the FFT algorithm, is that it takes equally spaced N samples from the time domain, and transforms them into N/2 equally spaced samples in the frequency domain, called “lines”.

- *The number of spectral lines is one half the number of digitized samples in the waveform record.*

The frequency resolution of the resulting spectrum plot, that is, how close together these lines are to each other, can be calculated as follows:

$$\text{Frequency resolution} = \frac{\text{Frequency span}}{\text{Number of lines}}$$

Consequently, if we apply an FFT to a synchronous waveform containing 2048 samples, we will get a 1024-line spectrum plot. Since all ADRE synchronous waveform records contain a fixed number of 2048 samples, there will always be 1024 lines available from such a sample.

In order to calculate the frequency resolution, we need to know which frequency span we are using. This brings up an important question: Is it possible to independently configure the frequency span in Synchronous sampling? The answer to this question is no. Frequency span is automatically set to half the selected synchronous sample rate.

Though this may sound arbitrary, it is not. It is based on the Nyquist sampling theorem, which states that in order to accurately extract the frequency information from the original signal; the sampling rate must be at least twice the highest frequency of interest in the original signal.

This requirement reduces the possibility of erroneously representing the original signal as a different signal with lower frequency. The presence of such spurious frequency components is referred to as "aliasing," and will be discussed in more detail when we explore asynchronous sampling. By highlighting the phrase "at least," we are emphasizing the fact that it is a minimum required sampling rate. When we discuss asynchronous sampling, we will see that a higher sampling rate is generally used.

Frequency Span

Let us go back to the first example scenario of Figure 5 to present some actual numbers. In this case, we saw that a synchronous sampling rate of 256/8 translates into 7692 samples per second (Hz), when the machine is running at 1800 RPM. As defined by the Nyquist criterion, sampling at 7692 Hz, or 256 samples per revolution, will allow us to accurately "see" frequency components in the digital signal up to 3846 Hz (half of the sampling rate described as frequency units), or 128 times running speed (half of the sampling rate described as "orders" of shaft rotation speed).

- 7692 Hz / 2 = 3846 Hz
- 256X / 2 = 128X

In summary, once the synchronous sampling rate has been selected, the frequency span will automatically be set to half that value. It is evident from this example that the resulting frequency span can tend to be much higher than is needed for a typical frequency analysis on rotating equipment – especially for fluid film turbo machines that do not generate very high orders of vibration relative to shaft speed (Figure 6).

If we also consider that this typically high frequency span is spread over a fixed number of only 1024 spectral lines, we will conclude that there are reasons to avoid the use of synchronous sampling in frequency domain analysis with the available options in the 408 DSPi. Synchronous sampling excels for time domain analysis, where the ability to collect many samples per shaft rotation results in a very accurate representation of the original analog signal. In other words, we will most often use synchronous sampling in those cases where the quality of the waveform itself is critical, either in timebase waveform plots or orbit plots.

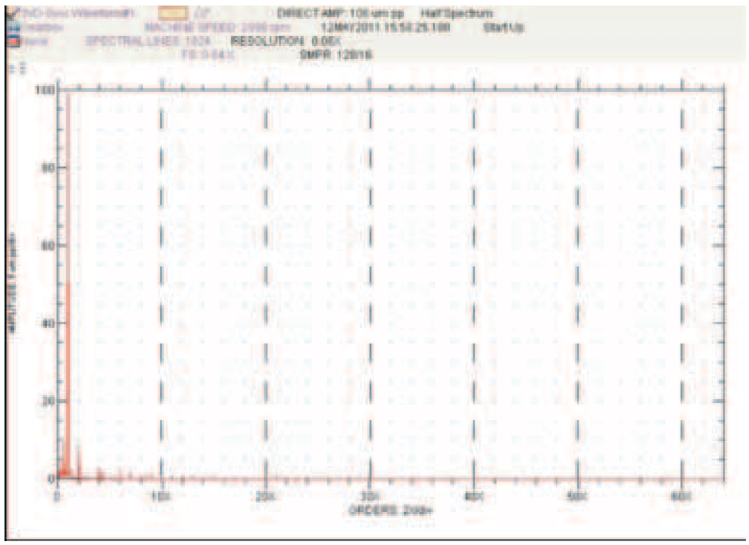

Figure 6A: In this example, the spectrum plot was generated from a synchronously-sampled waveform file. Observe that most of the vibration components occur below about 10X (orders of shaft rotative speed), and most of the frequency span is "wasted."

Figure 6B: This magnified view of the plot header makes it easier to see the sampling parameters. As we discussed, a synchronous waveform sample in ADRE will always have 2048 samples, so it will always provide 1024 spectral lines. The synchronous sample rate (128X) divided by 2 gives a frequency span of 64X.

Observe that due to the excessive frequency span of 64X, a relatively poor frequency resolution is achieved in this example: 64X / 1024 lines = 0.0625X / line

Recall: 1X frequency is simply the shaft rotative speed in rpm divided by 60 seconds/minute. So 1X = 2998/60 = 49.97 Hz.

Converting frequency resolution in this example to other units:

- (0.0625)(49.97 Hz) = 3.12 Hz
- (3.12 Hz)(60 s/min) = or 187.2 cycles per minute (cpm)

Synchronous Sampling Equations

Before we discuss asynchronous sampling in detail, here are some useful equations related to synchronous sampling. These can be very handy when configuring your 408 DSPi for collecting waveform samples.

$$\text{Number of revolutions for completing one waveform} = \frac{\text{record size (2048)}}{\text{Configured sampling rate}}$$

$$\text{Time for capturing one waveform} = \frac{\text{Number of revolutions in record}}{\text{Running speed (rev/sec)}}$$

Sampling rate (Hz) =
Machine speed (rev/sec)* sampling rate (samples/rev)

$$\text{Frequency span (nX)} = \frac{\text{Sampling rate (samples/rev)}}{2}$$

where X represents running speed

$$\text{Spectrum resolution (nX/line)} = \frac{\text{Frequency span (nX)}}{1024}$$

Asynchronous Sampling

In the previous section, we discussed how synchronous sampling was performed in the 408 DSPi, emphasizing its dependency on the phase reference pulse. Asynchronous sampling, however, does not depend on this pulse at all. The main difference here is that all of the samples included in the waveform file are equally spaced in time, and the sample rate is independent from changes in rotating speed or the signal frequency.

Also, this type of sampling differs from the synchronous type in the number of samples within each waveform record. There are several options available, and the number of individual digitized values within a waveform record varies based on the number of spectral lines, and the Frequency Span, which are both configurable in this type of sampling. Let´s review each of these parameters separately.

Frequency Span (FS)

Recall – The Nyquist Theorem says that in order to properly identify all the frequency components within a defined frequency range, the data acquisition device must collect samples at a frequency of “at least” twice the highest frequency of interest. With the 408 DSPi (as well as most data acquisition devices), once a particular FS has been selected, the asynchronous sampling rate is automatically set to 2.56 times that value.

For example, if we wanted to examine the frequency content of a signal up to 1000 Hz, once we have selected a FS of 1000 Hz, the 408 DSPi sets a sampling rate of (1000)(2.56) = 2560 Hz. Using a factor higher than 2 relates to the use of special low pass filters called “anti-aliasing” filters in this type of sampling (later we will talk a bit more about Nyquist and anti-aliasing filters). Though 2.5 would be an adequate multiplier to determine sample rate, 2.56 is the multiplier that is normally used, in order to comply with the digital sampling constraints of the computer world. The 408 DSPi offers FS options ranging from 50 to 50,000 Hz, which result in sampling rates from 128 to 128,000 Hz.

Number of Spectral Lines

Numbers of spectral lines ranging from 100 to 6400 are available when using asynchronous sampling in the 408 DSPI. This capability, along with a configurable FS, allows us to achieve the desired frequency resolution, by using the same expression we introduced in synchronous sampling:

$$\text{Frequency Resolution (Hz/line)} = \frac{\text{Frequency Span (Hz)}}{\text{number of lines}}$$

At this point, it is important to state that this expression should be used very carefully. The next few pages explain the reason for this cautionary statement.

As we discussed in the synchronous sampling section, the number of spectral lines of the FFT (samples in the frequency domain) depends on the size of the corresponding waveform, that is, the amount of samples included in the waveform record. Though we also stated that the FFT delivers N/2 lines from N samples in the waveform, the 408 DSPi, as well as most data acquisition devices, uses N/2.56 when applying the FFT to asynchronous waveforms. We could rephrase this as the following relationship:

Number of samples in the waveform =
Number of lines * 2.56

Again, using 2.56 instead of 2 in this expression relates to the use of the anti-aliasing filters, combined with a digital environment. Since the number of spectral lines is configurable for asynchronous sampling with the 408 DSPi, this equation becomes important, as the required amount of samples in the waveform will change based on the number of spectral lines that are specified. The list below shows all the available options for numbers of lines in the 408 DSPi, along with the number of digital samples in the waveform records.

- 100 lines: 256 samples in the waveform record
- 200 lines: 512 samples in the waveform record
- 400 lines: 1024 samples in the waveform record

- 800 lines: 2048 samples in the waveform record
- 1600 lines: 4096 samples in the waveform record
- 3200 lines: 8192 samples in the waveform record
- 6400 lines: 16384 samples in the waveform record

Relationship between Frequency Span (FS) and number of spectral lines

We have already discussed the two main configurable parameters involved with asynchronous sampling. Now let´s see how they combine with each other to determine the quality of the collected data.

The most important aspect of selecting a particular FS is not frequency span itself, but how fast the samples are collected to fill up a waveform file. As we stated earlier, the sampling rate is 2.56 times the selected FS. Also, we learned that the number of lines determines how many individual samples are required to be in the waveform record in order to generate the corresponding spectrum plot.

All of these relationships interact to determine how much time the data collection will take. If we want to apply an FFT algorithm to a waveform or time record, the time that is required to collect the samples may be very important. The reason for this is that the FFT algorithm assumes that the digitized signal is "periodic" throughout the time that was sampled.

In the real world, however, we should keep in mind that things may change with time. When dealing with rotating machines, the perfect example for changing conditions would be transient events such as startups, shutdowns, or speed changes (for variable-speed machines). To illustrate this point, let´s take a look at the following scenario. Hopefully, you will see that the shorter the collection time, the better is the possibility for acquiring a periodic signal.

Example

We want to collect vibration data during the shutdown of a machine. Since the machine is running at 4899 RPM (1X = 82 Hz), a frequency span of 500 Hz would be enough to examine the frequency content from a typical proximity probe signal.

We also set 400 lines for the corresponding spectrum plot, which combined with a FS of 500 Hz will give us 1.25 Hz/line of resolution. Everything looks fine, until we examine the cascade plot generated during the shutdown (Figure 7). There seems to be something wrong with the 1X and 2X frequency components in the range of 4000 – 5000 rpm. They are not exactly 1X and 2X, but are slightly lower frequencies.

So, what exactly is wrong with this scenario?. Let´s start by looking at the asynchronous sampling settings. In this case, the selected frequency span of 500 Hz automatically sets the asynchronous sampling rate to 1280 Hz (500 * 2.56). We also know that 400 lines will require a waveform record containing 1024 individual digital samples (400)(2.56) = 1024.

If the 408 DSPi collects 1280 samples in one second, the time required to fill up a waveform record with 1024 samples will be 0.8 seconds. If we want to generate a spectrum plot from a specific asynchronous waveform, we should verify that the amplitude and the frequency of the signal included in those 0.8 seconds do not change significantly.

In our example, the machine speed during shutdown followed the pattern shown in Figure 8. It changed rapidly at the beginning, and then more slowly. At the beginning of the coast-down, rotating speed dropped from 4842 to 4010 rpm in one second. Our 0.8 s sample time will probably include some changes in vibration amplitude, and definitely in frequency. As a result, the FFT will produce smearing in the corresponding spectrum plot.

The tradeoff of increasing the frequency span is a decrease in frequency resolution. In most cases, a compromise between the two will have to be considered. In this example, increasing the FS from 500 to 2500 Hz and keeping 400 spectral lines caused a decrease in frequency resolution from 1.25 to 6.25 Hz per line (Figure 9).

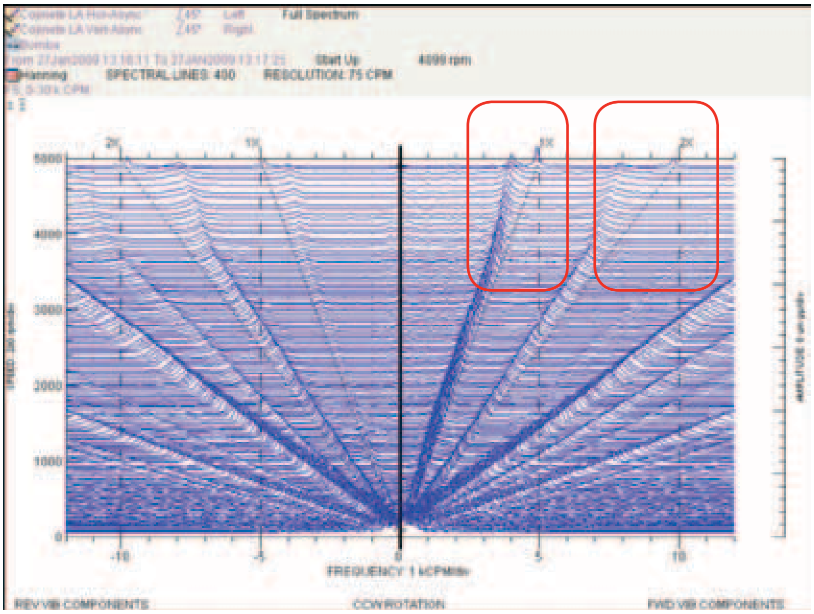

Figure 7: Full cascade plot for a machine shutdown, using a frequency span of 500 Hz.

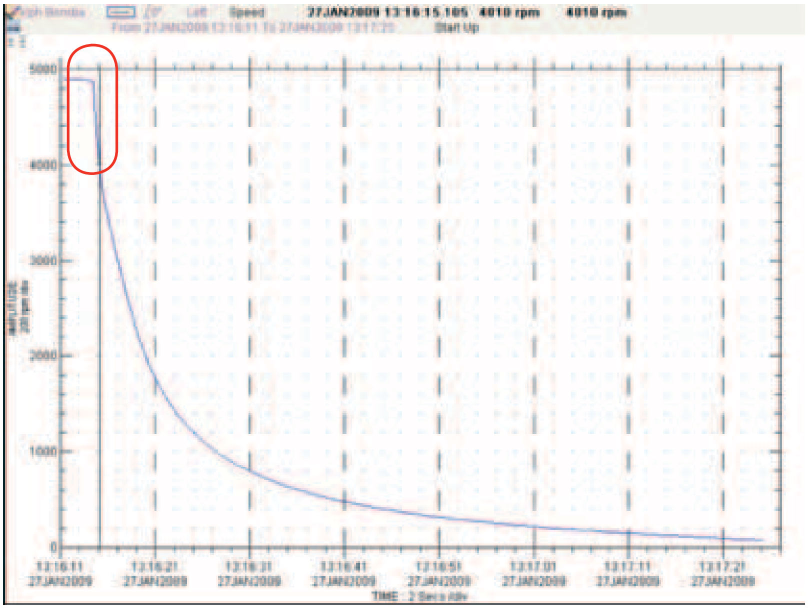

Figure 8: RPM trend plot for a typical machine shutdown. Speed drops rapidly at first, and then more slowly as the machine coasts to a stop.

Nyquist Theorem and Aliasing

When we talked about synchronous sampling we briefly introduced the Nyquist Theorem and an extremely important concept related to signal sampling – Aliasing. We will now take a deeper look at these concepts, as they are accounted for in asynchronous sampling. In order to do this, we will consider the following scenario:

We need to digitally sample the analog signal shown in Figure 10. For the purpose of this example, we will assume that the signal to be sampled is a single frequency sinusoidal signal. In previous sections of this article, we learned about a particular rule we need to follow when sampling signals, the Nyquist Theorem. We will stick to it by taking samples at twice the frequency of the analog signal.

Figure 11 shows black dots overlaid on the original signal. These represent the discrete samples collected by the acquisition device. By collecting two samples per signal cycle (which is the same as collecting samples at twice the signal frequency), we make sure that we can identify alternating amplitudes at the frequency of the original signal. In other words, we can detect the frequency of the original signal.

Now let us see what happens if we collect samples at a lower frequency. Figure 12 again shows black dots representing the digital samples, which are now being captured at different locations in the original signal. A direct consequence of this is that when we try to reconstruct the digitized signal, we will see a different signal (green). By comparing it to the original signal (red), it is evident that the frequency of the reconstructed signal is lower than the original. In other words, the original high frequency signal has been "aliased" to a lower frequency signal. It is important to state that once the aliasing of a signal has occurred, there is no way to know whether the reconstructed signal accurately represents the original signal or not.

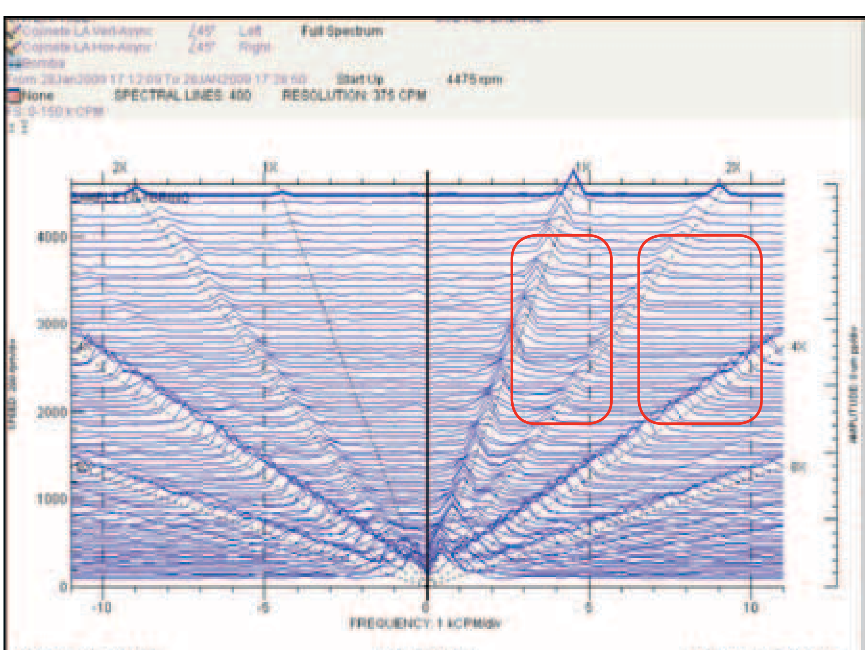

Figure 9: Full cascade plot for a shutdown, this time using a frequency span of 2500 Hz.

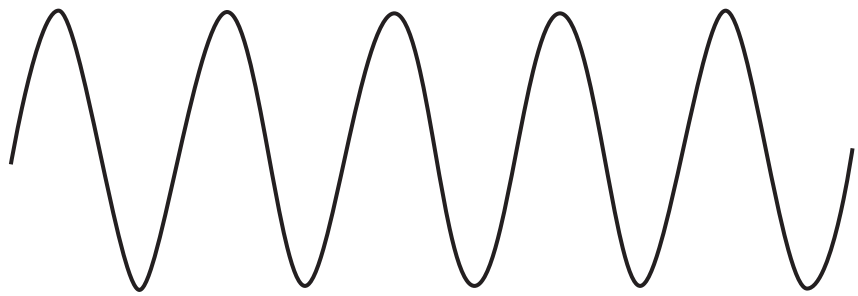

Figure 10: Simple example of an original analog signal.

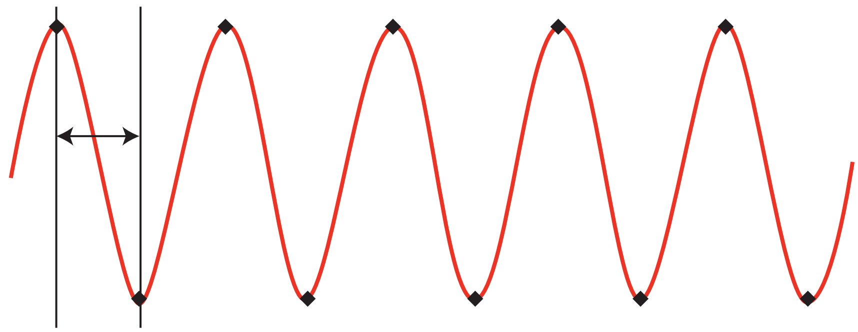

Figure 11: Digitized samples collected at twice the original signal frequency.

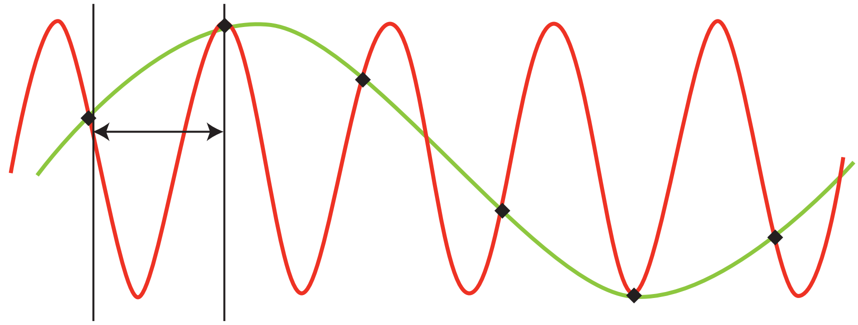

Figure 12: Digitized waveform (green) shows aliasing caused by sampling at too low of a sample rate.

Anti-aliasing Filters

Even when the Nyquist theorem ensures that we detect the frequencies of interest, undesired higher frequency components may still generate aliased components that will show up in our selected frequency span. Let us suppose that we want to examine a frequency span of 0 to 1000 Hz. The Nyquist theorem will force us to sample at twice the maximum desired frequency, in this case, 2000 Hz. This will ensure that any frequency component up to 1000 Hz will appear accurately in the reconstructed signal.

However, what would happen if the analog signal included a random 1600 Hz component? Signal sampling theory tells us that any frequency component f0 above half the sampling frequency will generate an aliased component at sampling frequency – f0. In our example, a 1600 Hz component will generate an alias at 2000Hz – 1600Hz = 400Hz. When this happens, we will observe a 400Hz frequency component that was not in the original signal. This can cause a tremendous waste of time trying to relate it to a real problem.

In order to avoid this problem, anti-aliasing filters are usually applied to the original signal before the digital sampling process is performed. These are basically low-pass filters that remove frequency components above our selected frequency span. By attenuating signal components that are beyond our identified frequency span, these filters reduce the chance of aliasing of any higher frequencies that might be in the original signal.

Ideally, an anti-aliasing filter would have the perfect characteristics shown in Figure 13. All signal components lower than the selected cutoff frequency are in the "pass-band" and are allowed to pass through the filter completely unaffected. All signal components higher than the cutoff frequency are in the "stop-band" and are perfectly rejected, or prevented from passing through the filter. The cutoff frequency for such a filter would be set at the selected value of frequency span for the sample to be collected, and the sample rate could be as low as exactly two times the cutoff frequency.

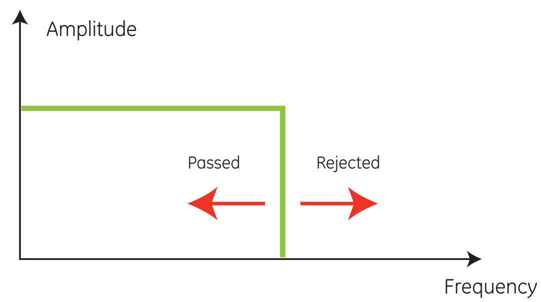

Figure 13: This example shows the behavior of an ideal low-pass filter used for anti-aliasing.

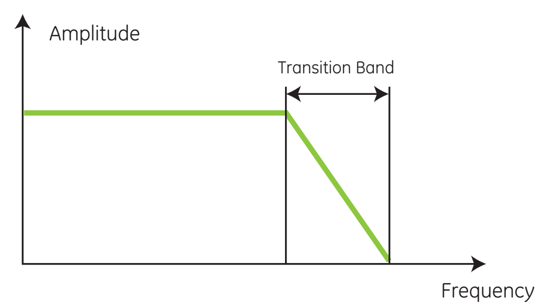

Figure 14: Real anti-aliasing filters have a sloped attenuation response rather than a sharp cutoff corner. This creates a transition band with only partial signal rejection.

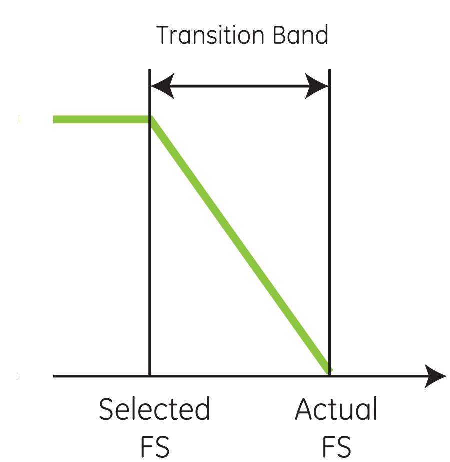

Figure 15: The actual frequency span that must be accommodated by the digital sampling process is defined by the high-frequency end of the transition band, rather than by the FS that has been selected in the configuration properties.

Unfortunately, real filters behave as shown in Figure 14. Here, a transition band is present, starting at the cutoff frequency, and with a sloping "roll-off" characteristic rather than a sharp corner. Just above the cutoff frequency, the signal is barely rejected at all. The attenuation increases as frequency increases within the transition band, eventually being complete where the stop-band is reached. If we set the cutoff frequency to the selected frequency span for the sample to be collected, and set the sample rate at exactly two times the cutoff frequency, any incompletely-attenuated signal components in the transition band would be aliased down into the digitized waveform file.

To avoid the possibility of components within this transition band aliasing into our selected frequency span, the sampling rate must be set to twice the highest frequency of the transition band. This point defines the actual FS that must be accommodated by the sampling process, rather the configured value of FS (Figure 15). The typical asynchronous sampling rate used in most data acquisition devices working in a digital environment, including the 408 DSPi, is 2.56 times the configured value of FS.

The asynchronous sampling rate used by the 408 DSPi is 2.56 times the selected value for FS. This sample rate is high enough to accommodate the width of the transition band, and prevent aliasing of signals beyond the configured setting for FS. It also means that more digital samples are collected in the waveform record than are displayed in the resulting spectrum plot.

Example

If we select 400 spectral lines, and FS = 1000 Hz, the number of collected samples in the waveform record is actually (400)(2.56) = 1024 samples, as shown in this relationship for asynchronous sampling:

Number of samples in the waveform =
Number of lines * 2.56

There are three

"Laws of the Universe"

that deal with digitally sampling waveforms and computing spectra with a Fast Fourier Transform (FFT):

- The sample rate governs the frequency span.
- The total sample time governs the frequency resolution.
- The number of samples governs the number of lines.

1024 samples are actually enough to create 512 spectral lines. Also, since the actual sample rate is (1000)(2.56) = 2560 Hz, the actual FS is 2560/2 or 1280 Hz, rather than our configured value of 1000 Hz.

Because we are only interested in the original frequency span (1000 Hz), and the selected number of spectral lines (400), our process truncates the spectrum to discard the highest frequency data (from 1000 to 1280 Hz) and the 112 spectral lines beyond 400. This process provides additional assurance against aliasing.

The 2.56 factor also accommodates the binary storage capability of digital buffers (512, 1024, 2048, etc.), and user preferences for traditional "round numbers" of spectral line options (400, 800, 1600, 3200, etc.).

Advantages of Asynchronous Sampling

In many cases, two characteristics of the 408 DSPi combine to make asynchronous sampling more appropriate than synchronous sampling for frequency domain analysis:

- The 408 DSPi allows both the frequency span and the number of spectral lines to be configured individually for asynchronous sampling. This allows more flexibility to select settings that correspond to the conditions of sample collection.
- The 408 DSPi applies anti-aliasing filters for asynchronous sampling. This reduces the chance of spurious frequency components showing up in the resulting spectrum plots.

Just as we did for synchronous sampling, we include some useful relationships for asynchronous sampling here.

Sampling rate (samples/sec) =
Frequency Span (Hz) * 2.56

Time required for capturing a waveform =

$$\frac{\text{Waveform size (samples in the waveform)}}{\text{Sampling rate (sample/second)}}$$

Number of samples in the waveform =
Number of lines * 2.56

Conclusion

There are three "Laws of the Universe" that deal with digitally sampling waveforms and computing spectra with a Fast Fourier Transform (FFT):

- The sample rate governs the frequency span.
- The total sample time governs the frequency resolution.
- The number of samples governs the number of lines (Reference 1).

We can generally say that synchronous sampling is often preferable for time domain analysis, and asynchronous sampling for frequency domain analysis. However, it is important to understand the relationships between these three laws, so that we can select settings that are an appropriate compromise for the machine conditions that exist at the time of sampling. (Reference 2)

*Denotes a trademark of Bently Nevada, Inc., a wholly owned subsidiary of General Electric Company.

References

1. Sampling waveforms and computing spectra, by Don Southwick. ORBIT Vol. 14, No.3, pg. 12, September 1993. This article is one of our classics on the topic of basic digital signal processing.

2. 3200 line spectrum – when shouldn't you use it? ORBIT Vol. 14 No. 3, June 1998. This article includes several examples of the tradeoffs that occur when collecting waveform samples with higher sample sizes – especially when the data collection may occur during machine speed transients, which can cause spectral smearing.

Both of these references are available for viewing or downloading at our Orbit Archive Directory: www.orbit-magazine.com

The Importance of Filtered Vibration Data

This article contains excerpts from the 2006 Orbit article "25 Years of Experience With Online Condition Monitoring at E.ON Benelux" (Reference 1). Two of the five case histories in that article described the use of acceptance region alarming to facilitate rapid detection of a blade failure in a steam turbine, and in a gas turbine. The vector data provided by 1X vibration monitoring allowed the plant staff to quickly shut down both of the machines before the failures could escalate, and helped them to plan appropriate corrective measures. -Editor

Overall vibration is a measure of the total amplitude of the original vibration signal. This is an unfiltered measurement that we refer to as being "Direct." Direct data can contain many frequency components – especially in a machine with a design that produces a rich spectrum of different characteristic frequencies during normal operation. When analyzing orbit or time waveform plots, it is useful to evaluate the direct signals, as they may contain various indications (such as impact spikes) that are worth evaluating further.

However, we can realize many additional benefits by evaluating filtered vibration data in addition to direct data. With many machines, it is especially valuable to filter the signal "synchronously," that is, to the frequency corresponding to the shaft rotative speed (1X) as well as integer multiples (2X, 3X, nX...).

Note: True synchronous filtering requires the use of a Keyphasor* transducer, which provides a consistent one event per rotation triggering pulse for use as a phase reference.

When we break the vibration signal into discrete frequency components corresponding to orders of shaft rotation (1X, 2X, etc.), we can measure both the amplitude and phase of the vibration. These two pieces of information give us additional insight that is not available with the direct signals alone. With both amplitude AND phase information, each vibration value is really a vector. The magnitude of the vector is the amplitude of the vibration, while its direction is the measured absolute phase relative to the phase reference signal.

Uses of Phase Angle Measurements

Phase angle measurements are used extensively in machinery diagnostics and condition monitoring. A few of the many phase angle applications are listed here:

- Direction of precession
- Location of fluid induced instability source.
- Shaft balancing
- Shaft crack detection
- Shaft mode shape
- Shaft/structural resonance detection

Synchronously-filtered vibration samples can be collected during steady-state (constant speed) operation during either slow-roll or normal operating conditions, and under conditions of changing speed – such as a machine startup or coast-down. The amplitude and phase of the vibration data is typically displayed in plots with Cartesian or polar coordinates.

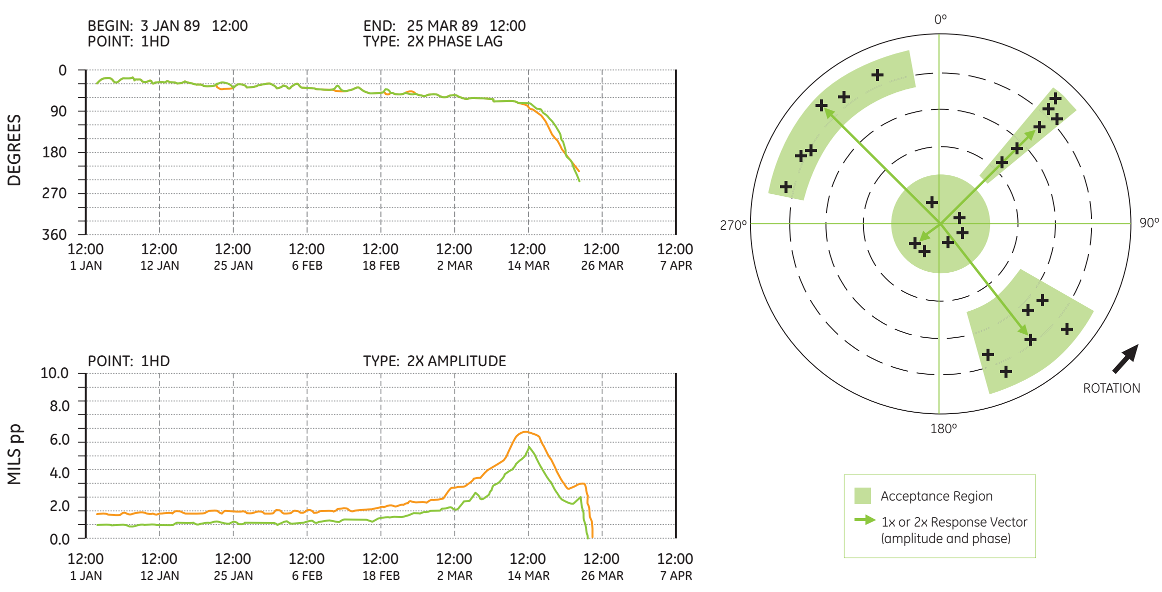

Figure 1: This example shows an APHT plot, and a polar plot with several acceptance regions.

The Usefulness of Acceptance Regions (Reference 1)

When vibration is filtered to a specific multiple of running speed (such as 1X), it can be characterized as a vector. When this vector is trended over time, this is known as an Amplitude/Phase/Time (APHT) plot. As shown in Figure 1, the APHT plot can be represented in either Cartesian or polar coordinates. When using Cartesian coordinates, it resembles (and can be easily mistaken for) a Bode diagram; however, unlike the Bode diagram, an APHT has as its X-axis units of time rather than machine speed. Similarly, when graphed using polar coordinates, an APHT resembles a polar plot. However, the polar plot is used to show vibration vector changes as a function of machine speed. In contrast, the polar APHT shows vibration vector changes as a function of time—not rpm.

There is a tendency by some – particularly novice vibration analysts – to be concerned only with increases in vibration amplitude. More skilled practitioners, however, understand that it is really change in vibration that should always be the basis for concern, and this can be represented by either a change in magnitude or a change in phase – both can be equally indicative of a serious malfunction.

For this reason, alarming strategies that can detect abnormal changes in the vibration vector (not just an increase in its magnitude) are highly valuable. Bently Nevada* monitoring systems pioneered the concept of an "acceptance region" in the late 1980s. Simple in concept, but highly useful in practice, the Acceptance Region is simply a defined region within the polar APHT for which the vibration vector is considered normal. When the vector goes outside this defined region, it represents an abnormality and an alarm is generated. Because the polar APHT plot is the most convenient way to visualize and establish acceptance region alarms, it is often referred to as an Acceptance Region plot.

Acceptance region alarming schemes have steadily increased in sophistication over the last 20 years. Systems today are available that can switch between multiple acceptance regions based on certain machine operating states, such as differing load conditions.

Case History – Waalhaven Unit 4 (Reference 1)

Units 4 and 5 at the Waalhaven plant in Rotterdam are both 340 MW steam turbine – generator sets. The units were put into operation in 1974/1975 and were augmented with gas turbines as part of a combined cycle upgrade in 1986. Partly due to recurring vibration problems, the units were equipped with an online vibration diagnostics system in 1992. One aspect of this system that we found highly useful was its ability to allow individual 1X acceptance region alarms for various machine loads. Acceptance region trending and alarming is highly useful for detecting malfunctions such as imbalance, shaft cracks, shaft bows, and shaft preloads

On February 6, 1996, the system detected a very rapid change in the 1X vector on the front bearing of the IP turbine. As shown in Figure 2, the cluster of 1X vector trend points jumped from 10 microns to 45 microns with a slight phase change. We instructed operations to make changes to both real and reactive loads; however, neither increasing nor decreasing load affected this “new” 1X vibration vector appreciably.

A few hours after this incident, the unit was taken out of operation, according to plan. During the coast-down of the unit, the online system collected transient run-down data. This data was overlaid with previously collected transient data from several other shutdowns from just a few weeks prior. As shown in the Bode diagram of Figure 3, there was a spectacular change.

The team analyzed numerous facets of the data from all machine train bearings along with previously acquired inspection data as follows:

- The Bode plot showed a much larger amplitude response, but no significant change in resonant frequency.
- The IP turbine rotor was known to be quite sensitive to imbalance based on previous balancing experiences.

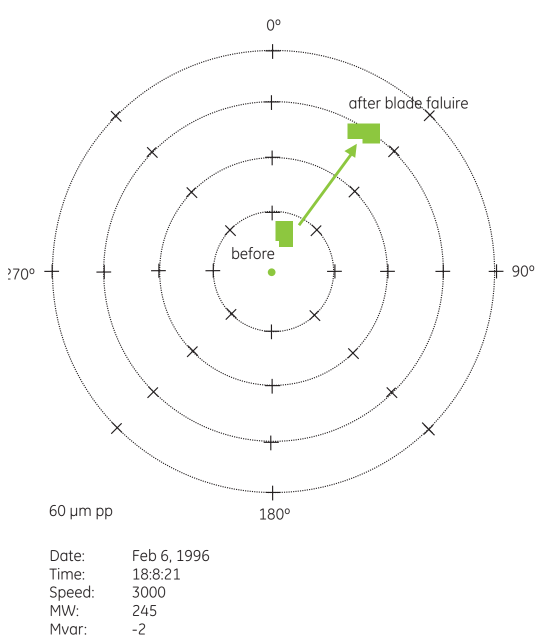

Figure 2: Polar trend plot from IP turbine bearing 1, showing before and after clusters of trend points with dramatic and sudden change of 1X vector. The vector change was more pronounced at #1 (front) rather than #2 (rear) bearing, suggesting the malfunction location was closer to the front bearing than the rear. (Each ring represents a 15 micron change in vibration amplitude, measuring outward from zero at the center.)

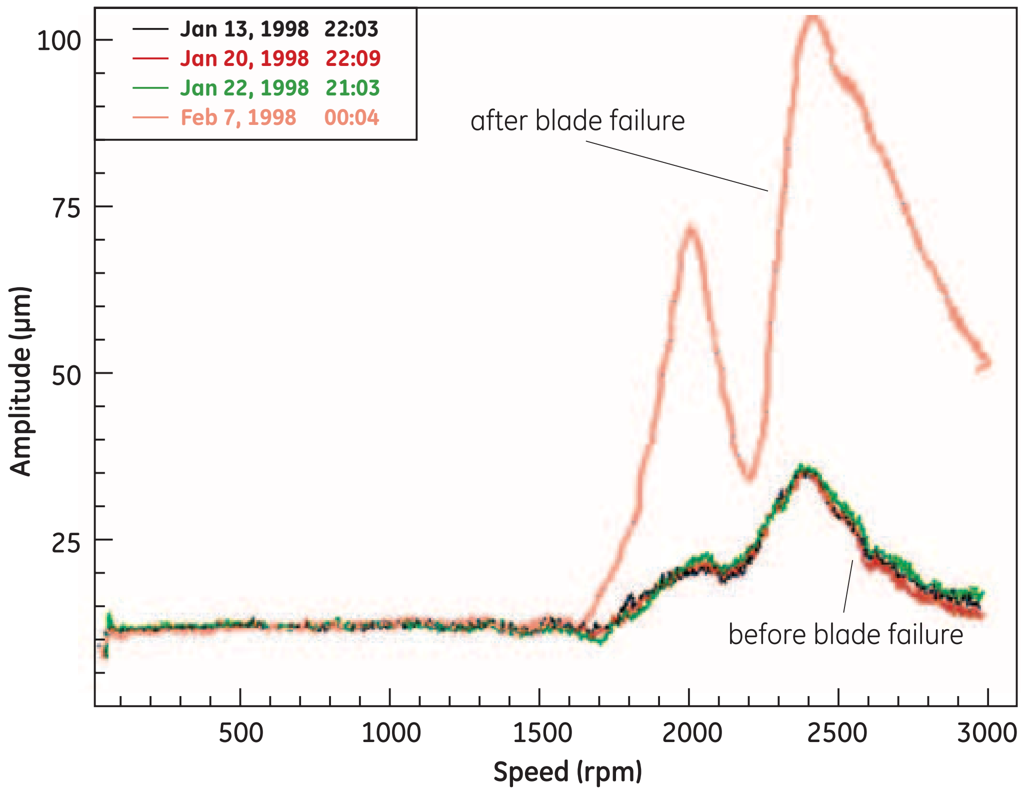

Figure 3: Bode diagram from IP turbine front bearing showing overlaid data collected prior to and after 1X vector change of Figure 2.

- The mode shape of the IP turbine rotor had changed.
- The 1X vector showed a rapid, sudden change and was most pronounced at the front bearing of the IP turbine.
- During an earlier inspection, pitting and cracking of blades on the #6 row of the IP turbine had been observed.

The most obvious conclusion based on the data was a sudden change in the amount and location of imbalance, caused by a loss of blading and/or shrouding in the IP turbine section. That same day, a decision was made to partially open the IP turbine to allow inspection of row #6. Preparations were also made to take stock of the repair options and to develop alternatives, carried out in collaboration with the machine OEM. Various scenarios were discussed, ranging from new blades, to blades repairs, to removal of blades. Affecting our discussions was also the knowledge that Unit 4 was scheduled to be removed from service in early 1997. Ten days after the 1X vibration vector alarms had occurred, Unit 4 was partially opened and, as expected, missing blade and shrouding material on row #6 was observed (see Figure 4).

Because the team was able to very narrowly pinpoint the suspect portion of the machine, the interior parts of the IP turbine (inner cylinders and glands) remained closed, resulting in a much less invasive inspection than would have incurred had the condition monitoring data not been available.

As mentioned, the unit was scheduled to remain in service for only another 12 months. As such, we elected to simply remove the entire row of blades (Figure 5), rather than replace or repair. The unit was returned to service on Feb 26, 1996, less than 20 days after the blades broke. The "repair" cost 100,000 USD, including 200 man-days of labor. Alternatively, renewing the entire blade cascade would have taken at least four months to complete and would have come to 1MM USD, including fines.

Had the condition monitoring system not been in place, the outage would have been far more invasive, as the source of the problem would not have been known with nearly as much precision. It is also likely that additional damage may have ensued, affecting other blade rows, rather than confining the damage to only a single row. While the removal of row #6 resulted in a 1% overall decrease in turbine efficiency, 3MW loss of power, and 100,000 USD in additional fuel costs for the remainder of its service life, this was more than offset by the savings realized by removing rather than repairing/replacing the blade cascade.

*Denotes a trademark of Bently Nevada, Inc., a wholly owned subsidiary of General Electric Company,

References

1. Gerard de Jong, "25 Years of Experience With Online Condition Monitoring at E.ON Benelux," Orbit, Vol 26 No 2, 2006, pp. 12-16.

Note: This article is available for download at the following link: http://www.ge-mcs.com/download/orbit-archives/online_condition_eon.pdf

Figure 4: : Inspection confirmed the loss of blading and shrouding on row #6 of the IP turbine.

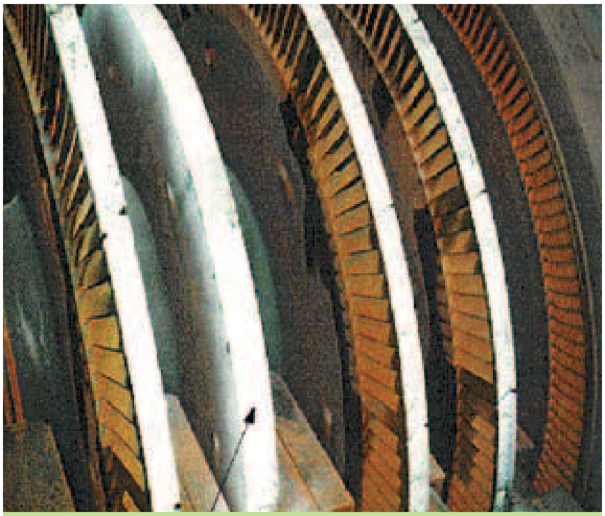

Figure 5: Row #6 was subsequently removed by grinding, since the machine was slated to remain in service for only another 12 months.

PCM Strategy Success at Dublin Bay Power, Ireland

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Dublin Bay Power Plant

The Dublin Bay Power Plant is a 400MW Combined Cycle operation. It is situated one mile (1.5km) from Dublin city center on the south bank of the River Liffey. It has been in operation for 10 years and typically supplies 10% of Irish electricity demand. It achieves over 90% availability (rolling availability over three years) and this, together with efficiencies of over 57%, makes this one of the most effective plants on the grid. The station is owned by Synergen Energy Limited, a subsidiary of ESB.

The maintenance strategy is focused on maximizing availability and minimizing forced outage rate. To achieve this, a Proactive-Centred Maintenance (PCM) strategy is applied. A cornerstone of this approach is an Integrated Condition Monitoring platform, which is based on GE's System 1* software. This is applied to the Main Generation Unit, Boiler Feed-water Pumps, Gas Compressors, Condensate Extraction Pumps, and balance of plant machinery assets together with the Main Transformer. A Supporting Services Agreement (SSA) is in-place with the GE Services team providing Remote Diagnostics and System Support, on both a planned and alarm/event basis.

The plant was originally equipped with Bently Nevada vibration monitoring equipment on the Main Generation Unit only. In the following years the monitoring equipment has been updated and developed in accordance with the PCM maintenance strategy. The wireless monitoring system has proven to be a very useful addition, as shown by the summary in Case History #1.

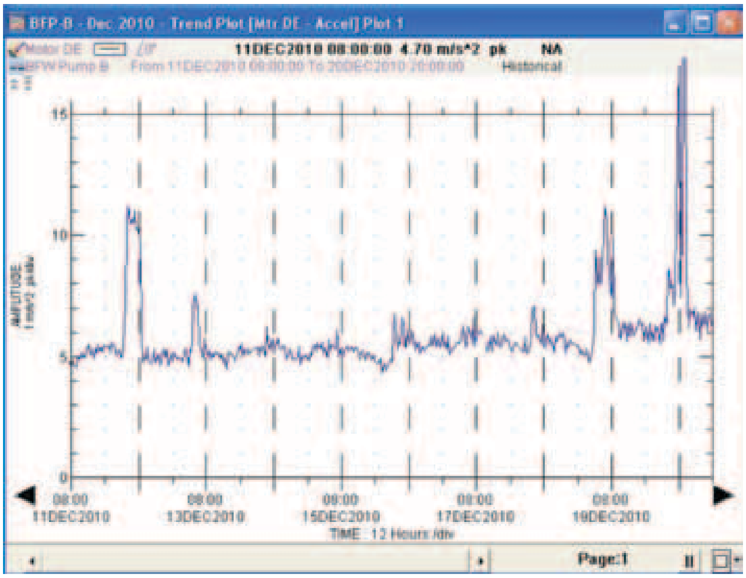


Figure 1: Motor drive end vibration showing periodic vibration peaks.

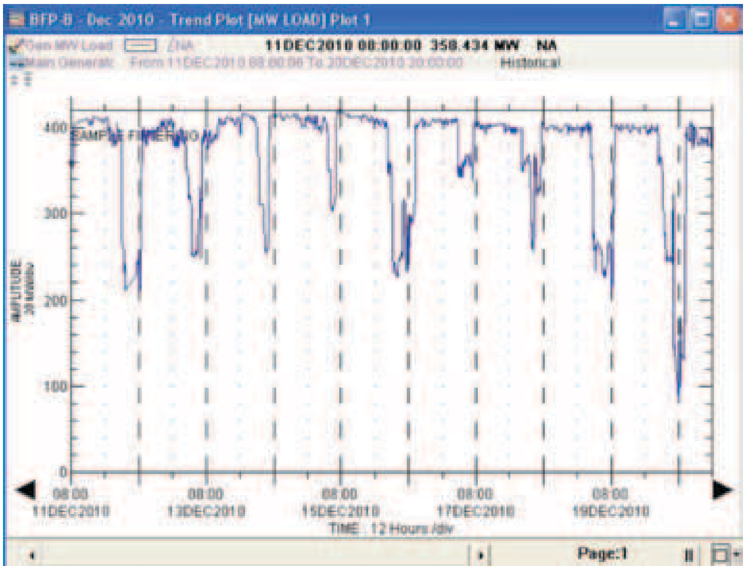


Figure 2: Trend plot showing daily load reductions from 400 MW.

Case History #1 – Pump Coupling Problem

In November 2010 a Bently Nevada Wireless condition monitoring system was installed on the Boiler Feed Pumps. During a routine remote connection, the Supporting Services team noted that the Motor Drive End (BFWP B) showed higher vibration levels than usual (Figure 1).

The observed periods of higher than normal vibration occurred at approximately 24-hour intervals, and correlated with daily plant output reductions (typically from midnight until 6:00 a.m.), as shown in Figure 2.

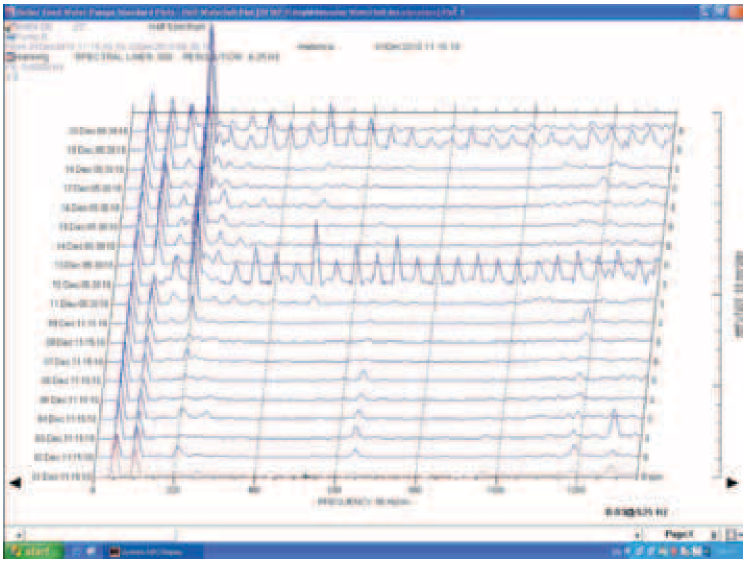


Figure 3: This waterfall plot shows a significant 200 Hz vibration component at the Feed Pump B motor DE bearing during the reduced load period.

Initially the wireless system was set for daily waveform data collection at 11.15 a.m. When this high vibration issue was noticed, the wireless system was remotely reconfigured to collect daily waveform samples at 5:30 a.m., in order to include the reduced load period. As shown in Figure 3, a significant vibration component was observed at 200 Hz.

The plant maintenance staff was notified of the situation and, with remote diagnostic support, further investigation was performed. The symptom was rapidly traced to an issue with the feed-water pump coupling.

Paul Collins, Maintenance Manager, concluded, "The vibration data gathered aided in the root cause identification of a faulty motor coupling. Prior to the Wireless being installed the fault would not have been identified until further damage to the fluid coupling and possibly the feed-water pump itself had occurred."

Ongoing Actions

The plant has two Boiler Feed Water Pumps. During normal operation, only a single pump is required. However, while this high vibration condition was being investigated on the B pump, the A pump was already out of service for maintenance. Hence, the B pump was critical to the ability of the plant to maintain its generation output.

This is being considered with the Dublin Bay team given that this level of criticality is better served with an online continuous monitoring system (3500 Series) with hard-wired operator alarms.

Case History #2 – Clutch Engagement Angle

The Main Generation Unit is a single shaft arrangement. The machine train consists of a Gas Turbine, Generator, Clutch, High, Medium and Low Pressure Steam Turbines. The Unit start-up sequence follows a programmed series of events, listed here:

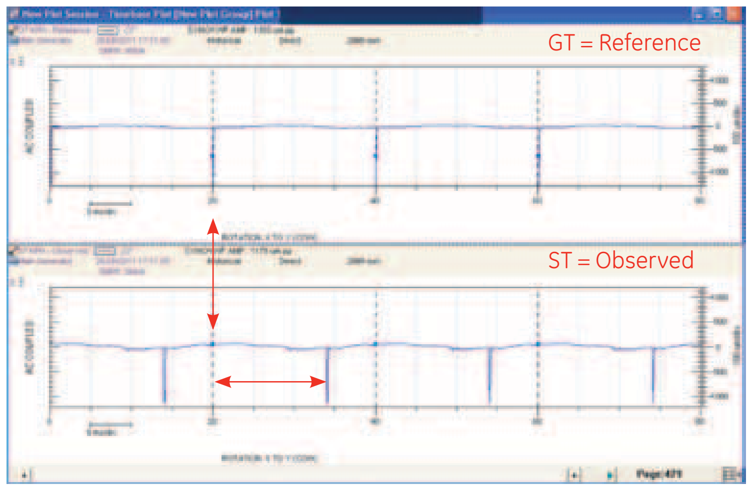


Figure 4: These plots show the timebase waveform signals from the Keyphasor channels. The upper plot is from the Gas Turbine and the lower plot is from the Steam Turbine. The RulePak determined that the phase lag between the two signals in this example was 251 degrees.

- Gas Turbine and Generator runs up to 3000 RPM
- Steam Turbine runs up to 3000 RPM
- Clutch Engages (torque direction across the clutch is towards the generator)
- Steam Turbine loading and the plant output continues up to 400MW

Over a period of time, it was noted that some start-ups had issues with vibration when the steam turbine enters service and the clutch engages. This resulted in random steam turbine trips on high vibration, and increased risk during plant start-up. The cause of this was suspected to be related to the balance condition on each side of the clutch. The balance condition would improve or degrade as a result of how the amplitude and phase interacted which is suspected to be dependent on the clutch engagement angle. However, the analysis of the problem was complicated by the variable engagement angle of the clutch which initially could not be monitored.

The GE Engineering Technology team review the application and determined that a System 1 RulePak could be developed to monitor the clutch engagement angle. This RulePak uses the Kephasor* signals from each side of the clutch to determine a Clutch Engagement Angle. This angle is essentially the phase lag between the Reference Keyphasor signal (from the Gas Turbine) and the Observed Keyphasor signal (from the Steam Turbine). The Phase angle between the two signals is the Calculated Phase Lag (Clutch Engagement Angle).

Figure 4 shows timebase waveform plots for the Keyphasor signals.

Figure 5 shows a trend plot of the measured Clutch Engagement Angle. In this example, the angle starts at 251 degrees (data trace at left side of plot), followed by a shutdown. The unit was restarted about 8 hours later, and the new Clutch Engagement Angle was 326 degrees.

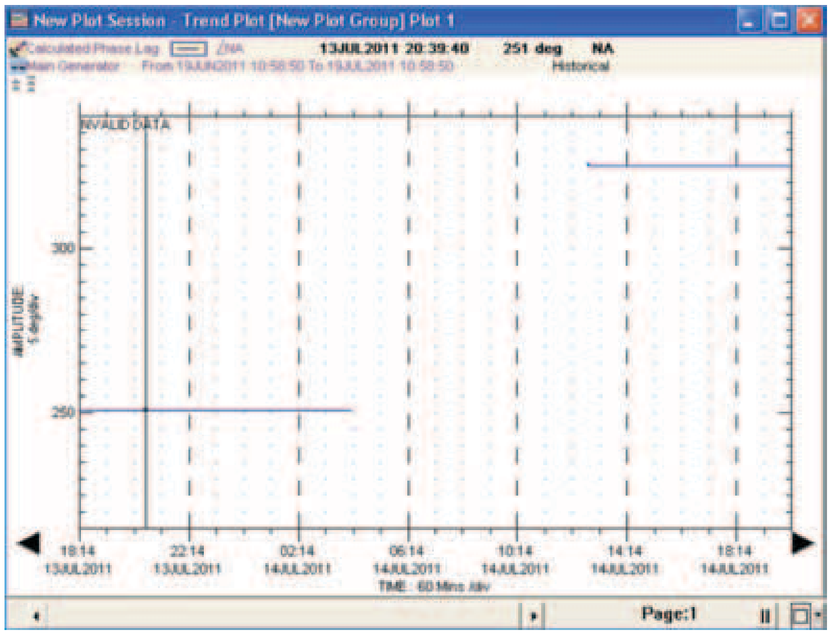


Figure 5: Clutch Engagement Angle trend plot.

Ongoing Actions

The next step will be to fully confirm the correlation between the Calculated Phase Lag (Clutch Engagement Angle) with the vibration behavior during steam turbine loading. Ultimately this will allow better analysis and fault finding of vibration issues and the clutch performance.

Case History #3 – Transformer Condition Monitoring

The main station transformer steps up the generator voltage of 22kV to the grid voltage 220kV. In accordance with the plant strategy GE's Kelman TRANSFIX™ Dissolved Gas Analysis (DGA) unit (Figure 6) was installed to provide insight into the condition of the transformer. The GE Supporting Services team integrated the data into the System 1 platform via MODBUS® over Ethernet protocol, so that Alarm status and Gas Concentration information is now available continuously (Figure 7). This enables the System 1 functionality to be applied to Transformer condition monitoring data in addition to remote support.

So far, the transformer is working fine, so this Case History is not about a specific problem. Instead, it is about how System 1 software is being used to continuously monitor a critical asset at the plant. This is a great example of condition monitoring for a "fixed" asset that is not a rotating machine.

Summary

These three Case Histories illustrate the benefits, flexibility and functionality of System 1 in a Proactive-Centered Maintenance (PCM) operation. As the business needs and technology have evolved, so has the System 1 platform.

As summarized by Paul Collins, Maintenance Manager for the plant, "The application of condition monitoring systems gives greater knowledge which allows better maintenance and asset management decision making. This has proven to be the case at Dublin Bay Power plant."

*Denotes a trademark of Bently Nevada, Inc., a wholly owned subsidiary of General Electric Company.

TRANSFIX is a trademark of General Electric Company.

MODBUS is a registered trademark of Modbus Organization, Inc.

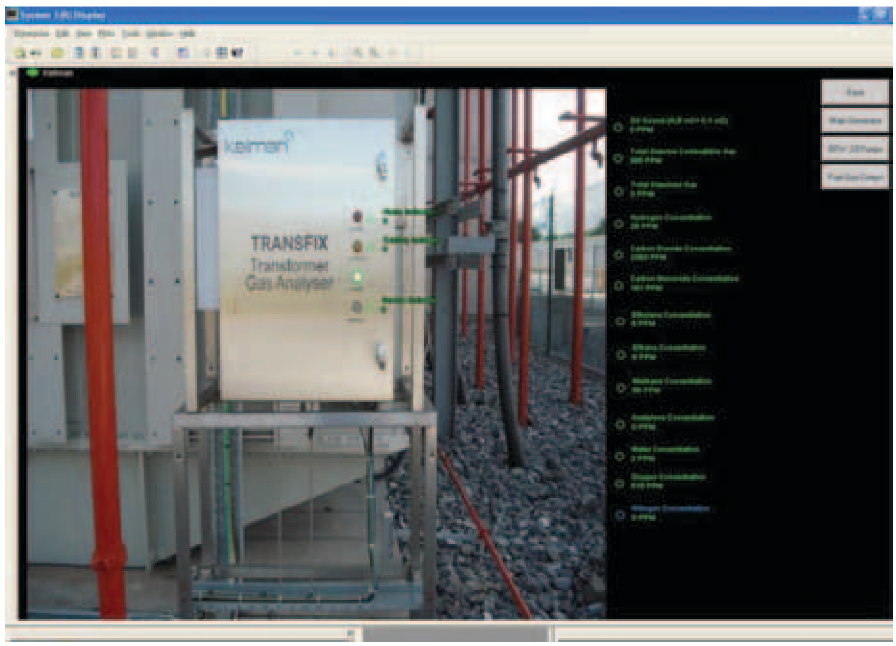


Figure 6: Dissolved Gas Analysis – Current Values shown in System 1 display.

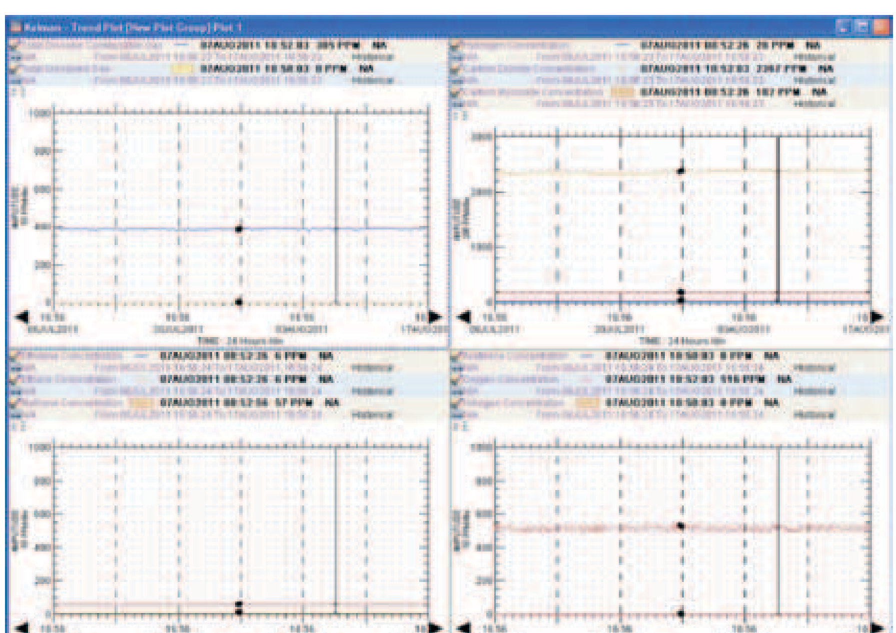
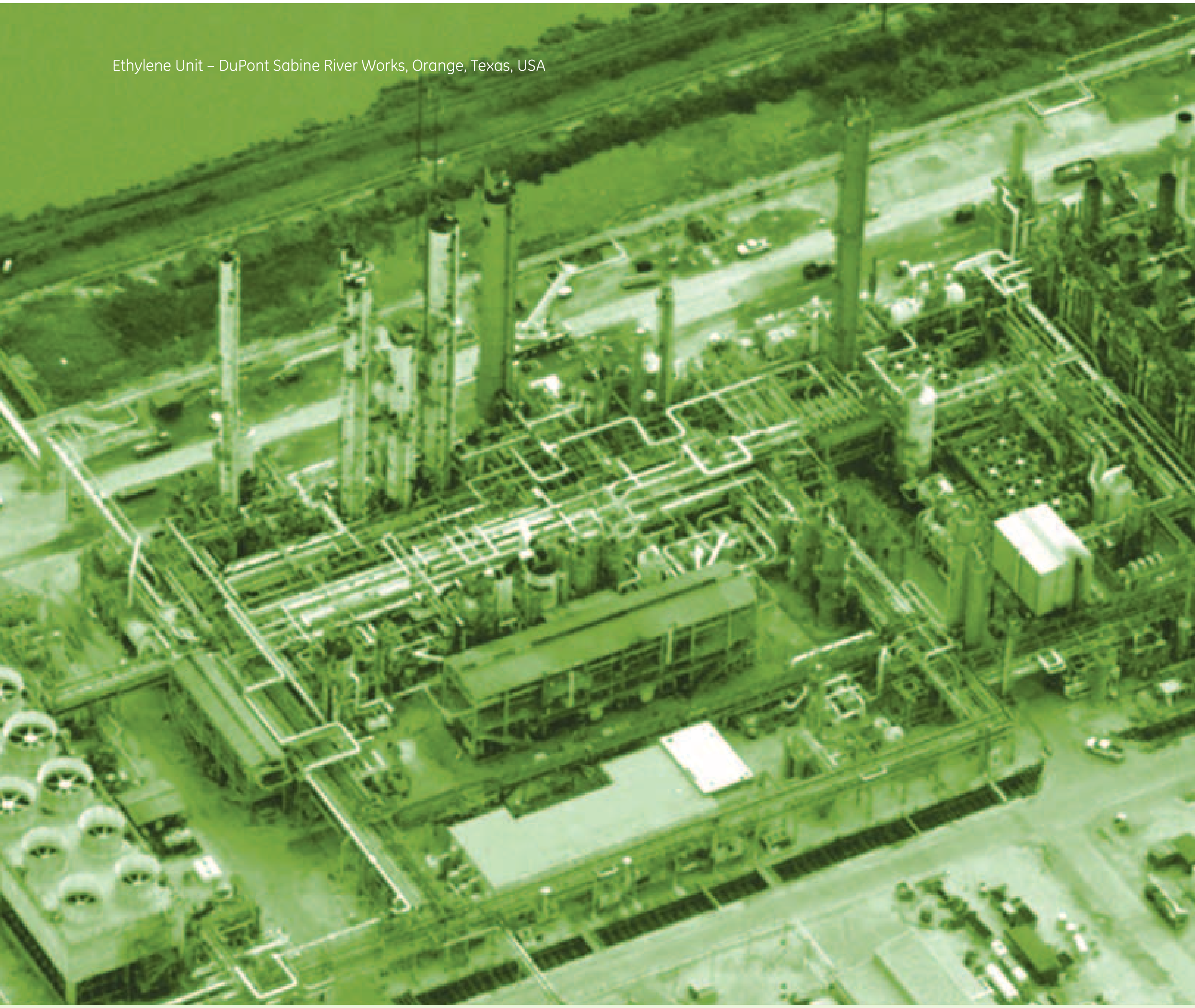
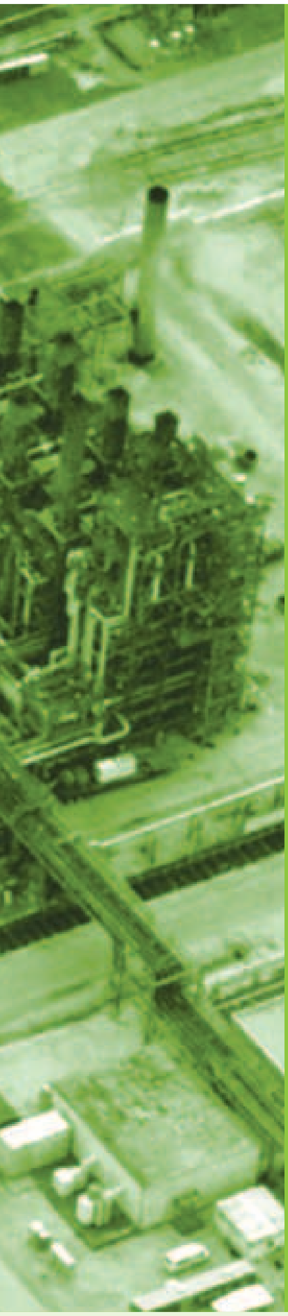


Figure 7: Dissolved Gas Analysis – Steady trend values show that transformer conditions are normal.



Ethylene Unit – DuPont Sabine River Works, Orange, Texas, USA



Electrostatic Discharge

in a Condensing Steam Turbine Driving a Propylene Compressor Train

FOUNDED IN 1802, DUPONT CURRENTLY OPERATES IN MORE THAN 70 COUNTRIES.

The Sabine River Works (SRW) site in Orange, Texas, USA, has contributed to DuPont's success for over 50 years, with its first ethylene plant in operation in 1948. A new ethylene plant was placed in operation in May 1967, and continues to supply ethylene for use in the manufacture of ethylene copolymers at both SRW and Victoria, Texas plant sites and for export to other users in the United States' Gulf Coast region.

In May 2008 the ethylene unit completed a major planned overhaul, which included six major compressor trains. During the outage the existing Bently Nevada* 3300 monitoring system was upgraded to the 3500 monitoring system with Transient Data Interface (TDI). The new monitoring system was connected to the existing System 1* platform, which includes the Bently Performance* option.

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Bently Performance software extends the functionality of System 1 to include online thermodynamic performance monitoring of machinery. This allows the plant staff to monitor compressor thermodynamic efficiency along with vibration in a collaborative environment. Acceptance regions and Rules are configured to send e-mail notifications for abnormal conditions. A remote capability is also available to plant engineers and other trusted consultants. This remote connection capability proved instrumental in assisting in a quick response to the developing machine issue described in this article.

After the outage, the Ethylene Unit was returned to service. The Ethylene Unit turbomachinery team, together with their corporate Engineering Team and GE's Bently Nevada resources, successfully diagnosed and mitigated a critical bearing failure mode on a 36,000 HP steam turbine, as described below.

Following a process upset, the steam turbine was diagnosed with a possible light rub. As vibration levels continued to rise over the ensuing weeks it was noted that there were indications of typical electrostatic discharge. Using their System 1 platform, the team was able to diagnose this rub and also identify an electrical discharge phenomenon that was destroying one of the critical steam turbine's journal bearings at an alarming rate of one percent per day.

The team employed grounding brush technology to stop the progression of this bearing failure mode. Because of the team's prompt reaction and troubleshooting skills using the System 1 tools, the failure mode was impeded before it would have necessitated an immediate unit outage to make bearing repairs. This allowed the Ethylene Unit to continue to operate and postpone an unplanned 14-day outage – which would have cost $3.2 million USD ($200,000 Labor & Materials, $524,000 Startup & Shutdown, and $2.46 million in lost earnings).

Machine Train Layout

Figure 1 shows the propylene compressor train that is the subject of this article. A steam turbine drives a Low Pressure (LP) and High Pressure (HP) axial compressor, which are coupled in tandem.

Machine Characteristics

- Steam Turbine: 36,000 HP 600 psi condensing unit, (rotor weight = 10,500 lb).
- Low Pressure Compressor (LPC): 8 stage centrifugal compressor, (rotor weight = 10,800 lb).
- High Pressure Compressor (HPC): 4 stage centrifugal compressor, (rotor weight = 6,000 lb).
- Typical machine operating speed = 3,800 rpm

Condition Monitoring System Display

The System 1 display consoles shown in Figure 2 are located where they are easily accessible by the turbomachinery team.

Process Upset

On the morning of 10 April 2009, a process upset following a converter mis-valving event sent the Propylene LP Compressor into a severe surge condition (Figure 3).

Figure 1: Propylene Compressor Train

Figure 2: This photo shows the System 1 display monitors that are a main part of the condition monitoring system.

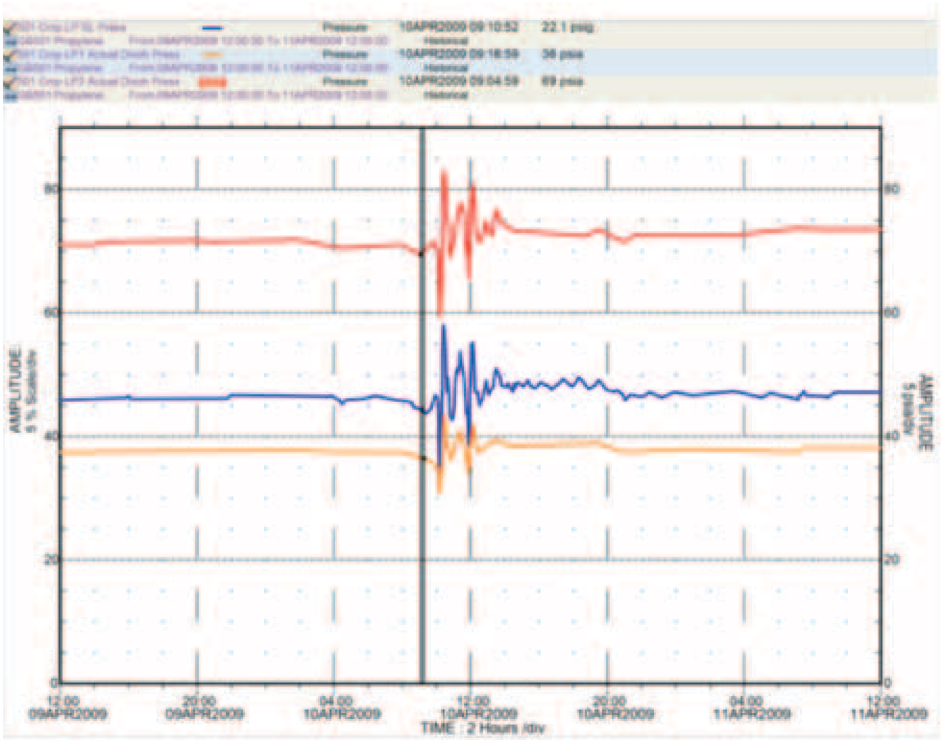

Figure 3: This pressure trend plot shows the process upset in the Propylene LP Compressor

Initial diagnosis of the event included reviewing the following parameters:

- Vibration on all bearings
- Temperature on all bearings
- Axial position of all rotors
- Phase angle shift of all rotors
- Spectral analysis of vibration
- Process temps & pressures
- Steam temps & pressures
- Plant loading
- Machine speed & horsepower

The data reviewed in these parameters did not appear to correlate with the vibration trends. However, the shape of the orbit (Figure 4) in the steam turbine outboard bearing suggested that a rub condition could be present. Figure 5 shows trends of the unfiltered (Direct) vibration amplitudes at the steam turbine bearings.

The decision was made to continue to monitor machine condition with the expectation that the process conditions would stabilize with the proper valve operations set.

We believed that this rub was due to a thermal bow of the rotor on that end of the machine, possibly a "hot spot" on the rotor. We adjusted the balancing steam to pull more flow from the high pressure end of the machine to the low pressure end. This slowed the rate of change in bearing vibration. At this point, we continued to monitor the machine, expecting stabilization.

Vibration continued to slowly trend up (Figure 6), even after waiting for the thermal bow to dissipate. The team began to look at other possible failure mechanisms that could be exhibiting such behavior. The rub was evident, but closer examination showed a continuous degradation in shaft position within the bearing. Having noted this, other previously unseen clues began to surface as suspect.

Subsequent Diagnosis

Over a month after the process upset and continuously monitoring the slow increase in the steam turbine outboard bearing vibration data the DuPont Engineering Team called in their partners at GE Energy's Machinery Diagnostics Services to remote into the System 1* server to assist in the determination of the unusual vibration trends that were being observed.

There was concern and a desire to avoid an unscheduled outage, which would have impacted contractual obligations for production. Also, the Memorial Day weekend was approaching, and personnel availability can be an issue during holidays. Through a remote wide area network connect the GE Energy team reviewed the data from the initial startup in February 2009 to collect reference data for proper review of various plots.

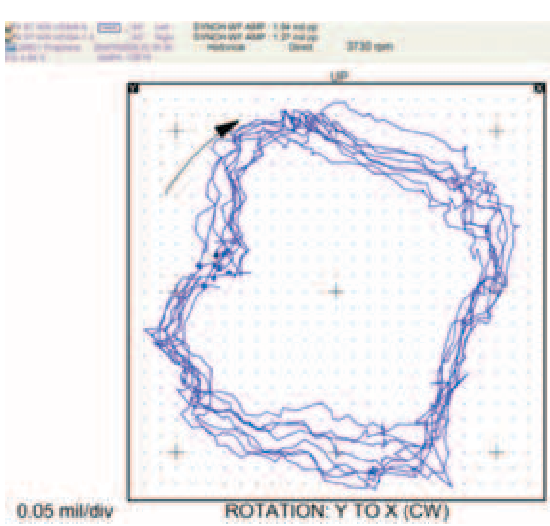

Figure 4: Steam Turbine Outboard Bearing Orbit

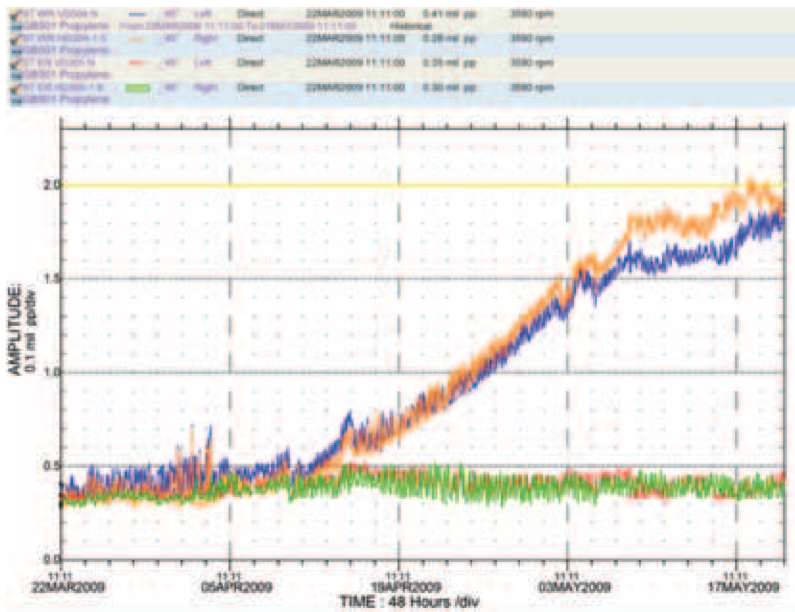

Figure 5: Steam Turbine Direct Vibration Trends. The upward trend of the orange and blue data (VD-304 & HD-304) indicates that vibration was increasing at the steam turbine outboard bearing

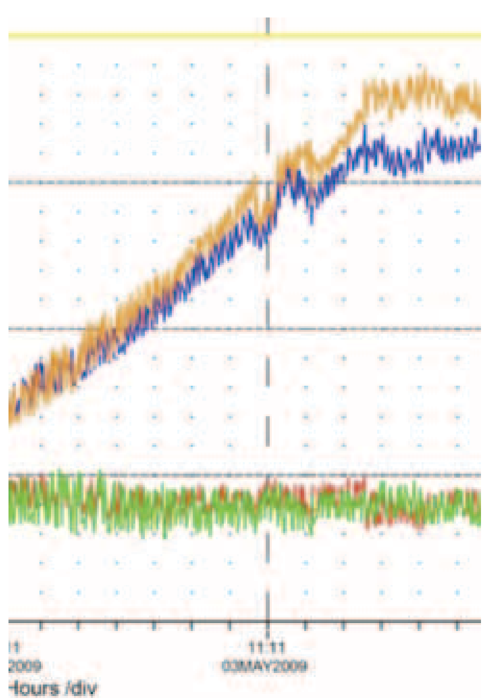

Figure 6: Steam Turbine Outboard Bearing vibration increase slows

The shaft centerline plot for the turbine bearing was reviewed with the plot compensated for the initial gap reference values from the startup (Figure 7). The data was startling as the shaft centerline data showed that the rotor had dropped outside of its bearing clearances, indicative of bearing damage. It was determined that the direction of decay was into the loaded portion of the bearing. The data review now took on more urgency as to determine a possible cause for the apparent damage and also to try to pinpoint when the degradation may have started.

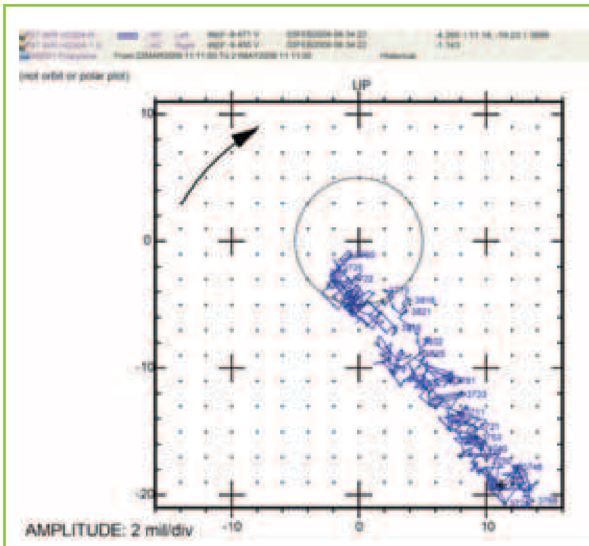

Figure 7: Steam Turbine Outboard Bearing Shaft Centerline Plot. Observe that the indicated position has exceeded the "clearance circle" by approximately 15 mils, indicating probable degradation of the bearing metal.

The process upset that had occurred on 9 April 2009 was initially reasoned to be the logical starting point that caused the bearing damage but as seen in Figure 8, it was apparent that the bearing revealed it was in distress starting almost 5 days prior to the process upset.

While the vibration amplitude increases for the steam turbine outboard bearing appeared to definitely begin to increase around the time of the process upset, the gap voltage for one proximity probe in the steam turbine outboard bearing was trending down, or in the negative voltage direction.

Proximity probes have two components, the ac component which is where we get the vibration signal from and the dc component, which is where we get the position information of the shaft within the bearing clearance. The proximity probes are mounted in an orthogonal orientation (90° apart) near the bearings in order to provide vibration and position information for the respective shaft journal. The probes are called Y and X (sometimes Vertical and Horizontal as well) to associate with the Cartesian coordinates from an oscilloscope.

The proximity probe operates with a negative voltage and as the shaft material moves closer to the probe the dc voltage becomes less negative (smaller values) and when the shaft moves away from the probe tip the d/c voltage becomes more negative (greater values). In this case it was the Y probe that was reflecting an increase in the voltage (more negative) which correlated with the shaft centerline plot seen earlier.

As the change in the steam turbine outboard bearing Y probe d/c voltage began prior to the time of the process upset event, the data review went into a search for possible causes. There had been observed periodic spikes in the orbits and timebase signals that had been originally thought to be noise in the vibration signals possibly related to a damaged signal cable. Additionally, the vibration signals had seen periodic spikes in the older monitoring system that was diagnosed to be from one of the monitors. After a monitor upgrade in the Summer of 2008 and the subsequent damage the plant sustained during the flooding from Hurricane Ike in the Fall of 2008, it had been theorized that the spikes observed in the vibration signals after the plant restart in February 2009 to be a result of some of the Ike damage that had not been able to be adequately discovered and repaired during the Winter 2008 forced outage.

The spikes seen in the orbits were reviewed again for possible other indications. Figure 9 is an example of the Orbit Timebase signal for the turbine outboard bearing on 25 April 2009.

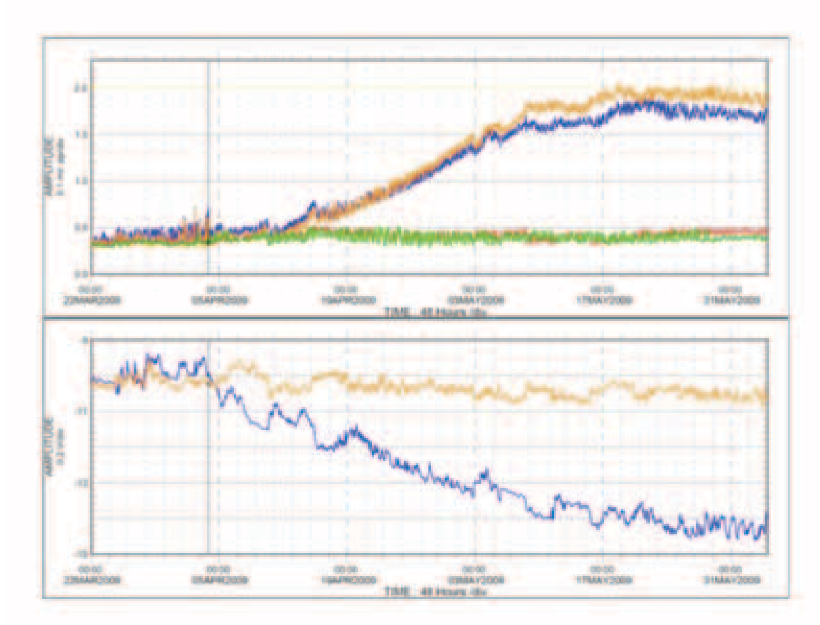

Figure 8: Steam Turbine Vibration Trends (upper) and Outboard Bearing Gap Voltage Trend (lower)

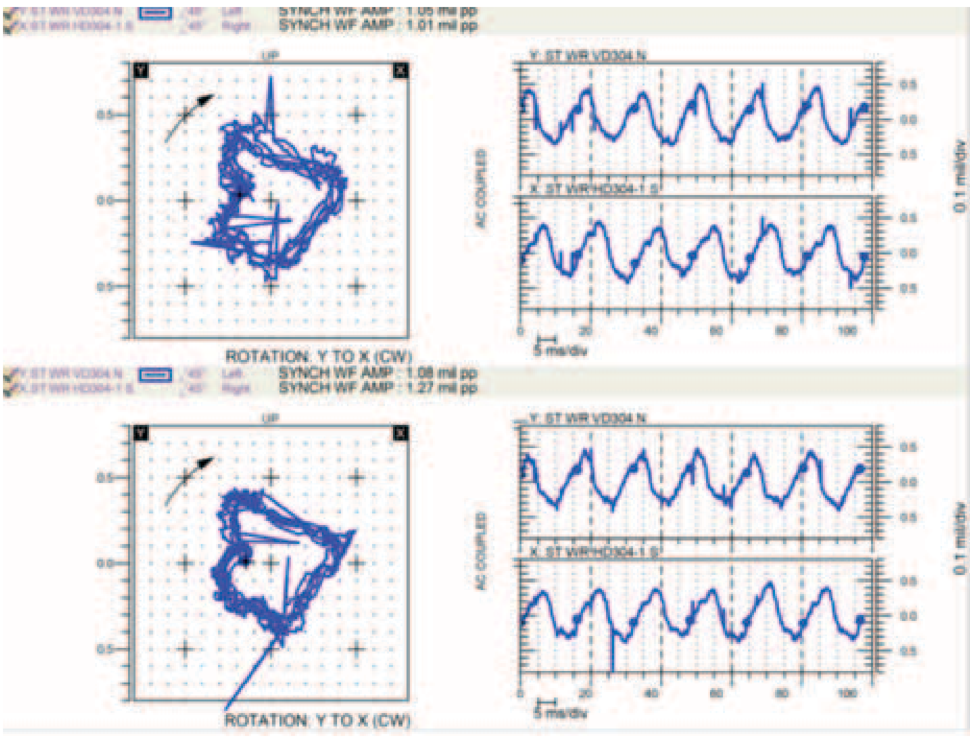

Figure 9: Spikes in Orbit Timebase for Turbine Outboard bearing 25 Apr 2009

Figure 10 shows the turbine outboard bearing orbit data taken one hour apart for six hours. The spikes are observed to be random, of varying magnitudes and occurring in both the positive and negative directions. Upon review of these characteristics it was theorized that Electrostatic Discharge may be the culprit. As the steam turbine was a condensing steam turbine then it was suspected that excessive static electricity was being developed by the rotative energy of the rotor in the environment of the condensing steam. Typically this is generally removed by a grounding brush to provide a path to remove such electrostatic energy.

Second Corrective Action & Response

Due to the direction of shaft movement into the load zone of the bearing, and the spikes seen in the orbits, the failure mechanism seemed to fit ESD (Electro Static Discharge) phenomenon. ESD bearing failures are typically due to the release of a static charge through the oil film of the bearing, causing babbitt pitting and deterioration.

The solution to this failure mode is proper electrical grounding of the rotating element, typically achieved by a grounding rod or brush (Figure 11). The installed grounding brush was inspected and found to be damaged – so a secondary grounding brush was installed to the turbine shaft as seen in Figure 12.

The grounding brush was installed on 28 May 2009 and the vibration trends were monitored to evaluate the effect of this solution.

The effect of the new grounding brush on the observed orbit plots are the bearing was immediately apparent (Figure 13). After the brush was installed, the "spikes" disappeared completely – indicating that ESD was no longer occurring through the bearing.

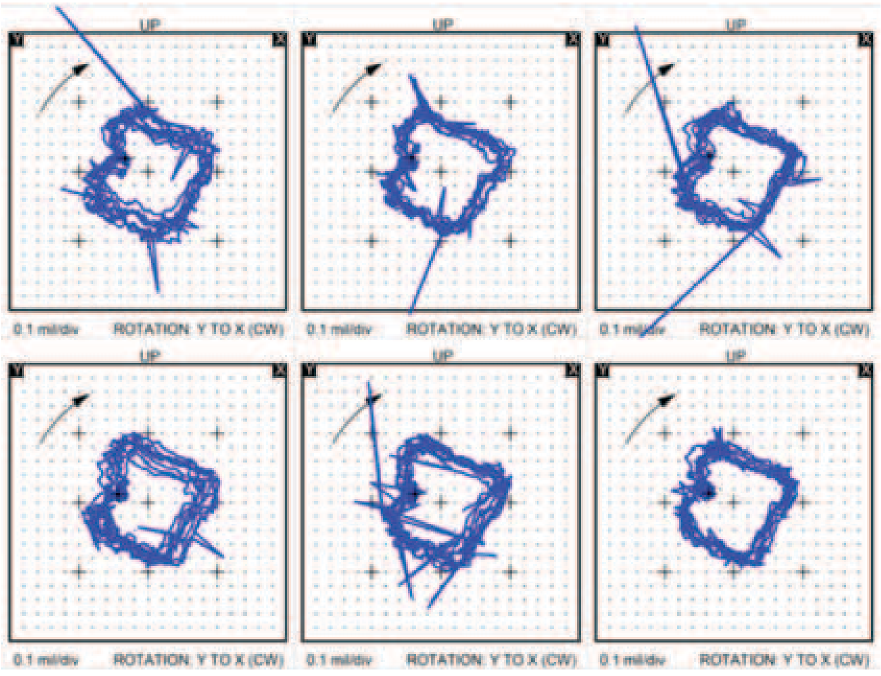

Figure 10: These orbits on the Steam Turbine Outboard Bearing 25 April 2009 were collected at one hour intervals.

Figure 11: Grounding Brush Tip is typically made of flexible conductive fibers or wires.

Figure 12: This photo shows the installation of a temporary grounding brush at the steam turbine outboard bearing

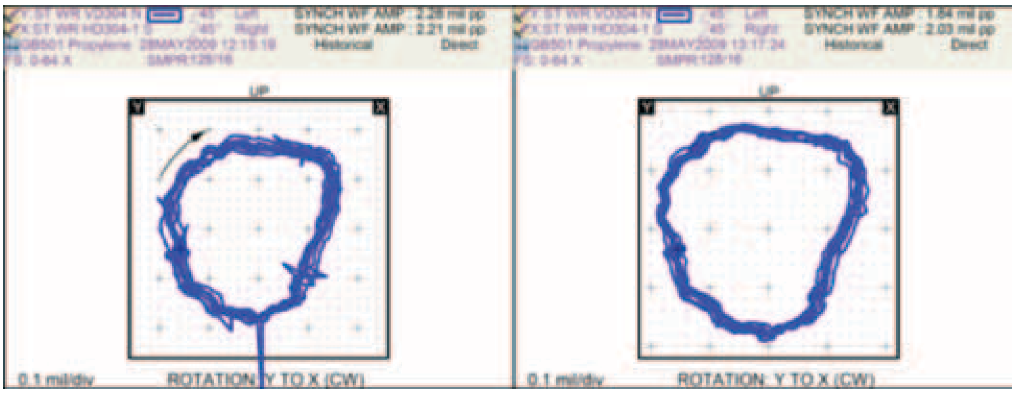

Figure 13: Orbit plots before (left) and after (right) the temporary grounding brush was added on 28 May 2009.

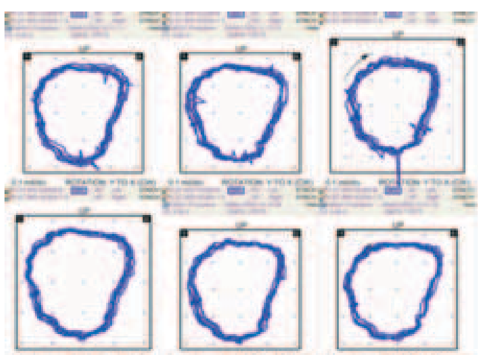

Figure 14: Hourly steam turbine Direct orbits on 28 May 2009, for the 3 hours before the installation of new grounding brush and the 3 hours after installation

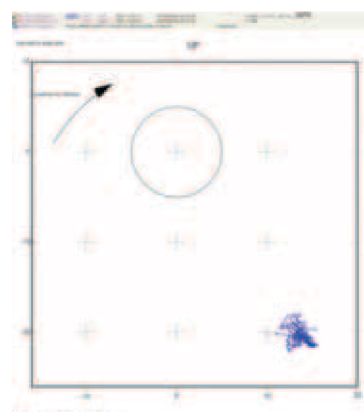

Figure 16: Although bearing deterioration has stopped, the shaft centerline is now located about 20 mils away from its normal position inside the bearing clearance circle.

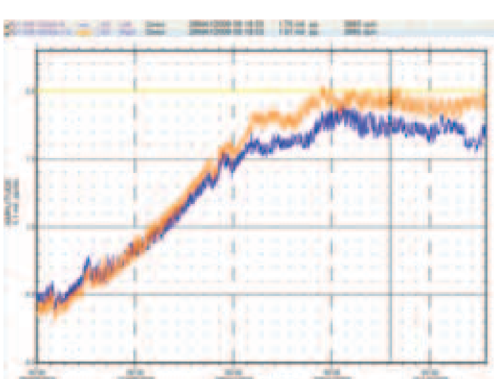

Figure 15: Vibration levels have stabilized below the Alert setpoint (yellow horizontal line).

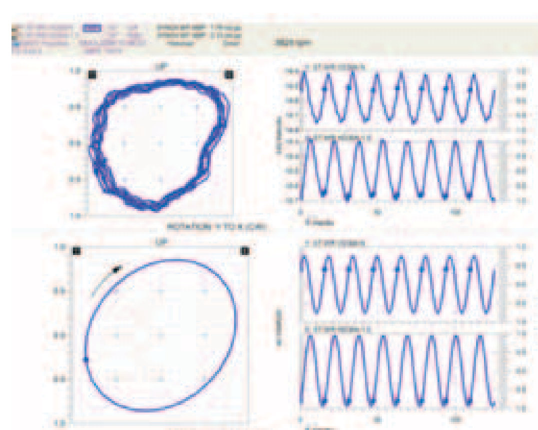

Figure 17: 08Jul2009 Shaft orbits have remained consistent.

More examples of the immediate effect of the ground brush application are shown in Figure 14 with spiking readily apparent for the three hours prior to the installation of the grounding brush but gratefully absent from the orbit trace for the three hours after the application of the grounding brush.

As shown in Figure 15, the steam turbine outboard bearing direct vibration amplitudes were observed to stabilize just below the alert alarm setpoint of 2 mil (0.0508 mm) peak-to-peak. This was a welcome sign that the evaluation on the second effort and the subsequent actions were successful to mitigate any further machine damage.

The average shaft centerline trace, seen in Figure 16, also indicated that no further damage to the bearing was occurring, although it did reflect that nearly 20 mils of babbitt was probably no longer present, indicating significant bearing damage had already occurred.

Six weeks after the installation of the new grounding brush, the steam turbine outboard bearing Direct Orbit Timebase plot continued to reflect an absence of electrical spikes - indicating that the ESD issue had indeed been mitigated.

The Rest of the Story

The resolution of the ESD issue allowed the operation of the unit to continue with planning put in place to replace the turbine bearings at an opportune time. An opportunity presented itself in mid August 2009 to take a quick outage on the propylene machine to replace the bearings for the steam turbine. Figures 18 through 24 reflect the damaged bearings and the damage to the shaft journals caused by Electrostatic Discharge.

> "Because of the team's prompt reaction and troubleshooting skills using the System 1 tools, the failure mode was impeded before it would have necessitated an immediate unit outage to make bearing repairs. This allowed the Ethylene Unit to continue to operate and avoid a 14 day outage."

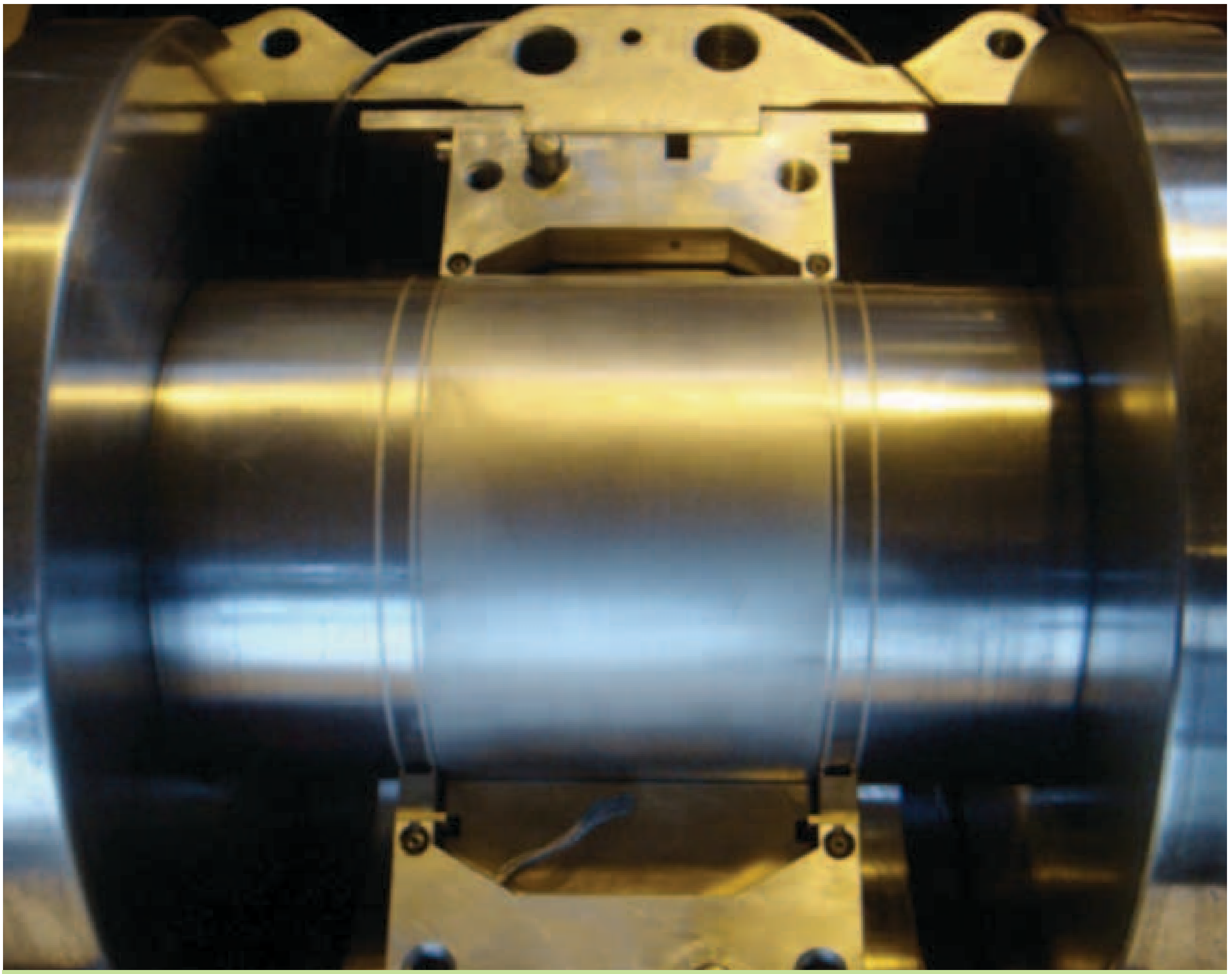

Figure 18: Steam Turbine Outboard Journal area displaying the "Frosted" shaft. This is a classic effect caused by Electrostatic Discharge (ESD), which creates microscopic pits in the shaft surface.

THE RESOLUTION OF THE ESD ISSUE ALLOWED THE OPERATION OF THE UNIT TO CONTINUE WITH PLANNING PUT IN PLACE TO REPLACE THE TURBINE BEARINGS AT AN OPPORTUNE TIME.

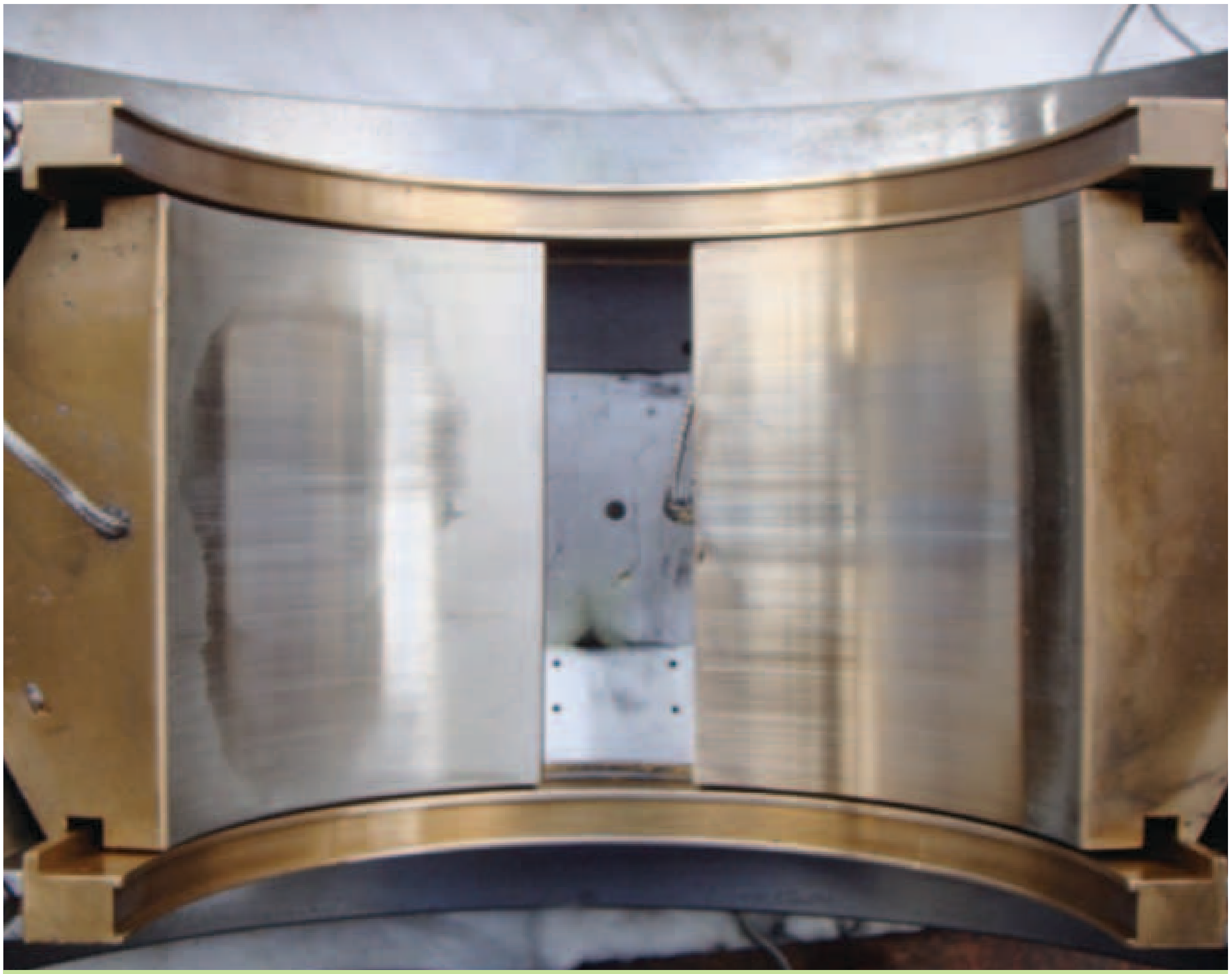

Figure 20: Damage to lower half of the steam turbine outboard bearing is very apparent.

Figure 19: Close-up photo of the Steam Turbine Outboard Journal, showing frosting effect.

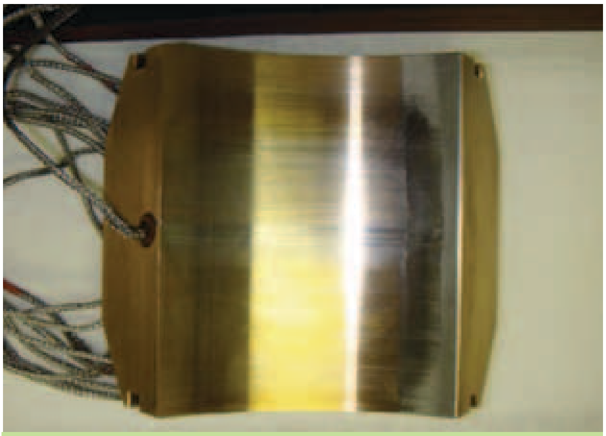

Figure 21: Close-up shot of the most heavily damaged bearing pad. The signal lead is for the embedded Type J bearing thermocouple.

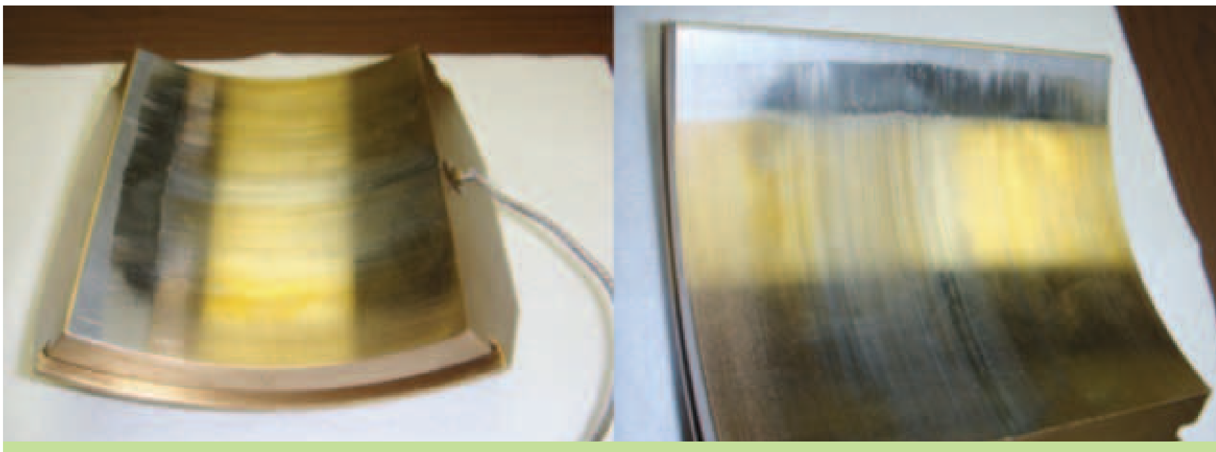

Figure 22: More photos of damage to radial bearing pad.

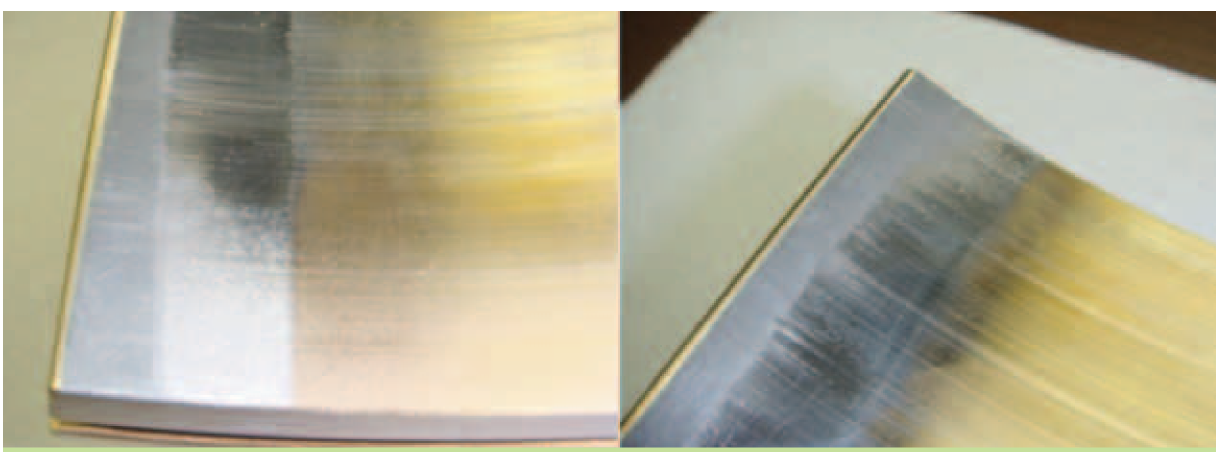

Figure 23: More close-up photos of damage to radial bearing pad

Summary

Vibration Monitoring is an important ingredient in any condition based monitoring program. Additionally, on line performance monitoring is an equally important part of the same condition based monitoring system. However, as discussed in this paper, the force multiplier for the Ethylene unit's Turbomachinery Team was their onsite expertise, their corporate expertise availability, and their well-established remote connectivity availability with GE's Bently Nevada trained Machinery Diagnostics personnel to quickly diagnose an issue with their machine. Their combined effective use of the GE System 1 Plant Asset Condition Monitoring platform to reliably review dynamic vibration waveform data for machine evaluation helped to make informed decisions for operations and corrective actions for their machine in distress.

With data and information in the appropriate trained hands, some inspections could be avoided and cost savings immediately recognized.

Acknowledgments

Photos, data plots, and analysis provided courtesy of, and used with permission of, DuPont Sabine River Works.

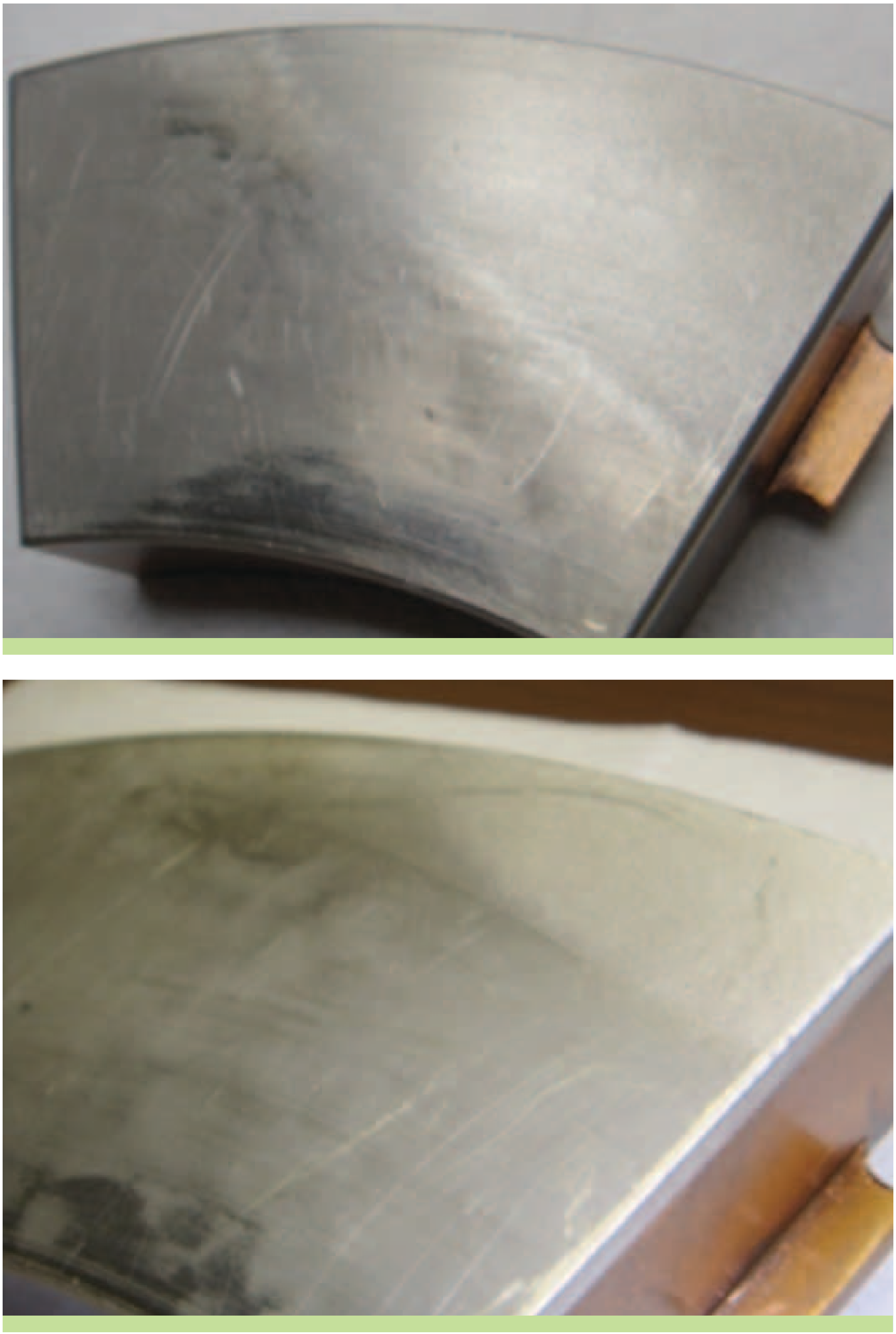

Figure 24: Although axial thrust position had not been a problem during this event, some ESD "frosting" damage was also observed on one of the thrust bearing pads.

(09/2011)