orbit

Volume 31 | Number 2 | 2011

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

Charting a Course for Condition Monitoring Software

Editor's Notepad

Editor | Orbit Magazine

Charting a course for condition monitoring software...

Greetings, and welcome to Orbit. In this issue, we will take a look at some interesting trends in Condition Monitoring (CM) software.

In keeping with the navigation theme of our cover image, our featured article, "The Evolution of Condition Monitoring Software," gives a strategic overview of where we are now and where we are headed in the future.

The ADRE* Tips article describes some useful features of Sxp software, and the User Centered Software article introduces modern techniques for developing software that meets the needs of users, while at the same time being intuitive and easy to use. Two machinery case histories describe examples of how System 1* software enabled users to avoid excessive downtime by supporting effective diagnosis of machine problems.

The Customer Value Realization article explains how we are working directly with our customers to gather specific suggestions to improve the effectiveness of our software, as well as the installation and commissioning process and network integration that is so vital for accommodating remote monitoring & diagnostics. Finally, the SmartSignal® article introduces a CM software application that uses advanced modeling techniques to provide very early warning of developing anomalies with sets of monitored parameters.

As I think back over the years, it is amazing to realize how far the computer/software/information technology revolution has progressed over just the past four decades. My own introduction to software came in 1971, when I took an introductory undergraduate course in programming, using a very basic application called (appropriately) Dartmouth BASIC™.

This program ran on a mainframe computer that was time-shared between my school and Dartmouth College, and accessed through a small (very slow) network of "dumb" teletype terminals. Our only GUI (Graphical User Interface) was the hardcopy paper output that the teletype machine printed. While some of my classmates moved on to more advanced programs, which they stored on stacks of punched paper cards, my very simple programs easily fit on several feet of rolled-up punched paper tape. Back then, it was difficult to imagine the full-color display screens and high-speed communication we now take for granted.

Here's to hoping the next few decades of information technology will welcome just as much innovation as the last. One day a future generation may look back and laugh at these primitive times when we were impressed by simple tools like phones that could connect to the Internet.

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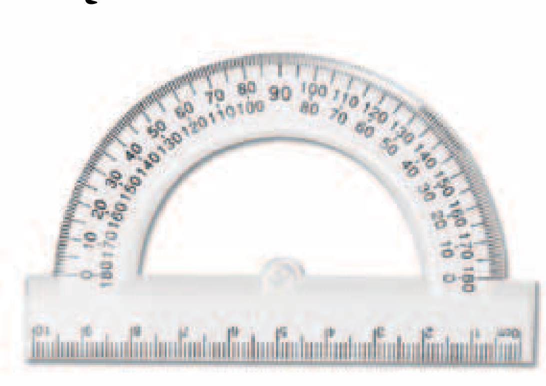
Cheers!
Gary



In this Issue

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3500 ENCORE* Factory Acceptance Test (FAT)

This news brief summarizes a recent Factory Acceptance Test that we performed at the request of a North American customer who purchased 3500 ENCORE modules to upgrade their existing 3300 monitor system. FATs are optional services that provide customers with direct access to the full resources of our engineering and manufacturing organizations while their monitoring systems are being tested.

Note: Even in the case where a customer does not specify a FAT, our Field Engineers perform loop checks and validate the satisfactory performance of all newly-installed monitoring system components as part of every installation job.

A 3500 ENCORE FAT is unique, as the modules are designed to be field-installed to replace the old 3300 modules in an existing 3300 rack, while retaining the transducer, Keyphasor* and relay field wiring system from the original system installation.

In order to perform a FAT for a customer who requests one, we need to recreate their plant environment. We do this by installing the Adaptor Cards, EMI Cage, and new Backplane into an appropriate 3300 rack (Figure 1) at the manufacturing facility, with the same kind of Input/Output (I/O) modules that are installed in the rack at the customer site.

After configuring the data collection and signal processing settings of the new monitor modules to match the old 3300 modules that we will be replacing, we apply test signals (Figure 5) to verify that the new 3500 ENCORE modules function as required, before removing them for transporting to the customer site.

After successfully passing the FAT, the 3500 ENCORE modules shown in these photos were sent home with the accompanying Field Engineer, for installation at the customer site. We will share details of the installation after the retrofit is complete. Stay tuned for more information. ■

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For more Information, visit our dedicated microsite at www.3500ENCORE.com.

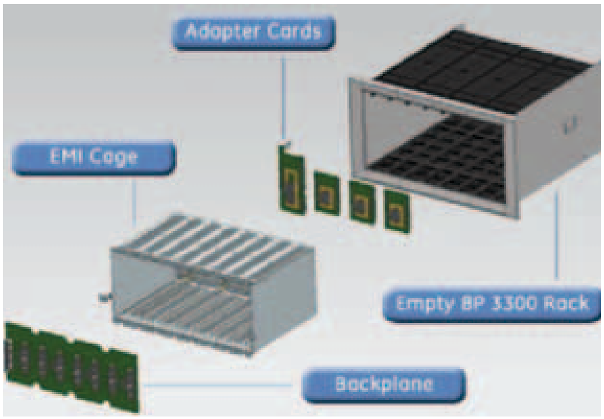

Figure 1: Components used to adapt an existing 3300 rack for new 3500 ENCORE modules.

Note: The EMI Cage is required because of increasingly stringent Electromagnetic Interference (EMI) regulations that have been implemented in the years since 1988, when the 3300 system was originally introduced.

Figure 2: Installing adaptor cards onto the existing 3300 backplane.

Figure 3: Field Engineer Randy Monkman and Manufacturing Engineer Doug Eckery discuss one of the modules to be tested.

Figure 4: After the adaptor cards, EMI cage, and new backplane are installed, the modules are inserted. Observe that the new backplane is blue, while the original 3300 backplane was green.

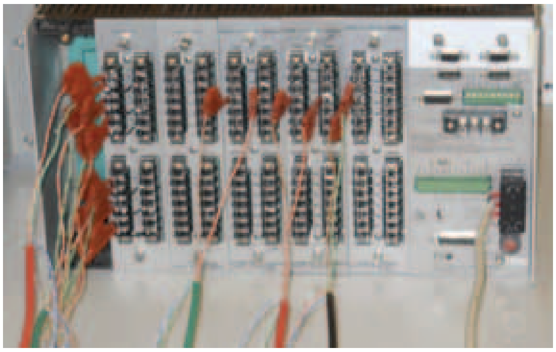

Figure 5: After the monitor modules are installed, power supply and signal leads are attached to the I/O terminals for testing the system.

Bently Team Receives Customer Value Enhancement Award

Based on its recent analysis of the condition monitoring market, Frost & Sullivan® recognized GE's Bently Nevada* product line, a unit of GE Measurement & Control Solutions, with the 2011 Global Frost & Sullivan Award for Customer Value Enhancement.

Each year, Frost & Sullivan presents this award to the company that has demonstrated excellence in implementing strategies to proactively create value for its customers – with a focus on improving the return on the investment that customers make in their services or products. This award recognizes the company's inordinate focus on enhancing the value that its customers receive (beyond simply good customer service), which leads to improved retention and ultimately to expansion of the base of satisfied customers.

The report recognized GE's Bently Nevada condition monitoring & machinery protection systems – particularly the 3500 ENCORE* Series Machinery Protection System – as examples of GE's dedication to customer-focused innovation. The 3500 ENCORE system is a pioneering upgrade package in the field of online condition monitoring that eliminates the need for a time-consuming and expensive replacement of existing systems.

"This means that customers can upgrade their existing Bently Nevada 3300 Series monitoring systems to the advanced 3500 ENCORE Series monitoring system and related digital technology through non-intrusive and cost-effective methods, without altering the existing infrastructure," said Frost & Sullivan Research Analyst Prathima Bommakanti. "This upgrade increases the life of the financial and resource investment made during the acquisition of the older 3300 Series monitoring system."

In addition to recognizing the new 3500 ENCORE system, the award acknowledged the value of GE's Customer Application Centers (CACs) for helping to familiarize and train customers with the family of Bently Nevada protection and condition monitoring products, including the following offerings:

- The 3300 XL series of proximity transducers
- Advanced Distributed Architecture Platform Technology wind solution (ADAPT*.wind)
- The ADRE* System: 408 Dynamic Signal Processing Instrument (DSPi) with Sxp diagnostic software
- The System 1* Condition Monitoring and Diagnostics Software Platform
- The Velomitor* series of piezo-velocity sensors

About Frost & Sullivan

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Customer Value Realization

Michael Turek
Bently Nevada Quality Leader
michael.turek@ge.com

At Bently Nevada, we are never satisfied with the status quo. In order to determine how much value our customers are actually receiving from our software products & services, we developed a process to gather detailed input.

In 2010, we launched this formal process to collect information from our customers, and regional teams are now using the results to focus their actions on addressing identified gaps at specific customer sites. The following areas of concern have been identified as a result of our ongoing assessments:

- Actionable Information (developing & implementing effective response process)
- Alarm Management (nuisance alarms vs. alarms of interest)
- Customer Training (onsite hands on training)
- Local Support (right people in the right place)
- Network Integration (cybersecurity, NERC & FERC compliance)
- Solution Implementation (better understanding of fit with site work practices)
- Software Extenders (for example, lube oil data import)
- System Complexity (making it easier to use)

Some of the questions that our assessment addresses include the following items. These questions are intentionally open-ended, and often result in very detailed discussions:

- Is our software driving effective decisions and actions?
- Is our software easy to use?
- Is our software integrated with your network?
- Are you receiving adequate training?

Assessment Results

Figure 1 shows the numerical results of our ongoing assessments. The x-axis shows a parameter called Value Realization Score (1.0 is the highest possible score). Our goal is to increase the average score and achieve greater customer satisfaction by looking at what those with the greatest satisfaction are doing differently and applying these lessons to those who are currently receiving less value from our products and services.

The following examples list some successful local practices that have been implemented for several years. The Customer Value Realization initiative encourages applying these existing practices more widely and is helping to make this approach a global standard.

Bently Days & Getting Close to Customer Events

A "Bently Day" or "Getting Close to Customer" event is typically a one day customer seminar focused at either a specific location for general Bently Nevada customers, or a at a location that is focused on an industry vertical such as Oil & Gas, Petrochemicals or Power Generation. These events are facilitated by our Global Field Application Engineers around the world for customers in their regions.

The objective of these events is to brief those customers on the latest developments with Bently Nevada monitoring & protection systems, condition monitoring & asset management technology and associated supporting services. It also provides a forum to share Bently Nevada Best Practices and for customers to present their case histories & lesson learned and to network with other users of the BN technology.

Bently User Groups

These events are customer focused, informal hands-on practice sessions for industry specific groups or internally for a large user lead by our Field Application Engineers. The invitation asks the customer to list any specific questions or issues that they would like to see covered. These are usually 4 to 7 hour events held up to four times per year.

Customer Application Centers (CAC)

CACs have been established in every global region, including locations such as Campinas, Brazil; Florence, Italy; Houston, USA; Manama, Bahrain; Moscow, Russia; Shanghai, China, and Singapore. Most recently, an all-new CAC is in the process of being established at Minden, USA. Existing CACs are continuously updated to improve the quality of the experience for visitors (Figure 2).

Drawing from a comprehensive portfolio of products and services, CAC specialists provide our customers with the latest information, recommended practices, and up-close experience with key offerings in their region. Examples of regional capabilities include the following:

- Product demonstrations and training
- Educational programs and conferences
- Custom product training
- Hands-on operation of Bently Nevada technology
- Factory acceptance testing

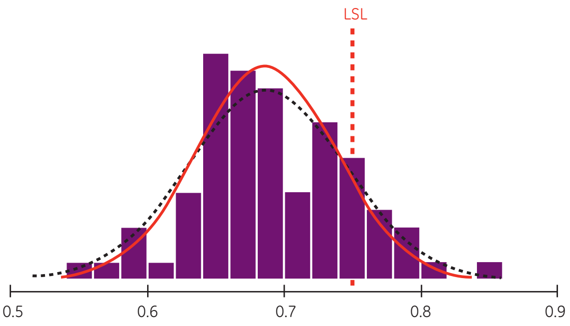

Figure 1: Numerical results of our Customer Value Realization assessments

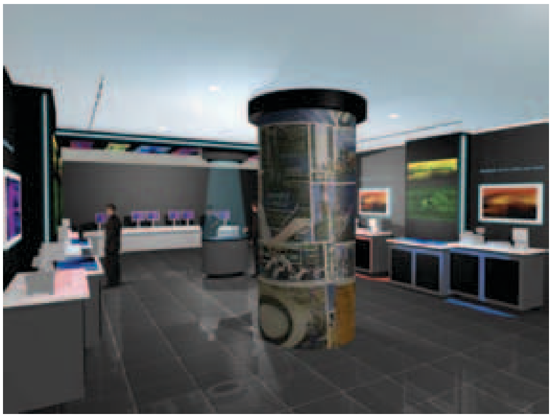

Figure 2: Shanghai CAC Concept Presentation Area enhancements (artist rendering).

Reference Sites

Reference sites are yet another global initiative that we have been implementing for the past several years. They allow our customers to partner with us in ways that help them to optimize the operation and maintenance of their plant – based on condition monitoring information provided by our products and services.

One of the top priorities that we are addressing is the issue of remote digital access to our customer sites. This is a challenging issue, as we need to balance the requirement for network security with the need to remotely access the data in order to provide them with expert assistance with evaluating and assessing their condition monitoring data. However, through engagement between our Systems Integration Engineering team and our customer's IT departments, we have successfully met the toughest security requirements while enabling remote access for expert machinery condition assessments.

Ongoing Software Development & Deployment

In addition to expanding the practices listed above, we are working to greatly improve the value that our System 1* software provides to users as it continues to evolve. Table 1 lists the overall goals of our software development and deployment processes.

Development	• User-centered interaction design • Scalable and modular architecture • Designed to accommodate network integration
Implementation	• Effective mapping of user requirements • On-site pilot runs with specific users • User-specific training and product manuals
Support	• Local language help system • Enhanced remote access • Technical support site & FAQs • Application-specific user forums • Mobile applications

Table 1: Software Development & Deployment goals.

In Closing

Your Bently Nevada account manager may be contacting you to participate in the value realization assessment. We welcome your input, and if you choose to participate, we promise to take your suggestions very seriously. ■

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AT BENTLY NEVADA, WE ARE NEVER SATISFIED WITH THE

STATUS QUO.

FEP Delegates Off to OJT

ABU DHABI: Field Engineers complete Systems Engineer School and prepare for OJT

FEP Delegates, from left to right: Mohamed Balway, Ahmed Busabiaa, Mahmood Alawi, Pranish, Glen Aussiker, Munir Qureshi, Ahmed Samir, Abdul Hameed, Morten Finsas, Tan Ban Lee, and Asrol Awalludin Bin Md Nor

After four weeks of accelerated learning,

a class of Field Engineer Program (FEP) delegates in the Middle East recently completed their final examination before returning to their home regions. The conclusion of this FEP Systems Engineer School session marks the end of the classroom & hands-on laboratory phase of the program and initiates the next phase, On-the-Job Training (OJT).

Mentored OJT is a critical component of certification for our Services team. It gives the FEP delegates the opportunity to take their experience to the next level – applying what they have learned to real-life situations at customer sites, while under the expert guidance of a certified mentor. **Congratulations to all of our Abu Dhabi FEP graduates!**

[Editor: I always enjoy seeing the diversity of our Services team. In this class alone, the Field Engineers represent several of our global regions – coming from Bahrain, India, Malaysia, Norway, Saudi Arabia, United Arab Emirates, and the United States of America. In addition to the professional learning that these delegates accomplish while in training, the friendships that they make will enhance their teamwork for the rest of their careers. —GBS]

In Memoriam

Robert D. Hayashida
Bently Nevada Technology
GE Energy
1961–2011

It is with deepest regret and profound sadness that we announce Robert (Bob) Donald Hayashida's passing Saturday, February 26, 2011 in South Lake Tahoe, California. He was an instrumental part of our team and touched many individuals internally and externally throughout his personal and professional career.

Bob was the son of Tetsuo and Janet Hayashida and is survived by his sister Aileen, nephew Evan, and niece Erica. He graduated from California State University, Chico, with a Bachelor of Science in Mechanical Engineering.

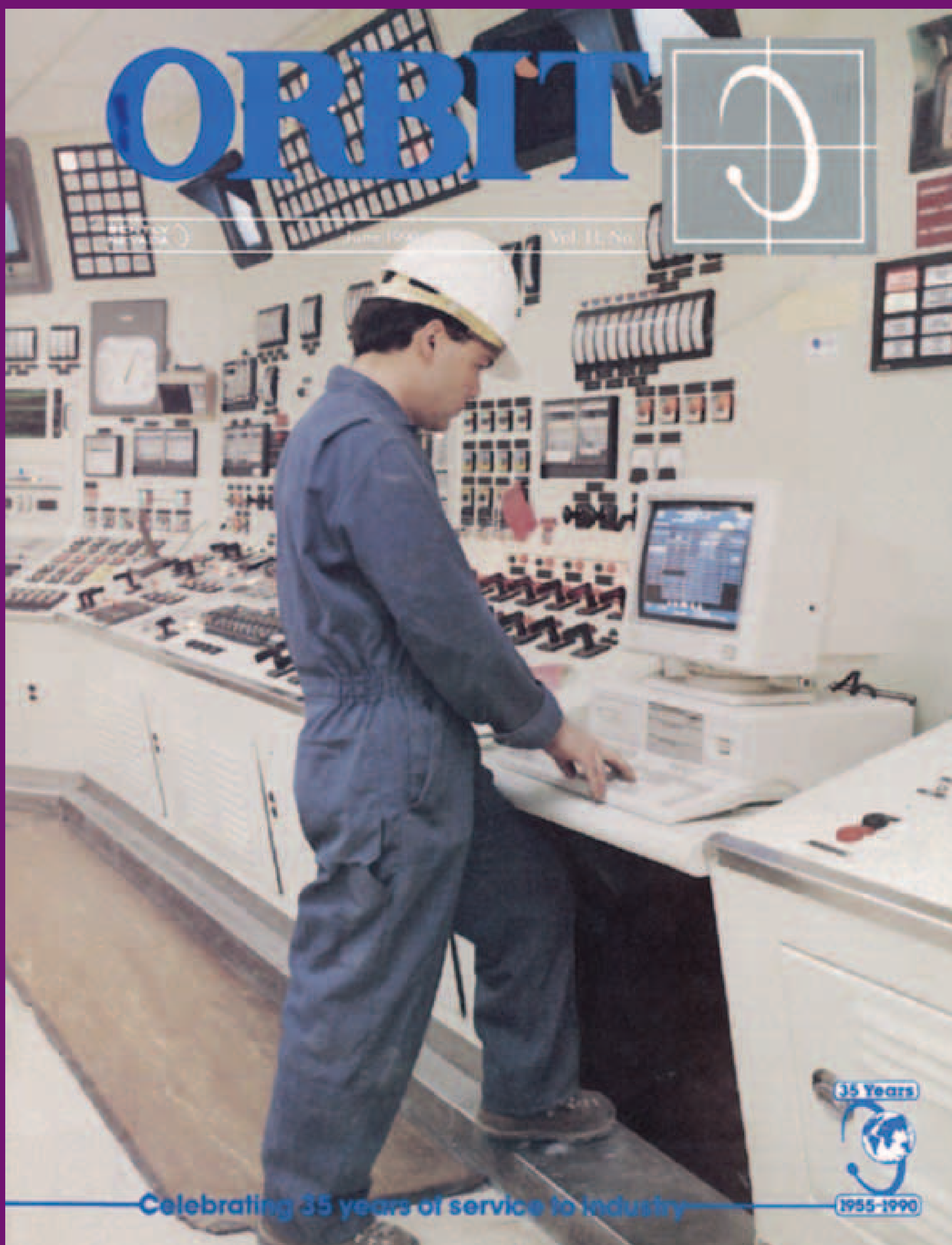
Bob started his career with Bently Nevada in 1986. He brought his impressive skills to many positions over the years, as a manufacturing engineer, field engineer, diagnostics engineer, research engineer for then owner Don Bently, new product design team leader, and most recently as our new technology research manager. During his 25 year career, he even had a role within marketing.

Professionally, Bob's strongest mark will be his research and diagnostic talent combined with his field engineering experience in developing the ADRE product line into the most powerful diagnostic tool on the market today. With each role, he embraced the challenge and lived by a credo from Vincent Lombardi: "The quality of a person's life is in direct proportion to their commitment to excellence, regardless of their chosen field of endeavor."

Bob's professional passion carried over to his personal interests. He enjoyed a variety of activities, including skiing and tasting fine wine. He was even an avid chef. Above all, Bob loved to go fast – whether it was in motorcycles, cars, or airplanes. He was a collector, a rider, and a professional racer. He enjoyed restoring, customizing, and making prudent enhancements to maximize performance and he didn't mind making the repairs himself when things didn't work out or his friends made mistakes.

Bob lived with honor, respect, and kindness. Our heartfelt condolences go out to Bob's family and friends. We honor the man and remember a dear colleague and friend. In remembrance, we are including a small sample of personal expressions from people who were close to him.

—Chris McMillen
Bently Nevada Technology, Hardware Leader



On the cover of ORBIT, June, 1990

I always thought very highly of Bob and his abilities and skills; there wasn't much he could not do. Bob came to work for me right out of college and from the very beginning he always approached every challenge with tenacity and professionalism. His work represents a significant contribution to the world of machinery diagnostics. I am honored to have had a business relationship and friendship with Bob over the years. My sincerest condolences to his family and friends.

— Donald E. Bently, P.E.
Bently Nevada Founder

I worked with Bob on several projects over the years and was always impressed with the enthusiasm and dedication that Bob applied to his work. Bob recognized the need to understand the customer needs and always focused his and his team's efforts upon customer satisfaction. Through this customer focus, he established the essential requirements for the ADRE 408 product making it a world class instrument for Machinery Diagnostic Engineers. Bob left an indelible mark on the lives of all of us that worked with him. It is sad that such a dedicated and enthusiastic individual is called to leave us in the prime of his career and life. He will be sorely missed by all who worked with him.

— Phil Hanifan
Bently Nevada Technology, Chief Engineer

...The legacy of the 208 and 408 products that Bob leaves us with are great reminders of his skills and forward thinking. I miss Bob daily, but will remember the times we had together, as well the good collaboration.

— John Kingham
Bently Nevada Sales, Field Application Engineer

Bob Hayashida was one of the most respected engineers Bently Nevada has ever had. He touched nearly all regions of the world with his knowledge, skill and experience. Bob will be missed by our global commercial team.

— Jerry Pritchard
Bently Nevada Global Sales Leader

Bob was one of our best engineering leaders and was influential in producing the latest generation of our ADRE product. He had a real passion for understanding and driving customer value. He was inspirational in leading our engineering teams in designing innovative and quality products. Bob was a great asset to the company and will truly be missed!

— Jeff Schnitzer
Bently Nevada General Manager

I had the great pleasure of working with Bob for many years. He epitomized the role of an Engineering Leader. Everything his team developed was of the highest quality, capability and value to our customers. As an Engineer he will be missed by many of those who had the opportunity to work on his team. For those of us who knew him outside of work it is a double loss. Bob's friendship was of more value to us than any product he delivered.

— Alan S. Thomson
Bently Nevada New Applications Leader

...Bob's efforts probably touch the lives of thousands who use Bently Nevada products in the quest to better understand machinery behavior. Thomas Edison once said, 'I never did a day's work in my life. It was all fun.' This was the same way Bob approached both work and life!

— John Winterton
Bently Nevada, MDS Team Leader

Update – System 1* Version 6.7.5

The new Bently Nevada System 1 v6.75 solution package is now available. This offering includes several service updates as well as many feature enhancements:

Monitor Support

With Version 6.7.5, the System 1 platform effectively accommodates a growing range of monitor systems with new or enriched functionality. These systems include 3500 ENCORE*, the Essential Insight.mesh* wireless system, and new Trendmaster* proTIMS units (Figure 1).

Our upcoming Orbit issue will focus on monitors, and we will discuss the new features of these systems in detail. Stay tuned... —Editor

3500 ENCORE Support

Our 3500 Rack Configuration Software has been updated to establish the required data collection, signal processing, and protection settings for 3500 ENCORE modules. System 1 software uses the standard process of importing the rack configuration file, which includes all of the required information for the new monitor modules. Once the new modules are incorporated into the enterprise, the collected data is available to all System Extenders, so you can leverage it for use in Decision Support Rules and state-based analysis, and for communication via OPC.

Wireless Condition Monitoring Support.

System 1 software now accommodates more frequent collection of samples from specified wSIM modules. In addition to the collection intervals that were already supported, the new options include intervals of 1, 2, 5, and 10 minutes. This allows increasing the frequency of data collection for identified assets that need to be monitored more often than normal. You can use this capability for closer trending of known or suspected problems, as well as for more frequent monitoring of assets that can have immediate Environmental, Health and Safety (EHS) impact if they fail.

Another application enabled by more frequent sample collection is the ability to use 4 hour static and once a day dynamic (waveform) data collection as the normal configuration. More frequent sampling intervals accommodate more effective decision making during times when asset condition is deteriorating.

System 1 software also includes a new configuration advisor tool for the Essential Insight.mesh system. This tool calculates the power consumption to help predict the battery life for wSIM modules that do not use external power. Power consumption is calculated from the details of the data sampling, processing and wireless data transmission cycles that are stored in the system configuration settings.

Figure 1: Updated solution architecture available with System 1 v6.7.5

Trendmaster proTIM Support

System 1 software now accommodates four new measurement types that have been incorporated into recently-updated Trendmaster proTIM units. These measurement types are Displacement, Pressure, Process, and "Rack Buffered Output" (RBO). The System 1 platform incorporates the configuration of signal processing and data collection settings, and facilitates display of data from all of these new proTIM point types.

Automated Plot Session Creation

System 1 software now includes the capability to automatically generate an appropriate set of condition monitoring and diagnostic data plots for any selected plant asset. All plot types and plot configuration settings are driven in accordance with our best practices to simplify the setup and viewing of data, based on the type of asset that is selected, and the way that it is instrumented. This approach provides the following advantages:

- Reduced plot setup time, with improved consistency and quality
- All plots are created and organized under a single plot session
- Plots are simple to duplicate and modify for user preferences

Dynamic Plot Data Animation

This new feature allows you to cycle through a series of dynamic (waveform) samples from a specified data range in a plot session. The animation "plays" the data as if it were a video, at up to 15 frames per second. The animation can be paused, started, stopped, and "rewound," using the slider, just as if it were any digital video. This feature allows you to develop an intuitive feel of how the collected data was behaving over a specified time period. ■

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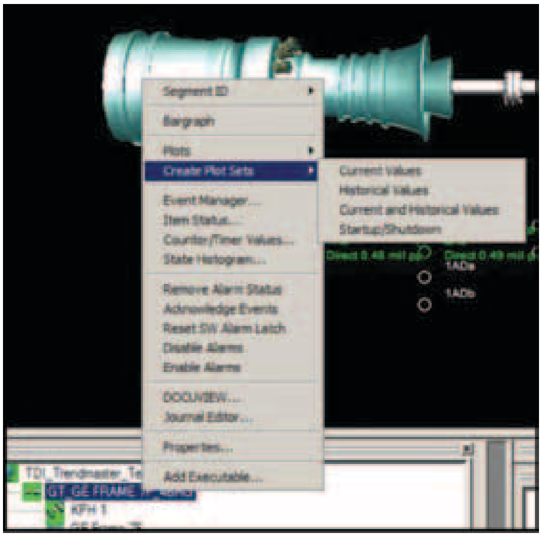


Figure 2: This example shows the Create Plot Sets option for a GE heavy duty (Frame 7) gas turbine from the System 1 Display shortcut menu.

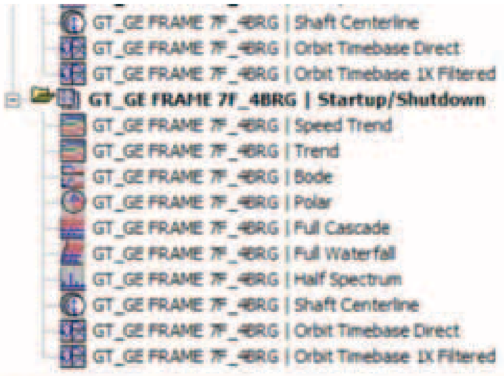


Figure 3: This list shows the appropriate Startup/ Shutdown plots that were automatically created for the gas turbine shown in Figure 2. These include Bode, cascade, polar, shaft centerline, spectrum, orbit-timebase, trend, and waterfall plots.

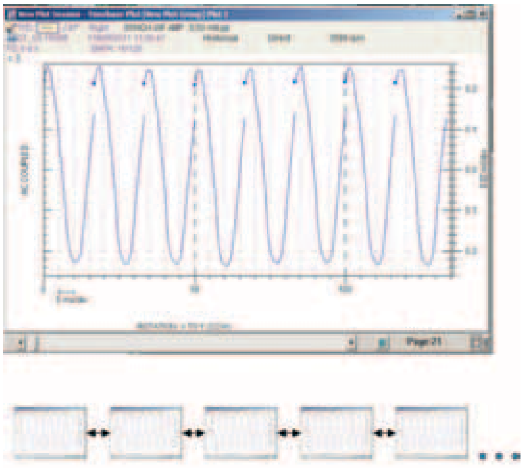
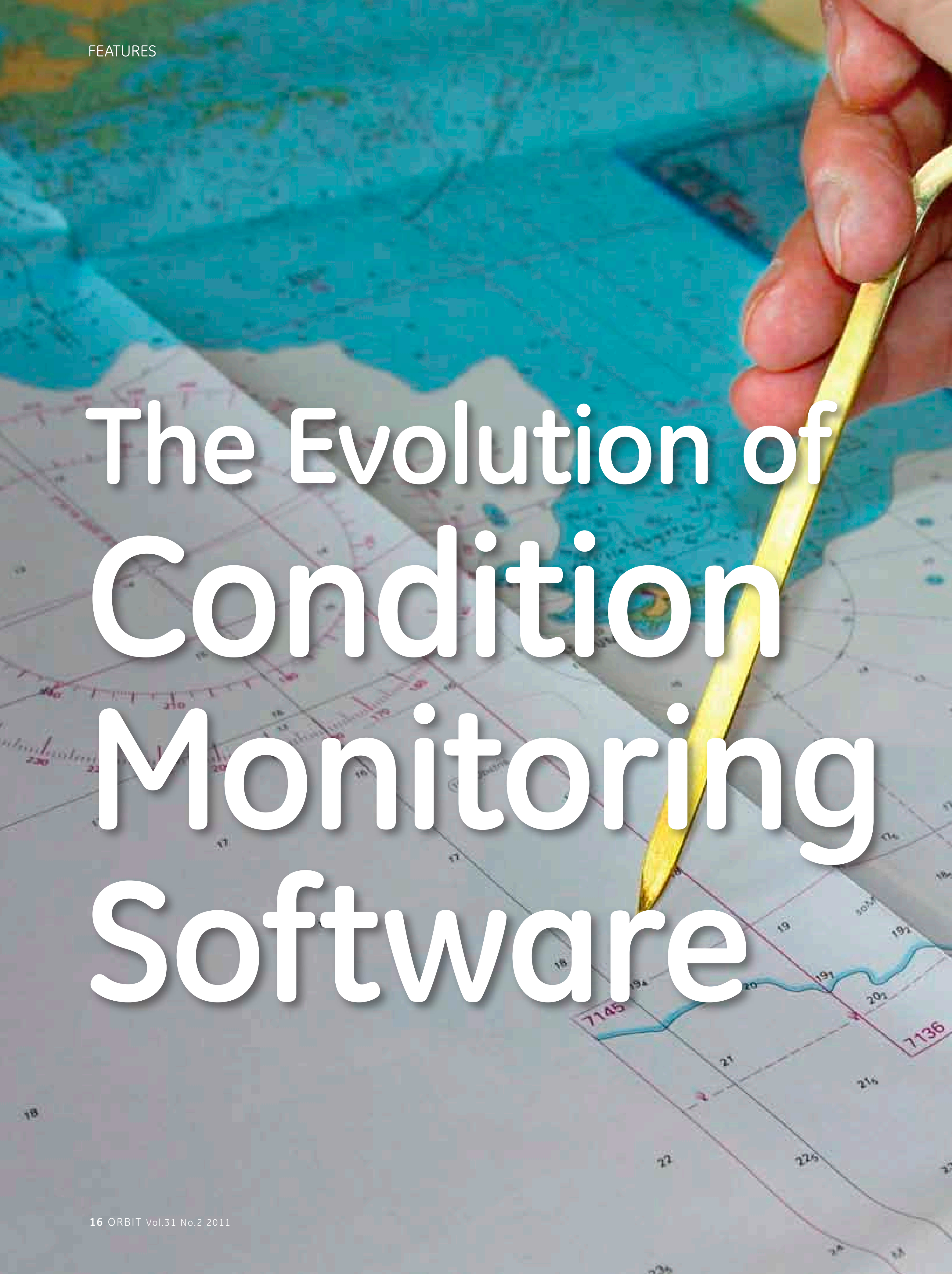
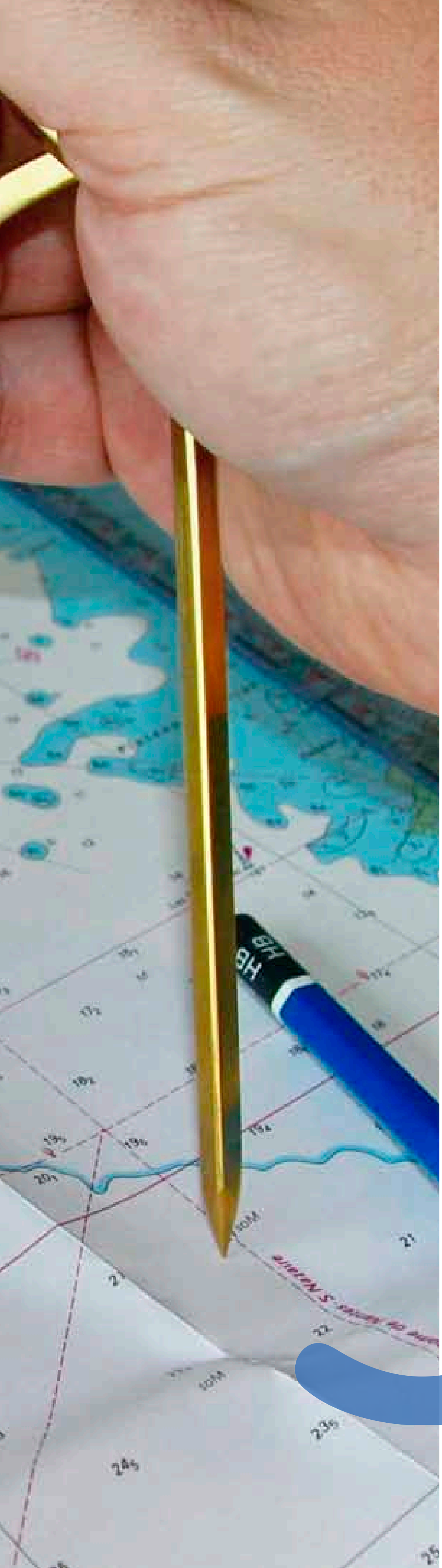


Figure 4: This illustration shows how a time waveform plot appears when it is being viewed with the new animation feature. The small "thumbnail" images at the bottom represent individual data samples, or "frames" in the video animation, which are displayed sequentially at 15 frames per second.



The Evolution of Condition Monitoring Software



Erik Lindhjem
Bently Nevada Software Leader
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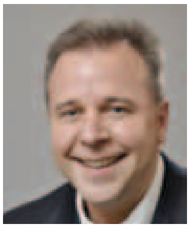

Dave Robertson
Software Engineering Manager
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Just as with information technology, condition monitoring technology has changed drastically in recent years. These changes can be seen in the type of data that is collected, and the way that it is transported, stored, visualized, and analyzed to create actionable information. Some of the biggest challenges to overcome are the proliferation of devices generating data, while at the same time accommodating a shrinking number of users with limited time to spend analyzing the data.

This drives the need for technology to help create foresight and insight into emerging issues – ultimately providing a better understanding of the inherent risk in the production assets you monitor. In order to bring our customers the best solutions, we constantly look for new ways to innovate not only technology, but also the implementation and delivery that can improve the productivity of the users.

There are potentially many different ways for condition monitoring to continue to evolve, and we will highlight just a few of the most significant examples here. The first is the evolution of the automated analytics that change data to information with the ultimate goal of supporting the asset health decisions. The analytics going forward will be the combination of not only different condition monitoring technologies, but also different modeling techniques. Just as with GPS technology, having multiple sources increases the precision of the information. Computing technology opens new horizons – especially given the increased instrumentation that gives a more comprehensive view. One of the interesting aspects with the analytics is the ability to transport some of this functionality from the software to the hardware layer where it makes sense.

The second area where we see the potential for even more radical change is in the delivery and deployment of the solution. These changes will enable the flexibility to address the constant evolution of cyber security requirements while balancing the need to connect machinery problems with the best technical experts. Many users today benefit from the remote connectivity to overcome the physical distance between assets and technical experts. By enabling broader remote access we see the potential to blur the lines related to the physical location of the computing resources, and increasing flexibility of the overall system.

More Applications, More Assets, More Measurement Options

By understanding the patterns of extension to our software over the past 10 years, we have been able to design a modern, modular, data-driven software platform that can be easily extended with far less code as new applications, asset coverage, and measurements are demanded by our customers. We have created an application development kit and tools to allow domain experts to model and extend the system even without writing code. This allows us to rapidly deliver more functionality.

In recent years, we have extended our software into new applications, such as wind turbine condition monitoring and gas turbine blade health monitoring. In addition to these, we continue to support the evolution of the modular ADAPT* monitoring platform, our Essential Insight.mesh* wireless condition monitoring system, the ADRE* portable diagnostic system, and GateCycle* and Efficiency Map* thermodynamic performance software. We are currently in the process of significantly updating the System 1* platform itself.

Analytical Capabilities

Of our more than 8,000 installations today, condition monitoring technology has grown to be much more than just a vibration diagnostic system. As Alan Thomson stated in the previous Orbit issue, combining multiple monitoring or modeling techniques in a collaborative environment provides the ability to correlate symptoms and reduce "false positive" indications.

More and more of our customers are integrating not only process data to provide operational context, but also lube oil sample data and "first principle" (physics) based thermal performance calculations. Thermal performance models provide the ability to determine performance degradation, predict emissions, and recommend maintenance activities based on these changing conditions.

As technology continues to evolve, we will also see the ability to more deeply integrate new and existing condition monitoring techniques into our software tools. A few examples of these various techniques are shown in this incomplete list:

- Infrared Thermographic Data
- Lubricating Oil Sample Results
- Motor Current Signature Analysis
- Partial Discharge Analysis
- Quantitative Preventive Maintenance Inspection Results
- Thermodynamic Performance Calculations
- Ultrasonic Acoustic Inspection Results
- Ultrasonic Piping Thickness Measurements
- Ultraviolet Corona Inspection Results
- Vibration Analysis

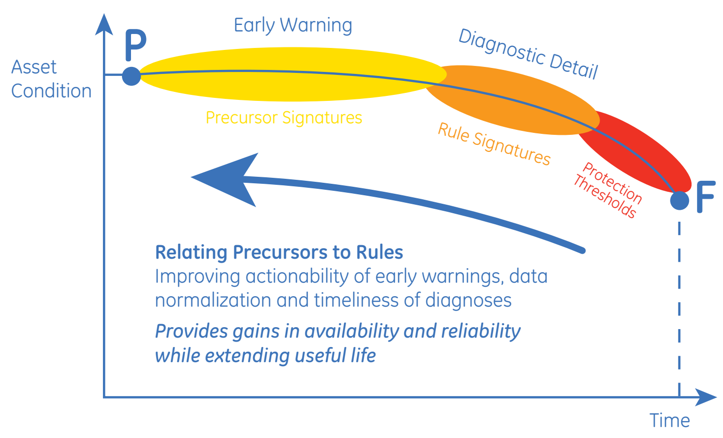

Figure 1: The P-F curve shows how asset condition typically degrades over time, from the Probable Failure point where it is first possible to detect symptoms (P) to the point where the asset suffers Functional Failure (F).

Now that SmartSignal® software is part of the GE Proficy® Platform, we will also see more sophisticated empirical analytics – such as the multi-dimensional modeling that SmartSignal software performs – "learning" the relationships between selected parameters, and providing notification when measured parameters deviate significantly from their expected values (see page 29 for an introduction to SmartSignal software).

Ultimately, all of these methods will help us to better understand the health of the machinery that we monitor and move further to the left on the classic "P-F" interval shown in Figure 1. Having access to the proper early warning information allows us to intervene and extend the lifecycle of the monitored assets.

Key Improvements in Analytical Capabilities

- **Enhanced Plots, Diagrams, & Reports:** Asset models allow us to pre-configure plot sets, diagrams, and reports for each asset in various contexts of interest (alarm, transient, steady state, etc.). The information you need to see is easier to find and display.
- **Fleet Dashboard:** Our users are increasingly centralizing their machinery diagnostics expertise, remotely monitoring several of their sites from a single location. Our fleet dashboard provides a top-level status and alarm view with analytical capability for detailed diagnostics.
- **Enhanced Diagnostics:** Our customers want one solution that accommodates all of the monitored equipment in the plant, regardless of machine type. We are strengthening our diagnostics in the frequency domain for machines with rolling element bearings, gearboxes, etc., with a strong emphasis on speed and ease of use of the software application.

Software Deployment

Even the best software in the world cannot provide value if it cannot be deployed (installed, configured, commissioned, validated, and optimized) effectively. Here are some of the areas where we are working to improve our deployment processes:

- **Easier Deployment:** We are improving and simplifying deployment and connectivity on security-hardened servers and networks.
- **Simplified Software Configuration:** We are dramatically reducing the configuration burden through asset libraries developed by our machinery experts. These libraries improve the accuracy and consistency of the configuration process and greatly reduce the amount of time that is required for this task.
- **Improved System Integration:** Customers who get the most value from our systems successfully integrate our software with their other systems (DCS, HMI, CMMS) and leverage the information we provide in the daily workflows of their operators, planners, and maintenance & machinery engineers.
- **Improved Remote Connectivity:** Modernizing our technology platform with the latest communication infrastructure enables more and better remote connectivity options, including mobile tablet and smartphone interfaces.

- **Scalability:** We are supporting a combination of centralized and decentralized models that enable local or enterprise installation, while also providing the potential for cloud deployment where users can benefit from stronger support and rapid development. Such systems enable our customers to have access to more computing and data storage capabilities, while avoiding the costs of maintaining the onsite infrastructure themselves. Of course, it is vital that such cloud-based systems are extremely robust – including redundant storage methods, uninterruptable power supplies, and very capable security systems to preserve the integrity of the data.

Software Development

In order to provide the best possible solutions, we are constantly improving our internal software development processes. One of our main tools for obtaining input from our users is the "Customer Value Realization Assessment," which is described on page 7 in this issue. This formal survey process allows us to walk through our systems with our customers to ensure they are receiving maximum value from the solution.

With this input, we can determine which factors most affect the value received. Where we find gaps, we are able to apply our resources effectively to make meaningful improvements. By following a goal-driven interaction design process with plenty of feedback from users, we are ensuring that our next generation of software is a delight to use (see page 34 for an interesting article about our software design process).

Key Improvements in our Software Design Process

- **Interaction Design:** We have progressed beyond the old thinking of developing our software to simply include a list of features. This approach led to interfaces that were described as being created "by engineers, for engineers". Now, we are focused on creating user-centered designs that are tailored to meet the needs of each distinct persona.

- **Agile Development:** We have also changed our development process to Agile, which encompasses many principles and practices that help us develop valuable, high quality software in less time. One key requirement for this approach is rapid feedback from our users. Our development cycles are now "release trains" with releases every three months – some internal, some external. Within these release trains, we develop in a series of two week "sprints." This helps us stay focused, and the rapid feedback ensures that we get it right.

- **Focus:** A key aspect for GE in the overall solution for asset condition monitoring is software and the role it plays in the system. With this in mind we have organized to ensure we produce world-class software that leverages the rapid advances in the field. Our software team supporting the Bently Nevada Asset Condition Monitoring product line is now functionally part of a broader Software Solutions Group (SSG) within GE Energy Services. Being part of this larger team with a focus on software has helped us drive tremendous improvement in software best practices, technology, and tools.

We have benefitted tremendously from including end users in our process, and those customers who have worked with us have told us that they appreciate the opportunity to help us steer our development. If you would like to be engaged early to help us better meet your needs, please contact the authors, Erik Lindhjem or Dave Robertson. ■

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Proactive Approach to Managing Production Assets

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This is the second article in a series. The first article focused on traditional maintenance strategies. These include Predictive Maintenance (PdM) – which is often referred to as Condition-Based Maintenance (CBM) – Preventive Maintenance (PM), and Reactive Maintenance (RM). It also identified Run-to-Failure, briefly discussing the use of Condition Monitoring (CM) as part of a PdM strategy, and described Potential-to-Failure (P-F) curves and asset criticality.

This article will continue the discussion of maintenance strategies, starting with a more detailed analysis of P-F curves and asset criticality. We will then discuss Reliability Centered Maintenance (RCM) and the use of Proactive Centered Maintenance (PCM), which combines traditional maintenance methodologies with the additional tools necessary to move towards a more proactive approach to managing production assets.

Understanding the Potential to Functional Failure (P-F) Curve

P-F curves graphically display the failure time cycle and various measurement techniques that can be utilized to detect asset failures prior to the asset incurring functional failure. Proactive strategies should focus on managing assets high on their P-F curve, or early (P1 to P5) in the failure cycle, (Figure 1). The ability to detect failures early in their development allows top quartile performers to proactively manage their maintenance programs by understanding the health of their assets. Many companies, however, find it difficult to operate proactively, continually reacting to assets that reach functional failure with little or no warning.

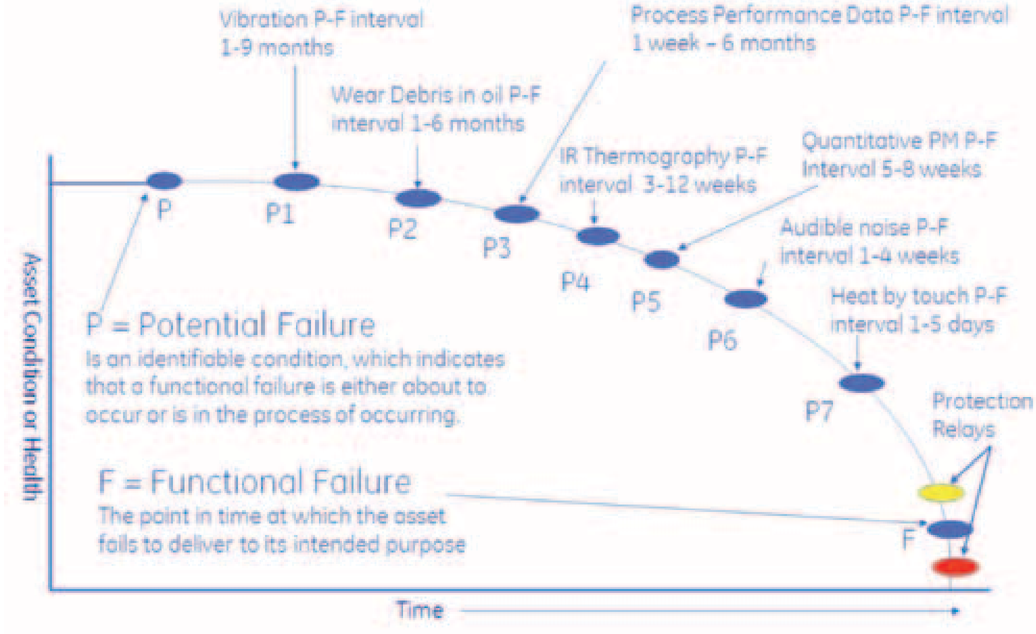


Figure 1: P-F Curve example for a mechanical asset. The P-F interval is the interval between the identification of a potential failure and the decay into a functional failure. Time can be measured in seconds, minutes, days, months or years. P1-Px indicates detectability intervals that can typically be provided by various techniques and technologies.

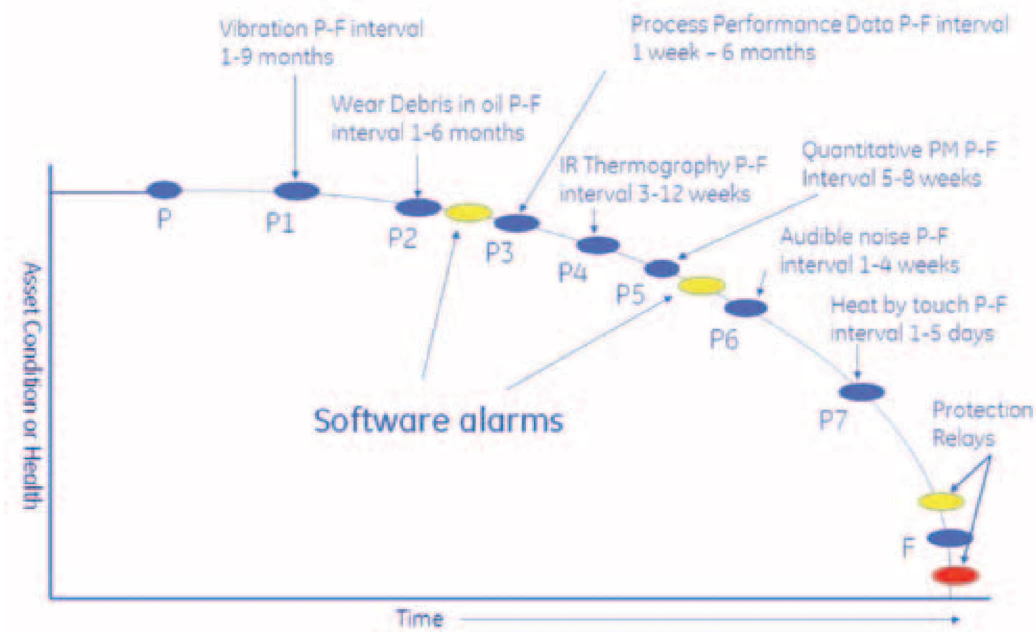


Figure 2: This is the same P-F Curve from Figure 1, with the addition of two software alarms. The challenge with software alarms is how to move them to a point earlier in the failure cycle, so that there is time to plan and schedule effective maintenance actions prior to functional failure.

The Value of Software Alarms

With the advanced diagnostic capabilities we have available to us today, software alarms allow us to provide additional warning for many types of failure modes. In Figure 2, we see the same P-F curve of Figure 1, with the addition of two software alarms. These alarms can automatically notify operations and maintenance of a pending failure – allowing proper planning and management of the asset through the remainder of the failure cycle.

Understanding Asset Criticality and the Impact on Maintenance Strategies

It is safe to say that not all assets have the same consequence of failure. Understanding the impact of failure of a specific asset is essential to defining the strategies we will use to mitigate the impact of those failures.

First, we have to understand that asset failures can have impacts on various aspects of our business. Safety, Environment, Regulatory Compliance, Product Quality, Production, and Operations & Maintenance Costs are often regarded as the key areas of asset failure impacts. Just as all assets do not have the same consequence of failure, key areas of business impact also do not carry the same weight.

It is essential to understand what is important to your specific business when prioritizing and weighting the key areas of impact. For example, a failure that results in a safety incident or death should be regarded as more critical than a failure that merely results in a poor quality product. While both results are important to understand and mitigate, addressing the safety impact would take precedence in today's production environment. In companies that are physical asset intensive, top performers assign a weighted value to the areas of failure impact and develop comprehensive rankings of asset criticalities. Top performers use this knowledge to apply the appropriate failure mitigation strategies.

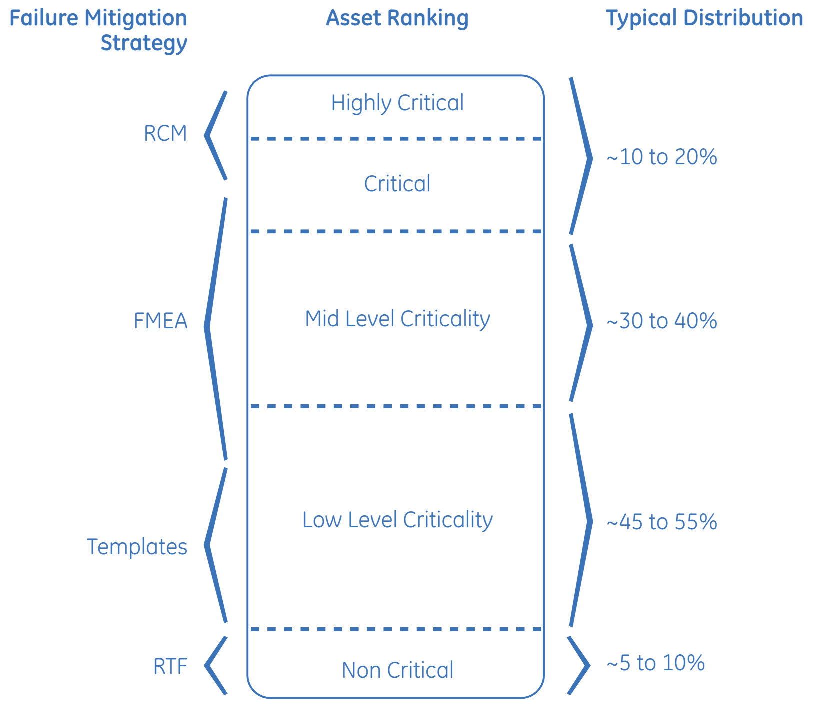


Figure 3: Shows an example of a distribution of assets (%) by criticality. It indicates where asset strategies – such as the application of RCM, development of complete Failure Modes and Effects Analysis (FMEA), application of FMEA or maintenance templates, and run-to-failure strategies – might be applied based on asset criticality. A key to applying the right strategy is to understand asset criticality and your business goals.

Reliability-Centered Maintenance (RCM)

RCM is a systematic, disciplined process to ensure safety and mission compliance that defines system boundaries and identifies system functions, functional failures, and likely failure modes for equipment and structures in a specific operating context. Because this process is very time and resource-intensive, RCM is typically applied only to the top 15% or so of the most highly critical assets.

Development of complete FMEAs is applied to about 55% of the assets and specifically those in the mid to low level criticalities. This technique applies unique FMEAs for each asset. Developing FMEAs require less time and resources to complete than applying RCM, yet still drives the mitigation and controls to address the asset failure modes.

The application of FMEA or asset class specific predefined maintenance templates is a strategy that can be applied to about 25% of the assets, primarily those identified as having low critically. Using this approach makes sense for lower criticality assets as it saves time, allows for immediate results and leverages past experience with failure mitigation techniques.

Run-to-failure strategies typically end up being applied to about the bottom 5% of the assets in terms of criticality and primarily those assets where it is acceptable for failures to occur without prior warning and where the most cost effective approach is to simply replace and not maintain the asset.

The percentages defined above are based upon experience and are reflected in Figure 3. For your particular process and associated assets the distribution will be defined in your criticality ranking sessions and will be driven by your specific maintenance strategy.

In addition to using the strategies described above, top performers also apply Root Cause Failure Analysis (RCFA). The business defines the criteria for conducting RCFA based upon business strategies and goals. Considerations typically include consequence of the failure, failure modes, and suitability of the current failure mitigation strategies, including CM, PdM, and PM. RCFA drives proactive maintenance and often results in changes to the techniques utilized to detect failures and changes to the design, process, or procedures to eliminate the root cause of the failure - or to minimize the effect of the root cause and avoid functional failure of the asset. RCFA findings need to be used to update the FMEAs and templates being used in the maintenance strategies applied to your specific assets.

The results of the above-defined strategies will be used to understand and put in place the right mix of CM technologies and their frequencies of application in addition to the right quantitative PM's as proactive work identification tools.

Condition Monitoring Methodologies

The most effective asset failure mitigation strategy will come from the application of RCM, FMEA, Templates, and RTF strategies. Taking the results of these efforts and driving the right CM and PdM technologies is vital to understanding asset health and is essential to optimizing return on investment. For companies that are physical asset intensive, top performers strive to have the correct mix of preventive, predictive, proactive, and run-to-failure maintenance strategies (Figure 4) for managing their assets.

Top performers understand which assets do not warrant maintenance time and effort. This helps them to define the proper run to failure strategies for these assets. Figure 4 shows that when employing 15% of your work efforts towards both Condition Monitoring/PdM and Optimized PM's, those efforts – along with the proactive results that come from understanding asset health early in the failure cycle – will yield about 80% of your total work efforts. The remaining 20 percent is made up of planned reactive (RTF) and unplanned reactive work. Unplanned reactive work can be further mitigated with improvements to and optimization of our PdM and optimized PM tasks.

The appropriate CM/PdM strategy will vary depending on the failure mode and how long it takes a failure to manifest itself from detection to functional failure, which is known as the failure cycle. The failure cycle is graphically displayed on the assets P-F curve (Figures 1 and 2). CM programs can be as basic as collecting and analyzing periodic oil samples or monitoring process variables

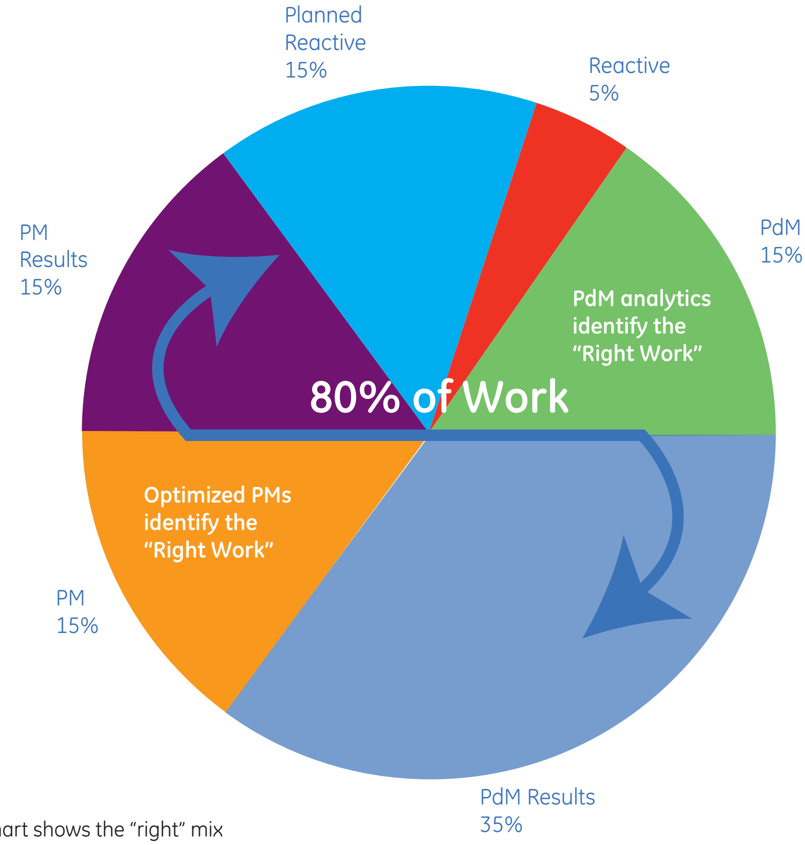


Figure 4: This chart shows the "right" mix of work for top performing businesses.

(pressure, flow, etc.) that are available for the asset. Note: The effectiveness of Process Performance data is highly dependent on calibration of sensor instruments and tuning of control systems.

Optimizing Investment

While these approaches may be sufficient for some assets, certain failure modes require additional data and less time between collection intervals in order to detect changes in condition and proactively manage and possibly prevent the failure. For some failure modes, periodic data collection (intervals ranging from once a week to once every six months, based upon the failure cycle) can detect failures with sufficient time to plan the required maintenance. Individual failure modes, consequences of failure, failure detectability, and the lead time in predicting functional failure are key factors in determining whether to use continuous online, scanning, or portable data collection frequencies and methodologies.

Under-maintaining or under-instrumenting a highly critical asset might ensure lower planned costs, but may also result in poor reliability, high RM costs, poor asset performance, and unacceptably high overall risk to the business. Conversely, over-maintaining or over-instrumenting a non-critical asset will incur higher-than-necessary planned costs compared to the level of risk reduction that can be achieved. The optimum level of investment (Figure 5) targets the right assets with the right mix of planned maintenance, resources, and technology, thereby reducing asset risk to a tolerable level at manageable planned costs. Optimizing your strategy over time will result in the right risk reduction while balancing costs.

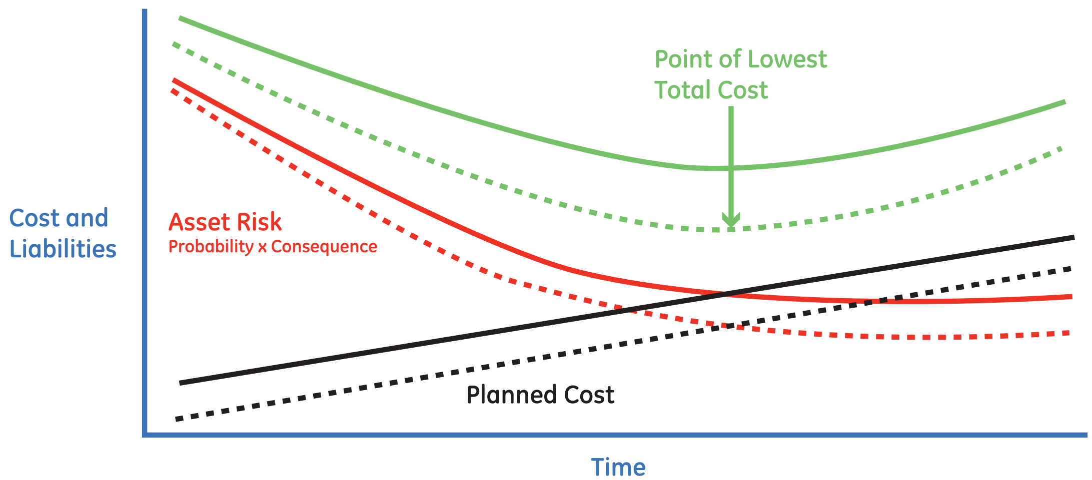


Figure 5: The point of lowest total cost occurs with the most effective balance of planned cost vs. asset risk.

The solid lines represent a baseline of planned cost and associated asset risk based upon a specific strategy being implemented. Where they intersect represents the point of lowest cost for that specific strategy. The dotted lines represent optimization or program improvements that have been implemented with a focus on reducing asset risk (more proactive, less reactive) and the associated cost benefits. The key to this optimization is to make sure that any additional planned costs are having an associated impact on risk reduction and either reducing the probability of a failure or reducing the consequence of failure. Increasing planned costs without reciprocal asset risk improvement simply increases costs.

Typically, many highly critical and critical assets need very frequent sampling, which requires a continuous online system. Such systems sample data continuously and often offer automated relays and shut down systems or automated alarms to address failures with very short failure cycles and very high failure consequences. In addition to these traditional online API 670 compliant protection systems, scanning systems (including both traditional wired and newer wireless scanning technologies) can be applied to assets that are critical, mid and some low level criticalities, which have failure cycles that allow for proper detection by the applied technology.

Advances in technology have made wireless scanning a more viable CM option than in the past. While wired systems have a higher bandwidth and can provide dynamic (waveform) data more frequently than wireless systems, wireless systems have a much lower initial cost than that of wired systems. Wireless scanning systems are appropriate predominantly on assets with detection-to-failure cycles of greater than two hours. In addition, scanning systems should only be used on assets where continuous machinery protection (immediate, automated shutdown) is not appropriate.

The most critical assets may require continuous monitoring for a combination of reasons. Many of their failure modes can occur rapidly, resulting in catastrophic damage to the asset. It is always beneficial to identify asset failures early so that parts may be ordered and maintenance can be planned at the right time to optimize production and reduce the costs. A continuous monitoring program may also utilize thermodynamic performance data (calculated from pressures, temperatures, and flows), to continuously analyze and optimize the asset to maximize production efficiency.

Proactive-Centered Maintenance (PCM)

Many companies spend a great deal of time reacting to asset failures (RM) due to lack of a proactive strategy – and in many cases – resources. Some more advanced maintenance strategies incorporate PdM or CM, but without thoroughly analyzing the asset criticality or consequence of failure. While these strategies may be effective, they both have some limitations. In Table 1 we show some of the limitations of a PM based maintenance strategy and some of the limitations of a PdM strategy. The PdM strategy is shown as it would be without leveraging RCM or FMEA development for the associated assets.

Proactive Centered Maintenance optimizes the use of all of the above maintenance and CM methodologies. It emphasizes doing the right maintenance on the right assets at the right time. In most cases, a PCM approach increases the use of PdM, while continuing to utilize PM and limiting RM to assets with no consequence of failure. However, PCM also emphasizes improving procedures, operating parameters, processes, and designs in order to limit or prevent recurring failures, thus reducing asset failures and extending the mean time between asset failures. This can result in up to a 42% reduction in maintenance costs when compared to PM and up to a 59% reduction when compared to RM (Figure 6). In addition, having a PCM program can reduce RM to 20% or less of the total time dedicated to maintenance, while 80% or more of the effort will be spent on predictive and preventative maintenance and on process/procedural/design improvements as we showed in Figure 4.

MOVING FROM A REACTIVE TO A PREDICTIVE APPROACH – AND THEN A PROACTIVE APPROACH – REQUIRES A HIGH DEGREE OF COMMITMENT FROM THE ENTIRE ORGANIZATION TO IMPROVE MAINTENANCE AND OPERATIONAL EFFECTIVENESS.

Shortcomings from relying solely on Preventive Maintenance (PM)	Shortcomings from relying on Predictive Maintenance without conducting RCM or leveraging FMEAs
Not based on failure modes	Not based on failure modes, many failures might be missed
OEM requirements time-based, not condition based	Not integrated with other reliability tools (PM, Lean Six Sigma, etc.)
Not enough detail in PM tasks to add value	Personnel not properly trained on all technologies
Too many non value added tasks	Too much focus on data collection and not enough on driving proactive actions
Asset unavailability during PM outage can outweigh reliability gains	Output not tied to work flow, events vs. a robust science based program
Lack of management focus toward optimizing the PM program	Training is oftentimes inadequate for the program expectations
Tasks not grouped to leverage efficient execution	Many times there is an overdependence on one technology type
Intrusive PM tasks performed regardless of asset condition	Maintenance not focused on maintaining asset health
PM tasks not quantitative	Not enough data being acquired on some assets and too much on others
Inadequate PM tasks are rarely removed from the PM program	Many times no feedback from the technicians back into the program

Table 1: Comparison of PM vs. (inadequate) PdM programs

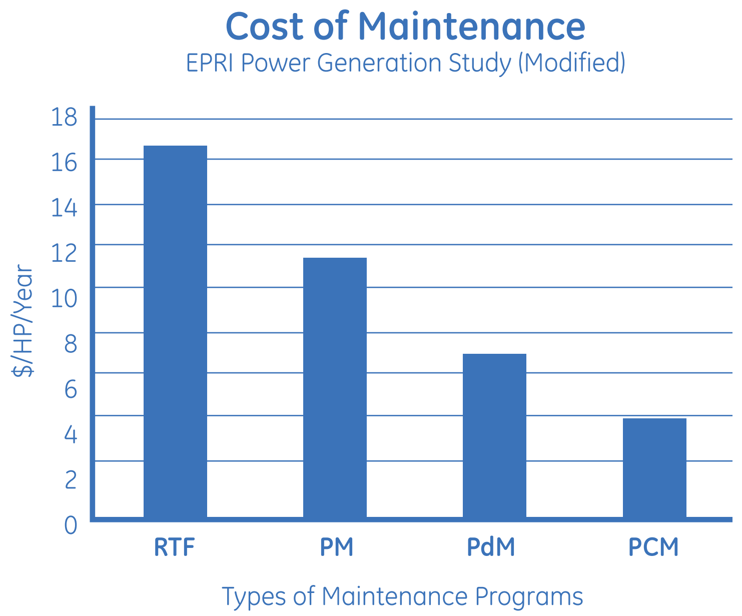


Figure 6: Implementing proactive measures resulting from RCM can help drive down costs and risks. Maintaining assets proactively and implementing design, process and procedural changes can reduce the probability of failure.

Conclusion

While most businesses strive to improve their maintenance, only a few are able to obtain and sustain best-in-class results. Top quartile performers incorporate PdM and CM on a majority of their assets as a means of proactively addressing asset condition and mitigating risk of failure. After performing an RCM analysis, FMEA will typically show that 80% of non-RM tasks require some form of CM, while less than 20% require time-based preventive maintenance tasks (as shown in Figure 4).

In addition, businesses that drive proactive strategies learn from past failures and successes and from the results of their RCM and FMEA analysis and can use this knowledge to redesign processes, procedures, and engineering designs to help reduce failures. Moving from a reactive to a predictive approach – and then a proactive approach – requires a high degree of commitment from the entire organization to improve maintenance and operational effectiveness. If this organizational commitment can be sustained over the long run, a proactive approach will ensure that maintenance dollars are spent on the right assets at the right time and that assets are available when needed to meet production demands.

In the third article in this series, we will discuss the use of wireless systems as part of a CBM program and how this technology enhances a PCM strategy. Significant advances in wireless technology, security, and reliability have allowed wireless platforms to begin to proliferate throughout industry. We will discuss the capabilities of wireless systems and how top performers can benefit from the capabilities of this new technology.

[Editor: The first part of this series, "Asset Management 101: Part 1 – Maintenance Strategy Overview" appeared in Orbit Volume 29, Number 1, November 2009. The article is available for viewing or downloading at our website, www.orbit-magazine.com. —GBS]

SmartSignal®

is Now Part of GE – What Does it Mean for You?

Proficy® SmartSignal can help you to optimize your Bently Nevada investment and take your operations and maintenance to a whole new level.

Don Doan
Senior Industry Specialist
don.doan@ge.com

SmartSignal is now part of GE's Proficy Software Platform, a full suite of software solutions that employ best-in-class technologies for process automation and production operations management. The addition of SmartSignal to the Proficy platform provides a solution to address availability and efficiency challenges in a robust way, and can add significant value when used jointly with GE Bently Nevada* Asset Condition Monitoring.

In January 2011, GE acquired SmartSignal, a company you know as a provider of predictive diagnostic software and monitoring services. Our software is used to anticipate, prevent and avoid equipment failure. But, as a Bently Nevada System 1* user, how does this new development affect you?

Well, as a user, you know that System 1 data and intelligence provides online condition monitoring of rotating equipment and raises operational and financial performance. In the last issue of Orbit we talked about how in more than 8,000 operations around the world, Bently Nevada's System 1 is proactively identifying looming problems, managing machines through to outage, and getting to the root causes of faults. Using the rules and dynamic (waveform) analysis capabilities of System 1, you can identify, diagnose and prioritize problems, reducing maintenance costs and lost production while increasing availability and safety.

Yet, equipment problems persist. You still face the dual problems of too much data, and too little time. You need to better focus your resources, clarify your decisions, and remove your risks. That's where Proficy SmartSignal can help.

The SmartSignal solution can significantly "turbo charge" your investment in System 1. It quickly analyzes data and identifies equipment that is at risk. It filters your data accurately and earlier in the degradation of equipment, giving you more time to take actions to mitigate an impending failure. This solution applies to all critical equipment, both rotating and non-rotating, across all OEMs.

Using SmartSignal with additional inputs from GE System 1 dynamic data, SmartSignal can improve foresight into actionable equipment problems by providing the very earliest detection of issue precursors. And, System 1 will deliver its insight to diagnose and define the causes of the changes in behavior earlier and with more accuracy.

Net benefits of the combined systems are decreases in work and maintenance dollars as well as increases in availability and reliability while extending useful equipment life. The solutions will help you grow both operational and financial performance, while avoiding surprises.

How Proficy SmartSignal Predicts Equipment Problems Earlier

Proficy SmartSignal uses patented algorithms based on its proprietary SBM technology (Similarity-Based Modeling) to predict equipment problems earlier and more accurately than any other solution. SmartSignal solutions are protected by more than 40 patents that make this advanced predictive technology possible.

SBM technology is a data-driven empirical approach that leverages existing instrumentation and IT infrastructures. The software samples data from your historian (this includes OSI PI®, Proficy Historian, and other historian data feeds) every few minutes and analyzes it to detect, diagnose, and prioritize impending problems.

In SBM, every piece of equipment is unique, as reflected in the models built from their own unique historical data. The advanced modeling puts into context the normal operating relationships among all relevant parameters, such as load, temperatures, pressures, vibration readings, and ambient conditions. In real time, at five-minute intervals, the software compares actual sensor readings to that particular machine's normal, predicted values.

SmartSignal's unique patented technology removes the confusion of alarm overload by "normalizing" the behavior of equipment for all known operational modes, including run up and loading, running unloaded, full-load operation, part-load operation, and load ramps. This minimizes alerts due to normal process and environmental changes, informing only on direct, observable, and abnormal changes in behavior.

The software detects and identifies events by the differences between real-time actual data and predicted, normal behavior—not by software alarm thresholds on sensor values without normalization.

The solution is readily scalable across a fleet because of the data-driven approach to modeling and the configurable blueprints which do not rely on machine-specific, First Principles approaches, where performance curves must be developed for each asset and process state.

How SmartSignal and System 1 Work Together to Optimize Diagnostics

SmartSignal excels at process and vibration data correlations, high true positives, and prioritized early warning. System 1 excels at capturing dynamic mechanical data and deep-dive diagnostics with millisecond integrity. Jointly, they deliver the earliest time to understanding of risk with confidence for decisions and action, while removing alarming burden and improving diagnostic focus. Together, they enable predictive, proactive, and risk-informed decisions sooner.

The Proficy SmartSignal solution includes subject matter expert reviews of failure mode symptoms to localize and prioritize how actionable the change in behavior is based on a combination of severity and confidence. System 1 software, with its Rule Paks, validates SmartSignal's "apparent causes" and provides detailed diagnostics. When working together, analytics and diagnostics are optimized, as SmartSignal detects more problems earlier and determines apparent causes, and System 1 validates the issues and provides deeper diagnostics based on insight into the failure modes. This combination allows your subject matter experts to use their time more effectively, rather than chasing down large numbers of alarms.

The concept is actually quite simple. Allow empirical models (SmartSignal) to monitor the process parameters associated with the plant and machinery. SmartSignal can detect significant changes to the equipment's operation relative to its unique operating context at an early stage. Whether for rotating or fixed assets, System 1 can be used to correlate, analyze, visualize, and validate the true condition changes that are significant. In the event the anomaly turns into a failure too quickly, System 1 is there for root cause failure analysis.

By using both together, you will be able to pull richer data from System 1 directly into SmartSignal for finer and finer localization. By using SmartSignal to model rapid transient data from System 1, you will improve the timeliness of analyzing intermittent issues.

Future updates of the combined solutions will help you drive into true Reliability-Based Maintenance and continuous optimization of strategies based on true equipment condition.

Additional technology information and use-case testimonials are available online at www.SmartSignal.com. If you have a web-enabled smartphone with QR code reader application, simply "take a picture" of this image to go to the site.

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

Proficy is a registered trademark of GE Intelligent Platforms, Inc.

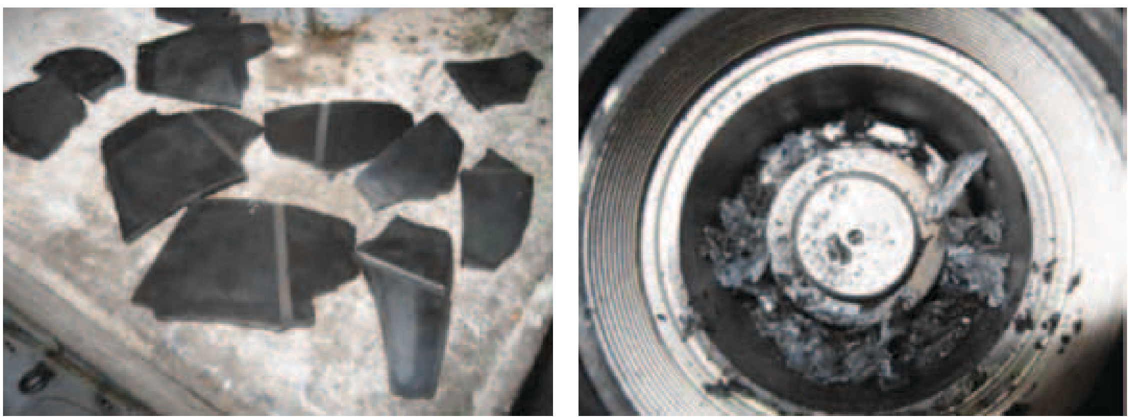
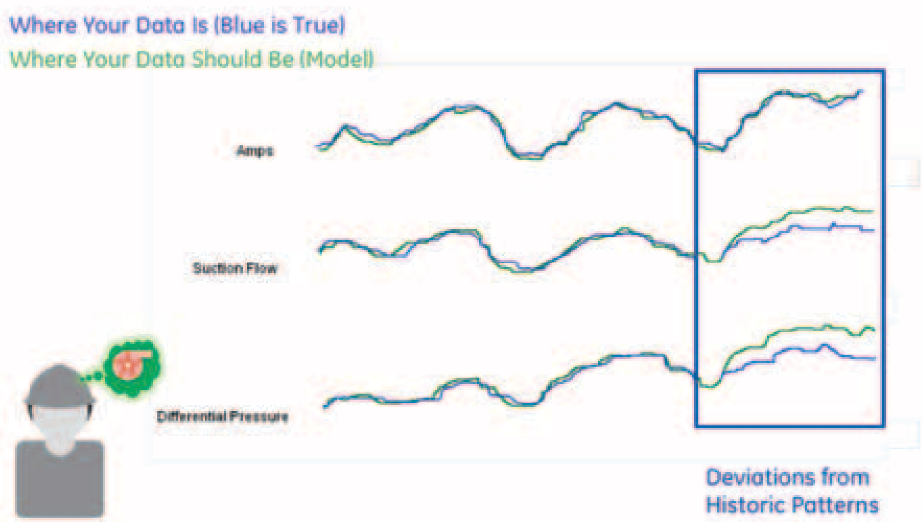


Figure 1. SmartSignal avoided damage to a hydrogen compressor by identifying deterioration of a consumable rider band in a reciprocating compressor throw. This allowed the operators to shut down the machine before catastrophic failure occurred to the piston and cylinder liner.

SmartSignal — Early Detection Based on Operation History

Figure 2: Associated parameters from monitored assets are modeled together. In this figure, Blue is True (actual reading) and Green is Good (model predicted reading). It is the overall behavior that determines what each individual sensor is "expected" to indicate.



Equipment is Operating

Equipment must be in operation for Diagnostic Incident creation.

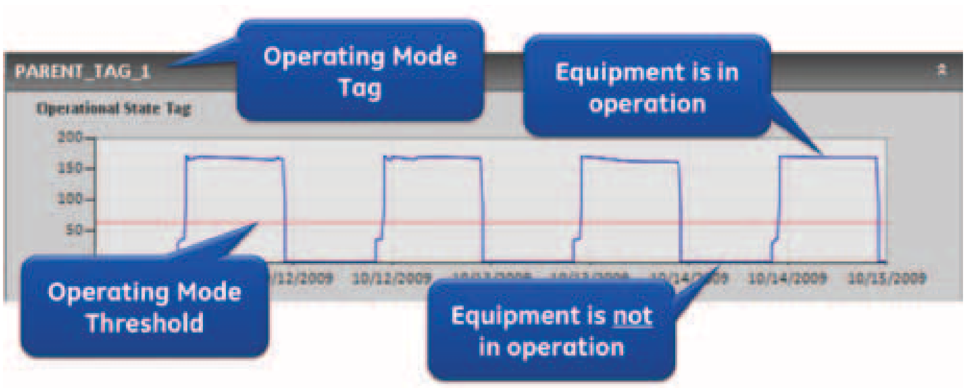


Figure 3: In order to avoid the creation of spurious diagnostic Incidents, the monitored equipment is not evaluated unless it is actually operating. Multiple operating mode tags are available. For each monitored parameter, there is an operating mode threshold. If the actual value of the operating mode tag is greater than the operating mode threshold, the equipment is known to be in operation. If not, the equipment is not in operation and the remaining parameters will not be evaluated. Additional capabilities monitor the equipment from the turning gear to operating mode. Note: This concept is similar to the System 1 idea of "state-based analysis."

Significant Deviation

Residual Deviation

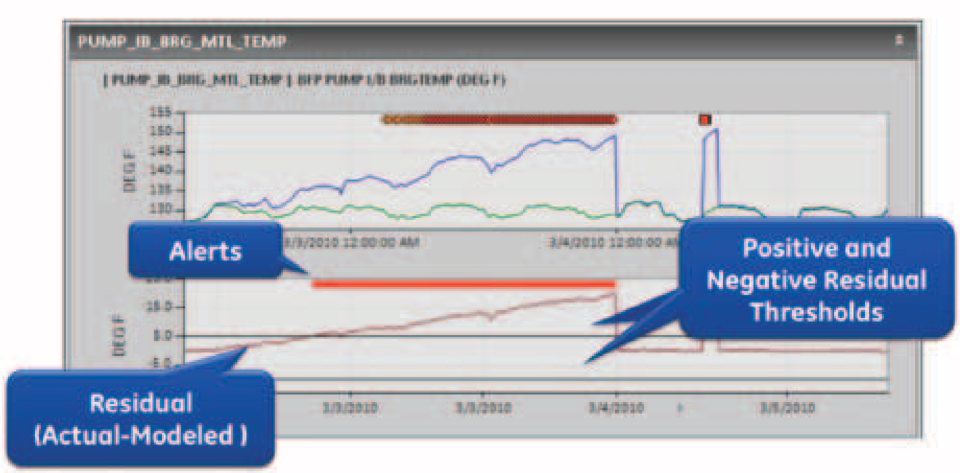


Figure 4: The deviation for each parameter (lower plot) is simply the "residual" (difference) between the actual measured value and the estimated (expected) value. The deviation is only considered to be significant when its value exceeds the residual threshold. SmartSignal marks significant deviations with an "Alert."

Persistence

Deviations Require Persistence

Figure 5: A deviation is not meaningful if it does not persist, and different kinds of deviations will have different amounts of required persistence. Persistence is a minimum amount of time a deviation must occur in order to be considered meaningful. SmartSignal will create notifications when deviations have persisted and can identify many types of failure precursors for each asset.

The Value of Synergy

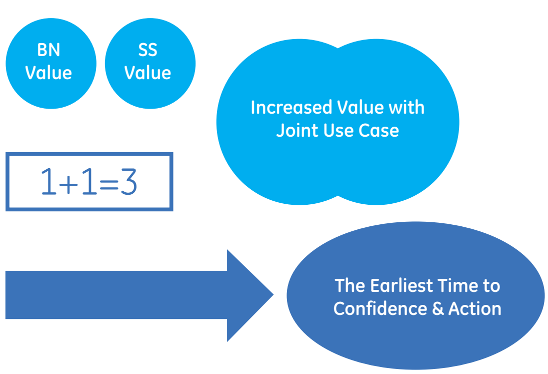


Figure 6: System 1 excels at capturing asset mechanical data and providing deep dive diagnostics with millisecond integrity. SmartSignal excels at process and vibration data correlations, high true positives, and prioritized early warning. Jointly, they can deliver the earliest time to understanding/confidence/decision/action, while removing alarming burden, improving diagnostic focus, and enabling predictive and proactive decisions sooner.

UPSTREAM CUSTOMER

- **2008–2009: North America**
  - — $10 million in measured savings in first year
    - Offshore platforms
    - On-shore gas gathering, processing
    - On-shore critical rotating equipment
- **2010: global expansion**
  - — Eastern and Western Europe, Africa, Asia, Pacific Rim, all co-generation plants

POWER CUSTOMER

- **2004: deployed SmartSignal**
  - — Their "Big Catch" was highlighted in POWER magazine—saved more than $30M
  - — They estimate total value of more than $50 million annually in repair costs and another $50 million annually in savings from lack of lost production, returning 20 to 30 times the cost of their monitoring function.

User Centered Software for Modern Plant Asset Management

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Modern software demands usability. You hear it everywhere and our expectations for easy to use software have never been higher. All of us have experienced that great software application that has everything we need, does everything we want, but is so hard to use that you avoid opening it, and when you finally do, you wish you hadn't.

The science of human factors and usability is now often the most important criterion for purchasing that new product or software. Yesterday, it was features and functions, but today it is usability. We see it today in our everyday tools and appliances. Just look at today's mobile cell phones; we look for what is easiest to use and what has the most compelling user interface over what has the most features. The game has changed, and the stakes for effective software development have never been higher and more challenging.

In the world of machine condition monitoring, this is equally true. Machinery diagnostic engineers juggle multiple problems – all demanding their undivided attention. Diagnostic engineers are under pressure from the time they walk in to a site until the time they leave. They need data and they need it fast. They don't have time to waste hunting for information in a complex system.

So what makes one software application so much easier to use than another? What goes into building a highly usable and easy to use software application? We'll explore that in the following pages and hopefully give you a glimpse of the life and challenges of crafting an easy to use software application. We'll take a look at one of our recent application releases, the ADAPT*.wind platform, and discuss the development processes involved in producing a highly functional user experience.

Software Development Processes

As with many engineering disciplines, designing and building a modern software application involves coordinating a lot of "moving parts." One of the best analogies for building software is building a house. You begin with a design or a blue print and start your construction with a solid foundation. Then you add plumbing, electrical cables and dry wall and complete with painting and finishing work. Software has a similar organization and we can borrow some tried-and-true techniques from our construction examples to help us build a successful software application.

Before you begin construction of a building, you may talk with an experienced architect who will ask you about your business needs, living style, habits and what you want out of your new construction. The architect will look at your environmental factors such as climate, lighting, ambient temperatures, road ways and so on. All of these factors are then taken into consideration when creating a blueprint or diagram for construction of the new facility.

User Domain Analysis

Just like our building architects, we want to capture the wants, needs and requirements of our end users before we start any construction on new software. Capturing these requirements is often referred to as User Domain Analysis (UDA). In the UDA, we immerse ourselves in the user's environment through hands-on-training and personal interviews – essentially "living and breathing" in the same environment as the software application's end users. The first step towards a successful user interface is experiencing the same environment as closely as possible.

Performing the UDA phase very early in the software development process is even more important when designing a Plant Asset Management software application for some of the most complex systems and environments known today. Wind Farms, power generation plants and modern refineries contain a tremendous number of diverse and complex assets from small pumps and electric motors to large scale industrial gas and steam turbines – all working together in a single environment. Capturing and presenting data and analysis in these highly complex and diverse environments quickly and efficiently presents a unique set of challenges, with little room for errors, or unneeded extra mouse clicks or keystrokes.

During the UDA, we first focus on first capturing and modeling the user. We capture and document who is the main, primary user of the application. This is most often referred to as modeling the "persona." A Persona is a model of a real user with specific goals, attributes and personality. When we model our personas, we give them names, job titles, even birthdays to help make them as real as possible. Capturing the persona is the first step towards that good interface. It allows us to understand and target the application for the right, primary user. It is important to note that a Persona is not just an average of all our users; rather, a persona is a specific user that we are targeting to be "delighted" by our application.

ADAPT.wind Example

ADAPT.wind is a Bently Nevada condition monitoring product that is specifically focused on Wind Turbine Generator (WTG) drivetrains. It includes "uptower" monitoring instruments that process vibration data from drivetrain components, and a software platform that is used to manage the monitored wind machines and to diagnose any identified deterioration in their condition.

In our ADAPT.wind software project, we identified three main Personas – "Bart," our Wind Turbine Manufacturing Technician, "Derek," a Customer Service Center Operator and "Fitz," a Diagnostic Engineer. These three personas composed the group of users that we were targeting. We identified people who represented real life examples of our personas and brought them in as consultants for the project development team. We interacted and worked directly with our live personas constantly throughout the duration of the project. Our live personas are one of the most important assets we had on our project team and they deserve credit for the much of our success with the software that we developed.

Context Scenarios

At the same time as we are modeling our personas, we are also capturing descriptions called "context scenarios." Context scenarios are small narratives (stories) that describe a common goal or situation. A typical context scenario for our users might involve performing a machine startup, restarting from a recent wind turbine trip, or diagnosing a gearbox or main bearing failure. Context scenarios are fairly short – usually not more than one or two pages long – and they help us to document the main needs or goals of the software in terms that a user would appreciate. Because the context scenario is written as a story with our persona as the main character, we get a much better feel for the problems and challenges that the user encounters. It is almost as if we are there with our end users as they use our software, and we can much better identify and relate to their goals and environment.

When we developed the software platform, we performed the UDA phase very early in the project – even before any code or engineering teams were assembled. The Usability teams started with one-on-one interviews with wind energy engineers, gearbox design engineers and field operators. These interviews typically lasted between one and two hours, and they allowed us to identify the most common scenarios of use for the different interviewees. As these interviews progressed, a clear picture of what the main Wind energy personas and their main scenarios of use started to emerge. We identified two main context scenarios or "epics" that we concentrated on expanding to get us started.

1 **Monitoring:** The first scenario was about monitoring. This scenario included the need to quickly assess the overall status of all WTGs in a wind farm and to view relevant information for any turbines that are in alarm. This was our first main scenario that captured the user's need to see, at a glance, what turbines required further attention.

2 **Diagnostics:** The second scenario was about diagnosing or validating the statuses or alarms for each Wind Turbine. A typical alarm might be a gearbox or bearing over vibration captured at a known fault frequency for that component.

When documenting your main context scenarios, you can start by just identifying the main scenarios of use. While you will end up with many scenarios by the time you are done, you want to start with just those main, few, primary scenarios of use to get started. Don't worry about capturing every detail of every possible scenario of use. Start by capturing the most important or main context scenarios to get started. The remaining scenarios will come more easily once you have captured the main context scenarios first.

Storyboarding

Once we had expanded the two epics into detailed narratives or stories, we "walked through" the scenarios and sketched a rough draft of an effective software interface to match each part of the story. This method is often called storyboarding. It is a tremendously effective method for designing a highly usable interface. Using context scenarios for our story boards took much of the guesswork out of the design process. As the story progressed through different activities and stages of diagnostics or monitoring, we sketched screens to match the steps in the stories, which allowed us to move elegantly through the application, just as the user naturally flows through their scenarios.

When we began designing our first user interfaces for the software, we used the storyboarding technique to create the needed interfaces directly from the context scenarios. As an engineering team, we started by reading through our primary context scenarios in the Monitoring epic – producing several storyboard sketches to match the user needs for the scenario. We quickly discovered that a successful interface would need to provide intuitive "at-a-glance" identification of tripped or alarming WTGs, and then seamlessly present the data and diagnostics for those alarms all in one single flow.

Figures 1 through 3 show examples of "wire-frame" mockups that we developed early in the storyboarding process for the ADAPT.wind software project. In these examples, we storyboard the user observing the status of each WTG, followed by a seamless flow from observing that a WTG is in alarm, viewing associated alarm events and viewing vibration data associated with alarm events. This Storyboard was based directly on the Context Scenario and was modeled to match the user's primary scenario of use.

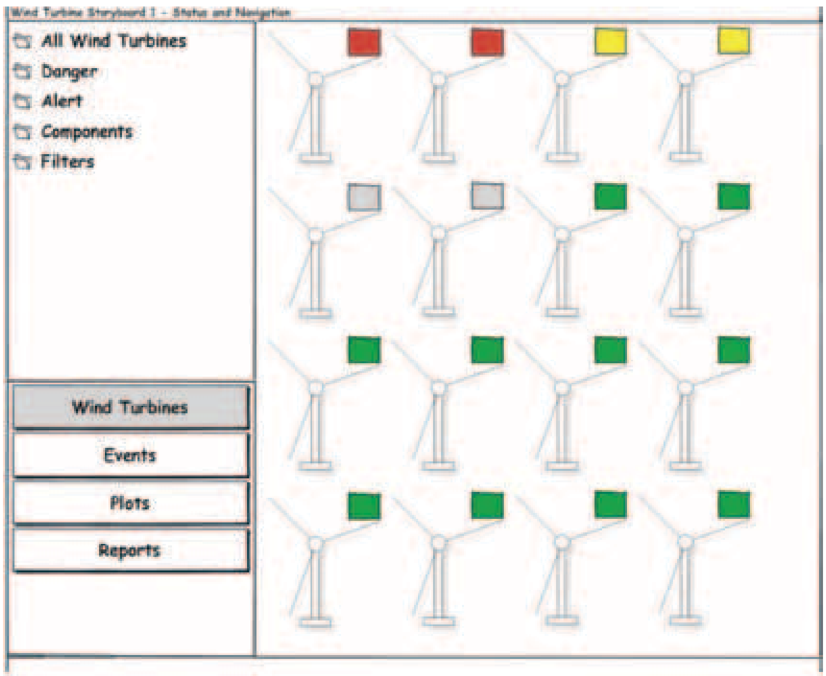

Figure 1: In this example, all of the turbines in the wind farm are shown in the large Status View display pane in the right hand side of the screen. The colors next to the WTG icons indicate their alarm status.

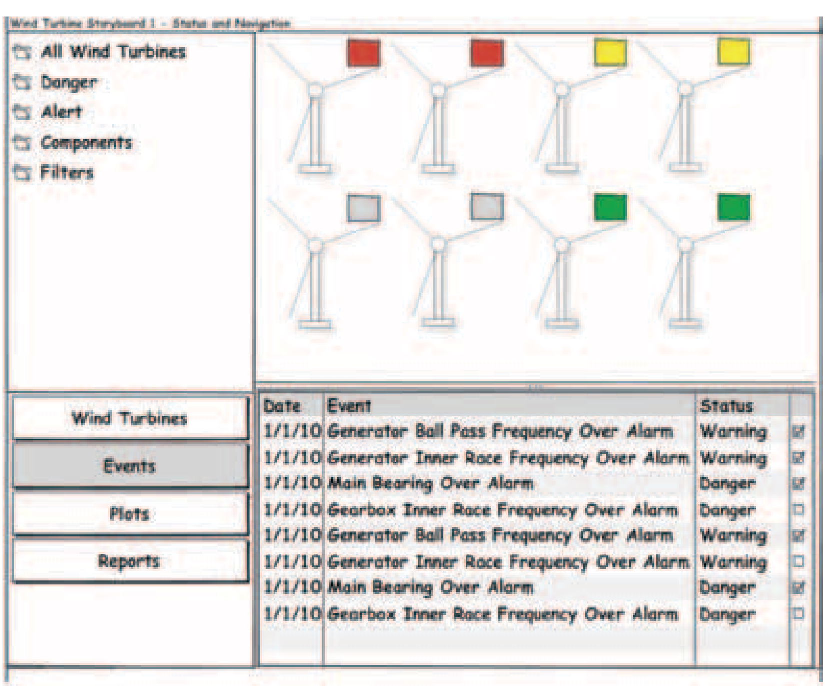

Figure 2: In this example, a "split view" allows us to see the Alarm List View in the pane below the Status View.

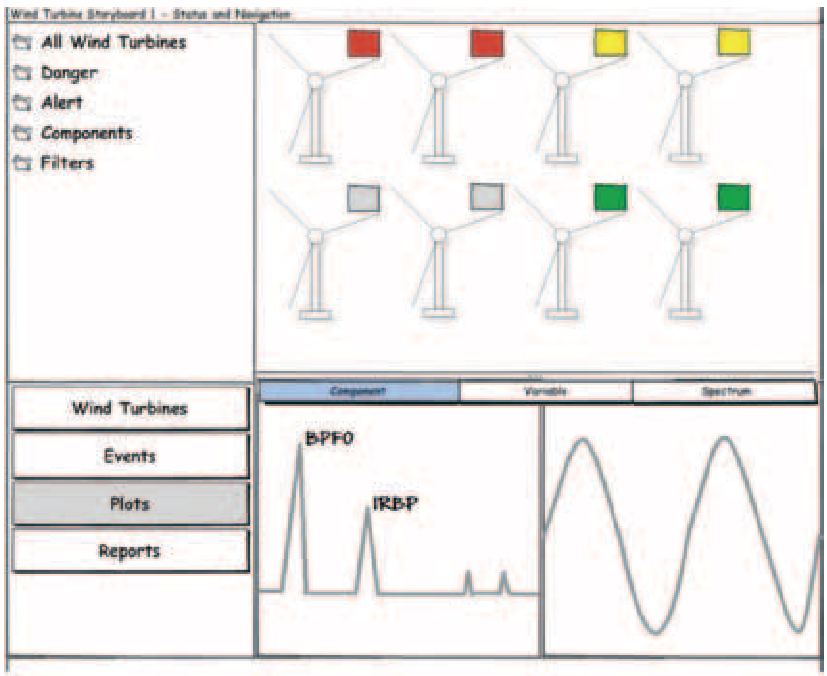

Figure 3: In this example, the time waveform and spectral data for the selected alarm event are shown in the Plots View below the Status View.

The end result of this process was a set of storyboards that we could use as a team for further development of our ADAPT.wind software user interface – starting with wireframe mockups such as these, and ending with the final interface screens.

When we started storyboarding our Wind application, we started with just the main or most important user context scenarios which were monitoring wind turbine statuses and validating or diagnosing alarms. We want our Wind Application's interface to excel at those primary scenarios of use, so we captured and storyboarded those first. Modeling your interface around your primary scenarios of use first will help ensure you are designing your interface around the most important scenarios and help avoid focusing or highlighting those less traveled fringe cases. The remaining stories usually come easily once you have modeled or captured the true application's purpose.

Interface Design & Validation

It is vitally important to validate that our interface actually meets the needs of the users that we designed it for. Without direct hands-on validation by our end users, we would only be guessing that our interface design is solid. So in this process, we took our storyboards to our actual end-users, and verified that our proposed interface would actually help our Personas accomplish their tasks for the identified scenarios.

Once we determined that our concepts were valid, we converted the hand-sketched storyboards into computer based wireframe models of the interface screens. The good news is we can use the same scenarios we created earlier to validate the wireframe designs, just as we used them to validate the storyboards.

Using the same context scenarios, we sat with our users and walked through using the wireframe interfaces, to verify that we have indeed, hit the target. If we can move through the scenarios easily and intuitively with our wireframes and story boards, we can start to build confidence we are on the right track to a successful and easy to use interface.

It is important to note that design and validation for your application go together and really should be looked at as one activity. Without exception, you will find problems in the initial wireframes, and other unanticipated areas for improvement. Good designs are iterative and often take several cycles to refine and polish. It is often incorrectly assumed that good designs come from an inspiration or single idea. The truth is that good designs – like most things – are a result of hard work and attention to detail, and that it usually takes several iterations and refinements to get it right.

As we can see, creating highly usable software happens long before the first line of code is written and starts by understanding who the true users of your software are and living in their shoes.

Now that we have a User Domain Analysis and a good wireframe or blueprint to work from, how do we go about building it? The key is actually in change. Software projects take time and during that time, requirements and markets change. One of the worst enemies of software development is in the initial assumption that nothing will change. Previous software development processes followed a very rigid model often referred to as the "waterfall" model. It was called that cause as you progress through your project, you continue forward and never go back upstream. While this was a great model for earlier software, today's fast paced environments need a process that can adapt to change.

Agile Development

A modern model for managing change is the new Agile development process. Agile is a recent and very "fluid" development process that is built around managing and working with change. But before we dive into the concepts of Agile you might be asking yourself, "We already have the wireframes or designs that we validated and we don't want to change anything, so how can 'Agile' help us?"

The truth is that we will continue learning as we progress through the project. We will learn new techniques, methods and improved designs as we go. Most larger software projects take between 12 and 18 months (or more), and we would like to take advantage of the total project time for our iterative designs, rather than trying to get every detail correct in a shorter up-front requirements definition phase. We want to design "just enough" to get us that top level blueprint or wireframes, but we have many details left to design - so why not take advantage of the entire project life cycle to do a better job?

Plus, some degree of change is bound to occur. Markets and user needs may change during this time, or new technologies might be introduced that you now wish to add in your application. As an example, you might have started out by only looking at vibration analysis for WTG gearboxes and now, with advancements in new technologies, want to include or add online lubrication analysis.

Usually, these major changes occur partway through the development process and you are challenged with how to incorporate the changes while attaining your original goals. Change is not unique to any project – whether it is a small household project, a multi-story commercial building, or developing a new software application. Modern development processes, such as Agile, can facilitate managing and adapting to changes. Using these processes can ensure that, in the long run, you will ultimately prove more effective in producing a highly successful application. How we manage this change is the key to a successful and usable interface, as we will see below.

WHEN WE MODEL OUR PERSONAS, WE GIVE THEM NAMES, JOB TITLES, EVEN BIRTHDAYS TO HELP MAKE THEM AS REAL AS POSSIBLE. CAPTURING THE PERSONA IS THE FIRST STEP TOWARDS THAT GOOD INTERFACE. IT ALLOWS US TO UNDERSTAND AND TARGET THE APPLICATION FOR THE RIGHT, PRIMARY USER.

Sprints

To make the process of building software more manageable, we break the overall project into two-week "sprints." Typically, each of these short sprints is long enough time to implement a small software specification (spec) called a "speclet," but not too long to allow the project and team to get lost.

A speclet is just a small, targeted interface design specification. It is a simple, concise document that defines exactly the portion of the user interface to develop for the sprint ahead. The speclet shows a simulated example of the user interface as it will appear when it is completed – along with a textual description of the interface and the key paths or user interactions, such as mouse clicks and cursor behaviors. Figure 3 shows a monitoring screen with the "farm view" at the top of the screen. The speclet for this particular example required that the alarm status of each turbine be shown as associated color coding for each WTG.

The success of the speclet lies in its small size. It is important for the speclet to be short and concise enough for the development teams to understand and execute it in a single sprint. A specification that is too big or a development period that is too long can often lack clarity, which can cause ambiguities to creep into the process, leading to a deviation from the original design goal. On the other hand, a development period that is too short may not allow enough time for the planned development to be

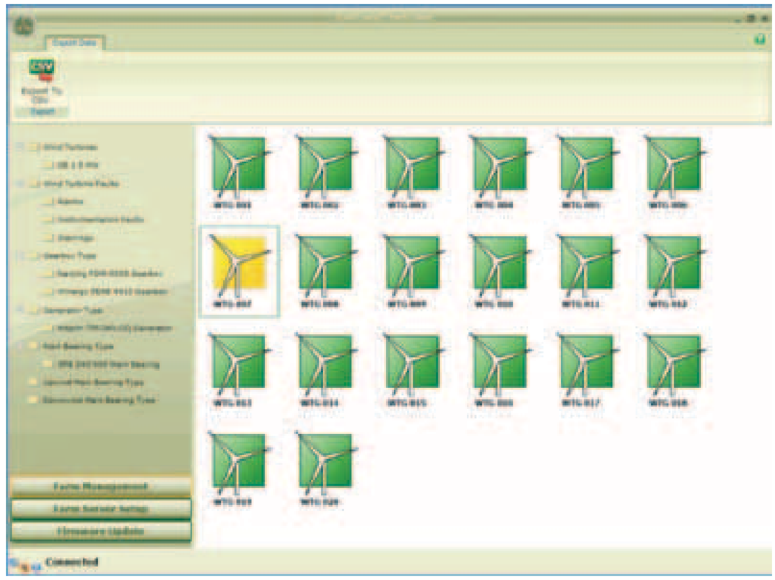

Figure 4: This example is an ADAPT.wind monitoring screen. The Status View pane at the right side of the screen displays WTG status colors corresponding to alarm status for each monitored machine. This functionality was implemented based on a speclet. It is obvious that this final screen was created based on the initial wireframe mockup shown in Figure 1.

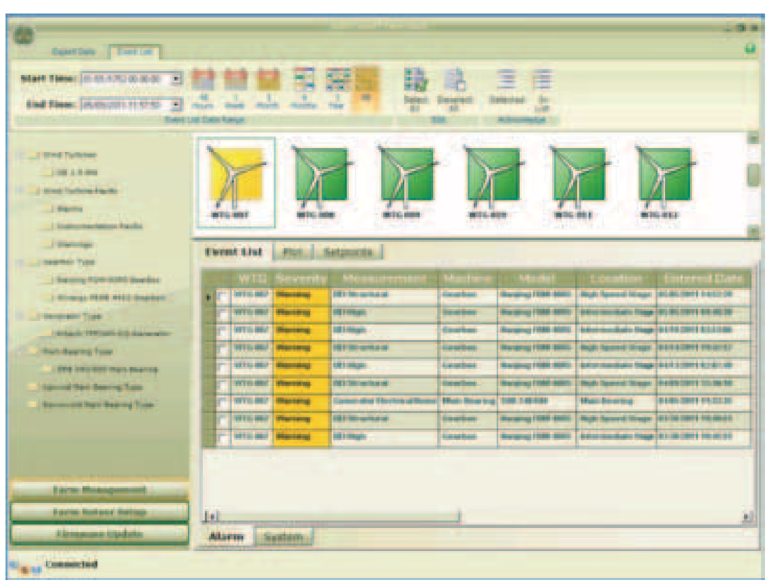

Figure 5: This example shows how the split view was implemented to show the Alarm List View in the pane below the Status View. This final screen was created based on the initial wireframe mockup shown in Figure 2.

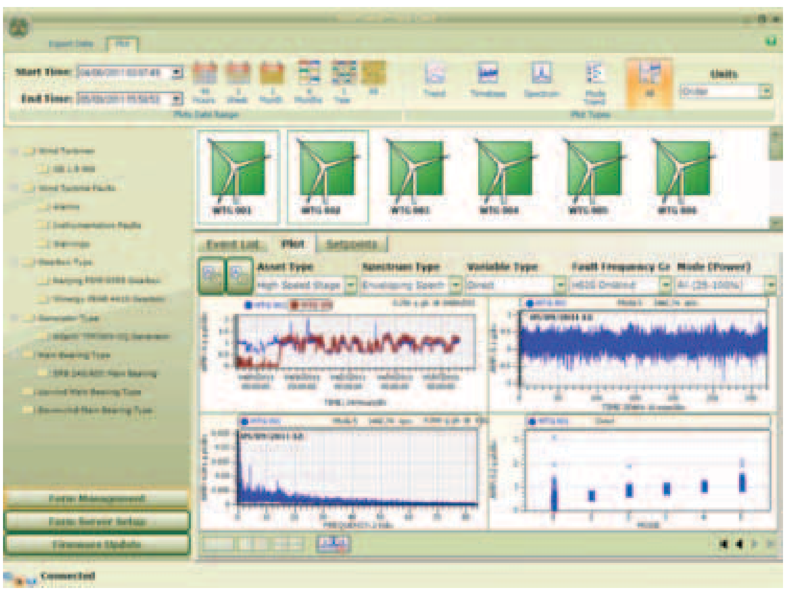

Figure 6: This example is a diagnostic screen. Compare this screen with the associated wireframe mockup in Figure 3.

completed. Success comes with a short – but complete and targeted sprint – that can deliver the speclet as intended.

At the end of each sprint, it is important to meet with your end users and review the work that has been completed, to validate your interface so far. Even if you have not completed very much, it is the constant cycle of design, validation and change that enables a successful interface. As mentioned earlier, it is often assumed that great designs come from a single inspiration or idea. In fact, great ideas and interfaces come from continual improvement and refinement. It is in the continuous refinement and iterations of Design, Validation, and Change where your great ideas and successful interfaces will present themselves.

For the ADAPT.wind software platform, a new design speclet was developed every two weeks that contained the user interface designs for the following two weeks of development. Then, at the end of the two weeks, the development teams would meet with our live personas for short 15-minute demonstrations of the interface designs. No matter how small or large your development sprint is, it is important to review your sprint speclets with your live personas to ensure continuous feedback.

Our live personas participated in the retrospective review at the end of each sprint, and offered their feedback and commentary on the changes made to the interface. Our live personas commented on what worked well and on areas where changes or improvements were needed. Invariably, each sprint review would result in some positive change feedback that would ultimately keep the project team on target. The goal for each sprint review was to make small changes and "mid-course corrections" rather than large sweeping changes. Through constant review, the engineering teams worked hand in hand with our live Personas to make the small adjustments required to deliver a highly functional user interface that met the demands and needs for our main users.

Conclusion

Successful software interfaces are grown and developed over time as result of hard work, attention to detail and constant improvement. To delight your customers, you first need to put yourself in their place "walking a mile in their shoes." It is vital to understand their environment, their struggles, goals and successes. It is also important to capture the few most significant context scenarios of your users and work with them throughout the life cycle of your project. Be ready for change and embrace it when it occurs. Let that change be your inspiration for creating great interfaces that improve the life and goals of your users. Remember, great interfaces are a result of continuous work and feedback and trying new ideas.

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Using Event Range for Plot Sessions

Editor's Note: Our ADRE* Tips department will include an ongoing series of short articles written by John Kingham. John will share helpful suggestions for effective data collection and analysis based on his many years of experience as a Machinery Diagnostic engineer. This particular tip is about a feature of the ADRE Sxp software, so it is especially appropriate for this software-focused issue. – GBS

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Figure 1: Bently Nevada ADRE 408 Dynamic Signal Processing Instrument (DSPi)

One of the many items in ADRE Sxp software that is an improvement over the old ADRE for Windows® software is the ability to easily select a range of data based upon events in the database log. This makes it extremely easy for you to select the data that you want to look at. In this topic, we will describe what events are, how to create them, and how to use them to select the data that you want to examine. Once you follow the steps in the article once or twice, I predict that you will want to use these techniques every time you look at your data.

For this topic, I must admit that I found so much good literature in the Sxp Help section (which is itself a pretty good improvement over the old ADRE for Windows software), that I am going to use a significant amount of it here.

Event Types

There are generally two different types of "events" that can be used for selecting the event range. The first type is automatically generated by the ADRE system. These include System Events that are created upon entry or exit of the Store Enable or Trigger modes, and whenever a sample is collected manually.

The other type of event – and the one that I find most useful – is the "annotated" event. You will find out more about annotating your data in the next section of this article. In essence, if you see that something interesting is happening, you can click the Annotation button in the toolbar, and an annotated event will be entered into the database. You can then add your own descriptive notes in the annotation that is associated with the event.

All of these event types are summarized here:

- Manually Annotated Events – those events that you specifically create
- System Events:
  - Unit Entered or Exited Store Enable
  - Unit Entered or Exited Trigger Mode
  - Manual Samples

Getting Started – Adding Annotation Events

An annotation is simply a manually-added comment that corresponds to a data sample that was collected at a specific point in time. Both the text and the time-stamp of the annotation are stored and displayed in the Event Manager dialog. You can also choose to view annotations on Trend and Replay Plots. It is important to realize that you can annotate your samples at any time – even long after the data was collected.

The ideal time to annotate a sample is while you are sampling the data and you hear something, feel something or otherwise notice something unique that may be happening. The other time is after you have finished sampling the data, and you see something in the data that makes you want to single it out for further study. So, you can see that you will always be able to annotate your data at any time.

For our discussion, I am going to run a Bently Nevada rotor kit up from a stopped condition, to a steady state speed, hold there for a while, and then ramp the speed down to slow-roll (simulated turning gear) speed. I will create three separate sets of data for the following modes of operation: run up, steady state and run-down. Each plot session will contain data that is unique to it, and that correlates to those events.

Annotating During Sample Mode

To annotate a sample while you are collecting data, follow this process:

Place the 408 DSPi in **Store-Enable** mode, and start sampling. Click on the **Annotation Tool** in the General Toolbar or select **Annotation** from the **Store-Enable** menu. This will open the Sample Annotation dialog shown in Figure 2.

In this particular case, I have set up my rotor kit to capture a startup, a period of steady state (constant speed) operation, and a shutdown. I want to annotate my data so that I can find the events where steady state operation begins and ends.

Enter a comment in the **Sample Annotation** dialog, and click **OK** to save the comment. Now when you follow the procedures listed later in this article, you will see your annotation comment within the **Select Event** box.

I should also note that every time you click the **Manual Sample** button, you are creating a new event. It is not an annotated event, but it will show up, and be selectable in the event list.

Annotating After Sampling (Post-Processing):

Do not be frustrated if you forgot to annotate events as they occurred. Remember that you can add annotation to your database even after the data has been collected. To do this, open a Trend or Replay plot and right click on the data point that you want to annotate. In the shortcut menu (Figure 3), you will see **Annotate Current Sample** in the list of options. Select this option, and the text entry box (Figure 2) opens to allow you to annotate that point. Now, the next time you open the **Select Events** dialog, this newly-annotated event will be in the list, and will be available for you to choose.

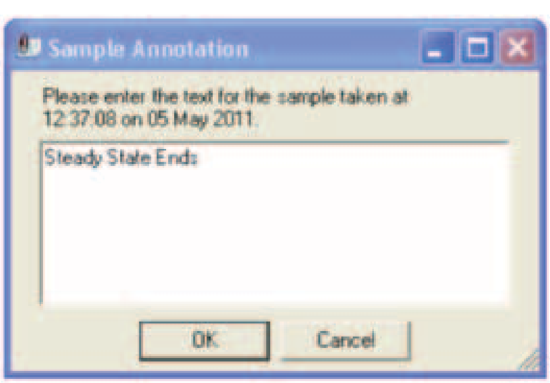

Figure 2: Sample Annotation dialog box

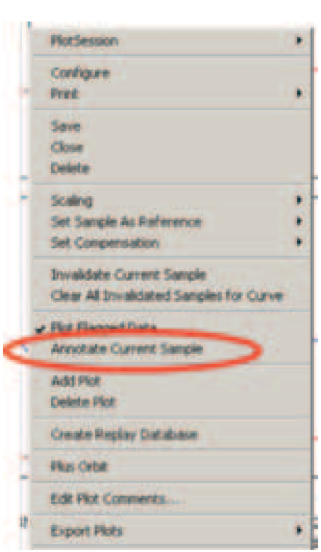

Figure 3: Shortcut menu, showing **Annotate Current Sample** option.

Configuring and Using Events

Now that we have created some events, let's use them to define our plot session! I should note here that despite our efforts above to create custom annotation events, they aren't absolutely necessary. The system generates its own events whenever you enter and exit the Store Enable mode or take a sample manually, so there are usually several events that are appropriate to use for defining plot session data ranges.

Using an Event Range Selection

The first step in using event ranges is to configure the settings for your plot session. In this example (Figure 4), I have named my plot session "Transient Run Up Plots."

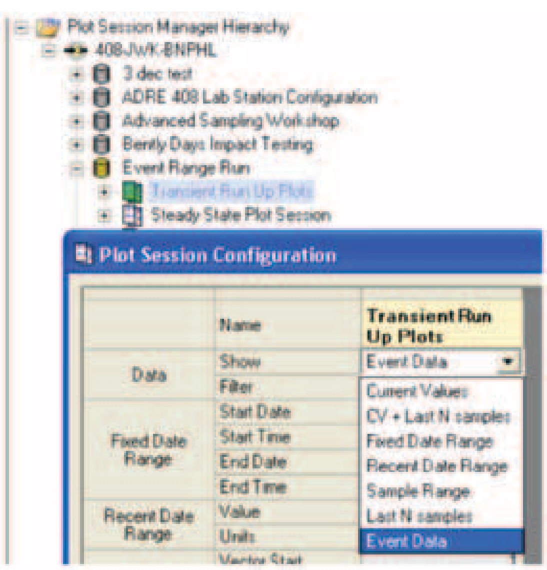

Figure 4: Plot Session Configuration dialog.

From the drop-down list in the configuration dialog, I have selected **Event Data**. When this choice is selected, you will see that the **Events** cells become active. From here, you will need to select whether you will be analyzing data from a single event or from a range of events.

For this example, I selected **Event Range** (Figure 5). This will allow selecting one event to define the beginning of the historical data to be evaluated, and a second event to define the end of the data to be evaluated. Note: Figure 5 is just a small part of the same Plot Session Configuration dialog, from further down the column.

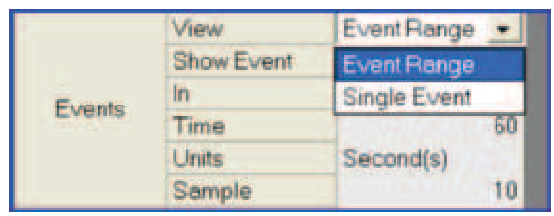

Figure 5: Event Data Selection

Even further down the column in the same Plot Session Configuration dialog is the Show Events box (Figure 6). We will use this option to display the events from which we can choose in order to define the beginning and end of the data range to be displayed.

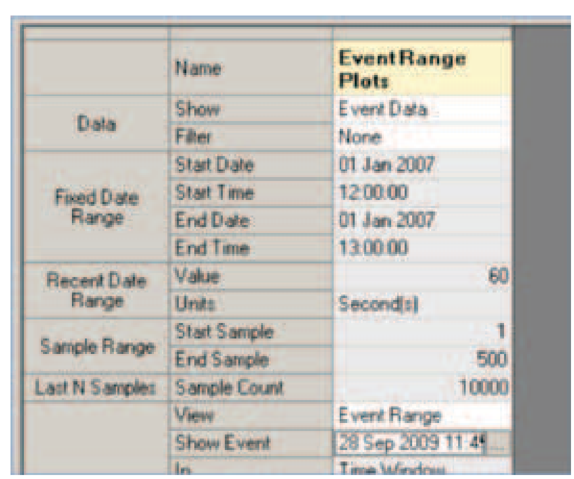

Figure 6: Show Event Box

The elipsis symbol (three dots) in the **Show Event** button indicates that further information will be required to complete the configuration.

When you click the Show Event button, the Select Event dialog opens in a new window (Figure 7).

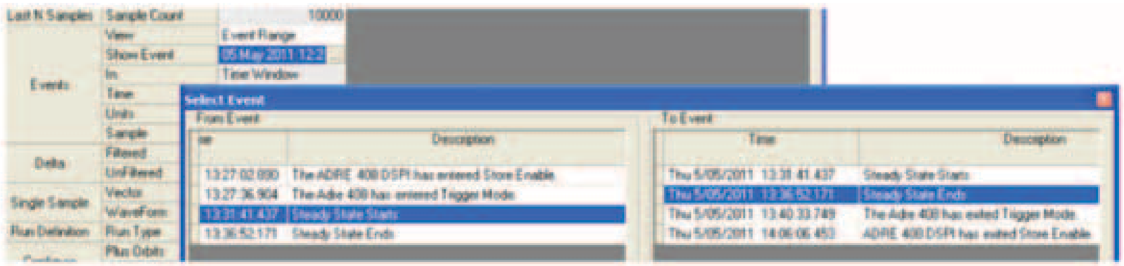

Figure 7: Select Event dialog. The left pane lists **From Event** choices, and the right pane lists **To Event** choices.

Since I wanted to develop my Steady State Plots, I chose the "Steady State Starts" annotated event as the "from" event, and the "Steady State Ends" annotated event as the "to" event for this example. The data displayed in the plot session will be the data that is bracketed by these two events.

If I had wanted to view data for the machine startup instead of for steady state operation, I would have chosen the "The Adre 408 has entered Trigger Mode" as the "From" event and the "Steady State Starts" as the "To" event.

Note: The annotation events that are displayed in the From Event and To Event lists are modified by your selections. The **From Event** list will not show any annotation events that are later than the event that is selected in the **To Event** list. Conversely, the **To Event** list will not show any events that are earlier than the **From Event** selection. This is usually fairly intuitive. However if you go back to modify the selections later, this may not be as obvious.

Single Event Selection

Another way to specify a range of data to be displayed is to choose the **Single Event** option from the Plot Group or Plot Session Configuration dialog. When you make this choice, a **From Event** list of all of the annotation and system events is displayed in the **Select Event** list (Figure 6). Choose the event that you want to include in the plot by selecting it in the list.

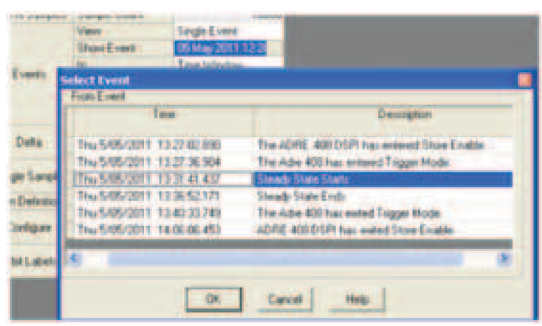

Figure 8: This example shows a specific selection in the **From Event** list.

When using the Single Event option, the amount of data that will be displayed in plots is determined by the In box (Sample Window or Time Window) and by the **Time** and **Units** boxes of the Plot Group or Plot Session Configuration dialog (Figure 9). This allows you to select a specified range of data surrounding the selected Single Event. As the choices imply, this can be set up to be an interval of time or a specified number of data samples.

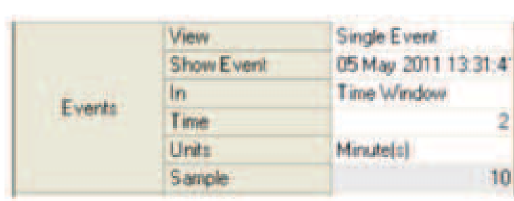

Figure 9: In this example, we opted to display 2 minutes worth of data centered on the selected event timestamp (beginning of steady state). In other words, the range of data that will be shown spans from 1 minute prior to the event to 1 minute after the event, for a total range of 2 minutes.

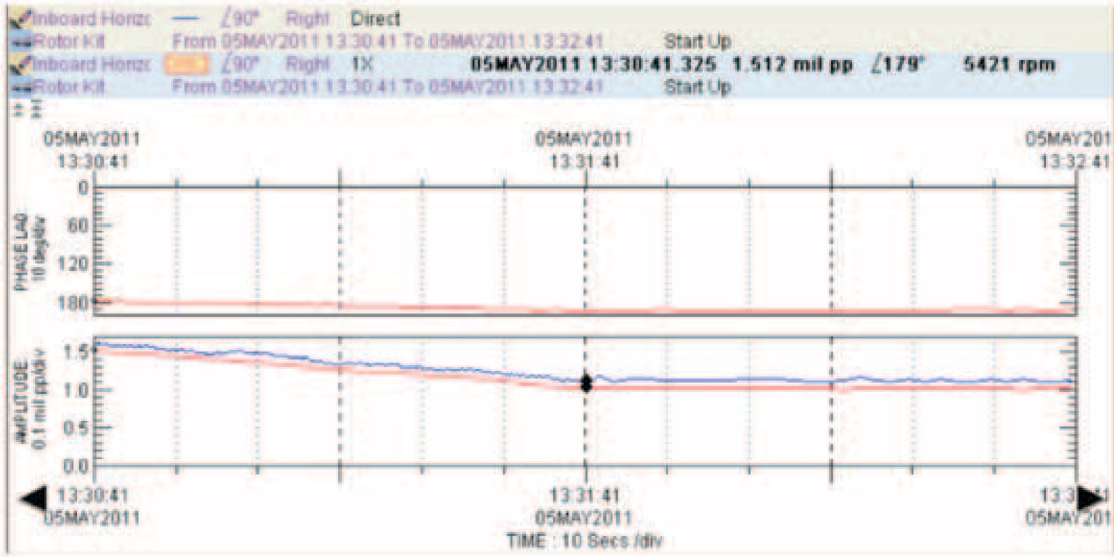

Figure 10: This trend plot displays the two minutes of data that surround the selected Single Event (indicated by a black diamond) that occurred at time 11:52:04.

The trend plot in Figure 10 displays the vibration data that was collected during the specified time interval. You can see that vibration amplitude decreased over the first half of this period – indicating a transient event. At the point where I created an annotated event to show steady state starting (at time 13:31:41), the amplitude becomes steady.

Finding Events

A handy shortcut for finding your events is to right-click on your database name. In the shortcut menu (Figure 11), you will see a choice for **Event Log.**

If you select this option, the Event Manager display will open (Figure 12), showing a list of all of the System Events that are associated with the database.

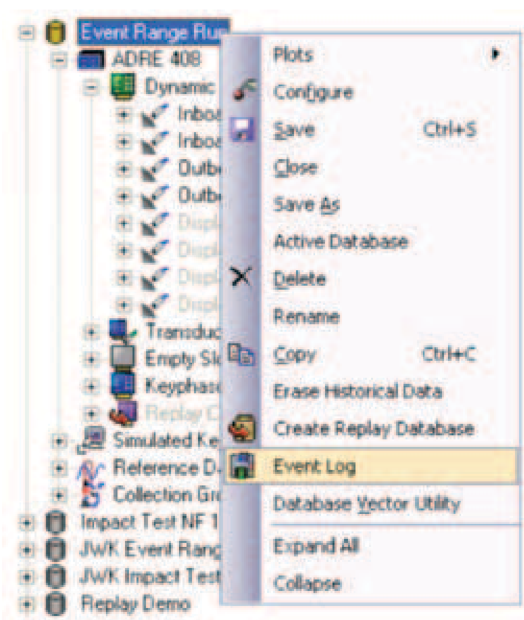

Figure 11: Database shortcut menu.

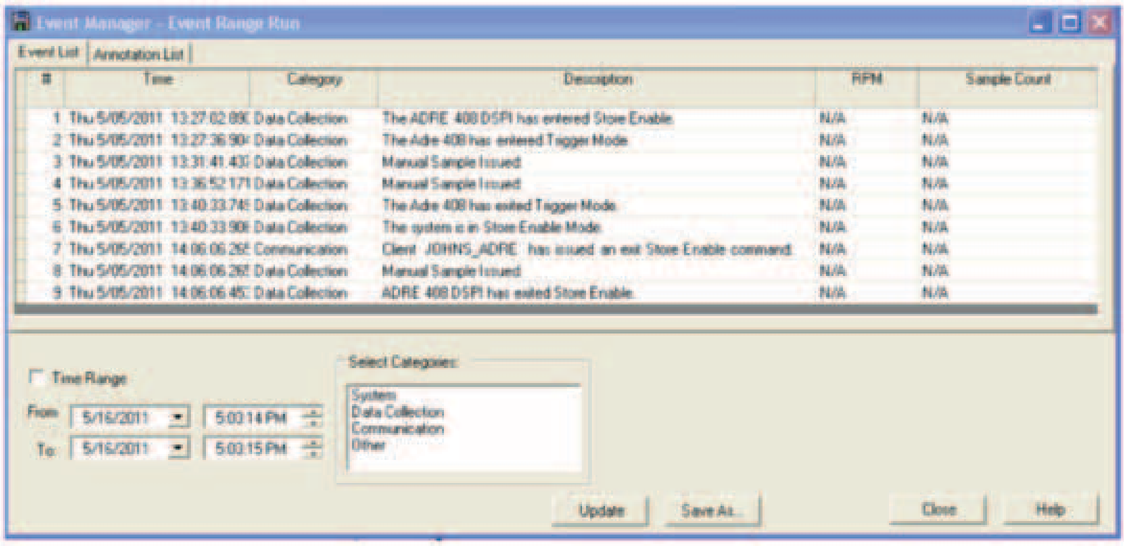

Figure 12: Event Manager dialog, showing a list of all events associated with the selected database.

If you select the **Annotation List** tab, you will see all of the annotation events (Figure 13).

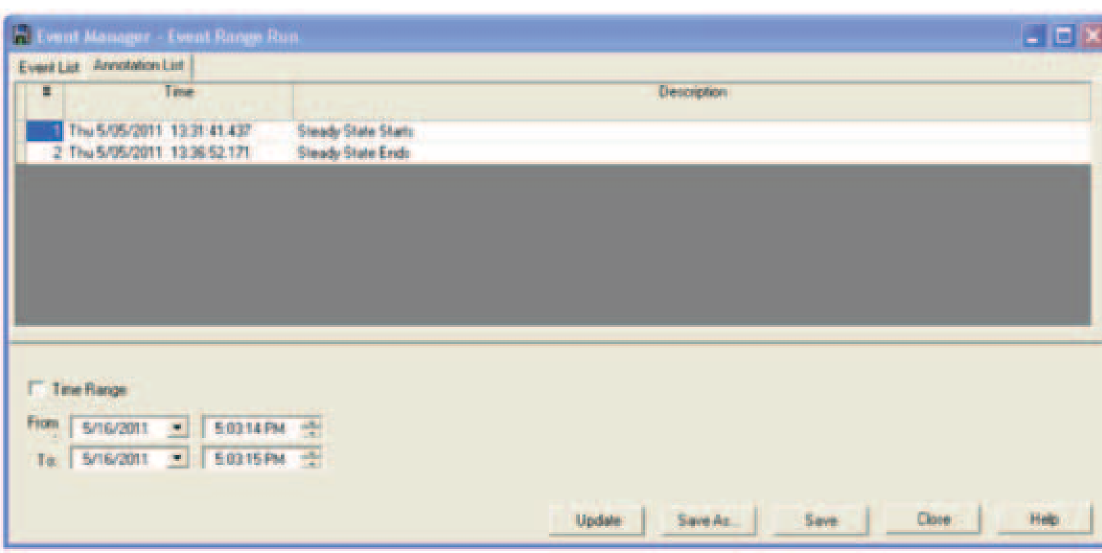

Figure 13: Event Manager dialog, with **Annotation List** tab selected.

In Conclusion

If you are already a user of ADRE for Windows, I think that you will find these new Sxp features to be a great enhancement over the old way of selecting data ranges for plot sessions. Once you become familiar with using events to specify data to be displayed, I think you will find these methods to be your "go to" method for setting plot ranges.

Catch you on the next Orbit – In the meantime, "stay balanced" – John

[Please note that I used ADRE Sxp version 2.60 software in the formulation of this tip.]

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

AnomAlert* Experience

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This article includes three mini case histories describing machine condition problems that were detected and identified by AnomAlert monitors. The monitored machines include an air compressor, a cooling tower fan and a water pump. All three cases occurred at facilities that are related to the global automotive industry.

Example 1 – Compressor Bearing Failure

Event Summary

In this example, an AnomAlert monitor had been installed on a motor-driven plant air compressor in a battery production facility. It started providing intermittent alarms on September 2005, and diagnosed that a bearing problem was developing. Maintenance action was scheduled for January of 2006, and the compressor was kept in service while its condition was constantly monitored. AnomAlert allowed the plant staff to proactively plan for the bearing replacement, and to defer the outage until it would not impact the plant production schedule.

When maintenance and repair actions were performed, they validated the diagnostic assessment of a failing bearing that AnomAlert had made. Upon more detailed examination of the AnomAlert trends, it was found that the bearing problem was actually detected even earlier than 13 September 2005, but that the assessed severity was not yet sufficient to cause an alert notification at that time. This demonstrates the capability of AnomAlert to indicate developing faults at a very early stage.

Machine Description

- Drive Motor: 100 kW, 3-phase squirrel cage AC induction motor.
- Air Compressor: Screw-type compressor
- Application: This compressor supplied all of the pneumatic systems in the manufacturing facility. Loss of the compressor would have a critical impact on the business, as it would stop key parts of the production process.

Data Trends (Figure 1)

This graph shows changes in mechanical parameters that are associated with bearing problems. Bearing faults are shown in different frequency bands: Bearing Parameter 1 (108.64 to 141.60 Hz), Bearing Parameter 2 (158.69 to 191.65 Hz) and Bearing Parameter 3 (208.74 to 241.70 Hz). The slowly rising green line indicates that the detected fault frequency is within the frequency span of Bearing Parameter 3.

The blue line indicates the alarm status for the monitored motor. It is easy to see that the alarm began occurring intermittently, and then became more and more persistent as the bearing failure progressed. The associated Status message was “Examine 1” which means that while failure is not imminent – it is recommended that the planning process for corrective maintenance should be started (Table 1).

Note: It is important to recognize that this trending information is typically not viewed by the user, until after the receipt of an alert notification. Then it is available to confirm concise fault diagnosis. In this case, the user was first alerted to a possible bearing defect on September 13, 2005, while the severity level was still relatively low.

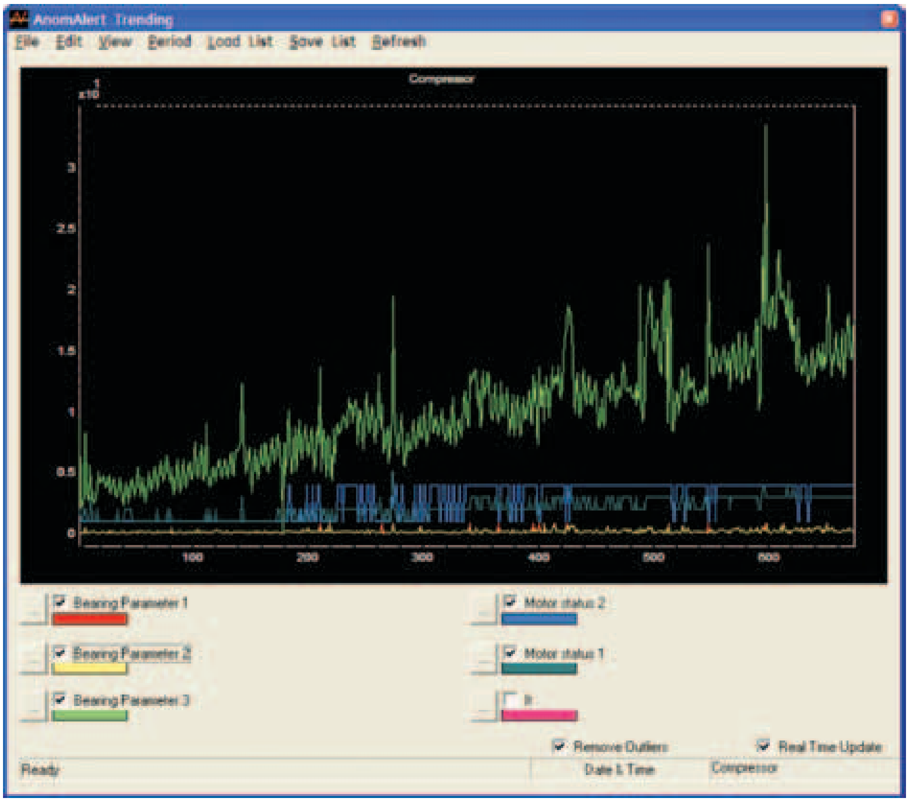

Figure 1: Trend of bearing parameters for plant air compressor

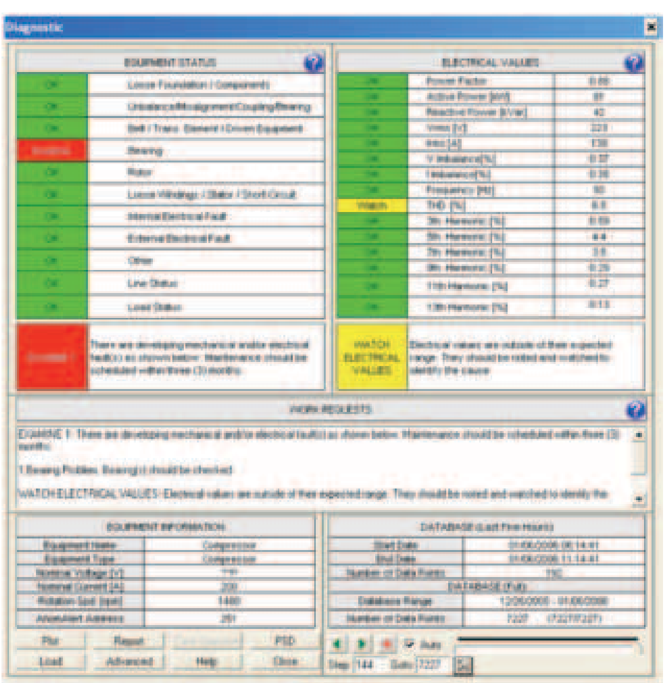

Figure 2: Diagnostic display for the monitored air compressor. Observe the red **Examine 1** recommendations in the **Equipment Status** list.

This early warning of more than three months provided exactly what was required for timely maintenance intervention. The trend graph actually shows that the system had detected early signs of the fault about a month before issuing its initial warning, showing both the sensitivity of the method and its ability to avoid excessive alarms.

Diagnostic Tools (Figure 2)

At the beginning of January, AnomAlert Diagnostic tools recommended checking bearings in the machine. The bearing was replaced on January 5, 2006, and inspection of the removed bearing confirmed the diagnosis that it was indeed beginning to fail.

This early warning of more than three months provided exactly what was required for timely maintenance intervention. The trend graph actually shows that the system had detected early signs of the fault about a month before issuing its initial warning, showing both the sensitivity of the method and its ability to avoid excessive alarms.

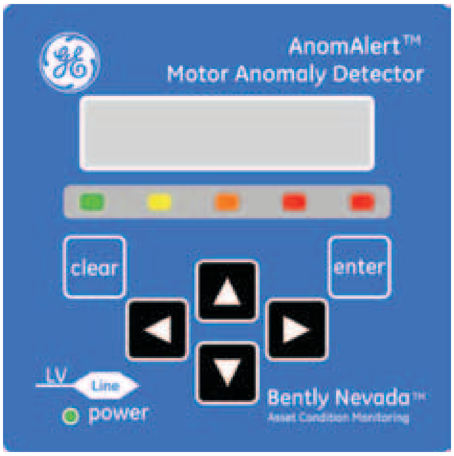

Figure 3: AnomAlert monitor front panel. The LED indications are numbered 1 through 5, with priority increasing from left to right. LED number 1 (green) means NORMAL, while LED number 5 (bright red) means EXAMINE 2 (perform corrective maintenance as soon as possible).

AnomAlert Monitor Indications

In addition to the various indications and notifications that are available through software, the AnomAlert monitor also displays indications on the front panel (Figure 3) of the instrument. These include a Status message in the LCD screen, and a series of colored LED indicators. The meanings of various front panel indications are listed in Table 1.

STATUS	LED NUMBER	FAULT SEVERITY
LEARN	N/A	AnomAlert has insufficient data to assess the status of equipment (learning phase is still in progress).
NORMAL	1	Motor is healthy or level of failure is below alarm thresholds.
WATCH LINE	2	There is a change in motor power supply voltage. If this alarm is persistent, check harmonic levels, capacitors, isolation of cables, motor connector or terminal looseness, damaged load contactors, etc.
WATCH LOAD	3	There is a possibility of a load change. If the process load has not been altered deliberately, check for leakage, valve and vane adjustment, pressure gauge faults, manometer, dirty filters (fans, compressors). If the process has been altered deliberately, AnomAlert should be updated.
EXAMINE 1	4	**Plan Maintenance:** Mechanical and/or electrical faults are developing. Although the level of the failure is not yet serious, appropriate maintenance should be performed during the next planned outage, within a period of 3 months.
EXAMINE 2	5	**Perform Maintenance:** Mechanical and/or electrical faults are developing. Severity indicates that corrective maintenance should be performed as soon as possible.

Table 1: This table describes the meanings of the LED indications and Status messages that are shown of the front panel of the AnomAlert unit.

Example 2 - Cooling Tower Fan Looseness

Event Summary

In this example, a global automobile manufacturer had installed AnomAlert monitors on a number of cooling tower fans. Because of their physical inaccessibility, these fin fans had proven to be expensive and difficult to monitor with other methods. The monitor gave its first warning on October 16, 2005, and diagnosed the problem as mechanical looseness. However, the severity level remained low, and over the next few days, the alert cleared. Based on the AnomAlert diagnosis, the plant staff decided to defer action, but to watch closely for further occurrences of the problem.

Gradual deterioration in fan condition led to a renewed alert on November 14, 2005. This time, the alert remained in effect consistently at a moderate severity. A maintenance inspection was deferred until February 14, 2006, at which time a loose attachment bolt was discovered at the point where the fan hub is attached to the driveshaft flange – validating that the initial AnomAlert diagnosis had been correct. Following correction of the loose fastener, the system remained in alert, accurately identifying a continuing mechanical unbalance condition which may have been related to the original problem.

Data Trends (Figure 4)

This example shows the ability of AnomAlert to manage two developing fault conditions simultaneously. Here the system has been monitoring a set of inaccessible cooling tower fin fans. The red trend line shows a gradual deterioration in the integrity of the supports for one of these fans, following the first notification of a problem in October, 2005.

Diagnostic Tools (Figure 5)

In February of 2006, the maintenance staff inspected the fan and discovered a loose fan attachment bolt that was quickly remedied (Figure 6). Throughout this same period (October through February), the system was also indicating an increasing unbalance or misalignment state as shown by the yellow and green trends.

The unbalance/misalignment condition was correctly interpreted as being less severe than the looseness problem. It was improved immediately after tightening the loose bolt by cleaning the fan – thus avoiding bearing problems that can often be caused by allowing such deterioration to continue without correction.

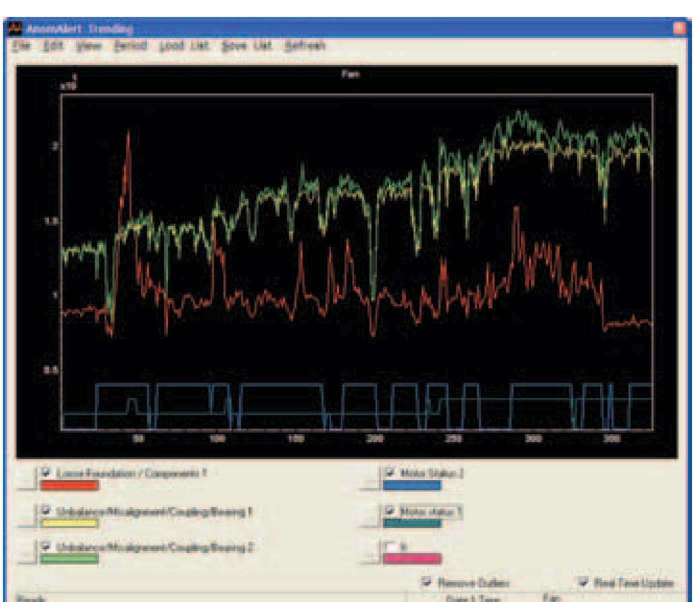

Figure 4: Trend of looseness and unbalance/misalignment parameters associated with the monitored fin fan.

Figure 5: Diagnostic display for the monitored fin fan. Observe the red **Examine 1** recommendations in the **Equipment Status** list.

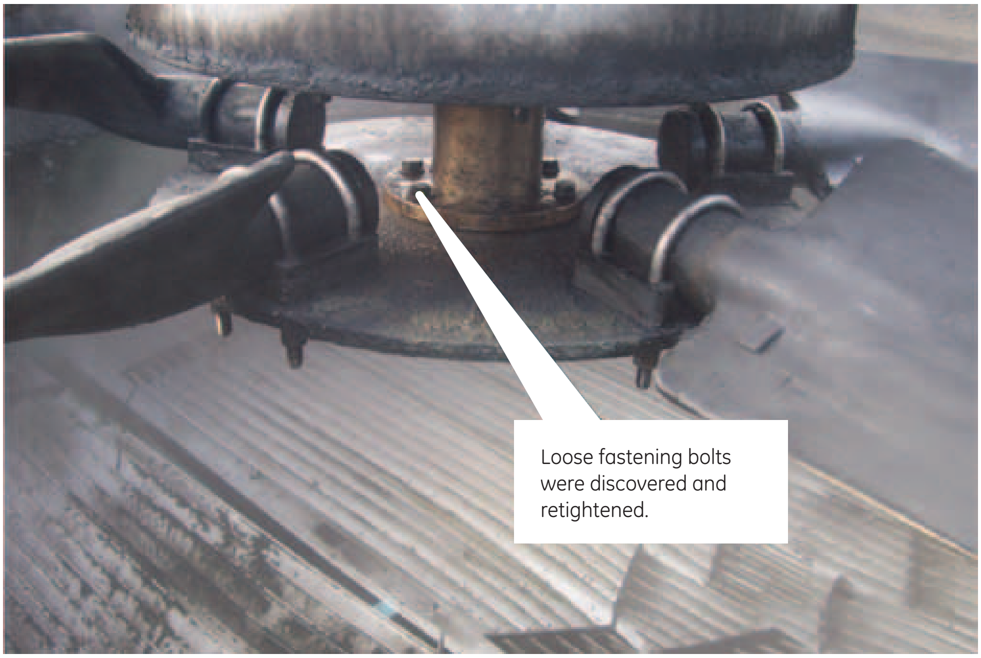

Figure 6: Photo of fin fan hub, showing fan attachment bolts.

Example 3 – Cooling Water Pump Internal Electrical Failure

Event Summary

This is a different example from the same automobile manufacturer that experienced the events in Example 2. An AnomAlert unit that was monitoring a critical cooling water pump provided a warning. The diagnostic software indicated that the developing problem was an internal electrical fault in the pump drive motor. An examination of current imbalance showed that its value was changing over time. Such a change in current – together with an internal electrical problem – pointed to a fault associated with the stator windings. The team used an infrared imager to inspect the leads in the motor junction box, and verified that an electrical problem indeed existed – just as indicated by the AnomAlert unit. The maintenance crew replaced the motor with a spare one to prevent unexpected down time.

Machine Description

- Drive Motor: 75 kW, 3-phase squirrel cage AC induction motor.
- Water Pump : Centrifugal pump.
- Application: Cooling water circulation pump. Provides cool water from the cooling towers to welding machines at the automobile assembly workstations. If the pump stops, the welding machines stop, and production is interrupted. This pump is critical to the business.

Data Trends (Figure 7)

The Internal Electrical faults refer to problems such as rotor/stator conductor problems, short circuits, degraded wiring insulation, winding slackness, etc.

Diagnostic Tools (Figure 8)

The Examine 2 status indicates that corrective maintenance should be performed as soon as possible. Following infrared and visual inspection of the power supply to stator winding terminals (Figure 9), the motor was shut down as soon as a very brief outage could be planned, and it was rapidly swapped out with the onsite spare (which took about 30 minutes). The normal production rate for this facility is 60 automobiles per hour (one per minute!). So it is easy to imagine the impact that an UNPLANNED outage would have had on production.

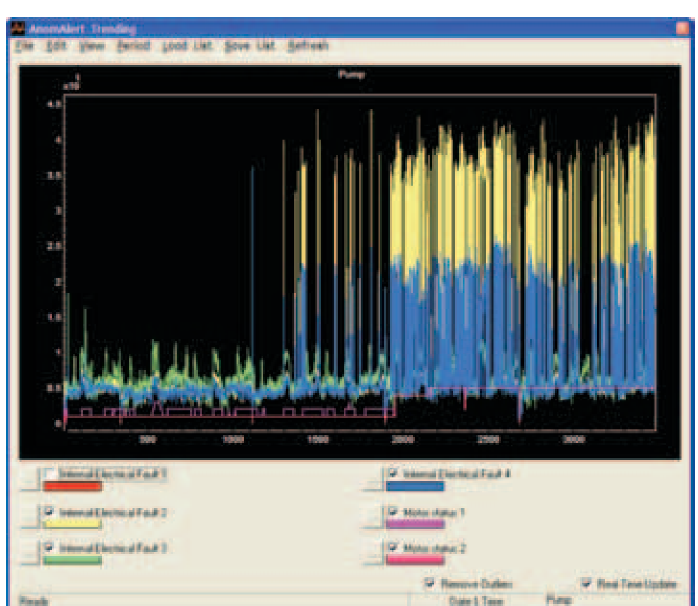

Figure 7: Trend of internal electrical fault parameters associated with the monitored water pump.

Figure 8: Again, observe the **Examine 2** notification in the **Equipment Status** list. The **Work Requests** text box describes that internal electrical faults can include "...short circuits, isolation problems, winding slackness, etc..."

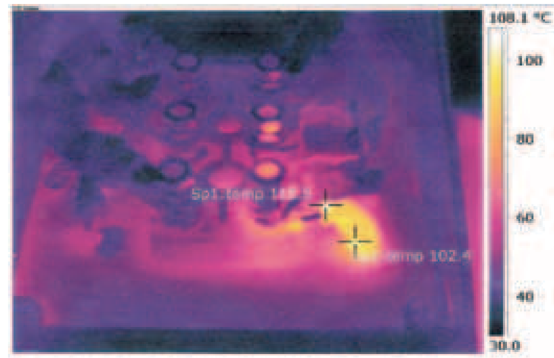

Figure 9: Thermographic image of the pump motor terminal junctions, showing the overheated stator winding lead caused by a fractured connector.

Figure 10: Since a visual photo was not taken at the time of the thermographic inspection, this photo was taken on another motor for reference. It shows a similar arrangement, with power supply leads, terminal connections, and stator winding leads.

Infrared Condition Monitoring Evidence

Since continuous operation of the cooling water pump is vital to production, the least intrusive possible motor inspection was performed before shutting it down for further inspection. Following proper safety precautions, a certified Electrician removed the cover from the motor power terminal box on the motor to allow infrared inspection (Figure 9).

The thermogram shows the terminal connections, power supply leads (left side of image), and stator winding connections (right side of image). This is a perfect example of combining infrared data with electrical parameter measurements in a "collaborative" environment. The photo in Figure 10 was taken on a different motor for reference, since a visual photo was not taken while the thermographic inspection was occurring.

The pump motor was removed for further troubleshooting and testing, and was replaced with the onsite spare that was known to be in good condition. Troubleshooting of the removed motor traced the problem to a fractured connector between the terminal and the stator winding lead.

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

IRPC Uses Online Machine Condition Monitoring System to Meet Plant Turnaround Schedule

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The Integrated Refinery and Petrochemicals Complex (IRPC) located in Rayong province, Thailand, is a vertically integrated producer of refined and petrochemical products. The complex consists of an upstream oil refinery unit and a downstream petrochemicals complex. The complex is located in an industrial estate managed by the company. The estate provides the necessary infrastructure that is used to support the production complex and includes a deep-sea port, oil storage tanks and a power plant.

The oil refinery unit has a total capacity of 215,000 barrels per day and accounts for more than 20% of Thailand's total refining capacity. The petrochemicals complex consists of an Olefins plant with a capacity of 728,000 tonnes, an Aromatics plant with a capacity of 367,000 tonnes, a Plastic resins plant with a capacity of 841,000 tonnes and a Polyol plant with a capacity a 25,000 tonnes annually.

Executive Summary

In mid-2007, a gas compressor in the Deep Catalytic Cracking (DCC) plant of the IRPC petrochemical complex experienced high vibration during normal operation. Using portable diagnostic instrumentation, a Bently Nevada Machinery Diagnostics Services (MDS) Engineer successfully diagnosed the cause of the high vibration as unbalance, and performed a trim balance to reduce the vibration until the compressor could be taken out of service for the removal of fouling deposits.

Based on this positive experience, the plant Mechanical Maintenance Engineering staff installed an upgraded vibration protection and monitoring system in early 2009 – replacing their old 3300 system with a new 3500 system. They also installed a System 1* Asset Condition Monitoring (ACM) platform, to provide continuously available "online" data collection and evaluation capability.

This case history details how the System 1 platform paid for itself immediately after installation during the first gas compressor startup following overhaul. Plant personnel used the system to troubleshoot a high vibration problem on the gearbox Low Speed Shaft (LSS) at the drive end of the gas compressor by combining the available data in System 1 with fundamental machinery diagnostics knowledge gained through advanced training performed during the project commissioning phase.

The root cause of the problem was pinpointed correctly and immediate remedial action was taken, minimizing delays in plant start-up with associated lost production. In contrast with temporarily-installed machinery diagnostic instruments, the continuously-available machine condition monitoring system enabled the assigned plant resources to utilize the available data and be very proactive, rather than have to gather data using temporarily-installed portable diagnostic systems.

Machine Description

The subject machine (31K002) is a two-stage centrifugal compressor in the DCC plant. It is driven by a variable-speed induction motor through a speed increasing gearbox. The compressor consists of two stages in one casing with a back-to-back impeller arrangement. Figure 1 shows the machine train diagram as it appears in the System 1 display.

The first stage receives wet gas (a combination of methane and light naphtha mixed with liquid condensate) from a "knock-out drum" (vapor-liquid separator) in the suction line. It compresses the gas to 4.36 barg (436 kPag or 63 psig) pressure and then discharges through a cooler and another knock-out drum to further separate water from the gas. The dry gas then enters the second stage suction where it is compressed

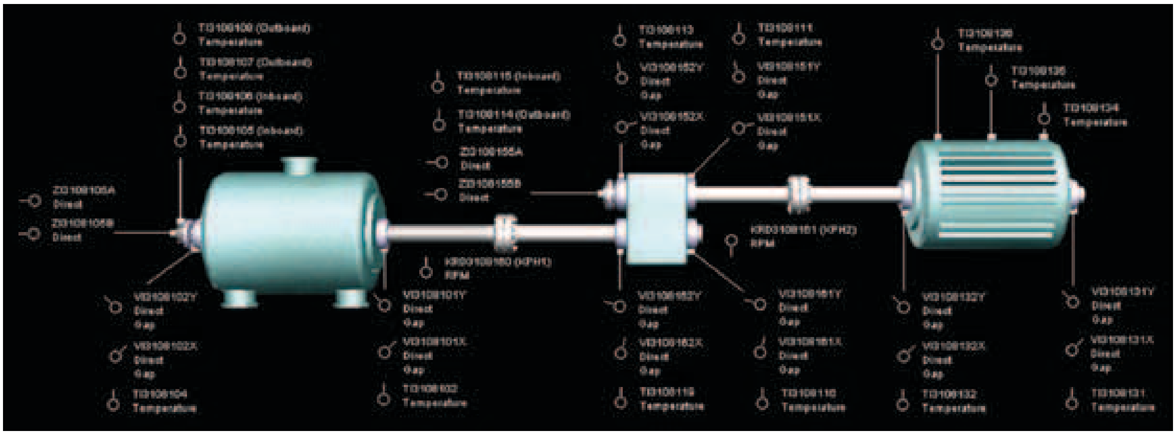

Figure 1: The System 1 machine train diagram shows the compressor at the left side, the gearbox in the middle, and the variable-speed drive motor at the right. The tag names indicate locations for measurement of vibration, temperature, machine speed and phase reference.

to 16.7 barg (1670 kPag or 242 psig) before being discharged to the gas production plant where ethylene, propylene, benzene and diesel fuel are produced

The compressor is fitted with dry gas shaft seals. The center seal, between the two stages, is a honeycomb design with a shunt-hole to help prevent vibration caused by any aerodynamic instabilities. The coupling between the motor and the gearbox incorporates both elastomeric and flexible disc elements. This allows it to minimize the occurrence of torsional vibration that can often be experienced on variable speed drive trains.

Diagnosing and Solving a High Vibration Problem (2007)

In early July, 2007, the gas compressor experienced high vibration during normal operation. The Bently Nevada Machinery Diagnostic Services (MDS) team was called to diagnose the problem and investigate the root cause, using a portable data acquisition system. The MDS Engineer brought an ADRE* 208 Data Acquisition Interface Unit (DAIU) with ADRE for Windows software. Vibration data was taken from the 3300 vibration monitors, which were installed in the local control panel adjacent to the machine train.

With the machinery diagnostic engineer onsite, a test plan was prepared and submitted to the machine overhaul and plant operation teams to seek agreement to allow the machine to be briefly shutdown – allowing the collection of data during conditions of changing speed.

Vibration data that is collected during a coast-down or startup transient provides the highest level of data quality and is essential in understanding the full picture of vibration characteristics when investigating the root cause of a machine problem. In this case it was suspected that rotor unbalance due to fouling deposits on the impellers was the cause of the vibration. It was anticipated that trim balancing might be required as a temporary solution to allow the unit to remain in operation until the next scheduled turnaround in February, 2009.

Approval was obtained to shut the unit down on July 3, 2007, for collection of data during the coastdown speed transient. Subsequent analysis of the vibration data revealed that the frequency of the vibration component was predominantly synchronous (1X). In other words, the vibration frequency component was equal to the shaft rotating frequency – a classic symptom of rotor unbalance. It appeared that the vibration was indeed being caused by rotor residual balance due to the buildup of deposits on the impellers. Therefore, trim balancing was carried out by adding weight at the coupling hub of compressor drive end.

Balancing Data

The polar plots in Figure 2 show the vibration vectors (amplitude and phase lag angle) for compressor 31K002 from the data that was collected on July 3, 2007. The left plot shows data from the Drive End (DE) bearing, and the right plot shows data from the Non Drive End (NDE) bearing.

The first (red) set of data was collected during the initial coastdown run between 12:48:00 and 13:30:08. Maximum amplitude was just over 65 microns peak-to-peak (pp) at the DE bearing, and just under 61 microns pp at the NDE bearing. The second (blue) set of data was collected between 21:16:27 and 22:43:11, following the installation of a correction weight at the gearbox-to-compressor shaft coupling. Amplitude at the DE bearing was reduced to 35.64 microns pp, while amplitude at the NDE bearing was reduced to 56 microns pp.

This balancing operation was the first field balance ever done on the machine, so it was performed in the classic “three-step” method:

1. Initial run before adding trial weight (red curve).
2. Run with trial weight to determine influence (not shown).
3. Final run with correction weight installed (blue curve).

Note: The trial weight was 15.8 grams at 283 degrees, relative to the 7YD_101X probe. The purpose of this trim balance was to improve the safety margin and extend the available time that the compressor could be operated until the rotor could be removed for cleaning of fouling deposits.

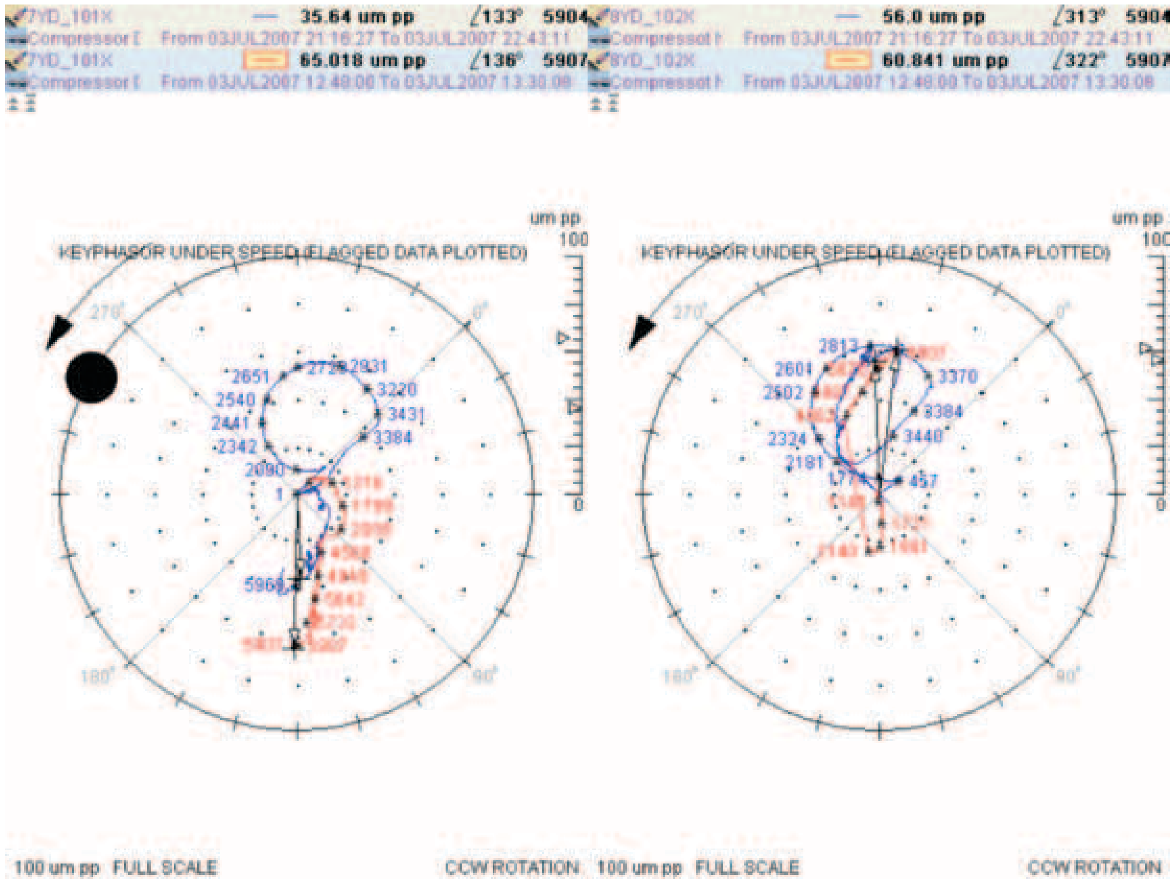

Figure 2: Polar plots for vibration vectors at the compressor DE (left) and NDE (right) bearings. The bold blue dot in the upper left corner of the DE plot represents the location of the correction weight (24 grams at 257 degrees lag angle, relative to the 7YD_101X probe (which is shown as the zero degree reference point). The weight was installed at the coupling hub closest to the compressor DE bearing.

Results of Trim Balancing

Before balancing, compressor vibration was highest at the DE bearing. Trim balancing reduced the vibration amplitude at the DE bearing from about 65 microns pp to less than 36 microns pp at normal operating condition, which was considered an acceptable level. Since no Keyphasor transducer was installed on the low-speed shaft, the diagnostic engineer recommended installing one at the next available opportunity, as it would enable greatly enhanced vibration analysis capability on the drive motor and the gearbox input shaft.

Upon completion of the successful trim balancing effort, IRPC plant personnel gained an appreciation for the value of the data that was available from the temporarily-installed portable diagnostic system. They also appreciated how machinery diagnostic expertise can transform that data into truly "actionable information" that can be used to manage complex machinery problems. The staff reached the conclusion that there would be a significant advantage in having the required data available continuously, so that real-time machine condition assessment could be done at any time during plant operations in all modes of operation. With better condition monitoring, the staff would be able to more effectively perform activities such as ordering spare parts and scheduling maintenance outages.

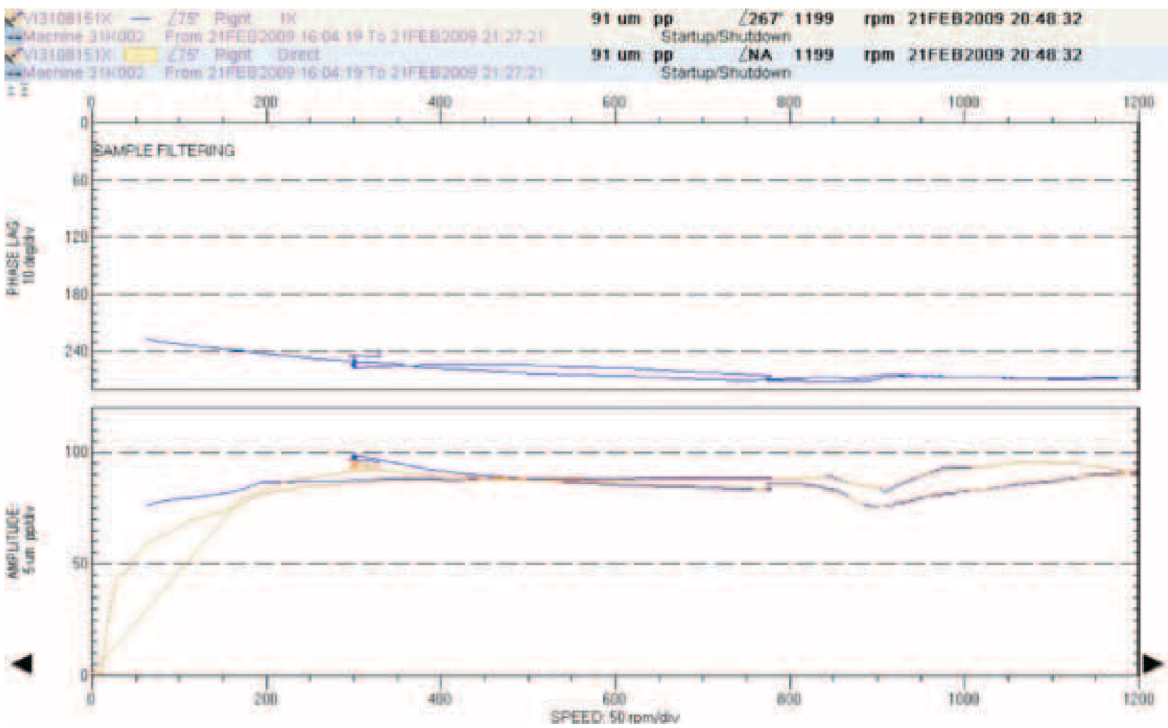

Figure 3: Bode plot of unfiltered "Direct" data (red curve) and 1X-filtered data (blue curve) from VI3108151 Channel X at the low-speed shaft gearbox DE bearing.

With these goals in mind, a budget was set to purchase a System 1 platform. The project scope included upgrading the existing 3300 vibration protection and monitoring system to a 3500 series system, installing a Keyphasor transducer on the low-speed shaft, and associated engineering, installation, project management, and training services – all during the next scheduled machine overhaul, which would happen in early 2009.

Compressor Overhaul (2009)

As planned, the gas compressor was overhauled during a scheduled one-month plant turnaround in the month of February, 2009. During the machine overhaul, the following work was performed

- A new rotor was installed in the compressor.
- New dry gas shaft seals were installed.
- The drive coupling and journal bearings were visually inspected.
- The coupling bolts and gearbox were inspected using dye penetrant.
- Journal bearing clearances were measured and confirmed to be within manufacturer-supplied specifications.
- Alignment between the induction motor and gearbox and between the gearbox and compressor was measured and adjusted as needed.
- Condition Monitoring (CM) system was upgraded as planned (with 3500 system, System 1 platform and Keyphasor transducer on low speed shaft.

Post-Overhaul Compressor Startup

The compressor unit was started up on 21 February 2009 after the major overhaul was completed. High vibration amplitudes of 80 to 100 microns pp were experienced on the low-speed shaft gearbox drive end. These vibration amplitudes were constantly high throughout the speed range during machine run-up from idle speed, but the vibration

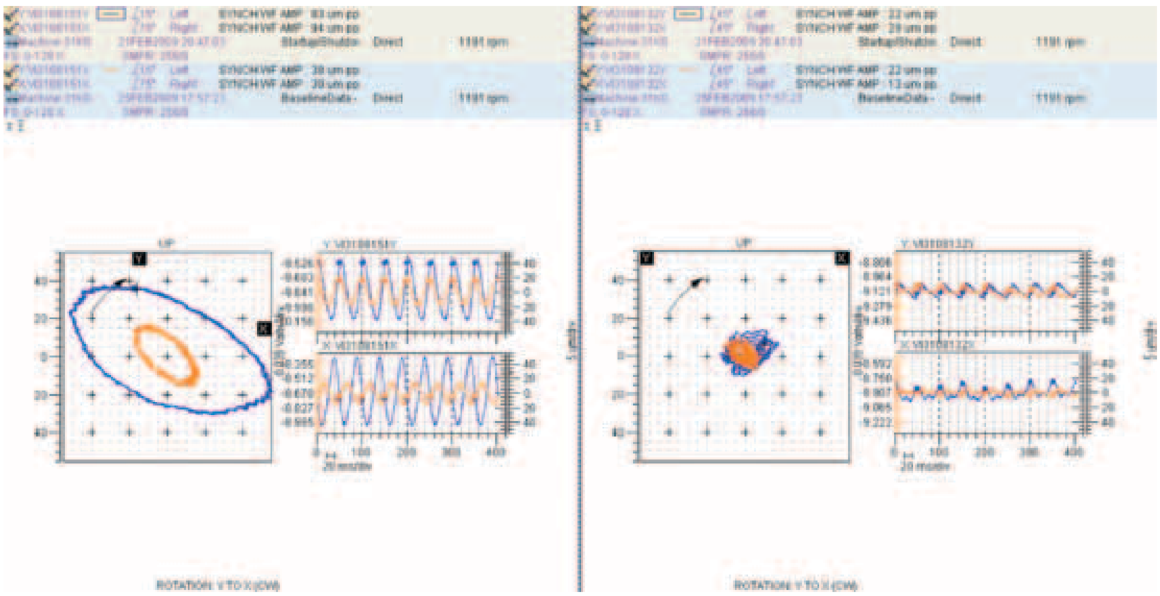

Figure 4: These plots show Direct (unfiltered) orbit shapes and time waveforms before and after fixing the coupling problem. The large (blue) amplitudes were collected on 21FEB09 at 20:47:03, and represent the vibration as it was before the coupling was repaired. The small (orange) amplitudes represent the vibration on 25FEB09 at 17:57:23, after coupling repairs were completed. The left plot is for the gearbox LSS DE bearing, and the right plot is for the compressor DE bearing.

amplitudes on the rest of the machine train were very low and acceptable.

Subsequent analysis of the continuously available data in the System 1 platform indicated that the root cause of the vibration might be related to a problem with the coupling between the variable speed motor and gearbox. The data showed that the high vibration had a predominantly synchronous (1X) component, which is a classic symptom of unbalance or misalignment. The vibration samples shown in Figure 3 were taken on 21FEB09, over almost a four and a half hour period - from 16:04:19 to 21:27:21. During this time, the machine was started and then shut down again.

The maintenance organization had not done any work on the motor or gearbox shafts during the overhaul. However, they had removed and reinstalled the motor to gearbox low speed coupling, so they suspected that it deserved to be removed and checked. Upon inspection, they discovered that the coupling flange at the motor end had excessive offset to the flange of the spacer piece. This caused the flexible membrane in the disk pack at the gearbox coupling flange to be distorted – leading to excessive vibration amplitudes.

The possibility of coupling misalignment was further supported by the orbit shapes of both the motor and the low-speed shaft gearbox drive ends. These orbits showed about a 90 degree phase different between vibration across the coupling (Figures 4 & 5) at an operating regime where the vibration should have been in-phase (first bending mode).

Motor-to-Gearbox Drive Coupling

The drive coupling (Figures 6 & 7) incorporates an elastomeric component in the hub that is attached to the shaft of the variable-speed drive motor. The outer (driven) hub is connected to a "spoolpiece" that attaches to a hub containing a disk pack, and is installed to the low speed input shaft of the gearbox. While the rubber components in the elastomeric part of the coupling dampen torsional vibration, the disk pack accommodates a small amount of angular misalignment between the shafts.

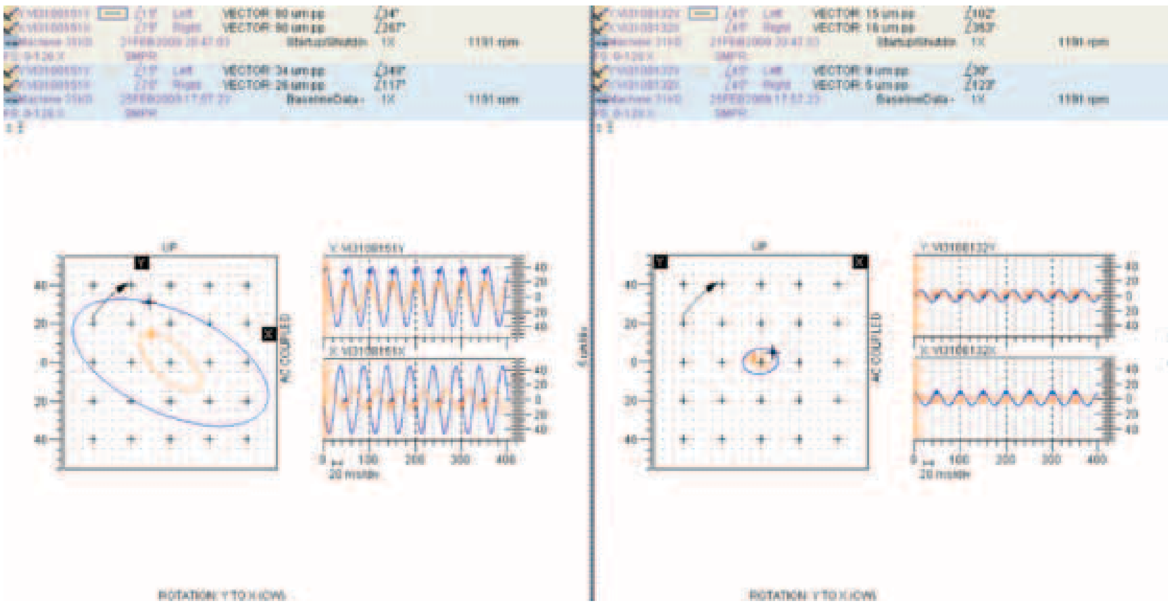

Figure 5: These plots show 1X-filtered orbit shapes and time waveforms before and after fixing the coupling problem. The large (blue) amplitudes were collected on 21FEB09 at 20:47:03, and represent the vibration as it was before the coupling was repaired. The small (orange) amplitudes represent the vibration on 25FEB09 at 17:57:23, after coupling repairs were completed. The left plot is for the gearbox LSS DE bearing, and the right plot is for the compressor DE bearing.

Figure 6: Elastomeric coupling installed between the variable-speed drive motor (green machine at left side of photo) and the gearbox (silver machine at right side of photo).

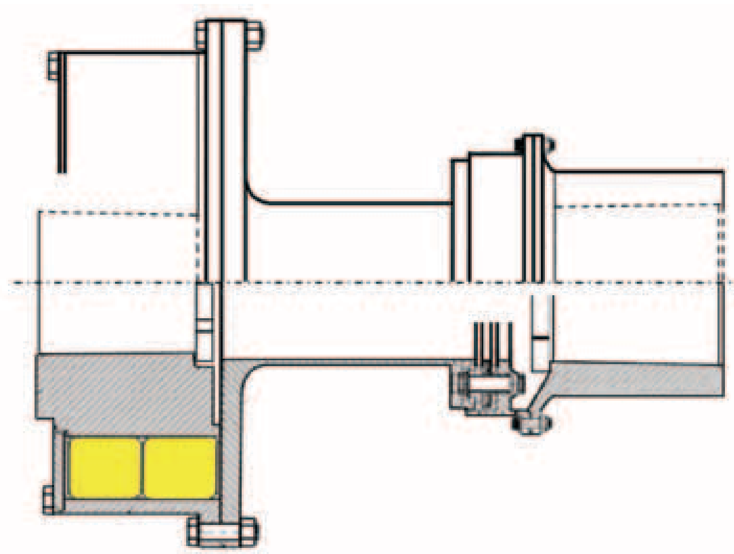

Figure 7: Simplified cross-sectional view of the elastomeric coupling. The yellow area indicates the rubber blocks in the drive hub at the motor end of the coupling. The driven hub at the right end of the coupling incorporates the flexible disk pack.

Deformation of the coupling's rubber elements was suspected as they had been in service for 11 years (Figure 8). Deformed elements could push the coupling hub's spacer radially, distorting the disk pack at the gearbox drive end's coupling hub. The coupling was opened for inspection and the offset value of the coupling hubs at both ends was checked. A radial offset of 2.00 mm was found between the motor coupling hub and shaft centerline. An offset of this magnitude would have caused the rotor to vibrate excessively – even while rotating at low machine speed – which correlates with observations.

The radial offset was apparently caused by rubber block deformation, so the blocks were removed from the hub, carefully trimmed to their original shape, and weighted and repositioned to minimize any residual unbalance effect. After repair, the radial offset was reduced from 2.00 to 0.50 mm resulting in acceptable vibration amplitude upon startup.

Results and Savings

The overall work activity to correct the coupling problem took about 2 days, compared to an estimated 4 days that would have been required if the continuously-available "online" System 1 data had not been available for diagnostic evaluation.

Significantly, the availability of the online system meant that the data from the initial unit start-up could be used for the diagnosis. There was no need to shut down the machine, mobilize a diagnostic engineer to temporarily install portable diagnostic instruments, and start up the machine again just to collect data during a speed transient.

The total production lost due to the coupling problem was approximately 10,000,000 Thai Baht per day (300K US dollars). Therefore, with the online condition monitoring system installed the plant saved approximately 20,000,000 Thai Baht (approximately 600K US dollars). Also, the plant personnel gained valuable experience and knowledge in troubleshooting machine malfunctions using their new System 1 platform.

The entire project cost was approximately 250K US dollars, so the new online system more than paid for itself immediately after installation. With the online monitoring system in place, plant personnel are now able to evaluate machine condition whenever maintenance work is carried out on the machine. In this case, expediting a spare coupling would have required about 2 months of lead time – an unacceptable amount of time for an operating plant.

Figure 8: This photo shows the elastomeric coupling hub installed on the drive motor. The flexible rubber elements are clearly visible as black segments between the driving splines of the inner hub and the driven splines of the outer hub. Also visible in the upper left corner of the photo is the housing for one of the radial vibration probes on the motor DE bearing.

Summary

In the petrochemical industry, rotating machinery such as a compressor train can be critical to the operation of a continuous production process. An unplanned shutdown of such a critical asset means lost production and lost revenue. A permanently installed condition monitoring system is highly recommended, in order to continuously provide "online" data during all operating modes of the monitored equipment.

"The Bently Nevada team installed and commissioned our upgraded condition monitoring system as a 'turnkey' project – on time and without delay. The new system paid for itself during the first startup of the 31K002 compressor train following overhaul. We gained additional value from the machinery diagnostics training course that our staff received as part of the project, as well as continued coaching and consulting that has allowed us to utilize the system effectively – to improve plant operation – and to retain key domain knowledge within the IRPC organization."

— Gun Inthon, Section Manager
Mechanical Maintenance
Rotating Division

Acknowledgements

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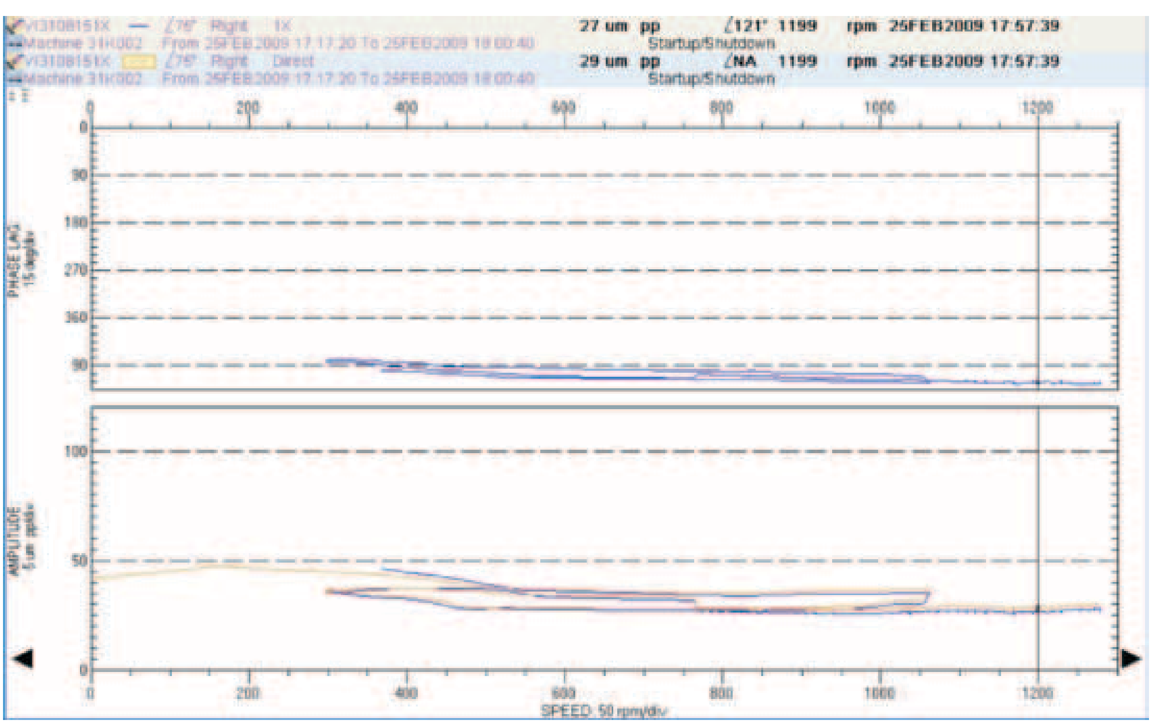

Figure 9: Bode plot of unfiltered "Direct" data (red curve) and 1X-filtered data (blue curve) from VI3108151 Channel X at the low-speed shaft gearbox DE bearing for the compressor startup following the coupling repairs. Compare the vibration amplitude (less than 50 microns pp) with the pre-repair values in Figure 3.

Kuwait Oil Company Case Study

Unnecessary replacement of the centrifugal gas compressor rotor was avoided by using System 1 software.*

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Facility Overview

This case study describes events that took place at Kuwait Oil Company (KOC) Gas Booster Station # 131 in North Kuwait fields. The overall purpose of the Gas Booster Station facility is to receive the natural gas from various Oil& Gas Gathering Centers at different pressure ranges and boost up the pressure before distributing the gas for further processing at the Refineries downstream.

After filtering and dehydrating the gas and removing entrained liquids, the Booster Station pressurizes the gas and sends it though High Pressure Transit Export lines to the downstream consumers such as Refineries, Liquefied Petroleum Gas (LPG) facilities, Petro chemical Industrial Plant (PIC) and MEW Power Generation Plants.

Booster Station #131 has two separate Gas Compression Trains (Phase 1 and Phase 2), each Phase with a maximum production capacity of 250 million standard cubic feet per day.

Executive Summary

During the startup of the Phase 1 Gas Compression Train at Booster Station #131, the HP Gas Compressor had repeatedly Tripped on High Vibration indication. This indication was initially thought to be a result of an unbalanced rotor. Since a spare compressor rotor was not available at the KOC warehouse, the initial plan of attack was to send the rotor to a nearby facility for a high-speed balancing, which would have kept the Booster Station shut down for 3 to 4 additional weeks if not more, with associated continuous Gas Flaring & loss of gas production revenue.

However, by utilizing the Bently Nevada System 1 Platform to perform a detailed analysis of the retrieved vibration data, the Equipment Support & Reliability Engineers were able to analyze and conclude that the real Root Cause of the vibration problem was a damaged drive coupling, rather than an unbalanced compressor rotor. After correcting machine alignment, the Maintenance Team replaced the damaged coupling with a spare one, and the Gas Compressor was able to be started and put back into normal production line service.

Phase 1 Compressor Train Description

As shown in Figure 1, The Phase 1 High Pressure (HP) Compressor is driven by a GE Heavy Duty Frame 5 Gas Turbine through a speed-increasing gearbox. This image is a typical Machine Train Diagram as used in the System 1 Display software.

From left to right, the components shown are the Gas Generator, Aerodynamically-Coupled Power Turbine, Low Speed Shaft (LSS) and Coupling, Gearbox, High Speed Shaft (HSS), Coupling and HP Compressor.

The "Performance" icons shown in this screen indicate that this System 1 installation is set up to perform Thermodynamic Performance Monitoring, in addition to monitoring the rotating speeds of 3 different shafts and the shaft vibration at 8 separate bearings.

Compressor Description

The subject Gas Compressor is a multistage centrifugal design, Model BCL-504, manufactured by GE Oil & Gas. These machines are designed for Medium and High Pressure Services such as Ammonia Gas, Urea and Methanol Synthesis, Refinery Recycle ,Natural Gas Compression and Gas Reinjection Plants .

This particular vertically-split design is sometimes called a "barrel type gas compressor", as its internal components are slid into a cylindrical outer shell, and retained by bolted end-covers. Figure 2 is a cutaway illustration of a generic BCL Compressor. The suction line connects to the larger diameter nozzle at the left, while the discharge line connects to the smaller diameter nozzle at the right. The stacked Impellers and diffusers are visible inside, and the thick pressure-retaining end covers are clearly visible.

The vertical vibration probes are shown as long sleeves that extend from the fluid-film bearings at each end of the compressor, upwards through the end covers, and terminating in a small wiring junction box at the top of each sleeve. As shown in the drawing, the left end of the Compressor is the Non-Drive End (NDE) and the right end is the Drive-End (DE).

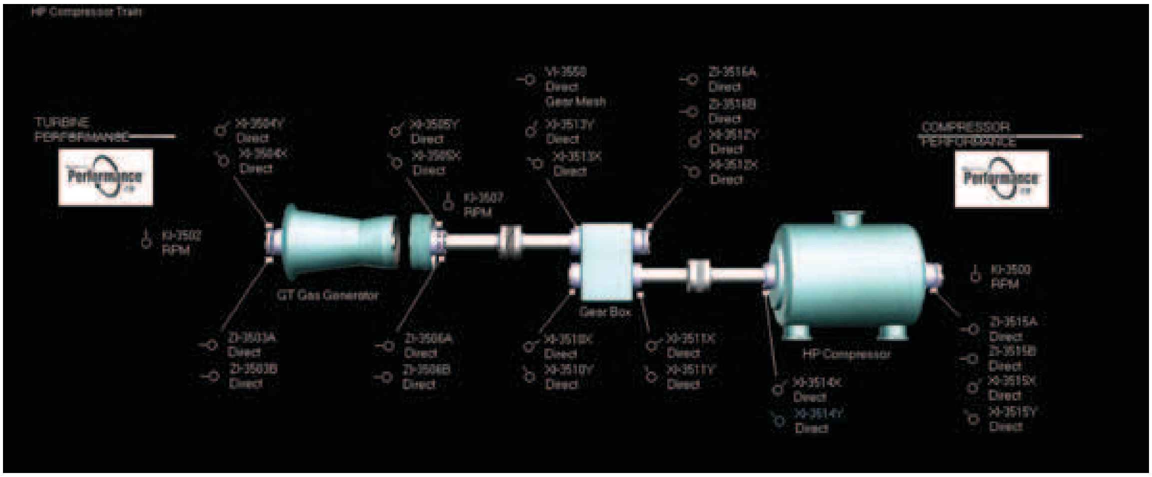

Figure 1: BS-131 Phase-1, HP Compressor (K-1103) System 1 Machine Train Diagram

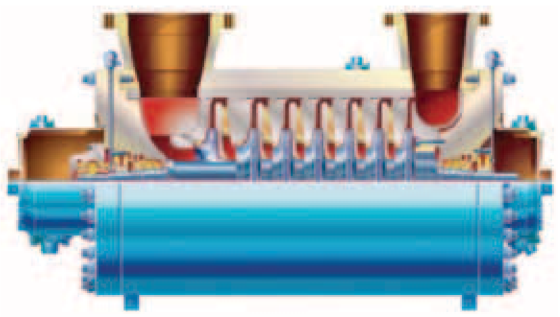

Figure 2: GE Oil & Gas BCL-High Pressure (HP) Series Multistage Centrifugal Compressor. The generic example shown in this cutaway drawing has 7 stages. The suction is at the left end and the discharge is at the right end.[1]

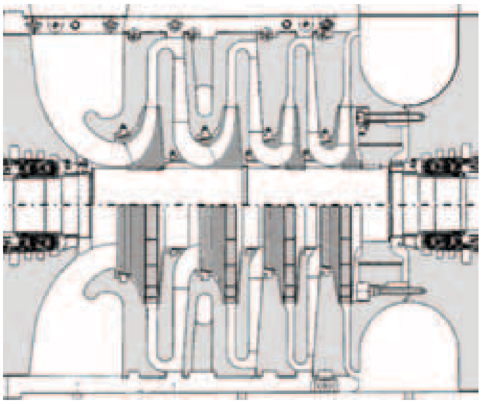

Figure 3: Simplified drawing of BCL-504 model compressor, showing the 4 stages. The suction is at the left end and the discharge is at the right end.

The BCL-504 model that is used as HP Compressor K-1103 actually has 4 stages, as shown in Figure 3. The installation drawing in Figure 4 shows how the driveshaft from the gas turbine (at the left) connects with the LSS of the gearbox through a coupling, and then the HSS connects to the compressor through a second coupling.

The driver is a GE MS 5002 C Heavy Duty Gas Turbine. The speed-increasing gearbox is a Model TG 50F unit from BHS-Cincinnati with a ratio of approximately 1:1.805. The flexible disc couplings are John Crane Metastream® TLGE 8500 Couplings. The gas turbine has its own steel baseplate, while the gearbox and the compressor share a common baseplate. Both baseplates are grouted into a concrete foundation.

Compressor Design Data

Table 1 summarizes a few of the key design parameters that were provided by the compressor manufacturer.

Compressor Photos

Figures 5 through 7 show the Phase 1 HP Compressor during its Major Overhaul (MOH) in the year 2007. This MOH had taken place several months before the startup described in this case study.

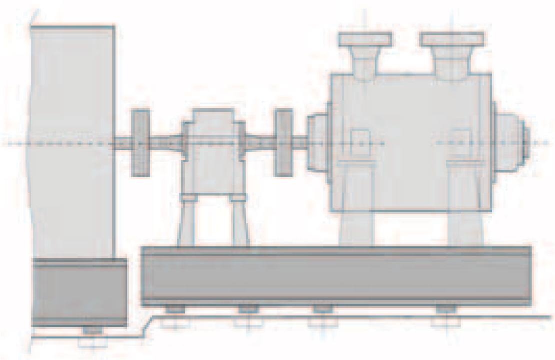

Figure 4: Compressor installation diagram.

PARAMETER	VALUE
Speed	8418 rpm
Shaft Power	15.2 MW
Mass Flow	107.1 kg/s
Suction Pressure	23.1 bara
Suction Temperature	65 °C
Discharge Pressure	66.6 bara
Discharge Temperature	141 °C
Rotation (viewed from driver end)	clockwise

Table 1: OEM Design Data

Figure 5: Removing Compressor K-1103 Rotor Bundle.

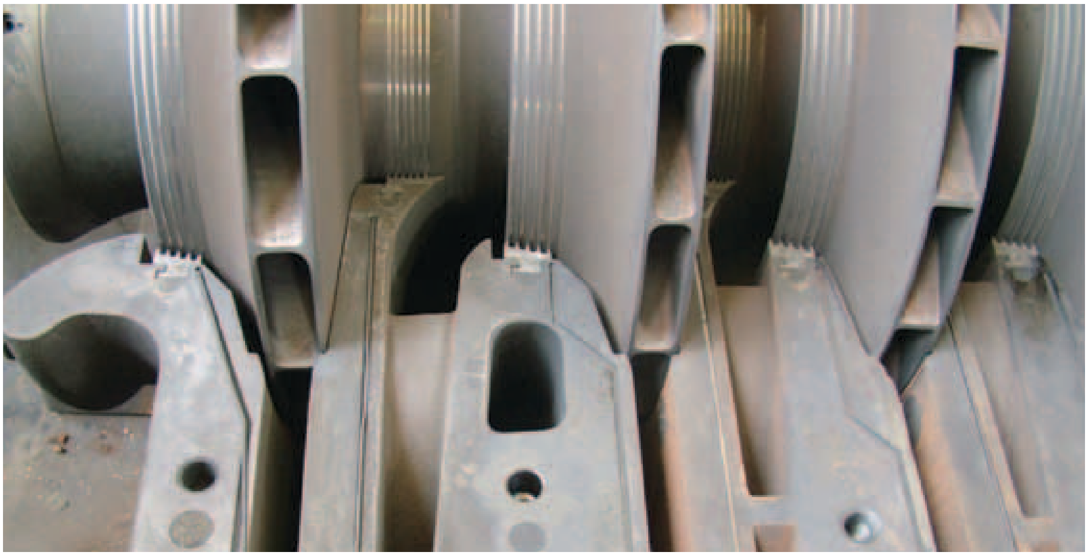

Figure 6: HP Compressor Rotor and lower Stator assembly after removal from the cylindrical "barrel type" Pressure Casing. The Impeller Vanes and Diffuser Channels are clearly visible.

Vibration Measurement Points

The Compressor Train incorporates permanently installed displacement transducers that measure vibration of the rotor shafts in the fluid-film bearings of the Gas Generator, Power Turbine, Gearbox, and Compressor.

As shown in Figure 8, the Radial Vibration measurement points for the DE Bearing are labeled XI-3514 (X & Y) while those for the NDE Bearing are labeled XI-3515 (X & Y). The points labeled ZI-3515 (A & B) are dual Axial Thrust position points at the Thrust Bearing. The point labeled KI-3500 is a Keyphasor* point that measures rotor speed and provides a one event per turn phase reference signal.

Startup Problems

On August 11, 2008, the Booster Station was being returned to service from "Level 1" conditions. This means that the plant had been completely shut down, and the machines would be started from cold initial conditions. During this startup, the Phase1 HP Compressor, K-1103, Tripped on four separate occasions.

The first Trip occurred due to indicated High Compressor Discharge Pressure at rated running speed (8800 rpm), while the machine was being loaded in the Stand-Alone Mode. The Phase 2 Compressor was running normally during this time.

At the time of the High Discharge Pressure Trip, the Compressor Drive End (DE) Radial Vibration (channel Y) reached 135 microns of Displacement, peak-to-peak (pp), which was just above the Danger (Trip) setpoint of 134 microns pp. At the same time, DE vibration at Channel X had reached 80 microns pp, which was very close to its Alert (Alarm) setpoint of 88 microns pp. The vibration at the Compressor Non Drive End (NDE) bearing was slightly lower.

The second, third and fourth Trips, which all occurred during the Compressor Ramp-up Mode, were triggered by exceeding the High Radial Vibration setpoint on Channel Y at the Compressor DE Bearing. These Trips had occurred at approximately 5000 rpm, which is very close to the first critical speed for the compressor. During coast-down following each of these Trips, the DE channel Y Vibration increased to 154 microns pp, and the channel X values increased just to the Alarm setpoint.

Two days later, the Gas Compressor restart was again attempted, after the vibration transducers had been checked to verify that their calibration was satisfactory. While the machine speed was ramping up, it was observed that the Radial Vibration at both compressor bearings has increased beyond the Alarm setpoints. The DE Radial Vibration (XI-3514Y) came very close to the Trip setpoint and then dropped back down.

At the 10 minute point, the Compressor was running at its Idle Speed (70% of its normal running speed). When the "Load" command was given, the machine speed began ramping up normally, and at approximately 73% of its running speed, the unit Tripped on High DE Radial Vibration (XI-3514X).

Background History

The previous Major Overhaul (MOH) of the HP Gas Compressor (which is shown in Figures 5 through 7) was completed with the assistance of a GE Field Service Representative during June and July of 2007. During the MOH work activities, we had observed that there was Rotor to Stator interference caused by a damaged anti-rotation locking pin in the DE Inner Labyrinth Seal.

The Labyrinth Seal, casing internal cover, and DE Dry Gas Seal (DGS) had all experienced some rubbing damage. The observed damage to the locking groove and pin was repaired, and new Inner Labyrinth Seals, Tertiary Seals and DGS components were installed.

Following these repairs, the compressor was returned to service on July 26, 2007. The vibration levels at the journal bearings of both the gearbox high speed output shaft and the drive end of the compressor were found to be higher than they had been before the maintenance outage.

The greatest vibration Increase was observed at the HP Compressor DE bearing. Over approximately the next 7 months, vibration trends at this bearing continued to gradually increase from about 30 to 60 microns pp. Eventually, vibration reached 80 microns pp, which was

Figure 7: HP Compressor lower Stator assembly after the Rotor was lifted out. The sharp-edged Labyrinth Seals are visible on the Diffusers.

rapidly approaching the Alert setpoints on both the XI-3514X and XI-3514Y channels. The compressor had experienced one High-High Vibration Trip on August 1, 2008, before the plant was shut down to "Level 1" (cold) conditions.

Event Manager Alarms

The events shown in Figure 9 indicate that Radial Vibration at the DE Bearing (XI-3514Y) had been intermittently alarming for the time period leading up to the short Level 1 shutdown, and subsequent restart attempt of the Phase 1 HP Compressor on August 11, 2008.

As shown in the left column, the yellow color indicates Severity 3 (Alert) events, while the red color indicates Severity 4 (Danger) events. The High-High Vibration Trip that occurred on August 1, 2008 is visible just below the halfway point in the event list.

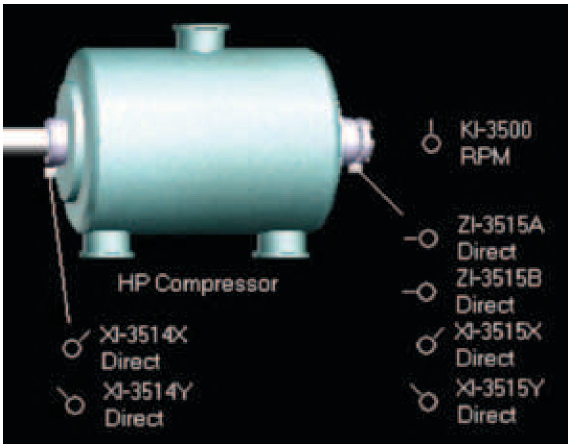

Figure 8: Compressor Measurement Points.

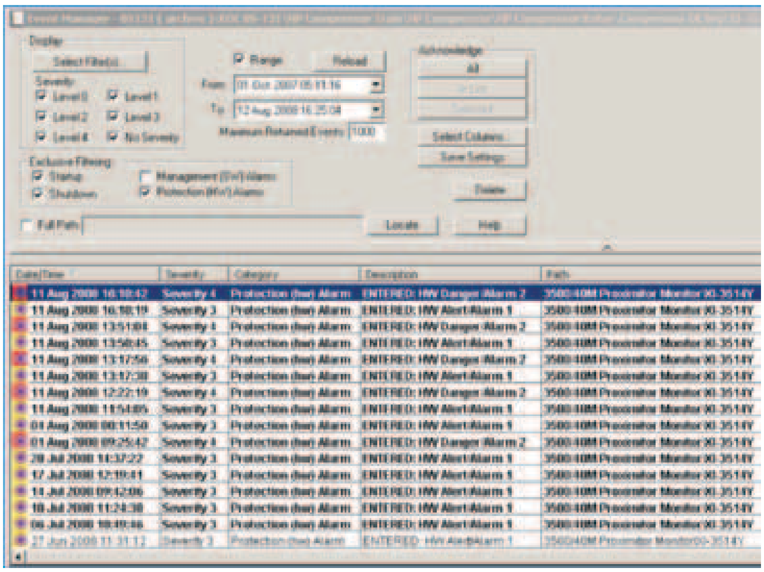

Figure 9: Sequence of Alarms in System1 Event Manager on 11/08/08. The most recent event (11AUG2008) is at the top of the list, and the oldest event shown here is at the bottom of the list (27JUN2008).

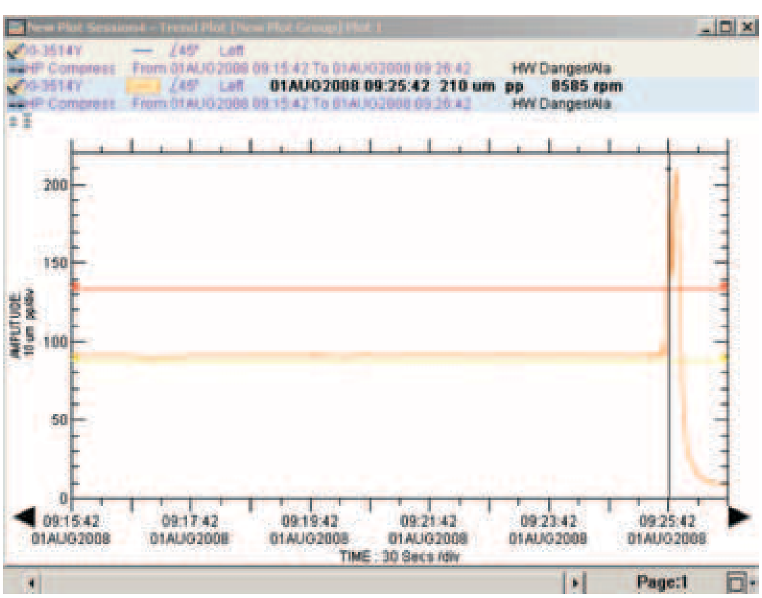

Figure 10: During the High-High Vibration Trip 01AUG2008 at 09:25:42, the maximum Direct vibration amplitude was observed to be 210 microns pp at 8585 rpm. The High Vibration in this case was caused by a process upset that suddenly raised the Suction and Discharge Pressures of the Compressor Train while the Gas Export line conditions were being stabilized.

Vibration Trends

The following trend plots show values of "Direct" (unfiltered) vibration amplitude at the HP Compressor DE bearing for a period of just over 10 minutes. The y-axis shows the amplitude in units of μm (micrometres), which is just another term for microns.

The horizontal red line at 134 microns indicates the Danger (Trip) setpoint, while the horizontal yellow line at 88 microns indicates the Alert (Alarm) setpoint. The vertical black line is a cursor that has been set at the time corresponding to the compressor Trip.

HP Compressor Restart Attempts

- The HP Compressor was restarted at about 13:14:30, but Tripped a second time – this time on indicated High-High Vibration – at 13:17:56, just over 3 minutes into the machine ramp-up. The maximum Direct Vibration Amplitude reached 136 microns pp at a machine speed of 4925 rpm.
- It was restarted for a third time at about 13:47:30, but Tripped again on indicated High-High Vibration about 4 minutes into the ramp-up, at 13:51:04. The compressor Tripped from 5065 rpm, and the maximum observed Direct Amplitude was 136 microns pp.
- It was restarted for a fourth time at about 16:07:00, but Tripped again on indicated High-High Vibration just under 4 minutes into the ramp-up, at 16:10:42. This time, the compressor Tripped from 5344 rpm, and maximum observed Direct Amplitude was again 136 microns pp.

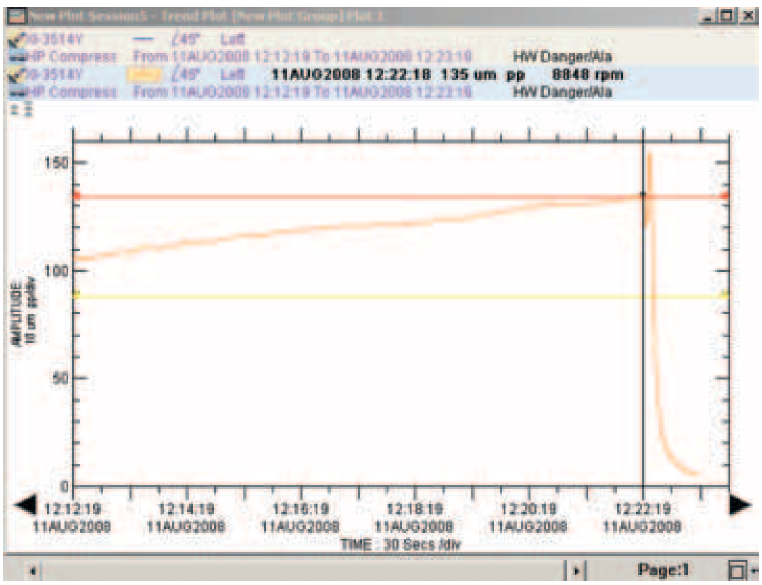

Figure 11: The first compressor Trip on 11AUG2008 occurred at 12:22:19 due to High-High Discharge Pressure while manually loading the compressor and stabilizing the Gas Export line conditions. Over the time interval of this Plot, Vibration gradually increased from 105 to 135 microns pp. The Compressor Tripped from 8848 rpm, after which the Vibration briefly spiked to about 155 microns pp.

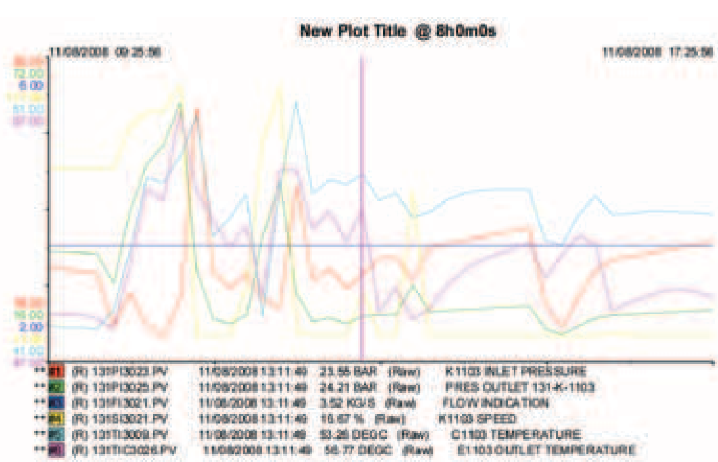

Figure 12: Trend plot of process parameters at the time of the second Compressor Trip on 11AUG2008.

Process Parameter Trends

In addition to evaluating the vibration data, the process parameters that were recorded by the Distributed Control System (DCS) were also evaluated & analyzed carefully. As shown in Figure 12, these process parameters include inlet and outlet Temperatures, Pressures, Compressor Speed and Mass Flow. All of the process parameters were observed to be within acceptable limits, and they responded normally to the Compressor Trips, indicating that the High Vibration Trips were not caused by an operational problem.

Shaft Orbits & Timebase Waveforms

Direct (unfiltered) and 1X-filtered shaft orbit and timebase waveform shapes during compressor ramp-up are shown in the collection of plots, below. All of these vibration samples were captured at the time of the High-High Vibration Trip from the fourth attempted HP Compressor startup on 11AUG2008.

The waveform plots show the values for channel X and Y data separately, while the orbit plot shows the same data in a combined two-dimensional display. The "blank-bright" spot in the orbit trace indicates the point at which the one event per turn Keyphasor reference pulse occurred. The arrow in the orbit plot indicates the direction of rotation of the shaft.

Note: The blank-bright sequence of the Keyphasor reference is significant. If it corresponds to the direction of rotation of the machine, this indicates

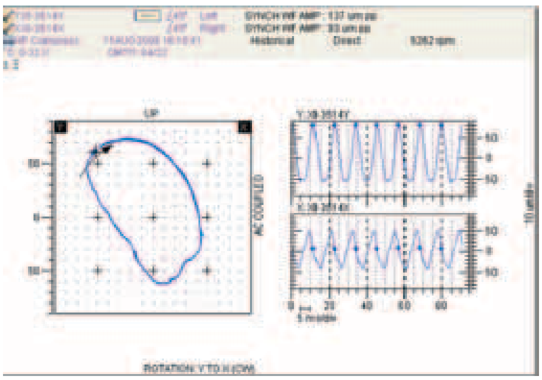

Figure 13: Compressor DE (XI13514 X & Y) Direct orbit and time waveforms. The arrow indicates that the rotor turns clockwise, as viewed from the driver end of the machine (Table 1). Observe that the blank-bright reference on the orbit trace occurs in the direction opposite to indicated machine rotation.

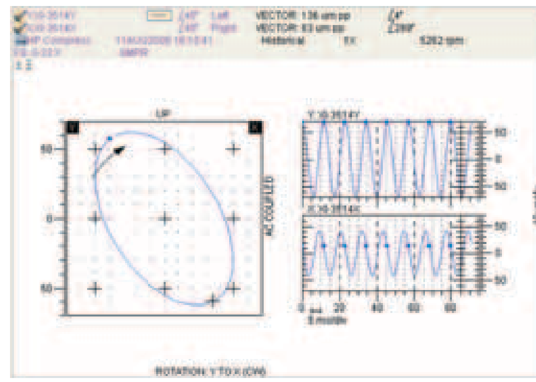

Figure 14: Compressor DE (XI13514 X & Y) 1X-filtered orbit and time waveforms. It is very easy to see that the X-Channel displacement is noticeably smaller than the Y-Channel displacement. This difference produces an elliptical orbit. Again we see that the blank-bright Keyphasor reference appears to indicate reverse precession.

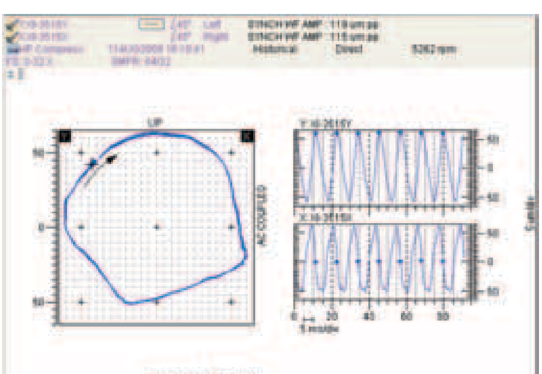

Figure 15: Compressor NDE (XI-3515 X&Y) Direct orbit and time waveform. Again, the blank-bright Keyphasor reference is opposite to the direction shown by the arrow.

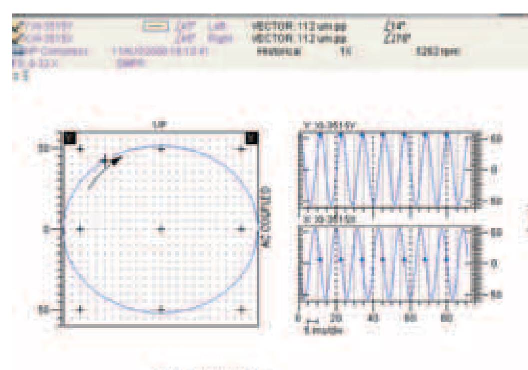

Figure 16: Compressor NDE (XI-3515 X&Y) 1X-filtered orbit and time waveform. Displacement values for the X and Y Channels at the NDE Bearing are fairly equivalent values, which results in a circular orbit shape. Observe the indication of reverse precession.

that the precession of the shaft vibration is in the forward direction – which is normal. If the blank-bright sequence occurs opposite to the direction of rotation, it indicates reverse precession. This is an abnormal Indication, which can be caused by the presence of a rub between rotating and stationary components – or by reversed wiring of the XY probe pair.

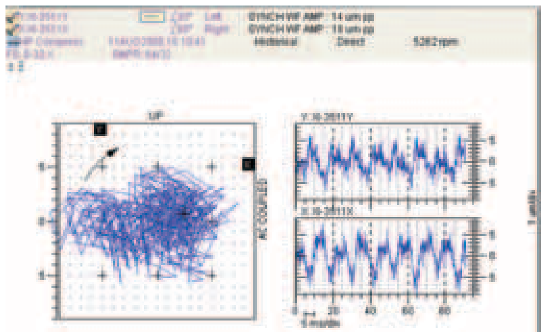

Figure 17: Gearbox High Speed Shaft (HSS) NDE (XI-3511 X&Y) Direct orbit & time waveforms. It is difficult to see the Keyphasor reference due to the spiky signal. Note: The direct vibration signals from this bearing do not normally appear to be quite this noisy. The shaft surface does not show evidence of scratches, although it most likely includes a small amount of electrical runout. The temporary roughness of this signal is also thought to be influenced by the High Vibration conditions that existed at the time of the Compressor Trip.

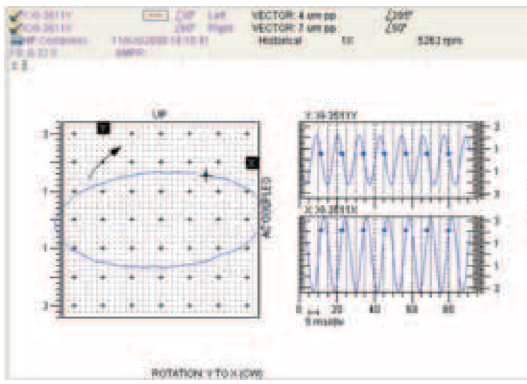

Figure 18: Gearbox HSS NDE (XI-3511 X&Y) 1X-filtered orbit & time waveforms. The filtered orbit is much cleaner, and it is easy to see that the blank-bright reference matches the arrow that shows direction of rotation. This time, the precession of the shaft vibration appears to be in the "forward" direction. The flattened orbit is a classic indication of radial loading that may indicate shaft misalignment.

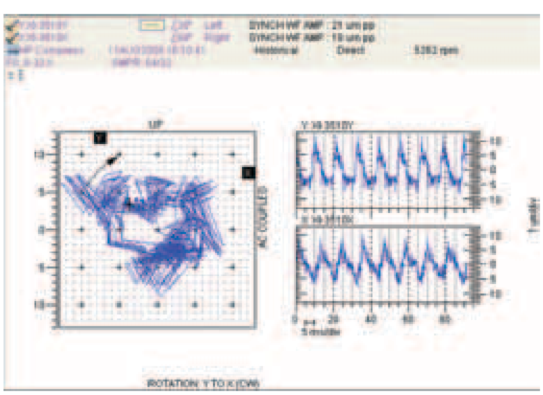

Figure 19: Gearbox HSS DE (XI-3510 X&Y) Direct orbit & time waveforms. Again, the direct signal temporarily appeared to be very noisy – due to a combination of high vibration conditions and some amount of electrical and mechanical runout of the observed shaft surface.

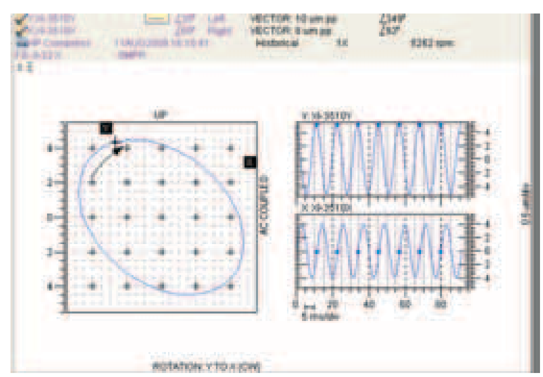

Figure 20: Gearbox HSS DE (XI-3510 X&Y) 1X-filtered orbit & time waveforms. The blank-bright spot corresponds to the directional arrow, indicating normal forward precession.

Average Shaft Centerline Trends

Shaft centerline plots show a trend over time of the average values of the centerline position of a monitored rotor shaft within the known clearance of its fluid-film journal bearings.

When a horizontal rotor machine is first started, an oil "wedge" forms underneath the shaft, forcing it to move upwards (against gravity) from its rest position. The wedge builds up on the side of the shaft where the shaft surface is moving downwards, so in addition to lifting the shaft vertically, it also pushes the shaft horizontally – away from the wedge.

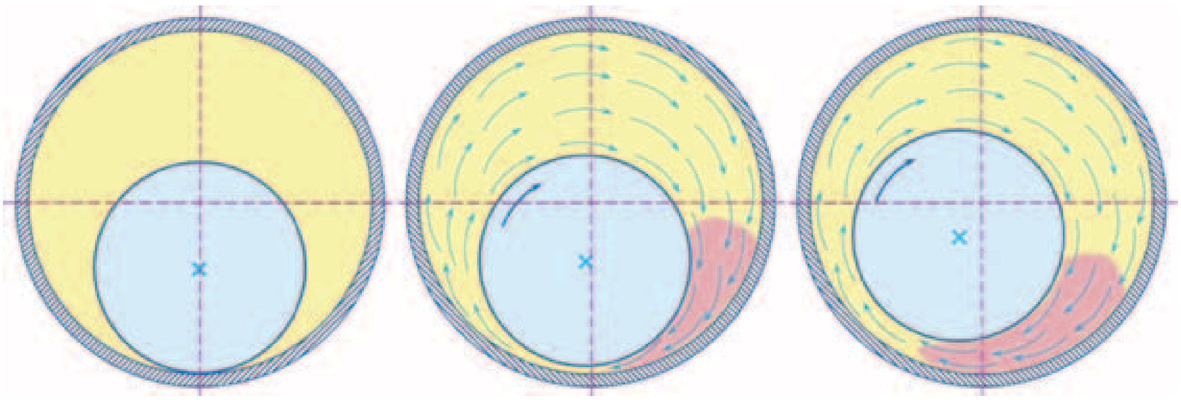

Figure 21: Formation of oil wedge in fluid film bearing of horizontal rotor machine. The internal bearing clearances are greatly exaggerated for illustration.

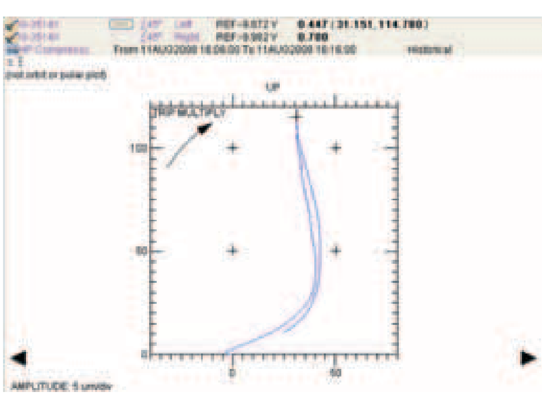

Figure 22: Compressor DE (XI-3514 X&Y) Average Shaft Centerline Position on 11AUG2008 from 16:06:00 to 16:16:00. Observe that the shaft started at the 0, 0 coordinates corresponding to resting on the lower bearing surface. Then, it moved upwards as expected. However, it also shifted to the right, which is opposite to the expected direction for a shaft with clockwise rotation. This may be an indication that the wiring to the DE bearing XY probe pair has been reversed. The Plot for the NDE bearing was almost identical to this one, indicating that those XY probes may also be mis-wired.

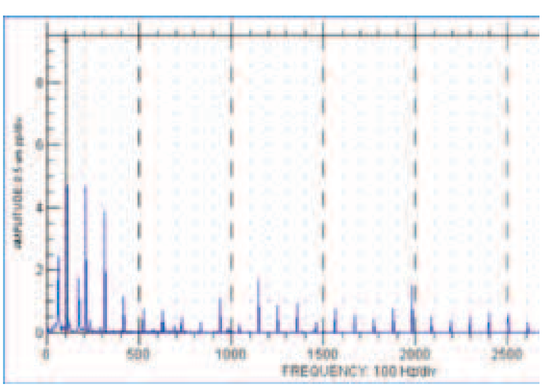

Figure 23: Spectrum Plot for gearbox HSS DE Bearing, XI-3511X. The cursor is set at the peak corresponding to 1X frequency for the running speed of 6277 rpm during startup. 1X Vibration Amplitude is 9 microns pp at 104.62 Hz. 2X Vibration Amplitude is 4.7 microns pp at 209.23 Hz.

For a shaft that is turning clockwise, it would normally be lifted vertically and shifted to the left as the oil wedge is forming, as shown in Figure 21.

The plot in Figure 22 shows Average Shaft Centerline Position trends for the HP Compressor rotor shaft within the DE and NDE bearings. The data shown in the plot spans from 16:06:00 to 16:16:00, capturing the movement of the shaft within its bearings for the fourth and final restart attempt on 11AUG2008.

Spectral Data

Spectrum plots of the vibration at the DE bearings for both the gearbox HSS and the HP Compressor shaft showed an elevated 2X frequency peak, when compared with the vibration from the NDE bearings. This is a further symptom that there may be some misalignment between the HSS and the HP Compressor rotor shaft.

Data Analysis

After thorough evaluation of the retrieved data, the following assessment was made:

1. Vibration trends at the Compressor DE Bearing (probe tag numbers XI-3514Y & XI3514X) have shown a gradual increase over a period of several months. This indicates that something about the machine train has changed.

   i. The predominant vibration amplitude peak was observed at 1X frequency with a smaller yet still significant component at 2X. These indications point to the possibility of unbalance, machine looseness and misalignment. It will be necessary to check the machine alignment, and also to check the machine for rubbing or unbalance that may have been produced by possible liquid carryover.

2. The phase angle data retrieved between the gearbox HSS output bearing and the Compressor DE Bearing was found to be approximately 180 degrees out of phase — especially in the horizontal plane. This discrepancy is another possible symptom of reversed wiring of XY probes on the compressor

3. The shaft orbit patterns at the Compressor DE and NDE journal bearings indicate symptoms of reverse precession. This suggests that a rub may be occurring between the rotor and stator components. It is also possible that the X and Y Probes may be mis-wired with respect to the actual machine direction of rotation. The unexpected behavior of the Average Shaft Centerline Position also confirms the probability that the wiring has been reversed.

4. The flatness in the compressor NDE shaft orbit and the slight increase in natural frequency response of the rotor from its designed speed (5050 rpm) to 5333 rpm are symptoms that some rotor rubbing may be occurring due to radial loading at the bearing. The flattened orbit was also a clue that misalignment may exist between the gearbox HSS and the HP Compressor shaft.

Conclusions

The first High-High Vibration Trip, which occurred on 11th AUG2008 at 12.22.19, was attributed to abnormal operating conditions that resulted from a process upset. Temporarily high pressure in the Compressor Discharge Line may have resulted in a rise in the compressor internal temperature, which could have contributed to the observed rapid changes in the shaft centerline position — resulting in excessive radial loading at the Compressor DE bearing and even causing some rub damage to compressor internals.

The high vibration indications at the Compressor DE Bearing appear to be real, and do not appear to be influenced by any probe or Proximitor*-related faults. The most likely causes of the high vibration at the Compressor DE Bearing were determined to be the following:

- Misalignment across the gearbox HSS & HP Gas Compressor shaft couplings.
- Excessive clearances in the Compressor DE Bearing.
- Rotor unbalance and rubbing of labyrinth seals or DGS.
- Coupling unbalance.

Troubleshooting Action Plan

1 Drain the Gas Compressor casing to check for any traces of crude oil, condensate or liquid that may be trapped inside the compressor casing.

2 Disconnect the Balance Line and pressurize the suction side with nitrogen. Install spading (blanks) between piping flanges of the discharge side Balance Line and attempt to drain any liquid trapped inside the compressor casing by opening the drain flanges one after another (one at a time).

3 Decouple the compressor from the gearbox and attempt to rotate the compressor rotor by hand - with a special tool fixture — to check whether the rotor turns freely, or shows signs of intermittent rubbing.

4 If steps 1-3 are normal, proceed to disassemble and inspect the journal bearings and the thrust bearing to check for signs of rubbing or abnormal clearance readings.

5 If step 4 is normal, remove the DE Dry Gas Seal along with the Tertiary Seal. Inspect the Inner labyrinth Seal for signs of any damage that may have occurred as a result of the repairs that were performed during the previous MOH.

6 If step 5 is normal, proceed to remove the Rotor Bundle for further detailed inspection.

7 In parallel with these steps, we should clear any doubt of reverse precession by verifying that the XY probes are wired correctly.

8 If we find the Root Cause in the steps above, then after attending to that step we will initiate a startup trial (with all safety Trip logic online) to verify the outcome.

Maintenance Actions Performed

- Verified that the HP Compressor "Trip Multiply" logic timing settings were appropriate, and were not contributing to High Vibration Trips.
- Checked System 1 and 3500 online monitoring system configuration. Ensured that the direction of probe orientation in System 1 configuration (i.e. Y to X) was correct with relation to the actual direction of the compressor rotation.
- Corrective Action: Discovered that the probe cables to the Proximitors for the XY probes on the HP Compressor DE & NDE Bearings had been reversed. Disconnected the cables and reconnected them appropriately, for consistency with rotation direction and the vibration probe orientation of the Gas Turbine.
- Checked the configuration of System 1 online monitoring system and reset the startup and coastdown data capturing speeds for more effective capture of the rotor fault diagnostic data during transient speed Modes.
- Decoupled the HP Compressor and spaded (inserted blanks) into the suction and discharge flanges.
- Pressurized the compressor barrel with nitrogen to 30 psi and opened casing drain flanges to check for possible liquid carry-over. No traces of liquid were observed.
- Checked machine alignment and discovered that the alignment between the gearbox output shaft and the compressor shaft was out of specification.
- Corrective Action: Realigned the compressor shaft to the gearbox output shaft to within allowable tolerances.
- Inspected the Drive Couplings. Discovered that the HSS Compressor-side hub flexible disk had signs of uneven gap between the shims, indicating that it had been deformed by misalignment.

- Corrective Action: Replaced the complete coupling with a new unit.
- Inspected the DE journal bearing. Verified that the clearances were within the specified limits and that no scratches were visible on the bearing surface.
- Rotated the rotor manually and discovered that it turned freely, with no indication of rubbing or binding.

Successful HP Compressor Startup

After all of the troubleshooting activities were carried out & completed, as described above, the HP Compressor was restarted on August 18th, 2008.

One High Vibration Trip occurred due to a temporary rotor bow condition caused by thermal shock from a brief episode of liquid crude carryover through the Process Gas Stream. But after normalizing the plant once again, the Phase1 HP Train was restarted and ramped up to 70% Speed (in Automatic Control Mode) without any unusual vibration. All HP Compressor vibration levels were found to be below 35 microns pp.

The Gas Compressor was loaded normally in the Automatic Mode and reached 102% of its design speed without any indicated Vibration Alarms. It then ran under loaded conditions for more than 24 hours, with all of the vibration levels below Alarm limits. The HP Compressor DE Bearing Channel X indicated 55 to 65 microns pp, while Channel Y indicated 40 to 50 microns pp. Both of the vibration channels at the NDE Bearing indicated less than 40 microns pp.

In Closing

Kuwait Oil Company is happy to share with other users in the world this case study as a success story. It is an example of how our commitment to applying industry-leading Condition Monitoring (CM) technology – such as System 1 software – has added substantial value to our day to day business. We will continue to count on the CM technology to provide early failure detection and enhance the Reliability of our critical machineries and to reduce unnecessary downtime or stoppages, by enabling more accurate diagnosis of symptoms.

"The diagnostic capabilities of our System 1 software have helped us significantly to identify that the real problem with our HP Gas Compressor was a worn drive coupling, rather than an unbalanced compressor rotor. This allowed us to save 3 to 4 weeks of unnecessary downtime with associated loss of production revenue."

—Abdulla Al-Harbi

References

[1]Figure 2 (BCL HP Series Centrifugal Compressor): GE Oil & Gas Centrifugal & Axial Compressors Brochure, COMK/MARK 768/II, © 2005 Nuovo Pignone S.p.A.

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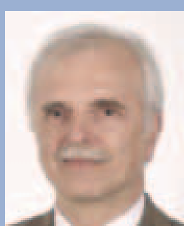
By utilizing the Bently Nevada System 1 Platform to perform a detailed analysis of the retrieved vibration data, the Equipment Support & Reliability Engineers were able to analyze and conclude that the real Root Cause of the vibration problem was a damaged drive coupling, rather than an unbalanced compressor rotor. This allowed us to avoid 3 to 4 additional weeks of downtime, with associated continuous Gas Flaring & loss of gas production revenue.

Monitoring Bearing Vibration with Seismic Transducers



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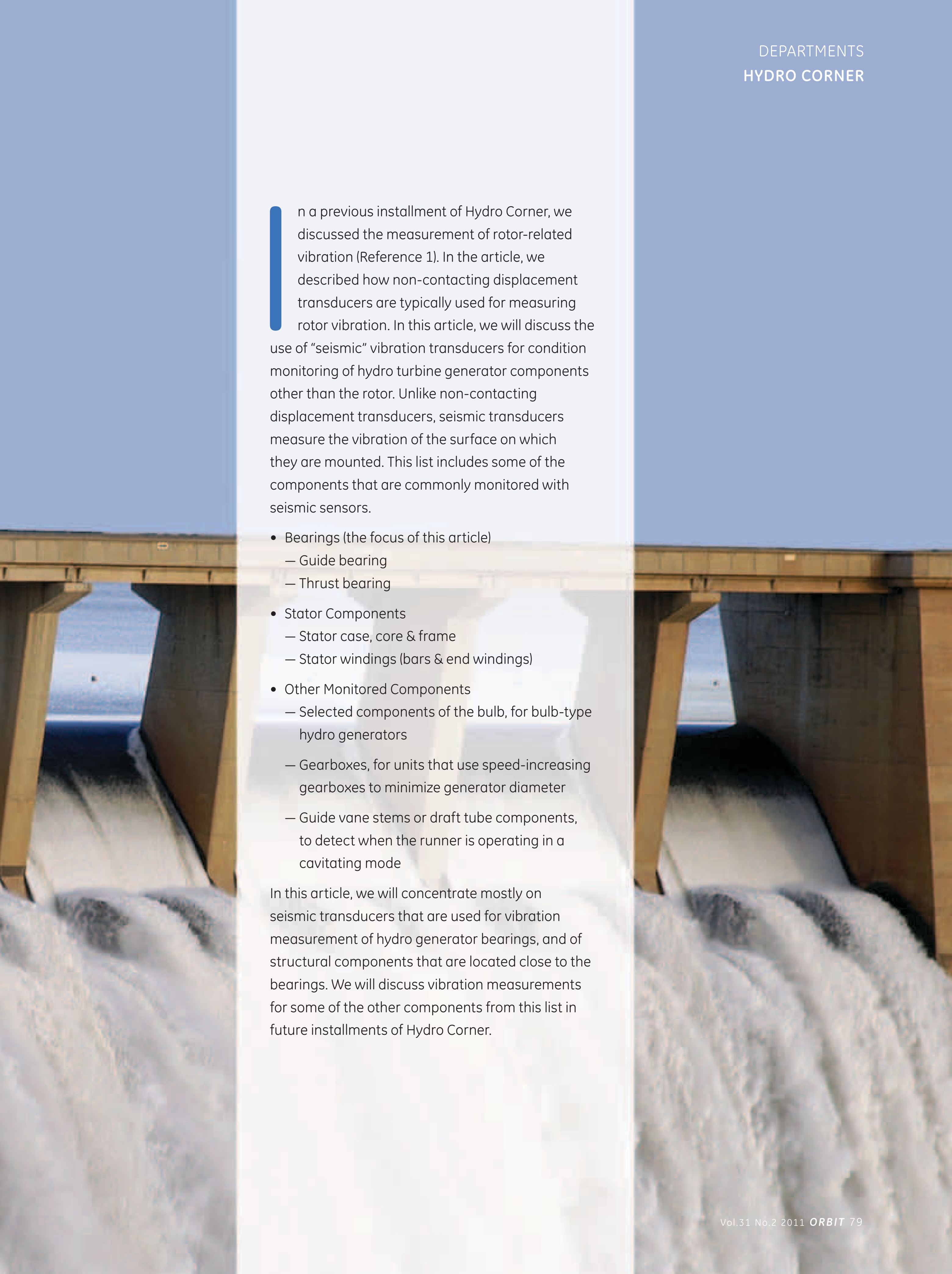


In a previous installment of Hydro Corner, we discussed the measurement of rotor-related vibration (Reference 1). In the article, we described how non-contacting displacement transducers are typically used for measuring rotor vibration. In this article, we will discuss the use of "seismic" vibration transducers for condition monitoring of hydro turbine generator components other than the rotor. Unlike non-contacting displacement transducers, seismic transducers measure the vibration of the surface on which they are mounted. This list includes some of the components that are commonly monitored with seismic sensors.

- Bearings (the focus of this article)
  - Guide bearing
  - Thrust bearing
- Stator Components
  - Stator case, core & frame
  - Stator windings (bars & end windings)
- Other Monitored Components
  - Selected components of the bulb, for bulb-type hydro generators
  - Gearboxes, for units that use speed-increasing gearboxes to minimize generator diameter
  - Guide vane stems or draft tube components, to detect when the runner is operating in a cavitating mode

In this article, we will concentrate mostly on seismic transducers that are used for vibration measurement of hydro generator bearings, and of structural components that are located close to the bearings. We will discuss vibration measurements for some of the other components from this list in future installments of Hydro Corner.

Seismic Transducer Characteristics

Many different types of seismic transducers are available, with a wide variety of characteristics. For successful application, it is important to consider the key characteristics when selecting a transducer for every specific installation. Some of the most important characteristics are introduced here:

Sensitivity: This term describes the ratio of the transducer electrical output to its mechanical (vibration) input. The output is usually expressed in terms of voltage per unit of vibration. Typical vibration units are g's or m/s^2 of acceleration or mm/s or in/s of velocity.

- **Example Specification:** 20 mV/mm/s (508mV/in/s) ±10%

Noise Floor: This term helps us to understand the low level of unavoidable internal noise that is created by the transducer itself. In order to accurately detect the vibration levels, the self-noise level must be below that of the actual vibration amplitude to be measured.

- **Example Specification:** 0.039 m/s^2 (0.004 g) rms, from 10 Hz to 15 kHz (broadband)

Note: This noise floor specification example is described in terms of a broad frequency span. Sometimes, manufacturers also describe the measured noise floor of their transducers over specified narrow frequency bands.

Frequency Response: This term defines the range of vibration frequencies that can effectively be measured by the transducer. It is typically stated as a range in Hz from the lowest to the highest frequency that can be measured within 3 dB of the reference amplitude level. It is important to match the frequency response of the transducer to the span of machine frequencies to be measured.

- **Example Specification:** 0.5 to 1000 Hz (30 to 60,000 cpm) ± 3.0 dB

Transducer Construction: For high head applications it is usually preferable to use transducers without moving components – especially for monitoring vibration of the turbine guide bearing(s). This is because high head facilities tend to have higher structural vibration in three dimensions than lower head facilities have. Moving coil velocity transducers are more susceptible to damage and loss of operational stability from cross-axis vibration than are solid-state piezoelectric transducers.

Signal Cables

When selecting a seismic transducer for use with a portable vibration instrument, consideration of these four characteristics (sensitivity, noise floor, frequency response, and construction) is often adequate. However, for permanently-installed transducers – especially those using very long cables – it is also important to consider the cables that route the signals to the monitoring and protection instruments.

The effectiveness of a permanently-installed condition monitoring and protection system does not depend only on the quality of the transducers. It can also be seriously influenced by the signal cables. A few of the most important cable-related factors are listed here:

- Long cables attenuate the signal, which decreases the level of the transducer signal that reaches the monitoring & protection instruments.
- Long cables also introduce more capacitance, which bleeds off high frequency components of the signal. The functional frequency range of an installed transducer can be significantly reduced by capacitance, which causes the cable to act as an unwanted low-pass filter.
- Cables that are routed inappropriately or not shielded effectively can significantly raise the amount of electrical noise that is introduced into the signal. This can happen with short cables as well as with long cables.

Vibration Basics

Vibration measurements are typically made using one of three different physical parameters - displacement, velocity, or acceleration. These parameters are related to each other, and measurements can be mathematically converted from one parameter to another by integration or differentiation, as shown in Figure 1.

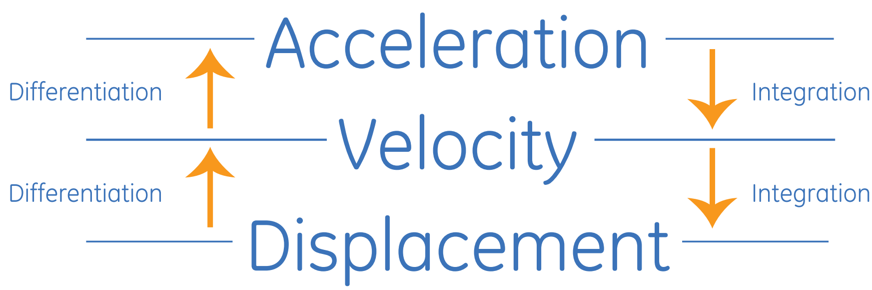


Figure 1: Converting vibration measurements

Vibration measurements for these various parameters are provided using different types of transducers. Examples include laser interferometers for displacement measurements, moving-coil transducers for velocity measurements, and piezoelectric transducers for acceleration measurements. A vibration signal can be converted from the measured parameter to a different one, using software or electronic circuitry.

The process of vibration signal integration is used much more often than differentiation. The most commonly used conversion is from an acceleration signal to a velocity signal. In fact, this is done so often that a special type of transducer, called an "integrating accelerometer" (piezo-velocity sensor) has been developed. This is simply a piezoelectric accelerometer with miniature onboard circuitry to accomplish the integration inside the transducer casing. Because the integration step is performed inside the shielded casing, rather than some distance away, this arrangement avoids the problems of integrating any electrical noise that is picked up by long signal cables.

As we have mentioned in previous articles, displacement is the most frequently used vibration parameter for evaluation of the vibration of a rotor shaft within the clearances of a journal bearing. However, velocity is the most frequently used vibration parameter for monitoring rotating machinery condition using seismic transducers. This is because velocity measurements correlate to the kinetic energy of the vibrating component, which can eventually lead to fatigue cracking and component failure.

Recall: Kinetic Energy = ½ (mv^2), where m is the mass of the moving object, and v is its velocity.

Also, since moving-coil velocity sensors existed for many years before piezoelectric accelerometers were widely available, the traditional body of knowledge of vibration severity levels and machinery protection setpoints was based on an extensive history of velocity measurements rather than acceleration measurements.

Finally, the vibration signal can be processed by the instrumentation in different ways to detect its amplitude. Peak measurements provide indication of the maximum velocity amplitudes in the signal, while rms measurements provide an overall indication of the vibration energy (Reference 2). Depending on the combination of frequency components in the vibration signal, it is possible to have high peak values with relatively low rms values and it is also possible to have lower peak values with relatively higher rms values.

Vibration Monitoring Approaches

In addition to velocity measurements, acceleration measurements are also commonly used for asset condition evaluation. However, acceleration measurements are not used as often for machinery protection as are velocity measurements. For hydro turbine generators, monitoring and protection based on measurement of vibration at the machine bearings most commonly uses one or more of the following four approaches:

Examples

1 Piezoelectric acceleration transducers are installed on the machine bearings, and the process of integrating the acceleration signals to units of velocity is performed by the instrumentation of an external monitoring or protection system.

2 Integrating accelerometers are installed on the bearings to provide velocity signals to the monitoring or protection system. As described earlier, these transducers use piezoelectric sensing elements, and they incorporate miniaturized integrating circuitry inside the transducer casings.

3 Traditional moving-coil transducers are installed on the bearings. These self-powered transducers generate velocity signals directly, by the interaction of a moving coil assembly with the field of a permanent magnet. The signals, which are already in velocity units, are used by a monitoring or protection system such as that in Example 2.

4 Non-contacting transducers such as eddy current displacement transducers or laser interferometers are attached to the stable structures such as the walls of the turbine pit, and view the appropriate machine surface as a measurement target (Reference 1). For very low speed rotating machines such as typical hydro turbine generators, these displacement signals may be appropriate to be adapted for machinery protection as well as for condition monitoring.

Advantages and Disadvantages of Different Approaches

Most hydro turbine generators operate with relatively low rotating speeds (and rotor-related vibration frequencies), while piezoelectric acceleration transducers typically have frequency response characteristics ranging from between 0.1 to 0.5 Hz at the low end up to more than 5 kHz to 15 kHz at the high end. The high frequency response of accelerometers makes them especially suited for measuring vibration that is well above the usual rotor-related frequencies – which are usually not more than 4 to 5 times the synchronous (1X) vibration at the shaft rotation speed. High frequency vibration can be created by components such as rolling element bearings and gearboxes, as well as impact events and structural resonances.

Some hydro turbine generators can generate significant vibration signals with frequencies beyond the measurement range of primary interest. Even though these vibration components are out of the range of interest for condition monitoring and protection, accelerometers are still excited by them. And since high frequency vibration components are usually accompanied by high acceleration amplitudes, these vibration components will often drive higher sensitivity accelerometers (such as 100 mV/g and 500 mV/g models) into saturation, causing erroneous readings.

If saturation by high frequency vibration becomes a problem, it may be appropriate to replace the transducers with models that have lower sensitivity. It may also be appropriate to use accelerometers that have built-in low pass filters. These sensors filter out the unwanted high

Synchronous Generator Relationships

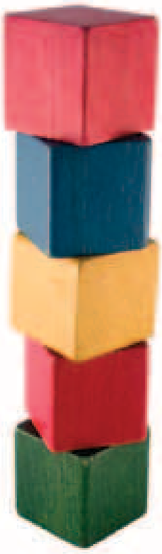
120f = np, or n = 120f/p

where f = power system (grid) frequency in Hz,
n = machine synchronous speed in rpm, and
p = number of poles in the generator.

- For the 50 Hz system, synchronous speed is (120)(50)/32 = 187.5 rpm.
- For the 60 Hz system, synchronous speed is (120)(60)/32 = 225 rpm.

Finally, to convert machine speed in rpm to equivalent synchronous vibration frequency (1X) in Hz, simply divide the speed by 60 rpm/Hz.

- For the 50 Hz system, 1X vibration = 187.5/60 = 3.125 Hz.
- For the 60 Hz system, 1X vibration = 225/60 = 3.75 Hz.



frequency signal components and thus provide better amplitude resolution at the rotor-related frequencies of interest (which typically do not exceed frequencies of 4X to 5X). It may also be appropriate to replace the accelerometers with traditional moving-coil transducers having frequency ranges that more closely correspond to the frequencies of interest for the specific machine.

Machine Example

Consider a small to medium-sized 32 pole synchronous generator. Operating on a 50 Hz grid, the generator would have a synchronous speed of 187.5 rpm (1X frequency = 3.125 Hz). Operating on a 60 Hz grid, it would have a synchronous speed of 225 rpm (1X frequency = 3.75 Hz). If you are not certain how to calculate these numbers, refer to the relationships in the Back To Basics sidebar.

For machinery protection, we are normally interested in rotor-related vibration frequencies that only extend to about 5X. For the 50 Hz generator example, 5X would be (5)(3.125 Hz) = 15.625 Hz, while for the 60 Hz generator example, 5X would be (5)(3.75 Hz) = 18.75 Hz. So from the viewpoint of machinery protection, we are mainly interested in vibration frequencies below about 20 Hz for this example machine.

Therefore, unless we are specifically interested in measuring high frequency vibration (such as for condition monitoring of rolling element bearings), transducers with a frequency response that reaches far beyond 20 Hz will introduce the risk of detecting vibration components that can negatively influence the primary task of machinery protection.

It is interesting to note that if we used a typical accelerometer with a frequency response of 0.5 to 5000 Hz to monitor vibration up to 20 Hz, we would only be using about 0.4% of the accelerometer's available frequency range!

Transducer Noise Floor

Now let us consider internal noise distribution through various frequency operating ranges of accelerometers. Not all accelerometer data sheets describe noise characteristics for specific narrow frequency bands. However, some manufacturers do provide this data. This particular example is for a Wilcoxon Research™ model 797L accelerometer. This transducer is dedicated for low frequency applications, with a sensitivity of 500 mV/g, and a frequency response of 0.2 to 3700 Hz:

- Broadband Noise Floor: 12 μg, from 2.5 to 25 kHz
- Narrowband Noise Floor:
  - 2.0 g, at 2 Hz center frequency
  - 0.6 g, at 10 Hz center frequency
  - 0.2 g at 100 Hz center frequency

From this information, it is easy to see that the internal electronic noise for a very low frequency application (2 Hz) is about ten times greater than the noise for a higher frequency application (100 Hz).

Transducer Frequency Response

It is important to understand that the lowest frequencies of importance for monitoring hydro generator machines are often well below the 1X frequency corresponding to the rotating speed of the machine. One example of a factor that can produce such subsynchronous vibration is a fluid instability in the guide bearings. These conditions can produce vibrations at frequencies as low as 0.2X. Another example is an operating regime known as "Rough Load Zone" (Rheingan's Influence). If present, this condition can appear over a broad range of machine loads – usually between about 25% and 70% of full load – and can generate vibration with a frequency at about 0.25X.

For our example of the 50 Hz generator with 32 poles, these two subsynchronous frequencies would range between approximately (0.2)(3.125 Hz)=0.63 Hz, up to about (0.25)(3.125 Hz)=0.78 Hz. To detect these conditions, we would need transducers with an appropriately low noise level at this very low frequency band.

Note: Non-contacting transducers provide very accurate displacement measurements all the way down to 0 Hz, so they can be used to detect fluid instabilities or rough load operation directly from rotor vibration measurements.

Transducer Sensitivity

Even late in the 20th century, it was not easy to find seismic transducers with optimal characteristics for hydro turbine generator applications. The most readily available and popular accelerometers for general purpose condition monitoring have a sensitivity of 100 mV/g. Although these have been widely applied to hydro turbine generator monitoring, it is often more appropriate to consider using a transducer with higher sensitivity (such as 500 mV/g) to measure the low amplitude acceleration that occurs at very low frequencies.

Seismic transducers are available in a variety of different sensitivities, for example, 25 mV/g, 50mV/g, 100 mV/g, 500mV/g, and 1000mV/g for accelerometers – and 4mV/mm/s, 20 mV/mm/s, 50mV/mm/s, etc. – for velocity transducers.

In addition to selecting transducers with appropriate sensitivity characteristics, it is also important to consider the span of frequencies to be measured, and the transducer noise floor for this frequency range. We will now consider some of these factors for selecting seismic transducers for hydro turbine generator condition monitoring.

Blade & Bucket Frequencies

In addition to determining the anticipated frequencies of subsynchronous and rotor-related phenomena, it is important to consider the vibration that is caused by the periodic passage of the vanes of buckets in the turbine runner. The basic relationship for determining such a "passage" frequency is to multiply the synchronous (1X) frequency based on machine speed, by the number of elements (in this case blades or buckets) that are on the rotor:

$$f_B = (N_B)(1X),$$

where f_B = blade or bucket frequency, N_B = number of blades or buckets and 1X = synchronous frequency associated with rotor speed.

The first step in calculating blade or bucket frequency is to determine 1X frequency by dividing rotor speed in rpm by 60 rpm/Hz. For example, a 600 rpm rotor has a 1X frequency of 10 Hz. Next, we simply multiply the 1X frequency by the number of blades or buckets to obtain the blade passing frequency. For a 600 RPM Kaplan runner with 5 blades, we would multiply the 1X frequency (10 Hz) by 5 to find the blade passing frequency of 50 Hz.

It is sometimes useful to be able to observe harmonic (integer) multiples of f_B during the diagnostic process. Some guidelines (Reference 4) recommend that the monitored vibration should include frequencies up to the third harmonic of these passing frequencies $(3)(f_B)$. For this example, the third harmonic of blade passing frequency would be 150 Hz.

Francis Turbines: For Francis runners, the rotor vane frequency is usually not very important for diagnostic analysis. This is because a typical Francis runner has many more vanes than a Kaplan runner has blades, and Francis runners have historically been machined and balanced to tighter tolerances than Kaplan runners. Because of the difference in design, Francis runners usually run with less vibration, and with much lower vane-passing pressure pulsations than the blade-passing events of a Kaplan runner.

Kaplan Turbines: The runners in these turbines do not usually have more than 9 blades. For a 9-bladed Kaplan runner turning at 225 rpm (32 poles, 60 Hz grid), the 1X frequency is 3.75 Hz, f_B is 9 times this value, 33.75 Hz, and the third harmonic of f_B is 101.25. For many such machines, the maximum required frequency range for monitoring rotor-related and blade passing frequencies is approximately 100 Hz or only slightly higher.

Pelton Turbines: The same formula can be also be used to calculate the bucket frequency for Pelton runners. The number of buckets (sometimes called "spoons" due to their shape) is usually several times higher than the number of blades of a Kaplan runner. A typical Pelton runner may have somewhere between 20 and 30 buckets. Also, the rotor speed of most Pelton turbines is several times higher than for other hydro turbine generators. Therefore, it is quite common for the bucket frequency of a Pelton turbine to be approximately 300 Hz, which means that the required upper frequency range (to accommodate up to the third harmonic of f_B can be close to 1 kHz.

Seismic Transducer Comparison

Now we will compare the signal characteristic of a set of typical transducers that can be used for condition monitoring and protection of hydro turbine generators. We will consider two accelerometers – with sensitivities of 100 mV/g and 500 mV/g. We will compare them with two velocity transducers (integrating accelerometers) – with sensitivities of 4 mV/mm/s (~100 mV/Inch/s) and 20 mV/mm/s (~500 mV/Inch/s). This comparison is shown in Figure 2.

Note: We included the 100 mV/g accelerometer in this evaluation based on its status as the most commonly used accelerometer for hydro turbine generator monitoring applications. We included the more sensitive 500 mV/g accelerometer based on recommended practices for monitoring machines with speeds below 500 rpm and acceleration amplitudes of 0.001 g or less (Reference 3).

In order to accurately compare the four different transducers, all four curves are based on exactly the same level of vibration – a constant 80 microns of displacement (peak-to-peak). This corresponds to evaluation zone C of ISO 10816-5 (Reference 2). It is interesting to note that the characteristics of the velocity sensors are linear, while those of the accelerometers are curved. These shapes reflect the mathematical relationship of velocity and acceleration to a constant value of displacement over the plotted span of frequencies. The curves with steeper slopes correspond to the transducers with higher sensitivities.

For vibration in the frequency range evaluated here, the transducer providing the highest output signal at all frequencies is the velocity sensor with 20 mV/mm/s sensitivity (red curve). For frequencies above about 12.5 Hz (corresponding to 1X frequency for a 750 rpm machine), the transducer providing the second highest signal is the accelerometer with 500 mV/g sensitivity (green curve). Observe that the transducer producing the lowest output at all evaluated frequencies is the accelerometer with 100 mV/g sensitivity. Unfortunately, this represents the most widely used condition monitoring accelerometer for the past decade.

In the case of Pelton machines, diagnostically-significant harmonics of the bucket frequency may occur at more than 500 Hz. In this higher frequency range, the velocity transducer with sensitivity of 20 mV/mm/s generates a stronger signal than the acceleration transducer with 100 mV/g sensitivity, all the way up to ~320 Hz. Even above 320 Hz, the velocity transducer signal is not significantly weaker than that of the accelerometer. The velocity transducer provides the additional advantage of lower noise over the accelerometer, since signal integration is accomplished inside the shielded transducer housing,

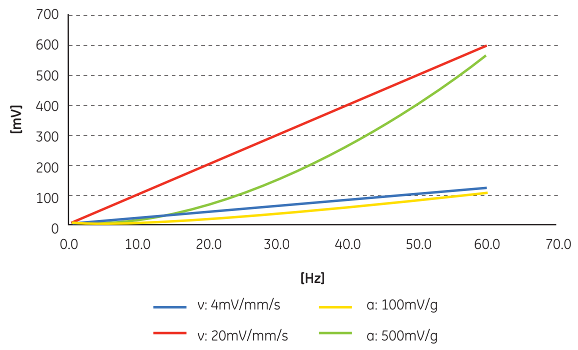


Figure 2: A comparison of measurement sensitivity for various transducers in a frequency range that is important for hydro-generator condition monitoring. The red and blue curves represent velocity transducers, and the green and yellow curves represent accelerometers.

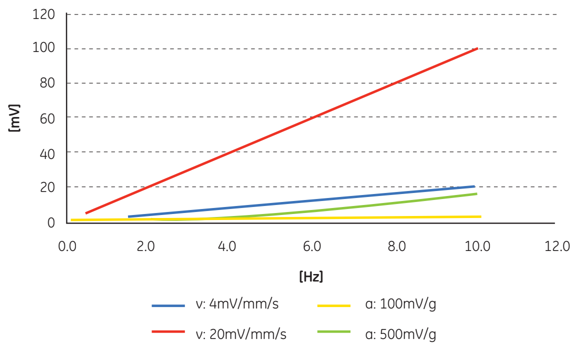


Figure 3: This chart compares measurement sensitivity for various seismic vibration transducers in a very low frequency range from 0 to 10 Hz.

rather than in the monitoring instrument (which can be a significant distance from the accelerometer).

Now we will take a closer look at the very low frequency portion of the seismic transducer comparison data (Figure 3). In this view, we are looking at the narrow frequency span from 0 to 10 Hz – a frequency range that is very important for slow-speed medium to large hydro turbine generators.

With this higher resolution frequency scale, it is possible to see that the frequency response characteristics for seismic transducers do not extend all the way down to 0 Hz, as they do with non-contacting displacement transducers. Integrating accelerometers tend to have higher minimum operating frequencies than normal accelerometers, in order to reduce the introduction of electronic noise at very low frequencies that is emphasized by the signal integration process.

As examples, the moving-coil design Bently Nevada 330505 Low Frequency Velocity Sensor is rated for use down to 0.5 Hz, while the Bently Nevada 190501 Velomitor* CT Velocity Transducer has a minimum rated frequency of 1.5 Hz. The Wilcoxon Research™ model 797V piezo-velocity transducer has a slightly higher minimum rated frequency of 1.6 Hz.

Because the linear vertical axis of this chart does not show small differences in sensitivity very clearly, we will view the same comparison data in Figure 4, which uses a logarithmic amplitude scale. Recall: A difference of 2 units on the vertical logarithmic scale of Figure 4 corresponds to a factor of 100 (10^2) on the linear scale, as shown in Figure 3.

As shown in this comparison, the most commonly used accelerometer (with 100 mV/g sensitivity) also produces the lowest signal over the evaluated frequency range. We will take one final look at this comparative data by normalizing all of the values with respect to this accelerometer (Figure 5).

In this dimensionless comparison, the 100 mV/g accelerometer is represented by a straight horizontal yellow line at constant normalized value of 1. The 500 mV/g accelerometer is represented by a straight horizontal green line (which covers the yellow line, hiding it from view) at a constant normalized value of 5.

In Figure 5, it is very clear that the most sensitive 20 mV/mm/s velocity transducer (red curve) is many times more sensitive than either of the accelerometers over the evaluated frequency range from 0.5 to 10 Hz. At the low end of the span, the signal from the most sensitive velocity transducer is more than 120 times higher than the signal from the most sensitive accelerometer. Even at the high end (10 Hz), it is still 6 times higher.

In fact, over the frequencies evaluated in these charts, the only region where the accelerometers have a clear advantage over the piezo-velocity transducers is in the very narrow low frequency range from about 0.2 to 1.5 Hz. As we mentioned earlier, this is due to the noise levels that are emphasized by the signal integration process at very low frequencies.

Transducer Response Linearity

This comparative analysis was performed with the assumption that all of the evaluated transducers have constant (linear) sensitivities over their full range of operation. However, it is important to realize that some velocity transducers have a significant decrease in sensitivity in the low frequency range.

Such transducers can have very high sensitivity for the linear region of their response curve (for instance, above 20 Hz), but sensitivity that drops to as low as 15% to 20% of this value in the non-linear region below 20 Hz.

Therefore, when selecting a transducer for hydro turbine generators with rotating speed below 300 rpm (1X = 5 Hz), it is not enough merely to look for a seismic transducer with high sensitivity. It is also important to verify that sensitivity will be adequate for the frequency range of 0.2X to 1X (which is 1 to 5 Hz for the 300 rpm machine example).

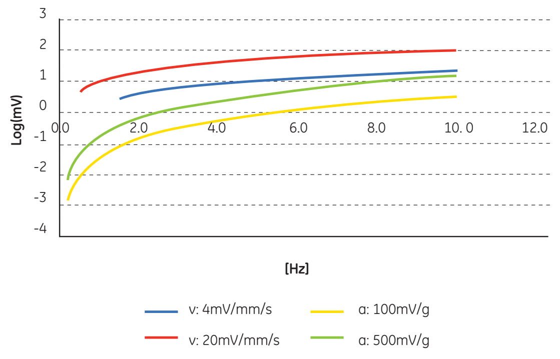


Figure 4: This chart compares measurement sensitivity of the same vibration transducers, using a logarithmic amplitude scale.

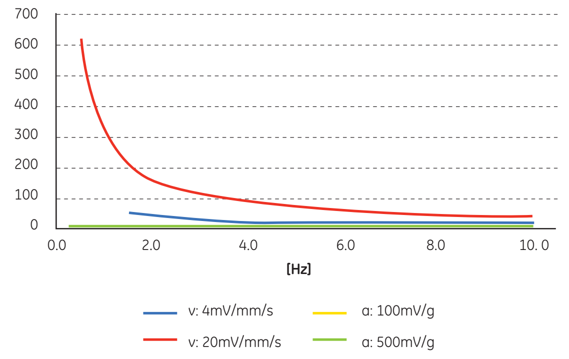


Figure 5: Transducer comparison normalized to the 100 mV/g accelerometer.

AFTER SELECTING TRANSDUCERS BASED ON THE CONSIDERATIONS DISCUSSED ABOVE, THE FINAL PART OF THE PROCESS IS DETERMINING OPTIMAL LOCATIONS FOR INSTALLING THEM ON THE COMPONENTS TO BE MONITORED.

Transducer Application Guidelines

After selecting transducers based on the considerations discussed above, the final part of the process is determining optimal locations for installing them on the components to be monitored. Here are some general guidelines that have proven to be effective:

1. Seismic transducers should be used when there is a strong suspicion of structural response in the frequency range corresponding to the operating speeds of the unit. In such a situation, there may not be suitable "fixed" locations on the structure to mount non-contacting displacement transducers.
2. If non-contacting transducers are being used along with seismic transducers, the sensor orientations should be aligned so that their signals can be compared and correlated with each other in a meaningful way.
3. In addition to measuring radial bearing vibration, it is also very useful to measure axial vibration with seismic transducers that are oriented parallel to the axis of the rotor system. Measurements from these axial transducers can be useful for guide bearings as well as for thrust bearings. These vertical (axial) transducers can be helpful for determining non-optimal operating conditions such as operating in the rough load zone or in a vortex condition.

The photo in Figure 6 shows an example of two transducers that were installed in conjunction on a 100 MW hydro turbine generator. A non-contacting displacement transducer is mounted radially on the bottom of the thrust bearing to observe the rotor shaft. A seismic transducer is also mounted radially – directly overhead on the thrust bearing support beams. Observe that both sensors have the same angular orientation with respect to the rotor, so that their measurements can be correlated.

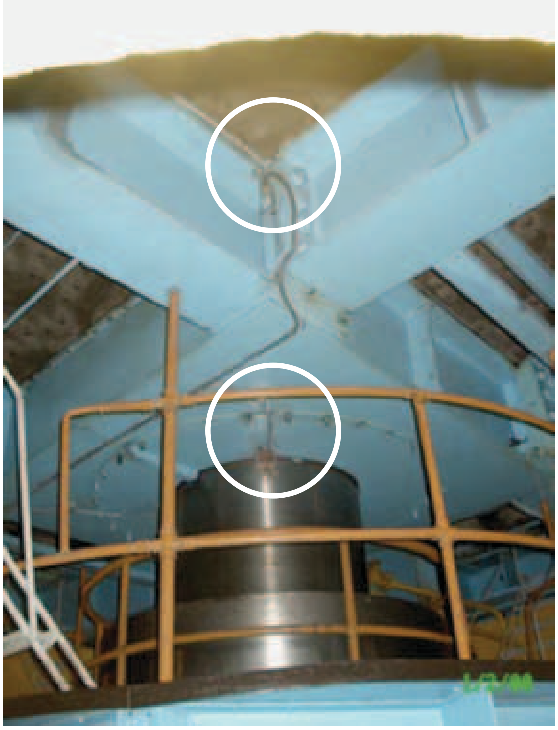


Figure 6: In this example, an eddy-current probe is installed to measure the radial displacement of the rotor shaft relative to the thrust bearing (lower circle). A seismic transducer is mounted in the beams of the thrust bearing support structure (upper circle).

Vertical & Horizontal Machines

When measuring vertical (axial) bearing vibration of a vertical hydro turbine generator, it may be adequate to use a single transducer per bearing. However, for measurement of radial vibration, it is more appropriate to use two transducers per bearing, arranged orthogonally (perpendicular) to each other.

Theoretically, the radial stiffness of guide bearings should be almost isotropic (the same in every direction) for new units. However, after the passage of time, it is common for the radial stiffness to become increasingly anisotropic. In such a situation, the use of an orthogonal pair facilitates the detection and trending of a developing problem.

With horizontal hydro turbine generators, axial vibration measurements are mostly made on the thrust bearing housing. If seismic transducers are also installed radially, it may often be adequate to use only one horizontal transducer on each bearing. If non-contacting displacement transducers are used to monitor the rotor shaft, it is again recommended to align them the same as any associated seismic transducers, so that their signals can be correlated.

High Head Applications

With high-head applications there is often significant vibration of the structure surrounding the hydro turbine generator. This three-dimensional vibration can have significant and chaotic amplitudes in all directions. For such an environment, it is better not to use seismic transducers with moving parts. In addition to being more easily damaged, moving-coil transducers are usually more sensitive to transverse (off-axis) vibration than solid-state models are.

The photo in Figure 9 shows two piezo-velocity transducers connected to a high-head Francis turbine guide bearing. The axial transducer is oriented vertically and the radial transducer is mounted horizontally. This combination of sensors has provided reliable data about the physical condition of this unit – even with the elevated levels of structural vibration.

Figure 7: This photo shows a seismic transducer mounted radially to a guide bearing.

Recommended Bently Nevada seismic transducers for bearing vibration measurements on hydro turbine generators

Transducer Type	Sensitivity	Frequency Response (3dB)
1. 330505 Low Frequency Velocity Sensor(**)	20 mV/mm/s 508 mV/in/s	0.5 to 1000 Hz
2. 190501 Velomitor* CT Velocity Transducer	3.94 mV/mm/s 100 mV/in/s	1.5 to 1000 Hz
(**)Transducer meets guidelines of ISO Standard 10816-5 (Reference 2)		

Figure 8: This photo shows another seismic transducer mounted radially to a guide bearing. Just above the seismic transducer is an eddy-current displacement probe mounted to observe the movement of the rotor shaft relative to the bearing. These sensors are all mounted in the same angular orientation relative to the rotor shaft, so that their measurements may be correlated.

Small Hydro Turbine Generators

Smaller machines, with capacity of ~1 MW or less, are likely to use rolling element bearings rather than fluid-film bearings. With rolling element bearings, it is much more common to use seismic transducers than non-contacting displacement transducers to measure bearing vibration. An exception to this norm exists with some machines that are known to experience fatigue wear to the rolling element bearings. Such a machine can develop excessive clearance in its bearings, and non-contacting displacement transducers are sometimes used to monitor the movement of the rotor shaft relative to the bearings.

As we mentioned earlier, velocity transducers are more often appropriate for machine protection application, while accelerometers are more effective to provide bearing condition monitoring based on detection of the relatively high characteristic fault frequencies.

In Closing

When collecting vibration samples with a portable data collector, it is usually a simple matter to change transducers or adjust data collection and signal processing settings as needed to capture usable measurements. However, with a permanently-installed "online" system, it is important to accurately determine the characteristics of the required transducers and

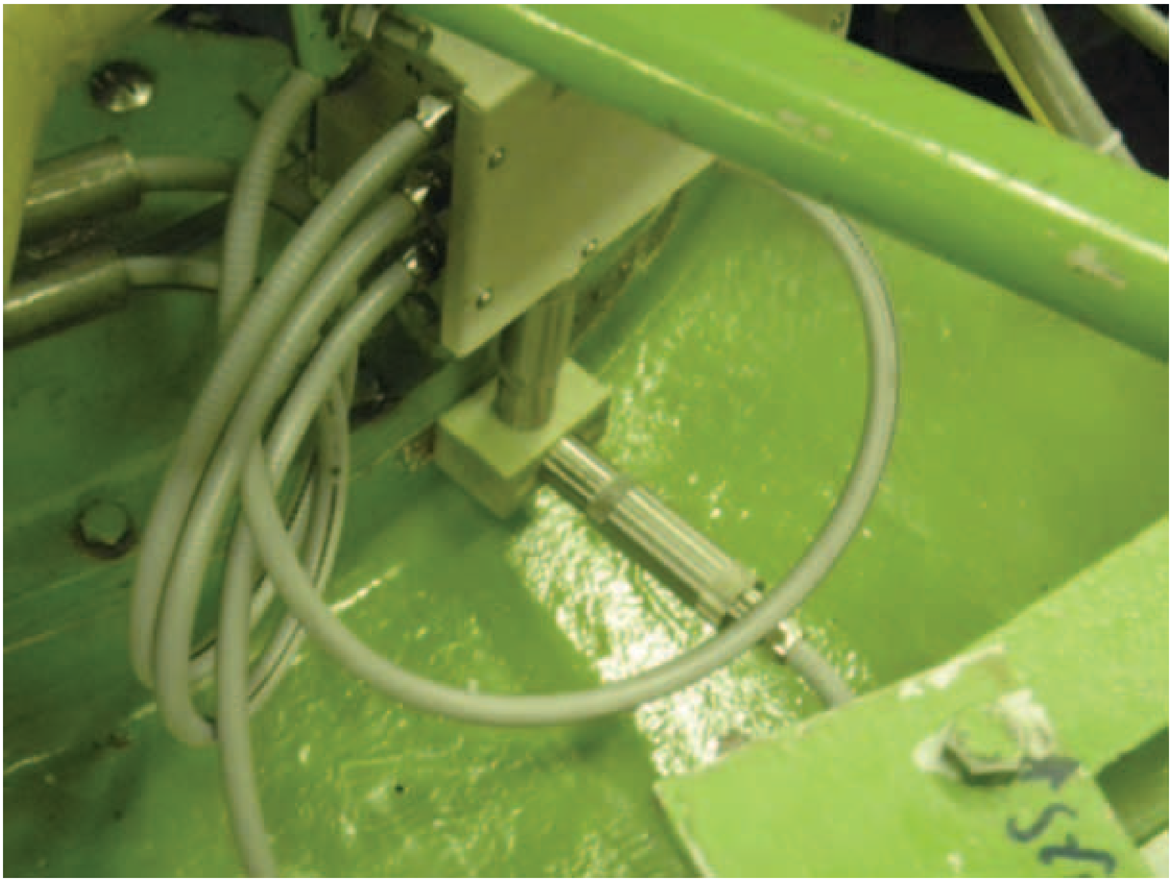


Figure 9: This photo shows two piezo-velocity transducers installed on the guide bearing of a high-head Francis turbine.

instrumentation settings when planning the installation. The topics discussed in this article provide some useful guidelines to consider when planning and installing a protection/condition monitoring system on a hydro turbine generator. ■

References

[1] Nowicki, Ryszard & Raegan Macvaugh, "XY Measurements for Radial Position and Dynamic Motion in Hydro Turbine Generators," ORBIT, Volume 30 Number 1, 2010

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[4] Eshleman, Ronald L., "Basic Machinery Vibrations: An Introduction to Machine Testing, Analysis, and Monitoring," VIPress, Incorporated, 1999.

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