Executive Summary
Is the pipeline industry different than the process industries, with respect to how alarms are handled? Alarm Management for Pipelines – Part 2 looks at the similarities and the differences between the pipeline industry and other process industries. Furthermore, it examines how one can interpret and apply the existing standards, user guides and publications to the pipeline control arena.
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Background
In the first paper "Alarm Management for Pipelines" (2007), we examined alarm management practices as they existed in industry based on the National Transportation Safety Board’s 2005 conclusion that an “effective alarm review/audit system would increase the likelihood of controllers appropriately responding to alarms associated with pipeline leaks”. The 2006 pipeline inspection, protection, enforcement, and safety act established a requirement whereby standards for the “review and audit alarms on monitoring equipment” would be in place not later than June 1, 2008. Many pipeline operators are now looking for available alarm management.

Standards
The most referenced documents for alarm systems and alarm management are:
- ISA S18.02 (DRAFT) 2008.01.01 Management of Alarm Systems for the Process Industries.
- NUREG 0700 Rev 2 Human-System Interface Design Review Guidelines
- NFPA 85 Boiler and Combustion systems Hazards Code
- NAMUR NA 102 – Alarm Management

The question for pipeline operators in the United States is: can any of these documents provide solutions, answers, or guidance for the mandate? The answer lies in our understanding of the intent of these documents, the understanding of human factors, the pipeline industry itself, and the understanding of one’s own organization. First let’s take a high-level look at each of these documents.

EEMUA 191
The first edition of EEMUA 191 was published in 1999, making it the first document of its kind to address the role of alarm management in the process industry. EEMUA is a European based organization that facilitates international standards making and provides a means to influence relevant national and European legislation and regulations. To examine the target audience of this documentation we need only look at the membership of EEMUA. Companies including AstraZeneca, BASF, BP, Chevron, ConocoPhillips, Dow Corning, E.on, ExxonMobil, Shell and Syngenta came together as leading plant owners and operators. A quick review of the scope will show that the guide was intended for “alarm systems in industries such as chemical manufacture, power generation, oil and gas extraction and refining and others”.

Yet in the vacuum of other literature on the subject of alarm management, the EEMUA 191 guide has become a de facto standard referenced around the world. It has become the best practice by which alarm systems are judged and benchmarked against. The interesting thing about EEMUA 191 was that it was never intended to be a standard. It was and still is intended to be a user guide. Yet regulatory bodies have been increasingly willing to reference the user guide as a standard. Therefore, until such time as alternate documents are available, EEMUA 191 appears to be an entrenched “de facto” standard that the pipeline operator must at least be aware of, understand, and know how it applies to their situation. In essence, EEMUA 191 points the direction on what should be achieved and gives direction in certain areas as to how to achieve.

ISA S18.02
In contrast to EEMUA 191, the ISA document has been developed with the intent to become a standard at a future time. Whereas EEMUA 191 provides direction on what should be done, ISA S18.02 provides direction on how to achieve.
The work in progress is intended to be applied to process facilities and provides general principles and processes for use in the alarm management lifecycle. The future standard, having a North American perspective, will undoubtedly have a higher profile in North America than the European counterpart.

However, at this time the document is only in draft form and cannot be referenced in response to any regulatory requirement. That being said, the ISA S18.02 even in its draft form provides guidance for the development of alarm management programs that are helpful to the reader.

The question again arises, how does this apply to the pipeline industry? Like EEMUA 191, the answer lies in the understanding of the principles and the knowledge that this document is intended to become an ANSI standard. The reader will appreciate the content of the current draft when trying to determine how to establish an alarm management program. It should be noted that future drafts of the ISA document will probably take the form of what needs to be achieved, rather than how. This change will be due to the nature of standards, which are more prescriptive in nature, filled with ‘shall, should, and recommended’ clauses.

**NUREG 0700**

This document is very specialized in its application to the US nuclear power industry. Developed with respect to human factors engineering. Section 4 of Part 11 is dedicated to alarm systems. Fifty-one pages are devoted to the alarm system, yet this document is very seldom referenced outside the nuclear industry. The document is prescriptive in nature providing ‘should’ and ‘should nots’ to the industry but provides little guidance on how to achieve the desired objectives. As a result operators of pipeline facilities may find this document to be interesting and perhaps even frightening in the level of requirements, but will not find much guidance in order to prepare for the rules coming out in June of 2008.

**NFPA 85**

To the uninitiated, one might think that the National Fire Protection Association was more about fire extinguishers and sprinkler systems than alarm systems. A quick review of NFPA 85 – Boiler and Combustion Systems Hazards Code, would change one’s mind. This is a very prescriptive code detailing to the tag level what alarms should be present and where they should be located. Review of this code will provide the pipeline operator with no direction for an alarm management system, but will make the pipeline operator feel much better about a performance based alarm management system environment vs. a prescriptive-based standard.

**NAMUR NA 102**

NAMUR is an international organization headquartered in Germany. Most members are from the process industry in either Germany or surrounding countries.

The document is neither a standard nor a guideline, but an optional worksheet for its members to use as they see fit. It is aimed at the chemical and pharmaceutical industries and as far as the US pipeline industry is concerned, it could be considered a German summary and translation of the EEMUA 191 user guide.

Interestingly, the EEMUA, ISA and NAMUR documents are surprisingly compatible in their nature, as is to a certain degree the NUREG 0700. As far as applicability to the US based pipeline industry, certainly the EEMUA 191 has been published, is available, and therefore recommended reading. The ISA is also recommended reading, but caution must be indicated in that the ISA document is still only a
Similarities to the Process Industry

Before we make the bold statement that the EEMUA and ISA documents do not apply to the pipeline industry, let us look at the similarities between the process and pipeline industry. For the most part both industries have centralized control rooms that are used by operators/controllers to run the facilities. This may seem somewhat trivial, but both industries measure the raw process variables of pressure, flow, temperature, level and status to provide the controller with information about the operational condition of their facilities. Both have piping, pressure relief, safety valves, rotating equipment, processing facilities (yes, the natural gas transmission industry has refrigeration plants, straddle plants, joule Thomson cooling plants, compression, salt cavern storage, propane-air, dehydration and LNG plants.)

From a manpower perspective, both run 24 hours/day, seven days per week and many use 12 hour shifts. The interface for the operator consists of a series of graphical-based monitors, an alarm summary, keyboard and a mouse. In some situations dedicated annunciated alarm panels also exist.

Both industries tend to handle hazardous products and are concerned with loss of containment. Both industries apply basic control theory to automate their facilities. The complexities of automation may vary, but the basic theories are the same. Equipment failures, failures of transmitters, mechanical failures of materials and equipment are common to both industries. Human factors engineering of the operator/controllers environment; operator fatigue, errors, misses, misinterpretation, and shift handover, are common issues to both control rooms.

Fundamentally an alarm generated on a DCS system is the same as an alarm generated on a SCADA system. The alarm indicates a process is operating outside pre-determined limits and requires an operator/controllers intervention to return the process variable to its normal operating range.

From the perspective of similarities, it would seem on the surface that the alarm management practices of the process industry would be entirely applicable to the pipeline industry. But what of the differences?

Differences to the Process Industry

One of the basic differences between the process industry and the pipeline industry is that there is no fence around the pipeline. Pipeline systems are long, linear, facilities that tend to cover long distances. This basic difference introduces several nuances.

The remote locations associated with pipelines, often mean unmanned facilities. The distance factor results in the need to travel and increases time to respond when a field operator’s attention is required. As a result we start to see a sharing of responsibilities between the control room pipeline controller and the field operator.
Communication or the loss of communication becomes more of a factor in the pipeline setting. Where polling exists, the operator interface is not in real time, but provided on a pre-determined interval, which coupled with intermittent communication could result in updates being hours apart. When a station is successfully polled or a successful communication is made for a report by exception scheme, all the exceptions are reported at once. This has the potential to create an instantaneous alarm flood to the control room, which may be quite different than what actually occurred in the field. If the communication attempts are intermittent and at first unsuccessful, then any abnormal situation may begin to escalate before the pipeline controller is given an indication of the situation.

The architecture of the control systems tend to be different with a distributed control system (DCS) tending to exist in process facilities and Supervisory Control And Data Acquisition (SCADA) systems in the pipeline control center. Remote locations in the pipeline industry tend to have a HMI application coupled with either PLC or RTU applications. As technology has moved forward the distinction between PLCs, RTUs and even Flow Computers has become blurred and a mixture of these devices are now operating pipeline facilities. Fundamentally these differences evolved out of the issues surrounding remote communications.

Another major difference between the pipeline industry and the process industry is that of 3rd party encroachment. Typically the process industry has a fence around their facility and is able to control through Management of Change and safe work permit systems, the work in and around their facilities. Though many efforts have been made, the pipeline industry is still exposed to the unpredictable nature of a third party tree planter reforesting the right-of-way to improve the view outside their front window. The ability to detect a loss of containment from a pipeline is still a major issue for the pipeline controller.

**Differences between the Liquid and Gas Pipeline Worlds**

As there are differences between the process industry and the pipeline industry, there are also differences between the liquid pipeline and gas pipeline worlds. Most of the differences have to deal with the difference in the product contained within the pipeline. Welding procedures will be different, due to the heat capacity of the liquids; fracture toughness requirements of the pipe materials will be different due to the differences in compressibility. The compressible nature of liquids results in the decompression wave occurring during a line break being typically faster than the crack arrest speed. The opposite can be true for gas pipelines, which creates the potential for a crack in a pipeline to propagate. This can result in effectively two locations where hazardous materials are released instead of just one. The compressibility of gas tends to make pipeline leak detection more difficult which tends to make a difference when looking at the alarms coming from computational pipeline modelling programs.

Density of the product results in differences to operations. The heavier than air products will pool around a leak creating a hazardous environment, whereas the lighter than air products will tend to dissipate. The lighter than air products still create hazardous environments, but the safety record shows that lighter than air releases have resulted in fewer major incidents. This fact alone will prompt some to say that the industries are different.

Liquid lines tend to be operated in batches and require storage, increasing the activity of the pipeline controller in filling tanks, blending, etc., whereas gas lines tend to be operated more on pressure control with the automation systems making the necessary adjustments. Yet, gas pipeline facilities also have storage in salt caverns and depleted reservoirs. In natural gas pipelines, propane-air peaking systems and LNG systems may exist adding to the complexity of what was initially interpreted as a simpler pipeline system.
A pipeline controller may operate more than one pipeline and indeed might operate both a liquid and a gas pipeline. Which pipeline has a higher priority and how are the alarms configured so that this is clear to the controller?

In the control room there are actually fewer differences than one might conjure up. The pipeline controller’s interface to the operation of the pipeline is the same, and in many situations the same SCADA vendor and software version is used by both. An alarm is still an alarm from the perspective of the controller. However, the configuration of the alarm may indeed be different. The consequences of an alarm, the environmental impact, the safety, may have different severities. The time to respond may be different. This may result in differences when assigning priorities to individual alarms. The differences in leak detection may make the controller’s job different in monitoring the pipeline. The natural gas pipeline might be part of an essential service, increasing the consequence of a flow interruption.

Understanding the differences between the industries is helpful, but the question still stands: How do we interpret the existing alarm management publications with respect to the pipeline industry?

**Alarm Management Publication Interpretation**

To interpret the existing user guides, standards etc. we need to understand the intent of each guide and the intent of alarm management best practices in general. Once the intent and basic principles are understood, then it is relatively easy to determine how these documents can be utilized by pipeline companies to improve the alarm management practices in their organizations. A review of the NTSB safety study will reveal five areas of potential improvement, with alarm management being one of the areas. A common definition for alarm management is:

Therefore, the publications of most use at this time would be EEMUA 191 to define what should be achieved in an alarm management program and the draft of ISA S18.02 to provide guidance on how to achieve improvements to an alarm management program.

The difficulty that will arise when referencing these two documents will be applying the key performance indicators to the pipeline control arena.

**Alarm Management KPIs**

Lord Kelvin has often been quoted for his profound statement “If you cannot measure it, you cannot improve it”. Understand this and one understands the intent of key performance indicators or KPIs. If you cannot measure the performance of your alarm system, you cannot improve it. The question becomes, what should we be looking at improving? If we can determine this, then we can determine what the KPIs should be. Here are some examples:

- How busy is the controller with respect to alarms? This could be measured simply as alarms/hour or alarms per shift. This is such a fundamental item that you will find in EEMUA 191 and the current draft of ISA S18.02. This is the average number of alarms that an operator can successfully manage over a shift, which is typically 12 hours.

- But a controller can handle more than the average number of alarms for a short period of time? What would be considered unacceptable? The next KPI we would probably want to consider is the burst rate or the maximum rate that alarms are received by the operator. EEMUA 191 looks at this problem as something the controller could handle for up to 10 minutes and therefore measures the maximum number of alarms received by the controller over a 10 minute time period. Common sense shows that the controller cannot keep up the maximum rate forever and eventually they will make an error or miss an alarm entirely.

- As a pipeline operator, an important piece of information for risk management would be the
percentage of time the pipeline is at risk of the controller missing an alarm. By determining a threshold whereby the controller is loaded to a point below the maximum burst rate, but at an excessive rate where the likely hood of missing an alarm increases, then this piece of information can be determined.

- As a measure of proper alarm configuration and nuisance alarms, a measure of the standing alarms would be useful. Alarms that have too low of an alarm limit or the threshold for the alarm was below the normal operating range would show as standing alarms of a long duration. Alarms that required no controller action would show as standing alarms as no action was possible to return the process variable to its predetermined optimal state.

- Is it important to understand how the alarms are managed, and whether the alarm performance is being fixed or merely patched? Is it important to know if the management of change system is being utilized properly? If so, then a measure of the inhibited alarms is a good indicator.

- A goal of the alarm system is to identify abnormal situations to the controller and provide guidance to the controller on an appropriate corrective action. During periods of higher alarm rates, part of that guidance provided to the controller should be which alarm to respond to first. Herein lays another KPI. The priority distribution. If the alarms that a controller receives are all priority one, then the controller is given no guidance in respect to what to respond to first, second and so on.

These are some examples of useful KPIs and indeed you will find similar KPIs in alarm management literature. Can you utilize the numerical targets published in EEMUA 191 or other alarm management literature? The numerical targets for the process industry are based on the operator:

- receiving the alarm
- reading the alarm
- acknowledging the alarm
- determining the consequence of no action
- determining the cause
- perhaps taking an initial action
- determining and implementing a corrective action
- monitoring the process variable to ensure its return to normal
- monitoring several alarm indications simultaneously

However, experience has shown that the typical process plant operator role is somewhat different than the pipeline controllers role and therefore we need to understand how we operate, before we can establish numerical targets to the KPIs that we may deem applicable.

**How Do We Operate?**

When it comes to pipeline operations, there is a continuum of roles that the controllers undertake. At the one end of the spectrum is the typical role of the process plant operator. At the other end of the spectrum is the role of dispatcher. In the case of a dispatcher, we find that the controller’s might be limited to identifying where the alarm occurred and then notifying the appropriate field operator about the alarm condition. The controller takes no further action, and all decisions are left to the field operator. If we extrapolate this to the field operator’s viewpoint, then a priority one alarm would be something where they would drop whatever they were doing, get into the truck and drive immediately to the location of the alarm. A priority two alarm might be something they will get to today, and a priority three alarm might be something that they will get to this week. This is taken to the extreme, but obviously there is a difference on how one would assign priorities and subsequently measure the performance of priorities between these two extremes.
The number of alarms or dispatch calls that the controller is capable of making would typically be considered greater than the number of alarms a process plant operator would be able to handle. The reality for most pipeline controllers is that a shared responsibility exists.

Determining where you are located on the controller’s alarm response continuum (process plant to dispatcher) is paramount to determining what acceptable targets would be. Or is it? If the aim of alarm management is to continually improve over time, then measuring the KPIs and ensuring positive progress may be more important than the actual target itself, at least at first. So where should one start?

**Build the Alarm Philosophy with the Appropriate KPIs**

The alarm philosophy is the cornerstone of any alarm management program. It provides the guidance to the organization to ensure the consistent and effective design, implementation and handling of alarms and the supporting alarm management system. Within the contents, define the KPIs that are appropriate to the organization and to the pipeline controller’s role. Determine appropriate targets based on the understanding of the actual role of the pipeline controller. Consider the human factors, then develop the means to measure, evaluate and make corrective action based on the measurements.

Remember that alarm management is a lifecycle and that each cycle brings improvement and clarity. Therefore a graduated set of KPIs may prove more useful. These KPIs can then be applied on a pipeline by pipeline basis or even by controller position and allow a means of evaluating successful progress at improving the alarm system performance. It may even be valuable to establish levels of targets so that the organization can celebrate reaching milestones. This helps to give alarm management visibility and reinforcement throughout the organization.

KPIs should be specific to the application being improved. If the role of the pipeline controller is that of a dispatcher, then a useful KPI might be the average number of alarms/unit of time requiring escalation. This would indicate the number of times that an alarm needed to be escalated due to the field operator not being able to respond. The inability to respond could be due to:

- road conditions
- vehicle conditions
- the field operator already responding to a different condition
- the field operator is at the wrong end of the regional territory and cannot respond in time
- the corrective action is not sufficient to prevent a worsening of the abnormal situation

At the start of any alarm management program, chattering alarms tend to contribute heavily to the controller’s alarm load. These are alarms that recur with a significant frequency and have the potential to mask important alarms from the operator.
A KPI to measure the number of chattering alarms may be useful at the beginning of an alarm management program, but less useful when the program has been established. A sample list of KPIs might look like:

<table>
<thead>
<tr>
<th>KPI</th>
<th>Measurement</th>
<th>Targets</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Rate</td>
<td>Number of alarms/hour measured over a long period</td>
<td>Bronze</td>
</tr>
<tr>
<td>Burst Rate</td>
<td>Maximum number of alarms/hour measured over a 10 minute period</td>
<td>&lt;20</td>
</tr>
<tr>
<td>% of time at risk</td>
<td>% of time the controller receives alarms at a rate greater than 30 alarms/hour</td>
<td>&lt;15%</td>
</tr>
<tr>
<td>Standing alarms</td>
<td>Average number of standing alarms per shift</td>
<td>&lt;50</td>
</tr>
<tr>
<td>Priority Distribution</td>
<td>Distribution of Priority 1,2,3 alarms that the controller receives</td>
<td>(1+2)&lt;3</td>
</tr>
<tr>
<td>Maintenance Shelved alarms</td>
<td>Average number of alarms that have been shelved for maintenance purposes</td>
<td>&lt;100</td>
</tr>
<tr>
<td>Inhibited alarms</td>
<td>Number of inhibited alarms that are not maintenance shelved</td>
<td>&lt;100</td>
</tr>
<tr>
<td></td>
<td>Bronze – exceeding a week</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Silver – exceeding two days</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Gold – exceeding a shift</td>
<td></td>
</tr>
<tr>
<td>Chattering Alarms</td>
<td>Number of occurrences/week</td>
<td>&lt;20</td>
</tr>
<tr>
<td>Escalated Alarms</td>
<td>Number of alarms per month requiring the controller to escalate the alarm past the field operator</td>
<td>&lt;30</td>
</tr>
</tbody>
</table>

**Develop Applicable Review Practice**

Develop a solid review practice. In the words of Peter Drucker, “You cannot manage what you cannot control, and you cannot control what you cannot measure.” Do an initial benchmark or baseline so that you can measure improvement against. Set up a continual monitoring process so that alarm management is embedded in the culture and developing problems are dealt with quickly. Conduct assessments to ensure that your program is actually accomplishing what is intended. Finally conduct a periodic audit where you evaluate the entire alarm management system including the applicability of your management of change system and so on.
Conclusion

Good alarm management can be achieved. Use the existing standards and user guides. Better yet, join the AGA Gas Control Committee or the API 1167 Alarm Management Committee and become actively involved in developing practices that address the uniqueness of the pipeline industry. Follow proven practices from the process industry.

<table>
<thead>
<tr>
<th>Benchmark &amp; Assessment</th>
<th>Have the tools in place to measure and audit the performance of your alarm system. Understand your starting point and what needs to be improved upon.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alarm Philosophy</td>
<td>Develop and consistently utilize an alarm philosophy. The entire alarm management program is defined here, and this becomes the cornerstone of an alarm management program.</td>
</tr>
<tr>
<td>Alarm Rationalization</td>
<td>Fix the bad actors, eliminate the nuisance alarms and re-engineer alarms developing alarming strategies that aid the controller, rather than hinder their performance.</td>
</tr>
<tr>
<td>Implementation &amp; Execution</td>
<td>Ensure that the implementation of changes is thought through. To some controllers, this will be a paradigm shift. Careful implementation is crucial to overall success.</td>
</tr>
<tr>
<td>Maintenance</td>
<td>Make it part of everyday operational practices, and part of the corporate culture.</td>
</tr>
<tr>
<td>Continuous Improvement</td>
<td>Good alarm management can be achieved, but remember it is a life cycle. It is not a one-time event. It needs to be sustained.</td>
</tr>
</tbody>
</table>
"There are more things to ALARM us than to HARM us, and we suffer more often in apprehension than reality."

- Lucius Annaeus Seneca

The final rules for the pipeline industry were not available at the time of publication of this paper. However, the experiences of other industries show that a methodical approach to alarm management can yield significant returns to the pipeline controller and the pipeline operator. At Honeywell we have been working with both the process industry and the pipeline industry in providing solutions for alarm management.