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Liquid Pipeline Rupture Recognition and Response

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Some high-profile liquid pipeline rupture incidents have highlighted that operators have room for improvement in more consistently recognizing and responding to high flow rate pipeline releases, often referred to as ruptures. Stakeholder expectation is for prompt and consistent rupture detection and response. This requires rupture focused pipeline monitoring systems and robust operating procedures that align with a strong "Think Rupture" culture throughout the operator's organization. The goal of the Rupture Recognition and Response document is to provide guidance to operators to ensure prompt and consistent detection and response to ruptures. This guidance is based on a composite of practices and shared knowledge on rupture tools and techniques being used within the liquid pipeline industry. This document provides an overview of key concepts for consideration in rupture detection and response.

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Liquid Pipeline Rupture Recognition and Response

Abstract

The API and AOPL Pipeline Leadership sponsored an initiative to evaluate and provide recommendations to further enhance an operator's ability to consistently respond to pipeline emergency events. Contributing background to this initiative were isolated cases where post incident analysis identified opportunities for improvement in recognizing and responding to high volume and high rate releases, commonly identified as ruptures.

A sub team, under the guidance of the API Cybernetics Work Group, was formed to further consider opportunities for shared learning from past events and to develop guidance material for beneficial use across the liquid pipeline operator community. The sub team completed this assignment in early 2014 with the development of the Rupture Recognition and Response document.

This document identifies the following four focus areas that were deemed critical to rupture recognition and response system design, implementation, and execution:

- Culture
- Training
- Rupture Recognition
- Rupture Response

This document identifies rupture recognition and response techniques and applications which can be used in conjunction with various levels of SCADA-based pipeline monitoring and leak detection systems and/or as a separate stand-alone rupture alert system. Highly reliable and very dependable, with minimal false indications, are characteristics of a properly designed and applied rupture alert system.

The document further describes the importance of promptly responding to a suspected or confirmed rupture alert as a means to minimize unintended consequences. The roles of remote SCADA personnel and field responders, along with coordination of response and investigative activities, are examined and guidelines offered for operator consideration in development and/or modification of its rupture recognition and response procedures.

API/AOPL Rupture Recognition and Response Background

GOAL: Improved Recognition of and Response to Pipeline Ruptures

- In 2011, the American Petroleum Institute (API)/Association of Oil Pipe Lines (AOPL) Pipeline Leadership (the principal and alternate executives of AOPL member company and the API Pipeline Subcommittee) identified Rupture Recognition and Response as a focus area where the liquid industry had an opportunity to proactively improve industry performance.
- API/AOPL Pipeline Leadership requested assistance from the API Cybernetics Work Group to quantify and structure an approach.
- The Rupture Recognition and Response Team formed in September 2012 to focus on sharing / generating ideas or noted practices on:
 - How to enable existing Supervisory Control and Data Acquisition (SCADA) systems to “Scream Rupture”
 - Distinguishing and highlighting rupture detection & recognition from leak detection and system deviation alarms
 - Enhancing pipeline controller rupture detection and response
 - How to optimize “lightly instrumented” or legacy SCADA software for Rupture Detection (separate from Leak Detection).
 - Enhancements that can occur quickly without significant
 - SCADA upgrades
 - technology replacements
 - equipment investments
 - Identifying distinct rupture detection programs/systems, training programs, simulations, and drills that are separate from overall leak detection programs/systems.
- The initial meeting included asset and practices surveys.
- The team identified improvement opportunities primarily in rupture recognition and rupture response.
- This document is the result of multiple face-to-face team and subteam meetings and review by industry subject matter experts (SMEs).

Scope

Introduction

Pipeline ruptures may result in negative consequences to public safety and the environment, so it is critical that rupture detection and response systems and procedures are designed, structured, and executed effectively. This document is intended to assist a hazardous liquid pipeline operator in developing and improving its pipeline rupture detection and response capabilities.

Perspective

Some high-profile liquid pipeline rupture incidents have highlighted that operators have room for improvement to more consistently recognize and respond to high flow rate pipeline releases, often referred to as ruptures. Rupture detection and response can be compared to the reliability paradigm, where good design forms the basis for good equipment, processes, and people. The operator's culture forms the basis for consistently and capably responding to rupture incidents.

As operators view this document, consideration of the key concepts and how they are best implemented or reviewed within a given operator's environment may align differently than stated here. The operator should consider the various components of this document in determining whether its existing methods for achieving the goals of rupture recognition, response, training, and culture should be modified.

This document is a composite of practices and shared knowledge on rupture tools and techniques being used within the industry. The operator should apply this paper to its current management, design, and operation of its pipeline systems. The operator may also apply other standards or outlined practices.

Key Points

This document contains the following key points:

- A rupture alarm is one means of communicating a large pipeline release significant enough to produce an unambiguous signature in the measurements made on the pipeline. This clearly defined signature provides the possibility of generating an alarm to pipeline controllers that would rapidly alert them to the rupture with a very high confidence alarm. The primary difference between a rupture alarm and a leak alarm is the certitude of the alarmed condition, which will increase the controller's confidence in the rupture alarm and allow for a more robust and consistently executed response procedure that may include accelerated or automated shutdown and isolation events.
- All pipeline leaks are not created equal. Taking out factors related to time to detect and location of the leak, ruptures typically present the most immediate and

acute threats to public safety and environmental damages. A distinct focus on pipeline ruptures represents a paradigm shift from traditional SCADA-based pipeline monitoring and alarm response systems.

- The focus of this document is on uniquely (sometimes implicitly) distinguishing recognition of and response to pipeline ruptures or high flow rate releases (events to which the operator assigns its highest level of response) from other release event types.
- This document is applicable to all hazardous liquid transmission lines.
- Rupture detection and response is significantly enhanced when applied to a continuously monitored SCADA system.
- While sophisticated leak detection systems are very beneficial to safe and efficient pipeline operations, highly effective rupture detection and response can be achieved in some cases with relatively low-tech algorithms implemented within the SCADA system.
- More complex pipeline systems may be further enhanced or optimized with additional software such as a computational pipeline monitoring solution.
- An operator should consider generating a separate rupture alarm and response distinct from all other leak detection and SCADA-generated alarm indications.
- Prompt rupture detection and response includes the following parameters:
 - Prompt does not necessarily imply instantaneous as the intent is to minimize false alarms that can quickly lead to reduced confidence and hesitation in response. Prompt for a rupture detection purpose typically means the alarm can be verified confidently in minutes versus seconds (distinguishing between prompt with high confidence versus instantly for typical SCADA-generated alarms).
 - In considering the recognition-window time length, operational factors include the following:
 - Highly volatile liquids (HVLs) operating at vapor pressure
 - Gravity flow lines
 - Highly variable operations (a large number of transients because of rate or flow changes)

- Complex receipt or distribution networks with multiple and variable flow configurations.
- The operator should provide the controller (also referred to as the pipeline controller or the SCADA operator) with clear instructions on how to respond to rupture events, both suspected and confirmed. Post incident analysis sometimes identified that the operator's actual response presented opportunities for improvement that could beneficially limit the consequences of a rupture event.
- Rupture detection and response is in addition to current monitoring and response, not in place of any existing techniques, and may use the same techniques; however, rupture indications are presented to the controller in a manner easily differentiated from other alarms. (See *API 1165 SCADA Display Standard [API 1165]* and *API 1167 Alarm Management [API 1167]*).
- Operators should consider distinct rupture detection and response training and drills, distinguished from leak detection and other SCADA indications, and inclusive of SCADA, control center, field operations, and other support groups.
- Operators should consider the effects of slack conditions within the pipeline as well as the effects of lines operating above the fluid-flowing vapor pressure in the pipeline on the confidence of the rupture indicator. An operator's controllers should be trained on these effects regarding rupture recognition.
- Central to an operator's culture is the recognition and functioning of the control center as the center of communication and the undisputed lead in the early phases of a rupture event.
- While leak detection and rupture detection share common techniques and methodologies, critical success factors for small volume/rate leak detection include highly accurate, repeatability, robustness, and sophistication in measurement processes. Large volume/rate rupture detection focuses on significant events on the pipeline that have unambiguous signatures, which can be readily achieved using robust CPM systems or with more fundamental analysis techniques. Small-volume leak detection focuses on detecting the smallest leak in the shortest possible amount of time with the inherent allowance for false positives. Rupture detection focuses on a highly certain indication that uniquely occurs when there has been a large volume or high rate product release. The rupture indication reliability and accuracy can typically be improved by expanding the time duration of the SCADA rupture detection algorithm to a few minutes to filter nuisance indications and false positives (versus seconds for typical leak indication alarms generated from a robust CPM system).

- Rupture detection can be viewed as a "second line of defense" to sophisticated SCADA leak detection and monitoring systems. Typically, SCADA detectable pipeline releases and ruptures are initially indicated and responded to by an operator's normal procedures, such that when the distinct rupture alarm is triggered, response activities are likely to have already commenced. By exception, in some high-profile pipeline rupture incidents, operators have not always initially and promptly diagnosed SCADA alarms as rupture events.
- Distinct rupture indications and response activities separate from leak indications and leak response are relatively new to liquid pipeline operators, particularly when applied as supplemental backstop systems to traditional SCADA pipeline monitoring and control applications. As such, the techniques for prompt rupture detection and response are likely to develop with increased experiences and continued sharing of operator best practices.
- This document is not intended to be a "how to" manual or to mandate performance, procedures, or applications' requirements.
- There is no implied or expressed expectation that operators should adopt this document in either its entirety or its parts, and it is presented for operator consideration purposes only for identifying potential improvements in designing and/or modifying its leak/rupture recognition and response systems and procedures.

Excluded from Scope

This document does not address the following:

- External leak detection systems
- Rupture reporting to regulatory agencies and emergency responder groups
- Topics already addressed in other industry publications. These topics may be referenced, but they are not addressed in depth. These topics include the following:
 - *API 1130 Computational Pipeline Monitoring (API 1130)*
 - *API 1165 SCADA Display Standard (API 1165)*
 - *API 1167 Alarm Management (API 1167)*
 - *API 1168 Control Room Management (API 1168)*
 - *49 CFR 195*

Section 1: Culture

This section focuses on the safety culture of an operator and some of the notable aspects that should enable it to achieve a better rupture detection and response performance. An operator should consider integration of the following concepts in the monitoring and shutting down of pipelines:

- Centralization and functioning of the control center as being in charge during the early phases of a rupture event (rupture recognition and response via line shutdown, isolation, and notification or direction of field first responders.)
- Empowerment of the controller to promptly shut down a pipeline system when a rupture is suspected, either by the monitoring of the SCADA information or by a rupture alarm annunciation (e.g., a culture of "Shutdown Authority – When in doubt, shut down," or "Think rupture first, shut down, and then assess") without any repercussions or negative ramifications. Like leak alarms, a rupture alarm should be presumed valid until there is proof that it is not valid.
- Formal and well-structured pipeline restart authorization process after a rupture-related shutdown.
- An operating philosophy where anyone can call for a shutdown, e.g., every controller in the room can call for a shutdown.

An operator should also consider integration of the following activities and programs to be conducted outside of the actual monitoring and shutting down of a pipeline:

- Develop and maintain a consistent process for conducting operational incident investigations and tracking corrective actions.
- Foster a culture of encouraging and recognizing a controller for reporting operational close calls or near misses.
- Incorporate lessons learned from historic rupture events into operator programs, procedures, and training.
- Ensure that other areas within the organization (e.g., field operations, maintenance, scheduling, etc.) are aware of these cultural initiatives and that they integrate their functional activities with the control center, particularly during actual or suspected rupture events.

Rupture Recognition and Response Procedures and Policies

An operator should articulate a safety culture through simple and easily understood procedures and policies. At a minimum, appropriate procedures and policies should cover the following:

- Authority for the controllers to respond to rupture indications by shutting down and isolating the pipelines under their control without requiring additional approval or authorization.
- Restart approval procedures with different levels of management or supervisory escalation authorizations.
- Communication, information exchange protocols, and responsibilities among the different roles within the Control Center (e.g., controller, supervisor, leak detection analyst, operation engineer, management, etc.) as well as other support groups (e.g., field operations, pipeline integrity, etc.) involved in the response.

Section 2: Training

Rupture specific training for both rupture recognition and response is highly recommended to ensure effective execution. This section focuses on training for each of these unique activities. Training begins with understanding emergency response procedures, recognizing a rupture, then knowing how to promptly shut down the pipeline, isolate the line segment, and understand the operator's communication protocol for ruptures. Training is defined for each member of the response team. The typical response team includes the controller; the controller's supervisor; a leak detection analyst; and some representatives from several levels of management within the operations control center, field operations, field supervision, asset integrity, and other support groups involved in rupture recognition, analysis, and response. Steps in the response process include the following:

- A shutdown and isolation of the pipeline
- Investigation
- Integrity verification
- A return-to-service protocol

The operator's Emergency Response Protocol or other appropriate response procedures should outline the process. Operators should develop a training program that considers the following concepts, topics, and methods.

Concepts

An operator should consider the following concepts for its training program:

- Ensure rupture detection focuses on simplicity, as ruptures are not subtle events.
- Train for prompt response.
- Provide training on the following:
 - Hydraulics
 - Equipment fail safe alarms
 - Analog high/low limits
 - Alarm limits justifications
 - Maximum Operating Pressure (MOP)
 - Vapor pressure of the fluid flowing
 - Elevation profile (highs/lows)
 - Start-up/shutdown sequencing per segment on the line
 - Low suction or high discharge pressures
 - How to avoid slack line operations where possible
 - How to manage normal slack line operations
 - Potential masking of physical production losses due to rapid vaporization of highly volatile liquids (HVLs).
 - Slack line or column separation and operational risk associated with this condition.
- Test for compliance, such that the controller performs as required.
- Implement a training policy. Prior to a controller operating alone on a console, consider having the controller physically tour a representative field location, observe representative equipment and pipeline right-of-way, and understand

High Consequence Areas (HCAs) in order to improve understanding of the physical pipeline systems that are represented on the SCADA console.

- Recognize and prevent desensitization, using the following methods:
 - Train to always respond to the specific rupture indication without exceptions.
 - Provide periodic re-enforcement training for experienced controllers.
 - Focus on following protocol for alarming, taking the safest route.
 - Emphasize "When in doubt, shut it down".
 - Make it a priority that to restart a pipeline following a rupture alarm, the Response Team must prove the alarm was not the result of a rupture.
- Use past incidents, both real and false through look-back and investigations, and capture lessons learned for training, drills, and protocol changes per *CRM* and *API 1168*.
- Ensure controller clearly understands the alarms and events in the summary register.
- Train controllers and field personnel on the investigation and communication protocols/templates/tools.
- Train support personnel on the investigation and verification protocols/templates/tools.
- Train management on the communication protocols/templates/tools.
- Provide training on roles and responsibilities to include the following:
 - Drill on rupture response.
 - Teach field responders to recognize the control center as the undisputed lead in the early phases of a rupture event.
 - Follow return-to-service protocols and checklists.
- Retrain at a predetermined frequency and/or as experiences dictate.

Topics

Rupture Indication Recognition

For a specific rupture indication, controllers should review the operator's Alarm Response Table.

Rupture Indication Response

A rupture indication response includes the following actions:

- Shut down and isolate the ruptured line segment.
- Notify control center management and field management.
- Obtain stakeholder and management approvals before controller restarts pipeline.

Methods

Procedure Review

Operators should conduct one-on-one procedure reviews with stakeholders, inclusive of testing and verification of understanding of procedures and policies related to each individual's role.

Interactive Simulations

If available, operators should use computer-based simulations. Operators should validate the simulator is accurate for ruptures. The more sophisticated a simulator is, and the more available it is to the controller, the better. Operators may consider simulating a sampling of representative lines.

Playback Simulations

SCADA playback shows past alarms and behavior during a rupture event. Showing the alarms that occurred and the sequence of the alarms in conjunction with the actual rupture will help the controllers learn to recognize and respond to alarms appropriately.

Table Top Drills

Table top drills present a scenario and allow trainees to perform a response to the scenario by using associated documentation and/or procedures.

Live Simulations

For SCADA point analysis, live simulations are primarily accomplished through SCADA data manipulation. Physically removing large quantities of product from the pipeline rapidly may pose safety and logistical challenges. However, physical removal is a definitive method to test people, technology, processes, and procedures. Modifying the pressures or flows or other values used by alarming logic and manually overriding them in production to induce an alarm achieves the same goals with greatly reduced risks. The live simulation for a very large leak by data manipulation typically does not require a great deal of precision; the simulation just needs to stand out. These simulations may be announced to the controller or unannounced. Announced drills typically focus on the alarm systems and rupture response. Unannounced drills can be an effective means to assess controller rupture recognition and response skills.

Team Training

Operators should conduct training as an integrated team exercise that includes all pertinent levels of authority as may be defined in a response procedure. The parties involved may include the control center staff, control center support staff, field operations, and external emergency support response personnel. The intent is to train, evaluate, and improve response as an integrated team.

Appendix A contains examples of drill documentation and return-to-service checklists.

Section 3: Rupture Recognition

This section focuses on techniques that operators could use to recognize ruptures with a very high degree of confidence, and could form the basis for development and implementation of a rupture detection system. These techniques should provide an indication that only reacts to ruptures and not to operational events or instrument malfunctions, thereby increasing operator confidence in initiating rupture response activities.

Two broad rupture detection areas were identified, **SCADA point analysis** and Computational Pipeline Monitoring (**CPM**), are described below. The areas are not mutually exclusive and could potentially be combined in a hybrid rupture recognition system.

SCADA point analysis involves examining individual telemetered signals using minimal basic SCADA capable calculations. To achieve the requisite high confidence, operators must apply interdependent rules of logic. For instance, operators should require multiple independent SCADA points to display a pattern of joint behavior.

CPM systems also rely on telemetered signals, but they use more extensive calculations to combine telemetered signals into a single metric that indicates a release. Most CPM systems rely on the conservation of mass principle, and they are designed to identify releases within detectable limits as determined by unique pipeline physical characteristics, product type and flow conditions, instrumentation, SCADA hardware, software, applications, and operator proficiency.

In current leak detection practice, both SCADA point analysis and CPM, can be subject to false alarms at a rate greater than what is desired in a rupture detection system. The subsections **SCADA Point Analysis Based Rupture Detection**, **CPM based Rupture Detection**, and **Validating and Corroborating Rupture Alarms** below offer several means that could improve this performance.

Validating and Corroborating Rupture Alarms includes a section that discusses the problems associated with slack line flow. Slack line flow occurs when the pressure in a pipeline falls below the vapor pressure of the product and results in a void filled with very low density hydrocarbon vapor. When these voids refill, the effect very closely mimics the behavior of a leak to both SCADA point analysis systems and CPM systems. A review of some of the high profile examples of ruptures indicates that slack line or the suspicion of slack line has often been a contributing factor to delayed recognition of the rupture event.

Validating and Corroborating Rupture Alarms also includes a brief section on rupture detection in shut in pipelines. The section addresses considerations of using the described techniques in shut in pipelines and particularly observable evidence of shut in pipelines to the SCADA measurements.

Regardless of the technique, this document recommends that the operator consider utilization of a specific rupture detection indication to alert the controller (verify consistency with *API 1167*). With a well-managed system, the rupture indication may alert as the highest priority, but this designation would be based on an operator's alarm philosophy. If the operator has not rationalized and/or managed the alarm system, a new priority may be required for the rupture indication. (See *API 1167*.)

SCADA Point Analysis Based Rupture Detection

SCADA point analysis based leak detection systems use simple algorithms comparing an analog signal to a high or low absolute limit, to a high or low Rate of Change (ROC) limit, or by monitoring for a specific state of a discrete indicator. These simple systems can have a high rate of false positive alarms even if the alarm thresholds are set at levels to detect only ruptures and not smaller releases. The goal of minimizing false rupture detection alarms to an acceptable level may be gained by requiring several individual point alarms that indicate a pattern that is only indicative of a rupture. Since the individual alarms will not occur simultaneously, operators will need to incorporate a "time to clear" for each individual point. In this case, once an alarm occurs, it is latched on for a preconfigured time. If during this time the other independent point alarms also occur, the rupture alarm is generated. Discussions of point-based alarm combinations should include that one of these alarms could be the discrete state of a CPM leak alarm. (Note that instrumentation failures can similarly impact point analysis rupture detection functionality and accuracy.)

The industry has used many examples of point-based alarming that would indicate a rupture. Some of these examples apply fairly generally to pipelines while others might be specific to a particular pipeline or operation. This document does not exhaustively identify all combinations that would be applicable for rupture alarm purposes, but it focuses on the most common pipeline segment configurations that could benefit from rupture detection applications. Operators are encouraged to employ and expand these examples to take maximum advantage of their own circumstances.

Appendix B includes examples of SCADA point based alarms. The main advantages of these techniques are decreased latency from a CPM solution and that if several points are used in logical combination, it is unlikely that an instrument failure will generate a false alarm. Limitations are that pressures and flows can change abruptly by large amounts because of normal operations of liquid pipelines. The logical component of combining multiple SCADA points to detect a pattern is key to avoiding false alarms. A system using three SCADA points demonstrates another limitation. This system will have three individual excursion limits and three times to clear durations that must be set appropriately to avoid false alarms and to identify ruptures. This system will require effort to properly set the parameters to achieve the rupture detection goals without generating false positive alarms.

CPM Based Rupture Detection

CPM based systems use more sophisticated algorithms and typically rely on more measurements than SCADA point analysis. CPM systems typically compute a single leak metric from the inputs. Therefore, independence of the measurements is lost

making them theoretically more susceptible to false alarms than SCADA point analysis systems. However, the hazardous liquid pipeline industry has a wealth of experience using CPM systems for leak detection, including addressing the issue of false alarms. Some in the industry think that this experience could be leveraged to employ CPM systems for rupture detection. All of the techniques for reducing false alarms in CPM leak detection systems would be applicable to a rupture detection system based on CPM. These techniques include the following:

- Using less sensitive thresholds. This obvious technique is effective to a point, but it cannot usually address issues such as instrument failure. When instrumentation failures are known they can be passed to the model to be handled but this technique will further reduce the sensitivity.
- Using dynamic sensitivity to lower the sensitivity of the system for more and longer periods following the trigger events that are known to compromise CPM system performance. This technique also will not address major errors in the measurements used as CPM inputs.
- Enhancing maintenance. CPM systems are inherently dependent on reliable inputs. Operators need programs to ensure that highly reliable devices provide the inputs and to ensure that the personnel responsible for maintaining the devices are trained in the criticality of the devices. Both will significantly reduce errors.
- Using longer time windows to verify a sustained line imbalance as a rupture event.

A technique that operators could employ in a rupture detection system that is not appropriate for a leak detection system would require that both the CPM system flow imbalance, based solely on the flow measurements, and the CPM system linepack imbalance, based primarily on the pressure measurements, register imbalances for the system to declare a rupture alarm. This technique takes advantage of the fact that ruptures, as defined in this document, cause large and distinct changes to the system operation that should be evident in both the measured pressures and flows.

CPM software should require minimum modifications to be used as a rupture detection system. Most changes would be to the configuration of the system, particularly to the parameters that govern the threshold sensitivity. To use a CPM system simultaneously as a rupture detection system and to detect smaller leaks, the CPM system would require a modification to issue a rupture alarm that is distinct from the leak alarm if a different controller action was required between the two types of alarms.

Appendix C discusses additional considerations for conventional and unconventional measurements for rupture detection.

Validating and Corroborating Rupture Alarms

A rupture alarm as defined in this document is intended to be a highly reliable alarm with a very low rate of false positives. For this reason, operators are expected to define a robust response to the alarm, but this document does not mandate an unconditional shutdown of a pipeline upon receipt of the alarm. Each operator is expected to establish its own procedures for responding to a rupture alarm, with consideration for risk to safety or to connecting facilities and the requirement that a rupture alarm must be integrated with each particular control center's alarm philosophy. If an operator decides that a rupture alarm requires a mandatory shutdown of the pipeline, this section would more appropriately be considered a response. If a mandatory shutdown is not a requirement, then validating and corroborating the alarm is part of the recognition process.

Trends

Trends are a powerful method for validating and corroborating rupture alarms. Operators should consider providing trends specific to the rupture alarm method being used as explained in the following examples:

- If a SCADA point based system uses a combination of several individual points, a single trend could provide trends of these measurements.
 - The trend could display the alarm limits, and/or the trend could visually indicate when the points are individually in alarm.
 - If alarm suppression is used, the trend could visually indicate the period when the alarm is suppressed.
- For CPM based rupture detection systems, operators should consider providing trends of analog inputs. In addition, trends could display calculated values from the procedure, including the compensated imbalance, the flow imbalance, and the line pack imbalance.

Slack Lines

A particularly problematic and common condition for accurate leak and, by extension, rupture detection occurs when refilling slack lines. Slack lines are more common in shut in lines, but they also occur in operating pipelines. The difficulty occurs when the slack volume is refilled, which typically occurs after starting the line or some other operating change. During this time, the line is expected to incur a measurement imbalance while the line is being refilled or repacked, as it would in a

leak event. In the past, the suspicion that a slack was being refilled led to decisions to continue operating lines that actually were leaking.

A possible means of mitigating this risk is to provide a quantitative estimate of the amount of slack in a pipeline. This estimate is not a simple determination and can be especially complicated in lines that operate in sections with multiple receipt and/or delivery locations. For the case of shutdown lines, operators can determine such an estimate from an over/short calculated over an interval starting when the pipeline was operating in a balanced and full condition before the shutdown and extending until before the start-up. Operators should include any drainage occurring because of preparing the line for restart in this estimate. For lines that operate with slack, the measured pressure and knowledge of the elevation profile can provide an estimate of the slack. If an operator employs a Real Time Transient Model (RTTM)-based CPM system, it may provide an estimate of the amount of slack in the line.

An over/short conducted over a time period starting from a known full condition is more accurate, and should be preferred over computations based solely on pressure and elevation. In any case, an operator can estimate the uncertainty from engineering analysis and/or historical operating data. The operator could provide the slack estimate adjusted by the uncertainty to the controller as a specific target beyond which rupture or leak alarms cannot be attributed to slack. Basically, the controller should be aware of a maximum permissible allowed shortage volume specific to the applicable line segment and that a slack line condition exists. Controllers should promptly investigate and respond to continued slack line indications beyond the maximum permissible repack time as a potential rupture event.

The sensitivity of a rupture detection system when slack is present can vary dramatically with the location of the rupture relative to the elevation features, the pressure measurements, and with the operation of the pipeline. This sensitivity is true for both SCADA point analysis and CPM based systems. Two possible mitigations are available. The first and preferred method is to prevent slack by maintaining sufficient back pressure. This method may not always be feasible for a variety of reasons. An example is where holding enough pressure at the high elevation point would exceed the MOP of the pipe at the low elevation point. Another example could involve a temperature reduction when the flowing line is brought to idle status. In cases where an operator cannot keep a line full, additional measurement locations can reduce the uncertainty of the amount of slack. This method improves both the size of event that can be detected and the time required to detect it.

Shut In Pipelines

Ruptures in shut in pipelines are usually quite apparent by the rapid depressurization of the line. Two key factors in detecting ruptures in a shut in pipeline are whether an operator can shut in a specific line segment with pressure above the product's vapor pressure and whether an operator can sustain this trapped pressure through the duration of the shut in condition. Even small releases of fluid from a shut in system cause large pressure declines, and declines are readily apparent because of the expectation of stable pressure. Both SCADA point analysis systems and CPM systems that include line pack compensation can sense this effect. The sensitivity of either system in this case is usually quite high. Hazardous liquid pipelines depressurize because of cooling after shutdown and come to equilibrium point where slack conditions may form at various peak elevation points. After this equilibrium point occurs, further pressure decline depends on the elevation of the fluid/vapor interface moving downhill as the pipeline drains. At this point, small leak detection is much harder to identify, but rupture detection may still be possible. These effects depend mainly on the elevation profile of the pipeline, and pipelines are very unique in this regard. Operators could estimate the expected sensitivity of a rupture detection system for shut in conditions. Operators would need to make this estimation for each line versus generalizing across a pipeline system. Slack that forms because of cooling in a shut in pipeline is not normally a large volume. When the line restarts, the slack region should refill very quickly, and the line should attain a balanced operation. Failure to do so could indicate a problem.

A second consideration particular to shut in pipelines is the observable evidence of the pipeline to the measurements. In many pipelines, measurements are only available at the terminals and booster stations. Block valves, check valves, and elevation features can render sections of the pipeline invisible to the available measurements. In these cases, leaks could occur and drain sections of the line without causing any effect at a measurement. Again, engineering analysis can determine the extent to which this effect is an issue for a particular pipeline, but no generalizations are possible from one pipeline to another.

As an example, consider the hypothetical pipeline shown in **Figure 1**. The pipeline descends over its 94-mile route from 7,400 feet to 4,250 feet. A pressure control station is located at Milepost 56 to prevent slack line conditions. Pressure measurements occur at the origin, on either side of the pressure control station, and at the terminus. When the pipeline is shut in, a leak or even a rupture located between the peak elevation and the check valve at Milepost 44 would not cause any observable effect at any measurement.

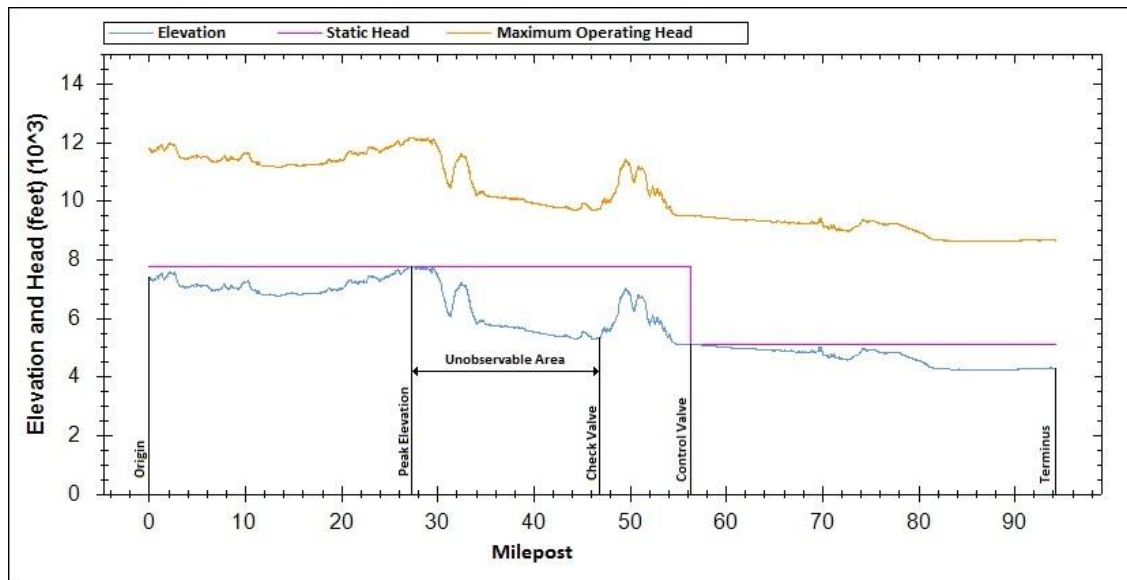
Figure 1: Example of Shut In Line Leak Detection

Figure 1 shows an additional and perhaps more common problem with rupture detection in shut in lines. The peak elevation occurs at a fairly level plateau that extends for over two miles along the pipeline route. When the line is shut in, little to no pressure is in this section. If third-party damage or a pipeline breach occurred in this area while the line was shut in, neither would immediately indicate a rupture as there would not be a recognized drop in pressure or inlet versus outlet flow imbalance. Neither a high flow rate release nor a significant effect in any measurement would occur even if pressure measurements were available at the check valve. A rupture condition would more likely be indicated upon restart of the line, due to a combination of lack of re-pressure within an acceptable time or an imbalance of inlet versus outlet flow rates. Since leak detection, even rupture detection, is more difficult during transient operations, this scenario poses a challenge for integrity monitoring systems.

Many of the problems with detecting ruptures in shut in lines could be addressed by maintaining pressure on them well above where any part of the line is slack. Historically, pipelines have not been designed with this consideration in mind, and operators should carefully consider deliberately pumping into a shut in line for purposes of trapping pressure before incorporating the practice as a new procedure. Because of the dramatic effect even slight cooling has on line pressure and the length of time it takes a pipeline to reach thermal equilibrium, a pipeline would need frequent re-pressuring for the duration of the time it was shut down for this process to be effective.

Implementation and Testing

The crucial attribute of the rupture alarm is reliability. Reliability can only be obtained with a very low false alarm rate. To achieve this reliability, the recommendation is to deploy rupture detection systems with very conservative settings. As operational data is gathered over time, operators may tune parameters to values that will detect ruptures to the potential of the techniques employed in conjunction with the required low false-alarm rates. Again, the intention of rupture detection is to be prompt versus instantaneous and to maintain a very high confidence level that a rupture detection alarm is truly indicative of a pipeline-rupture event. This confidence sustains consistent operator response to a rupture indication.

In a related vein, operators should use sound engineering judgment about extrapolating test results from one pipeline to another, even if they use the same software and if measurement, instrumentation, and schematic configurations are similar. This extrapolation might be acceptable for simpler algorithms and/or similar pipelines. With more complex algorithms, the results an operator obtains for one pipeline system may not be indicative of the results that it would obtain for the same software applied to a different pipeline.

Testing, by simulating a pipeline rupture or actually withdrawing product similar to a pipeline rupture, is a recommended method of assessing the reliability of the rupture detection algorithms. In many cases, operators should consider testing by manipulating SCADA data, bypassing meters, or simulation as a safer or more controllable testing method. The objective should be to provide as realistic a test as is possible without compromising safety.

Section 4: Rupture Response

The prerequisite for this section is that the controller has been specifically trained on rupture recognition. Rupture response is defined for each member of the Response Team. The team may include the controller, the controller's supervisor and control center management, leak detection analyst, field operations and supervision, asset integrity, and other support groups. Steps in the response process should include the following:

- An immediate shutdown and isolation of the pipeline
- Communication
- Investigation

- Verification
- A return-to-service protocol

Role of the Controller

A controller requires training on how to recognize ruptures and on controller response protocol (know to whom to communicate) for ruptures.

An operator should consider the following for a controller's role:

1. Upon receipt of a rupture alarm or indication of a rupture condition – shuts down pipeline segment
2. Isolates the affected line segment where the rupture is believed to have occurred, either remotely or via direction to field responders (de-energize, and then sectionalize the line—close all valves around the suspected location as well as upstream and downstream.)
3. Notifies designated field management and control center management via company emergency response procedures
4. Notifies local emergency responders, such as calling 911 and fire and sheriff departments, in accordance with company emergency response procedures
5. Restart pipeline only after receiving integrity verification and appropriate stakeholder and management approval.

Example – Controller Receives a Rupture Indication

Action: Controller shutdown is based on operator's technique and training to recognize a rupture event.

Policy: Company personnel prove that a rupture did not occur. Controller must obtain appropriate approvals from field, control center, and other related management before start-up and resumption of normal operations. (See Return-to-Service protocols.) The control center is the hub of communication with a no-exception policy regarding shutdown-issued (emergency response) directives.

Procedures: The on-duty controller implements company emergency response plans, and a designated individual or group investigates the event. They adhere to the following procedures:

- Emergency Response Procedures to reflect rupture response, roles and responsibilities, a communication plan, key stakeholder alignment protocol, and control center metrics
- Company training programs to reflect a rupture detection and response simulations curriculum and thorough look-back/investigations to capture lessons learned from past incidents both real and false per *API 1168* and *CRM*

Role of the Control Center Support Personnel

Control Center support personnel include console supervisors and leak detection analysts. These individuals require training on how to recognize ruptures and on response protocol (know to whom to communicate) for ruptures.

An operator should train the control center support personnel to perform the following actions if a rupture alarm occurs:

1. Investigate
2. Prove the rupture alarm is not a rupture before resumption of operations.
3. Understand that someone other than the controller (lead controller/shift supervisor) investigates and communicates with company-designated responders.

Role of the Field Operator

An operator should consider the following:

1. Require training on the field operator response protocol for ruptures.
2. Training may include locating and closing manual mainline valves in response to the rupture.

Control Center Return-to-Service Protocol

An operator's return-to-service protocol may include the following directions to control center staff:

1. Investigate
2. Prove the rupture alarm is not a rupture before starting up

3. Require controller(s)/shift supervisor to investigate and communicate findings with company-designated responders/subject matter experts (SMEs) and to solicit advice. Items to consider include the following:
 - A review of upper and lower control limit trends of the alarm/event
 - A review of alarm, event, and communication summaries
 - A review of SCADA measurement, instrumentation, trend/profile, and equipment details; these parameters may include the following:
 - Line pressure trends
 - Flow trends
 - Maximum operating pressure (MOP)/maximum allowable operating pressure (MAOP) violations
 - Low suction or high discharge pressure violations
 - Alarms for multiple and/or all Computational Pipeline Monitoring (CPM) or SCADA periods
 - Unintended valve closures and uninitiated equipment status
 - A rate of change (ROC) alarm (without a corresponding control input)
 - An increasing, prolonged slack condition
 - Hydraulic profile
4. Verify that the following field-based activities were conducted:
 - Walked or flew the line
 - Verified status of all pertinent valves
 - Investigated all pertinent valleys, peaks, and places near rivers/streams
 - Investigated abnormal conditions
 - Verified line integrity through visual and pressure gauge observations
 - Identified root-cause to satisfaction

- Assessed asset integrity via hydraulics, pipeline integrity technicians, and other integral SMEs
5. Verify (either through emailed communication or documented checklist) that the incident has been repaired, if warranted, and has been assessed and approved for start-up.
 6. For false rupture detection events, analyze and document why false indication occurred.
 7. Require approval by appropriate management (i.e., field management plus control center management) after review with key stakeholders.
 8. Un-latch applicable rupture signature event (management reviews Lockout before start-up.)
 9. Start-up of pipeline by controller.

Field Team Return-to-Service Protocol

An operator's return-to-service protocol for the field team should consider the following:

1. Investigate and communicate with company-designated responders back in the control center.
2. Validate line integrity including, but not limited to, the following:
 - Walk or fly the line.
 - Verify the status of all valves.
 - Verify line pressures are consistent with normal operation.
 - Verify all telemetered equipment back to SCADA.
 - Investigate all valleys, peaks, places near rivers/streams, and any other high consequence areas (HCAs).
 - Verify all work on the related line.
 - Verify line holds pressure during block-in.
3. Investigate abnormal conditions, verify all integrity, and identify root-cause before start-up. Field engineers, corrosion technicians, pipeline integrity technicians, and other field SMEs assess asset integrity.

4. Verify and document (either through emailed communication or properly executed checklist) that the incident has been repaired and has integrity for start-up.
5. Communicate to the control center; restart requires approval by appropriate management (i.e., field management plus control center management) after review with key stakeholders.

Process – Interaction between Controllers, Field and Others

An operator's process to guide interaction between controllers, field representatives, and others should consider the following:

1. Define interaction, typically in rupture detection procedures and emergency response procedures.
2. Adopt emergency communication plan with the appropriate level of stakeholder involvement.
3. Adopt an active management support, from appropriate leadership to the field team, for the controller when the controller has shut down the line because of a rupture indication that ends up being false, and positively recognize the controller for use of shutdown authority.
4. Adopt a company policy that requires appropriate management approval for restart. The restart procedure, which identifies verification, investigation, communication, and return to operation in a basic template, may consider the following:
 - Verification of the cause of the alarm documented (incident or not). The operator should follow *API 1130* guidelines to classify the cause as one of the following:
 - Data failure
 - Irregular operating condition
 - Possible commodity release
 - Root-cause analysis/investigation results and sign-off as complete
 - Verification that pipeline has been repaired

- Confirmation that asset integrity has been verified by both control center SMEs and field SMEs
- Line integrity verification that may include the following:
 - Visually observe the right-of-way by ground or aerial patrol.
 - Verify the status of all pertinent valves.
 - Verify that line pressures are consistent with normal operation.
 - Verify accuracy and functionality of all telemetered SCADA signals.
 - Investigate all pertinent valleys, peaks, places near rivers/streams, and any other HCAs.
 - Verify completion of and/or status of all work on the related line.
 - Verify that the line segment holds pressure during block-in.
- Communicate between multiple parties before resuming normal operations, including verbal and written methods to all appropriate personnel (e.g., control center management, field management, and key stakeholders) as required by the company policy for its "Return to Service."

Rupture Response – Measuring Improvement

To assess response performance, the operator may consider the following:

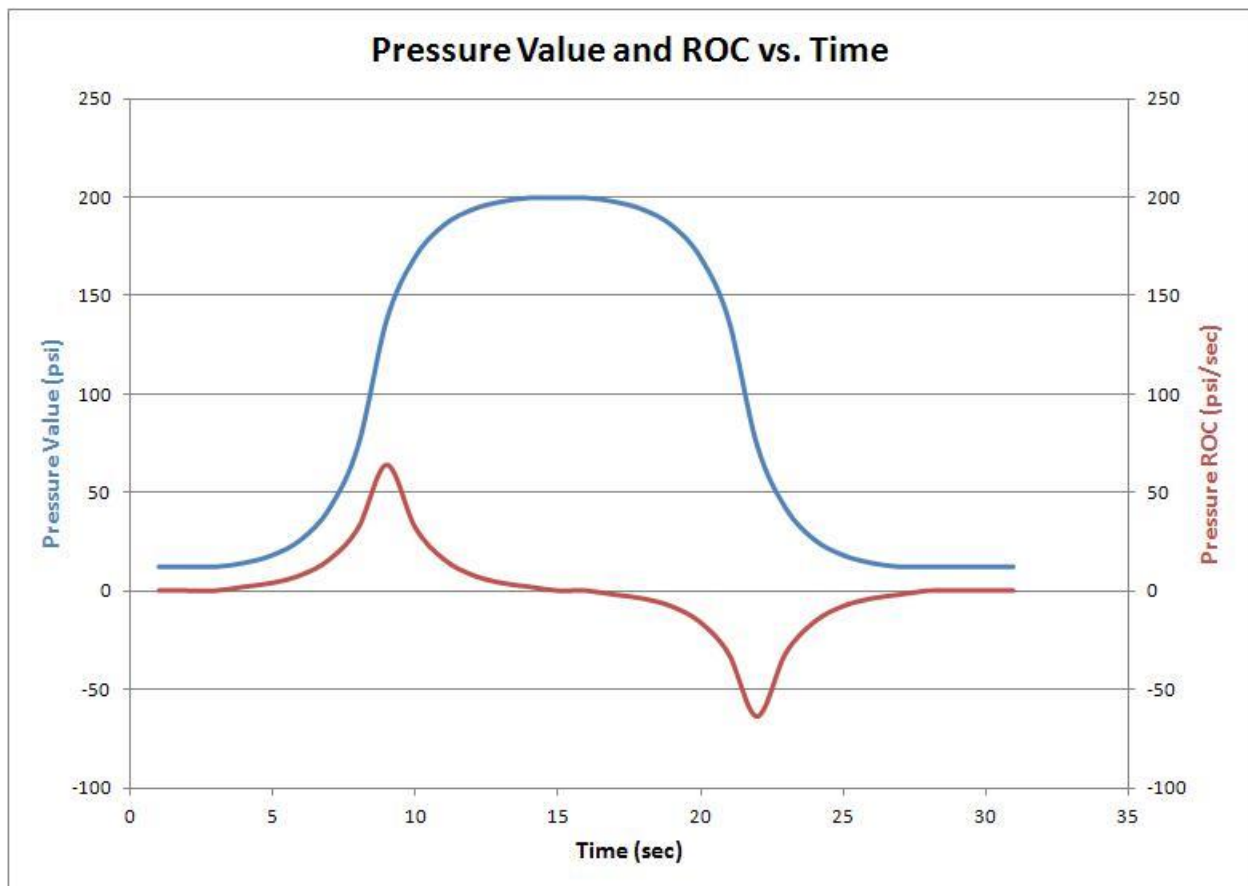
- Measure control center metrics (e.g., number of shutdowns, number of positive shutdowns, accumulated response time) that are reviewed and communicated through a monthly/quarterly correspondence.
- Measure improvements through simulations curriculum.
- Measure improvements through past incidents both real and false through look-back investigations, and capture lessons learned for training, drills, and protocol changes.
- Measure of ruptures that do not result in a distinct rupture indication

Definitions

Computational Pipeline Monitoring (CPM): An algorithmic monitoring tool that alerts the controller to respond to a detectable pipeline-hydraulic anomaly (perhaps while the pipeline is either operating or shut in) that may be indicative of a commodity release. (See *API 1130* as referenced in *Code of Federal Regulation (CFR) 49 195.134* and *195.444* for further information.)

Rate of Change (ROC): A calculated value that reflects the change in an analog-data value per unit of time. When a pressure, flow, or other analog point changes rapidly, many SCADA systems provide a ROC-alarm feature for those points. ROC is how quickly a value either increases or decreases over time. If a pressure value drops 30 percent of its value every six seconds, the controller may wish to be notified of that ROC. The sample graph in **Figure 2** below illustrates this type of change.

Figure 2: Pressure Value and ROC vs. Time



Rupture Indication: An unambiguous SCADA based signal that alerts the controller to a high volume/rate pipeline system release. The primary difference between a rupture

and a leak indication is the certitude of the alarmed condition. The goal is to increase the controller's confidence in the rupture indication to facilitate a robust and consistently-executed rupture response procedure.

Rupture: Operator defined. Pipelines are purpose built and operated to unique circumstances, and no two are precisely alike. This uniqueness precludes a fixed definition of the leak size or response time that would constitute a rupture according to this definition, and operators should evaluate their specific systems and determine an appropriate definition to meet their circumstances.

SCADA: An acronym for Supervisory Control and Data Acquisition, the technology that makes it possible to remotely telemeter, monitor, and control pipeline facilities.

Shut In: A pipeline operating condition during which a given segment of a pipeline is static, meaning in a non-flowing state, and is isolated by closure of all valves into and out of the segment. A shut in pipeline may or may not contain internal fluid pressure, depending upon fluid properties, physical line configuration, elevations, and shut in valve closure practices.

Slack Line: A pipeline operating condition during which a given segment of a pipeline is not entirely filled with product or is partially void. A segment is a discrete section of a pipeline that is bounded and defined by instrumentation, such as meters, or by physical features, such as valves.

Vapor Pressure: The pressure exerted by a vapor in thermodynamic equilibrium with its condensed liquid at a given temperature in a closed system. The equilibrium vapor pressure is an indication of a liquid's evaporation rate; it relates to the tendency of particles to escape from the liquid. A substance with a high vapor pressure at normal temperatures is often referred to as volatile.

Appendix A – Training Examples

Table 1 contains an example of documentation for a drill.

Table 1: Example of Drill Documentation

General Information		
Date: 03/05/19	Name of Person Performing Drill: George Patton	Operations Control Console: 99
Drill Type (Console/Table-Top, SCADA Simulated, Field Simulated): Table-Top		Time at Start: 06:30
		Time Complete: 07:30
Drills Type Description		
<p>Console/Table-Top: Unannounced scripted (see below) presentation of rupture scenario to Controller at console, using Drill Checklist as presentation vehicle. Process is to perform appropriate response steps, evaluate performance. (Make actual call to Qualified Investigator (QI), explaining as drill. Simulate sheriff and National Response Center (NRC) notifications.)</p> <p>SCADA Simulated: Unannounced presentation of rupture scenario to Controller using SCADA manipulation as presentation vehicle. (Make actual call to QI, explaining as drill. Simulate sheriff and NRC notifications.)</p> <p>Field Simulated: Unannounced presentation of rupture scenario to Controller using field manipulation to impact SCADA presentation. (Make actual call to QI, explaining as drill. Simulate sheriff and NRC notifications.)</p>		
Scenario		
Pipeline Segment	Scenario Description:	Controller:
9999	<p>(Example: Immediate pressure drop at Metro City from 1,000 to 100 and flow increase from 3,000/bph to 4,000/bph.)</p> <p>Line is idle from Metro City to Valhalla. All remote operated valves (ROVs) are closed on the line. The upstream and downstream pressure of milepost 14 ROV is 226 psi and 228 psi respectively. The upstream and downstream pressure of milepost 16 ROV is 253 psi and 335 psi respectively. A low pressure parameter alarm is received on milepost 16 south pressure. Within a few minutes, the pressure has dropped from 253 psi to 112 psi; a similar pressure drop is seen on the north side of milepost 14. These two ROVs are the only pressure transmitters indicating a change.</p>	John Smith
Response		
Action	Evaluation	Corrective Action Recommended
Perform emergency shutdown of all affected pipelines.	Controller did not immediately identify the #9-14" as an affected pipeline. Even after identifying the line as an affected pipeline, he indicated that he would perform a normal shutdown due to the fact he was not seeing any indication of a problem on the line.	Discussed procedure with the Controller. Explained reason why all affected pipelines are required to be emergency shutdown.
Initial call to Field Emergency Responder	Controller did not request an estimated time of arrival (ETA) for field response.	Discussed with Controller the need to verify that the Field will be able to respond within 1 hour to investigate.

Table 2 contains an example of a return-to-service checklist.

Table 2: Example of a Return-to-Service Checklist

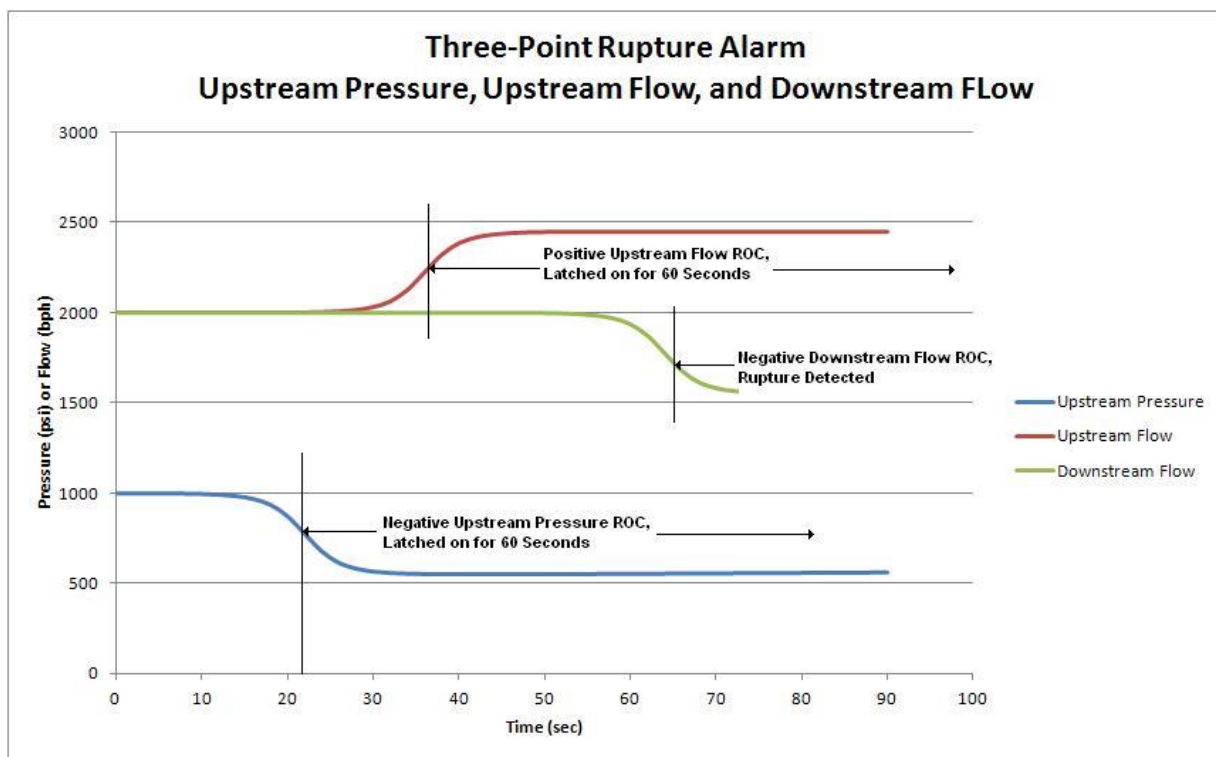
Role	Function	Approval Date	Signature
Manager of Asset Integrity	Verify data is consistent with historic-line integrity data.		
Manager of Operations Control	Ensure all parties have engaged.		
Console Supervisor	Coordinate with Field. Ensure all examinations are negative or all remediation needed to restart line is complete.		
Leak Detection Analyst	Verify SCADA indicators are functional.		

Appendix B – SCADA Point Analysis Based Examples

Example 1: Simultaneous Increased Upstream Flow, Decreased Downstream Flow, and Decreased Pressure

This combination is considered a classic pattern of measurement responses to a pipeline rupture. In this example, the upstream pressure drops, and the flow increases as the rupture effectively shortens the pipeline as the product has a reduced distance to travel to exit the pipeline segment. With a large part of the pipeline flow rate exiting through the rupture, the downstream flow rate drops. Each of these indicators and combinations of any two of these indicators may happen in response to normal operations, but all three of them occurring in a short time interval signal a rupture. **Figure 3** below illustrates the technique.

Figure 3: Three Point Rupture Alarm



Limitations: This technique is applicable to point-to-point pipelines without intermediate receipts or deliveries. If a pipeline contains intermediate booster stations, check meters may be required to utilize this technique. If any of the utilized pressures or flows is actively controlled, the pattern may not present as described.

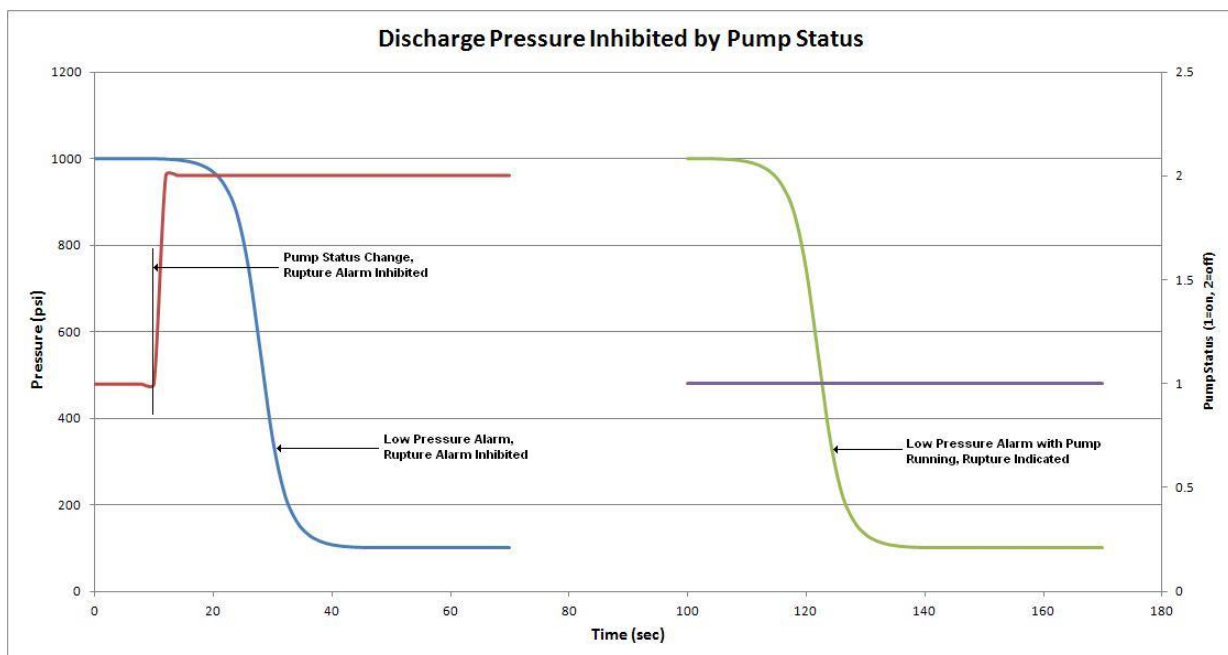
Advantages: Like all well designed SCADA point analysis techniques, a single instrument failure is very unlikely to result in a false positive alarm.

Disadvantages: Sensitivity varies with the location of the rupture. Releases occurring nearer the origin where the pressures are high are more detectable than ruptures occurring near the terminus. Operators need to set six user configurable parameters, an excursion limit, and an excursion duration for each of the inputs.

Example 2: Discharge Pressure Change without Pump Status Change

Particularly in simple point-to-point pipelines, a pressure decline or even a low pressure at the discharge of the origin pump station when the pump units are running is indicative of a rupture. **Figure 4** below indicates that pressure behavior that is normal when accompanied by a change in pump status can be considered as an indication of a rupture when it occurs with the pump running.

Figure 4: Discharge Pressure Inhibited by Pump Station



Limitations: This technique is most applicable to point-to-point pipelines without intermediate receipts or deliveries. This technique may not be applicable at intermediate booster stations. If a pipeline contains multiple pump units, the rupture alarm must be inhibited if any change in status occurs.

Advantages: The technique uses a very simple algorithm with only two user configurable parameters.

Disadvantages: Sensitivity varies with the location of the rupture. Releases occurring near the origin where the pressures are high are more detectable than ruptures occurring near the terminus.

Appendix C – Measurement Considerations for Rupture Detection

Conventional Measurements

In general, measurement considerations for rupture detection are similar to those for leak detection. To produce an alarm with very high confidence, highly reliable and repeatable inputs are required. Inputs are either correct, or the system receives an indication that they are suspect. Once the system receives indication that an input is suspect, the system can disable until the problem is resolved.

One area where some latitude may be possible in rupture detection is the accuracy of flow measurements. Leak detection systems typically require high-accuracy flow measurement. Since rupture detection is looking for high flow rate releases, operators may alternatively utilize a broad spectrum of flow measurements applications and/or technologies. Examples of technologies that operators could consider in rupture detection applications include clamp-on ultrasonic flow meters and constriction-type meters such as Venturi tubes or orifice plates.

Unconventional Measurements

SCADA systems typically receive data information from multiple field devices. Some of these may include valve status, control valve position, motor amperage, pump speed, pressures, tank level, and lower quality flow rate measurements. There may be opportunities for specific line segments to utilize existing SCADA data to detect an emergent rupture event, either in combination with or separate from a more sophisticated CPM system. Some unconventional methods for rupture detection may involve a combination of separate SCADA data points, combined with application of conditional logic functions to identify highly abnormal line segment conditions.

Examples of the utilization of unconventional measurements for rupture indication include:

- A control valve that suddenly swings to a different position without a change in valve alignment or supply pressure.
- Use of increasing or decreasing tank levels to calculate approximate volumes being delivered or received and to compare against higher quality flow calculation over a discrete period of time.
- A sudden increase or decrease in motor or engine speed, pump speed, or motor amperage without a change in valve alignment.

- Utilization of the calculated pumping capacity of a positive displacement pump to determine an approximate flow rate to compare with another flow rate from other higher (flow meter) or lower (tank or pump) quality flow calculation
- Utilization of a centrifugal pump performance curve to determine approximate flow rates. Centrifugal pump flow rates are impacted by pressure differential from suction to discharge of the pump, pump speed, specific gravity of the product, product temperature, pump mechanical condition (wear), and the accuracy of the manufacturer's pump curve. While impacted by multiple factors that can affect accuracy, a specific centrifugal pump will typically provide approximate repeatable flow rates over a period of time. Longer term, mechanical pump wear results in lower pump efficiencies and increased differences between the actual flowing and pump curve predicted flow rates. Rapid changes in the predicted flow rates could still be used as an indicator of a rupture event.

Appendix D – Team Membership

The Rupture Recognition and Response Team was formed as a sub-team of the API Cybernetics Work Group, and included:

- David Bolon - Enterprise Products Partners, L.P.
- Allen Bott – Marathon Pipe Line LLC
- Daniel Cochran – TransCanada
- Vlad Condacse – Magellan Midstream Partners, L.P.
- Robert Craig – Magellan Midstream Partners, L.P.
- Larry Davied – Magellan Midstream Partners, L.P.
- Martin Di Blasi – Enbridge Pipelines Inc.
- Steve Griffin – Colonial Pipeline Company (retired Feb 2014)
- Thomas Hebert – Chevron Pipe Line Company
- Robert Hemphill – ExxonMobil Pipeline Company
- John Hayward – Shell Pipeline Company L.P.
- Chester Hulme – Enterprise Products Partners L.P.
- Tim Jacobson – Magellan Midstream Partners, L.P.
- Gary Medley, P.E. - BP U.S. Pipelines & Logistics
- Gary Nabors – Enterprise Products Partners L.P.
- Ray Philipenko, P.Eng. – Enbridge Pipelines Inc.
- Les Reschny – Enbridge Pipelines Inc.
- Douglas Robertson - TransCanada
- Nikos Salmatanis – Chevron Pipe Line Company
- Karen Simon, P.E. – American Petroleum Institute
- James Simmons – Shell Pipeline Company L.P.
- David R Shotwell – ExxonMobil Pipeline Company
- Patrick S Smith – ExxonMobil Pipeline Company
- Ron Threlfall – Enbridge Pipelines Inc.
- Jon Van Reet, P.E. – Plains All American Pipeline, L.P.
- Gretchen Wendtland – Phillips 66 Pipeline Company
- Michael Wheeler – BP U.S. Pipelines & Logistics