PHMSA LDS Project Webinar
October 5, 2012

David Shaw – Lead Author
Martin Phillips – Project Manager

Outline

- Introduction
- The five Tasks
- Task 3 Review
- Task 4 Review
- Task 5 Review
- Task 6 Review
- Task 7 Review

- Introduction – Authors
  - David Shaw
    - LDS SME
    - 30+ years experience in oil & gas
    - Pipeline engineering and automation systems
    - Numerical simulation and modeling
  - Martin Phillips
    - Project Manager
    - 30+ years experience
    - Fitness for Service
    - ILI

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Introduction – The Focus

- Leak Detection in the industry today
- Performance
- Technology in use
- Practicalities
- Cost Benefit Analysis
- Applied to hazardous liquids, gas transmission and gas distribution

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- The Five Tasks
  - Report is based on five tasks
  - Task 3 Past Performance
  - Task 4 Technology
  - Task 5 Current Technology in use
  - Task 6 Cost/Benefits
  - Task 7 LDS Standards

Task 3 Past Performance

- As assessment of past incidents to allow PHMSA to determine if additional LDS could have reduced consequences
- The assessment was based on incident reports from January 1, 2010 to July 7, 2012 – 30 months

Task 4 Technologies

- A review of installed and currently available LDS technologies along with their benefits, drawbacks and their retrofit applicability to existing pipelines

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- Task 5 Current Technology in use

  - A study of current LDS being used by the pipeline industry

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Task 6 Cost/Benefits

- A cost benefit analysis of deploying LDS on existing and new pipelines

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Task 7 LDS Standards

- A study of existing LDS Standards to determine gaps and if additional Standards would be useful to cover LDS for the different pipeline industries

- Task 3 Review
  - Analysis method using Incident Reports
    - Filtered for all ROW releases
    - Filtered for pipe and pipe seam releases on ROW

Task 3: Incident Report Review

	Metric	Hazardous Liquids Pipelines	Natural Gas Transmission	Natural Gas Distribution	Total
	# of Incidents	766	295	276	1,337
1	**# of Ruptures**	21	41	13	75
2	**# of Leaks**	567	136	63	766
3	**# of Mechanical Punctures**	33	25	51	109
4	**# of Overfill or Overflow**	46	0	0	46
5	**# of Other Release Types**	99	93	149	341
6	**# offshore releases (not included in following numbers)**	7	56	0	63
7	**Contained on operators property**	521	95	4	620
8	**Started on operators property**	41	0	0	41
9	**Located on right-of-way (ROW)**	197	141	42	383

January 1, 2010 – July 7, 2012

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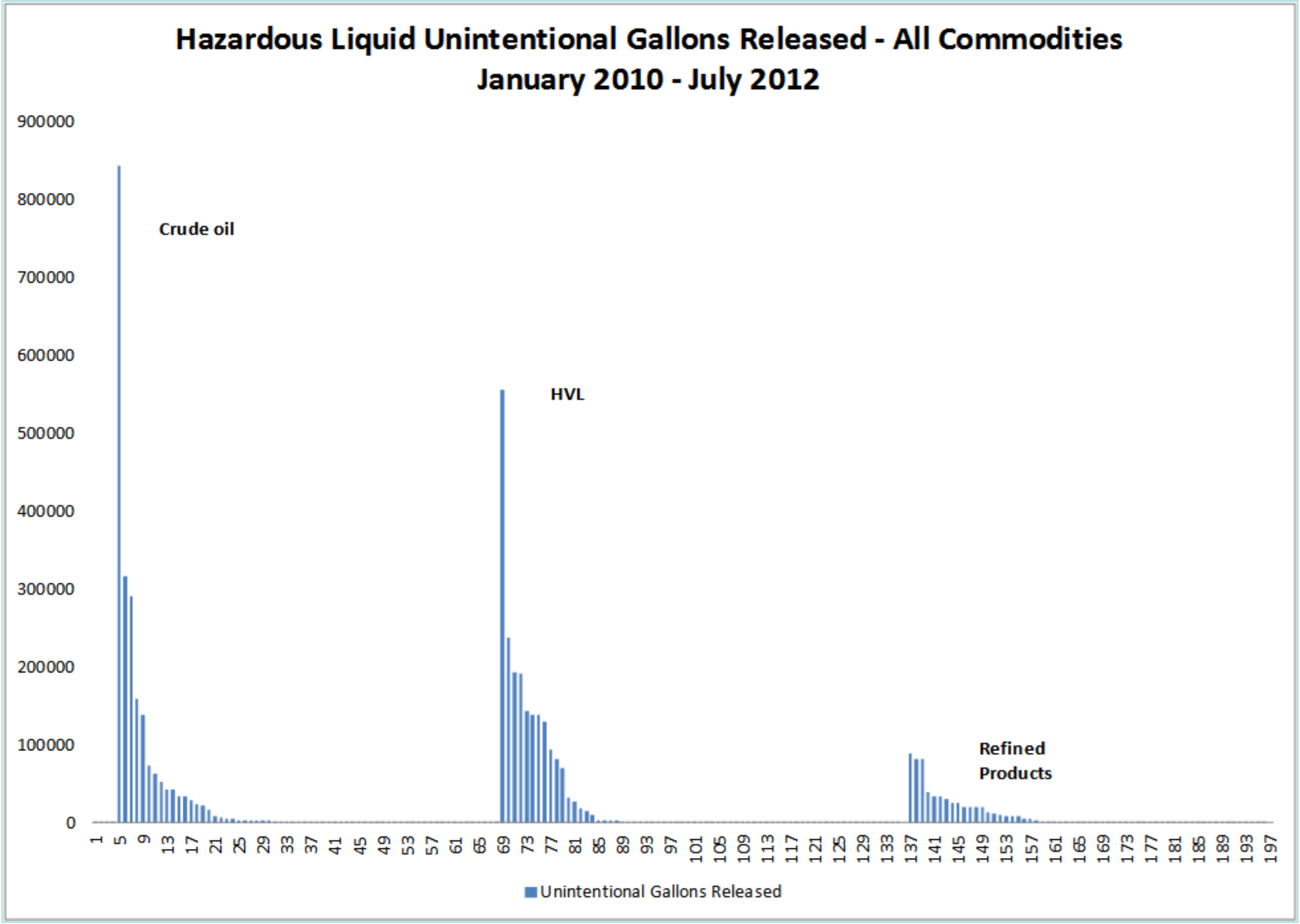
Task 3 Review - Hazardous Liquids Incidents



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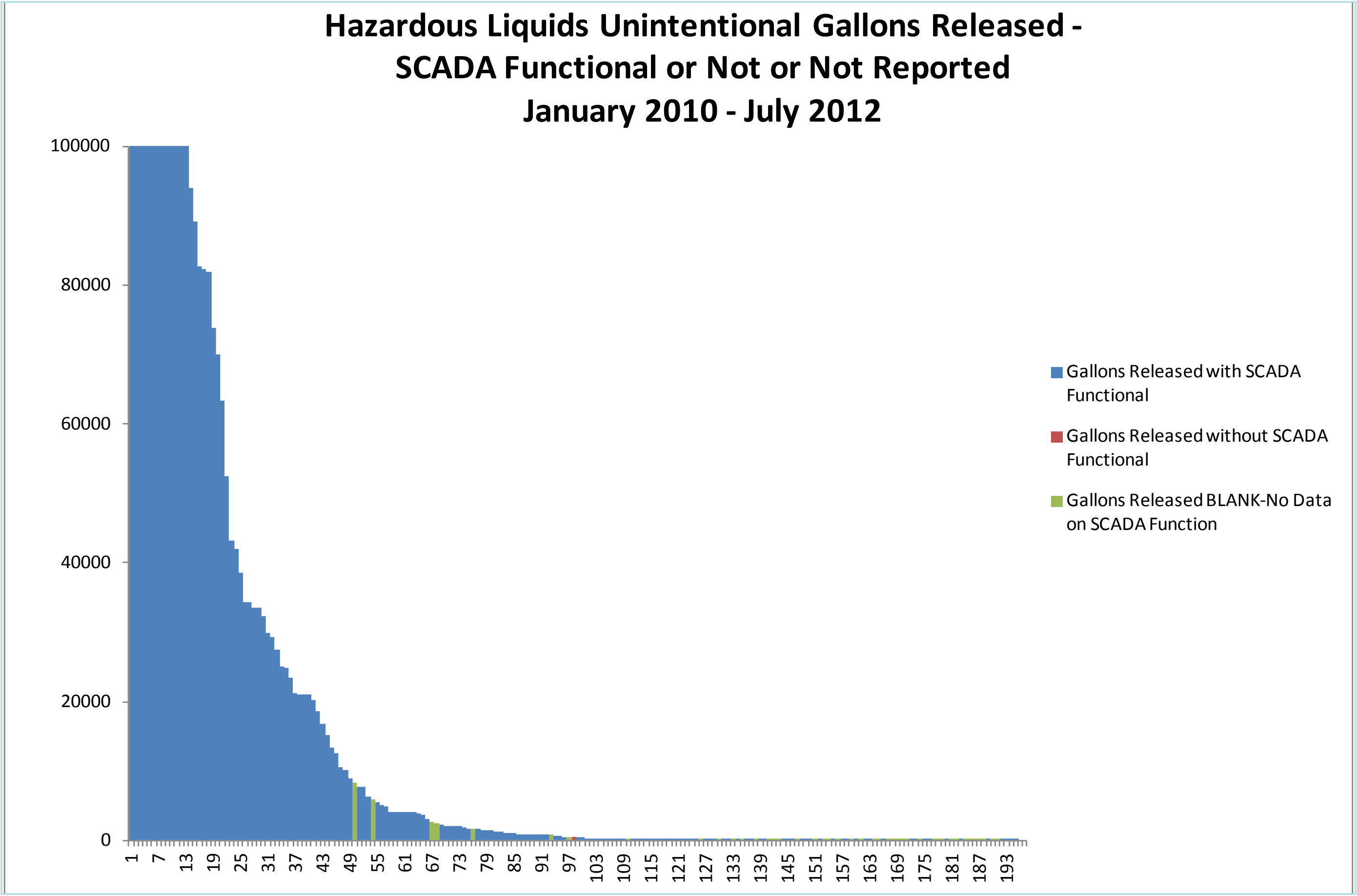
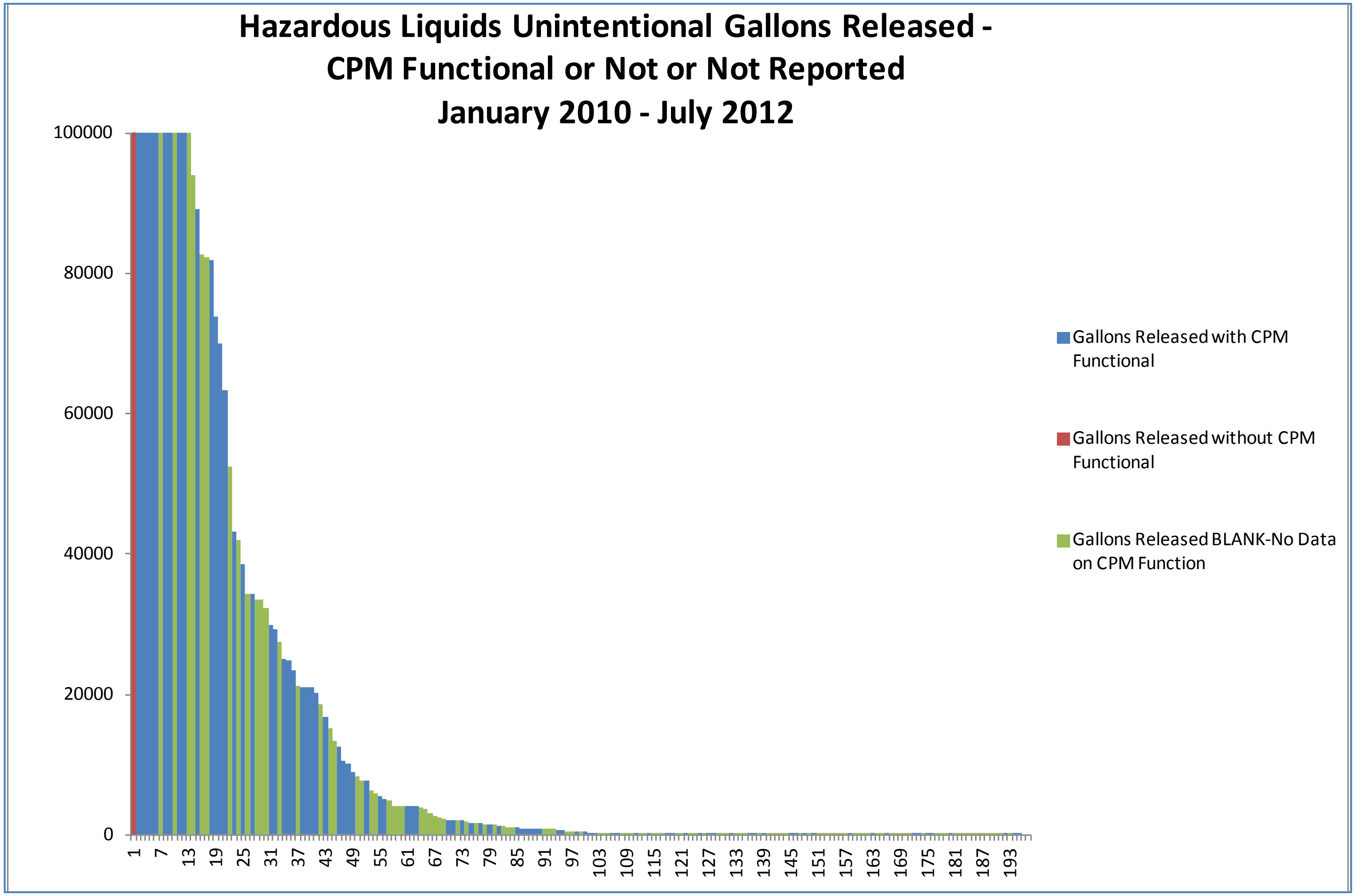
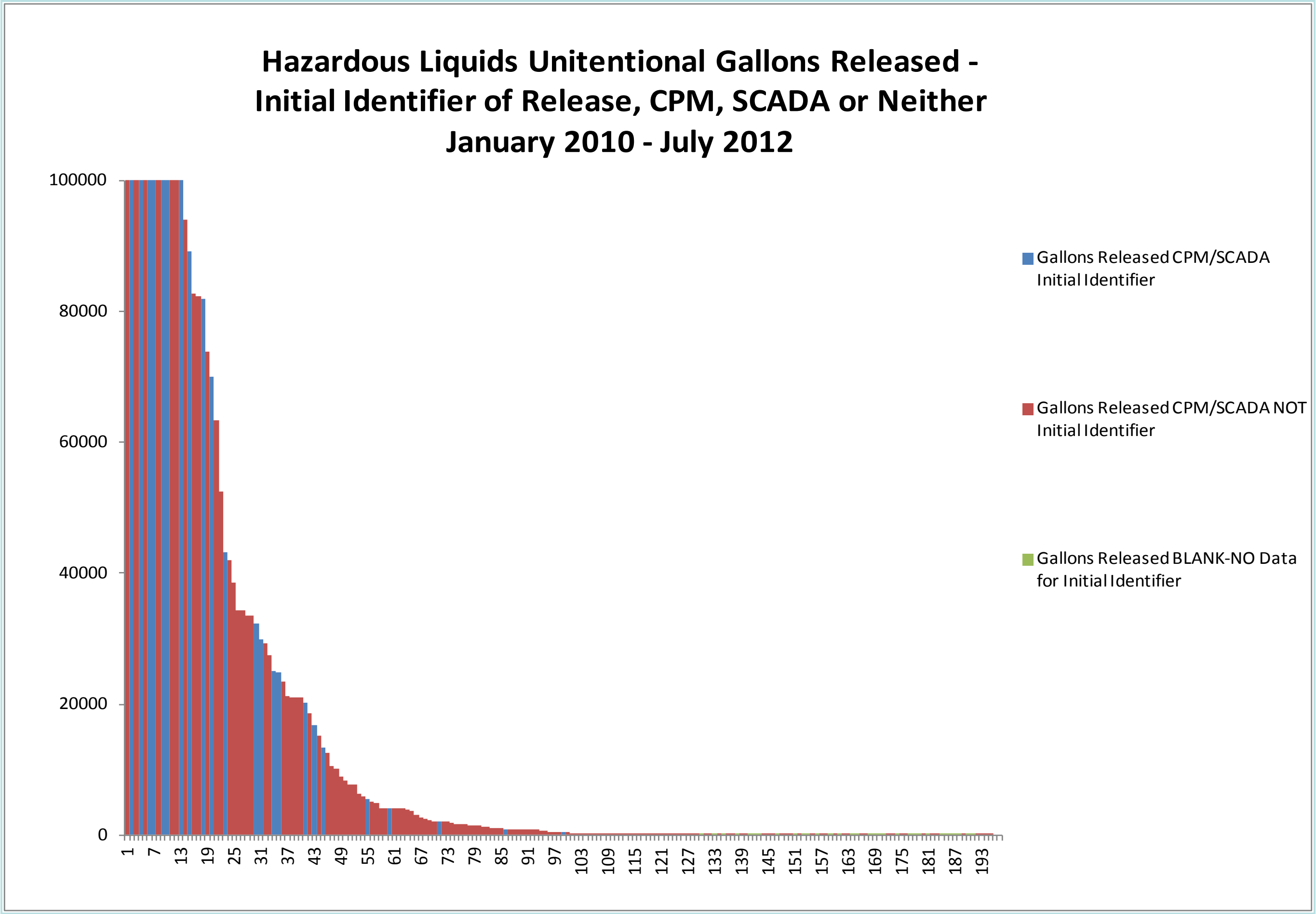
Task 3 Review - Hazardous Liquids Incidents



Task 3 Review - Hazardous Liquids Incidents



Task 3 Review - Hazardous Liquids Incidents



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Task 3 Review - Hazardous Liquids Incidents

Identifer	# of Reported Incidents	% of 197 Incidents Reports
AIR PATROL	10	5%
CONTROLLER	10	5%
CPM LEAK DETECTION SYSTEM OR SCADA-BASED INFORMATION	23	12%
GROUND PATROL BY OPERATOR OR ITS CONTRACTOR	4	2%
LOCAL OPERATING PERSONNEL, INCLUDING CONTRACTORS	38	19%
NOTIFICATION FROM EMERGENCY RESPONDER	14	7%
NOTIFICATION FROM PUBLIC	45	23%
NOTIFICATION FROM THIRD PARTY THAT CAUSED THE ACCIDENT	11	6%
STATIC SHUT-IN TEST OR OTHER PRESSURE OR LEAK TEST	2	1%
OTHER	8	4%
BLANK - No Data Entry	32	16%
# of Identifiers Reported	165	84%
January 2010 to July 2012		

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Overall Summary for Hazardous Liquids Incidents

- The pipeline controller/control room identifies17% of releases for hazardous liquids on the ROW
- Air patrols, operator ground crew and contractors are more likely to identify a release than the control room
- An emergency responder/member of the public was more likely to identify a release than air patrols, operator ground crew and contractors

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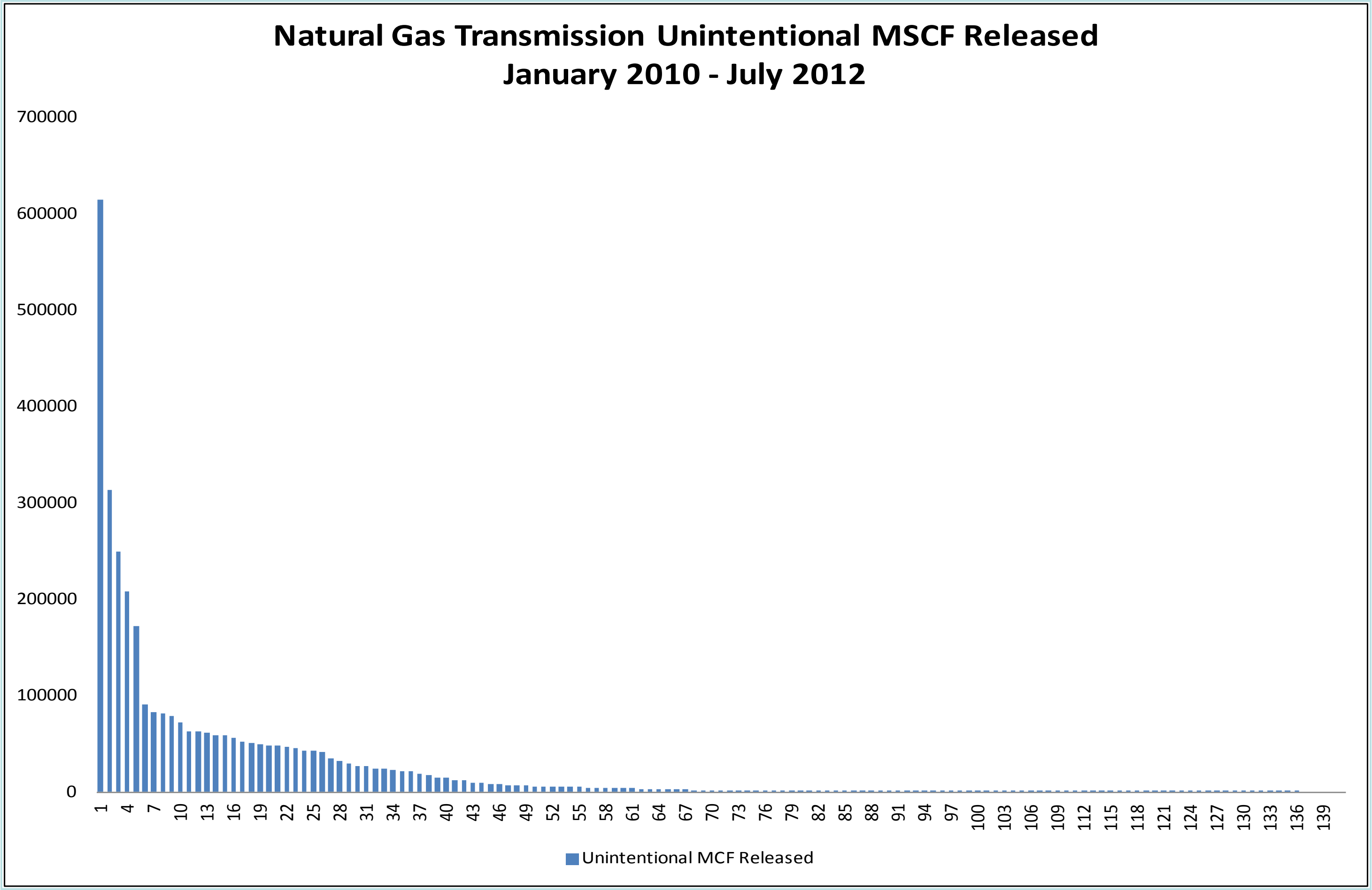
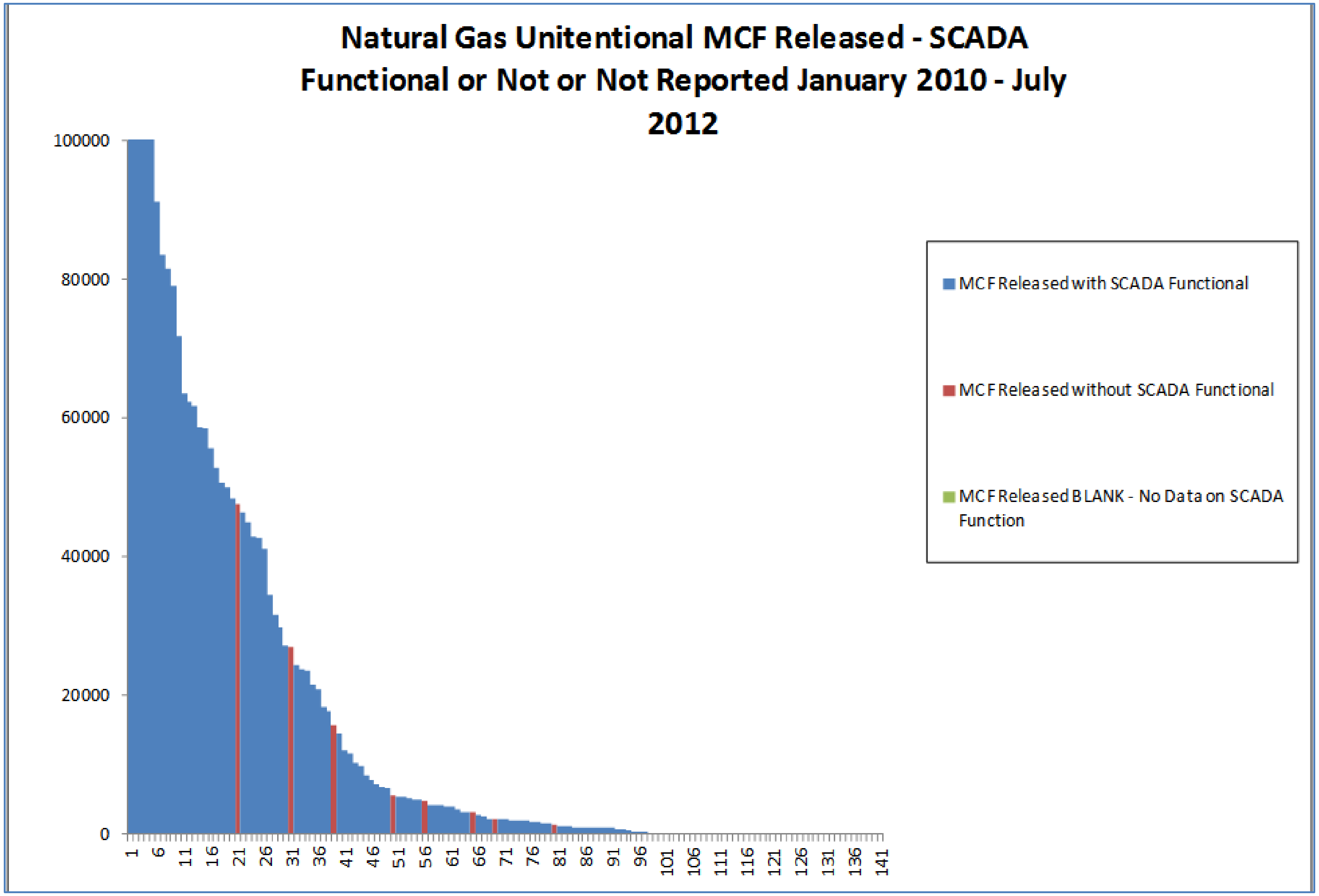
Overall Summary for Hazardous Liquids Incidents

- Chance of an above average release on ROW from pipe or pipe seam releases was 1 in 5
- Over 30 months, there were 28 above average releases from pipe or pipe seam
- Average volume was 29,230 gallons
- Shortest time to shut down a pipeline was 1 minute from all ROW releases
- Longest time was 44 hours and 10 minutes.

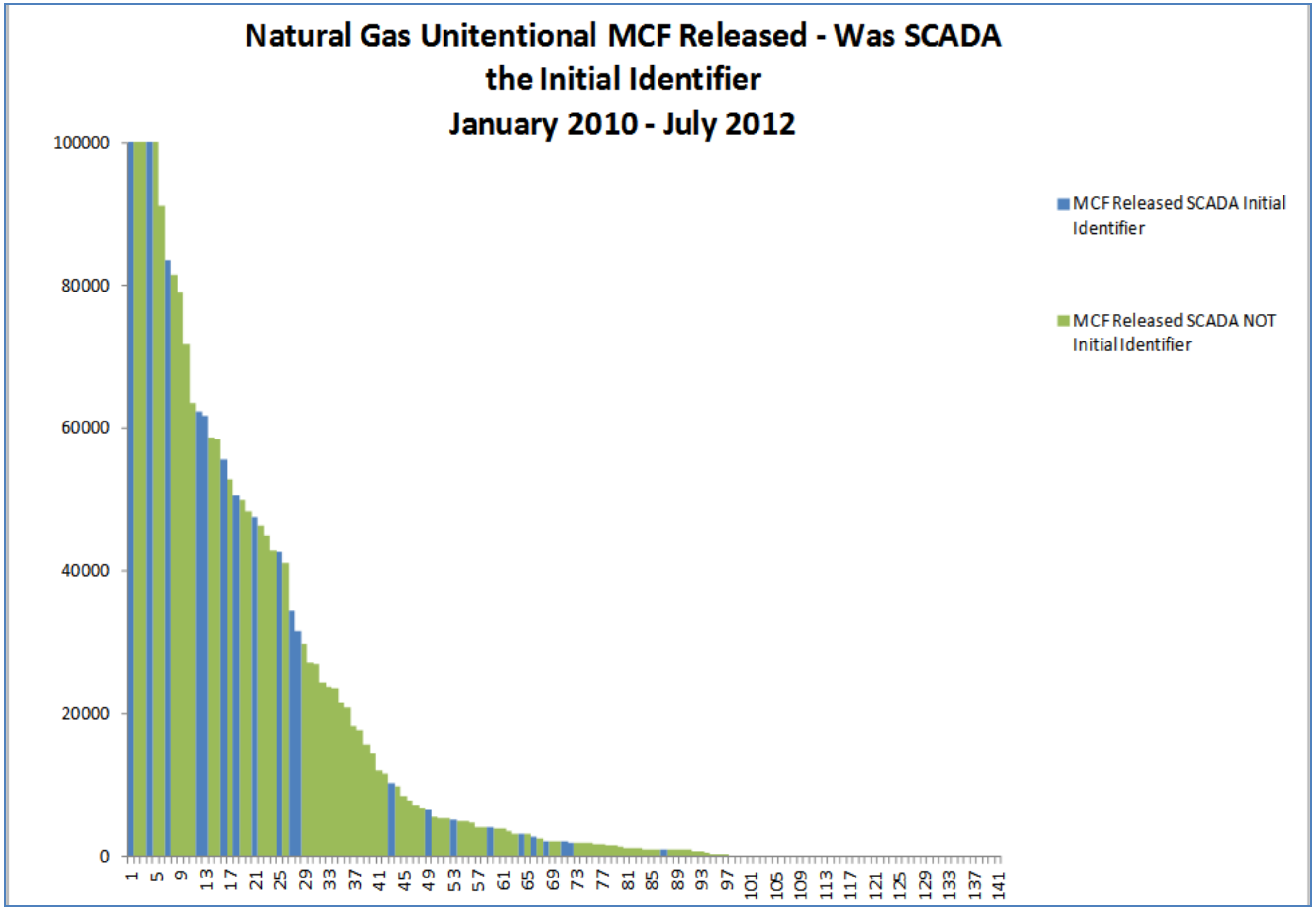
Task 3 Review – Gas Transmission Incidents



Task 3 Review – Gas Transmission Incidents



Task 3 Review – Gas Transmission Incidents



Task 3 Review – Gas Transmission Incidents

	# of Incidents	% of Incidents
AIR PATROL	5	3.55%
CONTROLLER	1	0.71%
GROUND PATROL BY OPERATOR OR ITS CONTRACTOR	7	4.96%
LOCAL OPERATING PERSONNEL, INCLUDING CONTRACTORS	40	28.37%
NOTIFICATION FROM EMERGENCY RESPONDER	4	2.84%
NOTIFICATION FROM PUBLIC	38	26.95%
NOTIFICATION FROM THIRD PARTY THAT CAUSED THE ACCIDENT	15	10.64%
OTHER	10	7.09%
CPM LEAK DETECTION SYSTEM OR SCADA-BASED INFORMATION	21	14.89%

January 2010 to July 2012

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Overall Summary Gas Transmission Incidents

- The pipeline controller/control room identified 16% for gas transmission incidents on the ROW
- Air patrols, operator ground crew and contractors are more likely to identify a release than the control room
- An emergency responder/member of the public was equally likely to identify a release as an air patrol, operator ground crew or contractors
- Chance of an above average release on ROW from pipe or pipe seam releases was 1 in 4

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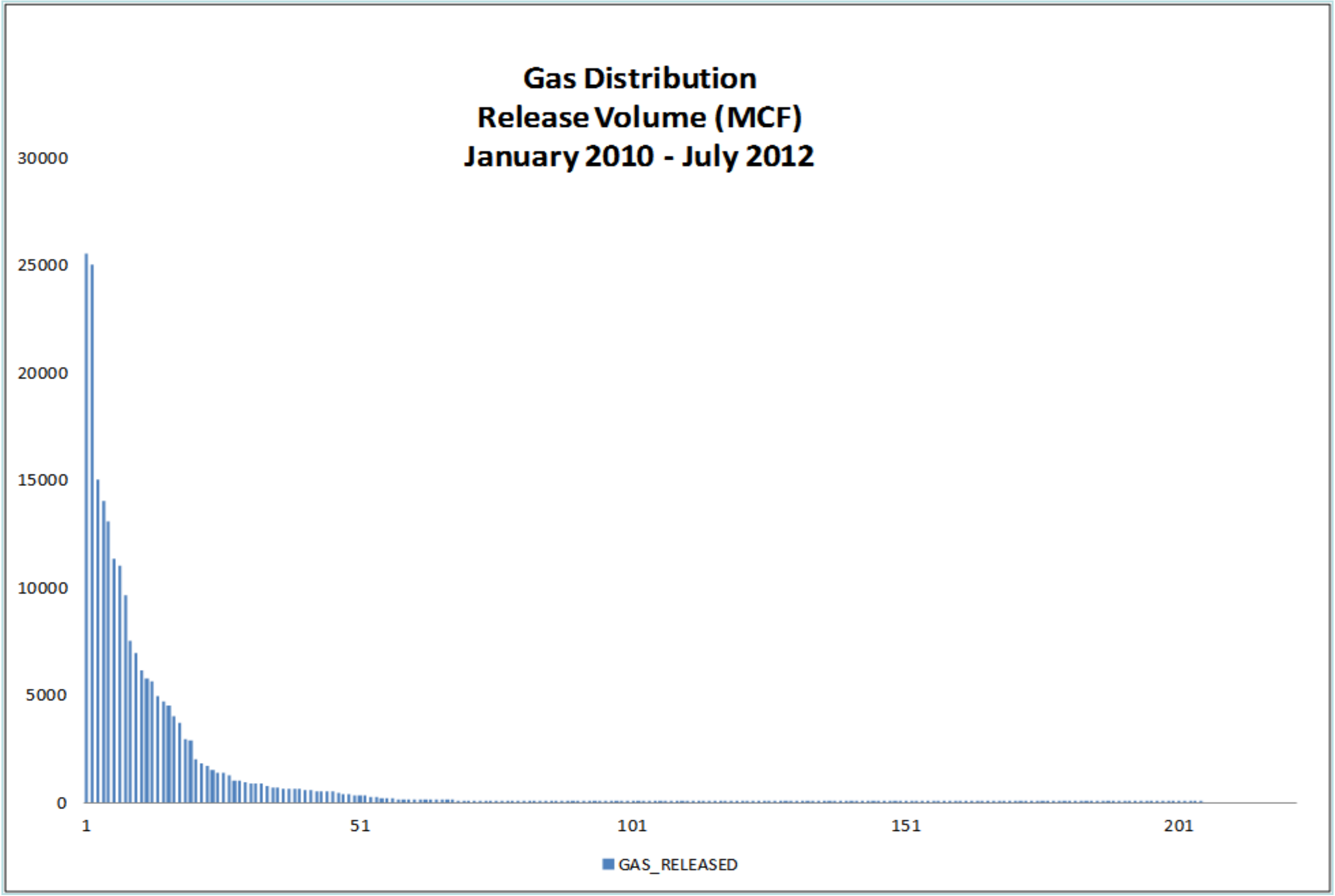
Overall Summary Gas Transmission Incidents

- Over 30 months, there were 22 above average volume releases
- Average volume was 23,078 MSCF
- Shortest time to shut down a pipeline was 2 minutes as reported
- Longest time was 223 hours and 10 minutes as reported

Task 3 Review – Gas Distribution Incidents



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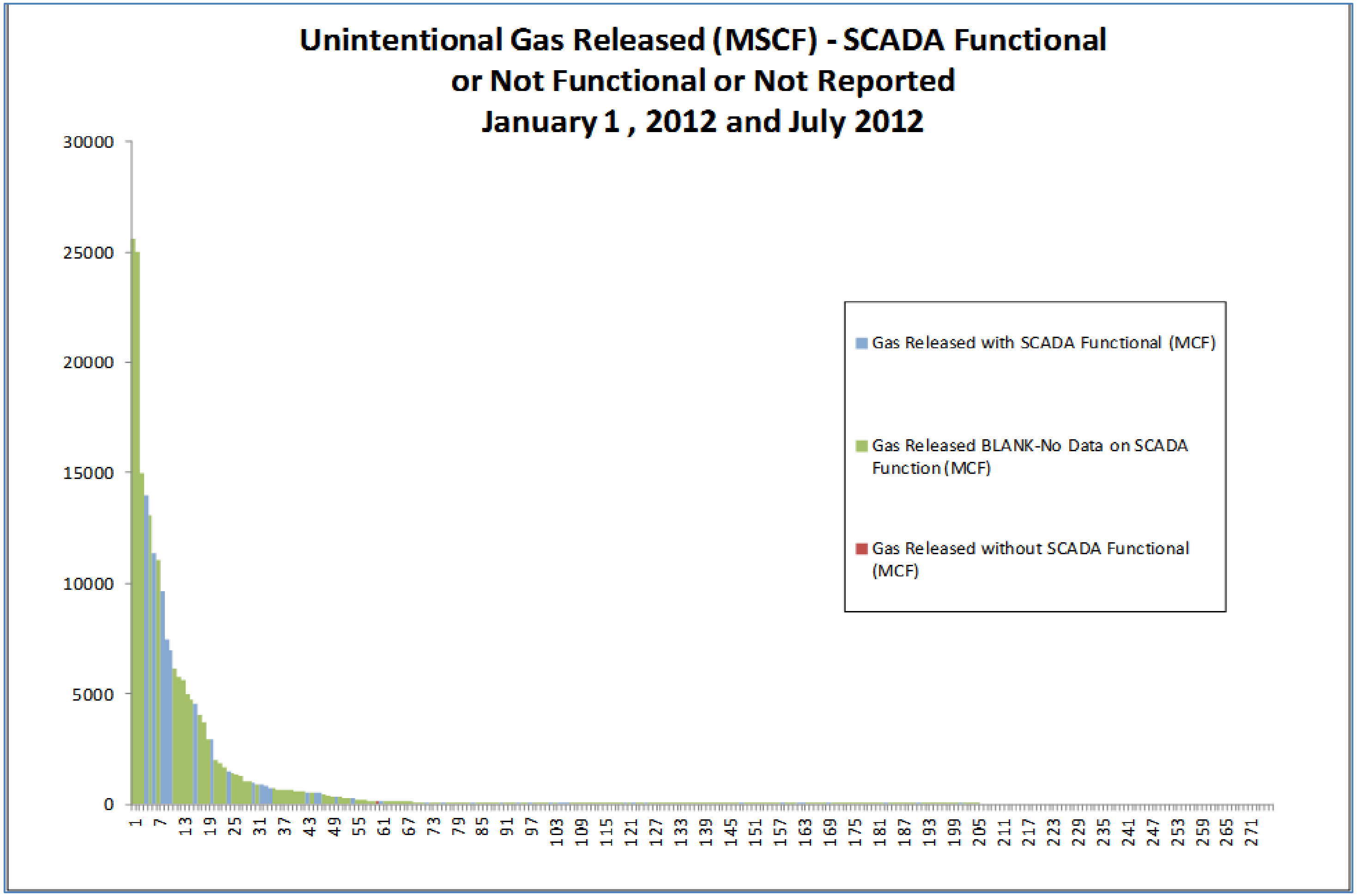
Task 3 Review – Gas Distribution Incidents



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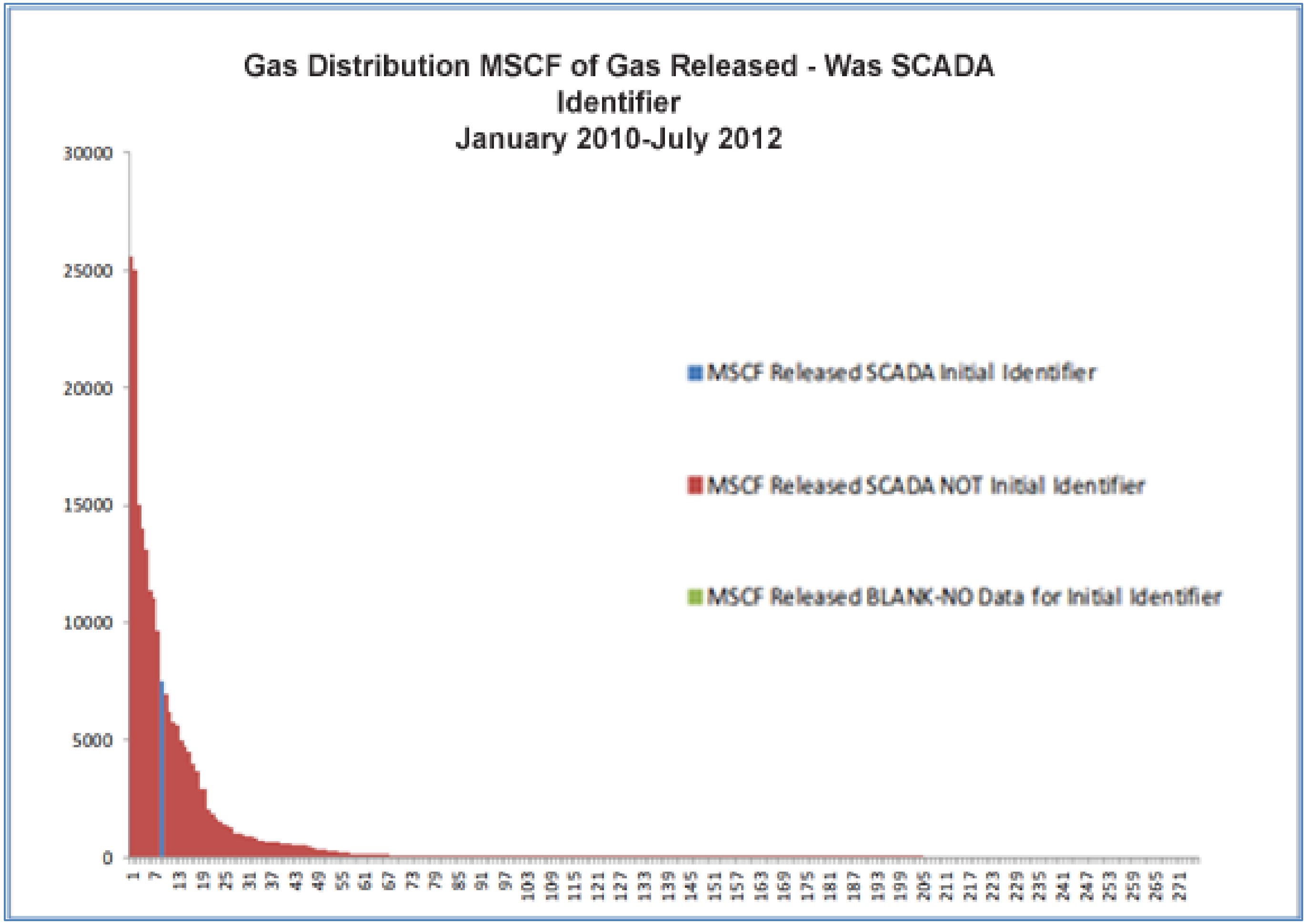
Task 3 Review – Gas Distribution Incidents



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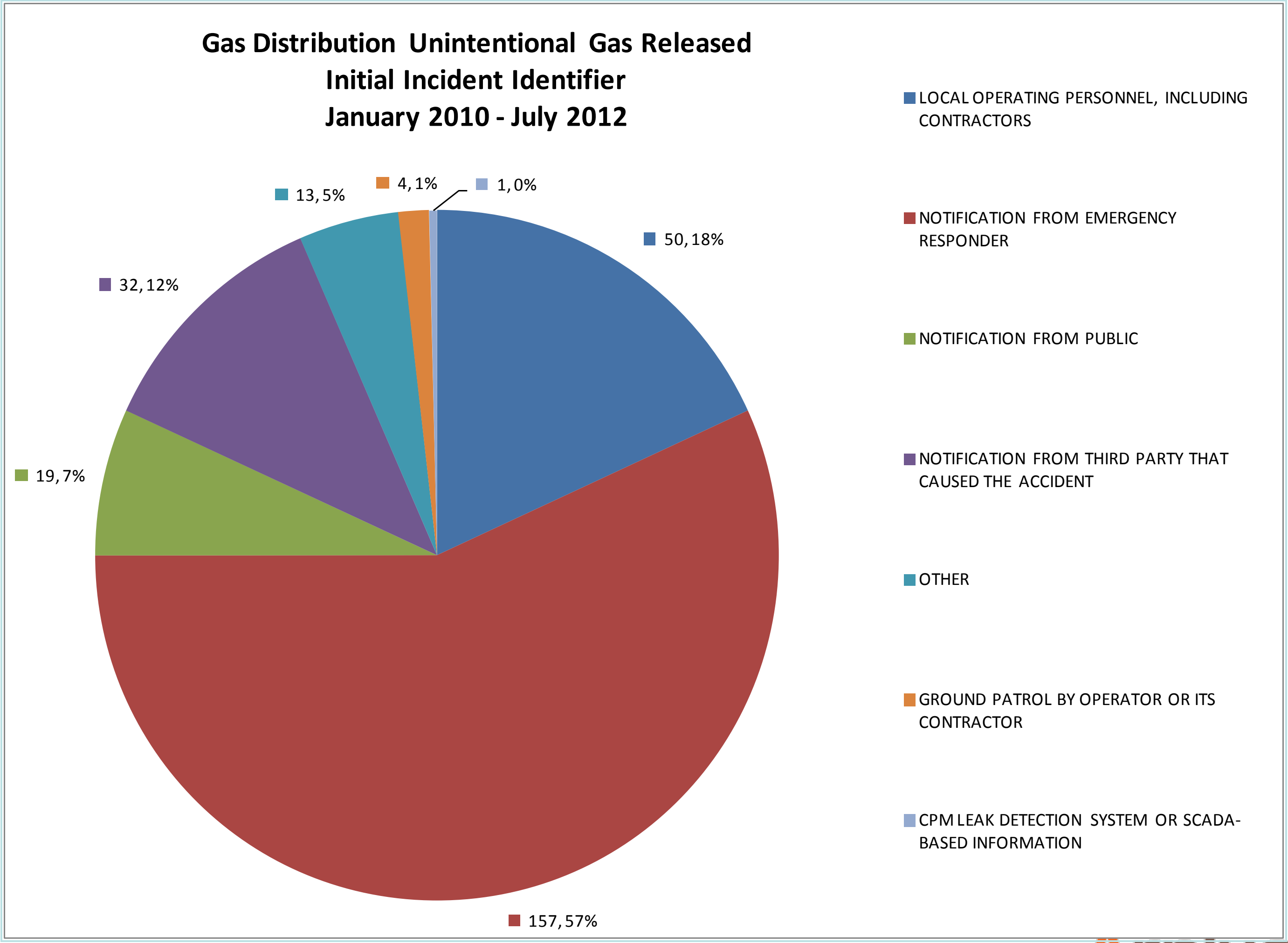
Task 3 Review – Gas Distribution Incidents



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Overall Summary Gas Distribution Incidents

- The pipeline controller/control room identifies 1% of gas distribution incidents on the ROW
- Operator ground crew and contractors are more likely to identify a release than the control room
- An emergency responder/member of the public is 3 to 4 times more likely to identify a release than operator ground crew and contractors

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Task 4 – Technical Review

David Shaw – Lead Author
Martin Phillips – Project Manager

- A technical study of the state-of-the-art and current industry practices.
- A comparison of LDS methods to determine whether current systems (or multiple systems) are able to adequately protect the public and environment from pipeline leaks and incidents:
  - Legacy equipment currently utilized by operators
  - Ability to retrofit legacy systems
  - Benefits and drawbacks of LDS methods
  - Ability to detect small/intermittent leaks
- Identification and explanation of current technology gaps

- SCADA system tools to assist in recognizing and pinpointing the location of leaks on gas lines, including line breaks; using appropriately spaced flow and pressure.

- Two-fold approach:
  - Technical Analysis: an update / expansion on the Leak Detection Technology Study for the PIPES Act (H.R. 5782) published by the U.S. Department of Transportation on December 31, 2007
  - A study of actual operator technology choices and current industry practices, summarizing direct contacts with industry operators and technology suppliers.

- Best practices, standards and regulation:
  - For the liquids pipeline industry, three API publications form the basis of currently accepted recommended best practices in leak detection: API 1149 (1993); API 1130 (2002); and API 1155 (1995)
    - PRCI is currently funding an update to API 1149, perhaps for adoption by the API in the 2014 – 2015 timeframe.
  - There are no corresponding recommended best practices for gas pipelines from AGA or the Gas Technology Institute.
  - There are no definite industry standards for leak detection as there are for instrumentation, safety equipment, metering, etc.
  - Neither the API nor the AGA have systematically researched or developed best practices for external sensor-based leak detection.

- Sources and origins of technologies:
  - It is notable that very few leak detection technologies for oil and gas pipelines were developed within the oil and gas industry.
  - Original research and development in this area continues to lag other industries – as a proportion of overall industry size – to this day.
  - Instead, most technologies have been adopted from other process industries that require fluid movement:
  - Storage, Chemical Process, Water/Wastewater, Nuclear

- Quantifying performance:
  - LDS do not have nameplate or rated performance measures that can be used universally across all pipelines. This is particularly true of CPM where computer software, program configuration, and parameter selection all contribute, in unpredictable ways, to overall performance.
  - Many performance measures present conflicting objectives. For example, leak detection systems that are highly sensitive to small amounts of lost hydrocarbons are naturally also prone to generating more false alarms.
  - The performance of a leak detection system depends critically on the quality of the engineering design, care with installation, continuing maintenance, and periodic testing.

- Leak Detection as Risk and Integrity Management:
  - Leak detection is the first line of defense in the sense that it triggers all other impact mitigation measures that a prudent operator plans for, including safe flow shutdown, spill containment, cleanup, and remediation.
    - Therefore a fast and sensitive LDS is valuable
  - The API Standard 1160: Managing System Integrity for Hazardous Liquid Pipelines, First Edition, November 2001, covers this in Section 10, Mitigation Options: 10.3 Detecting and minimizing unintended pipeline releases:
  - This reflects both the API best practices, and the regulatory view, that leak detection is an integral part of risk-based asset integrity management.

- Major performance factors:
  - Continuous operation, versus intermittent or scheduled operation
  - Ability to perform well during steady-state operations, versus transient conditions
  - Ability to detect leaks in shut-in conditions; to detect small, gradual leaks; and to estimate the leak position
  - Reliability: this means that the system must correctly report any real alarms, but it is equally important that the system does not generate false alarms.
  - Robustness: the system must continue to operate in non-ideal circumstances.
    - The LDS itself should be engineered to be redundant, by using multiple techniques that differ from each other.

- LDS categories:

  - There are two broad families of leak detection systems, named in the API 1149 recommended practice: Internal systems use measurement, and perform calculations to estimate the state of the fluids within the pipe; External systems use dedicated instrumentation equipment to detect escaped fluids.
    - Because all Internal leak detection involves some form of computation, it is often referred to loosely as CPM.
  - There is also visual and instrumented Inspection; covered, in part, by API 570: Inspection, Repair, Alteration, and Rerating of In-Service Piping Systems.
  - It is good engineering practice for a leak detection system to comprise separate subsystems including Internal, External, and Inspection technologies, carefully selected and engineered to complement each other.

- API 1130 Internal LDS categories:
  - Regular or Periodic Monitoring of Operational Data by Controllers:
    - Volume balance (over/short comparison); Rate of pressure / flow change; Pressure point analysis; Negative pressure wave method
  - Computational Pipeline Monitoring (CPM)
    - Mass balance with line pack correction; Real time transient modeling; Statistical pattern recognition; Pressure / flow pattern recognition; Negative pressure wave modeling / signature recognition
  - Data Analysis Methods
    - Statistical methods; Digital signal analysis
  - All these techniques apply equally well to gas pipelines.
    - But, practical implementation is usually more complex and delicate.

- External LDS categories:
  - External leak detection is both very simple – relying upon routinely installed external sensors that rely upon at most seven physical principles – and also confusing, since there is a wide range of packaging, installation options, and operational choices to be considered.
  - There is no API guideline forExternal systems. This often requires the engineer to make original design decisions, without the support of an engineering standard to quote.
  - External leak detection sensors depend critically on the engineering design of their deployment and their installation. Poorly installed sensors can perform orders of magnitude worse than laboratory specifications.

External LDS technology dimensions:

- 1. The physical principle that is used
- 2. How the sensors are packaged and deployed
- 3. How the system is utilized for leak detection

- Major physical principles:
  - 1. Acoustic emissions of a leak
  - 2. Fiber optic cable, specially treated surface
  - 3. Fiber optic cable, sensing strain and/or temperature
  - 4. Cables whose resistance and/or AC impedance change
  - 5. Permeable tubes that are swept with gas that is tested chemically for traces of contamination
  - 6. Detecting hydrocarbon vapors with chemical testers
  - 7. Atmospheric optical methods

- External LDS technology packaging, deployment and use:
  - a) Instrumentation attached to the pipeline
  - b) Point sensors
  - c) Continuous sensors, typically in the form of a cable
  - d) Hand or vehicle carried tools
  - e) Tools launched internally to the pipeline

  - i. Permanent installation with continual sampling
  - ii. Permanent installation with intermittent sampling
  - iii. Periodic or on-demand deployment

- External LDS background:

  - The U.S. EPA has commissioned a number of reviews of performance of point chemical sensors of liquids and gas. One of the earliest, EPA-510-S-92-801 of May 1988, states that even at that time the sensors could deliver:
    - Sensitivities to 250 ppm vapor concentrations and one-quarter inch layers of hydrocarbon liquids floating on water
    - Specific rejection of non-hydrocarbon vapor and liquid
    - Detection times as low as 15 seconds, with nearly all technologies responding within one minute
    - Elementary retrofit procedures

  - Therefore, even in 1988, these point sensors were delivering sensitivity and time to detection far ahead of any Internal system.

- Multiple performance objectives:
  - Work to a high degree of sensitivity and reliability during steady-state operations
  - Continue to work in transient conditions, perhaps with less sensitivity
  - Only cover highly critical specific sections (maybe quite short – rivers, roads, towns, etc.) of the pipeline with a high degree of sensitivity
  - Provide leak detection of some form while the pipeline is shut in
  - Can detect small, gradual leaks, even if relatively slowly
  - Estimates the leak position, even perhaps with poor detection capability

- General benefits and drawbacks; Internal systems:

  - They are widely used and most rely upon easily understood physical principles
  - They utilize measurement that is already on the pipeline and / or provide benefits and tools that are useful beyond LDS
  - They are rapidly deployed and provide a fast, procedural path to regulatory compliance. There are many recommended practices (for liquids pipelines).
  - Most methods are completely dependent on the quality of the support subsystems: metering, SCADA, computers, and telecommunications.
  - Line pack effects, especially during transients, potentially cause many false alarms. These are particularly bad for gas pipelines.
  - The value of threshold for an alarm, and therefore the sensitivity, is often chosen fairly arbitrarily and as a tradeoff against false alarms.

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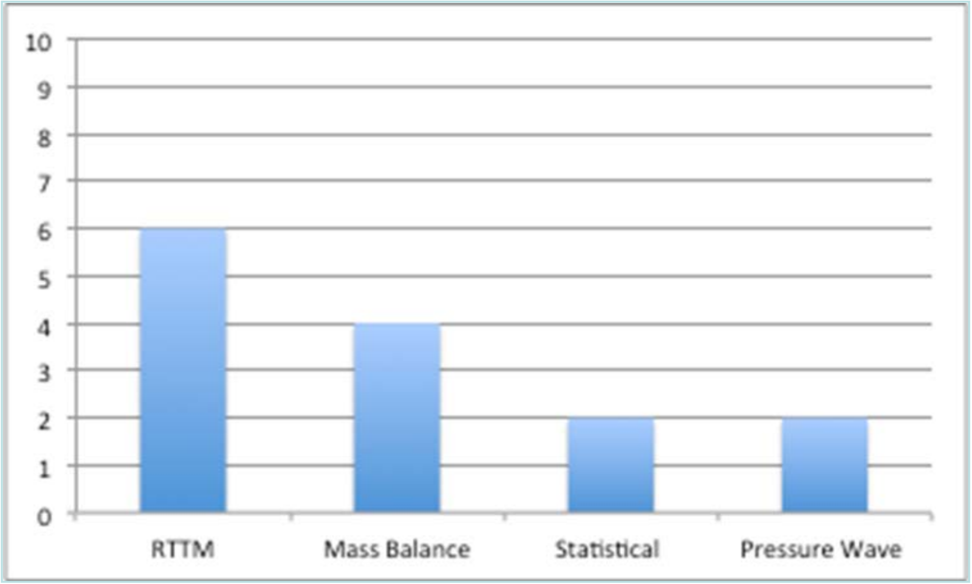
- General benefits and drawbacks; External systems:

  - External systems, when engineered and deployed well, are typically much more sensitive than Internal systems.
  - They are relatively immune to pipeline operational changes and transients, which plague Internal systems. Critical for slack line flow, often shut-in, multiphase fluid, or other transients.
  - External LDS are mostly standalone, simple instrumentation systems that do not rely upon ancillary support systems.
  - External systems require individual engineering design. Sensors are located critically, performance estimated individually, and often built to order from several component subsystems.
  - There is no systematic procedural approach or regulation that provides guidance to the operator in selecting, engineering, and operating External systems.
  - Mostly, External systems are *only* useful as leak detection systems.

- Dominant LDS:

  - All operators that we contacted stated that the most widespread actual current leak detection is by *Pressure/Flow Monitoring*.
    - For gas transmission pipelines, this is in fact pressure monitoring since flow measurement is widely spaced.
    - For gas distribution at intermediate pressure, this normally means flow measurement since pressures are rarely monitored.
    - In addition, nearly all the liquids pipeline operators also implements *a Volume Balance CPM*.
  - This is in part because all the operators that we contacted require SCADA for operational purposes, and/or was regulated by the DOT under 49 CFR 195.
  - Where ASVs are in use by gas pipeline operators, the only leak detection principle utilized is pressure measurement.

- Other CPM LDS, at liquids pipelines:



- External LDS in active use:
  - Only three External leak detection technologies were in active use, and all operators referred to these implementations as “pilots” or “experimental”:
    - Floating hydrocarbon sensors – used at river crossings – 2 operators
    - Fiber optic sensors, DTS and DAS – 1 operator
    - Acoustic sensors (used individually, not in an array) – 4 operators: 2 liquids, 2 gas transmission

- Performance Assessment:
  - The most used leak detection technique, Pressure/Flow monitoring, was acknowledged by all operators *not* to be generally a sensitive method. It is effective only for large ruptures, and even then not consistently so.
  - Six out of the nine liquids operators (67%) seek to assess this impact on Pressure/Flow monitoring sensitivity.
  - The same six out of the nine liquids operators (67%) seek to assess this impact on CPM sensitivity.
    - None of the operators (0%) actively install extra flow and pressure measurement with the single objective of improving leak detection sensitivity.
  - Operators who are piloting External systems report that their performance depends critically on the design of the application and on the quality of the installation.

- Technology Gap I; False Alarms:
  - The word “false” implies a failing of a specific leak detection system. Rather, it is an inherent difficulty with any technology that relies upon any physical side effect of a leak for its detection.
    - An imbalance in flow can be caused quite normally if the line is packing or unpacking fluid. Any significant change in pressure at a location on the pipeline can have this effect.
    - Early versions and some legacy hydrocarbon vapor sensors were sensitive to *all* hydrocarbons, including Biogenic sources of methane
    - Distributed temperature sensors rely on extremely small changes in temperature caused by leaks, but also caused by natural geothermal or atmospheric cooling and heating.

- Technology Gap II; Standardization and Certification:
  - The API “bibles” of liquid leak detection systems are in need of expansion.
    - An update of API 1149 is currently in preparation, but will not be ready until at least 2014. It will include natural gas pipelines for the first time.
  - Similarly, there is very little guidance on External systems from an operator’s perspective.
    - Perhaps the last public, useful guidance is in the Technical Review of Leak Detection Technologies for Crude Oil Transmission Pipelines by the Alaska Department of Environmental Conservation (2000). Most EPA tests and surveys are older still.
  - Operators of large infrastructure require systematic procedures.

- Technology Gap III; Short Lines:
  - The “last mile” for many liquids pipelines may be quite short and connect the main pipeline to a tank farm, terminal, or other third-party receipt.
    - These short lines are not suitable for most Internal technologies:
    - Operations on these lines is at the control of a third party;
    - They are often idle, which makes flow-based leak detection impossible;
    - It is hard to install External sensors since the land typically belongs to a third party.

- Technology Gap IV; certified, dedicated Point Solutions:
  - River crossings; road crossings; hospitals, schools and other low-mobility areas.

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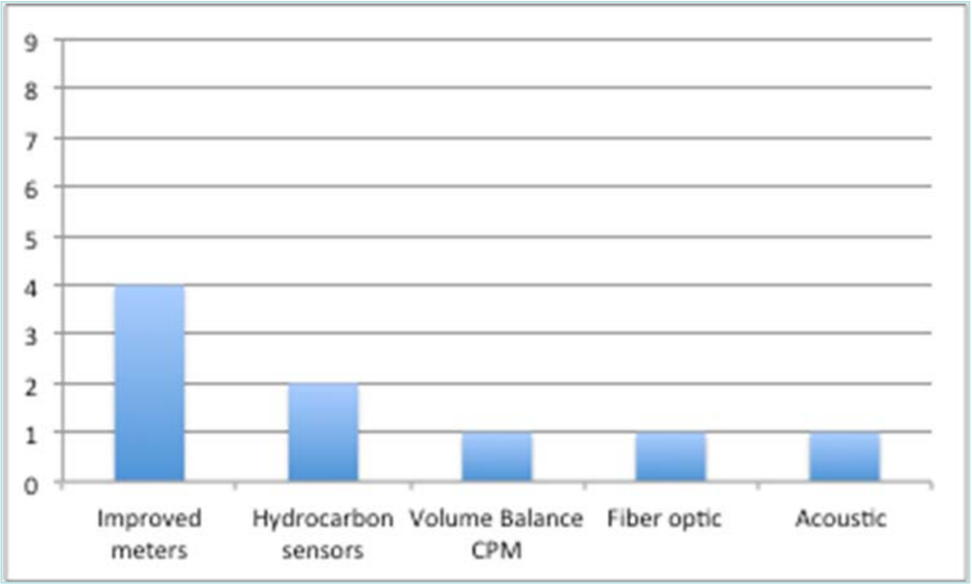
- Operator Practice I; Retrofit Capability:
  - Technically, practically any of the solutions described can be retrofitted safely and effectively on an existing pipeline.
  - Operators point out that the issues with retrofit are not really technical. The true difficulty is the high cost of permitting, installing, testing and maintaining any additional equipment on a regulated pipeline.

- Operator Practice II; Retrofit and Improvement Plans
  - None of the gas distribution operators had leak detection improvement plans.
  - Two out of the five gas transmission companies plan to upgrade their pressure monitoring with Pattern Recognition CPM.
  - Five of the nine liquids operators have no substantial leak detection improvement (as opposed to maintenance) programs.

- Operator Practice II; Retrofit and Improvement Plans
  - Four liquids operators do have new technology adoption plans, as follows:



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Task 5 – Operational Review

David Shaw – Lead Author
Martin Phillips – Project Manager

- Leak detection systems, as systems, involve people, processes and technology:
  - A technical study of recommended best operational procedures and current industry practices.
  - Consideration of reliability, availability and maintainability
  - Risk assessment and benefit assessment
  - Testing, maintenance, training and qualification, and continual improvement
- The approach to this operational review is two-fold:
  - Purely technical engineering analysis:
    - An analysis of the current standards and accepted best practices.
    - Current operational regulations and guidelines
  - A study of actual operator choices and current industry practices, summarizing direct contacts with industry operators and technology suppliers.

- Cost-benefit analysis:
  - Risk Analysis, which defines the anticipated value of leak detection as a means of reducing the consequence of a loss of containment.
    - As with any safety system, the value is measured as its ability or potential to reduce the residual level of risk in operating the pipeline.
    - It also defines what the value of accepted, assumed risk from leaks is in the operation of the pipeline.
    - Best practices ask for clarity and transparency in the units in which the level of risk is expressed.
  - Front-End Design, where an actual performance of a theoretically ideally installed and operated technology, as well as its cost, is evaluated.
    - This technical study provides input back into the risk analysis, so that an actual as-built risk reduction benefit is estimated.

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- 49 CFR Sect. 195.452(i)(3) includes operations requirements:
  - An operator must have a means to detect leaks on its pipeline system
  - An operator must evaluate the capability of its leak detection means
  - Leak detection analysis should include the impact of sudden significant failures, as well as smaller leaks that may take longer to detect
- There are no corresponding regulatory guidelines for gas pipelines.

- 49 CFR Sect. 195 also includes a number of operational guidelines:
  - Design Criteria for CPM Systems based upon the API RP 1130
  - Written Operations and Maintenance procedures
    - In particular: Responding to, investigating, and correcting … deviation from normal
  - Testing, at least once every five years
  - Record Keeping, and Retention
  - Formal Controller Training in leak detection
- The Canadian Standards Association (CSA) also has a standard Z662 that makes a leak detection system mandatory on a liquids pipeline. Its Annex E is written as a recommended best practice for the procedures to use in implementing leak detection as a system.

- CSA Z662 includes:
  - Operating companies should establish a procedure whereby *a material balance is made for all liquids transported*. In other words, CPM at least by material balance is mandatory, and Pressure/Flow Monitoring is insufficient.
  - Operating companies shall establish acceptable tolerances for material balance deviations ... deviations in excess of acceptable tolerances *shall result in immediate initiation of a shutdown procedure* unless such deviations can be explained and verified by independent means.
  - The *uncertainty in the receipt and delivery metering* used in the material balance calculation ... shall not exceed 5% per five minutes, 2% per week, or 1% per month.

- CSA Z662 includes:
  - A record of daily, weekly, and monthly material balance results *shall be kept for a minimum period of six months*. Records pertaining to maintenance, internal auditing, and testing *shall be retained for five years.*
  - Occasions when the leak detection system was inoperative because of equipment or system failures exceeding 1 h in duration *shall be audited.*
  - The leak detection system shall *be tested annually* ... Preferably, this should be done *by the removal of liquid from the pipeline*.
  - Personnel responsible for interpreting and responding to the leak detection system *shall receive training in*: liquid pipeline hydraulics ... as affected by related operational procedures; the leak detection method used; interpretation of results; the effects of system degradation on leak detection; a leak detection manual.

- 49 CFR 195.452(i)(2) requires operators to “evaluate the likelihood of a pipeline release occurring and how a release could affect HCAs”. In short, both the probability of a leak, and the consequence of this leak if it occurs.

- The International Standards Organization (ISO) standard no. 31000 cover risk analysis in general, and addresses general sound principles.
  - It is accompanied by ISO/IEC/FDIS 31010: Risk management – Risk assessment techniques (2009) that covers 31 different techniques.
    - Risk assessment is not static – it has to be updated regularly since the environment is changing and certain risks increase over time.
    - Risks can be complex in themselves, made up of several cumulative risks.
    - Risks should be expressed in understandable terms, and the units of risk should be made clear.

- Total risk is the product of a probability of failure times the consequence of that failure.
  - Leak detection has no effect at all on the probability of a leak. It does, however, mitigate the consequences of a leak dramatically.
  - Therefore leak detection systems are consequence mitigation measures, and not probability reduction measures like inspection, maintenance and repair.
  - Since risk is the product of probability and consequence, they nevertheless reduce total risk just as importantly as other integrity management measures.
- ASME B31.8 for Gas Pipelines, and B31.4 for Liquid Hydrocarbons and Other Liquids, identify a category of threat called Time-Independent where almost no amount of inspection and maintenance will reduce the threat probability. With these threats the only possible mitigation is via consequence reduction, in part by leak detection.

- Benefit and Performance Analysis

  - The 49 CFR 195.452(i)(3) explicitly requires the operator to: "evaluate the capability of its leak detection means and modify, as necessary."
  - Similarly, CSA Z662 Annex E, Sect. E.3.1 asks for a technical evaluation of the performance of the leak detection system.
  - In any case, it is prudent for the operator to know exactly what the as-built performance of the leak detection system is likely to be, both before deployment and during operations.
  - A performance study (commonly called a Leak Sensitivity Study, LSS) can be performed for any form of leak detection, whether Internal or External. Except for 49 CFR 195 regulated pipelines, which names the API RP 1130, the choice of procedure is left up to the operator.

- Testing
  - The 49 CFR Part 195.444 requires periodic testing of the leak detection system, at least once every five years.
  - Similarly, the CSA Z662 Annex E, Sect.E.4.3 asks that: “the leak detection system shall be tested *annually* to demonstrate its continued effectiveness. Preferably, this should be done by the removal of liquid from the pipeline.”
  - The testing has to be of the entire system. Therefore, both the technology and control room operators should be tested.
  - There is a preference for testing by actual removal of fluid from the pipeline, or “draw test”. This can be involved and expensive.
  - Simulated testing is far less expensive, but of course less reliable
  - *Auditing*: Any failure of a test, but also any other failure of the system, should be recorded and audited

- Maintenance:

  - In general, system components have maintenance requirements that go from high to low, according as:
    - They contain consumable fluids and chemicals. Only a few direct sensing External leak detection technologies require this.
    - They contain moving parts. Many forms of flow meter contain moving parts, for example, and require periodic calibration.
    - They contain electronics and software. Computers used for CPM, for example, require very regular IT maintenance.
    - They are inert, physical sensors. Most External technologies are in this category and require minimal maintenance.

- Procedures are called for by 49 CFR Part 195.402:
  - Actions should be based on documented work practices and/or covered in guidance or training material
  - Integration of emergency response procedures
  - Assurance for the restoration of any mute/disable functions that are used during certain operational modes
  - If procedures require such contact (with a supervisor) before action, assurance that any required supervision is always promptly available for contact
  - Adequate guidance in documented work processes: authority and responsibility
  - Corporate directive or policy on authority and responsibility
- The CSA Z662 Annex E, Sect.E.3.1 is explicit: “Material balance deviations in excess of acceptable tolerances shall result in immediate initiation of a shutdown procedure … “

- Training: at a minimum, controllers need to know the expected performance thresholds and operating window of applied leak detection system.

- The CSA Z662 Annex E, Sect.E.5.1 and E.5.2 is explicit about the content of the training:
  - The detailed physical description of each pipeline segment and the characteristics of all liquids transported;
  - Liquid pipeline hydraulics as applied to each pipeline segment and as affected by related operational procedures;
  - The leak detection method used on each pipeline segment and the interpretation of results;
  - The effects of system degradation on the leak detection results; and
  - The contents and interpretation of the leak detection manual.

- A particular difficulty with leak detection is identifying who “owns” the leak detection system. A technical manager or engineer in charge is typically appointed, but he is rarely empowered with global budgetary, manpower or strategic responsibilities.

- Leak detection system complexity or high cost does not directly translate to better performance. Without a focus on all three: technology, people and procedures, a single “weak link” can render the overall system useless.

- Even very simple technologies can be very effective, if they are backed up by highly skilled operators and well-designed procedures. Design choices need to be balanced with available and committed operating and maintenance resources.

- After implementation, field crews will almost certainly be affected by a need for more instrument maintenance.

- Operator Current Practices

  - Standards – very few operators develop independent, internal standards explicitly directed a leak detection technology. Three of the liquids operators (33%) have such standards, and none of the gas operators. External recommended practices and Federal Regulations make up the large majority of the standards in continual use.

  - Risk (Requirements) Analysis – most requirements analysis, in terms of absolute risk, is done outside the technical groups. Leak detection performance input was asked for at only four of the total 19 companies interviewed.

- Operator Current Practices
  - Value (Performance Benefit) Assessment – Four of the nine liquids operators do perform leak sensitivity studies in-house. The remainder relies on performance predictions supplied by their technology vendors. None of the gas operators assess their capability to detect a leak in-house.
  - Testing, Maintenance – all operators relied on the vendors for maintenance. Associated field equipment was not assigned to the leak detection or operations teams.

- Operator Current Practices

  - Two out of nine liquids operators perform testing by actual physical draw tests as a matter of course on most lines.
    - The remainder verifies functionality by providing deliberately bad readings through SCADA, deliberately mis-calibrating the meters, or other devices.
    - None of the gas pipeline operators had a systematic program for testing their ability to detect leaks.

- Operator Current Practices

  - Controller Procedures and Training – A written response procedure to an alarm (of any kind) is enforced at 17 out of the 19 operators. However, a specific written response procedure for a leak alarm is enforced at 6 out of 19 operators (all of them liquids operators). Among these, a procedure that sets a mandatory time limit to shutdown, following a leak alarm is mandated at 3 operators.
    - All operators have written controller procedures, training and qualification programs. However, the specific leak detection systems training content is generally vague. Three liquids operators specifically produced a Leak Detection Manual.

- Operator Current Practices
  - Continual Improvement – Four liquids operators do have continual improvement plans, mostly related to metering. Only two of the gas companies have active instrumentation improvement plans. Only one company out of the sample is testing advanced technologies with a potential for use beyond one years' time.
  - Responsibilities – of the pipeline operators that we interviewed, approximately one-third (six out of 19) had dedicated staff responsible for leak detection. The personnel that we talked with are given working budgets for a period of between one year and five years. Therefore, actual investment in leak detection has to be taken out of additional departmental responsibilities (metering, SCADA, Information Technology) that can only be increased on a long timeframe

PHMSA LDS Project Webinar Tasks 6, 7 – Economic and Standards Review

David Shaw – Lead Author
Martin Phillips – Project Manager

- The principles of cost benefit analysis for deploying leak detection systems on new and existing pipeline systems are covered.
  - Typical cost elements for equipping a new, and retrofitting an existing, pipeline system are listed as a guideline.
- The cost benefit is based on the lifetime operational cost of the system.
  - Variables including the benefits to the public and surrounding environment are assessed.
  - These are markedly different for pipelines that are situated within HCAs.
- The approach to this economic review is two-fold.
  - It covers the purely technical economic analysis components of Task 6.
  - It also includes a study of actual operator choices and current industry practices, by direct contacts with industry operators.

- Leak detection systems – in common with all safety systems – affect all stakeholders in slightly different ways:
  - Investors are assured of a more reliable return on investment, through the reduction in the risk of financial damages.
  - Similarly, Managers can deliver more reliable performance.
  - Employees can work in safer environments
  - The Community has a reduced risk of having to deal with serious safety and environmental hazards

- In brief, these all translate to a reduction in the risk of a leak (or any other safety-related incident). Conversely, it is an increase in the reliability of the overall business.

- Risk Reduction

  - The final corporate Exposure = Risk – Reduction. This represents the amount of risk that remains after risk reduction measures have been applied.

  - The *Assumed Risk* is the final accepted level of Exposure once the selected Mitigation is applied.

  - It is also called *Asset Liability*, which reminds us that the possibility of enduring undetected leaks is a continuing liability to pipeline assets.

- Cost-Benefit

- The economic benefit from a leak detection system is gained from a reduction in the consequential cost, or Consequence of the leak.
  - The leak detection system cannot reduce the Probability P, which is the domain of mechanical safety, inspection, maintenance and repair.

- The total lifecycle cost of the system is (Capital Expenditure) + (Annual Operational Expenditure)*Lifetime.
  - Over a sufficiently long period of time, this is dominated by OPEX. Therefore, the total lifetime cost-benefit approaches: OPEX / Risk
  - Over a short period of time, this is dominated by CAPEX.

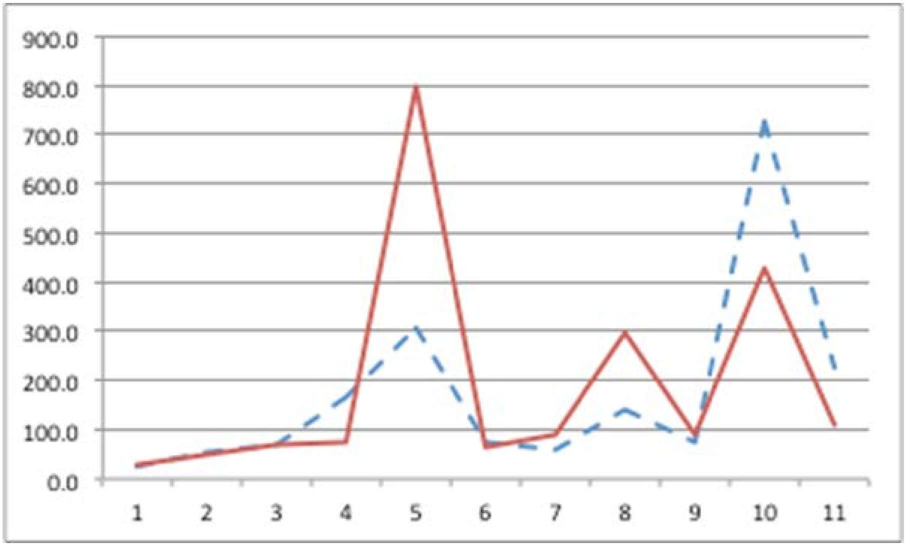
Study Guideline Economics

- We emphasize that costs vary widely, and so do benefits – especially as perceived by the operator.
  - Prices from suppliers vary by many multiples depending on the volume, product lifecycle, buyer and season.
  - Similarly costs for services vary widely depending on geographical location, certification requirements, in-house vs. outsource choices, to name only a few.
  - These variations can be as high as a factor of ten in some cases.
- We focus on the two main forms of leak detection in actual frequent use today: SCADA monitoring and CPM by volume balance.
  - The economics therefore fall into two categories: no current SCADA and metering, and piggybacking existing systems.

- The "Average" Pipeline

- This analysis can, at best, offer an order-of-magnitude illustration of which solutions are viable, and scale of returns on investment.
  - The reader is invited to imitate this analysis for his own particular operational situation and with cost values more appropriate to his own reality.

  - A liquids pipeline 400 miles long. This is the total U.S. hazardous liquids network length of 148,622 miles, over 350 DOT-registered companies.
  - A gas transmission pipeline 300 miles long. This is the total U.S. gas transmission network length of 301,896 miles, over 981 DOT-registered companies.



- There have been 201 major incidents related to liquid leaks in the U.S. over the last ten years. The "average" pipeline therefore has a 57% probability of a major leak per decade.
- The annual damages per notional average pipeline is:
  - Liquids pipelines: $490,000 per notional 400-mile pipeline, per year
  - Gas pipelines: $190,000 per notional 300-mile pipeline, per year

- In an HCA total remediation of the spill is often impossible, or takes an extremely long time. No hard data for the costs of cleanup in an HCA, relative to the average, are available to our knowledge. However, we estimate that they are at least 2 – 3 times as high and probably more.

- The impression made – both to the general public and to investors in particular – that the operator is not in control of his assets.
  - Occasional leaks and other failures are conceded as accidents as long as they are relatively infrequent.
  - Not knowing, for several hours, that the leak has even occurred and struggling to contain it appears as carelessness.
  - The economic impact to the operator in terms of investor confidence and share value may be much higher than the direct property damages.

- The report examines baseline economics for these systems, on the “Average” pipeline:

  - 1. SCADA monitoring of pressure and flow
  - 2. CPM using material balance
  - 3. Negative pressure wave monitoring
  - 4. RTTM
  - 5. External systems:
    - a. Acoustic
    - b. Fiber Optic Cable
    - c. Liquid Sensing Cables
    - d. Point Hydrocarbon Sensors

		Equipment	Labor	Total
1	SCADA monitoring of pressure and flow		$100,000	$100,000
	If SCADA is required:	$100,000	$100,000	$200,000
2	CPM using material balance	$270,000		$270,000
	If metering is required	$930,000	$120,000	$1,050,000
3	Negative pressure wave monitoring	$270,000		$270,000
	If pressure monitoring is needed	$730,000		$730,000
4	RTTM	$520,000	$100,000	$620,000
5	External systems:			
a.	Acoustic,	$1,200,000		$1,200,000
	If fiber is already in place	$1,000,000		$1,000,000
b.	Fiber Optic Cable,	$240,000	$60,000	$300,000
	If suitable fiber is already in place	$40,000		$40,000
	New construction	$240,000		$240,000
c.	Liquid Sensing Cables	$2,040,000	$60,000	$2,100,000
	New construction	$2,040,000		$2,040,000
d.	Point Hydrocarbon Sensors	$21,020,000		$21,020,000

Capital costs – 10% coverage of HCAs only by External systems

		Maintenance	Labor	Total
1	SCADA monitoring of pressure and flow			
	If SCADA is required:	$18,000		$18,000
2	CPM using material balance	$48,600		$48,600
	If metering is required	$200,600		$200,600
3	Negative pressure wave monitoring	$48,600		$48,600
	If pressure monitoring is needed	$120,600		$120,600
4	RTTM	$93,600	$100,000	$193,600

Operational costs

Liquids Pipeline, HCA				
		Three Year	Five Year	Ten Year
1	SCADA monitoring of pressure and flow	33.00	55.00	110.00
	If SCADA is required:	12.99	18.97	28.95
2	CPM using material balance	7.94	10.72	14.55
	If metering is required	2.00	2.68	3.60
3	Negative pressure wave monitoring	7.94	10.72	14.55
	If pressure monitoring is needed	3.02	4.13	5.68
4	RTTM	2.75	3.46	4.30
5	External systems:			
a.	Acoustic,	2.04	3.21	5.62
	If fiber is already in place	2.33	3.64	6.26
b.	Fiber Optic Cable,	4.61	6.77	10.42
	If suitable fiber is already in place	7.24	9.95	13.82
	New construction	5.03	7.30	11.04
c.	Liquid Sensing Cables	1.31	2.10	3.85
	New construction	1.34	2.15	3.93

ROI (multiples) for liquids pipeline, HCA

Kiefner

Gas Pipeline				
		Three Year	Five Year	Ten Year
1	SCADA monitoring of pressure and flow	4.32	7.20	14.40
	If SCADA is required:	1.70	2.48	3.79
2	CPM using material balance	1.04	1.40	1.90
	If metering is required	-	-	-
3	Negative pressure wave monitoring	1.04	1.40	1.90
	If pressure monitoring is needed	-	-	-
4	RTTM	-	-	-
5	External systems:			
a.	Acoustic,	-	-	-
	If fiber is already in place	-	-	1.44
b.	Fiber Optic Cable,	-	-	-
	If suitable fiber is already in place	10.80	18.00	36.00

ROI (multiples) for gas pipeline, non-HCA

Applus RTD

- Even if an entire SCADA metering system also needs to be procured, pressure/flow monitoring has a high ROI.
- As long as metering is present, CPM is also very economical. However, a complete and accurate metering system just for the purpose of material balancing is rarely economic.
- Similarly, if pressure monitoring is already present, pressure wave analysis is cost-effective. However, a complete and accurate instrumentation system just for the purpose of pressure wave analysis is rarely economic.
- If the pipeline already has fiber optic cable in the right-of-way, or if the construction is new, fiber optic technology has a high ROI. Any separate trenching work to lay cable typically reduces the economics

- Because of their relatively low OPEX requirements, External systems are worth consideration when a ten-year time horizon is used. This would especially be the case with a new construction.

- Just because liquid sensing cables and point sensors are expensive when deployed on 40-mile stretches of pipeline does not mean that they should not be seriously considered for shorter sections of truly critical areas
  - River, road and town crossings for example.
  - Our simplistic calculations overlook their potential sensitivity and potential for reliability.

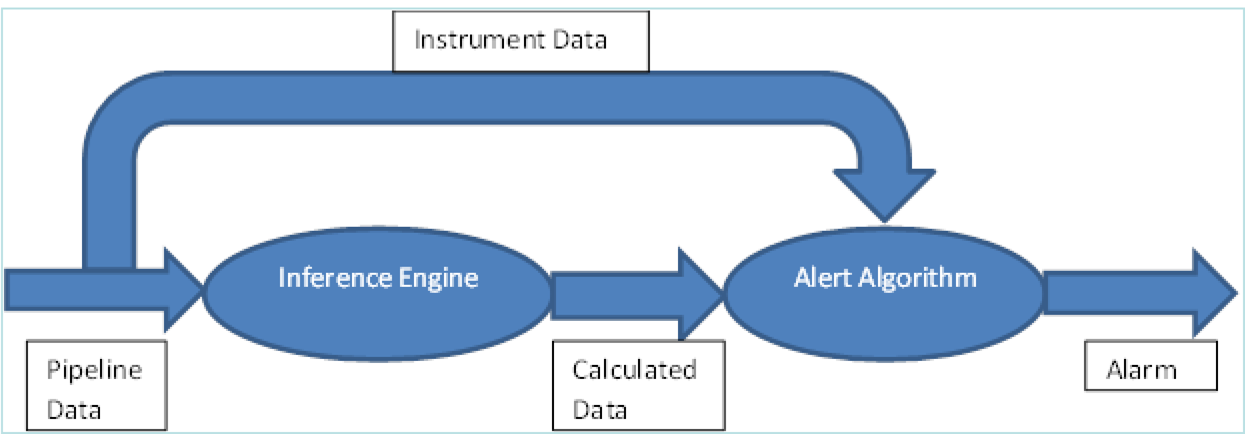
- Operator Leak Detection Budgets

- The opinion of the large majority of interviewees was that overall leak detection budgets are driven by an honest desire to meet regulations and industry standards, but no more.
  - In order to secure a program budget from the board, a case has to be made that it is necessary to meet an external standard or obligation.
- Although all the companies did have a corporate risk analysis group, our group of interviewees did not include any personnel from these groups.
  - Our interviewees were mostly of the opinion that leak detection was not considered a significant consequence mitigation measure at the corporate level. Only four interviewees have been asked for inputs for a risk analysis.

- The report reviews, but does not recommend, standards and regulations in LDS.

- Four of these standards are analyzed and summarized in this report. They are:
  - 1. API 1130
  - 2. API 1149
  - 3. CSA Z662 Annex E (Canada)
  - 4. TRFL (Germany)

- API 1130 defines Computational Pipeline Monitoring (CPM) as "an algorithmic monitoring tool that alerts the Pipeline Controller to respond to a detectable pipeline hydraulic anomaly (perhaps both while the pipeline is operating or shut-in) which *may be* indicative of a commodity release."
- Designed for liquids pipelines.



- API 1130 does not consider externally based leak detection systems as CPM systems because they "do not operate on algorithmic principles of physical detection of an escaping commodity".
  - Note, however, that the better External systems depend heavily on algorithms and signal processing. These are typically embedded in dedicated computers.

- "An alarm could be triggered by many causes including equipment or data failure, an abnormal operating condition or a commodity release"

- API 1149 is a detailed report on pipeline variable uncertainties and leak detectability.
  - It provides a step by step procedure and database for calculating leak detectability. It also provides examples and field trial results.

- Algorithmic leak detection systems can be divided into three components:
  - 1. Mathematical algorithms
  - 2. Pipeline variables
  - 3. Operator training and experience

- Many of these principles actually apply to gas pipelines and External systems as well.

Kiefner

- CSA Z662 Annex E Recommended Practice for liquid hydrocarbon pipeline system leak detection is an informative document which focuses on material balance methods for leak detectability.

- It states “ it is not the intent of this Annex to exclude other leak detection methods that are equally effective. Regardless of the method of leak detection used, operating companies shall comply as thoroughly as practical with the record retention, maintenance, auditing, testing and training requirements of this Annex”.

- This standard applies to all the Pipeline Operators not only in Canada but a lot of the trans-border pipelines between the U.S. and Canada need to comply as well.

- TRFL (Technical Rule for Pipeline Systems) (Germany) covers:
  - Pipelines transporting flammable liquids,
  - Pipelines transporting liquids that may contaminate water, and
  - Most pipelines transporting gas.

- It requires these pipelines to implement an LDS, and this system must at a minimum contain these subsystems:
  - Two independent LDS for continually operating leak detection during steady state operation. One of these systems or an additional one must also be able to detect leaks during transient operation, e.g. during start-up of the pipeline. These two LDS must be based upon different physical principles.
  - One LDS for leak detection during shut-in periods.
  - One LDS for small, creeping leaks.
  - One LDS for fast leak localization.

- Leak Detection in Gas Pipelines

- Currently there are not many standards for leak detection in gas pipelines. However, many principles and factors of the liquid leak detection systems standards can be applied to gas systems as well.

- After the San Bruno incident in 2010, leak detection regulation/ standards for gas pipelines might be forthcoming. Gas pipeline industry currently has its own safety procedures and processes and conferences are held regularly where operators express their desire to have a zero incident policy emulating the policies of other such industries i.e. the airline industry.

- The importance of having a safety culture in the member companies is often emphasized. Company safety culture has to be led from the top by corporate executives.