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December 30, 2016

Ms. Karlene Fine
Executive Director
North Dakota Industrial Commission
State Capitol, 10th Floor
600 East Boulevard Avenue
Bismarck, ND 58505-0310

Dear Ms. Fine:

Subject: EERC Final Report Entitled "Pipeline Leak Detection – Field Evaluation of Multiple Approaches for Liquids Gathering Pipelines"; Contract No. G-Produced Water Pipeline 02; EERC Fund 20602

Please find enclosed the subject Energy & Environmental Research Center report. If you have any comments or questions regarding the report, feel free to contact me by phone at (701) 777-5260 or by e-mail at jalmlie@undeerc.org.

Sincerely,

Jay C. Almlie
Principal Engineer
Mid/Downstream Oil & Gas Group Lead

JCA/bjr

Enclosure

c/enc: The Honorable Rich Wardner, Chair, Energy Development & Transmission Committee, North Dakota Legislature
Kevin Connors, Department of Mineral Resources
Lynn Helms, Department of Mineral Resources
Bruce Hicks, Department of Mineral Resources

Prepared for:

North Dakota Industrial Commission

and

Energy Development and Transmission Committee

PIPELINE LEAK DETECTION – FIELD EVALUATION OF MULTIPLE APPROACHES FOR LIQUIDS GATHERING PIPELINES

Prepared by:

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December 2016

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NOMENCLATURE

API	American Petroleum Institute
bbl	barrel
CFR	Code of Federal Regulations
CPM	computational pipeline monitoring
CRMP	control room management plan
DOT	Department of Transportation
EERC	Energy & Environmental Research Center
FWT	fluid withdrawal test
HB	House Bill
HDPE	high-density polyethylene
KPI	key performance indicators
LDS	leak detection system(s)
NDIC	North Dakota Industrial Commission
NTSB	National Transportation Safety Board
OOB%	out-of-balance percentage
PHMSA	Pipeline and Hazardous Materials Safety Administration
PLC	programmable logic controllers
psig	pounds per square inch gauge
RoC	rate of change
RP	recommended practice
RTTM	real-time transient model
SCADA	supervisory control and data acquisition
SPRT	sequential probability ratio test
SWD	saltwater disposal

PIPELINE LEAK DETECTION – FIELD EVALUATION OF MULTIPLE APPROACHES FOR LIQUIDS GATHERING PIPELINES

EXECUTIVE SUMMARY

Key Findings

This field evaluation successfully gathered data regarding the performance of leak detection systems (LDS) applied to liquids gathering pipelines in North Dakota. The strength of this evaluation rests in the fact that it is built on observed performance of actual LDS on real-world systems and operating conditions. As such, the collected data reflect the process, measurement, communication, equipment, and procedural complexity and anomalies that exist in the field but which might not otherwise be captured in a contrived experiment or simulation with rigid scientific controls. A number of key findings regarding leak detection approaches in real-world settings follow.

Performance Results

- Addition of LDS appeared to significantly reduce average size of releases on each of the three gathering pipeline systems that were evaluated:
  - 87%–93% reduction on unpressurized pipeline networks
  - 77%–99% on constant-pressure networks
- Addition of CPM (computational pipeline monitoring) appeared to enhance SCADA (supervisory control and date acccquisition) performance in unpressurized and more complex liquids gathering pipeline systems. CPM can also potentially estimate leak location, further reducing response time and volume released.
- Operation of less complex liquids gathering pipeline systems under constant pressure appeared to significantly reduce the average release size (however, pipeline physical characteristics can limit the ability of some pipelines to operate under such conditions).

	Overall		Constant Pressure*	Unpressurized	
	No LDS	LDS	SCADA	SCADA	SCADA + CPM
Average Volume Released Before Alarm, bbl	676	75	47	107	38
Time to Detect, hr			1–3	1–6	1–2

* Note: Constant pressure pipeline systems evaluated during this project were also smaller, less complex systems.

- LDS technologies vary widely in complexity, cost, and effectiveness. It is not appropriate to extrapolate the results of this field evaluation to other systems. There is no single, best solution for all gathering systems. In fact, as evidenced by test participants, multiple technologies are often employed simultaneously.

- A trade-off exists between faster detection and ability to detect smaller leaks. The penalty for pursuing faster detection of smaller leaks is an increase in false alarms. A limited number of false alarms can indicate that the LDS is sensitive to smaller leaks, but an excessive number of false alarms can be a distraction to operators.

- As reported in the Energy & Environmental Research Center's (EERC's) December 2015 study, "Liquids Gathering Pipelines: A Comprehensive Analysis," the importance of LDS is secondary to high-quality construction, inspection, maintenance, and operation of pipelines and to appropriate preparation and effective response to leaks that occur. However, as evidenced by the results of this study, LDS improves the timeliness of leak detection and reduces the volume of releases. It is therefore prudent that operators consider implementing LDS. Such consideration can be demonstrated by preparation and implementation of a formal leak detection plan.

Improvements as a Result of Testing

- By participating in this field evaluation, pipeline operators discovered limitations in their LDS and improvements that could be made. Each operator adopted at least one of the following improvements: tightened alarm settings to increase sensitivity, additional leak detection techniques to compensate for limitations in existing techniques, increased resolution or sampling frequency of some measurements, and/or additional leak-indicating variables not currently tracked.

Background

North Dakota has experienced a nearly fivefold increase in oil production since 2008, leading to rapid buildout of supporting infrastructure, including nearly 23,000 miles of gathering pipeline to transport crude oil and produced water from the production wells to various processing facilities. The vast majority of the fluids moving through the state's pipeline infrastructure reach their destination without incident. In fact, for every 10,000 barrels of fluid handled, only one is spilled. Nonetheless, growing public concern in North Dakota about the adverse effects of produced fluid spills on the environment led to passage of House Bill (HB) 1358. This legislation addressed many factors impacting gathering pipelines in North Dakota, including appropriating funding for the EERC to complete a study investigating construction standards and monitoring systems for liquids gathering pipelines. This study was utilized to guide the North Dakota Industrial Commission's (NDIC's) consideration of new administrative rules. The first of these new rules was released for comment in February 2016. The rules were approved by the North Dakota Legislature's Administrative Rules Committee in December 2016 and will become effective on January 1, 2017.

HB 1358 further directed the EERC to conduct a pilot project to evaluate a pipeline leak detection and monitoring system under real-world conditions. Going beyond the strict mandate of HB 1358, this field evaluation (the subject of this report) included testing multiple leak detection approaches on several pipeline systems operated by three different companies. This approach avoided the cost of building a test system and enabled a broader assessment of multiple LDS under multiple operating conditions.

A primary goal of the state is to ensure industry employs best practices to achieve safe transport of fluids and rapid detection and response in the event that a leak occurs. The results of this field evaluation provide valuable understanding and data about LDS performance on gathering pipelines, supporting efforts to allow monetization of North Dakota's vast petroleum resources while protecting public safety and the environment. The dynamic nature of oil production, rural geography, and extreme climate make the design, installation, and operation of gathering pipelines more difficult than pipelines in other industries and areas. These regionally unique aspects must be considered as operational practices, regulations, and technologies are developed to improve the safety and reliability of gathering pipelines. Within this context, it is important for the reader to understand several key assumptions that guided this project:

1) LDS do not typically prevent leaks, but they can minimize the magnitude or consequence of a leak.

2) LDS require installation of significant infrastructure to enable their use.

3) LDS performance degrades as operations and/or instrumentation deviate from optimal conditions.

4) LDS performance and optimal conditions vary from one detection approach to another.

5) LDS effectiveness has an important human component.

6) While LDS do find leaks, undetected leaks have occurred even in piping and detection systems considered to be of the highest quality.

LDS performance is not a product solely of LDS technology. Rather, it is the result of a complex relationship between the LDS technology, pipeline physical characteristics, and pipeline operating conditions at a specific point in time. This relationship is depicted graphically in Figure ES-1. Best performance arises when the LDS is designed and tuned for existing pipeline characteristics and conditions. Performance decreases as operating conditions move away from optimal—which can happen moment to moment—and as pipeline physical characteristics change because of aging or modification of pipelines. When LDS performance is evaluated, it is important to consider pipeline characteristics and conditions as well as the LDS technology.

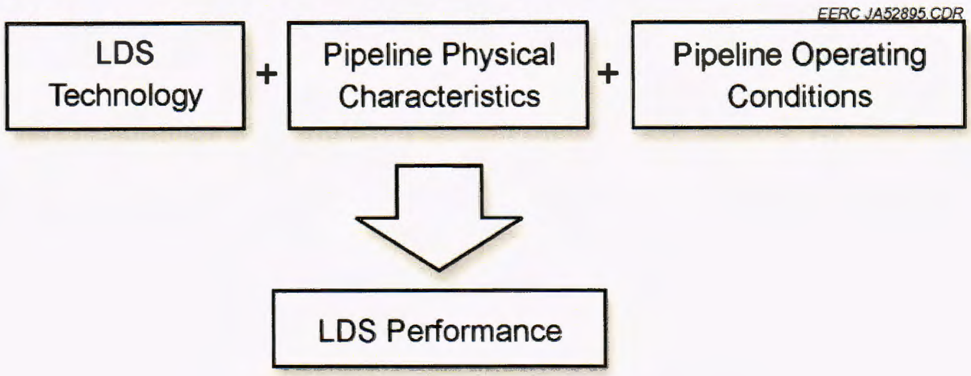


Figure ES-1. Elements of LDS performance.

Participating Volunteer Partners

Three pipeline operating companies agreed to participate in this field evaluation, each with a unique approach to leak detection and each relying on some type of SCADA system. Additionally, two of these companies agreed to participate in additional tests using an alternative LDS: one using a CPM approach and the other monitoring composite pipe annular space pressure. Thus the field evaluation project observed and evaluated the performance of the following:

- Seven varied LDS approaches developed
- Five different entities applied
- Six gathering lines of varying age and complexity
- Three operators
- Four patterns of withdrawal
- Eight days over the summer of 2016

It should be noted that the gathering pipeline systems of two of the field evaluation partner companies were similar in age and complexity. Both systems were simple, with only a few pumps on any lateral and only one or two pumping at any instant. Both companies' systems were fairly new, homogeneous in their design across their wellsites and, at the time of evaluation, overdesigned in anticipation of future multifold expansion. Additionally, both LDS appear to have been designed in conjunction with their pipeline systems. Consequently, both systems were nearly ideal in that many of the issues that might be encountered by more complex gathering systems with aging instrumentation and infrastructure were not evident. The third company's systems were older, much larger and complex, and less consistent (having originally been constructed by other operators). These are some of many factors that must be considered when seeking to understand and evaluate the performance of different LDS technologies.

Results Summary

The EERC conducted LDS testing using a general methodology tailored to meet the unique conditions of each pipeline and LDS. A test metering skid was designed and built by the EERC to allow EERC researchers to withdraw fluid from the partner company's pipeline, measure the rate and total flow withdrawn, and compare actual withdrawal data to the partner company's LDS. Fluids withdrawn from the pipeline were piped to a tanker truck and disposed of. The generalized test plan consisted of withdrawing fluid from the gathering pipeline at a steady rate and measuring the time and volume of fluid required before the partner company's LDS identified the "leak" and alarmed. Multiple tests were conducted at different flow rates and durations to assess the impact of different leak conditions on the LDS response.

A wide range of leak detection performance was observed from the EERC's fluid withdrawal tests (FWTs). Many different leak rates were evaluated. The time required to detect a leak for each test resulted in a wide range of "spilled" volumes. This variability can be attributed to many factors, including magnitude of gathering pipeline system flow rates, differences in the LDS, different geography and elevation of the pipeline system, and differences in the operational conditions—specifically, whether the pipeline is operated under pressurized or unpressurized conditions. Because testing was conducted on existing operational gathering systems, controlled tests could not be conducted to evaluate the effect of each of these factors on leak detection performance. However, a review of the data does provide some insight into these effects.

A summary of LDS performance during constant withdrawal rate testing is provided in Table ES-1. This information illustrates the wide range of spill volumes that occur based on test results and projections derived from available data.

Table ES-1. Summary of Constant Withdrawal Rate EERC Modeled FWT Spill Volumes

	Average, bbl	Max., bbl	Min., bbl
All 17 FWTs	75	299	<1
Five Tests on Pressurized Systems, SCADA	47	202	<1
Eight Tests on Unpressurized Systems, SCADA	107	299	12
Four Tests on Unpressurized Systems, CPM	38	90	16
All 17 Tests after 24-hr Manual Flow Accounting	676	1199	132

Operating gathering pipelines under constant pressure helps to reduce pipeline slack and makes leak detection by volume or mass balance (comparison of total fluid into the pipeline vs. total fluid out of the pipeline) much easier. Because void volume within the pipeline system is reduced, every barrel of fluid pumped into the system forces a barrel out of the system, making detection of leaked fluid easier. However, not all gathering systems can be operated under pressure since large elevation changes can lead to operating pipe pressures that exceed pressure specifications.

Another measure of LDS performance is the time required to detect a leak and alarm. Out of the tests conducted on pressurized gathering systems, the time required to detect a leak varied from less than 1 hour to almost 3 hours, excluding one test that was performed below the known detection threshold. In this case, the leak would likely be detected through a 24-hour manual volume comparison. The time required to detect a leak from tests on the unpressurized pipeline system ranged from less than 1 hour to nearly 6 hours. The time required for CPM LDS to detect a leak during testing on the unpressurized pipeline system ranged from less than 1 hour to under 2 hours.

The existence of pipeline slack in unpressurized gathering pipeline systems allows large amounts of fluid to be pumped into the pipeline, filling void volume, before flow increases out of the system. This condition can lead to slower response time in identifying a leak. Further, the amount of slack within the pipeline changes with time and operating conditions, creating a very dynamic condition that is hard to predict.

Cost–Benefit Analysis

Acknowledging the limitations of data collected from this field evaluation's relatively small set of pipeline conditions and LDS, the results provide some insight into the benefits that could be achieved by implementing SCADA-based or CPM-based technologies.

The addition of SCADA to a pressurized gathering pipeline system resulted in a 77%–99% reduction in total spill volume (depending upon how the data were averaged) when compared against manual logging and a time to detect of less than 3 hours. On unpressurized pipelines, the addition of SCADA resulted in a spill volume reduction of 87%–93% compared to daily volume accounting and a time to detect of less than 6 hours.

Using a simplified model pipeline system, defined for this analysis as a six-inlet gathering system with 10 miles of buried pipe, the addition of SCADA-based leak detection could cost as little as $100,000 (not including system development labor and management costs, which are likely significant but could not be ascertained from information provided by field evaluation partners) if communication costs are kept to a minimum and if existing instrumentation and process controls are SCADA-capable. This cost can climb to several million dollars if a more robust fiber-optic communication network is needed and installed as a retrofit to an existing pipeline system.

The use of CPM LDS requires an incremental addition of computer hardware and software on top of the entire infrastructure required for a SCADA-based LDS. Field evaluation results suggest that the addition of CPM to an unpressurized gathering system could provide a 96% reduction in total spill volume when compared to daily flow accounting and would reduce the time to detect to less than 2 hours. This improvement over SCADA would require an incremental cost of $50,000–$100,000 above the cost of SCADA, not including internal development labor costs, which are significant and difficult to accurately predict.

These costs are based on a relatively small model gathering system and are system-specific. Actual costs can vary significantly because of topography, miles of pipeline, and number of wellsites. Costs have been included here to provide an order-of-magnitude estimate for comparison with observed LDS performance.

An Important Note on Limitations of This Field Evaluation

Within this report, the authors provide observations of performance of several LDS on several unique gathering pipeline system configurations. The reader must avoid the temptation to directly compare performance of one LDS to another. This study does not, in any way, intend to directly compare performance of LDS. In fact, such comparisons are inappropriate to make accurately unless a controlled experiment with controlled test conditions is executed. This was not achievable within the scope, budget, and schedule prescribed to this project.

The results inform the reader on a possible range of system performance to calibrate expectations. These results cannot be directly extrapolated to other pipeline systems because myriad design/operational/environmental factors would significantly impact performance results. Similarly, costs to apply any particular LDS to various gathering systems vary widely because of many of these same factors.

Conclusions

This state-funded field evaluation resulted in real-world testing of LDS on three companies' gathering pipelines. This testing provided each gathering pipeline operator with valuable information that led to actual improvements to their LDS—improvements made after testing to improve sensitivity, add functionality, or reduce time to alarm in the event of a leak. The execution of this project directly contributed to improved leak detection functionality for multiple gathering pipeline systems operated by the three partner companies, reducing spill risk.

Basic performance results of each LDS tested are summarized in Table ES-2.

Table ES-2. Summary of Test Results

Participating Company	LDS Characterization	Leak Rate, bbl/hr	Volume Withdrawn at Time of Alarm, bbl	Time to Detect, hr
Company A	Volume balancing and pressure rate of change monitoring	5.5–5.6	13.8 –16.2	2.8–2.9
Company B1	Volume balancing over multiple moving time windows	21.2–49.9	11.6–121.3	0.29–5.71
Company B2	Statistical evaluation of flow balance and pressures with learning components	20.8–50.0	16.3–89.1	0.43–1.78
Company C1	Instantaneous flow balancing	8.4–14.0	0.1–0.94	0.07–0.96
Company C2	Annular space pressure measurement		No data	

Note: Differences in test conditions preclude direct comparison of performance.

Findings from the previously completed study and results from this field evaluation agree and indicate that adding some form of leak detection technology to pipelines increases the likelihood that a leak will be identified sooner, that leak magnitude will be reduced (relative to simple daily volume accounting), and that a leak will be located (if CPM is employed). Indeed, accurate location will reduce the response time and mitigate the environmental impact. An investment in LDS can be justified when compared to the cost of remediation of large spills. However, LDS technologies vary widely in complexity, cost, and effectiveness. There is no panacea for all gathering systems. It would be inappropriate and inaccurate to extrapolate these results to all gathering systems.

Pressurized gathering pipelines allow faster leak identification than unpressurized systems. In many cases, the topography of a region may prevent continuous pressurized operation because of pipeline pressure design limits. In these cases, alternative approaches may be used to enhance accurate flow balance through the use of backflow preventers, breakout tanks, or operating sections of pipeline systems under pressurized conditions.

This field evaluation project evaluated the performance of LDS and their ability to identify the occurrence of a leak. It was not within the scope to assess any company's effectiveness at responding to a notification of a leak.

PIPELINE LEAK DETECTION – FIELD EVALUATION OF MULTIPLE APPROACHES FOR LIQUIDS GATHERING LINES

INTRODUCTION

The last decade has seen growth in the oil industry at a rate that is unprecedented in the history of North Dakota. With over 12,000 producing oil wells in the state, oil production has undergone a nearly fivefold increase since 2008. Produced water is also generated along with the oil in volumes that are comparable to oil production. Industry has installed nearly 23,000 miles of gathering pipeline to move these tremendous volumes of fluids from the wellhead to various processing facilities. The vast majority of the fluids moving through the state's pipeline infrastructure reach their destination without incident. In fact, for every 10,000 barrels of fluid handled, only one is spilled. However, the increasing size of the system means that even low incident rates may result in a greater number of spills and attendant volumes in a given year. There has been growing public concern in North Dakota about the effects of spills of oil and produced water on agriculture, public health, and the environment.

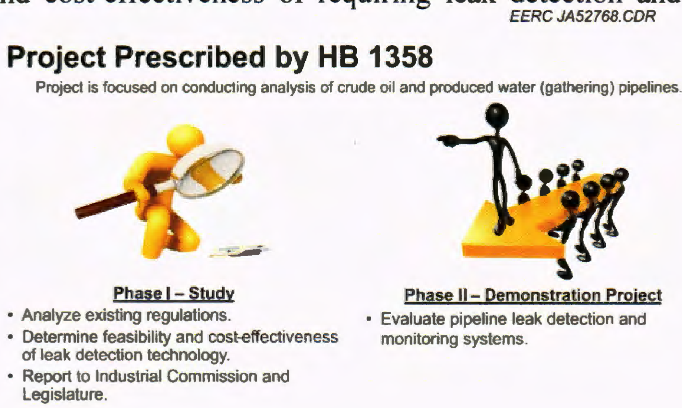
A primary goal of the state is to ensure that industry is employing best practices to ensure safe transport of fluids and rapid leak detection and attendant response in the event that a leak occurs. The results of the study will support the state's efforts to develop prudent regulations that enable the monetization of North Dakota's vast petroleum resources while protecting public safety and the environment. The dynamic nature of oil production, rural geography of western North Dakota, and extreme regional climate conditions make the design, installation, and operation of gathering pipelines more difficult than pipelines in other industries and areas. These regionally unique aspects must be considered as operational practices, regulations, and technologies are developed to improve the safety and reliability of gathering pipelines.

Pipeline Leak Detection Field Evaluation Pilot Project Directed by House Bill 1358

On April 20, 2015, North Dakota Governor Jack Dalrymple signed into law House Bill (HB) 1358. This legislation addressed the state's regulatory oversight of gathering pipelines for produced water and crude oil. The bill included enhancements for the prevention and detection of pipeline leaks and expanded the state's remediation and restoration program for land and water resources impacted by oil and gas development.

HB 1358 also authorized the North Dakota Industrial Commission (NDIC) to develop new rules involving the construction and operation of gathering pipelines. The bill included funding for the Energy & Environmental Research Center (EERC) to complete a study (Phase I) investigating construction standards and monitoring systems for liquids gathering pipelines. This study was utilized to guide NDIC's consideration of new administrative rules. The first of these new rules was released for comment in February 2016. The rules were approved by the North Dakota Legislature's Administrative Rules Committee in December 2016 and will become effective on January 1, 2017.

HB 1358 further directed the EERC to conduct a pilot project (Phase II) to evaluate a pipeline leak detection and monitoring system. The overarching objective of the legislatively mandated study was to determine the feasibility and cost-effectiveness of requiring leak detection and monitoring technology on new and existing pipeline systems. The more narrow objective of the field evaluation project was to demonstrate real-world applications of leak detection systems (LDS) and to define achievable performance. Going beyond the strict mandate of HB 1358, this pilot project actually evaluated and demonstrated on working pipelines several pipeline-monitoring practices and technologies identified in Phase I.



For purposes of this study, we choose to base our definition of LDS on concepts provided by the American Petroleum Institute's (API's) Recommended Practice 1175 "Pipeline Leak Detection – Program Management," defining a leak detection system as the collection of resources or components, including but not limited to processes, personnel, facilities, and equipment, intentionally and systematically applied to support leak and rupture identification on a specified segment of pipeline. An LDS can observe pipeline conditions continuously or noncontinuously, internally and/or externally; can interpret observations automatically or with human intervention; and can apply a single or multiple technologies to detect and indicate a leak.

Intent of Field Evaluation Phase

The gathering pipeline monitoring and leak detection field evaluation project prescribed by HB 1358 served as a platform to test current and new leak detection technologies applied to gathering systems. This field evaluation project was conducted to test performance, determine infrastructure requirements, estimate cost to pipeline operators, and provide objective analysis of the cost/performance ratio. It does not address the peripheral factors influencing leak detection, such as human performance. The human factor is an important facet of response, but the study is confined to an assessment of the more automated components of LDS.

While much information was provided in the original EERC report entitled "Liquids Gathering Pipelines: A Comprehensive Analysis," the field evaluation project reported herein was designed to provide additional detail on the broad array of liquids gathering pipeline leak detection systems employed in North Dakota. It was hoped that this information could highlight both the challenges and benefits of application of such systems within a context appropriate for consideration by North Dakota lawmakers and regulators.

The intent of HB 1358 with respect to this study was to determine the "feasibility and cost-effectiveness" of LDS applied to gathering pipeline systems in North Dakota. It is with that direction that the EERC conducted this work.

Within this report, the authors report on EERC observations of performance of several LDS on several unique gathering pipeline system configurations. The reader must avoid the temptation to directly compare performance of one LDS to another. This study does not, in any way, intend to directly compare performance of LDS. Such comparisons are inappropriate, unless a controlled experiment with controlled test conditions is executed. It was not financially feasible to construct an operating pipeline and install leak detection systems onto that pipeline within the scope, budget, and schedule prescribed to the project. Such a "test" pipeline would also not likely be able to adequately replicate real-world conditions.

The results inform the reader on a possible range of system performance to calibrate expectations. These results cannot be directly extrapolated to other pipeline systems because myriad design/operational/environmental factors would significantly impact performance results. Similarly, costs to apply any particular LDS to various gathering systems vary widely because of many of these same factors.

Prior Assessments of Leak Detection System Performance

The EERC report entitled "Liquids Gathering Pipeline: A Comprehensive Analysis" contained a lengthy discussion on previous LDS studies, including a 2012 Pipeline and Hazardous Materials Safety Administration (PHMSA) study, a 1999 Alaska Department of Environmental Conservation study, and preliminary reports on a 2015 Nexen Energy pipeline failure with possible implications for LDS performance expectations. The reader is advised to review this discussion in that report, which can be found at www.undeerc.org/Bakken/Pipeline-Study.aspx. These reports all indicate that LDS, although useful in reducing the magnitude of a leak, cannot prevent leaks.

Also available in the EERC report is a detailed description of available approaches to leak detection, including many approaches to internal leak detection and fewer approaches to external leak detection. This information may further assist the reader in understanding the limits of applying LDS to liquids gathering pipelines and thus may assist the reader in understanding the approaches employed by the volunteer field evaluation partners on which the EERC reports herein.

Key findings of the Phase I study with respect to the statistical analysis of spills and LDS can be summarized in the orange balloon below.

Phase I Key Findings on Leak Detection Systems

Leak detection technologies reviewed by the EERC pipeline study were either reported by or considered for use on transmission pipelines, where their success has been limited. No body of knowledge has been uncovered by this study documenting application of these technologies to gathering pipelines, which are expected to be more challenging than transmission pipelines. It should be emphasized that gathering pipelines present unique challenges to leak detection technologies. As a result, some care must be taken when transmission pipeline experience is extrapolated to gathering pipelines.

Most pipeline leaks are discovered visually by people who happen to be in the vicinity of the spill. Sensor and software technology is evolving to meet the needs of leak detection but has not yet achieved perfect reliability. To identify leaks earlier and to minimize impacts, operators should be encouraged to incorporate SCADA (supervisory control and data acquisition) technologies on their gathering systems. This will improve communication within and between the various operators using the system. A modest investment in advanced systems to decrease the impact of pipeline spills is easily justified when a company recognizes that costs of remediation efforts may be larger by orders of magnitude.

Setting Expectations on LDS

LDS performance is not a product solely of LDS technology. Rather, it is the result of a complex relationship between the LDS technology, pipeline physical characteristics, and pipeline operating conditions at a specific point in time. This relationship is depicted graphically in Figure 1. Best performance arises when the LDS is designed and tuned for existing pipeline characteristics and conditions. Performance decreases as operating conditions move away from optimal—which can happen moment to moment—and as pipeline physical characteristics change because of aging or modification of pipelines. When LDS performance is evaluated, it is important to consider pipeline characteristics and conditions as well as the LDS technology.

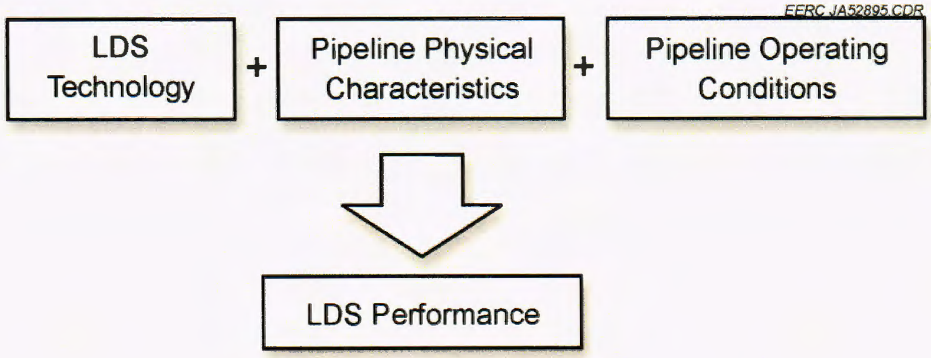


Figure 1. Elements of LDS performance.

It will be helpful for the reader to digest the contents of the current report with a realistic set of expectations regarding LDS. LDS are risk mitigation technologies capable of reducing the number and severity of leak incidents but are not a panacea for stopping leaks. Important calibrations of expectations are listed in the yellow balloons below.

1. Leak detection systems do not prevent leaks.

Pipelines are ubiquitous in modern society and provide much of the transportation of our water, oil, and natural gas. Unintended release of these commodities from the pipeline negatively impacts both the environment and operator finances. Naturally, therefore, attempts are made to reduce the likelihood of these occurrences.

In the event of an unintended release of the transported commodity, the objective is to minimize both loss of commodity and damage to the surrounding environment. Herein lies the mission of LDS: not to prevent leaks and commodity release but to alert the pipeline operator of the release such that it can be minimized. Control rooms dedicated to pipeline monitoring do aid in the reaction to leaks, but specialized LDS enhance the ability of an operator to identify a leak quickly and accurately.

2. Leak detection systems require installation of significant infrastructure.

In its most basic form, an internal LDS is a suite of physical measurements of a commodity being transported by a pipeline evaluated for inconsistencies that would indicate an imbalance between system inlets and outlets. For liquid commodities, these physical measurements can include temperature, pressure, density, volume, and mass of the material being transported. These measurements are taken at multiple locations along the pipeline to assess the quantity of commodity entering and leaving the pipeline at any given moment.

This information is communicated to a location that performs accounting functions and reports potential loss of commodity due to theft or unintended release. This communication can be formatted as analog or digital data and can be transmitted via cellular data networks, radio data networks, satellite transmission, or direct fiber-optic communication. All of these options are currently utilized in North Dakota. Application of these data flows varies significantly, depending on company, location, topography, and third-party availability. This instrumentation and communication network requires significant planning and development to properly deploy, operate, and maintain and can, therefore, be quite costly.

3. Leak detection system performance degrades as operations and instrumentation deviate from design conditions.

A key factor for effective LDS performance is instrumentation maintenance. Many organizations have routine instrumentation maintenance schedules. The wetted sensor can drift or become fouled with material and will give less accurate readings to the SCADA system if not maintained regularly. Additionally, gathering pipeline system operations change, sometimes at fairly significant rates because of various factors, including production decline of wells with time, changes in the number of gathering pipeline system inputs, changes in instrumentation quality and quantity over time, etc. All of these factors require change management schemes that are designed to bring all of the personnel involved and the actual LDS itself up to date and functioning effectively within the parameters of the latest system changes.

4. Leak detection system performance and optimal conditions vary from one detection approach to another.

Each LDS demonstrated within this field evaluation project possessed unique physical and operational attributes. In gathering pipeline systems, this is the norm, not the exception. Gathering pipeline operators exhibit wide diversity in approaches to, and circumstances affecting, leak detection and pipeline operational monitoring:

- Packed vs. Slack Lines: Two of the gathering pipelines systems demonstrated within this project were pressurized. The third system operated with limited, intermittent pressure and slack lines. Fluid leaks are easier to identify in pressurized and packed lines than in slack lines. However, because of topography, materials of construction, and other operational conditions, it may not be possible for all pipelines to run pressurized and packed.

- Control Room Facilities and Operations: One system employed a continuously manned control room in another state; one system employed a small, portable monitoring building at the disposal site which was only periodically manned but which has an advanced alarm notification system; and one system utilized an in-state, but remotely located, control room that was also continuously manned. These approaches result in vastly differing data management and transmission needs.

- Specific Algorithm Employed: Each of these systems employed unique approaches to leak detection algorithms: statistical methods, physics-based modeling, simple monitoring combined with operator intuition, or other methodologies.

- Communications Infrastructure: Each pipeline operations area in North Dakota presents unique communications infrastructure limitations. Hilly terrain is challenging to radio communications. Cellular communications towers are in limited supply in remote back country. Rights of way are often not negotiated to permit use of expensive fiber-optic cable communications. Companies must navigate these challenges specific to the location of each gathering pipeline system. Some gathering pipeline systems may require the integration of multiple communications platforms.

- Topography: Elevation changes across a gathering pipeline system result in greatly varying pressures because of hydraulic head. This, in turn, drives multiple gathering system design aspects and thus employment of leak detection on that system.

5. Leak detection effectiveness has an important human component.

Previous studies have concluded that most pipeline leaks are discovered by humans in the vicinity of the leak. Another important aspect of human factors in leak detection is the human–machine interface in the control room. Most LDS will issue an alarm. It is then left to the control room operator to determine the validity of the alarm and next steps to be taken. Many factors affect the time required to make decisions and the outcome of the control room operator's response: amount and quality of information displayed by the SCADA/LDS (e.g., large numbers of false alarms can decrease operator sensitivity to alarms), quantity of competing duties assigned to the operator, presence of other personnel in the control room, fatigue, extent of operator training, and many other factors.

In a National Transportation Safety Board (NTSB) review of 13 hazardous liquid pipeline accidents, NTSB found that ten incidents exhibited significant delays in reaction time due to causes directly related to human factors in LDS. Developing good control room management with procedures that include best industry practices and proper training methods should be a significant part of the overall LDS and process.

6. While leak detection systems do find leaks, undetected leaks have occurred even in piping and detection systems considered to be of the highest quality.

The Nexen Energy pipeline in northern Alberta was described as one of the most technologically advanced and safest pipelines ever commissioned. It consisted of double wall, pipe-in-pipe construction, with a state-of-the-art continuous fiber-optic external LDS. On July 15, 2015, a contractor walking along the pipeline discovered a 5-million-liter (31,500-barrel) spill of bitumen, sand, and water. According to various news accounts (D'Aliesio and others, 2015), the pipeline may have been leaking for almost 2 weeks before the leak was discovered. This would also imply that the containment pipe, the external fiber-optic system, and any internal leak detection and SCADA monitoring systems were ineffective in detecting the 31,500-barrel leak. While the cause of the pipeline failure was identified and publicly disclosed a year after the incident, no explanation for the LDS failure has been released. However, whether the root cause is found to be controller error, LDS error, or a design flaw, the principles of aggressive controller training, examining leading indicators that lead to failure, and spill response planning are still relevant.

Important Characteristics for Evaluating Leak Detection Systems

While LDS are commonly evaluated in various ways (e.g., cost and performance, quantitative, and qualitative) and by numerous characteristics, perhaps the most important characteristic is the fact that no single LDS is effective on all pipelines at all times. For this reason in 2003, Germany published rules (Technische Regel für Rohrfernleitungen) governing pipelines that transport flammable or otherwise dangerous fluids which require application of multiple LDS approaches to such pipelines.

Yet, even when multiple systems are applied, conditions can arise that mask leaks (e.g., Nexen's 2015 Alberta pipeline leak was monitored by an LDS that has been described as "foolproof," yet leaked an estimated 31,500 bbl before being discovered). A second important characteristic is that LDS detect, but do not prevent, leaks. This absence of certainty in detecting all leaks and inability to prevent leaks does not imply that LDS has no value. On the contrary, such systems have detected many pipeline leaks and greatly reduced the volumes of fluids that might otherwise have been released and impacted surroundings of the pipelines. For this reason, implementation of LDS on gathering pipeline systems has been increasing with time and is expected to continue.

LDS have been characterized as being "internal" or "external." Internal LDS monitor conditions within pipes to infer that a leak exists. External LDS monitor pipe, surroundings in contact with pipe, or aboveground surroundings to identify indications of leaks. Internal LDS apply SCADA oftentimes in conjunction with specialized computer software termed "computational pipeline monitoring" (CPM) to identify conditions within the pipe that are indicative of leaks. External LDS employs sensors in close proximity to pipelines or aboveground remote sensors to detect indications of leaks.

Both types of LDS identify leaks by comparing actual pipeline or surrounding conditions with either an understanding of "no-leak" conditions or an understanding of conditions that leaks create. Such understanding can derive from application of physical principles to the pipeline situation or historical experience of the pipeline. As depicted graphically in Figure 2, the effectiveness or quality of an LDS, relies on:

1. How closely the understanding of the pipeline matches the actual physical state and behavior of that pipeline.

2. How closely the monitoring of the pipeline matches the actual physical state and behavior of that pipeline.

3. How effectively they can be compared.

Comparison can be automatic (e.g., comparing two numerical values such as a measurement and an alarm limit) or might involve more qualitative interpretation. In both instances, human judgment is involved either in establishing the alarm limit or establishing guidelines for and performing interpretation. Thus, in both cases, the characteristic of understandability or simplicity

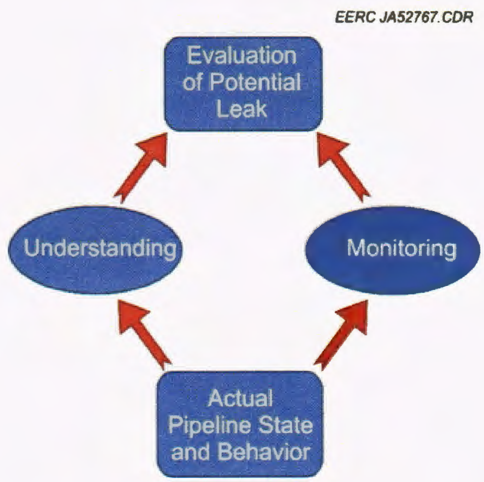


Figure 2. Relationship between recognizing a potential leak and actual pipeline behavior.

is required to enable the human decision maker to make the best possible decision. Another important characteristic affecting the effectiveness of LDS is timeliness. Delays in acquiring information or performing the comparison can reduce the effectiveness of the LDS by delaying action to stop a leak.

An overarching characteristic of LDS is cost. These costs include the following:

- Cost to acquire understanding
- Cost to install adequate monitoring which includes field sensors
- Cost of communication infrastructure
- Cost of computers and related infrastructure
- Cost to develop procedures
- Cost to train controllers
- Cost to develop software to aid controllers in decision making
- Cost of facilities
- Cost of other infrastructure
- Cost to operate
- Cost to maintain
- Cost to update
- Cost to upgrade the above as time degrades equipment, pipelines expand, and other conditions change

LDS vary considerably with respect to the demands they place on the amount, accuracy, quality, and timeliness of information and resources which creates a broad range of costs over time among LDS.

API-Defined Factors

Recommended practices (RPs) of the API, such as RP-1130 "Computational Pipeline Monitoring for Liquids," RP-1149 "Pipeline Variable Uncertainties and Their Effect on Leak Detection," and RP-1175 "Pipeline Leak Detection Program Management" provide numerous LDS characteristics that can be applied in evaluating LDS effectiveness. A summary of these RPs is provided in Appendix A. API RP-1130 has identified four performance metrics and several criteria for each. RP-1175 has identified several key performance indicators (KPI) that provide criteria by which to quantify LDS performance. A subset of these criteria, defined in Table 1, was considered in evaluating the performance of systems that participated in leak withdrawal testing. Project limitations such as project schedule and resources, test time available during a single day, and the fact that testing was performed on operating gathering pipelines constrained which metrics could be evaluated.

Table 1. Four Metrics for Assessing Leak Detection Performance

Metric	Definition	Limitation Relative to Field Evaluation
Robustness	Measure of an LDS ability to continue to function and provide useful information under conditions that are outside of the system's design conditions.	Requires operating outside of design conditions, which is not easily accomplished on live, operating gathering pipelines.
Reliability	Measure of an LDS ability to accurately report the existence of a leak.	Requires monitoring gathering pipelines for extended periods of time (durations that could potentially have exceeded this project's schedule) to obtain false indication statistics such as false positive or "alarm under no-leak conditions" indications, and false negative or "failure to detect leak" indications.
Sensitivity	Measure of an LDS ability to detect and notify operators of a leak. Related to time to alarm and leak size. The penalty for increased sensitivity is increased likelihood of false positive alarms; false alarms can decrease operator sensitivity to alarms.	Requires the operator to set tight alarm limits that would result in increased false positive alarms. This was another undesirable condition to impose on live, operating gathering pipelines.
Accuracy	Measure of the validity of LDS estimates of leak characteristics (e.g., leak location, flow rate, and volume released).	This metric could be evaluated in a limited sense. The extent was limited by the roughly 8-hour maximum daily test duration. This, in turn, limited the minimum size of withdrawal that could be detected by the LDS during testing (i.e., smaller leaks require more time to detect) and was limited by the fact that not all operators monitor and record each leak characteristic.

Ultimately, six KPIs were evaluated:

<u>SENSITIVITY KPIs</u>

- Observed withdrawal volume
- Flow rate alarm points
- Observed time to alarm

<u>ACCURACY KPIs</u>

- Withdrawal flow rate errors
- Volume errors
- Location errors

The limited duration of this project also limited the project's ability to thoroughly investigate false positive alarms and thus the metric of sensitivity. The EERC acknowledges this limitation in this field evaluation. A thorough evaluation of this metric would require a statistically representative sample of alarms incurred over an extended period of time—years, perhaps. The reader is encouraged to understand that almost any LDS can be tuned to respond to ultralow thresholds to achieve frequent alarms. This, however, must be balanced against the need to maintain a relatively high focus on alarms that do occur. Too many alarms tend to diminish the response of pipeline operations staff to those alarms.

Other Factors

Other factors, not formally considered by API standards, must be considered by designers of pipeline control systems and LDS, as summarized in Table 2.

Table 2. Other Factors Considered in LDS Evaluation

Factor	Description
Applicability	Selection of a leak detection method is highly dependent upon the available instrumentation, communication, and SCADA capability designed into the system.
Graceful Degradation	Changes in operation or system health can reduce the effectiveness of LDS. Graceful degradation monitors for and adapts to these changes to avoid a catastrophic failure.
Resource Requirements	Resource requirements vary considerably among leak detection approaches. Sophisticated approaches carry with them greater resource requirements, as depicted graphically in Figure 3. Notes below the blocks in the figure indicate approaches employed by field evaluation partners. These companies will be discussed further in the following report section.
Compatibility	Compatibility of components within an LDS and among the LDS pipeline and control personnel is critical to achieve optimal or even satisfactory performance of the LDS.
Ease of Use	Because more capable LDS tend to be more sophisticated and more sophisticated systems are often less easy to use, there is often a trade-off between performance and ease of use.
Accessibility and Security	Accessibility to LDS information is mandatory for control personnel but is sometimes limited by security requirements. Security ensures the reliability of LDS information by protecting it from tampering and unintended disclosure.

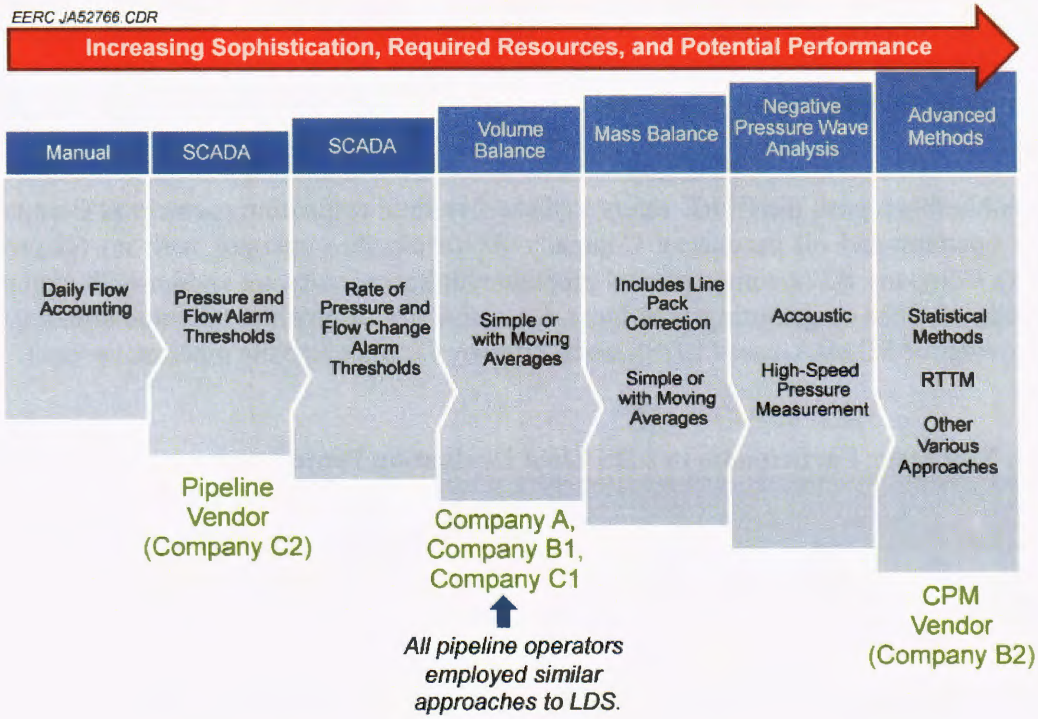


Figure 3. Relative sophistication of various LDS approaches.

SOLICITATION AND SELECTION OF INDUSTRY PARTNERS

During the course of the initial pipeline study (Phase I), the EERC made known among industry stakeholders advising the study that a follow-on field evaluation project would be executed, with industry support, in 2016. The EERC briefed the stakeholder group on general scope of work of the field evaluation project and general expectations of volunteer companies. The EERC continued to solicit participation from up to three partners into the spring of 2016.

This project was conducted with volunteer participation from willing pipeline operators who wished to share information with the State of North Dakota on leak detection approaches their companies considered to be proficient and cost-effective. Industry participation was critical to the success of this field evaluation project.

Site visits and information exchanges between potential industry partners and the EERC ultimately resulted in three operating companies volunteering to participate in the field evaluation project. Industry participation was contingent upon confidentiality. Therefore, the participants are not identified by name in this report.

In addition to pipeline operator companies, the EERC was also able to secure the participation of third-party vendors that have marketed their systems in the state for use on liquids gathering pipelines. One third-party vendor provided a CPM-based leak detection system that was installed in parallel to an existing leak detection system. This provided valuable data that demonstrated benefits and limitations of this particular approach to leak detection. Another third-party vendor participated by demonstrating the capability of its composite pipeline material to function as a critical portion of a leak detection system. These partners are summarized in Table 3.

Within this report, the EERC refers to these five field evaluation partners as Company A (a pipeline operator and oil producer), Company B1 (a pipeline operator with no oil production interests), Company B2 (a computational pipeline monitoring software vendor with experience in application of CPM to gathering pipelines), Company C1 (a pipeline operator utilizing a third-party provider of SCADA-based LDS), and Company C2 (a composite pipeline vendor).

Table 3. Volunteer Participants in LDS Field Evaluation Project

Partner	Sector	Fluid Carried	Pressurized Pipeline?	Pipeline Material	Leak Detection Technology
A	Oil producer and pipeline operator	Produced water	Yes	Fiberglass	In-house SCADA LDS
B1/B2	Pipeline operator/vendor	Produced water	No	HDPE*	B1: In-house SCADA LDS B2: Parallel 3rd-party CPM
C1/C2	Pipeline operator/vendor	Produced water	Yes	Composite	C1: 3rd-party SCADA LDS C2: annular space leak detection

* High-density polyethylene.

PLANNING AND EXECUTION OF FIELD EVALUATION OPERATIONS

General Fluid Withdrawal Test Plan

The EERC approached each field evaluation participant with a generalized test plan for the fluid withdrawal test (FWT). This generalized test plan was then modified through an iterative process with each committed organization to tailor the plan to fit their particular systems. The EERC asked each industrial partner to provide the EERC with a leak detection limit/fluid withdrawal rate that the company felt was an achievable detection limit for its particular LDS approach. The team then incorporated that target withdrawal into the test plan.

While each test was somewhat unique, the basic principles of the test plan remained the same for all of the FWTs. The general test plan is broken out into three separate activities:

1. Arrival and skid set-up
2. FWT
3. Sudden release testing

The arrival and skid set-up activity was conducted to ensure understanding of intended test protocol with all participants. The FWTs were intended to simulate leaks of different sizes. The sudden release series was intended to simulate an abrupt rupture at various sizes/leak rates, with a focus on observing the impact on pipeline pressure. The generalized test plan is outlined in Appendix B.

Fluid Withdrawal Metering Skid

The EERC designed and built a metering skid to measure fluid withdrawals from the pipeline. This metering skid was designed to pass pipeline fluid through a highly accurate Coriolis mass flowmeter to measure fluid withdrawal rate, density of the fluid, and temperature of the fluid. These data were recorded for each FWT on a computer connected to the metering skid. The metering skid measured this fluid withdrawal from a gathering pipeline before the fluid was transferred to a tanker truck.

A photograph of the EERC metering skid connected to a gathering pipeline is shown in Figure 4. In this photograph, the metering skid is connected to a gathering pipeline (to the right) by a steel-braided hose and to a tanker truck (to the left). This photograph shows that a fluid withdrawal port was available on the gathering pipeline that reduced down to a 1-in. fitting. Two valves were installed after the reduction: one valve was a ball valve for opening and closing the flow to the metering skid, and the other was a globe valve for controlling the rate of flow to the meter skid. The steel-braided hose connected the valve port on the gathering pipeline to the meter skid.

Figure 5 shows a close-up view of the metering skid connection to a gathering pipeline. Once through the Coriolis meter, the fluid exited the metering skid through a flexible hose that connected to a tanker truck. The metering skid logged the data continuously to a laptop for data reduction at a later date.

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Figure 4. EERC metering skid illustrating connection to a gathering pipeline.

Figure 5. Metering skid connection to the gathering pipeline.

FIELD EVALUATION PERFORMANCE RESULTS

The strength of this evaluation rests in the fact that it is built on observed performance of actual LDS on real-world systems and operating conditions. As such, the collected data reflect the process, measurement, communication, equipment, and procedural complexity and anomalies that exist in the field but which might not otherwise be captured in a contrived experiment or simulation with rigid scientific controls.

A concerted effort was undertaken to avoid introducing artificial effects other than withdrawal into the tests. When possible, control room operators were not informed of testing. Unfortunately, performing more than one test a day often required some form of reset of the LDS between successive tests. This was not a normal operation and impacted results variously among different systems.

In evaluating observed performance of gathering pipeline LDS, this study adopted standards specified in API RP 1130 and RP 1175, as well as API Publication 1155. The study also considered API RP 1149 and is aware of U.S. Department of Transportation (DOT) regulations under PHMSA (i.e., Title 49 CFR Parts 190-199), Canada's CSA Standard Z662, and Germany's Technische Regel für Rohrfernleitungen.

Operator Participation and Response to Testing

For many reasons, including realism, FWT is considered to be a petroleum transportation industry best practice for LDS testing (Vinh and others, 2012). While it is not uncommon for large interstate pipelines to perform such testing, the resources required to perform such testing on gathering pipelines with such small flows of low-value liquids are more difficult for gathering pipeline operators to justify. As a result, the first exercise of a gathering pipeline LDS is, in some cases, a response to an actual leak.

The operators and CPM vendor that participated in field evaluation activities were very supportive during all phases of testing: preparation, execution, and posttest data reporting. These partners should be lauded for their willingness to commit significant resources to the project. Their participation was instrumental in the success of the project. Operators who voluntarily participated in this project had not previously accomplished withdrawal testing, were able to observe the system perform under controlled "leak" conditions, and were generally pleased with their own LDS performance. Each also discovered limitations of the LDS and improvements that could be made. Each operator adopted at least one of the following improvements that can be attributed to participation in this project:

- Tightening alarm settings to increase sensitivity without significantly increasing risk of false positive alarms

- Incorporating additional leak detection techniques to compensate for limitations in existing techniques

- Increasing the resolution or sampling frequency of some measurements

- Monitoring leak-indicating variables not currently tracked

Detailed Analysis of Company A Field Evaluation

Company A's Approach to Leak Detection

Company A utilized an LDS developed in-house to monitor a pressurized produced water gathering pipeline. Company A's gathering pipeline system was relatively simple, consisting of five production sites and one disposal site and was operated with only one or two pumps functioning at any one time to create an essentially constant pressure of approximately 300 psig to minimize slack in the pipeline (see Inset A for definition). The decision to operate the pipeline at a pressure of 300 psig was based upon a company desire to limit the presence of a gas phase. The company's position was that slack causes issues with flow measurements, negatively impacting calculations of fluid volume moved through the line.

INSET A: DISCUSSION OF SLACK PIPELINE FLOW

Slack pipeline flow is the existence of gas phase in conjunction with the liquid-phase material at certain positions in the pipeline. This often occurs downstream of a peak in the pipeline as it traverses through uneven topography.

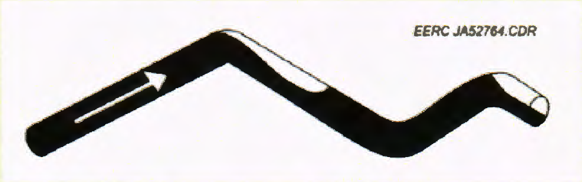

Illustration of slack pipeline flow

This phenomena is caused by the reduction of pressure in the pipe to below the vapor pressure of the liquid being transported as a result of an increase in the velocity of the fluid as it crests and starts flowing down. Slack can be problematic for LDS. In pipelines, the potential for water hammer in the pipe as vapor bubbles collapse presents serious potential harm to the integrity of the pipe material.

Slack pipeline can also be used to describe pipelines that run intermittently and have no flow entering the pipeline for periods of time while fluid is allowed to drain from the pipeline by gravity when no pumps are running. In this case, the pipeline will have sections of pipe that remain empty until pumps start up and begin to pack the pipeline, pushing these gas bubbles to either vents in the pipeline or to the end storage vessel.

Intermittent filling and emptying of pipelines can be problematic for LDS of almost any kind. For mass or volume balance LDS, some material will necessarily be left in the pipe at low elevations and will not be accounted for at the outlet of the pipeline, thus giving an indication that there is a potential leak in the system since not all that has entered the pipeline has exited the pipeline. The normal method of dealing with this is to average the flows over several periods of pumps shutting off and the pipeline emptying. This, however, increases the amount of time required for an LDS to account for leaks.

For systems running CPM, the solution is significantly more complicated computationally. An example of how slack is dealt with through techniques such as RTTM (real-time transient modeling) is presented in Nicholas (1995). Company B2 utilizes a different, proprietary method.

Company A was the only operator of those volunteering to participate in this field evaluation project that utilized fiber-optic communications for data transmission from field instruments to the SCADA server.

Company A's LDS is SCADA-based and performs balancing of the volumes entering and exiting the system. Pipeline pressure at the entrance to the saltwater disposal (SWD) site is maintained at 300 ±2 psig using a combination of pumps and actuated control valves. The LDS utilizes SCADA inputs to calculate a moving-window volume balance of the commodity flow through the pipeline in an 8-hour window.

At the start of the first day of testing, the pipeline was moving approximately 100 bbl/hr, but the flow diminished throughout the day as tanks reached low level limits. The LDS leak detection limit was set to approximately 1.25% of flow. If, during any 8-hour period, a discrepancy of 1.25% was detected between the incoming volume and the outgoing volume, a leak detection alarm was signaled. If the volume imbalance reached 1.5%, the system automatically stopped all pumps and opened the valve at the SWD site to depressurize the pipeline and minimize commodity release to the environment.

In addition, the system would alarm if the pressure dropped by greater than 10 psig for more than 10 seconds. The 10-second time period was used to avoid false alarms under normal operating conditions. Company A observed empirically that pumps turning on or off affect pressure within the pipeline. Therefore, a 2.5-minute delay was implemented to allow the pressure to stabilize. Depending on the commodity release rate, the LDS can signal a leak fairly quickly and be an effective tool for minimizing unwanted commodity release to the environment.

Specific Description of Company A Test Plan

Company A tests were performed at two separate locations on the same gathering pipeline, as shown in Figure 6. Location No. 1 was at the gathering pipeline entrance to the SWD site, just before the pipeline discharged into holding tanks at the SWD wellsite. Location No. 2 was several miles from the SWD site on the same gathering pipeline, located immediately downstream of a wellsite. Two locations were selected in an effort to evaluate differences in LDS performance as a function of location on the gathering pipeline system.

Company A operated the subject gathering pipeline at a constant pressure of approximately 300 psig. Company A's gathering pipeline has a pressure control valve at the SWD wellsite to maintain the pipeline pressure. During the first FWT performed at the SWD wellsite, the fluid was withdrawn a few feet upstream of the pressure control valve.

Company A monitored the gathering pipeline in a control room located at one of its North Dakota office locations some distance from the gathering pipeline. For this particular gathering pipeline system, Company A employed fiber-optic communication to connect all instrumentation and programmable logic controllers (PLCs) to the control room. The use of fiber-optic communication on a gathering pipeline is extremely beneficial because it dramatically improves the speed and reliability of data communication over cellular, radio, or satellite communications, which are more typical in North Dakota.

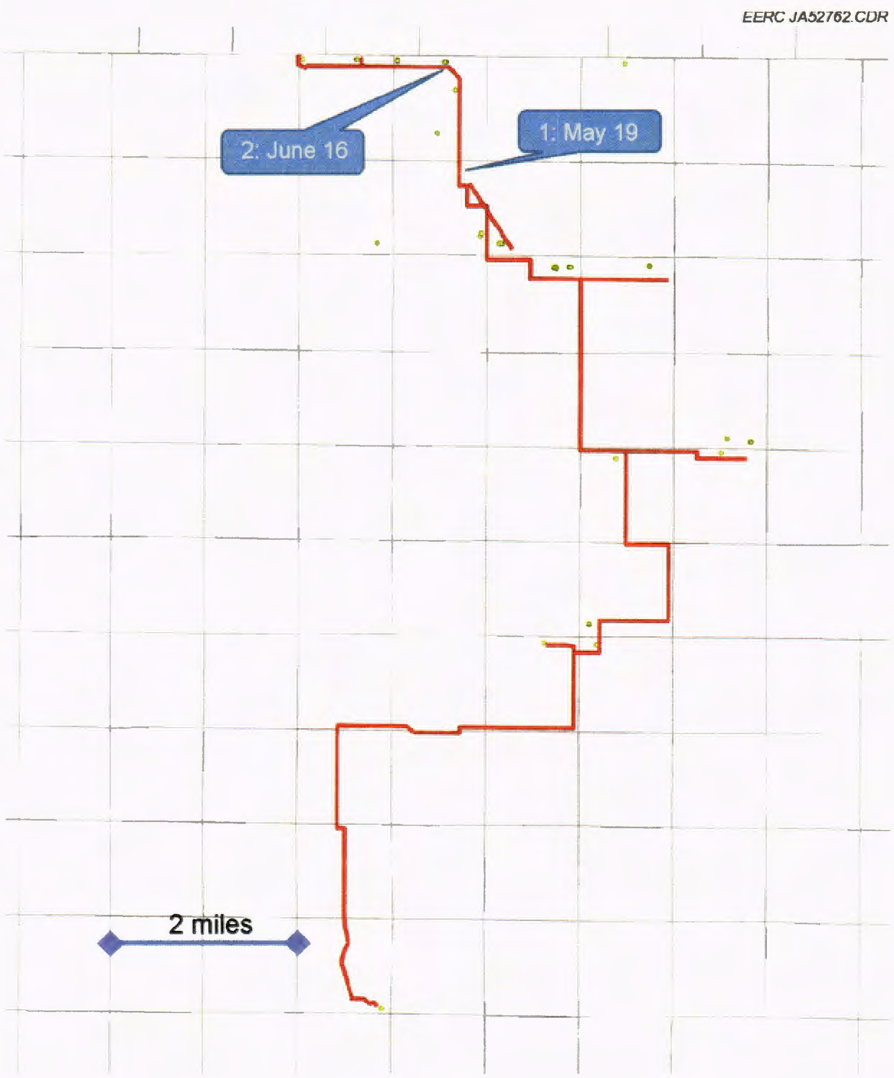

Figure 6. Map of Company A's pipeline system.

The EERC adjusted the general test plan shown in Appendix B to accommodate the unique physical and operational conditions of Company A's system. The test plan was reduced to only two series of tests each day: an FWT with a flow/leak rate of approximately 5.5 bbl/hr through the EERC metering skid and a series of sudden release tests. The time line of test activities is summarized graphically in Figures 7 and 8. In these figures, a red marker indicates an alarm produced by Company A's LDS. Note that because testing was intended to calibrate expectations of the sensitivities of LDS, some small leaks were below alarm thresholds. Consequently, not every test resulted in an alarm being triggered. The system configuration is summarized in Table 4.

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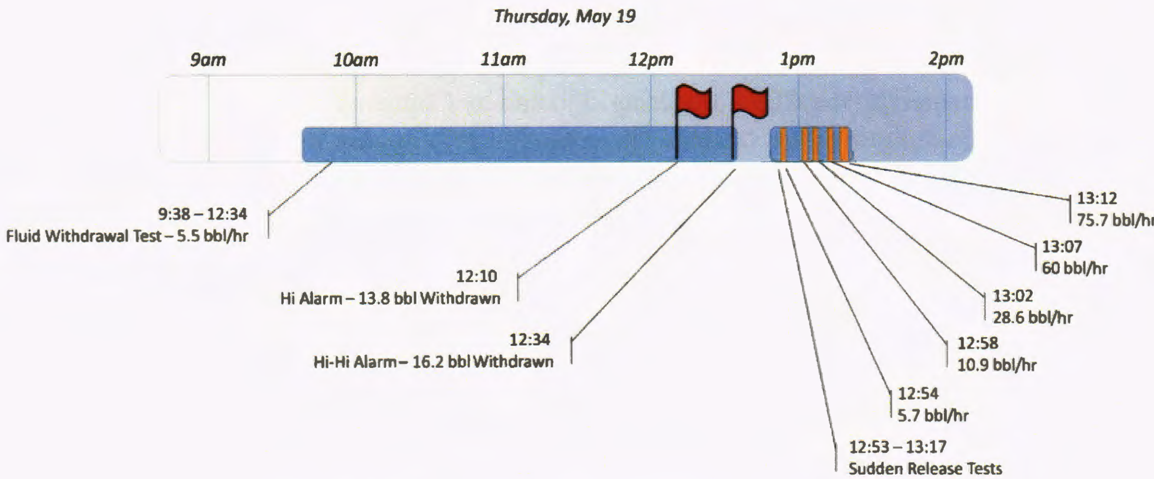

Figure 7. FWT time line, Company A, Test Day 1.

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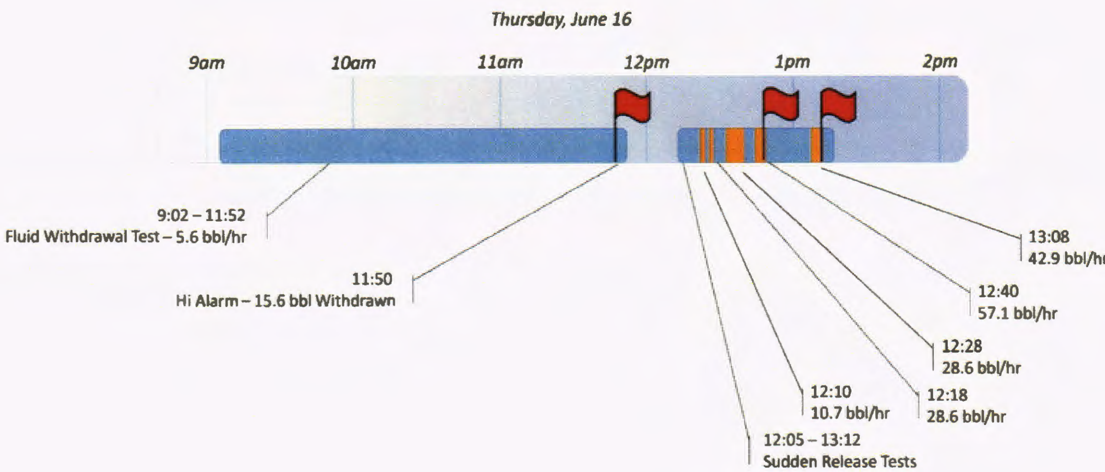

Figure 8. FWT time line, Company A, Test Day 2.

Table 4. Liquids Gathering Pipeline System and LDS Configuration, Company A

Pipeline Material	Fiberglass
Fluid Pressure, psig	300
Characterization of Topography	Relatively flat
No. of Pumps in Contiguous Gathering Pipeline System	5
Automatic or Manual Pump Start/Stop	Automatic
Permanently Staffed Control Room	Yes
LDS Developer	In-house
Communications Backbone	Fiber-optic cable

General Observations on Performance

Company A's LDS operated as designed and alarmed at leak rates predicted by Company A operations personnel. Figure 9 displays a comparison of the withdrawn volume over time during the May test, measured by the EERC metering skid and by Company A's LDS. Figure 10 displays the same comparison during June testing. The data similarity speaks to the accuracy of Company A's LDS at these conditions.

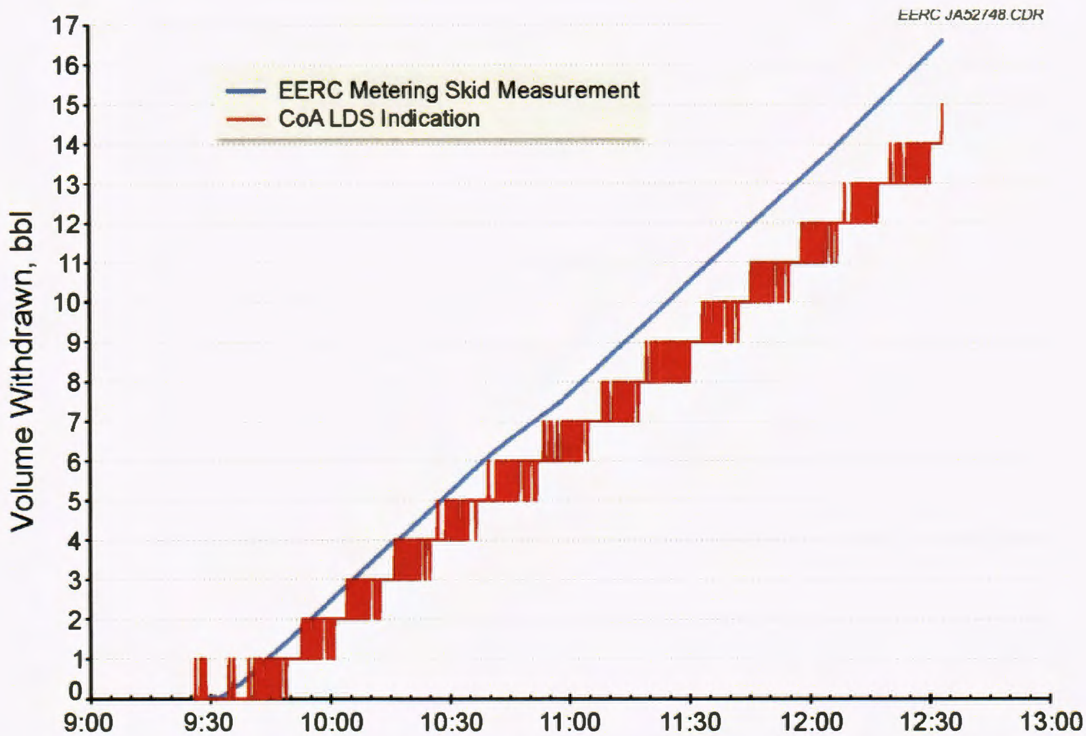

Figure 9. Comparison of measured withdrawal volumes, May 19, 2016, test (CoA means Company A).

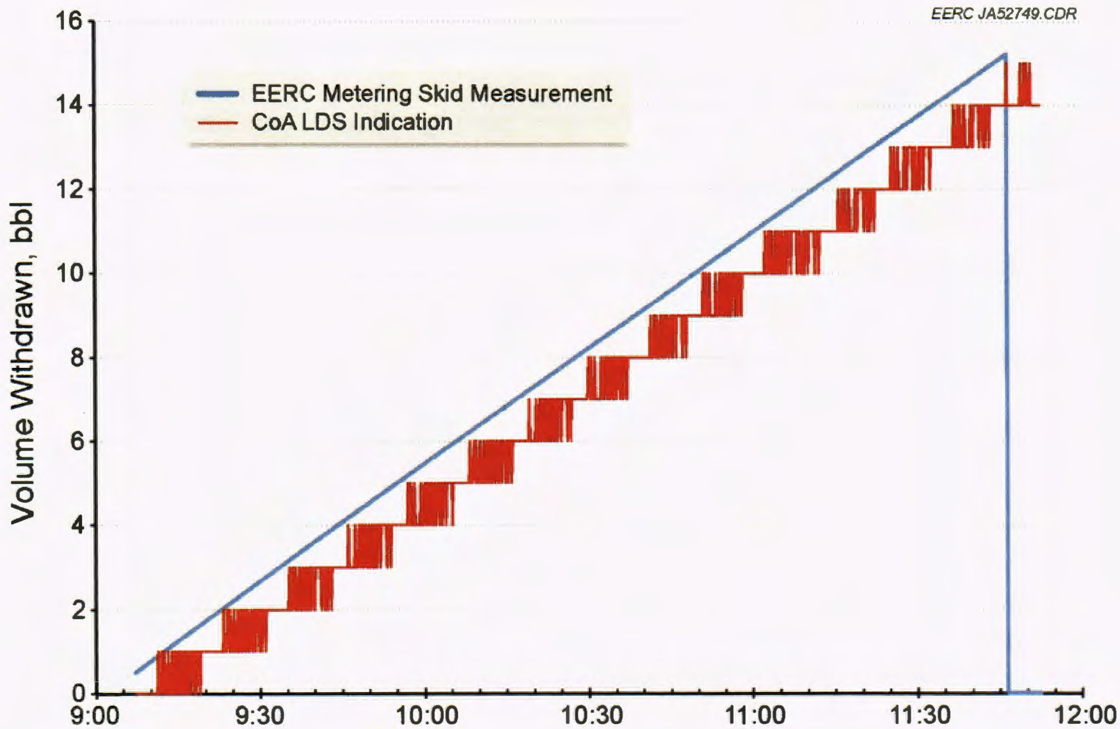

Figure 10. Comparison of measured withdrawal volumes, June 16, 2016, test.

Detailed Performance Analysis

Company A's LDS incorporated three leak detection measures based upon two different techniques. These measures included a volume balance technique and two instances of a pressure rate of change technique. The volume balance technique compared the volume received by the gathering pipeline systems with that delivered to the SWD site over an 8-hour "moving window" (see Inset B for an explanation of Moving Windows). "Hi" and "Hi-Hi" alarms were triggered when receipts exceeded deliveries by 1.25% and 1.5% of flow, respectively, over 8 hours. Alarm limits were established by balancing the expected volume released (approximately 13 bbl over 8 hours when the pipeline flow rate is about 2600 bbl/day) with the expected frequency of false alarms. In any pipeline LDS approach (not limited to discussion of Company A), excessive numbers of false alarms may lead to control room expectations that all alarms are false and can reduce control room operator responsiveness.

In parallel to the flow measurements, pipeline pressure measurements were collected from all producing and SWD wellsites, enabling pressure rates of change to be derived over 10-second and 10-minute intervals.

Figures 9 and 10 depict the actual withdrawal volume over time and the leak rate estimated by the LDS. Withdrawal occurs at a steady-state (i.e., constant) volume, which is represented by the smooth blue curve. The LDS estimate appears as a red sawtooth line that periodically takes single-barrel step increases. The sawtooth nature of the curve results in part from acquisition of various measurements that enter into the calculation at various times and in part from a unit-barrel resolution (i.e., at least one measurement changes in steps of whole barrels).

INSET B – MOVING WINDOWS

The term moving window sometimes appears in LDS discussions. Window refers to the time period over which a subset of data is considered in making decisions as to whether or not leaks exist. Moving refers to the fact that, as time progresses and new data are added, the oldest data are dropped from consideration. The size of the window is important because longer-duration windows consider data over longer periods of time and, thus, have a better chance to see the end of a temporary (transient) condition and recognize it as temporary as opposed to a leak. Unfortunately, waiting to see the whole window may delay alarms. Shorter-duration windows alarm more quickly but may mistake a transient condition for a leak. Some approaches incorporate multiple windows of different durations to provide both a fast response for large leaks and a slower, but more sensitive, response to smaller leaks.

Unlike volume and flow measurements which require only modestly fast speed and resolution, pressure events can require high speed and resolution, depending on the nature of the phenomena being monitored. Advanced measurement and monitoring techniques such as acoustic and negative pressure wave techniques can require introduction of specialized equipment into the LDS to achieve the necessary speed and resolution.

Sudden release testing enabled a qualitative evaluation of the utility of pressure RoC monitoring. As indicated by Figure 11, sudden, significant changes in withdrawal rate can induce pressure fluctuations that can be 2 to 11 times greater than the largest background peaks and 3 to 18 times larger than typical noise peaks. Even events that were not intentionally meant to generate pulses, such as starting and concluding steady-state FWT, generated distinctive peaks.

Based upon the data collected from the constant withdrawal rate tests conducted on Company A's system, the EERC summarizes performance of Company A's LDS as shown in Table 5. It is interesting to note that the time to detect was very consistent across tests at very similar rates despite being conducted at two different locations in the gathering pipeline system.

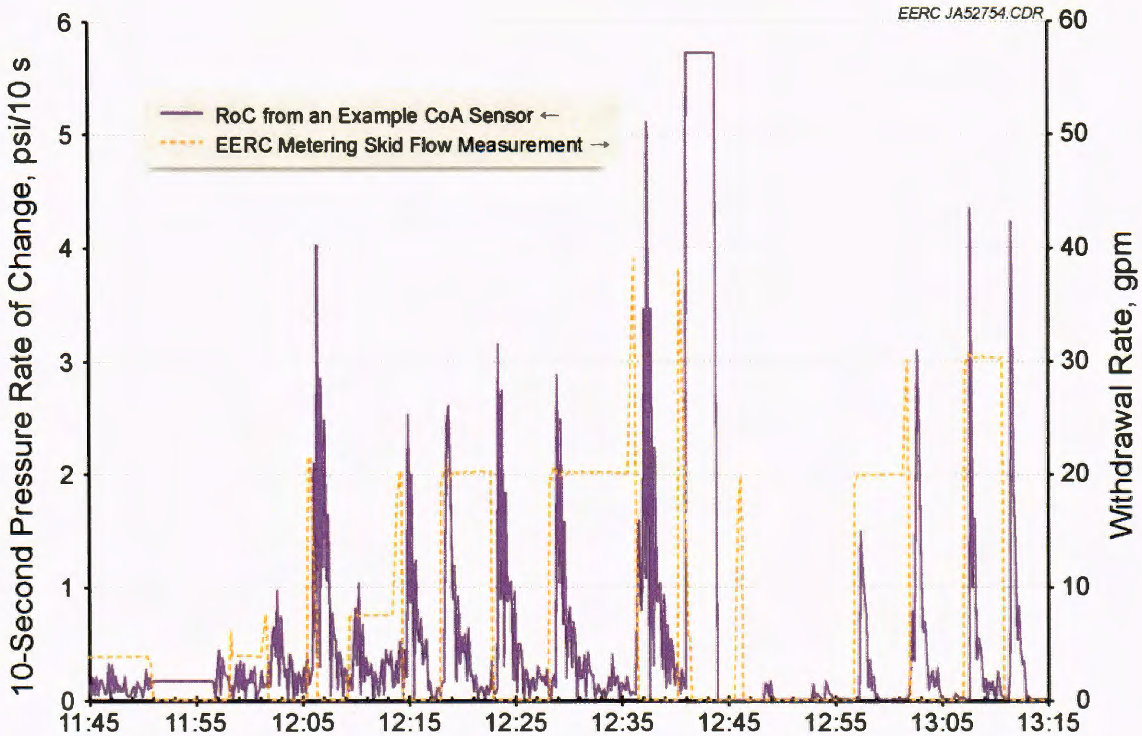

Figure 11. Company A pressure RoC (rate of change) relationship to EERC withdrawals, June 16, 2016.

Table 5. Key Performance Indicators of Company A Constant Withdrawal Rate Tests

		Test Number		
		1a	1b	2
	Date	May 19, 2016	May 19, 2016	Jun 16, 2016
	No. of producing wells continuously reporting data to SCADA (no. active)	5 (1)	5 (1)	5 (1)
	Alarm encountered	Hi	Hi-Hi	Hi
	Detected "leak" rate based on total flow, %	5.8%	5.9%	5.5%
Sensitivity	Time to detect, hr	2.5	2.9	2.8
	Actual withdrawal rate, bbl/hr	5.5	5.5	5.6
	Actual volume withdrawn, bbl	13.8	16.2	15.6
Accuracy	Estimated withdrawal rate error, %†	15.7%	16.2%	14.1%
	Estimated withdrawal volume error, %†	–13.0%	–13.6%	-3.9%

† Error calculated relative to actual withdrawal rate/volume, as measured by the EERC metering skid.

$$\text{Error} = \sum \left| \frac{\text{SCADA Value} - \text{EERC Value}}{\text{EERC Value}} \right|$$

Value to Operator

As a result of test observations, Company A modified the RoC algorithm to trigger an alarm when the system pressure changed by only 4 psig over 10 seconds, which is tighter than the original 10 psig over 10 seconds. This improved sensitivity was demonstrated when the sudden release testing was performed at a 42.9-bbl/hr flow rate. This rate caused the system to alarm quickly and shut down because of an observed rapid pressure drop.

Conclusions from Field Evaluation of Company A's LDS

Prior to May 19 testing, Company A's standard was to employ a 10-psig/10-second alarm setting. However, May's sudden release testing demonstrated that a leak with such behavior would likely not be indicated at that alarm threshold. Instead, testing demonstrated that a value of approximately 4 psig/10 seconds was required to generate an alarm for a 42.9-bbl/hr leak. May testing also showed that RoC noise from steady-state operation was less than 1 psig/10 seconds, which meant that there was a significant (3 psig/10 second) margin between normal noise and the alarm level that would produce a minimum number of false positive alarms under steady-state conditions (setting a system to produce NO false alarms heightens the likelihood of larger undetected leaks).

No false positive alarms were encountered during testing on Company A's pipeline system. The test duration was insufficient to observe the types and frequencies of events that might create RoC peaks. Therefore, it is possible that routine events not encountered during testing could potentially generate false-positive alarms.

During follow-on tests in June, modifications to methods or changes to alarm levels based on learning from prior testing had occurred, such as reducing pressure RoC alarm limits. It is not known what the effect of such changes by Company A will have on false-positive alarms. The project was unable to formulate a metric for false-positive alarms because there were no such alarms during the relatively brief test periods.

In an attempt to qualitatively understand false-positive alarms, the EERC discussed alarm history with each participating company. Company A provided two examples of false positive alarms that were encountered over the prior 2 months. One alarm was attributed to a plugged filter. Another was attributed to a synchronization problem amongst PLCs of different sites. The causes did not appear to be related to LDS inadequacies or excessively sensitive alarm thresholds.

Detailed Analysis of Company B1 and B2 Field Evaluation

Company B1's Approach to Leak Detection

Company B1 also utilized an LDS developed in-house. Data were transferred from the field to its SCADA system by means of radio, satellite, and cellular communications. Company B1 operated a large, unpressurized gathering pipeline carrying produced water (for a definition of slack lines, see Inset A). The pipeline pressure fluctuated as pumps were cycled on and off.

The leak detection scheme utilized SCADA data to calculate differences between volumes entering and exiting the system. The LDS utilized four volume difference moving windows of different durations to identify discrepancies in commodity flow. The durations varied from 1 to 24 hours. Weighting factors were applied to each of the four moving window volume differences to produce a composite value which serves as the basis for alarming. Pressure data are monitored by Company B1 but are not integrated into Company B1's LDS algorithms.

For an alarm to be triggered, a composite value derived from the moving average windows must exceed a predetermined threshold. Company B1 provided the EERC with limited information on the operation of the LDS, stating that the actual algorithms used are proprietary. Therefore, the EERC was able to test the effectiveness in the field through FWT testing but was not able to analyze the actual LDS algorithms.

Company B2's Approach to Leak Detection

Company B1 agreed to allow a third-party CPM vendor (Company B2) to demonstrate its own unique approach to leak detection in parallel to Company B1's own LDS. Company B2 received gathering pipeline system data such as pipeline pressure, fluid flows, pump status, etc. Company B2 then employed these data as input to its system to train the CPM on the gathering pipeline operational data. Company B2 trained its system on two separate gathering pipelines operated by Company B1 over the course of approximately 6 weeks.

The LDS that Company B2 applied to this field evaluation employed a statistical volume balance approach to leak detection. It used a function known as the sequential probability ratio test and pressure and flow analysis to optimize leak detection.

The CPM software automatically establishes communication with a SCADA server to obtain regular transfers of information. The CPM software reads raw data (instrument readings) from the SCADA server; processes these data; and returns the alarm status, leak size, and location along with relevant information back to the SCADA. Additional detailed information is sent to a database, which may be displayed graphically via the engineering interface.

The CPM software continuously checks instrument readings for validity. If they are not valid, a data fault is flagged. (Typical data faults include instrument readings "out of range" and "stuck.") Because faulty readings can easily be misdiagnosed as a leak, this data validation is an important part of the CPM software.

The leak detection algorithm uses a statistical technique to determine if the instrument readings are characteristic of a leak. If the statistical test indicates that a leak is present, the probability factors (lambdas) rise accordingly. A further pattern recognition test is applied to analyze whether the current measurement behavior is caused by an operational change. If so, the system changes the operational status and allows the leak detection system more time to evaluate the change before generating a leak alarm. Once the lambdas climb above zero, a Hi alarm is triggered and reported to the operator via the SCADA. At a lambda of +4.6, a HiHi alarm is generated and similarly sent to the operator via the SCADA.

When a leak is detected, the CPM software estimates the size and location of the leak. This is important, as it allows operations staff to assess the severity of the leak and the type of response that is required.

Specific Description of Company B1 Test Plans

Field evaluation of Company B1's LDS included a total of four test days spread among three different gathering pipeline systems, as shown in Figures 12–14.

Company B2 participated in the first FWT series (June 28 and 29) but decided not to participate in the second FWT series (August 9 and 10). Figures 15 through 18 depict the test time lines during each day graphically. In these figures, a red marker with an "O" indicates an alarm produced by Company B1's LDS. A red marker with a "C" indicates an alarm produced by Company B2's LDS. Note that because testing was intended to calibrate expectations of the sensitivities of LDS, some small leaks were below alarm thresholds. Consequently, not every test resulted in an alarm being triggered during the timeframe of the test.

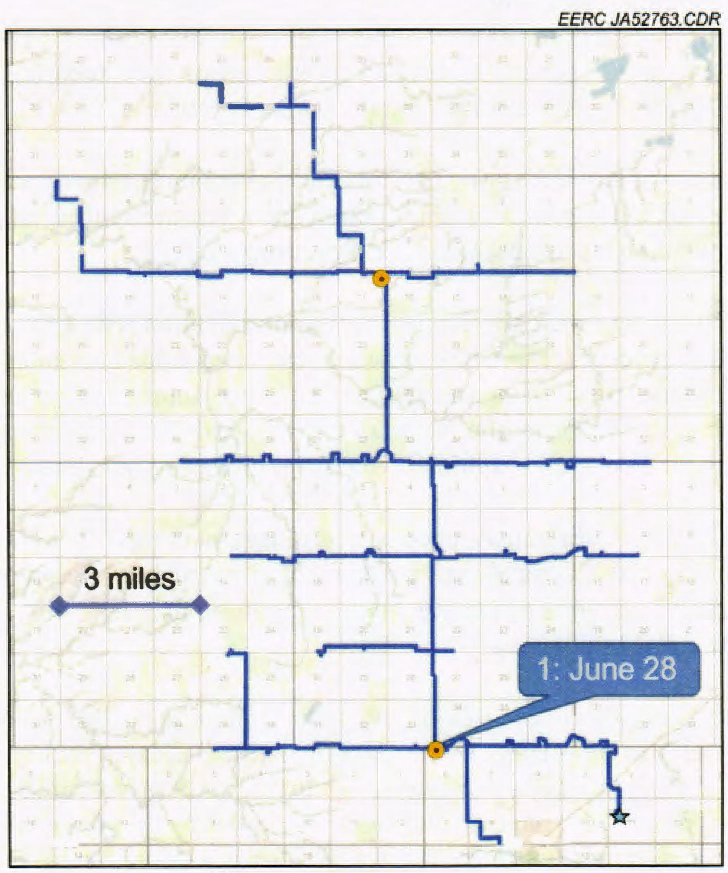

Figure 12. Map of Company B1's Pipeline System No. 1.

EERC JA52755.CDR

Figure 13. Map of Company B1's Pipeline System No. 2.

EERC JA52756.CDR

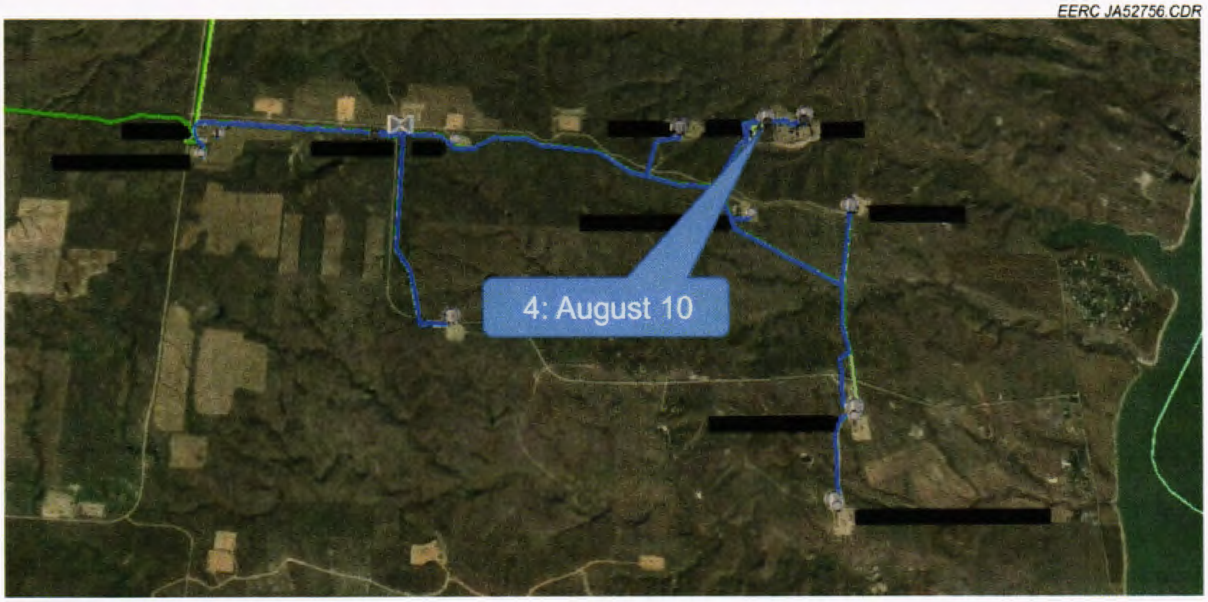

Figure 14. Map of Company B1's Pipeline System No. 3.

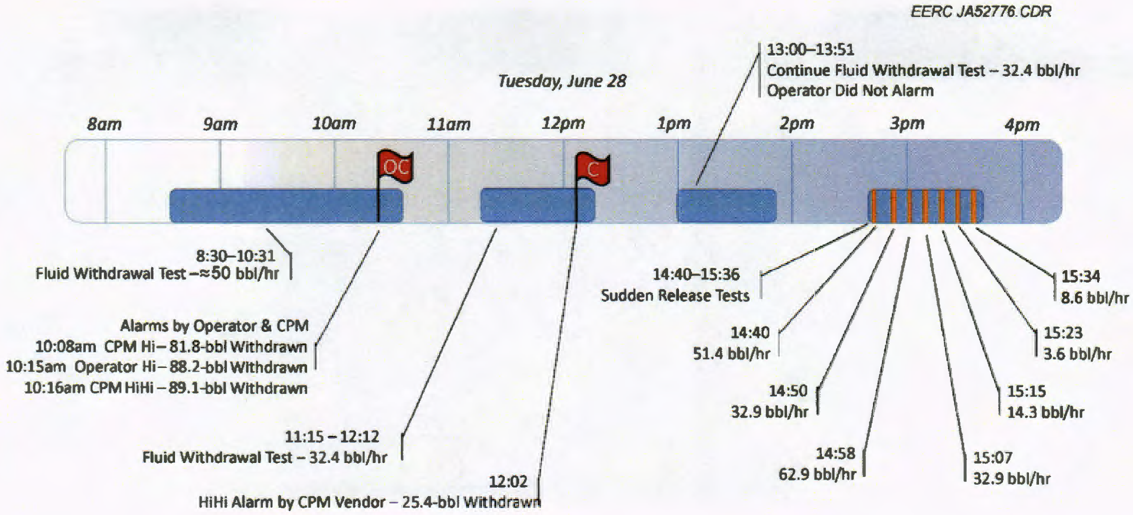

Figure 15. FWT time line, Companies B1 and B2, Test Day 1.

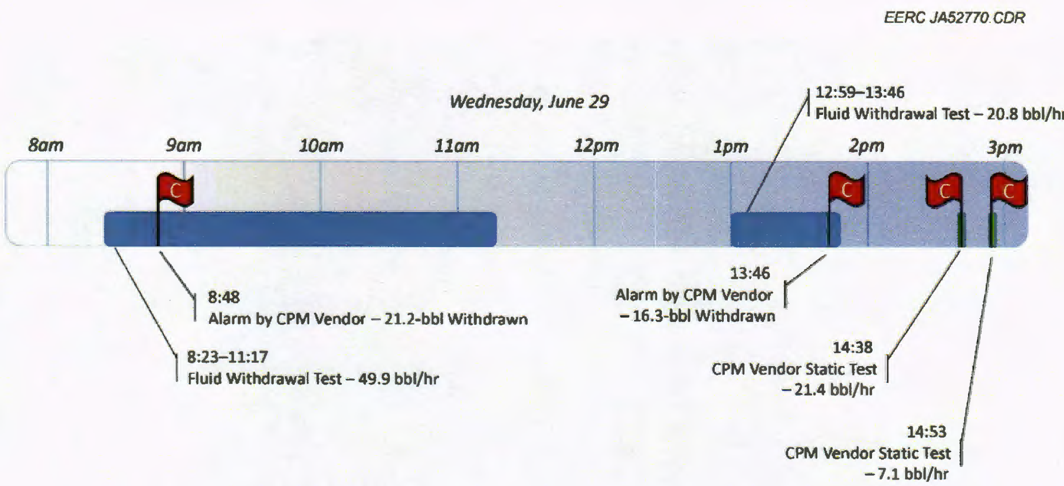

Figure 16. FWT time line, Companies B1 and B2, Test Day 2.

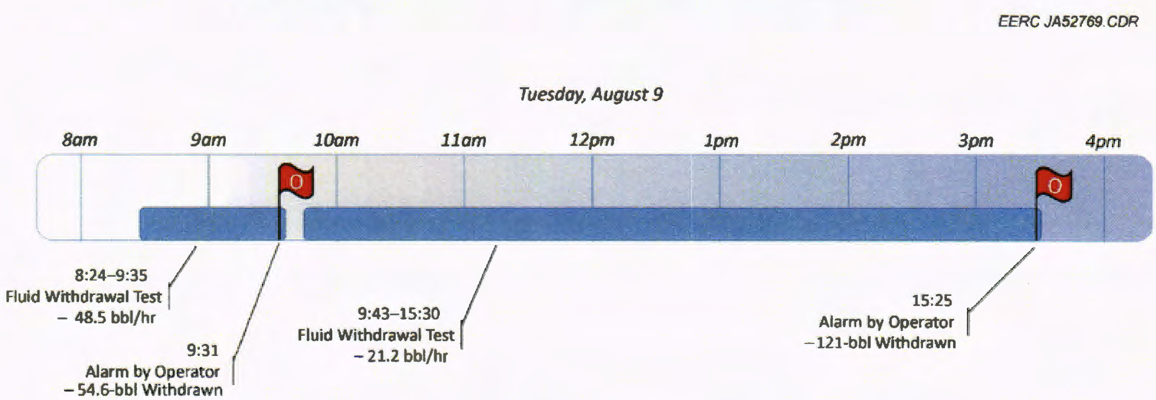

Figure 17. FWT time line, Company B1 only, Test Day 3.

EERC JA52775.CDR

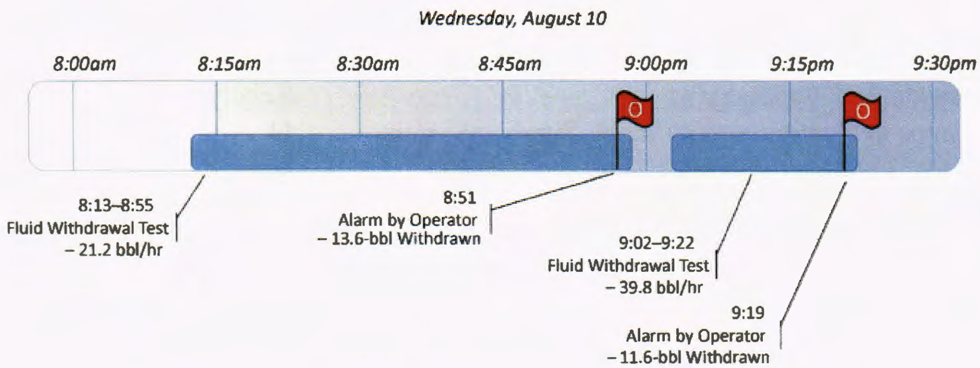

Figure 18. FWT time line, Company B1 only, Test Day 4.

Tables 6 through 8 present summaries of the various gathering pipeline system configurations offered by Company B1 for the purposes of the field evaluation.

Table 6. Liquids Gathering Pipeline System and LDS Configuration, Company B1, System No. 1

Pipeline Material	HDPE*
Fluid Pressure, psig	unpressurized
Characterization of Topography	Relatively flat
No. of Pumps in Contiguous Gathering Pipeline System	25
Automatic or Manual Pump Start/Stop	Manual
Permanently Staffed Control Room	Yes, out of state
LDS Developer	In-house
Communications Backbone	Mixed radio and cellular

* High-density polyethylene.

Table 7. Liquids Gathering Pipeline System and LDS Configuration, Company B1, System No. 2

Pipeline Material	HDPE
Fluid Pressure, psig	Unpressurized
Characterization of Topography	Relatively flat
No. of Pumps in Contiguous Gathering Pipeline System	21
Automatic or Manual Pump Start/Stop	Manual
Permanently Staffed Control Room	Yes, out of state
LDS Developer	In-house
Communications Backbone	Mixed radio and cellular

Table 8. Liquids Gathering Pipeline System and LDS Configuration, Company B1, System No. 3

Pipeline Material	HDPE
Fluid Pressure, psig	unpressurized
Characterization of Topography	Relatively flat
No. of Pumps in Contiguous Gathering Pipeline System	11
Automatic or Manual Pump Start/Stop	Manual
Permanently Staffed Control Room	Yes, out of state
LDS Developer	In-house
Communications Backbone	Mixed radio and cellular

General Observations on Performance

Slack pipeline flow (discussed in Inset A) is a major challenge for Company B1's LDS. Pipeline pressures rise and fall as the production site pumps start and stop. The result is significant variation in the amount of slack in pipelines which generates error in balancing receipt and delivery volumes. Thus when the number of production-site pumps operating increases, pressure builds, slack volume declines, and the volume entering the pipeline exceeds that leaving. This can be interpreted by an LDS as a potential leak. Company B1's LDS monitors this excess over time to develop confidence that the cause of the imbalance is a leak and not a decline in slack.

The reverse also holds true. When the number of production-site pumps operating decreases, pipeline pressures decrease, slack increases, and the volume of liquid that exits the pipeline exceeds the volume received by the pipeline. This excess could mask a leak that is smaller than the rate of change of the slack. Thus during periods that inflows exceed outflows, the system is biased to a leak imbalance and so will alarm quickly on a leak. When the opposite is true, the system is biased against a leak imbalance and so will alarm more slowly on a leak.

Test results depicted in Figures 19–21 of the next section exhibit a tendency for pump shutdowns (downward-pointing arrows in the figures) to temporarily reduce leak size estimates or slow the rate of progression of the system to alarm. It should also be noted that leaks cannot be detected by Company B1's current software approach when no pumps are operating.

Another factor in determining how quickly an alarm is indicated is the current value of the composite volume difference variable which is called the "out-of-balance percentage" (OOB%). All else equal, the closer the OOB% is to the leak alarm point when a leak appears, the faster an alarm will be indicated.

Detailed Performance Analysis

Company B1's LDS

Company B1 aggregates several volume difference moving-window totals of various timespans into an index that is termed the OOB%. Every 5 minutes, a volume difference snapshot is calculated as follows:

$$Volume\ Difference = Volume_{disposed} - \sum^{All\ Wells} Volume_{received} \quad \text{[Eq. 1]}$$

The snapshot is then incorporated into several moving-window totals of various time spans. Each moving-window total is multiplied by an empirically determined weighting factor to produce a composite total of weighted volume differences. The composite total is then normalized into an empirically determined range of acceptable volume differences to produce an OOB% index.

Alarm limits are set relative to the range of acceptable volume differences. The Hi and Hi-Hi alarm thresholds are set to –85% and –95%, respectively, of the difference between the mid- and minimum-acceptable volume differences. Similarly, Lo and Lo-Lo alarm thresholds are set to +85% and +95%, respectively, of the difference between the mid- and maximum-acceptable volume differences.

Weighting factors, the range of acceptable volume differences, and other tuning parameters are adjusted based upon historical data using a proprietary tool to attain an acceptable balance of sensitivity and low incidence of false positive alarms. Use of multiple volume differences permits shorter-duration volume balances to provide rapid response without the need to be very sensitive and risk increased false positive alarms. Longer-duration volume balances provide slower response but improved sensitivity, again without risking generation of excessive false positive alarms.

As presented in Inset A earlier in this report, slack is the presence of a vapor phase with liquid in a pipeline. The volume that the vapor occupies varies with changes in pressure and temperature. Volume balance methods assume that the liquid volume in a pipeline is constant and thus assume that the quantity of liquid entering a pipeline must be equal to the quantity exiting the pipeline (otherwise a leak is indicated). Slack can undermine this assumption and introduce error as the volume that the vapor occupies changes with temperature and pressure.

If pipeline conditions vary such that slack volume in the pipeline decreases by a gallon, there will be a gallon deficiency at the exit, but it will be due to changes in slack volume and not a leak. If the LDS is not aware of this condition, the deficiency might be interpreted as a leak and result in a false positive alarm indication. Conversely, if slack volume increases, there will be an excess of liquid exiting the pipeline.

This second condition is important because if slack increases and, simultaneously, an equal-sized leak occurs, there will be no net change. In this case, a gallon entering the pipeline will result in a gallon exiting the pipeline; therefore, the change in slack will mask the leak. Since temperature changes in gathering pipelines tend to be slower and limited in range, as compared to pressure changes, volume balances will need to account for at least pressure changes in monitoring for leaks to account for changes in slack.

One approach to attenuating slack effects is to operate gathering pipelines at constant pressure. Higher pipeline pressure will equate to smaller slack volume and, thus, decreased obfuscation by slack. Of course, not all existing pipelines can operate under elevated, constant pressure conditions. Therefore, LDS under such conditions must account for slack, which is difficult to do accurately.

Company B1 addressed slack through adopting multiple volume balances possessing moving windows of different durations. In that manner, brief variation in pressure and slack that would otherwise induce an alarm in shorter-duration windows will have less effect on longer-duration windows and avoid false positive alarms. Since leaks are long-term events, longer-duration windows will detect them. On the other hand, a substantial breach will be identified by shorter-duration windows.

Figure 19 depicts an example of the effect of slack. The solid line is Company B1 LDS's estimate of the withdrawal volume, and the dotted line represents the actual volume. Ideally, they should be identical, but it was observed that when a pump shuts down, the LDS rate estimate decreased both at 7:50 a.m. and at 9:45 a.m. In both cases, what should have been rising curves turned and became falling curves as pumps shut down, pipeline pressure dropped, and slack occupied more volume, temporarily masking the leak until the brief effects of shutdowns dissipated.

Figures 20 and 21 depict the OOB% metric which indicates a Hi alarm at –85%. Figure 20 shows that an extended period of time (i.e., many hours) may be required to attain a Hi alarm when the past history places the OOB% far from the –85% alarm level. On the other hand, alarming can occur very quickly (less than ½ hour) when the opposite is true, as depicted in Figure 21.

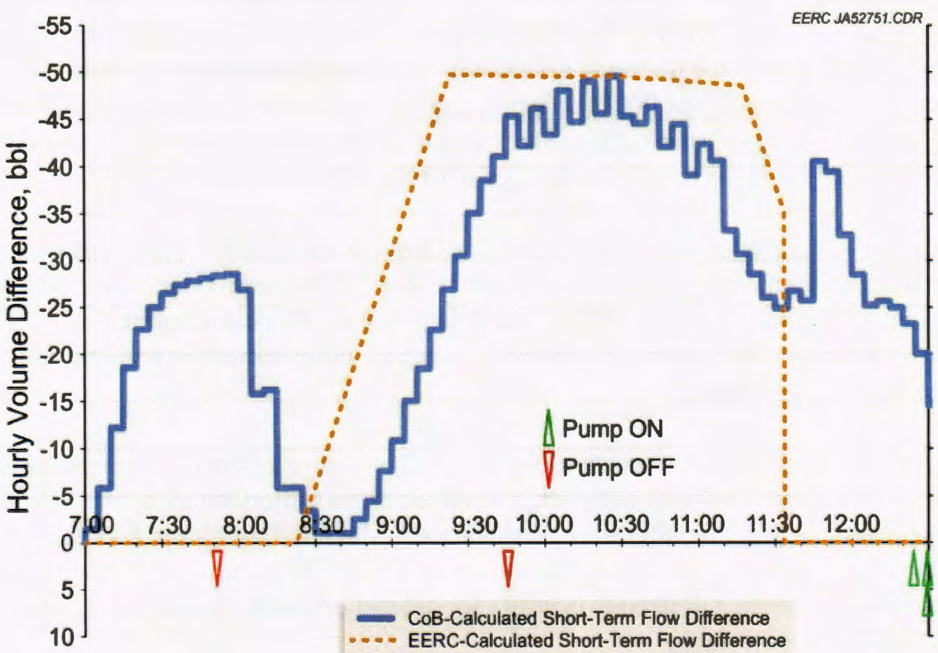

Figure 19. Comparison of Company B1 (CoB) to EERC calculated flow differences, June 29, 2016.

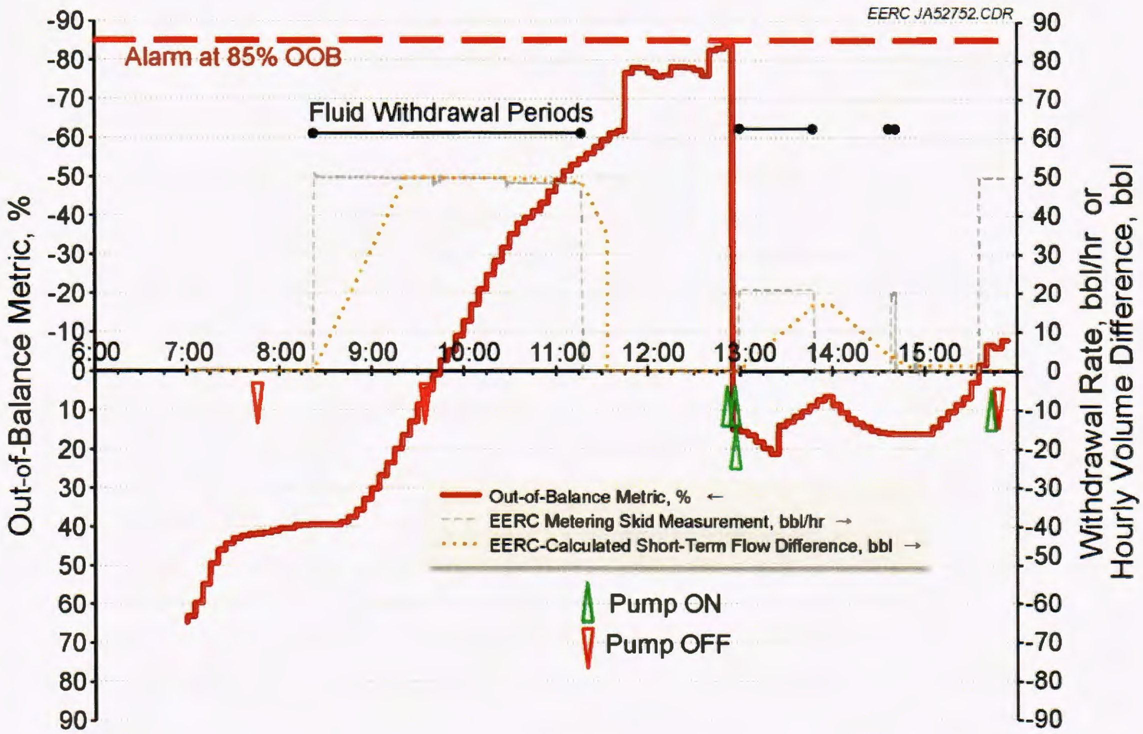

Figure 20. Company B1 OOB% calculations, June 29 test.

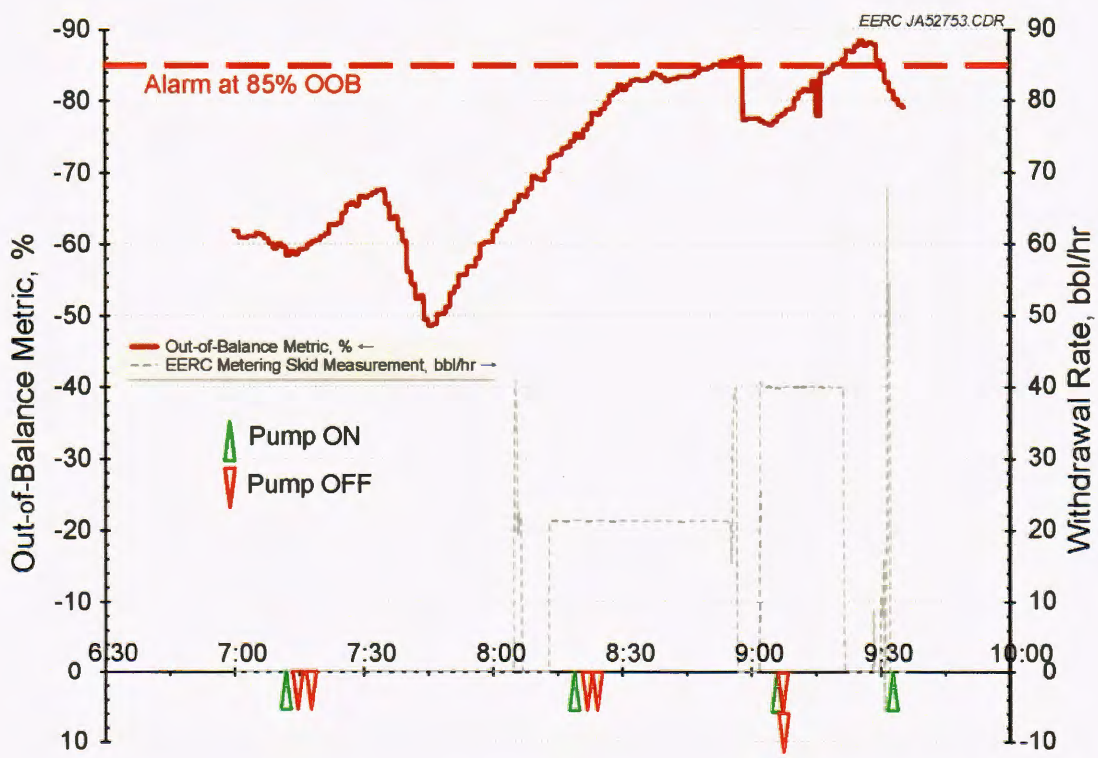

Figure 21. Company B1 OOB% calculations, August 10 test.

Because Company B1's technique considers conditions over many hours, its responsiveness depends on that history, especially pressure variation from pump start-ups and shutdowns. This means that if window memory contains periods of pumping followed by extended periods of shutting down pumps, the volume balance will be positive and will delay detection of a leak. This situation occurred during June 29 testing and significantly delayed the response of the OOB% index to the withdrawal test. Conversely, August 10 testing occurred under somewhat the opposite conditions, and the response was much quicker. Ultimately, the OOB% index recognized all withdrawals and, during each test, was moving toward generating alarms. The differences were in the rates at which the index moved to alarm and the amount of history that had to be overcome to attain the alarm threshold.

Table 9 exhibits sensitivity and accuracy performance indicators for Company B1's LDS approach.

Several LDS changes were implemented by Company B1 between June and August testing. Prior to June testing, volume balances were calculated every 5 minutes. In August, this interval had been reduced to 1 minute. Company B1 also had installed flowmeters capable of measuring and reporting reverse flow rates at key locations in the gathering pipeline system. One of these new instruments very rapidly provided evidence of withdrawal and helped to identify the withdrawal location.

Table 9. Key Performance Indicators for Company B1 Leak Detection System During Constant Withdrawal Rate Tests

		Test Number												
		CPM Vendor (Company B2) and Company B1 Tests					Tests Conducted with Company B1, Only							
		1a[b]	1b[b]	2[b]	3[b]	4[b]	1[b]	2[b]	3[b]	4[b]	5	6	7	8
	Date	Jun. 28, 2016	Jun. 28, 2016	Jun. 28, 2016	Jun. 29, 2016	Jun. 29, 2016	Jun. 28, 2016	Jun. 28, 2016	Jun. 29, 2016	Jun. 29, 2016	Aug. 9, 2016	Aug. 9, 2016	Aug. 10, 2016	Aug. 10, 2016
	No. of producing wells continuously reporting data to SCADA, (no. of active wells)	38 (2–8)	38 (2–8)	39 (2–8)	21 (0–3)	21 (0–3)	38 (2–8)	39 (2–8)	21 (0–3)	21 (0–3)	23 (2–9)	23 (2–9)	10 (0–4)	10 (0–4)
Sensitivity	Alarm encountered	Hi	Hi-Hi	Hi-Hi	Hi-Hi	Hi-Hi	Hi	None	None	None	Hi	Hi	Hi	Hi
	Detected "leak" rate based on total flow, %	25.6	25.5	15.7	163.4	23.4	25.4	–	–	–	50.6	17.0	36.7	350.2
	Time to detect, hr	1.65	1.78	0.78	0.43	0.78	1.77	–	–	–	1.13	5.71	0.64	0.29
	Actual withdrawal rate, bbl/hr	49.6	50.0	32.4	49.9	20.8	49.9	–	–	–	48.5	21.2	21.2	39.8
	Actual volume withdrawn, bbl	81.8	89.1	25.4	21.2	16.3	88.2	–	–	–	54.6	121.3	13.6	11.6
Accuracy	Estimated withdrawal rate error, %[a]	14.1	13.5	101.2[c]	71.9[d]	18.7	276.2[e,f]	35.2	96.9	177.9	162.5	53.3	164.4	39.0
	Estimated withdrawn volume error, %[a]	–	–54.0	45.6	–33.3	–	–12.5	–	–	–	–80.3	–29.2	–0.4	–86.0

NOTES:

[a] Error calculated relative to actual withdrawal rate/volume, as measured by the EERC measurement cart.

$$\text{Error} = \sum \left| \frac{\text{SCADA Value} - \text{EERC Value}}{\text{EERC Value}} \right|$$

[b] Tests 1–4 included participation of both Company B1 and B2.

[c] For an unknown reason, Company B2's data appeared to shift –12 minutes during this test. If this calculation compensates for the shift, the error becomes 33.1%.

[d] For an unknown reason, Company B2's data appeared to shift +9 minutes during this test. If this calculation compensates for the shift, the error becomes 43.2%.

[e] After 1 hour, the estimated withdrawal rate error was 34.3%. The algorithm needed to "burn off memory."

[f] Estimated withdrawal rate error was calculated using Company B2's alarm indication.

Company B2's LDS

Company B2 provided the only advanced CPM method evaluated by this study.

The quality of leak detection depends on the quality of the understanding and monitoring of the system. The performance of a very high quality leak detection method can be debilitated by an incomplete or incorrect understanding of gathering pipeline behavior (e.g., slack volume is unknown and variable), or by poor quality monitoring. Without adequate understanding and instrumentation, the improvement in the leak detection performance by the advanced technique is reduced, and the maximum benefit is not achieved.

In agreeing to participate in this study, Company B1 and Company B2 agreed to provide reasonable resources to accomplish the task. Company B1 provided historical data and access to its SCADA to Company B2 and performed some fieldwork that enabled Company B2 to prepare its CPM and participate in the test. Company B1's system design was sufficient to provide measurements for Company B1's LDS but did not provide all features and measurements required to maximize the performance of Company B2's LDS. The exact magnitude of the reduction in performance is unknown.

It should be noted that the method applied by Company B2 was not the most advanced of those developed by the company. To achieve optimal performance, the most advanced method requires substantial data and communications resources and performs best under constant, steady-state conditions. Such conditions are more descriptive of large, interstate pipelines than gathering pipelines. The method that was applied had fewer requirements and greater robustness for gathering pipeline conditions and, ultimately, was more justifiable for gathering pipelines than the most advanced technique. Company B2 said the method applied in the study had been applied commercially in many similar situations; however, confidentiality agreements constrained Company B2's ability to share test results, despite its desire to do so.

Company B2's method used a corrected flow balance along with statistical techniques to estimate leak size and location under steady-state, transient, or static conditions. The technology used measurements to constantly update its current understanding of the system. When transients occurred within the gathering pipeline, the technique adjusted its detection time until it had confidence in its understanding of the change. This was done to avoid false positive alarms. The extent of "slowing" depends on the magnitude and type of change. As a consequence, large gathering pipeline systems with many wellsites can result in slower detection of leaks. The gathering pipeline system tested on June 28 was such a system, which hindered detection. If the installation had been permanent (as opposed to a temporary test situation), Company B2 likely would have segmented the gathering pipeline system to attain faster response.

Table 10 exhibits sensitivity and accuracy performance indicators for Company B2's method for steady-state operation. Much as the OOB% is the index that is the basis for Company B1's LDS alarm decision and much as Company B1 employs multiple moving windows to detect leak indicators across a wide range of magnitudes, Company B2 monitors the values of several probability likelihood ratios, λ_i. Whereas Company B1 employed four moving-window averages, Company B2 employs seven probability likelihood ratios to monitor the pipeline system for leaks.

Table 10. Steady-State Operation Leak Detection Sensitivity Estimates

	Typical Values		Test Nos. 1 and 2		Test Nos. 3 and 4	
	Leak Rate, bph	**Detection Time,** min	**Leak Rate,** bph	**Detection Time,** min	**Leak Rate,** bph	**Detection Time,** min
λ_1	4	60	28.5	170	10	120
λ_2	8	30	33	120	20	60
λ_3	16	20	36	100	30	30
λ_4	40	8	39	70	37.5	20
λ_5	80	4	60	12	50	12
λ_6	120	2	90	4	75	6
λ_7	160	1	120	2	100	3

Although a mathematically rigorous explanation of these ratios and their application by the CPM software is beyond the scope of this report, it is sufficient to note that compatibility issues between the CPM and Company B1's gathering system and SCADA system hampered the CPM's performance in a way that made it difficult to achieve the "typical" sensitivities and detection times listed in Tables 9 and 10 (it should be noted that time and resource constraints prevented resolving these issues that would be resolved in permanent CPM installations).

Company B2 asked the EERC to note that these sensitivities are significantly worse than "typical" values because of what Company B2 termed as "problems with the instrumentation available on the Company B1 system." This note relates closely to an idea presented earlier in this report—that more sophisticated LDS requires additional instrumentation, higher polling speed, and more data bandwidth to achieve higher performance.

The method is capable of not only detecting leaks in flowing pipelines but also of detecting leaks under static (no-flow, shut-in) conditions by switching within the method to a different algorithm that relies more on pressure behavior to identify and estimate leak rate. Table 11 exhibits sensitivity and accuracy performance indicators for Company B2's method under static conditions. June 29 static (no-flow) testing on the smaller of Company B1's pipelines withdrew fluid at about 21.4 and 7.1 bbl/hr. Company B2's LDS detected this and generated alarms about 10 and 90 seconds, respectively, after withdrawal commenced. Ten seconds represented essentially one SCADA update cycle.

Table 11. Leak Detection Sensitivity Estimates under Static Conditions

	Test Nos. 1 and 2 (larger pipeline system)		Test Nos. 3 and 4 (smaller pipeline system)	
	Leak Rate, RoC of average pressure	**Detection Time,** min	**Leak Rate,** RoC of average pressure	**Detection Time,** min
λ_1	0.2	3	0.0003	1
λ_2	0.3	2	0.0006	0.75
λ_3	0.4	1	0.001	0.5

Together, Tables 10 and 11 represent the expected performance of Company B2's method on the specific pipeline configuration presented by Company B1 under typical conditions. Factors, such as pump operations, can create delays that slow detection.

Substantial work was performed based upon historical data to tune the algorithm for each of the gathering pipelines that was tested. During typical nonleak conditions, λ values are negative, rising only as conditions become more consistent with the presence of a leak. Since λ is actually a logarithmic function of ratios of probabilities, a change of 1 unit is, in fact, a change by an order of e ($\approx$2.71) in the ratio. Consequently, a move from –7 (the no-leak value) to 4.6 (the value of the HiHi alarm threshold) represents a very large change (more than 100,000) in likelihood.

No data are reported for Company B2 during August testing because Company B2 did not participate in that testing.

Leak Location

Except for Company B1's recent addition of a limited number of flowmeters capable of measuring reverse flow rates, Company B2's method was the only approach of those that were evaluated that provided leak location identification. While pump start-ups and some instrumentation limitations interfered with accurate location identification during some tests, Company B2's method was able to correctly identify the area of the pipeline where the leaks were in at least two of the tests and did so with consistency—in one instance the estimates were within 0.02 miles of each other.

Value to Operator

The rapid response and alarm indication by Company B2 as a result of monitoring pressure have led Company B1 to consider adding pressure monitoring to its LDS algorithm (pressure is currently monitored by operations personnel but is not integrated into the LDS algorithm).

Conclusions from Field Evaluation of Company B1 and B2's LDS

Company B1

Application of pipeline balance methods (also called "volume difference" methods) to leak detection is fairly common. The methods have advantages of being simpler to implement and understand, relative to more advanced statistical methods. Conversely, their simplicity tends to reduce their sensitivity and accuracy. They are ineffective during shut-in conditions, they are unable to identify leak locations, and they can be challenged by slack and transient conditions.

More advanced methods incorporate more measurements and understanding into their methods as they seek to improve sensitivity and accuracy. However, with such improvements comes the need to modify the LDS to reflect even subtle changes in pipeline conditions, which, in the case of North Dakota gathering lines, can be frequent. In light of the strengths and weaknesses of extremely simple and extremely advanced techniques, operators must make practical decisions as to which technology between those two extremes is best for their particular situation.

Company B1 implemented a novel approach based upon multiple volume balances of different durations. In doing so, it acquired the advantages of pipeline balance methods while seeking to address some of their deficiencies. Incorporating a short-duration balance provided faster response at the expense of less sensitivity. Simultaneously incorporating a longer-term balance, conversely, improved sensitivity at the expense of speed of detection. Including longer-term windows also was able to better accommodate changes in slack volume due to pump cycling.

Withdrawal testing demonstrated the ability of Company B1's approach to detect leaks. However, the speed of detection appeared to be a function of pipeline conditions over the past day, pump operations, and leak size. Unrelated to the leak, recent conditions were able to place the alarm metric closer to or further from alarm thresholds, and pump shutdowns and start-ups were able to affect slack in a manner that delayed or accelerated generation of alarm indications.

Although Company B1's LDS did not alarm during three fluid withdrawal tests, its OOB% alarm metric was progressing toward alarm and likely would have indicated leaks if test durations had been longer. On the other hand, two tests resulted in alarms within 45 minutes. This range of response is expected for Company's B1's approach because of the long, 24-hour window that enhances sensitivity while seeking to avoid false positive alarms. Company B1's LDS gave no false positive alarms during withdrawal testing.

Company B2

Company B2's LDS was tested in parallel to Company B1's LDS by acquiring process data from Company B1' SCADA and processing it on Company B2's own server.

As a vendor of multiple CPM products, Company B2 was faced with a decision similar to that faced by many operators: selecting the most appropriate approach for North Dakota gathering lines. Company B2 did not employ its most advanced technology for reasons similar to those stated above but, instead, chose its most appropriate method.

As is typical of more advanced techniques, increased performance comes at the price of more demanding instrumentation and data throughput requirements. Company B1 made a good-faith effort to satisfy those requirements but was unable to satisfy all requests made by Company B2, which handicapped Company B2's CPM during testing. Such difficulties included data timing issues and the size of the largest gathering pipeline system involved in testing. Normally, Company B2 divides large systems into appropriately sized segments to optimize performance.

Ultimately, Company B2's product identified all withdrawals without an erroneous false positive indication. Progress to detection was fairly consistent during all tests despite pump cycling and slack variation, and detection occurred under steady-state, static, and transient conditions—all within a single CPM LDS package. Additionally, Company B2's LDS was the only LDS evaluated that provided leak location estimates. Appendix D contains a detailed report of results authored by Company B2. Company B2's LDS also contains data validation and other functionality to improve LDS performance.

Company B2's LDS is a mature product that has been used commercially on large pipelines and increasingly on gathering lines.

Detailed Analysis of Company C1 and C2 Field Evaluation

Company C1's Approach to Leak Detection

Company C1 employed a third-party system integrator familiar with water systems control to develop a custom-built LDS to monitor pressurized produced water gathering pipelines. Company C1's pressurized system design included closure valves at both ends of its gathering pipelines to maintain pressure in the line.

Company C1's approach to leak detection was based upon calculating discrepancies between the total flow received by the pipeline and the flow delivered to the SWD wellsite. On the 4-in. pipeline, a deficiency at the SWD well greater than the equivalent of 12.5 bbl/hr triggered an alarm. On the 6-in. pipeline, a deficiency greater than the equivalent of 8.3 bbl/hr triggered an alarm.

Company C1 also had created, and was evaluating, a shut-in test for leak detection. This is mentioned here because the field evaluation project observed the behavior of this developmental approach and included results of these tests in this report. This test consists of the following steps:

- Stopping all pumps
- Closing block valves at the inlet to and outlet from the pipeline
- Allowing the pipeline pressure to equilibrate briefly
- Taking a snapshot pressure reading
- Waiting 12 minutes before taking another snapshot pressure reading
- Using a logic check to determine if there is a discrepancy between the two pressure readings of greater than 8 psig
- Triggering an alarm if the above logic is true

This test can be programmed to run at any time during the day and could potentially run several times a day at the expense of shutting down operations for about a dozen minutes a test.

Company C2's Approach to Leak Detection

Company C2 had asserted that the presence of an annular gas space within the layered construction of its pipeline product may provide a monitorable, pressurized space that could indicate the presence of a leak in either the internal plastic liner or the external plastic shield. Company C2's hypothesis was that any breach in the inner liner would cause an increase in the gas pressure within the annular space, thus indicating a compromised pipeline that may not necessarily be leaking. Conversely, a breach in the outer shield layer would cause a rapid decrease in annular gas pressure as the gas escaped to the surrounding soil. This may indicate either a complete breach of the pipeline or an external "nick" to the pipeline, compromising its integrity but possibly not resulting in a leak. A complete severing of the pipeline would result in rapid annular gas pressure loss, thus indicating a leak. With segmented pressurized segments facilitated by regular pipeline couplings, location of any leak could theoretically be ascertained. This approach required simple monitoring of pressure transducers for any unexpected changes.

Specific Description of Company C1/C2 Test Plan

Company C1 operates a small pressurized gathering pipeline consisting of two segments having only two active wellsites on each segment, as shown in Figure 22. Each segment is a separate gathering pipeline bringing produced water to the same SWD wellsite. One segment was a 6-in. composite pipeline material with an annular space, and the other was a 4-in. composite pipeline material with an annular space. Both segments were operated at approximately 65 psig. Test results indicate that significant slack flow exists at this moderate pressure.

Figure 22. Map of Company C1's pipeline system.

The 4-in. pipeline was tested on Day 1 and the 6-in. on Day 2. Both FWTs were conducted where the pipelines breached the surface at the SWD wellsite, immediately prior to entering the storage tanks on the site. During field evaluation operations, Company C1 did not utilize an off-site dedicated control room but rather operated out of a 5-ft by 10-ft all-weather, climate-controlled enclosure on the SWD wellsite that housed the SCADA computer, SWD PLC, and control system displays. Although the enclosure was not manned around the clock, the LDS was able to transmit alarm notifications and be monitored by Company C1 personnel through the Internet (the EERC is aware that, during field evaluation operations, Company C1 had plans for an off-site control room and that the control room is now implemented remotely from the pipeline system demonstrated; the control room utilized during field evaluation operations was a temporary solution employed on a very new pipeline installation).

Testing with Company C1 also involved an added test portion that monitored an annular space inherent in the design of the pipeline material for pressure fluctuations during testing. This was unique to Company C1 because Company C1 was the only pipeline operator participating in this project that used this composite pipeline with the annular space feature.

The annular space is the area between the outer protective HDPE layer and the inner HDPE liner. Steel reinforcement bands are present within this space but are spaced in such a way that permits a gas volume to be maintained between the HDPE layers. Figure 23 presents an illustration of this annular space.

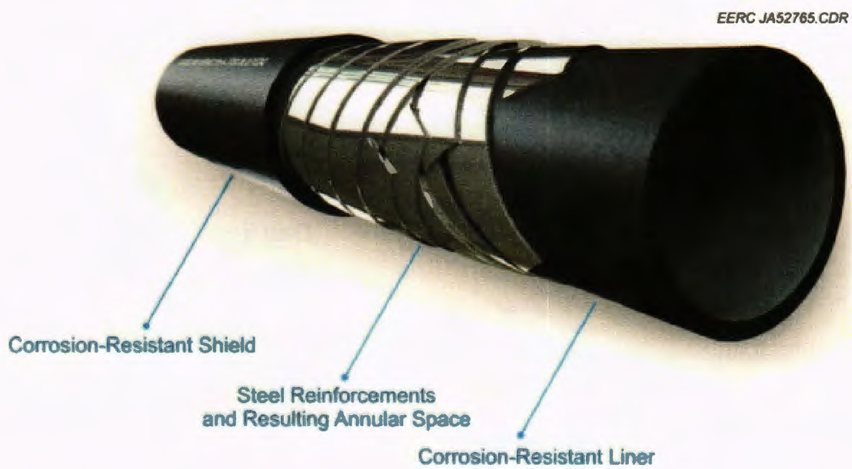

Figure 23. Illustration of the annular space in a particular brand of composite pipeline material.

Table 12 presents a summary of the gathering pipeline system configuration offered by Company C1 for the purposes of the field evaluation.

To facilitate a role in leak detection, this annular space is charged with nitrogen gas to approximately 12 psig. Company C1 monitored the pressure in this space and indicated an alarm if the pressure decreased to less than 5 psig or increased to greater than 25 psig, depending upon location. In theory, if the pipeline's outer protective HDPE layer were to be damaged, allowing the gas to vent, an alarm would be triggered. Similarly, if the inner HDPE liner were to be

Table 12. Liquids Gathering Pipeline System and LDS Configuration, Company C1

Pipeline Material	Composite
Pipeline Nominal Diameter, in.	4 in. and 6 in.
Fluid Pressure, psig	60
Characterization of Topography	Rugged hills
No. of Pumps in Contiguous Gathering Pipeline System	2 in each
Automatic or Manual Pump Start/Stop	Automatic
Permanently Staffed Control Room	No
LDS Developer	Subcontractor
Communications Backbone	Radio

damaged, leading to a fluid or gas breach into this annular space and subsequent rise in pressure, this would also trigger an alarm. Detailed in Appendix C is an appended test plan to explore the efficacy of this annular space monitoring approach to leak detection.

The time lines of tests completed on Company C1 pipeline systems are presented graphically in Figures 24 and 25. Characterization of the Company C1 system configuration is presented in Table 12.

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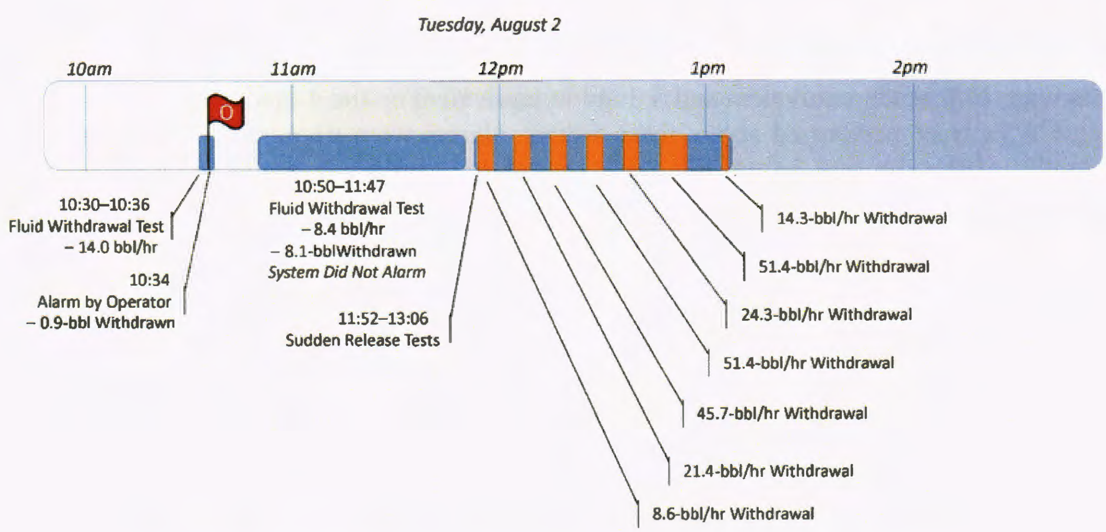

Figure 24. FWT time line, Company C, Test Day 1, 4-in. segment.

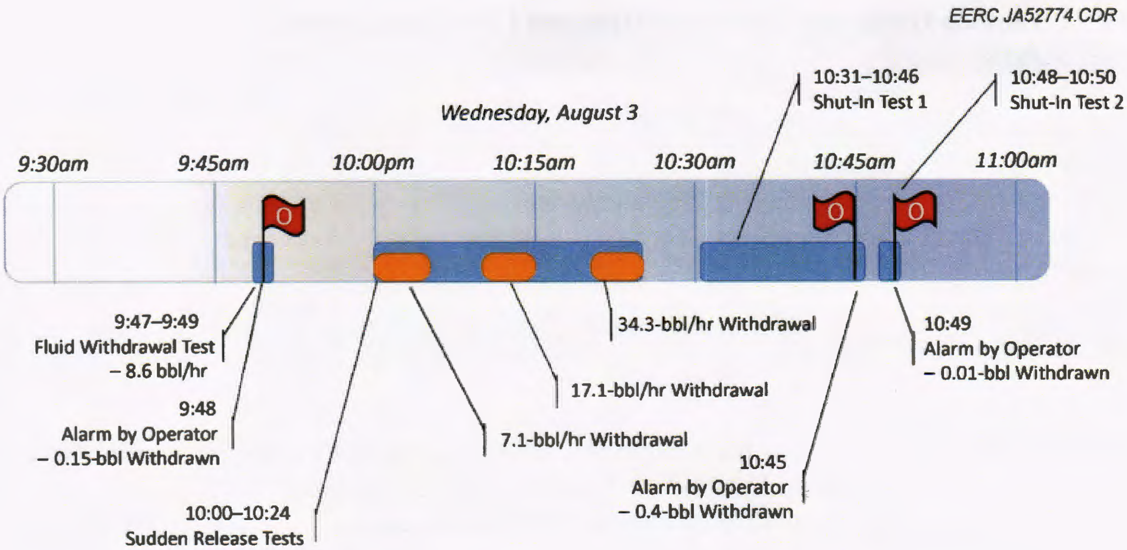

Figure 25. FWT time line, Company C1, Test Day 2, 6-in. segment.

General Observations on Performance

In general, the instantaneous differential flow rate LDS alarmed within 5 minutes when differential flow rates were at or above its alarm threshold. No alarms were generated for lesser flow differences. In general, the LDS operated as expected for this gathering line. The alarm limits were set at values that, if exceeded, would trigger an alarm fairly quickly. The alarm trigger set points were 12.5 bbl/hr equivalent and 8.3 bbl/hr equivalent on the 4- and 6-in. lines, respectively. When FWTs were performed above these values, alarms were triggered within minutes. If the commodity discharge was below this level, the alarm would not sound. This was verified by withdrawing less than the alarm threshold for a much longer period of time than that which alarmed earlier. Despite the longer test duration, no alarm was triggered.

Company C1's static pressure shut-in test initially employed a 1-minute hold period after production and disposal sites were shut in to permit any perturbations in the system to dampen out. The shut-in test then proceeded to monitor pressure changes over 12 minutes. The related alarm threshold was an 8-psig pressure drop over 12 minutes. After the first round of shut-in static pressure testing, the 1-minute wait was increased to 220 seconds because pressure oscillations inside the pipeline were observed long after the pipeline was shut in. The 12-minute observation period was subsequently reduced to 6 minutes.

The sudden-release testing conducted on the 4-in. pipeline indicated small but noticeable pressure changes in the annular space of the composite pipeline when the FWT withdrawal rate was increased above 24.3 bbl/hr. To observe the drop, the resolution of the LDS had to be increased to a relatively high value. This pressure change was undetectable on the larger 6-in. pipeline at any of the sudden release testing values. The team believes that this pressure change was not seen because the pipe volume of the 6-in. pipeline is significantly larger than that of the 4-in. pipeline and thus has more room to absorb the shock of the pulse. It is unclear at this point if this has value for potential LDS implementation. More development work by Company C2 likely needs to be completed before this can be considered for commercial leak detection application.

Detailed Performance Analysis

Company C1 engaged the services of a third party to assist in design, installation, and maintenance of its SCADA and LDS. The LDS comprises three active and one inactive techniques:

- Simple monitoring of pipeline pressure at all pump and disposal locations
- Implementation of an instantaneous flow rate balance
- Monitoring annulus pressure in its multilayered-pipe gathering pipelines
- Implemented but not active: automatically shutting in the pipeline and monitoring pressure over a specified period of time

As was true for other operators, heuristics were applied to arrive at alarm thresholds and other parameters that balance high sensitivity with acceptably low false positive alarm rates. Pipeline pressure alarm thresholds were determined based on conditions at the location of the pressure meter. A function also was included that caused the system to ignore perturbations induced by pump starts.

Instantaneous volume balance alarm thresholds were set at 8.3 to 12.5 bbl/hr, depending on the gathering pipeline. Thresholds had minimum time requirements that had to be exceeded before leak alarms were generated.

Annulus pressure monitoring incorporated three alarm levels:

- A very low pressure which, if exceeded for a few minutes, indicated a potential break in the outer shell
- A moderately low pressure which, if exceeded for many minutes, indicated a need to repressurize the annulus
- A high pressure which, if exceeded for a few minutes, indicated a potential break in the inner pipe

While not active, the static pressure test technique was configured to automatically shut in the gathering pipeline daily at a predetermined time while the pipeline was at pressure, wait several minutes, and then monitor pressures along the pipeline for several more minutes. If pressures changed by more than a preset threshold level, an alarm would be generated. Again, durations and levels were configured based upon heuristics.

Figure 26 depicts August 2 performance of Company C1's instantaneous flow balance with respect to the withdrawal rate. The approach was fairly accurate, and alarm was generated about 4 minutes after start of withdrawal. Table 13 exhibits sensitivity and accuracy performance indicators for Company C1's LDS approach.

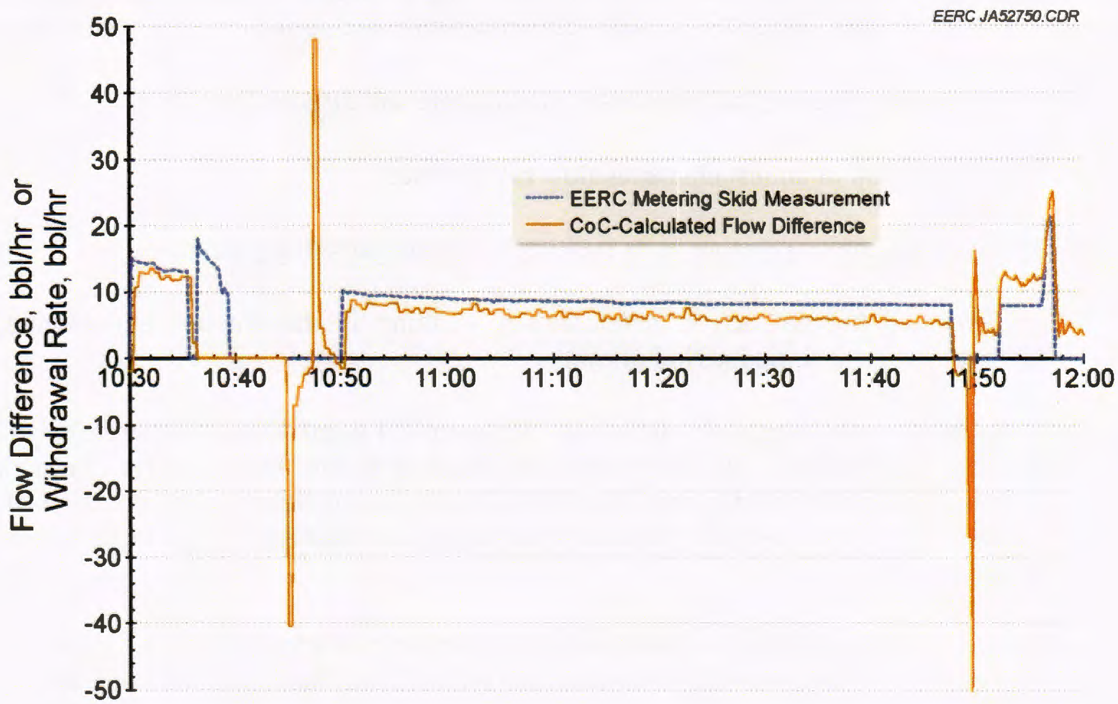

Figure 26. Effect of EERC withdrawal on Company C1 (CoC)-calculated flow difference, August 2, 2016.

Table 13. Key Performance Indicators of Company C1 Constant Withdrawal Rate Tests

		Test Number		
		1a	1b	2
	Date	Aug 2, 2016	Aug 2, 2016	Aug 3, 2016
	No. of producing wells continuously reporting data to SCADA (no. of active wells)	2 (1)	2 (1)	2 (2)
	Alarm encountered	Hi-Hi	None	Hi-Hi
	Leak rate based on total receipts, %	13.3%	8.0%	No data
Sensitivity	Time to detect, hr	0.07	No detect	0.017
	Leak rate, bbl/hr	14.0	8.4	8.6
	Volume withdrawn, bbl	0.94	N/A	0.15
Accuracy	Estimated withdrawal rate error, %†	11.1%	25.3%	No data
	Estimated withdrawn volume error, %†	−11.2%	N/A	No data

†Error calculated relative to actual withdrawal rate/volume, as measured by the EERC metering skid.

$$\text{Error} = \sum \left| \frac{\text{SCADA Value} - \text{EERC Value}}{\text{EERC Value}} \right|$$

NOTE: Company C1 process data were unavailable for August 3 because of database challenges; therefore, limited analysis was completed.

After August 2 steady-state flow withdrawal testing was completed, sudden release testing was performed. Unfortunately, changes made to the SCADA at that time and through the following day created technical problems with data analysis. As a result, a detailed evaluation of the data could not be performed.

During August 2 testing, it was pointed out to Company C1's SCADA contractor that instantaneous flow rate monitoring can provide a very rapid response to detecting leaks. The limits for such monitoring must be set relatively high to avoid "momentary" disturbances that might occur and generate an alarm. Thus an alarm threshold of 7% meant that a leak of 6% will never generate an alarm. In response, by the start of testing on August 3, the contractor had implemented a more sensitive volume difference approach that had a window whose duration was an extended period of time with a smaller alarm threshold.

August 3 testing, which was performed on a different gathering pipeline than August 2 testing, included exercising the static leak test algorithm that had been implemented but was not active. The static test monitored pressure for a 12-minute duration. If the pipeline pressure dropped more than the alarm threshold, an alarm was generated. The first withdrawal that tested this function experienced an unusually large rise and fall in pressure early in the test.

At that time, it was determined that an alarm might have been produced even without fluid withdrawal because shutting in the pipeline produced a pressure perturbation that resulted in an abnormally high initial pressure. Successive tests of the algorithm included a lockout interval of a few minutes during which pressure was permitted to equilibrate before monitoring for leakage commenced. By this method, withdrawals of less than 0.7 bbl/hr were detected. No tests were performed in the absence of withdrawal to test for false positive indications. The duration of testing was inadequate to determine what disturbances might generate false positive leak alarms.

August 3 testing also included a steady-state withdrawal test of 8.6 bbl/hr which the instantaneous flow balance LDS detected and alarmed within 2 minutes.

In an attempt to qualitatively understand false positive alarms, the EERC discussed alarm history with each demonstrating company. Company C1 provided a systematic list of alarms, but the descriptors did not reveal the ultimate cause of the alarm.

Company C2 was the manufacturer of the multilayered pipe whose annulus pressure was monitored for indication of leaks, as described above. Testing involved opening a valve at the disposal end of the gathering pipeline and monitoring flow rate until an alarm was indicated. During annulus testing on 2 days, the annulus gas flow was so slow that no alarm was indicated during EERC's presence at the disposal site. Consequently, there are no results to report. However, serendipitously, on August 2, a miniscule change in annulus pressure was observed during sudden-release testing. Accurate characterization of pressure waves often requires higher resolution and more frequent measurement than routine pressure monitoring. SCADA adjustments were made to increase sampling rate and expand the resolution of the annulus pressure measurement. Continued testing on the 4-in. pipeline indicated that annulus pressure appeared to respond to changes in inner pipe pressures. It is premature to extrapolate what utility this effect might possess (assuming that it is predictable and assuming that other common events do not interfere with the signal), but it appears to be an interesting research topic.

Value to Operator

EERC staff discussed with Company C1 and its controls contractor the advantages that instantaneous flow rate balances possess with respect to volume balances. A significant disadvantage was also discussed: instantaneous flow rate balances require higher alarm thresholds to avoid false positive alarms caused by brief but large OOB conditions. Conversely, volume balances that monitor over longer periods of time are less sensitive to brief excursions and are thus able to detect smaller leaks without triggering false positive alarms. The sensitivity of the volume balance is proportional to the duration over which flow is monitored.

In response, Company C1's controls contractor is considering permanent addition of longer-term volume balance functionality.

Conclusions from Field Evaluation of Company C1 and C2's LDS

Company C1

Company C1's LDS is a system developed, installed, and maintained by a third-party. The LDS comprises four approaches:

- Differential flow balance
- Monitoring of annulus pressure of its multilayer pipe
- Monitoring (inner-pipe) pipeline pressure
- Static pressure testing (which was implemented but inactive prior to and during withdrawal testing)

Monitoring differential flow in the pressurized system gave very rapid indications during all steady-state flow tests that experienced steady-state withdrawal rates in excess of alarm thresholds. Expectedly, the method did not generate alarm indications for withdrawal rates just below the thresholds. Such short-term methods tend to be insensitive so as to avoid transients that generate false positive alarms, even if the difference must be sustained for a few minutes.

Withdrawal of gas from the annulus to simulate a pipe break and test the related detection system failed to occur at a rate sufficient to generate an alarm indication while the EERC was at the test site. However, other observations were made during pressure pulse testing.

Sudden withdrawal testing did not generate flows that sufficiently reduced pressures below alarm thresholds.

Static withdrawal testing was performed on the last day of testing on one of the laterals. Steady-state withdrawal at several rates down to less than a barrel an hour successfully generated alarm indications.

As with other participants, Company C1's LDS provider made several changes based on learning acquired during withdrawal testing. After the first test, an extended-duration volume balance was added to the LDS to increase its sensitivity. Additionally, during the second day of withdrawal testing, the static pressure test leak detection method was exercised. The initial test demonstrated that a 30-second wait after shut-in and before the 12-minute observation period was inadequate for the system pressure to stabilize. Shutting in the gathering pipeline caused perturbations that lasted for more than a few minutes. Thus the approach was changed to include a several minute wait but only a 6-minute observation period. After adopting those parameters, the system was demonstrated to detect withdrawal rates of less than 1 bph.

It should be noted that Company C1's systems were simple, with only a few pumps on any lateral and only one or two pumping at any instant. Company C1's systems were fairly new and were overdesigned in anticipation of multifold expansion. Additionally, the LDS appears to have been designed in conjunction with the pipeline system. Consequently, the systems were somewhat ideal in that many of the issues that might be encountered by more complex gathering systems with aging instrumentation and infrastructure over long periods of time were not evident. This is one of many factors that must be considered when an LDS approach is selected and LDS technologies evaluated. As gathering pipeline systems age and grow, they will be exposed to a wider variety of conditions and potential issues (such as age-related issues) than were encountered in the brief course of withdrawal testing.

Company C2

As noted earlier in this report, an attempt was made to test Company C2's LDS approach of monitoring annulus pressure in the multilayer pipe to detect breaches in the outer layer. Withdrawal rates were lower than the time available for the EERC to observe testing. Consequently, no results were acquired. However, during sudden release testing of the smaller pipeline, very small pressure variations were detected in the annulus that appeared to be related to the pulses. More sensitive and higher rate data acquisition confirmed the observation. While such high-resolution monitoring might have the potential to indicate leaks or other conditions, many unknowns exist, such as what conditions interfere with accurate monitoring or what events other than leaks might appear as a leak (false positive indications). Therefore, this report does not offer detail on this approach to leak detection. It holds promise but is in a developmental stage.

INDIVIDUAL LDS APPROACHES APPLIED TO A SIMPLIFIED PIPELINE SYSTEM MODEL

In order to aid in the assessment of the feasibility and cost-effectiveness of LDS, the EERC created a hypothetical or "model" gathering system. This model system provides a common basis by which to assess the incremental cost of different leak detection methods and compare relative leak detection performance, based on data gathered from field activities. The model also provides a useful example from which to illustrate the impact that leak location and system configuration (geometry, elevation, pipe size, etc.) can have on the magnitude of a spill.

The model system developed by the EERC for this report consists of six wellsites, 6 miles of 4-in. diameter pipe, 4 miles of 6-in. diameter pipe, and a single aggregation point represented as a produced water disposal well (the model system could equally represent a crude oil gathering system in which the aggregation point is a truck or pipeline terminal, transferring oil from the gathering system to a larger transmission pipeline). An illustration of this model system is provided in Figure 27.

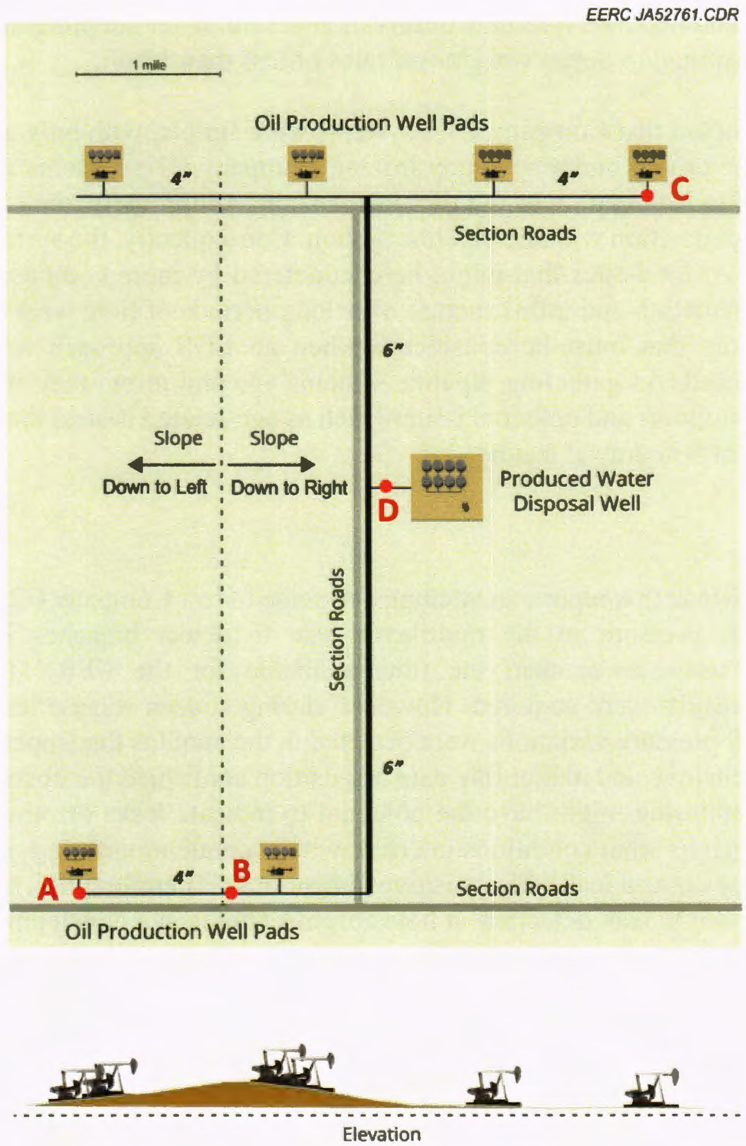

Figure 27. Illustration of model gathering system.

This model is a simplified representation of existing gathering systems and does not capture all of the numerous factors/variability that can be present in an operating gathering system. As described in the EERC's previously cited pipeline study report, gathering systems possess widely varying configurations and levels of complexity due to topography, land ownership, climate, and fluid properties. Therefore, this model system does not exactly represent any specific gathering system but provides an illustration of the complexities that are possible in any system and the challenges imparted to effective leak detection.

Magnitude of Leak – Best-Case Scenario

A pipeline system's configuration, elevation, and pipeline size (length and diameter) can all impact the magnitude of a spill when a pipeline is breached. Depending upon the location of the pipeline break, the volume of fluid released to the environment can range from less than a barrel to thousands of barrels simply because of the volume of fluid that can leak out of the pipeline after the leak is detected and flow to the gathering system is stopped.

The purpose of any good LDS is to identify the presence of a leak so that flow to the system can be stopped and the impact of the leak can be minimized. Although no LDS can prevent a leak from occurring, an LDS can serve a role in minimizing the magnitude of the resultant fluid loss. However, fluid lost when a pipeline is breached will almost never be zero. In an ideal (unattainable) system, some fluid will exit the pipeline because of gravity, even if the pipeline breach were identified immediately and flow to the system stopped.

To illustrate this point, the EERC identified four leak points on the model system and calculated the total volume loss (spill magnitude) assuming a pipeline break occurred, the leak was detected, and flow to the system was stopped immediately. These leak points are labeled A–D on Figure 27.

Using the geometry, pipe volume, and elevation difference of the model system, hypothetical spill volumes that would be experienced after flow to the system was stopped were calculated and are summarized (Table 14). Leak Location A would allow fluid from approximately 1 mile of 4-in. pipe to drain out of the gathering system, resulting in a spill volume of 68 bbl. This spill volume is based solely on the volume of fluid contained in the buried pipe between the leak location (A) and the elevation break indicated by the dotted line. If the leak point were located at the highest elevation point (Location B), it is possible that the spilled volume could be minimized to less than 1 bbl since no gravity drain to the leak location would occur. Location C represents the largest potential spill volume since almost 8 miles of pipeline could drain by gravity to a pipeline break at this location. In this model system, 920 bbl of fluid could leak from the pipe, but larger spill volumes are possible from larger gathering systems with larger pipe and longer pipeline lengths. Leak Location D represents another scenario and would allow fluid from approximately 6 miles of pipe to drain out of the system, resulting in a spill volume of 782 bbl.

No leak detection system can prevent leaks from occurring or detect a pipeline breach immediately. However, the more sensitive and responsive a LDS is, the smaller the magnitude of a resultant spill. This analysis and the data in Table 14 illustrate that there is a practical limit to what LDS can achieve relative to pipeline spills.

Table 14. Spill Volume from a "Model" Gathering Pipeline Due to System Drain Out

	Location A	Location B	Location C	Location D
Length of Pipe Drained, miles	1	0	8	6
Leaked Volume, bbl	69	<1	920	782

LDS Effectiveness

LDS come in many types. A description of their function, strengths, and weaknesses is offered in the previously cited EERC pipeline study. Two general classes of LDS were used by companies that participated in this field evaluation project: SCADA and SCADA + CPM defined below. Therefore, these systems are the basis for the EERC's evaluation.

Using the model system illustrated in Figure 28, the EERC has defined three levels of automation or sophistication of leak detection that, when applied to this common gathering system, can illustrate the relative cost and benefit which could be achieved with different methodologies (LDS):

- Daily manual volume accounting – daily, manual recording of field data with leak identification performed during accounting activities
- SCADA – continuous, automatic, monitoring of pipeline conditions by control computers and pipeline operators
- SCADA + CPM – continuous, advanced specialized LDS software that uses data from but is distinct from SCADA

A summary of each of these configurations is provided in the subsequent sections.

Manual Volume Accounting Approach

Using a manual volume accounting approach to LDS, fluids are pumped from the storage tank to the gathering pipeline, relying on local instrumentation and process control. No communication or data transfer beyond the well site exists. Flow volumes, pipe pressure, and tank levels are measured and logged on-site, most commonly by a PLC. Leak detection using this configuration is achieved by manually recording totalized flow readings on a daily basis and comparing total flow from all of the production locations to the total flow measured at the aggregation point (disposal well). This manual logging of data is done by pipeline personnel visiting each wellsite on a regular basis and recording data in a log book or computer. In this way, total flow entering and exiting the system can be monitored daily, and discrepancies can be investigated if indicative of a leak. An example diagram illustrating instrumentation for the model system is provided in Figure 28.

Manual volume accounting represents the simplest form of leak detection and, in the worst case, could allow produced fluid to leak for 24 hours before it was detected. In practice, the addition of leak detection equipment or procedures should lead to more rapid identification of a

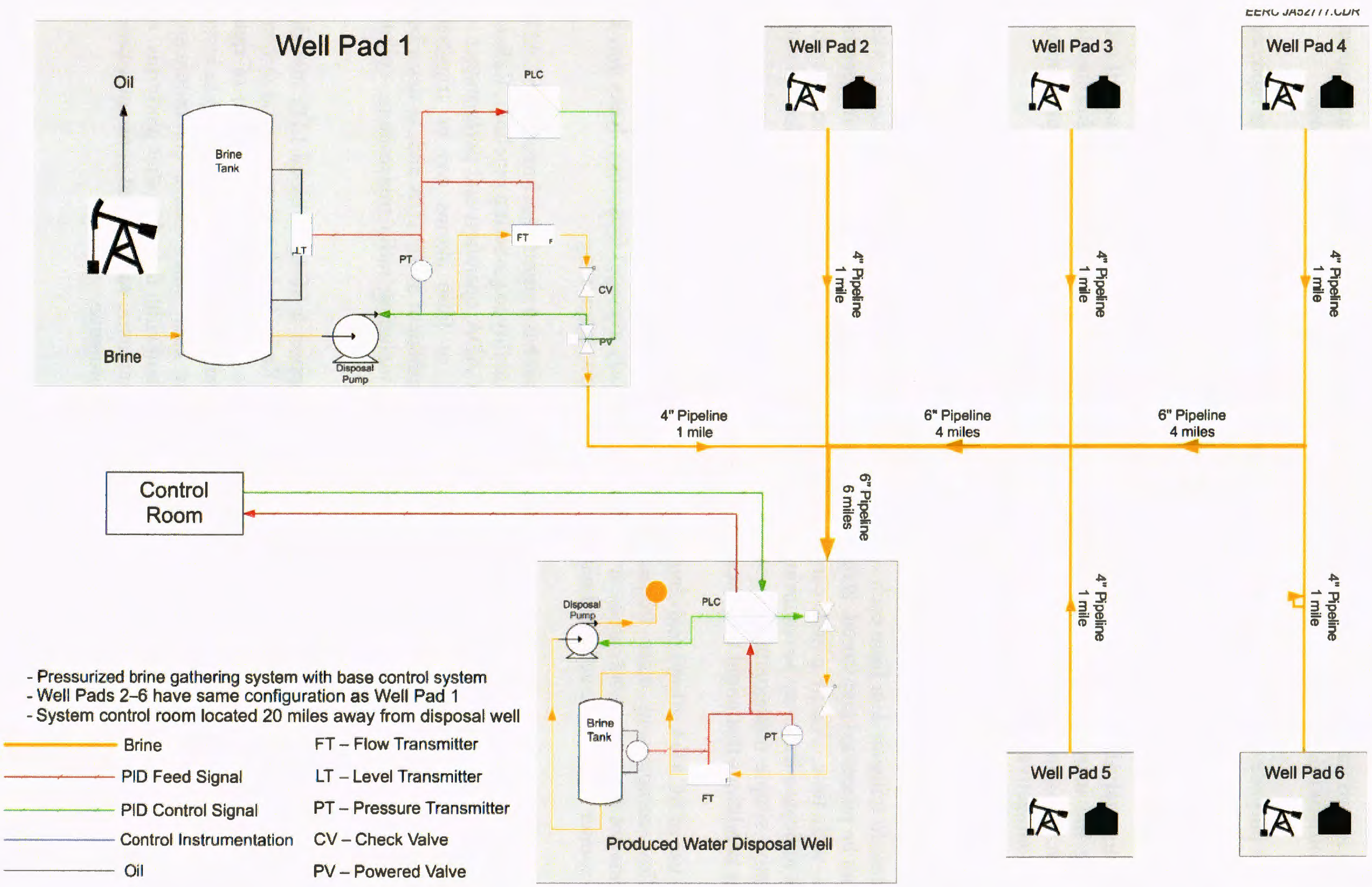

Figure 28. Piping and instrumentation diagram of the model system.

leak and/or identification of a smaller leak than could be achieved using manual volume accounting; otherwise, the cost of additional process/procedures would not be warranted.

For the purpose of this analysis and cost comparison, manual volume accounting represents a baseline. There is significant cost associated with conducting manual volume accounting, including instrumentation, labor and travel to inspect sites and review flow data, and manual system inspection to ensure safe and effective operation of a gathering system. This level of instrumentation and site labor would be essentially equivalent in all three scenarios compared. Therefore, this analysis does not estimate the cost of these items. Instead, the analysis will focus on assessing the incremental cost of adding SCADA and SCADA + CPM to this baseline configuration. The analysis will then evaluate the relative difference in leak detection performance to provide a subjective comparison of cost vs. benefit.

SCADA-Based Leak Detection System

A SCADA-based LDS uses existing wellsite instrumentation and adds communication infrastructure to transmit data from each wellsite and aggregation point to a central location where the data can be processed and stored. Data trends can be created to illustrate changes in operating conditions with time. Alarm points can be programmed to provide an alert when operating conditions indicate a leak may be occurring (drop in pressure or difference between inlet and outlet flow). Lastly, simple mathematical algorithms can be developed to analyze data and identify anomalous conditions that could be indicative of a leak or other operational problems.

The use of SCADA allows real-time monitoring of operating conditions, providing a way to conduct flow comparisons more frequently than manual volume accounting. When volume comparisons are done on a continuous or periodic (e.g., hourly average) frequency, leaks may be identified sooner than can be achieved with daily manual flow accounting.

Communication infrastructure is an important factor that has a significant impact on SCADA performance and can lead to substantial differences in applicability to gathering pipelines. Reliable and rapid communication of data is critical to effective SCADA operation and performance. If communication is interrupted, leaks can go undetected, or false alarms can be triggered. Communication infrastructure is typically installed as a component of SCADA and, as described previously, can be achieved with multiple technologies, including radio transmitters, cellular communications, or fiber-optic lines.

The selection of communication infrastructure to support a SCADA-based LDS includes competing factors of cost, applicability, and performance. Radio-based communication systems are typically among the least expensive option but require "line-of-sight" installation of radio towers. Extremely rugged or hilly terrain and/or lack of land access (lease agreements) to install towers can dramatically impede performance or increase cost. Radio-based communication typically provides the slower communication and smaller bandwidth than the other platforms. As system complexity, size, and amount of instrumentation increases, radio-based communications can experience limitations and negatively impact LDS performance.

Cellular-based communication systems require less installed infrastructure and can accommodate faster data transfer and greater bandwidth than radio. The capital costs are similar to radio but require monthly service fees to a cellular communication provider which can increase lifetime costs of operation.

Fiber-optic cable has the ability to provide the fastest data transfer and high bandwidth, exceeding what would be required for most LDS. The cost for installing fiber-optic cable is extremely high in retrofit situations in which new cable must be installed separately. However, this cost can be reduced substantially when cable is installed along with pipeline during new construction.

SCADA Plus CPM Leak Detection System

CPM is a software-based algorithmic monitoring tool that uses the information gathered by the SCADA system in complex calculations to help identify anomalies in the pipeline system that could be indicative of a leak. The sensitivity (ability to identify smaller leaks) of CPM techniques depends upon the accuracy with which internal pipeline conditions are measured and accuracy with which normal conditions or leak-indicative conditions are understood. In general terms, CPM requires all of the same technical requirements that a SCADA system does, namely, flow and pressure measurement at the wellsite and aggregation point and communication infrastructure. However, CPM can benefit from additional operational data. Measurement of fluid temperature, fluid density, pressure at additional locations, and data impacting pipeline pack add complexity and cost to a CPM system but can contribute to improved leak detection performance. With increasing data comes the need for more robust communication infrastructure and more data bandwidth to accommodate the increased amount of data at a rate that is beneficial to CPM performance.

General LDS Performance

A wide range of leak detection performance was observed over 17 FWTs conducted on multiple gathering systems of three different pipeline operators. As described previously, many different leak rates were evaluated during each test. The time required in each test to detect a leak resulted in a wide range of "spilled" volumes. This variability can be attributed to differences in the LDS, different geography and elevation of the pipeline system, and differences in the operational conditions—specifically, whether the pipeline is operated under pressurized or unpressurized conditions. Because testing was conducted on existing gathering systems, controlled tests could not be conducted to evaluate the effect of each of these attributes on leak detection performance. However, a review of the data does provide some insights into these effects.

A summary of LDS performance during constant withdrawal rate testing is provided in Table 15. This information illustrates a wide range of spill volumes that could occur based on test results and projections derived from available data. Across 17 constant withdrawal rate tests, the average spill volume required to trigger an alarm/detection was 75 bbl. By comparison, the average spill volume that would occur if no LDS were in place is 676 bbl. This assumes that daily manual volume accounting allowed the leak to be identified after 24 hours and represents a worst-case

Table 15. Summary of Constant Withdrawal Rate EERC-Modeled FWT Spill Volumes

	Average, bbl	Max., bbl	Min., bbl
All 17 FWTs	75	299	<1
Five Tests on Pressurized Systems, SCADA	47	202	<1
Eight Tests on Unpressurized Systems, SCADA	107	299	12
Four Tests on Unpressurized Systems, CPM	38	90	16
All 17 Tests after 24-hr Manual Flow Accounting	676	1199	132

scenario for the purposes of our analysis. In actual practice, leaks have continued for more than 24 hours, even with manual volume accounting because of variability in meter accuracy, pipeline loading (slack lines), equipment problems, and/or operator error. Nonetheless, in an effort to define a non-LDS limit, a 24-hr manual volume balance was selected to cap the maximum spill volume that could occur under each of the tested conditions. For the purpose of establishing the observed range of performance across multiple gathering systems and LDS, only constant withdrawal rate data are included here.

Five tests were conducted on gathering systems operated under pressurized conditions using SCADA-based LDS. Operating gathering pipelines under constant pressure helps to eliminate pipeline slack and makes leak detection by comparison of total fluid into the pipeline vs. total fluid out of the pipeline much easier. Because void volume within the pipeline system is minimized, every barrel of fluid pumped into the system will force a barrel out of the system within a short time, making detection of leaked fluid easier. As stated previously, not all gathering systems can be operated under pressure. Limitations in pipeline pressure specifications and substantial elevation changes can prevent or prohibit operation under fully packed and pressurized conditions.

The average spill volume from constant withdrawal rate tests conducted on pressurized systems using SCADA-based LDS was 47 bbl. Out of five tests, one test was conducted at a flow rate below the known threshold of the SCADA alarm programming (this test was performed on Company C1's pipeline system). If results from this test are removed from the data set, the average spill volume would drop to 8 bbl. Small leaks can only be identified if observed over a longer period of time until the volume of lost fluid increases to a level above the alarm threshold of the SCADA system. Under these conditions, longer-term flow balancing within the SCADA can provide appropriate leak detection (refer to Inset B, earlier in this report). Planned changes to Company C1's LDS incorporate this longer-term flow balancing and may enable improved leak detection under the tested conditions.

Another measure of the performance of an LDS is the time required to detect a leak and alarm. Out of the tests conducted on pressurized gathering systems, the time required to detect a leak varied from less than 1 hour to almost 3 hours, excluding one test that was performed below the known detection threshold. In this case, the leak would likely be detected through a 24-hour manual flow comparison.

A total of eight tests were conducted on a gathering system operated under gravity flow (unpressurized) conditions using SCADA-based LDS. The complex nature of the gathering system and variation in pipeline slack means that large amounts of fluid can be pumped into the pipeline, filling void volume before flow out of the system matches the inflow. This condition can lead to slower response time to identifying a leak. Further, the amount of slack within the pipeline changes with time and operating conditions, creating a very dynamic condition that is hard to predict. The average spill volume from tests conducted on an unpressurized system using SCADA LDS was 107 bbl. Out of eight tests conducted on these types of gathering systems, three were conducted under pipeline conditions considered atypical, resulting in an unusually long time to detect. If results from anomalous tests are removed from the data set, the average spill volume would drop to 58 bbl. The time required to detect a leak from eight tests on unpressurized pipeline systems ranged from less than 1 hour to nearly 6 hours.

Finally, four constant withdrawal rate tests were conducted on an unpressurized pipeline system using a CPM LDS. Using the same instrumentation and data utilized by the SCADA system, the average spill volume was 38 bbl before being identified by the LDS. The time required for CPM LDS to detect a leak from these FWTs ranged from less than 1 hour to under 2 hours. Static test results were not included in this average spill volume or time to detect.

Using the data generated from these limited field tests, it can be deduced that, for pressurized pipelines, the addition of SCADA to a daily manual volume accounting system reduced total spill volume by 77%–96%. Using a similar analysis for unpressurized pipelines, the addition of SCADA to a manual volume accounting system could reduce the total spill volume by 87%–93%, given the range of performance observed over eight tests.

Using our model system as a basis, this relative improvement in leak detection performance comes with costs for both the SCADA system and the necessary communication infrastructure. Engineering estimates on these costs were developed for the model system by an engineering firm experienced in this field. Since the cost of different communication options varies so significantly, a summary cost breakdown for the six-input model pipeline system is provided in Table 16.

The significant variability in these estimates is due almost entirely to the high cost of installing fiber-optic cable in a retrofit scenario. An engineering estimate for the model system, which assumed installation of 40 miles of fiber-optic cable, represents the most expensive option for communications infrastructure. As stated previously, installation of fiber optic, along with pipeline as part of new construction, has the potential to dramatically decrease the cost. However, for retrofit applications, this estimate is more representative.

Table 16. Comparison of SCADA and Communication Costs

	SCADA	Radio Communication	Cellular Communication	Fiber-Optic Communication	Total
SCADA + Radio	\$71,000	\$62,000	–	–	\$133,000
SCADA + Cellular	\$71,000	–	\$43,000 + access fees	–	\$114,000
SCADA + Fiber Optic, Retrofit	\$71,000	–	–	\$3,400,000	\$3,471,000

Implementation of CPM appears to have resulted in a 96% reduction in spill volume when compared to what could be achieved with daily volume accounting. This represents an incremental improvement over SCADA at a cost of \$50,000–\$100,000 for a six-inlet system similar to the model described here. However, it is important to remember that CPM can only be implemented when the instrumentation, software, and communications infrastructure of a SCADA system are also in place.

CONCLUSIONS

- **This field demonstration led to specific improvements in LDS performance for each system tested.**
  This state-funded field evaluation resulted in real-world testing of LDS on three companies' gathering pipelines. This testing provided each gathering pipeline operator with valuable information that led to actual improvements to LDS that were made after testing to improve sensitivity, add functionality, or reduce time to alarm in the event of a leak. The execution of this project directly contributed to improved leak detection functionality for multiple gathering networks operated by the three partner companies, reducing spill risk/liability in excess of the funds expended. It could be valuable for companies to conduct fluid withdrawal tests as part of an ongoing performance management plan.

- **The addition of LDS can improve response time and reduce the magnitude of a spill, reducing spill remediation and associated costs.**
  Findings from the previously completed study and results from this field evaluation agree and indicate that adding some form of leak detection technology to pipelines for monitoring the integrity of the pipeline increases the likelihood that a leak will be identified sooner, that leak magnitude will be reduced (relative to simple daily flow accounting), and that a leak will be located (if CPM is employed). Indeed, accurate location will reduce the response time and mitigate the environmental impact. An investment in LDS can be small, relative to the cost of remediation of large spills. However, LDS technologies are widely varied in complexity of installation, cost, and effectiveness. <u>There is no one size fits all solution for all gathering systems. It would be inappropriate and inaccurate to extrapolate results from this field evaluation to all gathering systems.</u>

- **Operating pipelines with consistent pressure can reduce slack and improve LDS performance.**
  Pressurized gathering pipelines can enable faster leak identification than unpressurized systems. In many cases, the topography of a region may prevent continuous pressurized operation because of pipeline pressure design limits. In some of these cases, alternative approaches may be used to enhance accurate flow balance through the use of backflow preventers, breakout tanks, or operating sections of a pipeline network under pressurized conditions. However, it is important to note that selection and design of alternative approaches will be site-specific.

- **Human response to pipeline operation is an important component of leak detection and needs to be part of an effective pipeline performance management plan.**
  This field evaluation project evaluated the performance of LDS and their ability to identify the occurrence of a leak. It was not within the scope to assess any company's effectiveness at responding to notification of a leak. Nonetheless, the human response to an LDS notification is critical to achieving effective spill response. This human factor can be enhanced by implementing a control room management document, identifying responsibilities of employees involved in pipeline operation, and defining specific control room operator alarm response procedures. Operator training is also helpful to reduce leak response time.

- **No LDS will detect every leak under every condition.**
  Results from testing each LDS indicated the possibility that leaks could go undetected for extended periods of time. No LDS is perfect, and no LDS performs perfectly in all system configurations and all operating situations, but an LDS has potential to decrease the risk of large, prolonged, undetected pipeline leaks.

- As reported in the EERC's December 2015 study, "Liquids Gathering Pipelines: A Comprehensive Analysis," the importance of LDS is secondary to high-quality construction, inspection, maintenance, and operation of pipelines and to appropriate preparation and effective response to leaks that occur. However, as evidenced by the results of this study, LDS improves the timeliness of leak detection and reduces the volume of releases. It is therefore prudent that operators consider implementing LDS. Such consideration can be demonstrated by preparation and implementation of a formal leak detection plan.

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