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NEW METHODS FOR RAPID LEAK DETECTION IN OFFSHORE PIPELINES

FINAL REPORT

Contract 14-35-0001-30613
SwRI Project No. 04-4558

Prepared for:

Minerals Management Service
U.S. Department of the Interior
381 Elden Street
Herndon, VA 22070-4817

April 1992



SOUTHWEST RESEARCH INSTITUTE
SAN ANTONIO HOUSTON
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DISCLAIMER

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EXECUTIVE SUMMARY

Domestic oil and gas production from offshore facilities accounts for about 1 million barrels of oil per day and about 12 billion standard cubic feet per day of natural gas. The majority of these products are transported from the offshore production sites to onshore processing facilities through more than 20,000 miles of subsea pipelines. The subsea pipelines have proven to be a reliable and safe transportation method. However, the number of reported accidents has been increasing steadily as existing pipelines age and the number of pipelines in operation continues to increase. Obviously, as the number of operational pipelines increases, it will take a concerted effort to prevent the impact from accidental product discharges from increasing at a corresponding rate.

Because accidental product discharges cannot be entirely eliminated, one of the most effective methods of reducing the impact of spills is to quickly detect the leak and to act quickly to stop the discharge. Leak detection methods that depend upon visual inspections or a single pressure sensor provide very slow response and may only detect a leak after it has reached a considerable size. As new production moves further offshore, pipeline length will continue to increase, and leak detection will become even more difficult. In addition, the trend toward transporting unprocessed products as a multiphase stream further complicates the leak detection efforts because metering multiphase lines is very difficult and inaccurate. To minimize the impact from the increasing number of subsea pipelines, there is clearly a need for rapid leak detection systems.

In order to evaluate rapid leak detection systems, the MMS funded a brief study (in 1990) to identify new methods for rapid leak detection in subsea pipelines. Four promising methods were identified: (1) computer simulation software linked to a Supervisory Control and Data Acquisition (SCADA) system, (2) continuous monitoring of acoustic emissions, (3) monitoring for chemical emissions using chemical sensors, and (4) fiber optic strain monitoring system. Each of these methods was identified from reports in the technical literature, but no detailed evaluation of the methods was performed in the initial study. The purpose of the work reported here is to evaluate the technical feasibility of applying the four different leak detection methods to subsea pipelines.

Part of the evaluation effort entailed reviewing prior work, evaluating sensors, contacting equipment vendors, determining system installation and operation methods, and assessing the reliability and sensitivity of the systems. Because the four different leak detection methods utilize

completely different technologies, the evaluations were performed by persons familiar with each different technology. The report is, therefore, broken down into the four different leak detection methods since each evaluation effort was essentially independent.

Several different acoustic-based leak detection methods were reviewed and the most promising method is the low frequency impulse detection method. The other methods, that require installation of acoustic sensors along the pipeline, were deemed feasible but impractical from an installation and maintenance point of view. The impulse method uses sensors installed at the ends of the pipeline to detect the rupture event. This method captures the transient acoustic event produced by a rapid pipe failure. The method can detect larger size failures (over one inch in diameter) at distances of up to 100 km. The method is therefore applicable for rapidly detecting large leaks or pipeline ruptures, but would not detect smaller leaks or leaks that grow slowly over several hours.

The fiber-optic-based leak detection system selected as having the best potential for development for subsea pipelines is a system that detects a break in a fiber bonded to the pipeline. Other methods, such as monitoring local strain along the fiber, do not have the resolution or reliability needed when employed over long distances. The other methods also require sensitive instrumentation and highly-trained operators to interpret the response from the sensors. The breakage of fibers bonded to the pipeline will immediately detect and pinpoint large pipeline failures or ruptures, but will not detect small leaks caused by corrosion.

The chemical leak detection system with the most promise for subsea pipeline leak detection is based on a special sampling tube placed on the pipeline. The special tube allows diffusion of the leaking chemicals through the tube walls and into the fluid in the tube. The fluid in the tube is periodically pumped through a detector that is sensitive to the pipeline product. This method can provide complete coverage of the pipeline and detect low level leaks in either single or multiphase flowlines. The response time of the system is fairly slow (typically 12 hours), so another leak detection method would be required to quickly respond to large leaks or ruptures. The method can accurately determine the leak location and the size of the leak.

The SCADA-based leak detection methods have the widest range of applicability to subsea pipeline leak detection and are by far the most highly developed of the leak detection methods reviewed. SCADA systems can rapidly detect large leaks and, over a period of time, detect smaller leaks as well. Because the SCADA-based methods can provide a continuous indication of a leak, these methods are preferred over the methods that give a one-time indication of a leak initiation.

Presently, the major limitations to SCADA-based leak detection systems are: they may not detect leaks less than 1 - 10% of the total flow, the minimum leak detection limits increase as the distance between instrumentation stations increases, and the SCADA-based methods are not generally able to handle multiphase flowlines.

Because large leaks can cause considerable environmental damage, any leak detection system must be able to quickly detect large leaks or pipeline ruptures. The acoustic, fiber optic and SCADA-based leak detection systems are all capable of detecting large leaks quickly. Of these, the SCADA-based methods have the widest range of applicability. The SCADA-based methods can provide a continuous indication of the leak size and, therefore, the pipeline operator can provide the appropriate response to the leak signal. The fiber optic and acoustic methods only produce a one time alarm indicating a potential leak producing event occurred, and no indication of leak size is given. In addition, the SCADA-based methods have the sensitivity to detect smaller leaks, independent of how they are formed. The acoustic and fiber optic leak detection systems can only detect relatively large leaks that develop rapidly or produce a crack in the pipe. For these reasons, the SCADA-based leak detection systems are preferred, for most applications, over either the acoustic or the fiber-optic-based systems.

Detection of small pipeline leaks is important so that the small leaks do not continue over an extended period of time and accumulate into a sizeable spill. The only leak detection methods, reviewed in this study, capable of reliably detecting small leaks are the SCADA-based methods and the chemical leak detection method. SCADA-based leak detection systems can detect small leaks, down to about 1 to 10% of the total pipeline flow, but the time to detection is longer than with large leaks. The chemical leak detection method is the only method that has the potential to detect leaks smaller than about 1% of the total pipeline flow. Because the chemical leak detection system cannot provide a rapid response to large leaks, another leak detection system must be installed to quickly detect large leaks.

Future development efforts on rapid leak detection systems for offshore pipelines should first focus on applying SCADA-based systems to rapidly detect large leaks. Processed-liquid lines, that run from the production platform to shore, transport large quantities of crude oil (collected from many smaller gathering lines) and, therefore, have the potential to produce a large spill if a leak is not quickly detected. Since the fluid stream is processed to remove the gas, the fluid can be accurately metered, and a volume or mass balance leak detection method can be applied. The leak detection system sensitivity and response time depends upon the pipeline system parameters, such as line

length and meter accuracy. Problems that are particularly important for implementing leak detection on offshore pipelines include: long subsea runs between SCADA-metered locations, subsea tie-ins (branch connections) from many production platforms into the pipeline, intermittent or transient flow from the connecting pipelines, difficulty in communicating between metering locations and the SCADA system, and costs associated with installation of high accuracy, custody transfer instrumentation on the offshore platforms. The effects of these parameters on the leak detection system sensitivity and response time should be investigated for typical offshore pipeline configurations.

The trend toward transporting unprocessed well fluids as a multiphase flow stream is another area where development work on leak detection systems is needed. Because a multiphase stream cannot presently be accurately metered, volume- or mass-balance-based leak detection systems cannot be applied. Pressure trend analysis systems have been applied to multiphase systems, but the sensitivity and response of these systems has not been documented. For multiphase SCADA-based leak detection systems, accurate and reliable flow measurement instrumentation and transient flow computer models will need to be developed, or leak detection systems based on other technologies will need to be developed.

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1.0 INTRODUCTION

The mission of the Minerals Management Service (MMS) is to preserve, protect, and develop the oil and natural gas resources of the Outer Continental Shelf (OCS) while balancing the orderly development of these energy resources with the protection of human, marine, and coastal environments. The OCS Lands Act specifies that the Best Available and Safest Technologies (BAST) which are economically feasible shall be used on all exploration, development, and production equipment. The Technology Assessment and Research (TA&R) Program is designed to support the quest for BAST, and to ensure that the equipment used in the OCS environment meets strict standards. This project addresses the research program area of rapid leak detection for subsea pipelines.

Recently, Mastandrea, et al [1.1], carried out a preliminary assessment of the most promising technologies for rapid leak detection for sea floor pipelines for the TA&R Program. Information was obtained primarily from the technical literature (the literature citations appear as Appendix A of the report) and telephone surveys. The report identifies two factors that contribute to large-quantity product spills (from 25,000 gallons to 750,000 gallons): (1) delays in detecting that a leak has occurred, and (2) delays in closing block valves to isolate the segment in which the leak has occurred. Reducing the time required for leak detection is a key factor in limiting the amount of product lost and the potential for environmental damage. Despite an increasing number of installations of rapid leak detection systems to onshore pipelines, most off-shore pipelines still rely on visual detection of leaks from the platform, from ships at sea, or from aircraft that patrol the pipeline right-of-way.

Mastandrea, et al [1.1], identified four promising methods for rapid leak detection for off-shore pipelines as follows: (1) continuous monitoring for sound emission from a pipeline leak, (2) monitoring for hydrocarbon emission using chemical sensors to detect the presence of hydrocarbons in the environment, (3) computer software simulations of pipeline operation in real-time linked to a Supervisory Control and Data Acquisition (SCADA) system, and (4) systems for monitoring local strain deformation using fiber optic technology.

The goal of this study is to evaluate the technical feasibility of each of the four leak detection methods identified by Mastandrea. This effort included characterizing the leak signal and propagation to a detector, reviewing prior work, evaluating sensors, contacting equipment vendors, determining system installation and operation methods, and assessing the reliability and sensitivity

of the systems. Because the four different leak detection methods utilize completely different technologies, the evaluations were performed by persons familiar with each different technology. The report is, therefore, broken down into the four different leak detection methods since each evaluation effort was essentially independent. The results of the evaluations of the leak detection systems are presented in Sections 2.0 to 5.0. The study conclusions are presented in Section 6.0, along with recommendations for future development work on subsea leak detection systems.

2.0 EVALUATION OF SCADA-BASED LEAK DETECTION SYSTEMS

2.1 INTRODUCTION

During the 1980's, SCADA-based leak detection systems were applied to pipelines transporting either liquid or gas over land. In addition, a computer-based leak detection method that analyzes trends in pressure readings at specified points in the pipeline was developed. These systems are now being proposed and installed to protect pipelines that connect offshore platforms to shore-based facilities.

To date, most actual leak detection applications have been to single phase (either all gas or all liquid) lines. Yet, a review of the recent literature identified papers that describe pioneering applications of SCADA-based and trend analysis applications to multiphase offshore pipelines as well.

2.2 LEAK DETECTION METHODS REQUIRING SPECIALIZED COMPUTER SOFTWARE

Nicholas [2.1] categorized various methods used for pipeline leak detection into three simple classes, (1) commonplace methods, (2) methods requiring special instrumentation, and (3) methods requiring specialized computer software. The methods of interest in this section all require specialized computer software. These are pressure *trend change* detecting techniques, and transient-model-based leak detection systems.

2.2.1 POINT PRESSURE ANALYSIS

The point-analysis leak detection method described by Farmer [2.2] and Farmer et al [2.3, 2.4] is based upon the idea that the statistical properties of a series of pressure or velocity measurements taken on a pipeline are different before and after a leak occurs. The PPA method detects leaks by extracting signals representative of current operation and the most recent *trends* from data taken at a single point along the line. Software determines if the behavior of these two signals contains evidence of a leak, or is a result of known events that may produce a leak-like signal. If the software determines that a leak is the most probable event, the results are reported to the operator.

The PPA method was developed using simulations carried out with a hydraulic transient computer model. Farmer et al [2.3] indicate that the transient model simulations

allowed the exploration of sensitivity to flow rate, operating pressure, noise of various kinds, different control schemes, and fluid composition. Several hundred transient model runs were used to learn how to tune the PPA for leaks of various magnitudes and character.

One problem associated with a pipeline instrumentation variable was discussed by Farmer et al [2.3]. During a simulated leak test in the field, it was found that a pressure transducer with a minimum span of 200 psi, sensing a pressure of 20 psi would not respond to pressure changes that were less than its specified accuracy of 0.25% of calibrated span (or 0.5 psi). Specifically, during an event that produced a transient of 0.2 psi, the pressure transmitter output occasionally would not change at all. The instrument manufacturer confirmed that this behavior was normal for this transmitter in this situation.

Another problem encountered during field trials was that PPA did not detect a leak when the leak valve was slowly opened half way. Slow opening of the valve caused a series of small transients that interacted with and were absorbed by a storage tank close to the pressure transmitter. There was insufficient pressure change for PPA to detect it as a leak.

2.2.2 SCADA AND TRANSIENT-MODEL-BASED LEAK DETECTION - COMPENSATED VOLUME BALANCE

Nicholas [2.1] describes a software-based method that calculates the flow balance as the difference between the metered volumetric flow rate into the pipeline minus the metered flow rate leaving the pipeline. In addition, a hydraulic transient computer model is used to calculate the packing rate of product contained in the pipeline. The packing rate term is calculated by the transient model from pressure and temperature data provided by the SCADA system readings or by other instruments. A quantity called the volume balance is calculated as the flow balance minus the packing rate. Ideally, the volume balance will always be calculated as zero, and a positive imbalance is interpreted to be a leak. The advantage of this system over the simpler flow balance analysis is that system transients like pump start-ups and shut-downs should not sound an alarm.

One requirement of this method is that a hydraulic transient computer model must be specifically adapted to the pipeline geometry, the products contained in the pipeline, and the pipeline operating conditions, and be running on a computer in real time to compute the packing rate during leak detection system operation. Nicholas [2.1] discusses an example

of the operation of the compensated volume balance system during a simulated leak test. The system functioned normally through pump start-up and shut-down events, and correctly indicated a product leak of 200 bbl/hr (2% of the product flow rate) within 5 minutes.

Nicholas [2.1] lists and discusses the "practical limitations" that can limit the sensitivity of a computer-based leak detection system. These are (1) noise in pressure and temperature measurements, (2) the accuracy of the flow rate, pressure and temperature measurements, (3) short-term drift in measurements (perhaps caused by direct exposure to the sun, rain, snow or freezing conditions), (4) uncertain ground thermal properties (which affect the rate of heating or cooling of product in the pipeline between measurement stations), (5) uncertain fluid properties (particularly the bulk coefficient of thermal expansion, and fluid viscosity), and (6) slack line flow uncertainties.

2.2.3 SCADA AND TRANSIENT-MODEL-BASED SYSTEM - STATE VARIABLES COMPARED TO SCADA MEASUREMENTS

Wade and Rachford [2.5, 2.6] and Mountford et al [2.7] describe a system for detecting leaks in pipelines using SCADA reports of pressure and temperature data together with a real-time computer-based model of the pipeline network. The model is a transient hydraulic model of each element of the pipeline network including the pipe geometry and the fluid properties of each batch of material flowing in the line. Leak detection is accomplished by requiring that the pressures and flows predicted by a concurrently running network model of the pipeline agree with the measured pressures and flows at each SCADA scan at the locations corresponding to the measured values. This system requires the same amount of pipeline variable information as the compensated volume balance method described by Nicholas [2.1]. The methods differ primarily in how they calculate and present the results to the pipeline operator.

One potential problem with this system is at very low flow rates. It is assumed that the normal flow rate and/or the leak flow rate would be large enough to produce a significant change in the frictional pressure loss caused by the leak. It is suggested that the detectability threshold (i.e. the minimum detectable leak flow rate) for a leak in a liquid line when the normal flow rate is very small, is about four times what it would be if the normal flow rate is close to the design flow rate.

Noise in the pressure measurements made by the SCADA system is identified as another potential problem that could mask small leaks. Wade and Rachford [2.5, 2.6] discuss an example of the operation of a leak detection system for the simulation (using a pipeline simulation model) of a 161 mile section of 24" pipe carrying 14 different products in steady flow at 151,000 bbl/day. A noise level equal to 0.25% of the pressure level was superimposed onto the pressure signals. They claim that leaks in the 2,000 to 3,000 bbl/day range (1.5% to 2% of the normal flow rate) could be detected within 5 minutes. However, if the leak were to occur in a pipeline segment in slack line flow, the detectability threshold was increased to 15,000 bbl/day (10% of the normal flow rate) and the time to detect the leak increased to 20 minutes.

2.2.4 SCADA AND TRANSIENT-MODEL-BASED SYSTEM - VOLUME BALANCE AND PRESSURE/FLOW DEVIATION METHOD

Lippitt [2.8], and Griebenow and Mears [2.9] describe the development and operation of an actual leak detection system being installed on a network of 8,500 miles of pipeline. This system incorporates two methods of leak detection; the volume balance method and the pressure/flow deviation method. Again, a key feature of this system is the on-line operation of a computer-based pipeline simulator that is adapted to the pipeline geometry, products and operational conditions.

Griebenow and Mears [2.9] discuss problems associated with modeling some of the complex line configurations present on the pipeline system. An interesting problem arose during shut-in (no flow) operation when check valves were integrated into the pipeline hydraulic model. By itself, a check valve causes no problem *if* pressure and temperature data are measured on both sides of the valve. However, it is not normal practice to provide a Remote Transmission Unit (RTU) to measure product temperature and pressure when check valves are installed on the downstream side of a river crossing. It was found that product shrinkage in the segment beneath the river could cause the check valve to shut and introduce a pressure discontinuity across the check valve that could upset the leak detection system.

Several other issues associated with "tuning" the leak detector software to discriminate between normal operational transients and potential leaks are also discussed. Consistent instrument deviations (always read high or always read low) associated with SCADA

readings can be tuned out to avoid an unnecessary alarm. However, this practice can allow the pressure and flow deviations caused by a small leak to be tuned out and ignored by the system entrusted to detect them.

2.3 OFFSHORE PIPELINES WITH LEAK DETECTION SYSTEMS

During the literature review, four references were found that discuss an application of a computer-based leak detection system to an offshore pipeline. Conversations with computer software vendors indicated that additional offshore leak detection systems are currently being proposed and studied.

2.3.1 STATPIPE GAS PIPELINE

Sjoenen [2.10] reports that a real-time pipeline simulation system was developed for the Statpipe gas gathering and transmission pipeline system in the Norwegian sector of the North Sea. This system includes 550 miles of pipeline, two offshore riser platforms, and an onshore terminal at Karstoe for gas treatment and natural gas liquids (NGL) extraction. One 30 inch diameter pipeline segment transports "rich" natural gas in the dense phase regime from the Statfjord and Gullfaks fields to the terminal at Karstoe. The line pressure in this segment ranges from 1,750 to 2,400 psi and exceeds the critical pressure of the rich gas mixture, so that liquid condensate does not form. Dry gas from Karstoe is transported back offshore in a 28 inch diameter line and is joined by a 36 inch diameter dry gas line from the Heimdal field. A 36 inch diameter line carries the dry gas on to the Ekofisk platform for delivery to the Norpipe system. Pressures in the dry gas system range from 875 psi to 1,650 psi.

A SCADA system was installed for the Statpipe system. It includes 16 Remote Terminal Units placed on the platforms or at locations along the onshore part of the pipeline to acquire and transmit process instrumentation data. Distances between the RTU locations are large, up to 180 miles. The real-time model reads data from the SCADA data base at fixed intervals and carries out calculations based upon these data. The real-time model is set up to issue alarms when limits are exceeded for (1) maximum and minimum operational pressures, (2) pipeline design pressures, (3) maximum and minimum operational inventories, (4) minimum operational survival time, that is, the ability to maintain deliveries, (5) instrument drift, and (6) leak detection, both leak size and leak location.

Two methods of leak detection are implemented in the real-time mode. The first method compares calculated flow variables with measured flow variables at the pipe section boundaries. The discrepancy between measured and calculated values are analyzed to determine if a leak is detected. The second leak detection method is a mass balance method. The accumulated flows into and out of a leg and changes in gas inventory in the leg are summed over a given time period.

2.3.2 NORPIPE GAS PIPELINE

Wike [2.11] reports that an "advanced on-line modeling system" for the Ekofisk-Emden gas pipeline in the North Sea is in the final stage of installation. This pipeline is operated by Phillips Petroleum Company of Norway on behalf of the Norpipe consortium. The pipeline is 36" diameter and 270 miles in length. The pipeline delivers natural gas from producing fields in the Norwegian sector of the North Sea into the European gas transmission network for transportation to Emden, Germany. No condensate is formed in the gas stream. Gas from the Ekofisk platform is discharged at 1,800 psia. The Norpipe modeling system installation includes pipeline leak detection capability, but leak detection system information was not given in the referenced article..

2.3.3 TROLL-OSEBERG GAS INJECTION (TOGI) PIPELINE

Ek et al [2.12] report that a computerized monitoring system that includes leak detection and leak location capability was developed for the TOGI gas condensate pipeline in the North Sea. The pipeline is 20 inches in diameter and 30 miles in length. It was designed to transport unprocessed natural gas from a subsea installation at the Troll field to a platform in the Oseberg field where the gas is processed, compressed and injected into the gas cap of the Oseberg reservoir. Start-up of the production system was planned for early 1991.

The unprocessed gas in the TOGI pipeline has a liquid drop out of approximately 4.5% by weight of liquid condensate. The depth of the subsea production installation is approximately 1,000 ft below sea level. The platform stands in 340 feet of water. Due to the formation and accumulation of condensate, the computer-based pipeline simulation system uses the OLGA transient one-dimensional multiphase flow simulator model for two-phase hydrocarbon flow in pipelines and pipeline networks described by Bendiksen et

al [2.13]. The OLGA model calculates the transient state all along the pipeline. This includes the pressure, temperature, liquid and gas flow, liquid holdup, and flow regimes. The code can simulate slow mass flow transients as well as terrain-induced slug flow.

Both Bendiksen et al [2.13] and Ek et al [2.12] comment on the need for accurate pipeline elevation data for successful two-phase flow modelling. The pipeline elevation profile has a strong influence on the accumulation of liquids particularly at low flow rates. Ek et al state that depth information for every 5 to 10 meters was measured in order to get a representative elevation profile to use in the pipeline simulator. To minimize the number of pipeline segments in the simulator, the accumulated length of high inclination angles between 1° and 2.5° were lumped into 5 equivalent "dips". This allowed reducing the number of pipeline segments to about 100.

Measured data is provided by the SCADA system every 16 seconds. A Well Simulator produces temperature and flow rate data as a function of the measured well head pressures. A real-time pipeline simulator keeps track of the dynamic state in the pipeline from the well head to the inlet of the slug catcher at the production platform. Simulation of pigging operations may be included. The pipeline monitoring software notifies the operator when certain quantities exceed their defined limits. The monitoring system covers (1) pipeline leakage, (2) blockage due to hydrate formation, (3) insufficient methanol injection, (3) excessive liquid outflow, (4) excessive liquid build-up in the pipeline, (5) low pipeline temperature, and (6) production rate from individual wells exceeding design limits. The leak detection algorithm is based on a mass balance calculation, including the prediction of the line pack rate. A method for estimating the leak location is also provided.

2.3.4 PHILLIPS OIL/GAS/WATER PIPELINE IN SANTA BARBARA CHANNEL

Peterson [2.14] and Farmer et al [2.4] report the results of a field test of the point pressure analysis technique carried out on an offshore pipeline transporting oil, gas and water. The pipeline is 10 inches in diameter and 7 miles in length. It connects two platforms, Houchin (milepost 0) and Hogan (milepost 1), operated by Phillips Petroleum Company in the Santa Barbara channel to an onshore processing facility at La Conchita, California (milepost 7). The flow rate is approximately 175 gpm of crude oil, water, gas and solids. Each platform has two double-acting reciprocating pumps with a nominal discharge pressure

of 75 psi. Bypass valves are configured to divert flow from the pumps to a vessel used to maintain pump suction head. The purpose of the bypass loop is to allow the pump system to accommodate variable production rates.

Six separate leak tests were performed. Leaks were simulated physically by opening valves to divert a fluid stream to a drain pit. Three leakage locations were included: platform Hogan, platform Houchin, and an onshore pig trap at La Conchita. The point pressure analysis system was configured to monitor a single pressure transducer (spanned 0 to 300 psi) on platform Hogan. The estimated leak rates were 3 to 9 gpm. All simulated leaks were detected successfully. The detection times (corresponding to 99% probability of an actual leak) ranged from 12 to 66 seconds.

In the summary report of the PPA on-line test, Peterson [2.14] reports that pressure swings greater than 10 psi were noted by the pressure transducer installed to monitor the pipeline. It was determined that the pressure fluctuations were caused by the operation of the bypass valve controller which was over-shooting its set point. The bypass valve controller was retuned before the test which reduced the fluctuations to less than 1 psi for a line pressure of 70 psi. Then, the point pressure analysis system was tuned normally to follow "normal" fluctuations attributed to the bypass valve operation. Peterson (1990) notes that pressure or flow fluctuation "noise" that could affect leak detection can be reduced by proper engineering design and instrumentation.

2.4 COMPUTER MODELS FOR MULTIPHASE FLOW OF LIQUID AND GAS

The point pressure analysis leak detection system discussed in sections 2.2.1 and 2.3.4 is unique in that it uses signal filtering and trend detection software to distinguish pipeline leaks from other operational transients. The other methods in this section that rely on specialized computer software require a model for the transient behavior of the fluid flow in the pipeline. For onshore and offshore pipelines that transport single phase fluids (either all gas or all liquid), several transient pipeline flow simulation models are available for use in computer-based leak detection systems.

However, in some existing offshore pipelines, gas and liquid are transported simultaneously in a two-phase flow. Ek et al [2.12] has described how liquid condensation can occur in a gas pipeline when the gas is cooled to the local sea water temperature, to produce a

gas/liquid two-phase flow. In other circumstances, flow lines may transport liquid and gas together from an offshore platform to shore, or from a subsea completion manifold to an offshore production platform where liquid and gas separation will be performed.

In these cases that involve the simultaneous flow of gas and liquid, the choice of available models for pipeline flow simulation is very limited. Two transient, two-phase models are reviewed below.

2.4.1 OLGA TRANSIENT TWO-FLUID, TWO-PHASE FLOW MODEL

Bendiksen et al [2.13] describe a transient, two-fluid model for two-phase (gas/liquid) flow in pipelines and in piping networks. The OLGA computer code can be used to model pipe flows involving terrain slugging, pipeline start-up and shutdown, variable production rates and pigging. Bendiksen et al [2.13] state that the OLGA code has been tested against experimental data over a range of pipe sizes from 1 inch to 8 inch diameter (also against some data in 30 inch diameter), for pipeline length/diameter ratios up to 5,000, pipe inclinations from -15° to $+90^{\circ}$, and pressures from atmospheric to 1,450 psi, for a variety of fluids. It is claimed that the two-phase flow model gives reasonable results compared with transient data in most cases, and that the predicted flow maps and frequencies of terrain slugging compare favorably with experiments.

Bendiksen et al [2.13] also report a comparison of measured and predicted pressure drop results for a 10 inch diameter, 27.4 mile long onshore pipeline transporting heavy crude oil and associated gas. The agreement of predicted and measured values of pressure drop was excellent when a detailed pipeline elevation profile map was used. It was concluded that the liquid holdup prediction (which depends upon pipe inclination) must be very accurate in order to obtain a correct estimate of pressure drop. There are a limited number of available field lines where the fluid composition and the line profile are sufficiently well documented for a meaningful comparison of predicted and measured results. It should also be noted that Rygg and Ellul [2.15] have used the OLGA computer code to simulate the time dependent release of oil and gas from a topside rupture of a flowline-riser on an offshore live crude pipeline.

2.4.2 TAITEL'S SIMPLIFIED TRANSIENT TWO-PHASE FLOW MODEL

Taitel et al [2.16] describe a simplified, flow pattern dependent, transient model for calculating transient behavior of two-phase flow in a pipeline system. Taitel et al [2.16]

assume quasi-steady state flow for the gas phase, and a local equilibrium momentum balance of the liquid and gas flows. In this model, only the liquid mass balance equation is solved as an ordinary differential equation for the liquid flow rate and liquid holdup as a function of space and time. Taitel et al [2.16] claim that this formulation is adequate for investigating slow transients caused by changes in inlet flow rates and exit pressures that are of interest in the oil and gas pipeline operation. The main advantage of this method is in its simplicity, which may permit the incorporation of more accurate and realistic hydrodynamic models into the computer code. The main limitation is that the quasi-equilibrium assumption for the gas flow rate is not valid if the gas flow is not continuous. Model use should be restricted when the flow rates are very low, or when the liquid flow rate exceeds the gas flow rate.

Sarica et al [2.17] have used a transient, two-phase flow simulator based on the method of Taitel et al [2.16] to investigate the complex gas/liquid flow in the offshore segment of a pipeline transporting "wet" sour gas from the Hermosa platform in the offshore Point Arguello oil field to an onshore processing plant at Gaviota, California. The study showed that the offshore segment would operate under slug flow conditions at low flow rates, with pigging required to remove accumulated condensate. Although no experimental data is shown for comparison with model predictions, this type of simplified model may be sufficiently accurate for incorporation into a leak detection system for pipelines in multiphase flow.

2.5 LEAK DETECTION SYSTEM SENSITIVITY

Some of the questions that are asked about leak detection systems are (1) how small a leak can it find, (2) how soon will it find a leak, and (3) how accurately will it indicate leak location? Unfortunately, there is not a single simple answer to any of these questions, because leak detection sensitivity depends directly upon the system being modeled, and even on the size of the leak itself.

In a discussion of alternative hardware and software techniques for leak detection monitoring, Turner [2.18] comments on the sensitivity of "transient" flow modeling methods. He notes that most vendors will undertake a sensitivity analysis before quoting figures for leak sensitivity. He states that the uncertainty in leak location is unlikely to be much better than

± 5% of the pipeline length, and may be greater than ± 5% if the pipeline is less than about 6 miles in length. He mentions that "transient" flow models have struggled in the case of two-phase flow.

Turner [2.18] claims that a comparison between "transient" model predictions and field measurements has been made for a major subsea pipeline, and that 70% of the "transient" models available commercially were investigated. Although no results are presented in his paper, he states that the performance of the various models varied considerably, and that an important feature in performance was the handling of instrument noise.

The American Petroleum Institute (API) is currently sponsoring a project to assess the capability of software-based leak detection systems for liquid transportation pipelines. Liou [2.19] recently reported progress on the investigation of the influence of measurement uncertainties in pertinent pipeline and fluid variables on leak detectability. For software-based leak detection methods using mass balance, mass balance with line pack correction, and/or transient flow modeling, up to 20 variables or more may be involved in the method. These variables are divided into two groups: system parameters (properties of petroleum products and the pipelines), and measured data (reference mass density, volumetric flow rates, pressures, and temperatures). Values of measurement uncertainty are assigned to each of the variables, and the influence upon leak detectability is calculated.

Assuming the mass balance method and steady flow, Liou [2.19] notes that for a time period dt , a leak becomes detectable when the volume of leakage, Q_l exceeds the sum of the volumetric uncertainties due to flow measurements and line fill.

$$\frac{Q_l}{Q_{ref}} \geq 2k + \frac{dQ_s}{Q_{ref}} \quad (2.1)$$

where Q_{ref} = Reference steady flow rate
 k = uncertainty in flow rate measurement
 dQ_s = bound for uncertainty in line fill change due to system parameters and measurements of temperature and pressure

and $dQ_s = (2/\rho_o) * di/dt \quad (2.2)$

where ρ_o = reference fluid density
 di = uncertainty in line fill (itself a function of the other variables)

Figure 2.1 taken from Liou [2.19] shows the leak detectability for the mass balance method for a 100 mile pipeline example, and for a second example in which all experimental uncertainties are reduced by 50%. As dt becomes large in equation (2.2) dQ_s becomes negligible, and the leak detectability is a function only of $2k$, the uncertainty in flow rate measurement. The minimum response time is given by the largest possible leak, $Q/Q_{ref} = 1$. From equation (2.2), the minimum response time, dt will be controlled by the uncertainty in the line fill, di .

Liou [2.19] notes that transients often exist in pipelines, and that transients result in line fill changes that render the steady state mass balance method ineffective. Corrections for line pack changes must be made in any mass-balance-based leak detection method for steady and time-varying flows. Including a transient induced fill uncertainty, dQ_t , in the mass balance method, equation (2.3) becomes the leak detectability equation.

$$\frac{Q_t}{Q_{ref}} \geq 2k + \frac{dQ_s}{Q_{ref}} + \frac{dQ_t}{Q_{ref}} \quad (2.3)$$

If pressure transducers are installed only at the ends of the pipe, then the effect of the transient on the line fill must be made based upon two transducer readings. The line fill correction due to the transient will be improved by adding additional evenly spaced transducers between the ends of the pipe. Figure 2.2 from Liou [2.19] shows the effect of the line fill correction on leak detectability. Note that the line fill correction strongly influences the detectability of smaller leaks at longer response times.

Liou's system variable study for the API should be concluded late in 1992. The full API leak detection system study will continue under the direction of the API Leak Detection Task Force through 1993 or 1994. It should make a major contribution to the awareness of leak detection system capabilities within the pipeline transportation industry.

2.6 CONCLUSIONS AND RECOMMENDATIONS

The potential is good for the extension of SCADA-based leak detection systems to offshore oil and gas pipelines. The literature indicates that leak detection systems for gas pipelines have been and are being installed in the North Sea. While no references to leak detection systems

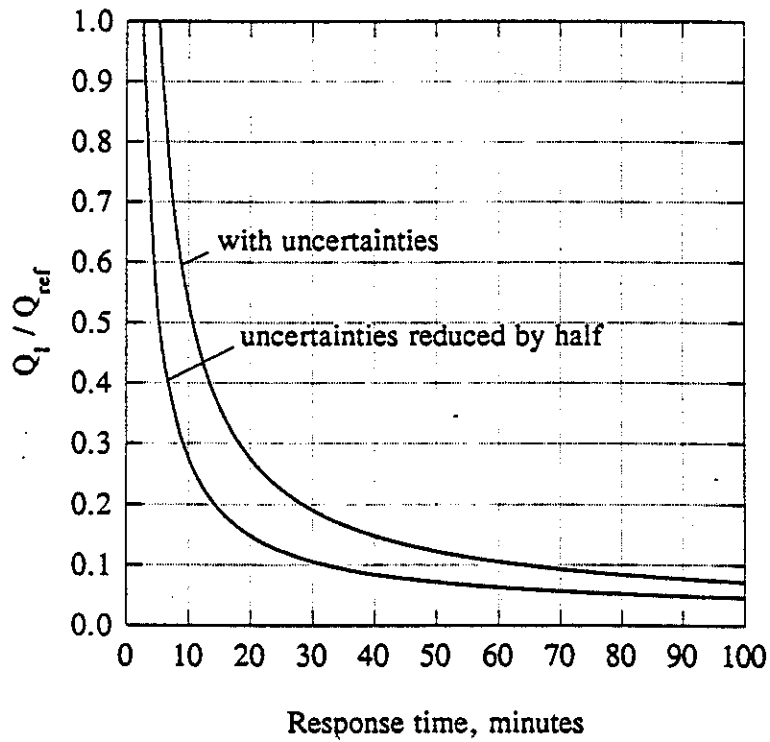


Figure 2.1 Detectable Leak Rate by the Mass Balance Method as a Function of Response Time for a 100 Mile Pipeline Example from Liou [2.19]

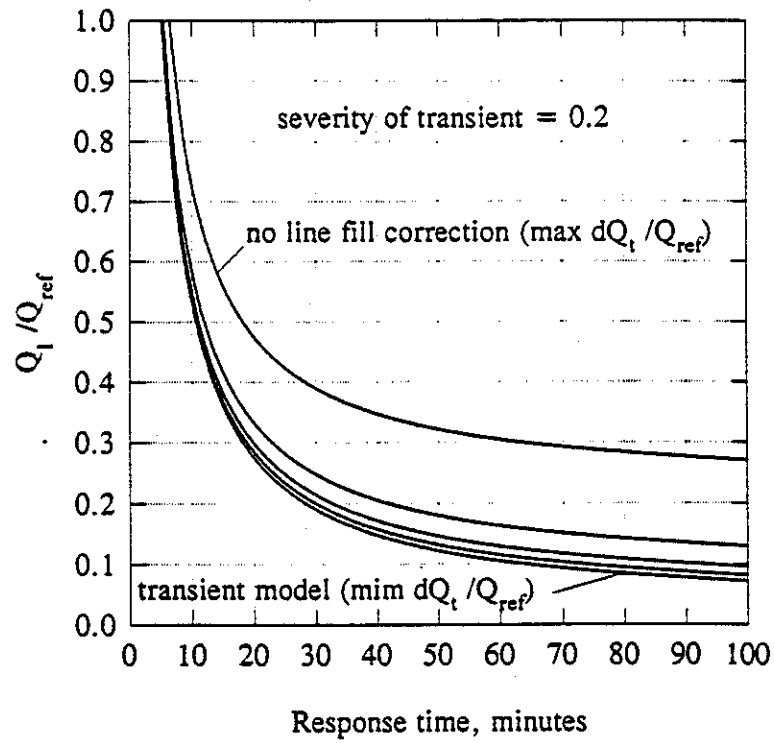


Figure 2.2 Influence of Line Fill Corrections on the Detectable Leak Rate as a Function of Response Time for a 100 Mile Pipeline Example from Liou [2.19]

for offshore liquid pipelines were found, the technology developed for onshore pipelines should be applicable to the offshore environment. The development of a pipeline monitoring system with leak detection capability for a gas/condensate pipeline in the North Sea may also point the way for future applications to multiphase pipelines. Also, the use of point pressure analysis systems for pipeline leak detection appears to be promising, particularly for transportation between neighboring offshore facilities, and between those facilities and the shore.

Software-based leak detection systems are available commercially from several reputable vendors. Current trends in computer system development will reduce the costs associated with installing and operating SCADA computers for pipeline monitoring and leak detection.

Although the application of leak detection software to offshore pipelines should not pose a problem, there are some significant differences between onshore and offshore pipelines that could affect leak detection system sensitivity. Installation of instrumentation, SCADA RTU and telemetry units are usually limited to surface locations. Therefore, the distance between RTUs can become great, as in the Statpipe and Norpipe systems. As shown in section 2.5, pipeline transients directly affect the line fill calculation, and the line fill uncertainty may become the ultimate limiting factor on leak detectability. Another difference is the hydrostatic pressure exerted by sea on an offshore pipeline compared to the soil pressure that surrounds a buried onshore pipeline. The external hydrostatic pressure might act to reduce the leakage rate of product from the pipeline as the submergence depth is increased. Finally, the majority of offshore pipelines appear to be production lines, and are not likely to be used for the batch transportation of products having different values of density and viscosity.

If further investigation of the application of software-based leak detection systems is pursued, it is recommended that an additional study be conducted to investigate the influence on leak detectability of the factors that characterize and distinguish offshore pipelines from onshore lines. This study should take advantage of the current research being performed for onshore liquid transportation pipelines under API sponsorship, and extend the study of pipeline installation variables to include typical offshore pipeline conditions including pipeline length, subsea tie-ins, intermittent or transient flow, and intermittent communication between the remote sensors and the SCADA system.

3.0 ACOUSTIC EMISSION METHODS FOR LEAK DETECTION IN UNDERWATER PIPELINES

3.1 INTRODUCTION

The need for a leak monitor system to assure the integrity of underwater pipelines on a continuous basis and provide a quick indication of the occurrence of a leak led to the survey of acoustic methods for detection and location of leaks. Monitoring of long runs (more than 10 km) on an underwater pipeline presents a problem of scale. Existing techniques offer sufficient sensitivity, accuracy and resolution to meet pipeline needs, but when the sensor density required by these existing methods is addressed in terms of the difficulty in reaching the pipe surface, or interior to mount a sensor, and the required cabling is considered, the enormity of the problem becomes apparent. Clearly, we must advance the technology or exploit special features of some of the existing techniques if a practicable leak monitor for underwater pipelines is to be realized.

While none of the literature surveyed directly addressed the problem of monitoring long distance sea-floor pipelines, the technology does suggest a combination of methodologies that promise to give warning in proportion to the seriousness of a leak, and indicate location in proportion to range over hundreds of kilometers of pipeline. The suggested strategy would quickly detect and localize leaks that begin suddenly (less than 10 seconds) and represent a significant amount of leakage. Small leaks that increase flow over days or weeks would be detected by periodically running the line with a towed sensor array, or a remotely piloted vehicle.

The primary trade-offs depend on the amount of leakage that may occur before detection and repair can be completed. This report summarizes the leak detection methods found in the literature and discusses a suggested approach for acoustic monitoring of long runs of underwater pipeline.

3.2 SUMMARY OF PREVIOUS WORK

The literature surveyed falls into four main categories. The essential features of each category are summarized below and the bibliography citations are shown in brackets.

Acoustic Emission - [3.4,3.5,3.6,3.7,3.20,3.23] - This method uses sensors mounted on the outside of the pipe to listen for the noise of leaks. The frequency range is usually 5 to 300 kHz, and this method has been used for gas, steam, and liquid. The detection range for gas-filled pipe is about 2.5 times that for liquid-filled lines at a frequency of 5 kHz. A 2 gpm

leak was detectable at 140 meters while a 200 cfm (equivalent mass) gas leak was detectable at 350 meters. Acoustic emission applies more properly to structures such as boilers or petrochemical process plants because the sensor is mounted on the outside of the structure to detect leak noise propagated along the surface, or through the material of the structure.

Correlation Techniques - [3.1,3.2,3.8,3.13,3.16,3.18] - Correlation techniques are used to enhance the identification of leak noise and to locate the source of the leak at a distance from one or more sensors. Geophones, microphones, and hydrophones are used for sensors. Geophones are buried in the earth over a pipe, microphones are mounted inside gas pipes and hydrophones are mounted inside liquid-filled pipes.

Correlation and signal averaging techniques extend the leak detection sensitivity and improve the signal-to-noise ratio as well as improve the accuracy of locating the source of the leak under analysis. This process may be applied to any digitally-recorded signals from a pipeline. The detection range is limited by the sensitivity of the sensor (hydrophone in the water or in the pipe) and the extraneous noise from the sea and the flow in the pipe.

Impulse of Sudden Leak- [3.3,3.9] - This method of leak detection listens for the pressure pulse caused by a suddenly-opened leak. The acoustic frequency generated by the leak event is in the 0.05 to 10 Hz range. The sensors used to detect the pressure pulse are microphones mounted in the pipe. This method offers the greatest range of detection because the low frequency impulse of a sudden leak has a high acoustic energy, a very low attenuation factor, and a unique signature. Applications discussed in the reviewed literature address leaks in gas lines; however, extension to liquid filled lines would be straightforward. Response time would be shorter, frequencies higher, range resolution better, and signal-to-noise ratio lower in liquid lines.

Active Interrogation - [3.10,3.14,3.15,3.21,3.22] - Active interrogation leak detection methods work by transmitting an acoustic pulse into the pipe to detect leaks by the impedance discontinuity at the leak site. The active interrogation techniques may take advantage of the freedom to tailor the spectrum of the impulse for maximum detectability after transmission over a long distance, or for maximum reflection from a target leak. The reflected signal from the leak site and other artifacts in the pipe (valve, joint, bend, transition, etc.) may be processed by correlation techniques to extract the leak-site reflection from the extraneous artifacts in the pipe.

3.3 DISCUSSION

The literature yielded six papers on methods to detect and locate leaks in pipelines using a correlation technique that matches the signal at several sensors to determine the point of origin of the source of the signal [3.1,3.2,3.8,3.13,3.16,3.18]. These pipelines include water mains, gas mains, and water and gas distribution piping. Methods addressing primary transmission of gaseous or liquid products over land or under sea were conspicuous by their absence.

Correlation techniques use microphones or hydrophones to detect the continuous noise produced by the turbulent flow through the leak orifice. Such techniques offer higher sensitivity and improved location accuracy but shorter range capability when sensors cannot be installed inside the pipeline. Fuches, et al, produced several papers over a period of years that show the development of the LOKAL system [3.13,3.16,3.18]. It is reported to cover 160 meters between sensors and has been used on 50 km water mains. The correlation technique should prove useful for detecting and locating leaks in underwater pipelines. The use of a correlation spectrum associated with leak noise propagating along a pipe may be useful in identifying a given noise source as a leak. The range of detection is extended by the use of hydrophones in the pipeline to detect the leak signal propagating through the fluid. Where the pipeline cannot be economically breached to install hydrophones, a towed array may be used to periodically run the line.

Rocha [3.3,3.9] gives a method for detection of a low frequency pressure wave that arises from a sudden break in a pipeline. The sudden (0.1 to 10 sec.) local change in pressure at even a small break causes low-frequency (0.05 to 10 Hz) components of an impulse to propagate great distances in a pipe. The patented technique can detect a 21 mm diameter break in a 20-inch (500-mm) pipe at a distance of 6.5 kilometers. For a given pipe size, the detectable leak size increases linearly with distance from the leak to the detector. The rate of increase is about 3.14 mm per kilometer for a 500 mm diameter pipe operating at 1,000 psi. Simple extrapolation leads to the conclusion that a 100 mm diameter break in a 500 mm pipe should be detectable at a range of 30 km and a complete guillotine break of the pipe should be detectable at 150 kilometers distant. This technique should have the necessary sensitivity to detect and locate any leak that would be an environmental hazard, or constitute significant product loss over a period of hours to days.

Rocha's technique does not apply to leaks which begin by a slow onset. A small leak which grows to a very large leak over hours or months does not produce the impulsive pressure change that can propagate through the pipe for great distances.

Watanabe relates the size and length of the pipe to the frequency range to be monitored [3.10,3.14,3.15]. Treating the line as a giant wind instrument, resonances and standing waves are computed as a function of leak position along the line. A complicated noise source such as white noise is used to excite the line acoustically. Lines of several km in length need to have monitors with fractional Hz frequency response and the localization resolution is about 100 m. Resolution scales with distance between sensors. Sensors need to be installed in the line for long-range detection.

A variation of the acoustic excitation technique, described by Jette, et al, [3.21] and Parker [3.22] uses induced sound pulses to detect the discontinuity of the leak. Sound pulses directed down the interior of the pipe radiate into the surrounding medium (in the example, the medium is the earth) to be detected by accelerometers at the surface. A leak in the line results in a local increase in the received sound as the accelerometer is moved from point to point along the surface. While this approach may be adaptable to a towed array for detection of leaks in underwater pipelines, the low sensitivity and the need for an active sound source inside the pipe present some implementation difficulty.

3.4 CONCLUSIONS

From the work reviewed on leak detection in pipelines, we may have the basis for a dual system to monitor long runs of underwater pipelines for leaks. The low frequency impulse monitor for sudden leaks and the correlation technique for smaller leaks are our best candidates. The other methods reviewed, that require installation of acoustic sensors all along the pipeline, were deemed feasible but impractical from an installation and maintenance point of view. A key strategy of the impulse detection method is that the sensors may be spaced at 30 to 100 km for detection of suddenly occurring large leaks, and that a chemical or acoustic technique should be used to detect smaller leaks by periodically running the line with a towed sensor or remotely operated underwater vehicle. The active acoustic excitation method may find application for locating the leak in a section of pipe that has been shut down due to leakage. Once the pressure

in the line has dropped to near ambient, other detection methods may not detect a leak because the outflow has stopped. The active acoustic excitation method is not affected by the lack of flow or pressure except for the reduction of acoustic background noise when flow is stopped.

3.5 RECOMMENDATIONS

If further investigation of acoustic leak detection methods is undertaken, it is recommended that continuous monitoring by the impulse technique be combined with a periodic inspection using the correlation technique. The impulse technique can detect and locate suddenly-occurring large leaks, and the correlation technique can be used to detect and locate smaller leaks.

Further development efforts for acoustic leak detection systems for subsea pipelines should be focused on applications where the other leak detection methods are not applicable, such as retrofitting existing pipelines that have multiple tie-ins, for rapidly detecting large leaks in multiphase flow lines, or diagnostics on non-flowing pipeline segments. The active excitation acoustic leak detection approach can be used to detect and locate leaks in a non-flowing, non-pressurized condition. The other area where acoustic methods will have a role in leak detection is in pinpointing smaller leaks by towed arrays of acoustic sensors. A towed array can pin-point a leak within a few feet under favorable conditions. If the array is within 100 feet, parallel to the line with sensors spaced 20 feet or less apart, and towed steadily at a slow speed, then the location can be resolved within 2 - 3 feet.

The acoustic methods evaluated in this study had not been applied to sea-floor pipelines. Any practical development of acoustic methods should be preceded by proof-of-concept experiments with underwater lines. The following tasks are suggested:

1. Assess the background noise near production platforms over the frequency range of 0.1 Hz to 10 kHz.
 - a. Noise in the sea near a subsea pipe during minimum platform activity.
 - b. Noise measured directly from the outer surface of a subsea pipe.
2. Assess the array size, frequency, towing speed constraints for towed acoustic array.
3. Investigate the reliability of detecting a large leak by means of the initial acoustic impulse due to the onset of leakage.

- a. Assess detectability versus distance to leak.
 - b. Assess detectability versus leak size.
 - c. Assess detectability versus rate of onset of leakage.
4. Investigate problems attendant to application of active acoustic excitation on out-of-service lines.
- a. Evaluate methods of access to interior of pipe for acoustic transmitter and receiver sensors (hot tap, through a valve, through the pipe wall).
 - b. Assess detection and location resolution as a function of range from transmitter-to-leak and leak-to-receiver sensors.

4.0 EVALUATION OF CHEMICAL BASED LEAK DETECTION SYSTEMS

4.1 INTRODUCTION

Chemical sensors can be used to detect the presence of chemicals after they have escaped from a subsea pipeline. Chemicals leaking from a subsea pipeline produce changes to the physical and chemical environment near the pipeline and it is these changes that can be detected with chemical sensors. For hydrocarbon products leaking into the ocean, there are several different "effects" that can be used to detect a leak. Table 5.1 lists some of the effects produced when oil or natural gas leaks into the ocean. Naturally occurring changes in ocean water clarity make light absorption or light transmission measurements difficult to distinguish from changes that could occur from a pipeline leak. Any sensing methods, such as measuring water fluorescence, that requires optically viewing the water to detect the presence of hydrocarbons would be difficult to deploy for long term monitoring since debris would eventually cover the optics. Most hydrocarbon products are buoyant and quickly rise to the sea surface. This limits the ability to sense the leak by detecting physical changes (electrical conductivity for example) in the vicinity of the pipeline since the leaking product quickly moves away from the pipeline. Chemical detection methods that sense the presence of the chemical in the form of water-soluble species or small droplets are the most practical and will be discussed below.

The chemical leak detection methods consider in this study are limited to methods that provided rapid response time and could be used as input to shut down the pipeline operation. To provide rapid response, the leak detection system must monitor continuously, independent of weather conditions. The sensors need to be deployed all along the length of the pipeline to insure complete pipeline coverage. With the sensors mounted on the pipeline, the likelihood of detecting leak signals from other pipelines or chemical sources is reduced. There are several different chemical sensing methods for detecting leaks from subsea pipelines that were not considered in this study. These methods include; visual inspection methods, detecting airborne chemicals (laser and optical absorption spectroscopy, laser-induced fluorescence, and aerosol detection), surface oil detectors (airborne laser fluorescence, satellite mapping, and radar tracking of spills) and towed or Remotely Operated Vehicle (ROV) sensors. These methods

were excluded from consideration because they do not provide rapid detection of pipeline leaks. In addition these methods cannot pinpoint the leak source or operate effectively during adverse weather conditions.

To detect the presence of a leak, the effect of the leak must propagate to the detector. The propagation time from the leak site to the detector determines the maximum response time of the system. As the chemical propagates to the detector, the signal strength is generally attenuated. When the signal strength becomes fairly weak, background, or natural, levels of chemical become more difficult to segregate from true leak signals. For these reasons, the distance between sensors needs to be as small as possible, so a strong signal is obtained at the sensor in a fairly short time. For discrete sensors spaced along the pipeline there is a trade off between good coverage and having a reasonable number of sensors. Better pipeline coverage is obtained with distributed chemical sensors that can detect leaks along the entire length of the sensing element. Because the distributed sensor can be laid continuously along the pipeline, the distance from a leak to the detector is small and the signal strength is therefore relatively strong. Discussions of both discrete chemical leak detection systems and distributed chemical leak detection systems are given in the following sections.

Table 4.1. Changes in the Environment Due To Chemical Leaks That May Be Detected

- Reduced light transmission.
- Temperature change in the environment near the leak.
- Presence of soluble chemical species in water.
- Presence of oil droplets in water.
- Changes to fluid properties (pH, electrical characteristics, surface tension).

4.2 DISCRETE CHEMICAL SENSORS

A discrete-chemical sensor-based leak detection system consists of an array of chemical detectors spaced along the pipeline so that any product leaking from the pipeline will be sensed at one or more of the detectors. Power and communication lines are needed to tie each detector to a central monitoring location. The critical parameters that define the system leak sensitivity and response time are the detector sensitivity to the pipeline product and the spacing between detectors along the pipeline. For a rapid response time, the spacing between the sensors needs to be minimized. But, there are practical limits to the number of detectors that can be mounted on long pipelines. The required spacing is also driven by the maximum detector spacing where the likelihood of sensing the leak, under all conditions, is fairly high. Discussions on pipeline products that are detectable in the ocean, chemical sensors for leak detection applications, and chemical transport in the ocean are presented in the following sections.

4.2.1 CHEMICALLY DETECTABLE PIPELINE PRODUCTS

Most subsea pipeline products are hydrocarbon products that are produced in offshore fields and transported to shore through a pipeline. The product lines generally contain either natural gas or crude oil or a multiphase mixture of both oil and gas. These products are generally buoyant in water and will move to the sea surface if they leak from the pipeline. For this reason, direct detection of hydrocarbon products in the ocean by discrete chemical sensors mounted on the pipeline is not practical. If a leak occurs several feet from a detector, the product will begin to rise as it disperses and will quickly be above the level of a pipeline mounted detector. To eliminate the negative effect of chemical transport away from the detector by buoyancy, the chemical detectors should be sensitive to water-soluble products. Once the chemical is "dissolved" in the water, it is no longer effected by buoyancy and, therefore, can be transported along the pipeline to the location of a detector.

Most hydrocarbon products have very low solubility in water. Tables 4.2 and 4.3 present the typical components in natural gas [4.1] and some of the more volatile crude oil components [4.2] and their solubility in water [4.3]. As seen in these tables, the solubility of most hydrocarbon products is on the order of a few ppm (or g/m^3). Other possible chemical tracers that may be detected are the chemicals injected at the well head, such as corrosion inhibitors, foam inhibitors, and wax inhibitors. Several chemicals, such as benzene and toluene, have solubilities as high as 1,700 ppm. But, this solubility data is for pure chemical

compounds in contact with fresh water at 25°C. Tables 4.4 and 4.5 show the change in solubility for seawater [4.3] and for a mixture of hydrocarbons in contact with water [4.4]. As seen in Table 4.5 the solubilities of the individual components is reduced by as much as one or two orders of magnitude when a mixture of compounds is present. These tables show that detecting water-soluble hydrocarbon products in seawater, the detector will need to be able to sense in the range of 100 ppm or less. If the detector is located some distance from the leak site, the concentration of water-soluble chemicals at the detector will be considerably less than the solubility limit. Detecting these low concentration levels in the harsh environment presents a significant challenge. In addition, the leak detection system must be able to discriminate between true leaks and other sources of chemicals such as natural seeps or surface spills.

Table 4.2. Solubility of Typical Natural Gas Components in Water

COMPONENT	TYPICAL FRACTION	WATER SOLUBILITY (25° C, 1 ATM) g/m ³
METHANE	70 - 98%	24
ETHANE	1 - 10%	60
PROPANE	0 - 5%	62
BUTANE	0 - 2%	61
PENTANE	0 - 1%	39
HEXANE	0 - 0.5%	10
HEPTANE	TRACE	3
CARBON DIOXIDE	0 - 4%	1461
HYDROGEN SULFIDE	0 - 6%	35

**Table 4.3. Solubility of Typical Gulf Coast Crude Oil Components in
Water
(97°F to 243°F Boiling Range Only)**

COMPONENT	VOLUME PERCENT	WATER SOLUBILITY (25° C) g/m ³
<i>n</i> -PENTANE	.55	39
CYCLOPENTANE	1.08	156
2,2-DIMETHYLBUTANE	.74	
2,3-DIMETHYLBUTANE	1.94	
2-METHYLPENTANE	3.71	14
3-METHYLPENTANE	2.22	
<i>n</i> -HEXANE	8.84	10
METHYLCYCLOPENTANE	6.40	42
2,2-DIMETHYLPENTANE	1.38	4
BENZENE	1.82	1780
CYCLOHEXANE	9.64	55
1,1-DIMETHYLCYCLOPENTANE	.59	
2,3-DIMETHYLPENTANE	5.32	4
TRANS-1,3-DIMETHYLCYCLOPENTANE	2.98	
TRANS-1,2-DIMETHYLCYCLOPENTANE	1.29	
3-METHYLHEXANE	2.01	
<i>n</i> -HEPTANE	7.96	3
METHYLCYCLOHEXANE	21.58	14
ETHYLCYCLOPENTANE	2.70	
2,2-DIMETHYLHEXANE	1.27	
2,5-DIMETHYLHEXANE	1.69	
TOLUENE	9.61	515
TRIMETHYLCYCLOPENTANES	2.56	
2,3-DIMETHYLHEXANE	1.87	
A TRIMETHYLCYCLOPENTANE	.25	

Table 4.4. Solubility of Selected Chemicals in Sea Water

HYDROCARBONS	WATER (g/m³)	SEAWATER (g/m³)
<i>n</i> -PENTENE	38.5	27.6
DODECANE	0.0037	0.0029
TETRADECANE	0.0022	0.0017
BENZENE	1780	1391
TOLUENE	515	402

Table 4.5. Solubility of a Chemical Mixture in Contact With Water

COMPOUND	PURE COMPOUND IN H ₂ O (g/m ³)	AQUEOUS SOLUTION IN CONTACT WITH GASOLINE (g/m ³)
BENZENE	1740	65
TOLUENE	554	34
2-BUTENE	430	2.4
2-PENTENE	203	1.4
ETHYLBENZENE	131	4.8
<i>o</i> -XYLENE	167	5.4
<i>p</i> -XYLENE	157	13.8
<i>m</i> -XYLENE	134	8.9
BUTANE	61.4	2.7
1,2,4-TRIMETHYLBENZENE	51.9	1.1
2-METHYLBUTANE	48	3.7
PENTANE	39.5	1.0

4.2.2 DISCRETE CHEMICAL SENSOR DEVELOPMENT STATUS

As discussed in the previous section, the discrete chemical sensors deployed along the pipeline will need to have sensitivity to hydrocarbon products in the range of 100 ppm or less. The great majority of chemical sensors used today are strictly laboratory instruments or detect the presence of the chemicals with a non-reversible chemical reactions. These types of sensors are obviously not practical for long term deployment along a subsea pipeline. The chemical sensors that seem to show the most promise for subsea deployment are

fiber-optic-based chemical sensors. Peterson [4.5] presents a review of fiber-optic-based chemical sensors and the different chemical detection methods that are commonly employed. This type of sensor generally consists of a fiber optic cable with a specially treated coating placed at the end of the fiber. When the end of the fiber contacts the product of interest, the light reflecting or absorbing properties of the coating change and are detected remotely at the other end of the fiber optic cable.

Table 4.6 shows a summary of some of the more recent developments in remote chemical sensors. The first two items in the table are commercially-available sensors that are intended to perform ground water monitoring tasks. These sensors can detect the presence of hydrocarbons with concentrations as low as a few ppm. The next two items in the table indicate present research efforts focused on developing chemical sensors that respond to the presence of specific chemicals in water. To date, the sensors have been designed to detect radioactive elements, nitrogen dioxide, mercury, chlorine, sulfur dioxide, and hydrogen sulfide. The researchers feel the techniques are capable of being used to detect solvents and organic chemicals with the proper coatings applied to the end of the fiber. The relatively recent use of infrared (IR) transmitting fiber optics for performing remote detection of chemicals by spectroscopic methods is another area that holds promise for remote chemical sensing. The IR absorption and emission signatures of hydrocarbon molecules can be used to identify the presence of specific chemicals. Spectroscopic techniques have been used for some time, but the emergence of IR transparent fibers has allowed the sensitive instrumentation to be mounted remotely from the detector. Many other types of fiber optic sensors have been developed and demonstrated [4.12, 4.13, 4.14] for specific chemical detection but many of them are presently limited to laboratory environments or short term deployment. These sensors work on a variety of different techniques that have varying degrees of applicability to subsea chemical detection.

The chemical detectors discussed above have a number of promising features that include, no subsea power requirements, no maintenance on the sensor element (topside instrumentation will require maintenance), and very good sensitivity to the presence of hydrocarbons in water. The drawbacks to these sensors include: limited reliability and sensor life data, the fiber sensor lengths currently being employed are on the order of 10 to 100 m in length, methods to install the large number of sensors subsea and provide signals from these sensors have not been addressed, and none of these sensors have been demonstrated

in a subsea environment. For subsea pipeline applications, sensors are needed that cover distances of 10 to over 100 km, and therefore signal transmission methods that employ common communication lines must be employed. The present generation of chemical sensors are not yet developed enough to deploy on long subsea pipelines. There is presently a significant amount of work being done on chemical detectors for detecting pollutants in water so developments in the near future may provide longer sensor lengths and signal transmission methods that utilize common communication lines.

Table 4.6. Discrete Chemical Sensors

Sensor Detection Method	Chemicals Detected	Sensitivity	Reference
Fiber optic light sensor based on the refractive index change in fiber cladding.	gasoline, kerosene, diesel, jet fuel	PPM level	5.6, 5.7
IR light absorption at 3.4 μm wavelength.	oil	1 PPM oil in water	5.8
Fiber-optic-sensor-based on light absorption by the chemical in a "thermal-lens" at the fiber tip.	radioactive elements, solvents, pesticides	Two to three orders of magnitude greater sensitivity than commercially available spectrometers	5.7
Fiber-optic-sensor-based on detecting changes to the reflective properties of a thin film coating at the end of the fiber.	Mercury, nitrogen dioxide, chlorine, sulfur dioxide, hydrogen, solvents	N/A	5.7
Fiber optic time-resolved fluorescence sensor.	aromatic hydrocarbons	N/A	5.9, 5.10
Infrared transmitting fiber optic sensors. Infrared spectroscopic techniques.	organic chemicals	N/A	5.11.

4.2.3 TRANSPORT OF HYDROCARBONS IN WATER

In order to detect the presence of hydrocarbon products in water, the chemicals must be transported from the leak site to the detector location. When hydrocarbon products are released into the water, they generally begin to rise to the surface of the water because they are buoyant. As they rise they are in contact with the seawater and the water near the leak will become saturated with the water-soluble chemicals. Dispersion of the water-soluble chemicals in the ocean occurs by molecular or turbulent diffusion and transport by currents. Transport of chemical species by molecular diffusion is very slow and is not the dominant mechanism in chemical transport in the ocean. Molecular transport will only dominate in stagnant water, or in special cases, where the fluid is immobilized as in transport in soils. In the ocean, turbulent transport mechanisms will dominate. Figure 4.1 presents an example of one-dimensional molecular and turbulent diffusion of benzene in water. The concentration of benzene in water is 1,780 ppm at the benzene-water interface. As the benzene diffuses away from the interface, the concentration in the water is reduced. The plot in Figure 4.1 for molecular diffusion shows the benzene has diffused less than 0.1 meter from the source even after 10 days. For turbulent diffusion in the ocean, an equivalent diffusivity of between 0.01 and 1.0 cm²/sec [5.3] is typical. Figure 4.1 shows the transport of benzene in the water after 1 hour and after 10 hours for a diffusivity of 1.0 cm²/sec. Even with turbulent diffusion, the chemical is only transported about 6 meters over 10 hours. Because the chemical movement is so slow, detectors will need to be placed close together to obtain a rapid response to a leak.

In order to have turbulent transport of the chemical species, there must be a turbulent flow or current. This current will carry the chemicals along as the chemicals diffuse outward. This is similar to a smoke stack plume slowly rising and being blown downwind. As the plume is carried downwind the diameter of the plume grows with the turbulent mixing in the plume. The same phenomena occurs when a current transports the chemicals leaking from a pipeline. If the current happens to be flowing in the same direction as the pipeline, the chemicals will be transported toward a downstream chemical sensor. If the flow is not in the same direction as the pipeline, the chemical plume will be carried away from the pipeline and will not be detected at any of the detectors located on the pipeline. Because the subsea currents do not generally flow along the pipeline, the chemical sensors would

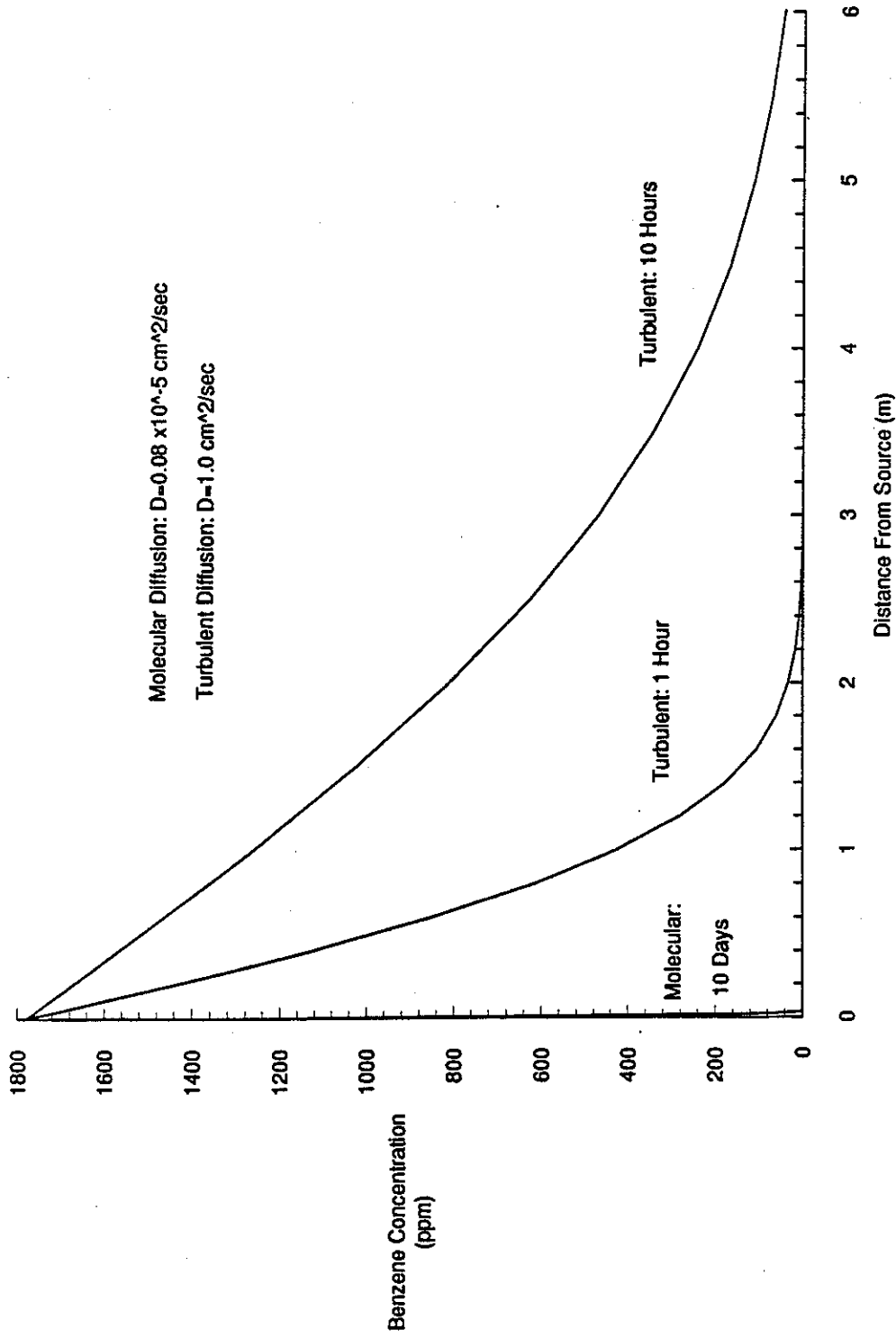


Figure 4.1. Molecular and Turbulent Diffusion of Benzene in Water.

need to be spaced very close together to ensure a leak could be detected. Even with sensors spaced only a few feet apart, a small leak could go undetected if a steady current was flowing such that it transported the chemicals away from the sensors.

4.2.4 CONCLUSION ON DISCRETE CHEMICAL-SENSOR-BASED LEAK DETECTION

A number of factors limit the applicability of discrete chemical-sensor-based leak detection systems to subsea pipelines. The first factor is the buoyancy of hydrocarbon products limits the ability to directly detect the chemical in the water near the pipeline since the chemicals move rapidly toward the surface. This means the discrete chemical detectors need to detect the water-soluble hydrocarbons, since, once they are in solution, they will not rapidly migrate toward the surface. Most hydrocarbons have a very low water solubility so the sensors will have to be able to detect chemical concentrations below 100 ppm. Practical chemical sensors that can detect chemicals at these concentration levels are just now becoming available but have not yet been used in a subsea environment and have not been used at distances approaching those necessary for subsea pipelines.

Because the chemicals are transported with the water currents, the distance between detectors will need to be very small (on the order of 10 feet) to insure a leak source is detected in a reasonable time. A long pipeline with closely spaced sensors becomes impractical from the standpoints of installation, maintenance, repair, and signal transmission. As an example, the number of discrete sensors on a 20 mile pipeline, with a 10 foot spacing, is over 10,000 sensors. This large number of sensors has been shown to be impractical for even an onshore pipeline where access to the pipeline is better and special cables were used [4.15]. The biggest problem with the discrete chemical-sensor-based leak detection system is, that even with closely spaced sensors, a leak could occur and go undetected for a considerable amount of time if the subsea currents carry the chemicals away from the detectors.

4.3 DISTRIBUTED CHEMICAL SENSORS

Distributed chemical-sensor-based leak detection systems can provide complete coverage along a pipeline since distributed sensors are sensitive to the presence of the chemicals along the entire sensor length. The advantages of distributed sensors include common sensing and signal transmission lines, complete coverage of the pipeline, simplified installation compared with mounting and wiring discrete sensors, and the ability to locate the leak position. Two

different distributed chemical-sensor-based leak detection systems were evaluated as part of this study. The first sensor type detects changes in special fiber optic cables caused by the presence of chemicals in the water. The second leak detection system uses special tubing laid along the pipeline to detect the presence of a leak. Each of these two different distributed sensor techniques is discussed below.

4.3.1 DISTRIBUTED FIBER OPTIC CHEMICAL SENSORS

Distributed fiber optic sensors utilize special properties of the optical fiber to measure the parameters of interest all along the length of the fiber. Distributed fiber optic sensors have been applied to measuring strain, temperature and recently some applications for detecting chemical species along the fiber have been reported. Rogers [4.16] presents a recent review of distributed fiber optic sensors and reviews the many different techniques and instrumentation types employed in making distributed fiber optic sensor measurements. Rogers concludes that distributed fiber optic chemical sensor development is in its infancy, but the potential for development is very good. Two chemical sensing techniques discussed by Rogers are the changes to cladding fluorescence due to ingress of the chemical species, and differential absorption in the evanescent field caused by the presence of the chemical species. Both of these techniques have been demonstrated in a laboratory environment and significant developments can be anticipated in these techniques.

Research efforts on distributed fiber optic chemical sensors have resulted in sensors for measurement of oxygen [4.17], pH [4.18], ammonia [4.19], methane [4.20], and bare fiber sensors for oil-in-water monitoring [4.21]. Additional types of hybrid fiber optic based chemical sensors are discussed by Lambeck [4.22]. The hybrid chemical sensors can consist of sections of sensitized fiber optics manufactured into the cable with sensitivity to the desired chemical species. Lambeck also discusses placing integrated-optic devices in the fiber line in addition to the intrinsic sensing capability of the fiber optic cable itself.

Another possible method of detecting leaks in some subsea pipelines is using distributed fiber optic temperature sensors to detect leakage of pipeline products that are at a different temperature from the environment. This technique has been tried for onshore leak detection with a specially-designed (electrical) temperature sensor array [4.15]. Distributed fiber optic temperature sensors are presently commercially available and can be deployed over fairly long distances. Table 4.7 shows some typical fiber optic temperature

sensor performance data presented by Turner [4.15]. This method would only work for pipeline products that are a different temperature than the surrounding environment. Other types of fiber optic sensors have been designed to allow microbend losses to be used to measure the temperature along a fiber [4.23]. This sensing technique requires small bimetallic elements to be applied to the fiber so microbends are induced in the fiber when the temperature of the fiber changes. These microbends create light losses from the fiber core that can be detected as attenuated light transmission. The same type of extrinsic technique can be envisioned for detecting oil in water by wrapping the fiber optic with materials that swell on contact with chemicals and induce stress or microbends in the fiber. This type of sensor has not yet been reported in the literature, but similar sensors, based on electrical properties of wires in special materials have been developed. An example of one of these systems is an electrical conductor covered with a special expanded Teflon that absorbs hydrocarbons, but is waterproof [4.27]. When exposed to hydrocarbons, the change in capacitance is detected by time domain reflectometry. In addition to detecting the leak, the location of the leak along the cable (up to 4000-ft. lengths reported) is also accurately determined.

Conclusions on Distributed Fiber Optic Chemical Sensors

Fiber optic chemical sensors are presently being developed for a variety of applications. The techniques employed in detecting the presence of chemicals generally produces a very low level signal that can only be detected with very sensitive instrumentation in a laboratory environment. This makes it unrealistic to expect these techniques will be able to perform long term, unattended, monitoring task in the near future. In addition, distributed fiber optic sensors for detecting hydrocarbon products in water have not been developed with the exception of the bare fiber oil-in-water sensors. The bare fiber sensors are not practical for long-term subsea deployment because bare sensors are too brittle and the surface would quickly become fouled. Development of sensors sensitive to hydrocarbon in water will require development of the proper sensitivity material, developing the technique to apply the material to the fiber, and insuring the materials are stable in the subsea environment. Once these problems are solved, the additional problem of expanding the current sensor length from 100's of meters to 10,000's of meters must be addressed. While

distributed fiber optic chemical sensors hold significant promise for environmental monitoring, the sensor development is still in its infancy and will require significant levels of development before it can be applied to subsea pipeline monitoring.

**Table 4.7. Typical Fiber Optic Temperature Sensor Performance
(from [4.15])**

Range (metres)	Spatial Resolution (metres)	Measurement Time (seconds)	Temperature Resolution (K)
500	1	5	± 1
1000	1	5	± 1
4000	1	10	± 1
10000	1	60	± 2.5
20000	10	60	± 2.5

4.3.2 CHEMICAL-SENSOR-TUBE-BASED LEAK DETECTION SYSTEMS

4.3.2.1 SYSTEM DESCRIPTION

A chemical leak detection system that has been used for onshore pipelines for a number of years is based on detecting the presence of the leaking chemical with a sensor tube placed near the pipeline. The specially designed tube has a wall material that allows diffusion of hydrocarbon vapors into the air inside the tube. The tube is periodically pumped out and the air in the tube passes through a sensor that detects the presence of the hydrocarbon vapors in the air stream. A schematic representation of Teledyne Geotech's Leak Alarm System for Pollutants (LASP) [4.24] is shown in Figure 4.2. As illustrated in the figure, the system can determine the size of the leak by the height of the peak recorded by the detector. The location of the leak can be determined by the peak arrival time at the detector compared with the arrival time of the test gas injected at the far end of the sensor tube when the sampling event is started.

LASP Detector Diagram

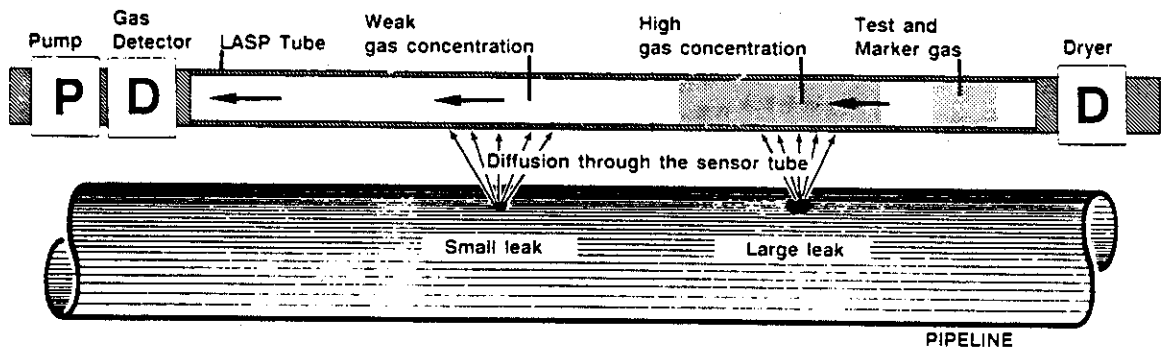
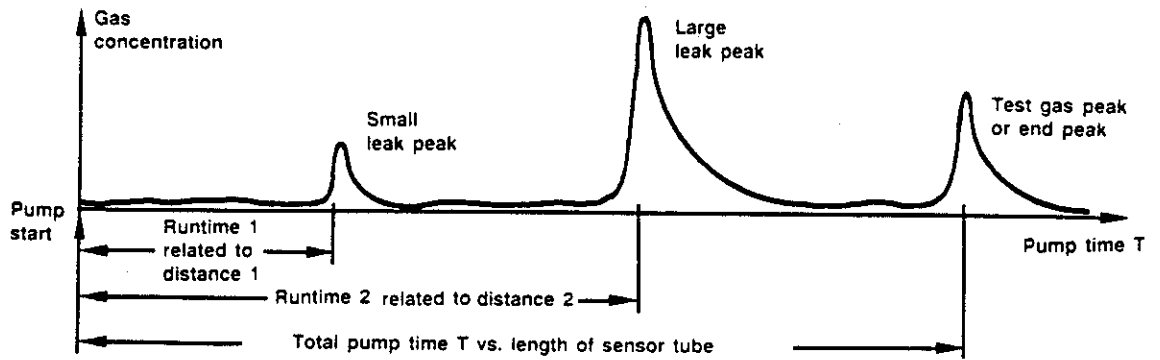


Figure 4.2. Chemical-Sensor-Tube-Based Leak Detection System Schematic (from [4.24]).

The main advantage of this type of leak detection system is that it directly detects the presence of the leak and does not have to infer it from small changes in the volume balance or small deviations in line pressure. In addition, the method is suited to detecting very small leak sources that are well below the detection level of SCADA-based systems. This method can also be used for multiphase flow lines since it can detect the presence of either vapor or liquid products. Once the sensor tube is installed near the pipeline the tube does not require any routine maintenance. The system pumps, vapor detector, valves, and dryer unit all require periodic maintenance and calibration, but these items would be located at the ends of the pipeline and would therefore be accessible (not subsea).

The detector-tube-based system has been installed on several different pipelines to provide leak detection in sensitive environments. Issel and Swiger [4.25] reported on several different installations where this type of system was installed. One system was installed on an 4 km ethylene pipeline that crosses an especially sensitive environmental area. The system was installed in 1977 and had experienced no failures at the time the paper was written in 1985. A test on the leak detection sensitivity showed the system was capable of detecting 2 grams of ethylene placed in the ground near the pipeline to simulate a small leak. The leak location was also correctly located in the test. Another leak detection system was installed in a half mile long tunnel with a variety of hydrocarbons transported in the pipes in the tunnel. The leak detection tube was installed to monitor any pools of liquid product that might collect on the bottom of the tunnel.

Issel and Swiger [4.25] also reported on an installation under the Rhine River in Germany where the pipeline and sensor tube were installed in a water-saturated environment. The pipeline carried ethylene and passed through an environmentally sensitive area so a sensitive leak detection system was required. The system was installed in 1978 and had 2 miles of sensor tube. Since methane is generated naturally in the area around the pipeline, the gas pulled through the sensor tube is monitored with a detector that is not sensitive to methane. No false alarms have occurred due to the naturally-occurring methane. The system has detected leaks of about 30 g/hr from a pair of gate valves. The valves were dug up and the leaks were verified and repaired.

The manufacturer of the LASP system [4.24] lists 10 different installations of their system for onshore pipelines. The systems vary from 300 ft to 10 miles in length and the products sensed by the detectors include; ethylene, benzene, jet fuel, pentane, fuel oil, H₂S, ethylene oxide, gasoline, diesel and LPG. Sperl [4.26] reported on a sensor-tube-based system installed on ten miles of onshore natural gas pipeline. The line was designed to contain sour gas and passed through populated areas. To get a fast response to leaks and to be able to detect the very small leaks, two sensor tubes were installed over the pipeline. One sensor tube is pumped continuously, and a detector monitors continuously for the presence of H₂S. The second tube is allowed to sit for about 12 hours before it is pumped through the detector. This allows time for the concentration of H₂S in the tube to reach measurable levels for even small leaks. Some problems with naturally-occurring vapors have occurred and the system has proved so sensitive that other source of vapors have been detected. Repairs to a broken water line near the LASP system caused an alarm from the vapors from PVC glue. Small amounts of alcohol in fire-fighting foam residue that were washed into the storm drain near the LASP system also alarmed the system. Initial problems with the gophers chewing through the polyethylene braid on the tubing were eliminated by going to a stainless steel braid on the tubing. Installation of the tubing had to be done very carefully to avoid damaging the tube. Sperl feels installation of the system in a perforated conduit should be considered for future installations to protect the tubing and allow simpler tubing repair and replacement.

4.3.2.2 SYSTEM APPLICABILITY TO SUBSEA PIPELINES

The sensor-tube-based leak detection method has not yet been demonstrated for subsea pipelines. Based on the installation in a water saturated environment reported by Issel [4.25], it appears the method is feasible for subsea applications. The basic criteria for applicability of the sensor tube based leak detection system applied to subsea pipelines are addressed below:

System Installation

The sensor tube must be placed near the pipeline and is generally placed on top of the line. Some method of maintaining contact between the sensor tube and the leaking product is required. The pipeline can be buried with the sensor tube placed on top of it or the pipe must be wrapped with the sensor tube to maintain contact of the leaking

product with the sensor tube. The sensor tube is relatively brittle compared with steel pipe so care in handling will be required. Installation of the sensor inside a perforated tube may provide the needed protection and allow simpler installation. Repair sections could be pulled inside the conduit if necessary. Another issue is the ability of the sensor tube to withstand external pressure. Teledyne Geotech [4.24] indicates they presently have sensor tubes that can go to 1,800 ft, and with design modifications, this could be extended to deeper water. The sensor-tube-based leak detection system would be extremely difficult to install as a retrofit to existing subsea pipelines.

System Life

No data are available for sensor tube life in a subsea environment. The oldest reported installation, on an underwater system, is a 14 year old system that is still in operation.

Maintenance

No routine maintenance is required on the sensor tube. The onshore components, such as pumps, detectors and drier units, require routine maintenance and calibration.

Maximum Length of Sensor Tube Run

Issel [4.25] reported demonstrating the transport of ethylene vapors 5.5 miles with little degradation in the detectable signal. Teledyne Geotech [4.24] claims the system is capable of transporting detectable vapor concentrations up to 50 miles.

System Leak Response Time

The minimum leak response time is determined by the frequency the air in the tube is pumped through the detector. The sampling interval is selected so the desired level of leak detection sensitivity is achieved (depends upon the diffusion rate of the product through the tube wall). Typically the system is pumped every 12 hours. For longer sensor tube lengths, the pumping time required to clear the entire sensor tube can be several hours. This leak detection method is clearly designed for low level leak detection, not rapid response to major leaks. A second sensor tube can be installed and continuously pumped to obtain a faster response for larger leaks (see Sperl [4.26]).

Detection Sensitivity

The minimum detectable leak level depends upon the installation, pipeline product, and the sampling detector sensitivity. Teledyne Geotech [4.24] claims that leaks less than 0.04 gal/hr of gasoline can be detected.

System Cost

The system cost depends upon the installation method employed. To provide a reference, Sperl [4.26] reported the cost to retrofit a buried onshore pipeline with the LASP system cost about \$300,000 per mile. Sperl estimated that if the system were installed with the pipeline initially it would have cost about \$170,000 per mile.

4.3.2.3 CONCLUSIONS ON SENSOR-TUBE-BASED LEAK DETECTION SYSTEMS

It appears the sensor-tube-based leak detection system is a feasible method for detecting leaks in subsea pipelines. The method is particularly well suited to detecting smaller leaks, from corrosion pin holes for example, before they develop into larger leaks. The system response time is on the order of 12 hours, so another type of leak detection system must be installed for immediate response to large leaks or pipeline ruptures. The sensor-tube-based leak detection method can be applied equally well to single phase flow lines or multiphase lines. Other attractive features of the system include: no subsea power requirements, no subsea equipment or routine subsea maintenance is required, the instrumentation is located on shore or on the platform, and leak location and leak size can be determined. While the system looks feasible, engineering work on the system is required prior to installation of a demonstration system in a subsea environment. If further investigation of the sensor-tube-based leak detection method is undertaken, the following list presents some of the items requiring development work:

- Design the sensor tube to withstand the subsea environment.
- Demonstrate detection of hydrocarbon mixtures at subsea conditions.
- Develop subsea installation methods and a method to insure contact between the pipeline product and the sensor tube.
- Develop subsea tubing connection and repair methods.
- Perform preliminary testing to identify system problems.

5.0 EVALUATION OF FIBER OPTIC SENSING TECHNOLOGIES FOR RAPID LEAK DETECTION

5.1 INTRODUCTION

5.1.1 OVERVIEW

The objective of this task was to evaluate the feasibility of using fiber optic sensors for undersea pipeline leak detection. This task included determination of fiber optic sensor technology applicable to pipeline leak detection, estimation of the maturity and practicality of development of deployable systems, and recommendations for future efforts. Initial interest was toward fiber optic methods useful for the detection of mechanical strain.

An initial investigation of literature for applicable previous work was performed. This literature search identified various sensor types and sensor configurations previously used for pipeline and related applications. Selected technical papers and reports were evaluated and reviewed in-depth.

The feasibility and practicality of several fiber sensor configurations were investigated. Recommendations of approaches towards demonstration-level leak site detection techniques were developed. The recommendations cover the capabilities and limitations of the system, installation methods, and maintenance concerns.

5.1.2 FIBER OPTICS BASICS

An optical fiber is a fiber made of an optically transparent material and manufactured in such a manner that light can be forced to travel entirely within its core. A representation of a typical "step index" optical fiber is given in Figure 5.1. There are other types of construction including graded index, which has gradual radial index changes and single mode, which allows only a single mode (ray) of light to propagate. Obviously, to be of use in most applications, the material should be of low loss. Typical optical fiber loses less than half of its original light energy over a mile length. The low loss of optical fibers and its large information capacity are reasons many communications systems use fiber optic networks. The capabilities of optical fibers are continuing to improve.

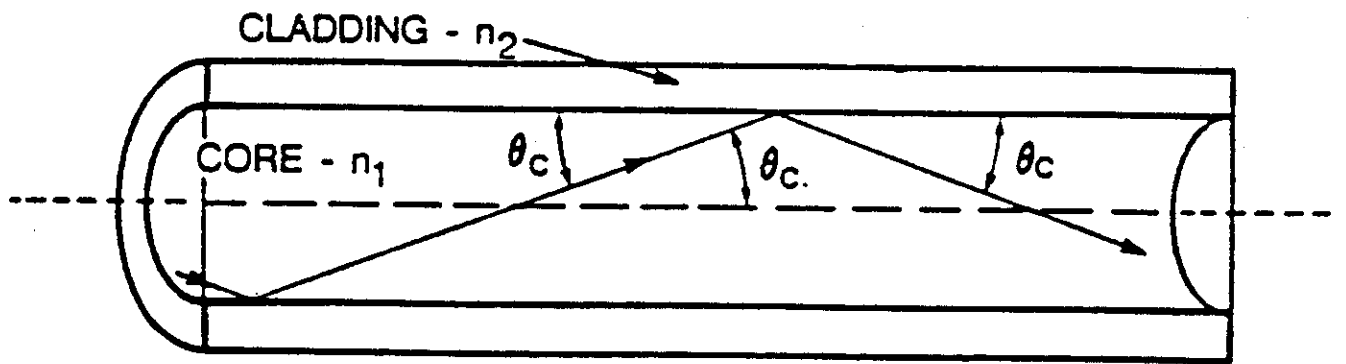


Figure 5.1 Typical Optical Fiber Construction

Light energy travelling within the fiber is channelled using differences in the index of refraction of the material. If any of the energy moves toward the outside of the fiber, it is reflected or redirected back toward the center of the fiber. This channelling mechanism is a function of the characteristics of the optical fiber layers and can be used to define the steepest angle for "total internal reflection". For "step index" fiber, the outer layer of material is called the cladding. For most communications applications, efforts are made to reduce those conditions which cause energy loss or reduce the information handling capacity of the fiber. For sensors, on the other hand, use is made of these energy loss or phase change phenomena.

5.1.3 OPTICAL FIBER LOSS MECHANISMS

No material is transparent to all wavelengths of light. Typical optical fibers have two "windows" or spectral regions in the infrared where the losses are very low. Figure 5.2 shows the response curve for a typical optical fiber. To achieve this low loss the material must be very pure. The fiber losses would increase if the purity of the fiber were degraded by diffusion of material into the fiber or if the wavelength of the light source were moved away from the low loss window. In a similar manner, the center channelling mechanism can be altered to cause light energy to leave the fiber. The escape of energy is measured as fiber loss.

If the fiber is bent at sharp radius, the light energy is no longer completely channelled toward the center of the fiber. This again is because the materials of the fiber support low loss light propagation only for certain ranges of angles. This loss phenomenon is referred to as "microbend" losses. Figure 5.3 shows a representation of this effect where light is escaping from the core in the area of a "microbend".

Splices in an optical fiber are always a source of energy loss. There are three major loss effects dealing with mis-alignment of similar diameter fibers at a junction. These concern the distance between fiber ends, the axis offset and the angle offset. Figure 5.4 shows these three loss mechanisms. Movements in each of these coordinates cause loss and this loss mechanism can be used for displacement sensors. Obviously an abrupt loss of the optical path by a break in the fiber or the removal of a component can also be used as a sensing mechanism.

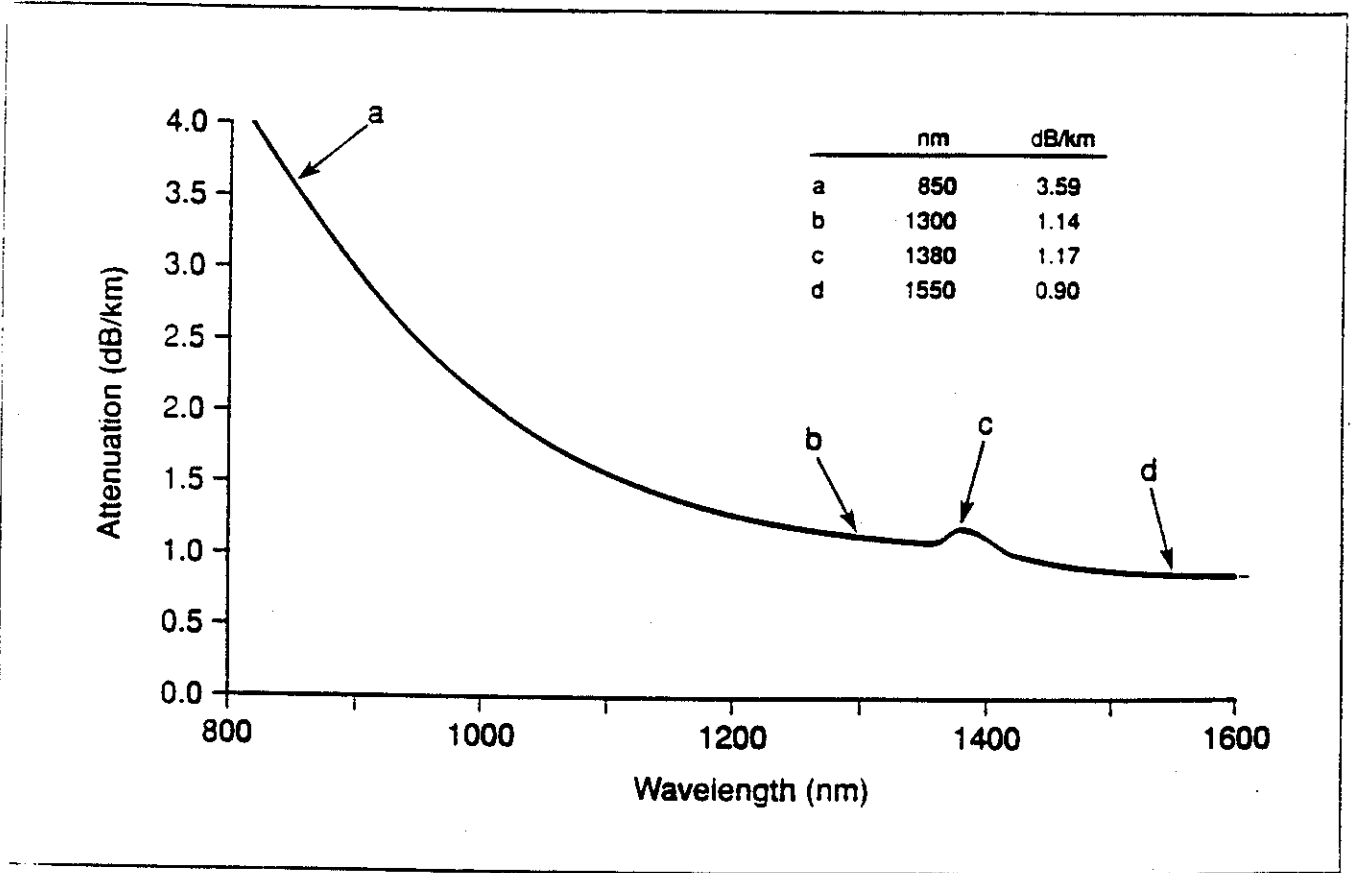


Figure 5.2 Typical Optical Fiber Response

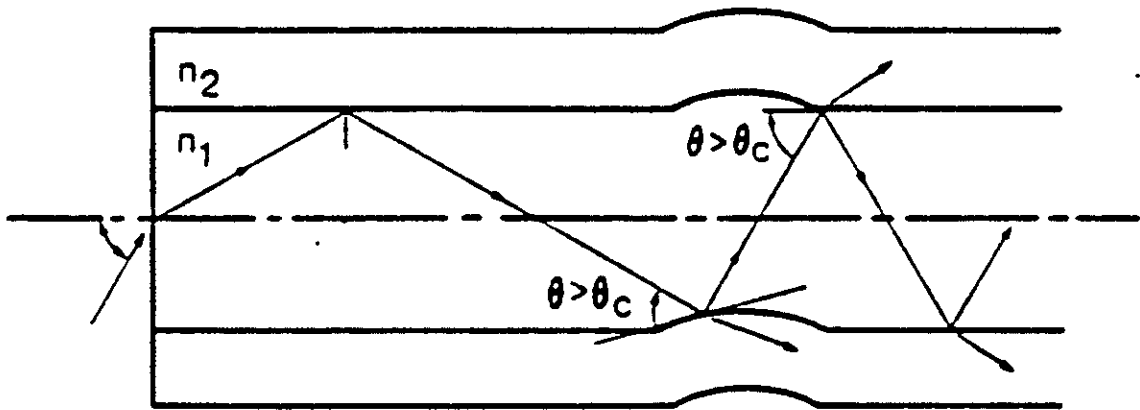


Figure 5.3 Microbend Loss Phenomenon

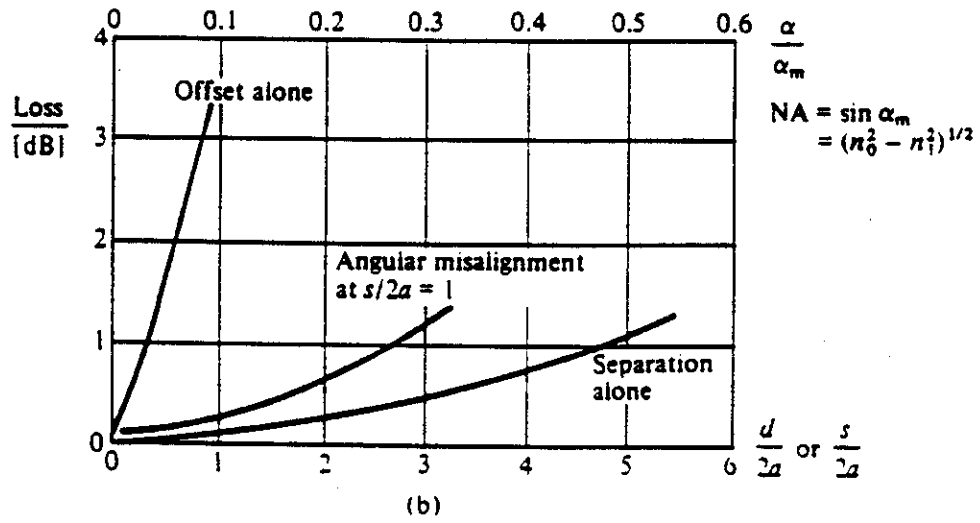
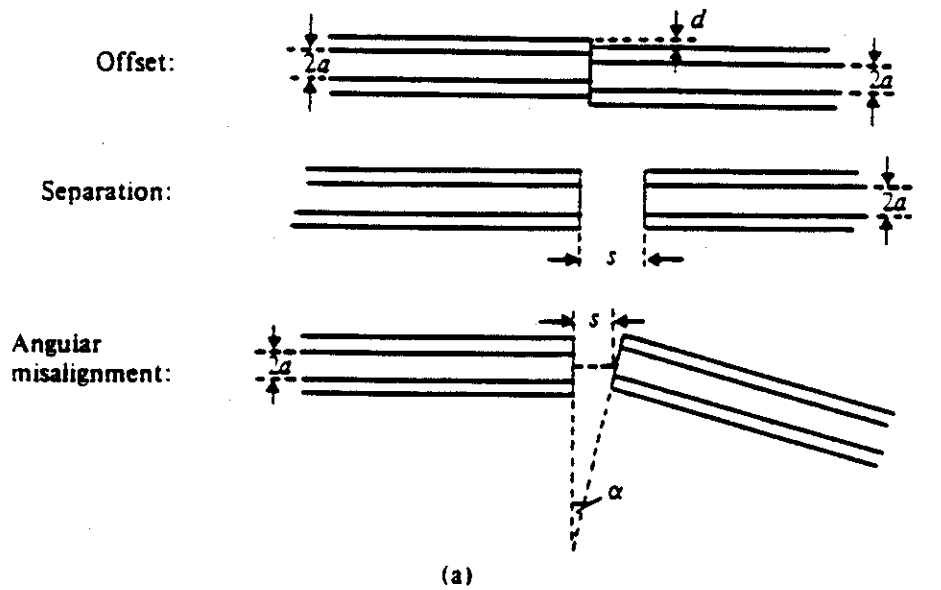


Figure 5.4 Splice Displacement Loss Mechanisms

There is another signal loss mechanism which does not require the loss of light energy. When many mode or light paths can propagate in a fiber, propagation time differences between the modes can cause signal to be distorted. Energy is not lost. It is spread out over a larger period of time. Temperature changes and mechanical stress cause changes in the light energy propagation velocity. It is normally complicated to measure propagation velocity changes.

5.1.4 FIBER OPTIC SENSOR TECHNOLOGIES

Fiber optic sensors can be developed using the known loss properties described above. Two advantages that optical fibers have for use in sensors is its non-metallic nature and its capability for distributed sensing. A third advantage optical fibers may bring to sensor system is that it can be used to carry large amounts of information in a relatively small cable.

Fiber optic sensors are developed by coupling the parameter to be measured to a fiber loss mechanism. Mechanical strain or other small displacements may be measured by coupling to fiber ends (splices, reflectors, breaks, etc.) or to mechanisms which inflict microbending. Stress coupled to the fiber will cause propagation velocity changes which could be sensed. Fiber optic sensors using single mode fibers and lasers can be used to detect strains on the order of wavelengths of the transmitted light. These sensors rely on the light's propagation velocity changes. The propagation time changes are typically measured using a second reference path and allowing the light from the two paths to interfere. Coherent light and single mode optical fibers are normally required for best effects. It should be mentioned that situations other than stress, such as chemical contamination, can also be sensed.

In the following section, some previous efforts with fiber optic sensor system are briefly described. The present practicality of using fiber optic sensors for undersea pipeline leak detection is examined. The review is limited to work which could be adapted for pipeline leak detection. This includes reviewing the current state of the art in fiber optic sensors that could be used for this application, estimating the potential for development into a deployable system, and making recommendations for future development efforts.

5.2 PREVIOUS WORK

5.2.1 FIBER OPTIC SENSOR TYPES

A literature search was conducted to determine previous efforts in fiber optic sensors involving pipeline leak detection. The result of the computer search was a list of articles with an abstract for each article. This list was reviewed to determine which publications should be acquired for further review. A total of 13 articles were selected for review. In addition to the computer-based search, a cursory manual search was performed to locate recent publications that had not been added to the computer database yet and those published in key journals not a part of the database. Seven additional articles were located from the manual search.

Fiber optic and other optical sensors found during the literature search can be divided into several groups:

- Non-fiber optical methods which rely on nonlinear optical properties of petrochemicals and gas.
- Fiber optic methods that depend on breakage or interruption of the optical path.
- Fiber optic methods that depend on using microbending losses.
- Narrow band fiber optic spectral absorption sensors.
- Sensitized fiber cladding sensors.

General leak detection system installation methods are described in Section 5.2.2.

The paper by Wanser [5.1] describes a software tool useful for modeling fiber optic sensor systems. Udd [5.3], Rocke [5.12], Claus [5.18] and Talat [5.16] provide overviews of fiber optic sensors.

Three of the articles [5.10, 5.11, 5.13] addressed methods of detecting pipeline leaks using laser illumination of the environment around the pipeline. None of these systems use fiber optic but the articles were reviewed for adaptability to fiber optics.

The first of these papers (Xun, et al) described a method of detecting petroleum using laser-induced fluorescence. A diagram of this method is shown in Figure 5.5. A laser of a particular wavelength causes petroleum products to fluoresce. The wavelength of

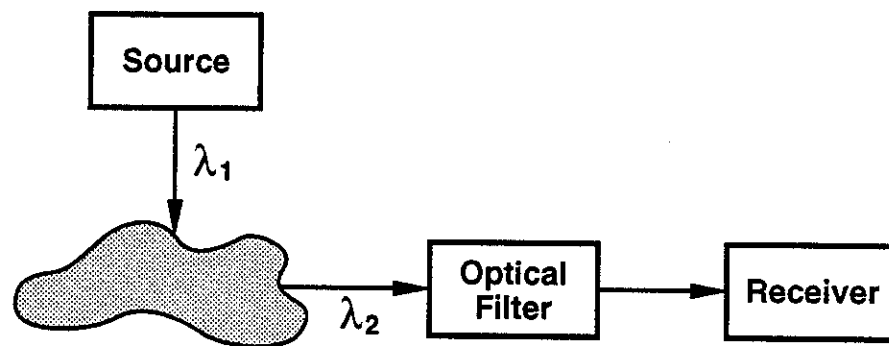


Figure 5.5 Fluorescence Detection Sensor

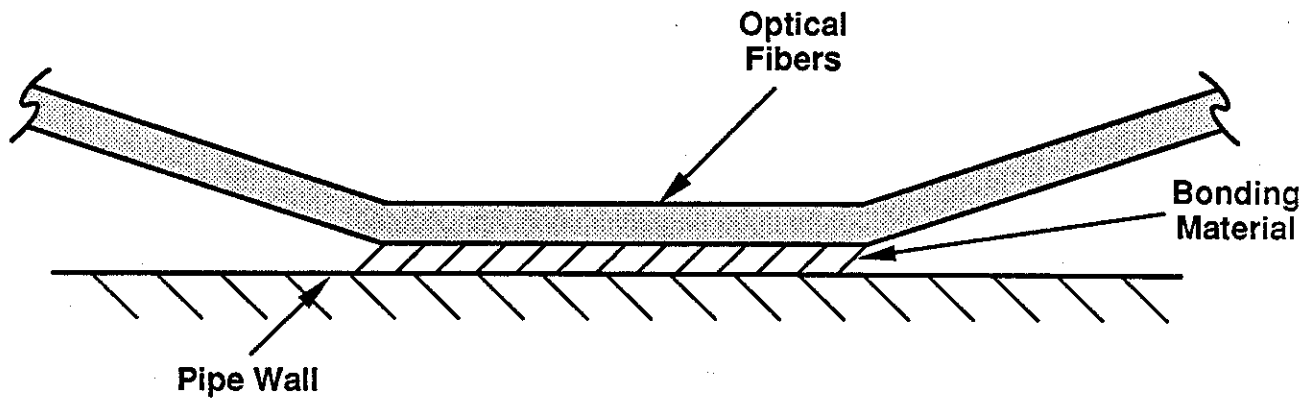
fluorescence is different from the laser's. Prototype systems have been developed and successfully deployed using this type of sensor towed behind support ships. The method requires a relatively high power laser source and very sensitive detector. Considerable effort would be involved in adapting this technique to fiber optic technology.

The second paper (Rosengreen) described a similar system where the presence of gas in the air causes a change in the optical properties of a laser beam. Again, the adaptation of this technique to fiber optic technology appears unlikely.

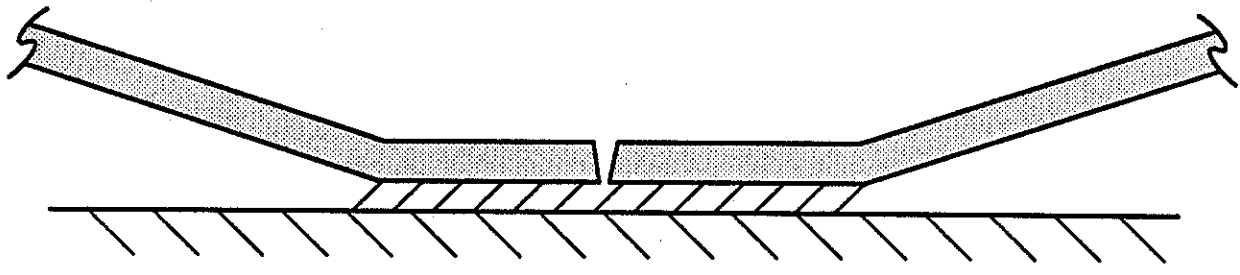
The third paper (Lawford, et al) also describes a system which detects hydrocarbons in water using laser-induced fluorescence. A prototype system was constructed and has been used in the field. While this unit has been successfully deployed, its prospects for an automatic, distributed sensor system are minimal. Like the previous two devices, a high-power laser and very sensitive detection device are also required.

A fiber break sensor is described by Hale [5.8]. The simple break sensor is represented in Figure 5.6a. The sensor is a section of fiber that is bonded to the wall of the pipe. The optical fiber is brittle and will break if the strain exceed a threshold. The strain of the pipe wall is coupled to the fiber by bonding the fiber to the pipe. A pipe wall break or excess strain will cause the fiber to break as shown in Figure 5.6b. The abrupt interruption of the light path is sensed. Sensors can be connected in series along a connection optical fiber. The position of the break can be determined by reflecting a extremely short pulse of light from the break site. Distance to the break can be determined from the time required for the reflection.

Prototype work has been done using break sensors for strain threshold detection on pipe and turbine blades. Break-induced sensors are capable of 'tripping' on crack widths down to 10 to 100 micrometers. The tripping of this sensor typically causes a 10 dB reduction in light transmission. The break-induced sensor has been successfully tested on the following materials and structures:



a) Intact



b) Tripped

Figure 5.6 Break Induced Sensor

Material	Tests	Crack Detection Sensitivity
Reinforced Concrete	Static Load	20 to 100 micrometers
Steel Fillet Welds	Cyclic	10 to 30 micrometers
Steel Butt Welds	Cyclic	10 to 75 micrometers
Steel Longitudinal Stiffening Plates	Cyclic	10 to 30 micrometers
Aircraft Grade Aluminum (Near rivet locations)	Cyclic	10 to 30 micrometers

The test conditions for the cyclic tests were:

Humidity:	up to 100%
Temperature:	-25 to +60 degrees Centigrade
Cycle rate:	10 to 27 Hz
Number of Cycles:	up to 5×10^6

The surface strain threshold can be set within some limits during sensor installation. Careful selection of the bonding compound and methods used to fasten the sensor to the pipe surface can be used to adjust break thresholds. The sensor break strain threshold could possibly be set below the crack strain level of the pipe. Detection of excessive strain prior to failure of the pipe would then be possible.

Under some operating conditions, a break in the sensor allows partial transmission of light through the sensor, thus allowing sensors down line from the failure site to remain active. The primary disadvantage of this sensor is that if a large crack occurs, no transmission may be possible beyond the tripped sensor. Depending on the procedures for repair and maintenance, this may or may not present a problem.

A variation of the break sensor is a "chemical fuse" sensor described by Tenge [5.5]. The fuse sensor is designed to 'trip' when exposed to a specific phenomenon. A diagram of this sensor type is shown in Figure 5.7. In this sensor, a gap is placed in the center of the sensor and filled with a material that changes optical transmittance when exposed to the phenomenon of interest. The optical change can be darkening, lightening, or dissolving. Most work with this type of sensor utilized a material that dissolves when exposed to the phenomenon of interest. A common type of sensor using this technique is a temperature threshold sensor where the fill material melts or darkens when the desired temperature threshold is surpassed. In leak detection applications, the fill material would need to change optical properties when exposed to petrochemicals. The primary disadvantage with this sensor is that it operates some time after the leak has started.

An acoustical sensor described by Kline [5.9] also uses the properties of a fiber end. The development of a fiber optic microphone was attempted using the mechanical displacement of a fiber end. The intent was to pick up the acoustical emissions from gas leaks. The sensitivity and dynamic range of the microphone proved to be too low to be useful and the effort was abandoned in favor of conventional microphones. An additional problem for acoustical sensors is the strong background noise normally present in an undersea environment and in the pipeline fluid flow.

Similar to the effect of a mechanical break in the fiber, abrupt fiber loss can occur when the optical interface on the fiber's surface is disrupted. The characteristics of an optical fiber can abruptly change when it is emersed in water or petroleum fuels. Yoshikawa [5.4] describes a system using a special optical fiber design to detect liquids. Johanssen [5.6] describes a fuel tank monitoring system using several fuel/water fiber optic sensors along a single fiber.

The microbending sensor is closely related to the break sensor. A diagram of this sensor type is shown in Figure 5.8. The microbend sensor operates by inflicting many sharp bends on the fiber. The loss of energy at each of these bends was discussed previously. Optical fibers operate on a principle of total internal reflection using the refractive indices of the core and the cladding to establish a reflective boundary. The maximum angle at which light can strike the boundary and be reflected back into the fiber to continue its journey is a function of the indices of refraction of the fiber material and the light's wavelength. This

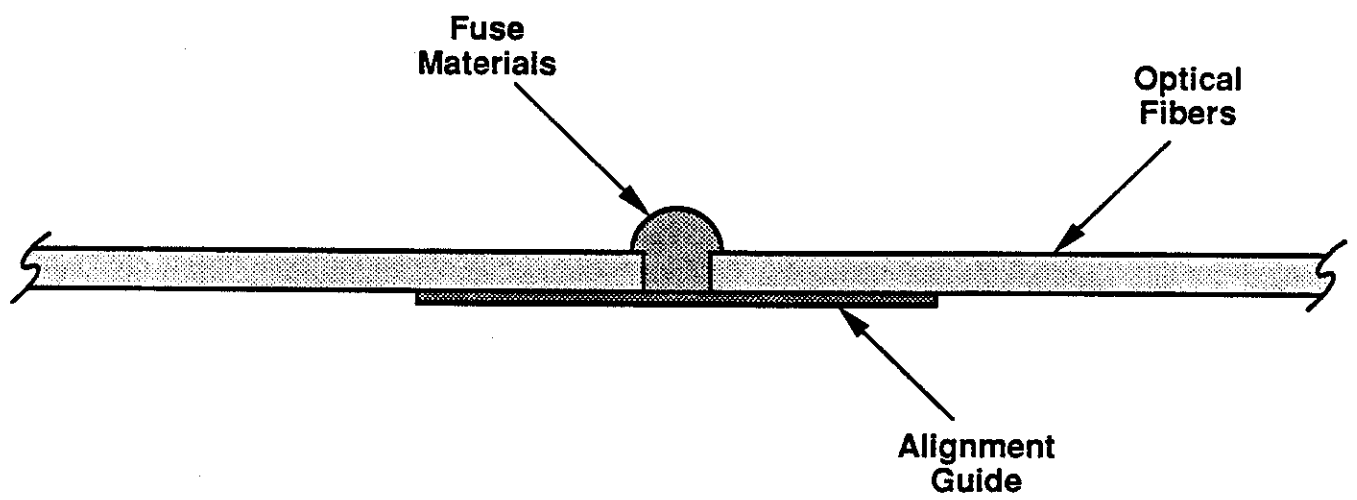


Figure 5.7 Optical Fuse Sensor

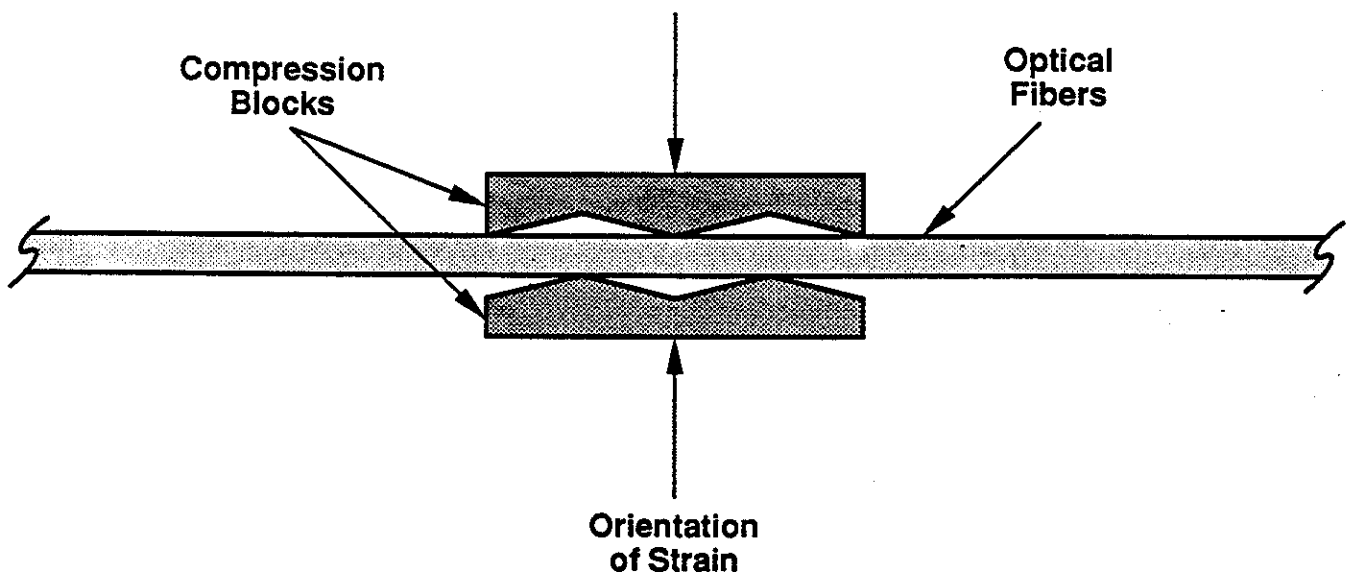


Figure 5.8 Microbend Loss Sensor

angle establishes a minimum bend radius for the fiber. If a section of the fiber is bent tighter than its minimum bend radius, light energy is lost from the fiber. This energy loss of this fiber section can be detected. Compression applied to the sensor results in the grated surfaces pressing against the fiber. The grated surfaces cause small bends (microbends) in the fiber that are beyond the minimum bend radius of the fiber. The key difference between this sensor and the break sensor is that under normal operation the optical property of the sensor changes continuously with strain, but the fiber is not broken. The microbend sensor could be used to detect excessive strain before pipeline failure.

Jongh [5.2] describes a sensor where the optical fiber is mechanically coupled to a material that swells when exposed to a material. The swelling causes microbending strain on the fiber which can be detected. The material in this case is water. However, the technique could be adapted to use other materials that mechanically distort when exposed to petrochemicals. McKeehan [5.14, 5.15] addressed this type of sensor. Wilson and Tay [5.17] discussed the use of microbend-based sensors for composite structures. Each article dealt with microbend sensors, but detected a different phenomenon.

Microbend losses may be involved in the acoustical pipeline sensor described by Lieberman [5.7]. An optical fiber was exposed to acoustical energy simulating the disturbance that might occur close to a pipeline gas leak. There was some indication of the leak in the optical signals.

The outer surface of an optical fiber can be treated to attract and bind to certain chemicals. When the chemical is present, the changes in the optical properties of the fiber surface create additional light loss. A sensor of this type is described in a paper by Silvus [5.20]. To detect oil, the fiber core can be treated to make the surface organophilic. If the sensor is placed in water, the light in the core will propagate with relatively low loss. When the sensor is placed in water containing suspended oil particles, the fiber's surface acquires oil. This results in a change in the refractive index of the cladding and increased light loss in the fiber. Oil pollutant levels of approximately 3 milligrams per liter are detectable. The primary advantage of this sensor is that the transmission fiber is the sensor. This removes the need for separate sensors and connecting fibers. The location of the loss could possibly be detected using a Optical Time Domain Reflectometer (OTDR). This work has been done in a laboratory setting. The system requires special optical fibers having the sensitized

cladding applied. The cladding or treatment would need to be evaluated to insure that undersea organisms and other normal environmental conditions do not affect the fiber or give a high false indication rates.

Another fiber optic sensor is devised by selecting the light source wavelength to coincide with an absorption band of the material of interest. This type of sensor was also addressed by Johanssen [5.6]. A small exposed gap exists between two fiber segments. A diagram of this sensor type is shown in Figure 5.9. For pipeline applications, the wavelength of the source would be selected to match an absorption band of the fluid carried inside the pipeline. When a leak occurs, the fluid would enter the gap in the sensor and cause increase energy loss.

5.2.2 SYSTEM INSTALLATION METHODS

Four types of optical fiber sensor system installation methods are common. These are:

- Discrete Sensor Systems
- Clustered Sensor System
- Discrete Distributed Sensor Systems
- Continuous Distributed Sensor System.

A discrete sensor system uses a single fiber optic sensor at a single location. The system uses properties of the fiber (insulator, high band width, etc.) for sensing. Single sensors appear to have little use for pipeline applications.

The Clustered Sensor System (CSS) approach uses multiple individual sensors tied to a single node. A diagram of the CSS configuration is shown in Figure 5.10. The node polls the sensor on a preset basis and sends fault commands to a central processor via a data transfer cable. Multiple nodes can be tied together in series via the data transfer line, as shown in the Figure 5.10. The primary advantage of this approach is that the nodes can be tied end-to-end to attain a system which is as long as necessary. The primary disadvantage of CSS is that the hardware for the nodes is not available 'off-the-shelf.' The nodes would have to be designed and prototyped. It should be noted that the per unit production costs of the nodes should be relatively low. Since the range to the sensors is short, LEDs and

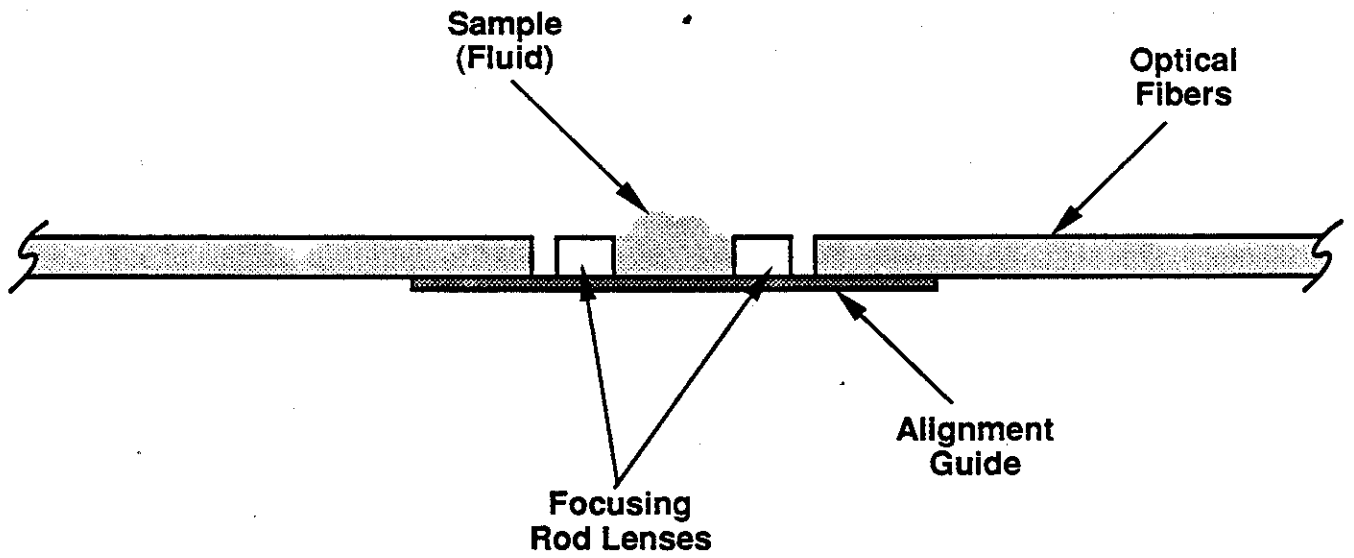


Figure 5.9 Narrow Band Fiber Optic Adsorption Sensor

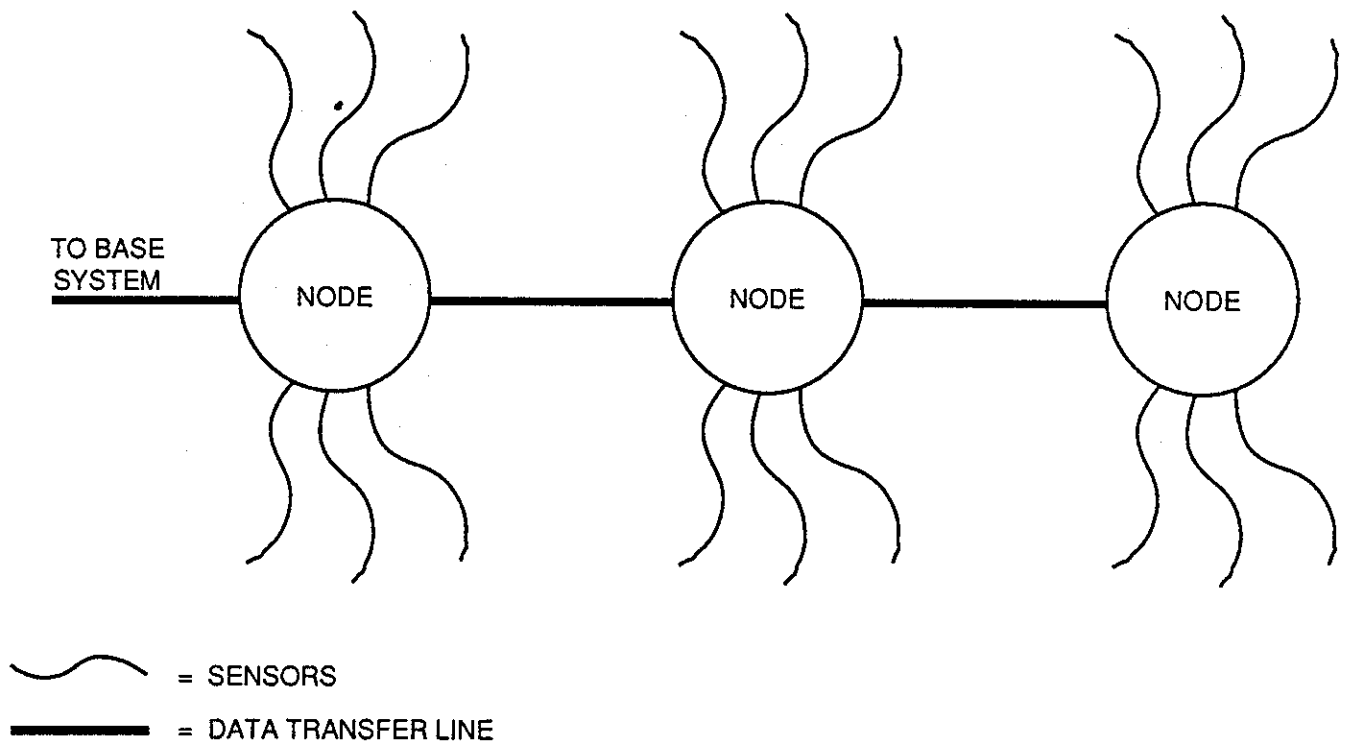


Figure 5.10 Clustered Sensor System

photodetectors under simple microprocessor control will be the most complicated part of the electronics design. The hardest part of the node design will be hardening the node against the environment.

Optical fiber sensors can be placed at intervals along an optical fiber. Figures 5.11 and 5.12 show this distributed arrangement of discrete sensors. When the fiber itself is used both as the sensing and communication element along its entire length, it is a continuous distributed sensor system. The Distributed Continuous Sensor System (DCSS) utilizes a special fiber that is sensitized to change when exposed to the phenomenon of interest. It should be noted that the transport fiber for this system is also the sensor. This eliminates the possible problem of determining adequate sensor spacing to detect the effects of interest, since the entire fiber is the sensor. This type of sensor system is normally used with an Optical Time Domain Reflectometry (OTDR) to determine the location of events.

Three methods are useful for interrogating the sensors. These are:

- Total Attenuation Sensing
- Optical Time Domain Reflectometry
- Optical Time Domain Transmission.

The attenuation or loss of the sensor can be determined by injecting light into the sensor and measuring light loss. Information concerning the locations of the loss, due to strain or breaks, is limited to the position of the sensor. For example, a sensor can be an optical fiber secured to the wall of a pipeline. If light is injected at one end of the fiber and received at the other, excess strain in the wall causing a break in the fiber would be detected. However, no information concerning the position of the break is obtained.

Other methods use the propagation velocity of the light moving through the cable to determine the position of the sensed event. The OTDR approach uses short light pulses to interrogate a group of sensors that are connected in series. A basic diagram of an OTDR system is shown in Figure 5.11. Light pulses are launched into the splitter. At each point where the refractive index of the fiber changes, a reflection occurs. The magnitude of the reflection is based on the change of refractive index at the sensor locations. A typical system output is shown in Figure 5.13. This system approach has several advantages. OTDR systems have been in use in the communications field for years. OTDR's are used by every major

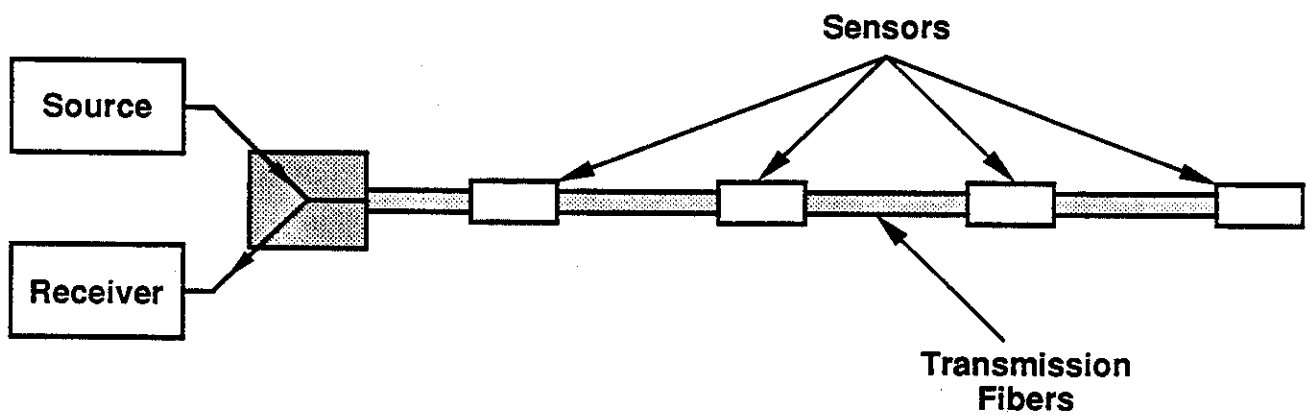


Figure 5.11 OTDR System Configuration

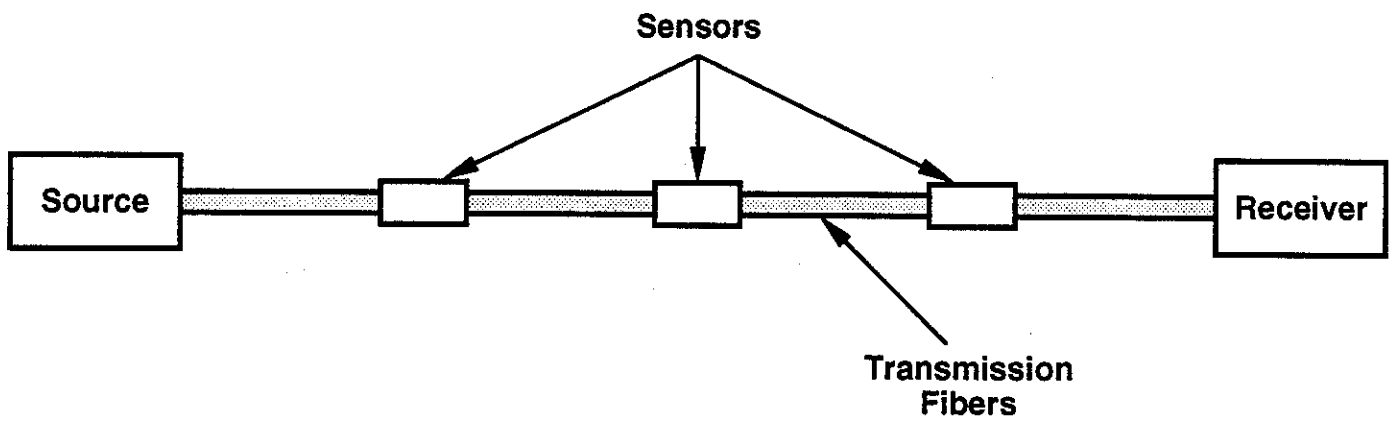


Figure 5.12 OTDT System Configuration

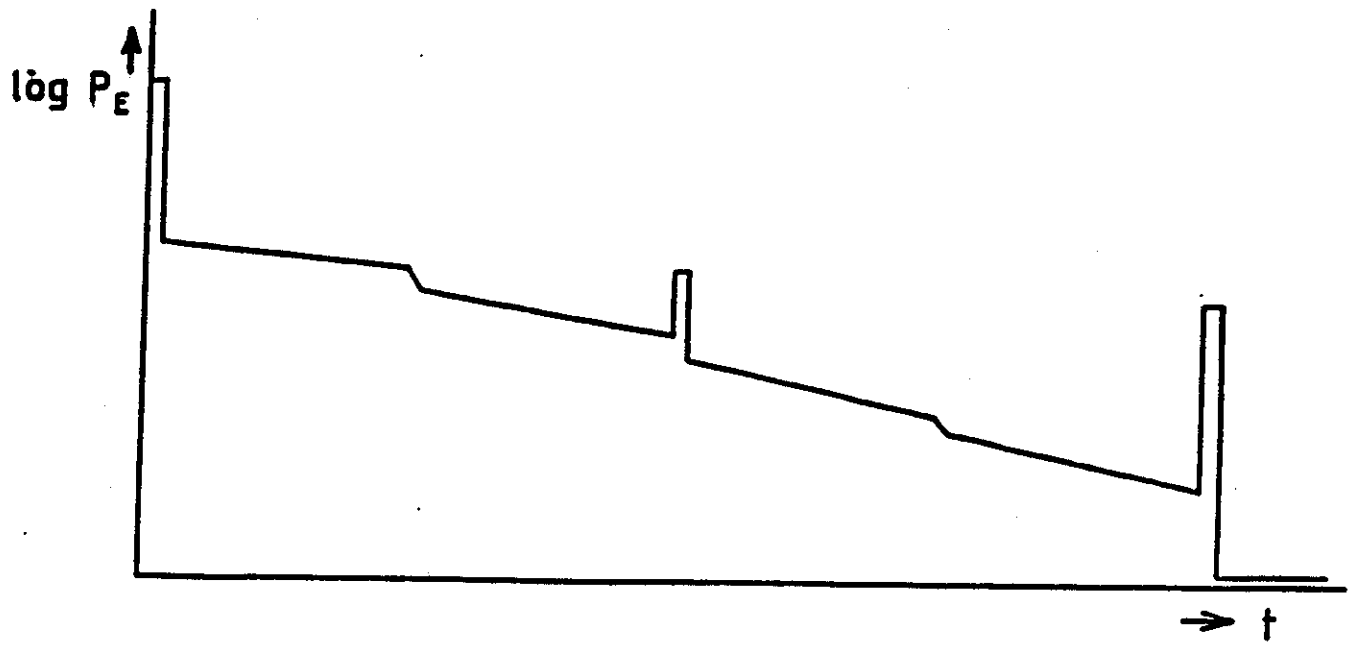


Figure 5.13 Typical OTDR Output

fiber optic user for diagnostics. The users for these systems include long haul telephone companies, which use the systems for locating breaks in fibers. Another advantage is that all the interrogation hardware is at one end of the system. The typical key performance specifications for an OTDR are:

Distance Range	Dynamic Signal Range
9 km	22.5 dB
20 km	20 dB
32 km	16 dB
46 km	16 dB

The primary disadvantage for this technique is a combination of distance and dynamic range limitation. While the hardware may be able to 'see' 46 kilometers, a system having a dynamic range of 16 dB may be only one or two sensor locations. The second disadvantage is cost. The hardware for the OTDR system remains relatively high in cost and requires either special training for the operator or 'smart' support hardware to interpret the response from the system. Another disadvantage is that the light pulse may have to travel a distance equal to twice the length of the sensor network. Depending on the length of the network, pulse dispersion may occur. This effect may be minimized by using single mode versus multimode fiber.

The Optical Time Domain Transmission system (OTDT) operates on changes in optical properties similar to OTDR. A typical OTDT system is shown in Figure 5.12. Pulses are launched into the fiber and exit at the receiver end of the fiber. The pulse shape changes based on the inverse of the refractive index at the sensor locations. This is the inverse of the operation that occurs for OTDR systems. The output of the OTDT system can be configured to look like that of an OTDR system. The primary advantage of OTDT is that the light only has to travel a maximum of one system length compared to two system lengths required for OTDR. The primary disadvantage of this approach is cost and the knowledge base required to interpret results from the system. The OTDT system uses hardware similar to that of an OTDR, and therefore shares the cost and training/ support hardware problems of the OTDR

approach. Another disadvantage is that hardware is required on both ends of the system. Having hardware on both ends of the system will probably further constrain the sensing range since both ends of the sensor system will have to be accessible by an operator.

A variation of OTDR and OTDT systems is the distributed OTDR or OTDT. This involves using more than one OTDR or OTDT net to cover a given area. The primary advantage of this system is that if a catastrophic failure occurs, only one portion of the sensor net will be affected. In a standard OTDR system, if a transmission fiber breaks, the sensors beyond the break will be cutoff.

5.3 PRESENT TECHNOLOGY AS APPLIED TO UNDERSEA PIPELINE LEAK DETECTION

5.3.1 CHARACTERISTICS OF PIPELINE LEAKS

To determine what monitoring system will give the desired response, the characteristics of a pipeline near or in failure mode must be characterized. The basic phenomenon which can be used to detect pipeline failures are:

Phenomenon Type	Time of Occurrence
Strain	Prior to Failure
Pipe Deformation	Prior to Failure
Acoustic	During and After Failure
Leakage Material	After Failure
Casing Rupture	After Failure

We have found little in the literature to indicate what typical levels of strains exist around leaks or impending leaks. This area obviously needs more study.

Detection of an impending failure is more desirable than detecting the failure after its occurrence. This would allow preventive measures to be taken to minimize or eliminate a potential spill. This concern must be weighed against what is technically feasible with the

sensor technologies presently available and the specifications of the intended application. While pre-failure detection is more desirable than post failure detection, post-failure detection is easier to accomplish. The reliability level of most of the post failure sensors tends to be better than that of pre-failure sensors.

Most of the transducer types discussed in this report could work as pipeline sensors. Of the types discussed, the break-induced sensor has the best probability for success in this application. This sensor type has been tested for use on different materials and under various environmental conditions with a high level of reliability on crack detection. The break-induced sensor would also have the lowest cost for development and production. This recommendation is based on simplicity of the sensor design.

5.3.2 SENSOR SYSTEM STRUCTURES

A successful pipeline monitoring system should meet the following criteria:

- 1) System installation and maintenance should be relatively easy to perform.
- 2) The system should have acceptable coverage of the entire pipeline system that is being monitored. There should be no 'dead zones' that are not monitored.
- 3) The system should allow good localization definition of a failure. The resolution of the system should be sufficient to direct repair crews to the failure site.
- 4) The system should be essentially an 'alarm'-type system that activates only when a failure has occurred. Monitoring and support crew should be small.
- 5) Installation and operational costs should be acceptable to undersea pipeline users.

To date, no system has been completely developed and deployed on an operational pipeline system. Several systems demonstrate very good potential for use for this application, but there were no reports of final development work being undertaken. In some cases, a single prototype has been developed for testing, but no production units were discussed.

5.4 RECOMMENDATIONS

The fiber-optic-based leak detection system selected as having the best potential for development for subsea pipelines is a system that detects a break in a fiber bonded to the pipeline. Other methods, such as monitoring local strain along the fiber, do not have the resolution or reliability needed when employed over long distances. The other methods also require sensitive

instrumentation and highly trained operators to interpret the response from the sensors. The breakage of fibers bonded to the pipeline will immediately detect large pipeline failures or ruptures, but will not detect small leaks caused by corrosion. It should be noted that large pipeline failures comprise a relatively high percentage of total pipeline failures. This type of system would give immediate indication of a pipeline failure caused by ship anchors, construction or maintenance equipment, or similar incidents. This system will also give a very precise location of the failure. Location uncertainties typical in other systems, such as OTDR, will not be present using this technique.

The primary system configuration to be investigated under this program should be the Cluster Sensor System using break-induced sensors. The production costs of this type of system should be relatively low (compared to production costs based on other methods), and since the basic approach is relatively simple, the probability of success of this configuration is higher than some of the more sophisticated techniques investigated under this program.

Development of a fiber-optic-based leak detection system will require considerable development effort since there are many unknowns. These unknowns include the stress/strain characteristics of pipelines at a leak site, stress/strain characteristics at impending failures, normal-operation fluid-induced stress/strain characteristics, and environmental noise sources. In addition, the long term environmental exposure of the fiber and bonding methods must be evaluated. If further investigation of the fiber-optic-based leak detection method is pursued, the following areas require further development work:

- Correlate pipeline leaks with strain induced near the leak site.
- Determine strain induced in pipelines due to environmental (noise) sources.
- Develop the method and needed materials to bond the fibers to the pipe so the fiber breaks at the desired strain level.
- Develop installation methods including; subsea connectors, signal transmission methods, subsea fiber repair methods, and determine effects of installation methods on the induced fiber strain.
- Demonstrate the fiber optic leak detection system in a subsea environment.

6.0 CONCLUSIONS AND RECOMMENDATION

6.1 CONCLUSIONS

Several different types of leak detection systems were reviewed in this study. For each leak detection method, the most promising systems were reviewed and their specifications described. Because there is a variety of factors that determine the applicability of a leak detection system, one system can not be applied to all applications. Factors that influence the selection of a leak detection system include; pipeline length, line pressure, single versus multiphase flow lines, rate of leak growth (rupture versus slowly growing leak) and environmental sensitivity in the area of the pipeline. Table 6.1 presents a break down of the leak detection methods by applicability to single phase and multiphase flow lines. In addition each section is further broken down by ability to respond quickly to large leaks and the ability to detect small leaks. As seen in the table, most of the proposed leak detection methods can detect major leaks or line ruptures quickly. For smaller leaks in single phase flow lines, SCADA-based systems can detect leaks down to about 1 - 10% of the line flow, and below this level only the chemical sensor-tube-based leak detection system, or LASP-type system, is feasible for detecting the smaller leaks.

For multiphase flow lines, the inability to accurately meter multiphase flow (present multiphase metering development efforts are targeting 5% accuracies) precludes the use of volume balance techniques. SCADA systems based on the PPA method can still provide rapid leak detection of large leaks but, at reduced sensitivities because of the increased pressure variations in multiphase flow. Acoustic and F/O break detection methods can also be used to monitor multiphase lines for major pipeline leaks of ruptures. For minor leaks in multiphase flow lines the only feasible method is the LASP-type chemical leak detection system.

Another important consideration is the ability to retrofit existing lines with leak detection systems. Methods that require placing instrumentation along the length of an existing pipeline are not practical. This means the chemical leak detection and the F/O break detection systems are not practical for most retrofit applications. Since the SCADA-based method and the proposed acoustic method only require instrumentation at the ends of the pipeline, these methods could easily be applied to existing pipelines.

Table 6.1. Leak Detection System Applications

LEAK DETECTION METHOD	SINGLE PHASE FLOW		MULTIPHASE FLOW		RETROFIT EXISTING LINES	RETROFIT WITH SUBSEA TIE-INS
	MAJOR LEAK (RAPID)	MINOR LEAK	MAJOR LEAK (RAPID)	MINOR LEAK		
SCADA - PPA	✓		✓		✓	✓(1)
- Volume Balance	✓	✓			✓	✓(1)
- Simulation Model	✓	✓			✓	✓(1)
Acoustic Method	✓		✓		✓	✓
Chemical Detection		✓		✓		
F/O Break Detection	✓		✓			

1. Information on flow rates at each subsea tie-in must be available to SCADA system.

Difficulties arise in retrofitting transmission lines with a SCADA-based system where multiple subsea tie-ins exist. For each tie-in, accurate flow metering information must be available. If each tie-in is not metered, the SCADA-based method cannot be applied. The acoustic-based leak detection system is the only alternative to retrofitting transmission lines with multiple, unmetered, tie-ins. Because of the "one shot" nature of capturing a rupture event with the acoustic method, there will be considerable reluctance to shutting in a pipeline based on a single transient event. Therefore, some additional information, such as a deviation in line pressure, is required to provide the confidence in the sensor readings an operator needs to shut in a pipeline.

For the majority of subsea single phase liquid flow lines, the SCADA-based leak detection systems can provide reliable and sensitive leak detection. For subsea gas lines, the SCADA-based methods can provide the needed leak detection, but because of the gas

compressibility, at reduced sensitivity. For many applications, this reduced sensitivity to rapidly detect small leaks, may be acceptable since gas line leaks produce less environmental damage. For single phase flow lines, the acoustic and F/O leak detection systems do not present any significant advantages over the SCADA-based systems. For these lines, there is no justification to pursue development of these alternative methods. In environmentally sensitive areas, where even very small leaks must be detected, the only method that can detect these small leaks is the chemical leak detection method. This method has a fairly slow response time, so it must be used with another leak detection system that detects large leaks rapidly.

For multiphase flow lines, the SCADA-based leak detection methods become much more difficult to apply, and the sensitivity to detecting leaks is reduced. SCADA systems for multiphase lines are not nearly as well developed as for single phase lines, and only a couple of multiphase SCADA leak detection systems have been reported. For these multiphase lines, the need to develop better SCADA systems and alternative leak detection systems is justified. The acoustic and fiber optic leak detection systems can be applied to subsea multiphase flow lines but will detect only large leaks or pipeline breaks rapidly. For detecting smaller leaks in the multiphase lines, the chemical leak detection system is the only option.

6.2 RECOMMENDATIONS

Future development efforts on rapid leak detection systems for offshore pipelines should first focus on applying SCADA-based systems to rapidly detect large leaks. Processed-liquid lines, that run from the production platform to shore, transport large quantities of crude oil (collected from many smaller gathering lines) and, therefore, have the potential to produce a large spill if a leak is not quickly detected. Since the fluid stream is processed to remove the gas, the fluid can be accurately metered, and a volume or mass balance leak detection method can be applied. The leak detection system sensitivity and response time depends upon the pipeline system parameters, such as line length and meter accuracy. Problems that are particularly important for implementing leak detection on offshore pipelines include: long subsea runs between SCADA-metered locations, subsea tie-ins (branch connections) from many production platforms into the pipeline, intermittent or transient flow from the connecting pipelines, difficulty in communicating between metering locations and the SCADA system, and costs associated with installation of high accuracy, custody transfer instrumentation on the offshore platforms. The effects of these parameters on the leak detection system sensitivity and response time should be investigated for typical offshore pipeline configurations.

The trend toward transporting unprocessed well fluids as a multiphase flow stream is another area where development work on leak detection systems is needed. Because a multiphase stream cannot presently be accurately metered, volume- or mass-balance-based leak detection systems cannot be applied. Pressure trend analysis systems have been applied to multiphase systems, but the sensitivity and response of these systems has not been documented. For multiphase SCADA-based leak detection systems, accurate and reliable flow measurement instrumentation and transient flow computer models will need to be developed, or leak detection systems based on other technologies will need to be developed.

The leak detection methods reviewed in this study were intended to provide rapid leak detection along the entire length of a subsea pipeline. While all of the methods reviewed here are technically feasible for leak detection, the acoustic, chemical and fiber optic techniques will require significant development prior to demonstrating a practical system that can be deployed over the entire length of a pipeline. One area where future development of these techniques would be more practical is in monitoring portions of the pipeline where damage is common. Development of acoustic, chemical and fiber optic-based leak detection systems that only cover the piping near the platform would allow development of the methods on a smaller scale and provide coverage of a high failure area. Acoustic correlation techniques or chemical-sensor-tube-based systems could be applied by laying specially-instrumented lines along the pipeline to detect leaks. For these shorter line lengths, issues such as power, are not as significant. In addition, this type of system could be replaced, if necessary, by laying new lines when required.

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