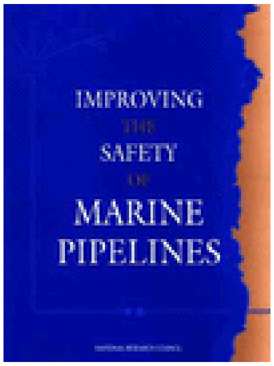

Improving the Safety of Marine Pipelines

Committee on the Safety of Marine Pipelines, Marine Board, National Research Council

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Marine Board
Commission on Engineering and Technical Systems
National Research Council

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Preface

The safety of the United States' undersea pipeline systems, in terms of both human safety and potential for environmental damage, is a major national concern. These systems, in federal and state Waters in the Gulf of Mexico and off Southern California and Alaska, extend more than 20,000 miles, carrying almost one-fourth of the nation's natural gas production and more than one-ninth of its crude oil.

Several accidents in the late 1980s, which claimed more than a dozen lives, raised public and congressional concern about the safety of the subsea pipeline system. That system must coexist with some of the world's busiest ports and most productive fisheries. Its structural integrity and maintenance are also subject to question, for much of it was installed in the 1940s and 1950s. Both maritime accidents and pipeline structural failures could result in pollution of fishing areas and coastal lands.

In discussions with the Marine Board, the Minerals Management Service (MMS) of the U.S. Department of the Interior and the Office of Pipeline Safety (OPS) of the U.S. Department of Transportation requested an interdisciplinary review and assessment of the many issues—technical, regulatory, and jurisdictional—that affect the safety of marine pipelines in U.S. offshore waters, including state waters. The National Research Council appointed the Committee on the Safety of Marine Pipelines, under the auspices of the Marine Board. The committee was charged with the following tasks:

- Review and analyze the historical causes of pipeline failures;
- Assess the state-of-practice and the potential for pipeline failures—whether caused by external, man-induced forces, seabed geotechnical conditions, or hydrodynamic ocean forces from currents and wave actions—and the means of mitigating them;
- Review and assess means for conducting right-of-way surveys and pipeline inspections;
- Assess the operation of pipeline safety systems and devices, and the maintenance and rehabilitation procedures for detecting and mitigating hazards and leaks;
- Assess periodic inspection, data collection, and analyses needed to evaluate the integrity of the pipeline systems;

- Identify alternatives for improvements in the regulatory framework and guidance for rulemaking that may enhance pipeline system safety and environmental protection.[1]

In undertaking these tasks, the committee excluded from consideration pipelines in harbors and inland waterways and those related to refinery and storage facility interconnections. Pipelines in Alaskan state waters were also excluded (except for statistical information), in view of the special climate conditions and technical issues, such as ice protection, that are unique to operations off the North Slope and in Cook Inlet. The committee, seeking to address the most salient issues of pipeline safety, did not attempt a general survey of pipeline repair and rehabilitation techniques, and focused on measures to improve pipeline safety. In its review of pipeline survey techniques, the committee placed primary emphasis on pipeline inspection rather than right-of-way surveys, which have a more indirect influence on operational safety.

With regard to the geographical coverage of this report, the greatest emphasis by far has been placed on the systems in the federal and state waters of the Gulf of Mexico, where about 99 percent of the marine pipeline mileage is located. The pipeline safety issues applicable to California are often significantly different, including the relatively few miles (about 300) of marine pipeline there, and the risk of seismic action.

The Committee on the Safety of Marine Pipelines is composed of experts in offshore oil and gas development, research in systems safety improvements, ocean engineering, development of deep water pipelines and offshore structures, risk analysis and environmental management, pipeline safety regulations, corporate safety management, chemistry and corrosion, geotechnical engineering, petroleum economics, and environmental policy from a state and local viewpoint.

The committee met five times from the beginning of its activity in April 1992. During these meetings, the committee received briefings from the MMS, OPS, and U.S. Coast Guard on these agencies' responsibilities in executing regulations, and their operational issues and problems. The committee reviewed the concerns of persons and organizations affected by offshore pipelines and their regulation through briefings by pipeline operators and representatives of the fishing industry. It also received presentations on the dynamics of shoreline change and its influence on pipelines, on the location and reporting of navigational obstructions, and on charting. The problems of safety data bases were explored. Through reports and data from federal and state agencies and industry, the committee reviewed technical topics such as pipeline operations and inspection, corrosion control, and leak detection. Finally, individual committee members visited state agencies in Louisiana and Texas, as well as industry sites, to obtain first-hand views of particular issues.

In preparing its report, the committee was aided by representatives of the two sponsoring agencies and their staffs. The Minerals Management Service representative to the committee was Mr. E. P. (Bud) Danenberger, Chief, Engineering and Technology Division. Alexander P. Alvarado, Supervisor, Pipeline Unit, MMS Gulf of Mexico Region, and Melinda S. Mayes, Geologist, MMS Pacific OCS Region, were particularly helpful in providing regional data. Cesar DeLeon, Director, Regulatory Programs, Office of Pipeline Safety, and William Bertges of the OPS Southwest Region provided pipeline data

[1] The term "regulatory framework" is understood to mean the complex of laws, regulations, scientific and engineering knowledge, and formal and informal relationships that shapes regulation and determines the roles of regulators and regulated entities.

and correspondence related to marine navigation safety concerns. George P. Vance, Manager, Subsea Marine Section, Mobil Research and Development Corporation, served as the Marine Board's liaison to the committee. Albert H. Mousselli of Applied Offshore Technology, Houston, generously guided the committee through the geotechnical problems of pipeline installation in the Gulf of Mexico.

The committee extends its thanks to the many persons who provided briefings and correspondence to inform committee and staff members of current measures to ensure safe operations and of problems that have yet to be resolved; these persons are listed in Appendix F.

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Executive Summary

More than 20,000 miles of marine pipelines lace the coastal waters of the United States, nearly all in the Gulf of Mexico, with a few hundred miles off the coasts of Southern California and Alaska. Since its first ventures into the shallows in the early 1950s, the pipeline industry has steadily improved its designs, materials, and techniques for construction, operation, and maintenance. Today pipelines are operated with confidence in waters as deep as 1,700 feet, with near-term plans for 3,000 feet. Marine pipelines carry about one-fourth of the nation's gas production and one-ninth of its crude oil.

Yet several dramatic accidents in the late 1980s raised new public concerns about the safety and integrity of marine pipelines. These events, and in particular two separate fatal incidents in which the fishing vessels *Sea Chief* and *Northumberland*, in shallow waters, struck pipelines that were no longer properly buried, drew attention to the fact that pipelines must share the waters with some of the nation's busiest ports and most productive fisheries, and must retain their integrity for decades in the face of frequent storms, coastal erosion, and, in California, seismic activity. These and other factors have led owners and regulators to ask whether the practices and standards that evolved over the past 40 years are adequate today. Hurricane Andrew, by closing down much of the marine pipeline network in the Gulf of Mexico for weeks in late 1992, brought home the economic impact of interrupted service, and the vital importance of the integrity of the marine pipeline system for the long term.

To gain fresh perspective on these risks, the Minerals Management Service (MMS) of the U.S. Department of the Interior and the Office of Pipeline Safety (OPS) of the U.S. Department of Transportation requested that the Marine Board conduct an interdisciplinary review and assessment of the many technical, regulatory, and jurisdictional issues that affect the safety of the marine pipelines in U.S. offshore waters. The Committee on the Safety of Marine Pipelines, under Marine Board auspices, accordingly reviewed the causes of past pipeline failures (except for seismic activity); the potential for future failures; and means of preventing or mitigating them, including operational measures, inspection techniques, data collection efforts, and improvements in the regulatory framework. For the committee, the term "safety" encompasses all of the potential consequences of pipeline failure: human injury or death, environmental pollution, and property damage.

The committee found that the marine pipeline network does not present an extraordinary threat to human life. Pipeline accidents involving deaths or injuries are disastrous, but rare. The most widespread risks are due to oil pollution, mainly from pipelines damaged by vessels and their gear. These risks are not precisely quantifiable with the data available; however, they generally can be managed with available technology, and without major new regulations, if enforcement of some current regulations is improved. Better coordination among operators and regulators in gathering safety data, assessing risks, and planning and implementing risk management programs is the most fundamental requirement.

SHARED REGULATORY JURISDICTION

Safety regulation of marine pipelines is shared by federal and state agencies. In the federal waters of the outer continental shelf (OCS), the OPS regulates nearly 13,000 miles of so-called transmission pipelines (generally larger, longer pipelines that carry oil and gas ashore), and the Minerals Management Service about 4,000 miles of production pipelines (associated with production and initial processing). In state waters, OPS has jurisdiction over transmission pipelines, and the states over production pipelines. OPS certifies state agencies to enforce its regulations for intrastate transmission pipelines.

MMS has extraordinarily broad regulatory authority. Under the Outer Continental Shelf Lands Act of 1978 (43 U.S.C. 1334), it issues permits and rights-of-way for all OCS activities, including pipelines, to ensure "maximum environmental protection." In pursuit of this goal, the agency sometimes also applies its regulatory requirements to OPS-regulated pipelines that begin on the OCS and extend to state waters. Implementation of the Oil Pollution Act of 1990 (P.L. 101-380) will expand MMS's authority further, making the agency responsible for ensuring oil spill prevention and response capability for all pipelines off the nation's shores.

Other federal, state, and local agencies are involved. The U.S. Army Corps of Engineers issues permits for pipeline crossings of waterways, shorelines, and navigation fairways. The U.S. Coast Guard may declare pipelines hazards to navigation; it also conducts annual safety inspections of ports, including pipelines, and may close facilities that fail to meet its standards. State and local agencies issue permits for coastal activities, under their coastal zone management plans.

SAFETY EXPERIENCE

Analysis of past pipeline failures is difficult, because data collection by federal and state agencies has been inconsistent and incomplete. MMS, OPS, and the Coast Guard all receive reports on pipeline failures for their particular purposes, but have never assembled a coordinated data base.[1] Most state regulatory agencies have only rudimentary records, with the exception of California. Only for the Gulf of Mexico OCS did the committee find an organized and reasonably complete data base on pipeline failures, their causes, and their consequences. Even that information is insufficient to establish such important statistical connections as those between rates of corrosion leaks and pipeline

[1] This committee uses the term "failure" to refer generally to any pipeline damage required to be reported to safety regulators. Such damage ranges from small pinhole leaks caused by corrosion to major failures resulting in fires, explosions, or large oil spills.

age or product carried; and this information cannot be used to find patterns in the locations of corrosion failures or anchor damage that would help in setting risk management priorities. Several important patterns do appear, however:

- Corrosion, although it was the reported cause of nearly half of the 1,047 OCS pipeline failures recorded between 1967 and 1990, produced only about 2 percent of the pollution from pipelines.
- Damage from vessels (and especially from anchors and groundings) is dramatically more significant than corrosion as a source of pollution and other consequences, including deaths and injuries. Anchor damage alone accounted for 90 percent of the pipeline-related pollution on the Gulf OCS.
- A very few incidents have produced most of the pollution. The largest 11 pipeline spills, all caused by vessels, accounted for 98 percent of the pollution from pipelines.
- Deaths and injuries are rare. Six incidents, over 24 years, resulted in all of the deaths (24) and serious injuries (17) associated with pipeline failures. (The committee considered only deaths and injuries associated with pipeline failures; casualties in routine operations and maintenance or in production activities were outside its charge.)

It must be emphasized that these patterns emerge from incomplete data. Most importantly, except for the data on deaths and injuries, they do not reflect experience in state waters.

MAINTAINING THE INTEGRITY OF MARINE PIPELINES

Although it is not a major source of oil pollution or other safety consequences, corrosion remains a troublesome inspection problem. Much of the pipeline system has remained in service for more than 30 years, thanks to improvements in corrosion control and leak detection; small pinhole leaks, however, are a continuing concern. Repairs and inspection are costly for underwater pipelines, and the industry accordingly emphasizes prevention of damage and deterioration.

To limit external corrosion, pipelines are coated and have cathodic protection systems, which apply a small electrical current to counteract the electrochemical interaction of pipeline steel and seawater at any coating defects that may develop. The systems are designed to provide uniform protection for at least 25 years, and are renewed as necessary. The uniform electrochemical characteristics of seawater make external corrosion protection simpler than it is on shore or on pipeline areas that are intermittently immersed, such as risers on platforms. Verifying the adequacy of protection, on the other hand, is more difficult offshore than on shore because access points are more limited.

Internal corrosion is more difficult to locate and quantify. Marine pipelines, to varying degrees, carry corrosive mixtures of brine, microorganisms, and other materials along with the hydrocarbons. Operators monitor the corrosivity of pipeline fluids, injecting corrosion inhibitors as needed and scheduling runs with internal cleaning devices called "pigs." Furthermore, operators can usually predict the circumstances in which internal corrosion will occur, so that specific inspection and remediation techniques can be used in situations where they will be most effective.

In-line internal inspection devices, or "smart pigs," have been in use, with steady improvement, for more than 20 years. These instrumented devices transit pipes and measure and record changes in magnetic flux or ultrasonic signals to indicate cracks, dents, corrosion pits, or other problems. They have seen increasing use in pipelines onshore, and in a few marine pipelines. However, they are limited in several ways by the nature of offshore operations. Physical access to suspected faults is more difficult and costly offshore than onshore, particularly because false indications of faults are common. In addition, most marine pipelines physically cannot accommodate these large (8 to 12 feet long) devices, because of their tight bends and multiple subsea pipeline connections. Finally, existing offshore platforms often have little or no room for the bulky launching and receiving fittings required by smart pigs. (California is a special case; because most marine pipelines there run directly to shore, with relatively few lateral tie-ins to other pipelines, regulators require the use of smart pigs there as a matter of course.) The smaller and more accurate devices of the future are likely to see increasingly wide use offshore.

Leak detection options for operating pipelines are varied, depending on operational and environmental conditions:

- Visual detection of gas bubbles or oil sheens, during periodic overflights, can detect small or large leaks, but may take several days, depending on the frequency of overflights.
- Manual line-balance calculations, comparing volumes delivered into a pipeline system with volumes delivered out, are nearly as sensitive as visual detection, and are quicker to indicate problems. These techniques are not applicable to gas pipelines, owing to the pressure and temperature variations of natural gas.
- Line-balance calculations made automatically by supervisory control and data acquisition (SCADA) systems, which remotely monitor and/or control key operating parameters, can detect even small leaks in liquid lines, provided they have simple geometries and minimal variations in pressure. (Detection of smaller leaks takes longer.) They require meters at inputs and outputs to the pipeline system. A growing number of marine pipelines—and nearly all transmission pipelines—have SCADA systems.
- "Setpoint-limit" control systems, which use changes in pressure or flow rates to signal leaks, can detect large leaks promptly, but require fairly steady flow conditions, and are not appropriate for pipelines with multiple inputs and wide variations in flow.

Leak detection thus involves a number of coordinated and complementary techniques. No one system or combination is sufficient for every pipeline.

Timely notification is as important as timely detection. The discoverer of a leak may find it difficult to identify and establish the precise location of the leaking pipeline, and notify the operator or operators likely to be affected. (It is commonly necessary to shut down in an orderly way the pipelines and platforms injecting into the leaking pipeline.) A more effective process of notification is needed.

AVOIDING OUTSIDE INTERFERENCE WITH PIPELINES

The most significant pipeline failures, as noted earlier, are those that result from damage by vessels and their gear. Impacts of anchors, nets, trawl boards, and hulls of cargo, fishing, and offshore service vessels and mobile drilling rigs can lead to major pollution incidents, costly repairs and replacements, and even injuries and deaths.

No available sensor technology allows moving vessels to detect pipelines at a distance in time to avoid them. While satellite-based location technology is improving rapidly, and is now accurate enough to be used to reduce the risk of vessel and pipeline interaction, the benefits of this technology can seldom be realized since older pipelines are often inaccurately charted. It is therefore incumbent on the operators of pipelines to anticipate interactions with vessels. In some cases, such as the anchoring of supply boats near platforms, fixed mooring systems for service vessels and improved communications between platforms and vessels can provide protection. In most areas, sufficient pipeline burial (pipes are placed in a trench but not covered over) is the only practical way to reduce the chance of interactions with vessels. For this reason, regulatory standards and engineering practice require pipelines to be buried below the bottom (generally by at least 3 feet) in waters less than 200 feet deep, with coatings of adequate weight to keep them in place. But occasionally, and in rare cases tragically, they become exposed. A recent survey ordered of OPS-regulated pipelines found that 1.7 percent of the pipeline mileage in less than 15 feet of water (enough to accommodate the drafts of large fishing and service vessels) had less than one foot of cover. (The survey, ordered by Congress in the wake of the *Sea Chief* and *Northumberland* accidents, was an attempt to shed light on the potential for additional accidents of that kind.)

Burial in the Gulf of Mexico is complicated by the area's coastal dynamics, which feature large movements of sediments and a general pattern of shoreline erosion and retreat, modulated by severe storms. Pipelines in shallow water and those near the shore must be inspected regularly to ensure that they remain adequately covered.

PLACING RESPONSIBILITY FOR SAFETY

By law, the responsibility for safety lies with the operator, not the regulator. Regulatory standards are minimum requirements and must be supplemented by sound engineering and operating practice. Mere compliance is not enough. Every pipeline operator must appreciate the unique circumstances affecting each pipeline, and take the necessary steps to control risk. The industry as a whole must recognize that the entire offshore oil and gas industry could be severely weakened by major pollution incidents or fatal accidents resulting from pipeline failures.

This observation does not minimize the importance of a strong and consistent regulatory framework. Regulatory agencies are responsible for setting appropriate policies for risk management on the basis of objective risk assessments. To do so, they need detailed and comprehensive information about pipeline failures, and they need the engineering knowledge to translate their priorities into standards that provide cost-effective solutions. In the case of marine pipelines, where several agencies are involved, they need a consensus about their priorities.

MAJOR CONCLUSIONS AND RECOMMENDATIONS

The safety record of marine pipelines is a good one, but it can be improved. During the late 1980s, the Gulf of Mexico OCS experienced about one reportable pipeline failure every five days. Most of these failures were small leaks of gas or small oil spills caused by corrosion. Still, transmission and production pipelines account for about 98 percent of all the oil spilled by OCS oil and gas operations (nearly 11,000 barrels annually from the late 1960s to the late 1980s).[2] Although it is estimated that petroleum hydrocarbons (including crude oil and its refined products) enter the Gulf of Mexico from river and

[2] This average obscures great variation from year to year.

stream runoff and from natural seeps in significant volumes (greater than the spillage from offshore operations and accidents), offshore oil and gas operations and tank vessel accidents are two areas where preventive action can possibly be effective in reducing pollution. The volume of oil that enters the Gulf from the oil and water mixture produced from offshore wells (known as "produced waters") is estimated to be the largest source of oil into the Gulf from offshore oil and gas operations (which do not include ship transportation). This report addresses the second largest source of spillage from offshore oil and gas operations, that from pipeline accidents and line failures. Accidental pipeline spills have released more volume than offshore drilling accidents during the past ten years. Tank vessel and tank barge accidents are another source of spills which, like pipeline accidents, result in widely varying annual volumes of oil spilled into the Gulf. The great uncertainties in rates from source to source, owing to large annual variations (as in the case of tanker spills) and lack of data (in the case of runoff) make quantitative comparisons about oil pollution in the Gulf of Mexico meaningless.

Improvement depends on better information, to put safety planning on a sound basis. Pipeline failures and spills are reported to several different agencies, which have different reporting formats and information requirements. No agency coordinates the collection of information. The available data on failures of offshore pipelines are correspondingly incomplete. The responsible agencies must improve the process of information gathering, archiving, analysis, and reporting.

The committee, therefore, recommends that the regulatory agencies involved develop a common safety data base, covering both state and federal waters, and periodically review their data requirements. The focus should be on collecting, archiving, analyzing, and reporting safety data with the intent of improving design and operating regulations. The extended data base should include the information needed for risk and cost-benefit analysis. MMS, which has the greatest test experience and resources in data gathering, should coordinate this effort.

Even in the absence of better safety data, safety planning can be improved. Modem risk analysis methods, using incomplete data supported by inferences and expert opinion about the nature and distribution of risks, can clarify priorities for risk management. For example, the risks to human safety and to the environment due to failures of marine pipelines are not uniform across the Gulf of Mexico. Resources being limited, a risk analysis approach that compares risks in different geographic areas (or "zones") would allow cost-effective risk management decisions. In this way, regulations can be developed to address safety everywhere and provide the basis for strengthening regulations in high-risk areas. The goal is a consistent risk management strategy that involves both regulatory agencies and the pipeline operators in the process of reducing human and environmental risks.

The committee recommends that safety regulations be based on sound risk analyses and cost-benefit analyses. Specifically, regulatory agencies should agree on a consistent risk management strategy for setting priorities about human safety criteria, and about the use of cost-benefit analysis for the reduction of property and environmental damage. A zone-based risk analysis model, based on the zonation approach outlined in Chapter 3 of this report, should be developed on the basis of currently available information and then be regularly updated, to *help determine whether regulations should be revised, strengthened, or relaxed and to assist in establishing priorities for the operational use of resources by both government and industry for enhancing pipeline safety (such as inspection coverage and frequency, use of internal inspection devices, and establishment of burial depths for areas having high erosion rates).*

Enforcement of safety regulations also reflects a lack of coordination among agencies. This situation is largely related to the great differences in the scope and approach of the enforcement programs of OPS and MMS. OPS is responsible for over 1.7 million miles of interstate and intrastate pipelines on land and under the waters of the United States. The marine portion of the OPS jurisdiction is small, consisting of nearly 13,000 miles of pipelines (in the OCS), or less 1 one percent of the total OPS mileage, and presents little risk to public safety and the environment compared with land lines that traverse densely populated and industrial urban areas and are exposed to frequent threats to their system integrity. In contrast, the 4,000 miles of pipeline under MMS jurisdiction are all in the marine environment.

The marine inspection resources assigned by each of the two agencies and the approaches taken to inspection reflect the differences in the scope of their individual regulatory responsibilities. MMS assigns 70 inspectors to the Gulf of Mexico region to make regular on-site inspections of pipeline maintenance and safety systems and spot inspections of construction and repair activities. By comparison, OPS assigns only 2 of the 30 inspectors on their staff to this region. Although OPS also has the services of approximately 250 state inspectors who are assigned (by agreement with the OPS) to both interstate and intrastate pipeline inspection, these personnel are not available for OCS inspection assignments. OPS inspection efforts are conducted primarily through periodic audits of company records. Although, these differences in resources and approaches focused on marine pipeline inspection reflect differences in the physical location of facilities and the safety issues faced by the two agencies, it appears likely that OPS enforcement personnel are too few to cover adequately the 13,000 miles of marine pipelines and more than 160 operating companies in the Gulf of Mexico region of the OCS that are under OPS jurisdiction.

To make better use of inspection resources and help integrate enforcement of MMS and OPS marine pipeline safety regulations, the committee recommends that enforcement of OPS regulations offshore be performed by the MMS, through an interagency agreement or redefinition of the memorandum of understanding that defines the jurisdictional division between OPS and MMS. Such a system would continue OPS's role in regulating offshore pipelines, while strengthening the application and enforcement of such regulations by bringing to bear MMS's greater resources.

Another regulatory discrepancy is apparent in the MMS and OPS requirements for internal inspection of pipelines. MMS, under its law requiring the use of the "best available and safest technology," has established a general requirement for the use of in-line inspection devices (generally known as smart pigs) where practicable. OPS is studying the matter, under congressional mandate. The committee finds that the technology of smart pigs is progressing, and that these devices are seeing increasing use onshore. However, the vast majority of today's marine pipelines cannot physically accommodate smart pigs, and modification of pipelines generally would be impractical and uneconomic. In addition, the current devices are relatively inaccurate in locating flaws. Because the costs of verifying suspected flaws are much greater offshore than onshore, this inaccuracy is a greater handicap. The use of smart pigs offshore will not be widely practical until further technical improvements are made, especially in the reliability and accuracy of three-dimensional anomaly measurement and in the compactness and maneuverability of smart pigs themselves.

The committee recommends that marine pipelines already constructed be exempted from federal or state requirements for the use of currently available smart pigs for external or internal corrosion detection. New medium- to large-diameter pipelines running from platform to platform or platform to shore should be designed to accommodate smart pigs whenever reasonably practical.

Pipeline operators and regulators should continue to assess developments in smart pigging technology and seek cost-effective opportunities for its use.

Detecting and limiting leaks quickly is as important as preventing them in the first place. A variety of techniques is available. Periodic aerial surveillance can detect leaks of all sizes, but sometimes with a delay of days to weeks. Setpoint-limit control systems (which monitor changes in pressure or flow rates) can detect large leaks, but are not effective for pipeline systems with routinely varying pressures and flow rates. For liquid pipelines, manual or automated line-balance calculations (comparing volumes in with volumes out) can detect small to large leaks, with speed and accuracy that depend on the complexity of the pipeline system and its operation. Manual calculations are generally made only once per day, while automated calculations may be made more frequently (with substantial additional costs for the necessary monitoring and communications equipment).

Many leaks are first detected through visual sightings by parties other than the pipeline operators. The detector of a leak generally cannot identify the operator of the pipeline. Often there is no agency or entity that can establish the responsible party in a timely fashion. The responsible operator in turn, once made aware of a leak, can have difficulty contacting in a timely manner all connecting pipeline and platform operators who must take action.

Pipeline operators should use a combination of leak detection methods to ensure timely detection of a broad range of leaks. Setpoint-limit control systems, where practical, should be used to provide quick detection of relatively large leaks. Line-balance calculations—either manual or SCADA-based—should be conducted at least daily, where practical, to monitor pipeline systems for small-to medium-sized leaks (which can be detected in this way with a time delay of I to 24 hours). Periodic visual surveillance (with a time delay of 1 hour to 2 weeks) should be used to detect very small leaks and those that have gone undetected by other means. The method chosen will depend partly on the product transported, the throughput of the pipeline system, the potential consequences of leaks in particular locations, and the nature of the pipeline system's operations (such as its relative stability of operating conditions and its location and accessibility by personnel).

MMS should coordinate an effort by appropriate federal and state regulatory *agencies and industry to establish a system through which leaks detected by third parties can be reported to a single agency or notification center with continuous coverage around the clock. This one central location should have a comprehensive data base permitting easy identification of the operator of any marine transmission or production line based on the reported sighting location. All maritime entities should be encouraged to use this single reporting center. Pipeline operators, in turn, should have 24-hour telephone numbers or a means of immediately contacting all other pipeline and platform operators who must take action.*

No sensor technology is available to permit moving vessels to detect nearby pipelines at a distance, and thereby avoid them. Location-determining technologies are too inaccurate. However, there are operational measures by which vessels can lessen the risks of inadvertently interfering with pipelines.

An obvious but difficult problem is the control of the mooring of supply and service vessels in areas adjacent to offshore platform installations. A specific risk is that these vessels may drop anchors on nearby pipelines or flowlines, or interfere with pipeline risers. Clear communications between vessels and offshore platform operators would help avoid these risks.

In areas where supply and service vessels operate adjacent to fixed platform installations associated with high densities of pipelines or flowlines, permanent mooring systems should be considered. In other circumstances, platform operators should be required to provide detailed and timely information to vessel operators on the configurations of local pipelines or flowlines, so that the vessels can anchor in designated areas. To lessen the risks of damage further in these congested areas, new pipelines should be installed whenever possible in well-defined "corridors."

In shallow waters (generally less than 200 feet deep), the best protection against the interference of vessels and pipelines, generally, is burial of the pipelines, with enough weight coating to keep it in place. In the shifting, often unconsolidated coastal sediments and eroding shorelines of the Gulf of Mexico, however, achieving and maintaining adequate burial requires care and vigilance. Pipeline installation must take into account detailed knowledge of soils, currents, and shoreline processes, so the pipeline can be buried and weighted to keep it in place, even if its surrounding soils are fluidized by currents and wave action.

The committee has no information leading it to believe that the initial burial depths required by regulatory agencies are either adequate or inadequate. Anecdotal evidence suggests that initial cover may be adequate, but loss of cover over time, through erosion or fluidization of surrounding soils, exposes pipelines to interference by vessels. Pending further study, the current regulatory standard for depth of initial burial must be considered adequate, if it is maintained through the life of the pipeline.

Much of the Gulf shoreline is eroding rapidly. This erosion may expose pipelines buried at installation and can be accelerated by the trenching used to install pipelines across the shoreline. The directional bore method of installing pipelines under beaches without breaking the surface minimizes this problem and is also attractive from the standpoint of construction and maintenance costs.

The need for periodic inspections of pipelines, to ensure that they do not lose cover or become exposed, is not addressed in standard industry practice or in regulations.

Geotechnical studies of soil conditions, with sampling at intervals determined by local site conditions, should be required as a condition of marine pipeline construction permits. Soil core samples should be analyzed and interpreted for design parameters relative to weight, specific gravity, grain size, shear strength, and potential for liquefaction and fluidization. Permitting and regulatory agencies should work with industry to develop criteria for specific gravities of marine pipelines in varying soil environments.

To provide baseline data for subsequent depth of cover and bottom status surveys, newly installed pipelines should be surveyed at once and their depths of cover recorded, with reference to Global Positioning System locations. Maintenance of this baseline data should be required by the agencies issuing the construction permits.

All agencies involved in the permitting of pipelines crossing shorelines should require the use of the directional bore installation method wherever feasible.

In waters less than 15 feet deep (where interactions between vessels and pipelines may, albeit rarely, expose vessels and crews to fire and explosion), periodic depth-of-cover surveys in the Gulf of Mexico should be scheduled according to the specific local shoreline and seabed dynamics, and the passage of severe storms, according to the criteria outlined in Chapter 5 ("Periodic Depth of Cover Inspections). In brief, a baseline depth of cover measurement should be established for each pipeline, and subsequent inspections should be made—at intervals determined by local shoreline and seabed dynamics and storms—to determine the direction and rate of change of the depth of cover. Later inspection intervals can be lengthened or shortened according to this rate; this approach might be called "self-adjusting."

Pipeline operators and regulatory and permitting agencies should conduct studies to determine the appropriate standards for initial depth of burial under various shoreline and seabed conditions, using the results of the recommended periodic depth-of-cover surveys.

Abandonment of marine pipelines will continue to increase as producing fields reach maturity and are shut-in. Most of these abandoned lines are in shallower state waters. A properly abandoned pipeline poses no risk to public safety or to the environment. Abandoned pipelines have not been reported to cause any loss of life or significant property or environmental damage. The current practice of remediating abandoned pipelines once they come to the attention of the operators is adequate, so long as operators are vigilant and responsive. A more aggressive periodic inspection program is not warranted until, and unless, public safety or the environment is shown to be adversely affected.

The committee recommends that pipeline abandonment standards include a requirement for a one-time inspection at the time of abandonment to verify that *abandonment requirements were met. Removal, continuing surveillance, or periodic inspection of abandoned pipelines should be required only where unique public safety or environmental conditions exist, such as rapid coastal erosion in areas of high vessel traffic. Pipeline operators should take timely corrective action when they are made aware of problems caused by their abandoned pipelines. Remediation should be the responsibility of the owner or successors until or unless the abandoned pipeline is removed.*

1

Introduction

The safety of marine pipelines is a timely topic for assessment. New public concerns about the integrity of this vital network—carrying one-fourth of the nation's gas production and one-ninth of its oil—were raised by several dramatic accidents in the late 1980s, involving loss of life and heavy property damage (Chapter 2). These events drew sharp attention to the offshore industry's aging pipeline infrastructure, its move toward deeper water, the recent entry of many small pipeline operators (some without extensive experience or large financial resources) and other developments, which have led owners, regulators, and others to ask whether the operational practices and standards that evolved over the past 40 years are adequate today. Hurricane Andrew, in September 1992, by closing down much of the marine pipeline network for weeks, brought home the economic cost of interruptions, and the vital importance of assured safety for the long term.

More than 20,000 miles of large- and medium-diameter marine pipelines, some dating from the 1950s, lace the coastal waters of the United States. Nearly all are in the Gulf of Mexico; a few hundred miles lie off Southern California, and a few miles of pipelines are in the state waters of Alabama and Alaska. Most are off the coast of Louisiana, which accounts for about 90 percent of the nation's offshore oil and gas production; nearly all the rest are divided between Texas and California (Lindstedt et al., 1991). The federal waters of the outer continental shelf (OCS) contain nearly 17,000 miles of pipeline. State waters—within the 3-mile limit (in Texas 3 marine leagues, or just over 10 miles)—have perhaps 5,000 miles more (personal communication, James Thomas, Office of Pipeline Safety, July 7, 1993). The total mileage of marine pipelines increases by a few hundred miles each year, with new additions nearly balanced by abandonments.

The offshore pipeline industry, since its first ventures into the shallow coastal waters of the Gulf of Mexico and the Pacific in the early 1950s, has steadily improved its operating practices, with new materials, more robust designs, and more efficient techniques for construction, operation, and maintenance. Today it operates with confidence in waters as deep as 1,700 feet and has developed the technology for much deeper waters, up to perhaps 3,000 feet. It has longer term plans for depths of perhaps 6,000 feet. Figures 1-1 and 1-2 show production trends for the OCS.

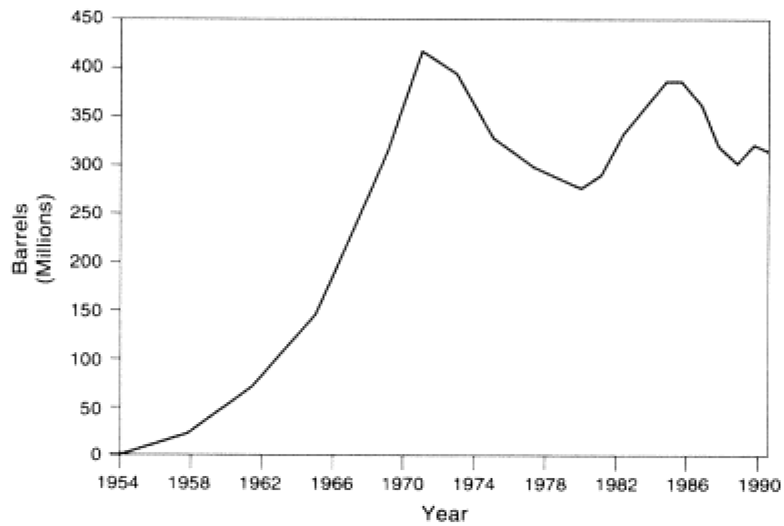

Figure 1-1 Offshore crude oil and gas condensate production in federal waters, 1954-1991.

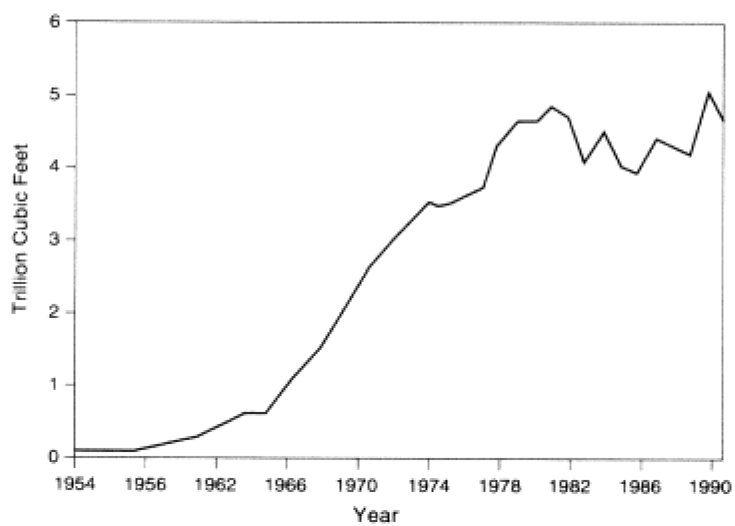

Figure 1-2 Offshore natural gas production in federal waters, 1954-1991.

DIVIDED REGULATORY RESPONSIBILITIES

Safety regulation of marine pipelines is shared by federal and state agencies. On the OCS, the Office of Pipeline Safety (OPS) of the U.S. Department of Transportation regulates nearly 13,000 miles of so-called transmission pipelines (generally the larger, longer pipelines that carry oil and gas ashore), and the Minerals Management Service (MMS) of the U.S. Department of the Interior about 4,000 miles of production pipelines (those associated with production and initial processing). In state waters, OPS has jurisdiction over transmission pipelines, and the states over production pipelines. OPS may certify state agencies to carry out enforcement of OPS regulations on intrastate transmission pipelines in state waters; agencies in Louisiana, Texas, Alabama, and California are thus certified. (States may have additional or more stringent requirements as long as they

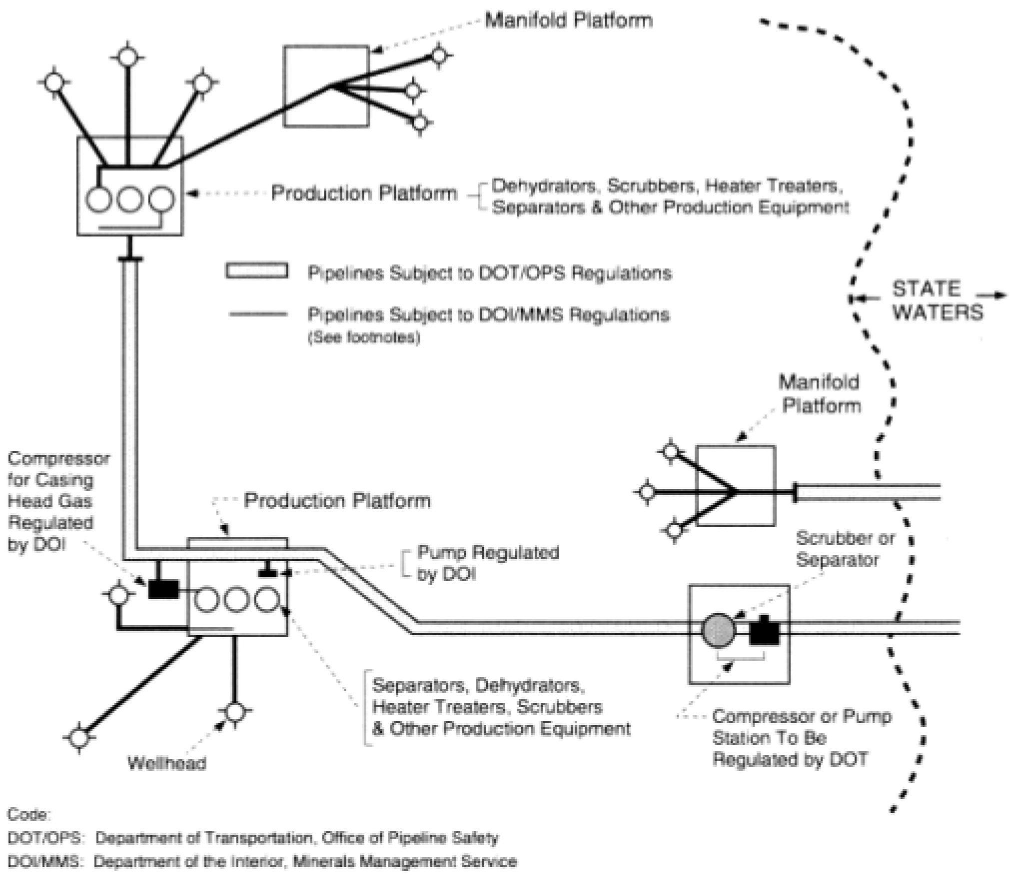

Figure 1-3 Pipeline safety regulatory jurisdictions in federal outer continental shelf waters.

are compatible with OPS requirements.) Figure 1-3 is a schematic drawing of the jurisdictional boundaries between the two agencies.

MMS has broad regulatory authority beyond its immediate concern with production pipelines. Under the Outer Continental Shelf Lands Act (43 U.S.C. 1334), it issues permits and rights-of-way for all OCS activities, including pipelines, to ensure "maximum environmental protection by utilization of the best available and safest technologies ... taking into account, among other things, conservation and the prevention of waste." MMS is responsible for ensuring that pipelines are installed, maintained, and operated in compliance with permits. In pursuit of this goal, the agency sometimes establishes requirements for OPS-regulated pipelines that originate on the OCS.

The Oil Pollution Act of 1990 (P.L. 101-380) will further expand MMS's authority over pipeline operations. The act, implemented by Presidential Executive Order 12777 (October 1991), makes the agency responsible for ensuring spill prevention and response capability for all marine pipelines, including those in state waters, which are regulated by OPS or the states for safety purposes. Regulations to implement the act, through cooperative agreements between MMS and the states, are being prepared.

Other federal, state, and local agencies have their own responsibilities. The U.S.

Army Corps of Engineers issues permits for pipeline crossings of waterways, shorelines, and navigation fairways. The U.S. Coast Guard regulates navigation generally, and may declare pipelines hazards to navigation. The Coast Guard also conducts annual safety inspections of ports, including pressure-tests of pipelines, and may close facilities that fail to meet its standards. State and local agencies issue permits for coastal activities, in accordance with their coastal zone management plans.

SAFETY CONCERNS

Marine pipelines operate in a physically and technically demanding environment. They are subject to severe weather, shifting sediments (especially in some areas of the Gulf), and a constant threat of corrosion. In California they also face seismic risks. New pipelines are being installed in deeper waters, farther offshore, where the large gas and oil discoveries have been made, but where operation and maintenance present even greater challenges (Figure 1-4). The costs of inspection, maintenance, and repair are also generally far greater than on shore.

The rapid growth in the number of firms operating marine pipelines has also caused some concern, because many are new entrants who have assumed control of major operators' older and less profitable pipelines in hopes of lowering operating costs. Today there are about 170 pipeline operating companies in the Gulf, up from about 65 a decade ago. It is essential that attempts to cut costs not interfere with adequate pipeline maintenance and safety. At the same time, all pipeline operators must contend with new regulatory costs, notably those entailed in the new standards for controlling oil pollution under the Oil Pollution Act of 1990.

Pipelines also must share the seabed and waters with vessels of all types, near some of the most heavily used cargo ports in the nation and some of the most productive commercial and recreational fisheries. The potential for interference with other users was underscored in the late 1980s by two fatal accidents in which fishing boats operating in shallow waters struck inadequately buried pipelines, with ensuing explosions, injuries, and deaths (Joint Task Force on Offshore Pipelines, 1990; National Transportation Safety Board, 1990). A more general concern is pipeline damage caused by anchors and fishing gear. Oil field service and supply boats are a particular concern near platforms, where their maneuvering threatens pipeline risers and their anchoring can damage pipelines on the seabed.

In addition, hurricanes, mudslides, and other natural forces can damage pipelines or cause them to fail. Oil spills from storms can be limited by shutting down and evacuating the platforms and pipelines. Still, disruption of this portion of the nation's energy supply for days or weeks is costly.

The ongoing shift of production to deeper waters will increase the need for attention to safety. Much of the existing offshore pipeline infrastructure—and particularly the transmission pipelines—will remain in service, carrying hydrocarbons from the new deeper fields. Deep water pipelines are relatively inaccessible to workers, and they operate at low temperatures, which encourage the formation of corrosive brines, icelike gas hydrates, and waxes; the resulting inspection and maintenance problems will require new and innovative solutions.

These trends have led the industry and its safety regulators to reexamine their approach to ensuring safety. They are asking fundamental questions:

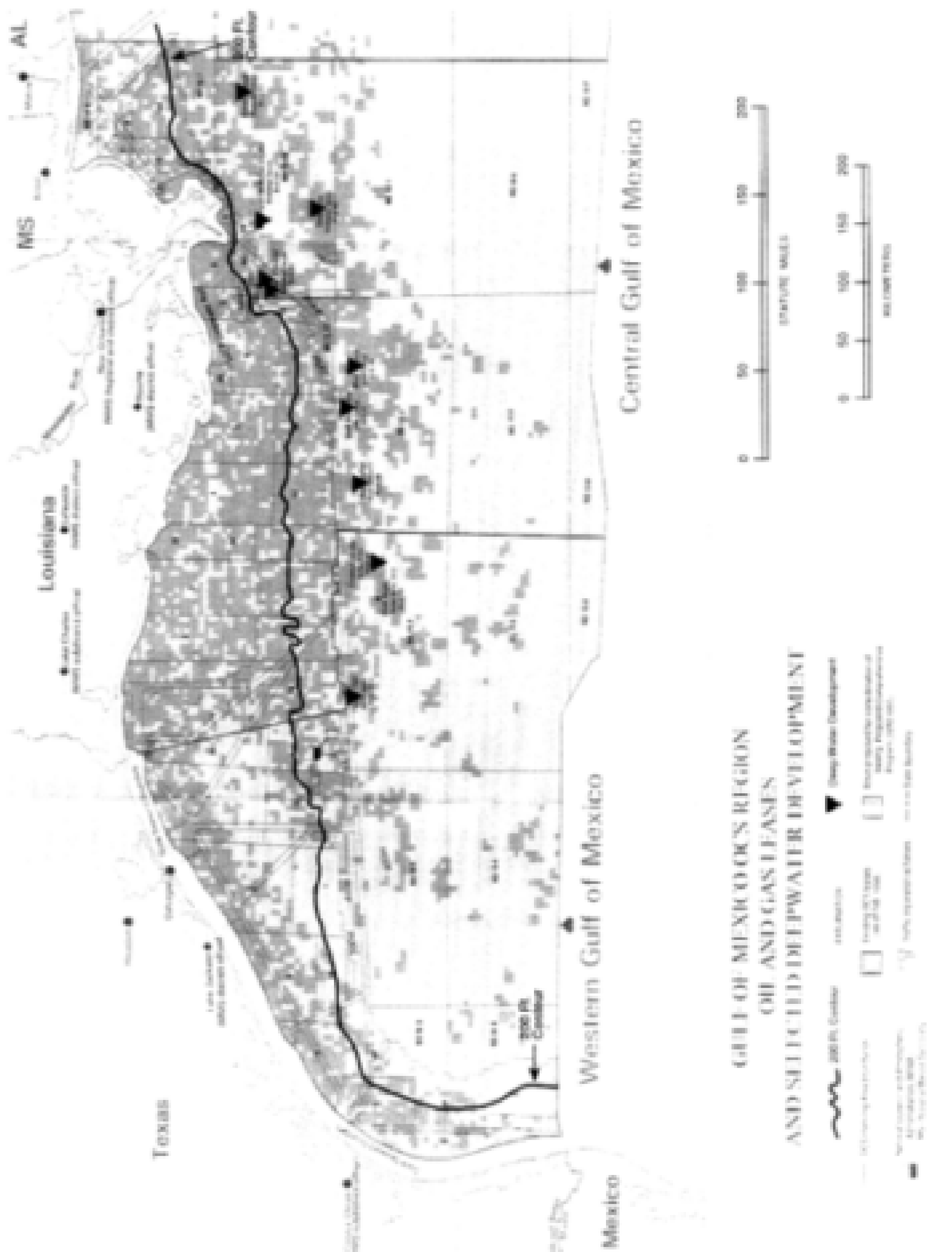

Figure 1-4 Offshore production areas in the Gulf of Mexico, showing active and proposed federal leases.

- What are the risks, and are they growing? Is maintenance technology keeping pace with the aging of the pipelines?
- Are today's inspection and repair techniques suitable for the new deep water pipelines?
- Are the measures taken to avoid interactions of pipelines with fishing vessels, cargo vessels, offshore supply and service boats, and recreational boats adequate?
- Do oil spill prevention and response requirements harmonize with the regulations to ensure personnel safety and protection of property?
- Do the industry and its regulators collect the right data to support decisions about risk abatement?

SCOPE OF THE STUDY

In considering these questions, this committee has limited its scope to the risks to human safety, environmental quality, and property associated with pipeline failures. Accidents and oil spills due to activities of drilling and production platforms are outside the committee's charge, as are the occupational risks of routine pipeline operations and maintenance. The committee has concentrated its assessment on the Gulf of Mexico, which contains the vast bulk of offshore pipelines.

Conditions in California the committee agreed, are so different from those in the Gulf of Mexico, in size, in history, and in geology, that it is difficult to generalize. The California oil fields are small in geographical extent. Their geological setting includes the risk of earthquakes. Development of the offshore fields there has been relatively recent, and has been regulated strictly by the state and federal authorities, with drilling limited and pipeline installation and maintenance subject to more thorough environmental oversight. Statistical studies of the national data on pipeline failures, for these reasons, cannot be considered representative of conditions in California. The committee has noted several specific features of California's offshore pipeline system and its operation, maintenance, and regulation that offer useful comparisons with the Gulf.

The committee excluded from consideration pipelines in harbors and waterways as well as those related to refinery and storage facility interconnections. Pipelines in Alaskan state waters were also excluded, in view of the special climate conditions and technical issues such as ice protection, which are unique to operations off the North Slope and in Cook Inlet.

INADEQUATE SAFETY DATA

Unfortunately, trends in the safety of marine pipelines are impossible to discern clearly, because the data are incomplete and unreliable. The several public agencies that regulate the industry have varied missions. Their individual efforts to investigate failures have not led to the development of a comprehensive safety data base. Data are collected inconsistently, without a well-thought-out or coordinated plan, and without a consistent focus on safety planning. Reports are often incomplete or inconclusive. Risk management on the basis of such limited information is challenging.

The Marine Board of the National Research Council, in an effort to improve the factual basis for safety planning, commissioned the most complete study yet of the available data on pipeline failures on the outer continental shelf (OCS), drawing on the 1967

1990 pipeline failure records of the MMS, the OPS, and the U.S. Coast Guard's National Response Center, for 1,047 incidents in all (Woodson, 1991). This study reveals some important broad patterns.

First, most damage to marine pipelines results in relatively small leaks of oil or gas, which may pollute the ocean and shore but are not serious threats to human safety. Pipeline oil spills of more than 50 barrels are rare (Minerals Management Service, 1992).

Injury or loss of life from pipeline damage is also rare, but not unknown. Natural gas pipelines in particular (about 70 percent of the offshore pipeline mileage) hold the potential for explosions. Several accidents in the late 1980s, involving natural gas explosions associated with pipeline damage, resulted in deaths, injuries, and substantial property damage (see Chapter 2).

Corrosion, the reported cause of about half of the pipeline failures on the OCS between 1967 and 1990, generally produces small leaks. The resulting pollution—in the case of oil or gas condensate pipelines—averages about 13 barrels (or, if one excludes a single 5,000-barrel spill in 1973, about 6 barrels).

Vessel groundings or damage by anchors, nets, and trawl boards, while less common, produced the vast majority of pollution, and occasionally injuries and deaths. More than 95 percent of the pipeline-related pollution on the OCS was due to such incidents. And more than 95 percent of that pollution (90 percent of all marine pipeline spills, by volume) was due to anchor damage. (A single 160,000-barrel spill in 1967, caused by an anchor drag, accounted for nearly two-thirds of the pipeline spills, by volume.)

The data base does not lend itself to detailed statistical analysis, owing to the variability of data collection standards from agency to agency and over time, the lack of precise information on pipeline locations, and gaps in the record. Because the data base is limited to the OCS, it does not support analysis of incidents in state waters, which house older pipelines and those most exposed to damage from vessels and storms. Nor can it show trends over time in rates of pipeline failures from different causes. The locations of pipeline failures—which might reveal patterns in anchor damage or corrosion—cannot be assessed systematically. Relationships between failure rates and length of service or product carried cannot be established, although such information would be extremely valuable in safety planning and should be assigned a high priority in future risk assessment efforts.

Assembling a more useful data base should have a high priority, but will take years. Meanwhile, modern risk analysis can guide the industry and its regulators in focusing their abatement efforts. Some of these techniques are outlined in Chapter 3 of this report.

FINDINGS

Operators and regulators are seeking better assurance of the safety and integrity of marine pipelines. The importance of the marine pipeline infrastructure to the nation's economy, and the potential human, environmental, and monetary costs of damage, make this effort vital.

Safety concerns are not to be taken lightly. There are significant unknowns in the safety record, owing to inadequate data collection by regulatory agencies, and safety trends over time are simply not available. However, enough is known to support development of risk management measures, guided by quantitative risk assessment, which affect pipeline design and operations and safety regulations. This report lays the groundwork for taking such measures.

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2

Safety Experience

The hazards presented by marine pipelines are not to be taken lightly: environmental and property damage and, albeit rarely, human injury and death. Vessels maneuvering in shallow water may dent or rupture pipelines, releasing explosive or environmentally damaging hydrocarbons. In deeper water, fishing vessels sometimes snag nets and other gear on valves and other pipeline features, tearing the nets and occasionally causing leaks. Larger vessels may drag their anchors across pipelines, bending or cracking them. Internal and external corrosion are pervasive threats of leaks. Storms and seafloor mudslides may move, damage, or expose once-buried pipelines, allowing anchors and nets to foul them. Objects dropped from vessels or platforms can also damage pipelines. During the late 1980s the 17,000 miles of pipeline in the waters of the U.S. outer continental shelf (OCS) experienced a leak or other reportable failure about once every five days, owing to one or another of these causes (Woodson, 1991).[1]

Most pipeline failures result in relatively small leaks of oil or gas, which may pollute the ocean and shore. While pipeline oil spills of thousands or even tens of thousands of barrels occur occasionally, between 1967 and 1990 an average of only 10,585 barrels annually of oil pollution from marine pipelines was reported to federal regulatory agencies on the OCS (Woodson, 1991).

Oil pollution of the Gulf from pipelines is roughly comparable to that from tank vessel accidents, but with great variation from year to year. Another source, probably much greater, is runoff from urban and industrial areas in the Mississippi watershed. Natural seeps are also estimated to be very large sources. Oil remaining in the oil and water mixture produced by offshore oil wells (called "produced waters") probably contributes several times as much oil to the Gulf as pipelines or tanker accidents. Judging the relative impacts of these sources is beyond the scope of this study.

Injury or loss of life as a result of pipeline damage is rare, but not unknown, and it is these risks that are perhaps most prominent in the public mind. Natural gas and natural gas liquid pipelines in particular (about 70 percent of the marine pipeline mileage) hold the potential for explosions. A series of dramatic accidents in the late 1980s, involving

[1] For this committee the term "failure" includes any damage that is required to be reported to safety regulators. Such damage may range from small pin hole leaks caused by corrosion to major failures resulting in fires, explosions, or large oil spills.

natural gas explosions associated with pipeline damage, resulted in deaths, injuries, and substantial property damage.

The *Sea Chief* accident. In July 1987, while working in shallow coastal waters off Louisiana, the menhaden purse seiner *Sea Chief* struck and ruptured an 8-inch natural gas liquids pipeline operating at 480 psi. The resulting explosion killed two crew members. Divers investigating found that the pipe, installed in 1968, was covered with only 6 inches of soft mud, having lost its original 3-foot cover of sediments (Joint Task Force on Offshore Pipelines, 1990). (Chapter 5 outlines the activities of the menhaden fishing fleet.)

The *Northumberland* accident. October 1989 saw a strikingly similar accident, with even greater consequences. The menhaden vessel *Northumberland* struck a 16-inch gas pipeline in shallow water near Sabine Pass, Texas. The vessel was engulfed in flames; 11 of the 14 crew members died. The pipeline, installed in 1974 with 8 to 10 feet of cover, was found to be lying on the bottom, with no cover at all (National Transportation Safety Board, 1990).[2]

Sonat/Arco, South Pass 60. In March 1989 a flash fire and explosion occurred on a Sonat/Arco platform in lease block South Pass 60, during repair of an associated pipeline. Seven of the platform crew died, and ten others were injured. Property damage totaled about $70 million. Investigation showed the incident had been caused by human error, leading to the sudden release of gas and liquids from the pipeline cut during repair work (which had been occasioned by damaged from an anchor line). The repair was complicated by the operator's failure to update pipeline drawings, which left the workers unaware of a subsea valve assembly that would have made the repair easier and safer (U.S. Department of Transportation, 1989).

These events illustrate the most catastrophic risk posed by pipelines: the possibility of human deaths. They have understandably aroused public and congressional concern about the overall safety of the offshore pipeline industry. Most of the events of interest are less serious, involving releases of gas or oil caused by corrosion or mechanical damage to pipelines and by natural forces, such as mudslides, and destabilization by storms and hurricanes.

The industry and its regulators are reexamining their approaches to safety in the light of this experience. This study seeks to help define the risks and to assess the adequacy of measures to control those risks. This chapter reviews what is known about the safety record.

DATA SOURCES

Various federal and state agencies independently collect data on pipeline failures:

- The Minerals Management Service (MMS) of the U.S. Department of the Interior, requires operators to report "serious accidents," including all spills of oil and deaths or serious injuries, on the OCS (seaward of state waters). These reports go back to 1967.
- The Department of Transportation's Office of Pipeline Safety (OPS) requires

[2] A subsequent survey of shallow-water pipelines, ordered by Congress through the Office of Pipeline Safety, found only a small fraction of the mileage (1.7 percent) with less than 1 foot of cover. These pipelines are now required to be reburied.

pipeline operators to report all pipeline failures involving damage, death or injury, or pollution above certain thresholds. These reports extend from 1984 to the present.

- The U.S. Coast Guard's National Response Center, since 1982, has received immediate telephone reports of spills of oil or other hazardous substances that meet or exceed thresholds established by the U.S. Environmental Protection Agency. (Even a light sheen of oil is sufficient to trigger a report.)
- Most state agencies have rudimentary records of pipeline failures in their waters. (California is an exception, with a comprehensive record of failures in state waters going back more than a decade.)

LIMITATIONS OF THE SAFETY DATA

The several data sets on past pipeline failures, assembled independently, for varied purposes, by agencies with different (and changing) reporting requirements, and over different periods, cannot be expected to provide clear pictures of safety trends over time, or of subtle relations between operating or design practices and safety consequences. Only the broadest of patterns can be discernible in such a data base.

The agencies have collected data inconsistently, without interagency coordination, and often without a strong focus on safety planning or priorities. The reliability of the safety data is also limited by the unevenness of the agencies' data collection programs, which have widely varying reporting requirements (and varying incentives and disincentives for reporting). Some incidents are not reported at all (Bea, 1992; Donnell, 1992). Others are reported in more than one place (Mandke, 1990; Woodson, 1991).

As a result, data that would be useful in a thorough and detailed analysis of failures, their causes, and possible preventive or corrective measures are not requested or reported. The historical information to allow useful correlations between failure modes and such factors as pipeline age, type of pipeline, seafloor soil conditions, and water depth does not exist. Finally, the reported causes and consequences of failure identified by incident reports are often inaccurate, and follow-up reports are not always made.

Safety planning on the basis of such limited information is challenging, but not impossible. Modern techniques of risk analysis can guide the industry and its regulators in setting risk management priorities. Some of these techniques are outlined in Chapter 3 of this report, along with the framework of a risk analysis approach of a type that could be applied to the marine pipeline industry.

Minerals Management Service

The Minerals Management Service has the most comprehensive data-gathering program on pipeline failures on the OCS (Minerals Management Service, 1992; Woodson, 1991). The MMS requires more detailed accident information than OPS, and has an incident reporting system that follows up more thoroughly on the corrective measures taken. Under MMS regulations, all spills of oil must be reported both by telephone and in writing to the MMS District Supervisor. Reports must include the cause, location, volume of spill, and remedial action taken. Reports of spills of more than 50 barrels must include information on sea state, weather, and size and appearance of the spill (30 CFR 250.41). Serious accidents, deaths or serious injuries, and any fires, explosions, or blowouts on any pipeline area covered by an MMS permit must be reported (30 CFR 250.19). Appendix B is the Minerals Management Service form for reporting offshore accidents, oil spills, and blowouts.

The agency has compiled these reports, with some variations, since 1967. In addition, it routinely gathers OPS reports of incidents on the OCS. However, its data are confined to the OCS, and therefore do not shed light on many of the most important issues, such as the safety record of older pipelines, which are disproportionately located in the shallower state waters nearer shore.

MMS keeps detailed maps of all OCS pipelines (including OPS-regulated pipelines), which it is in the process of digitizing, with accident data, net hang sites, abandoned lines, and other information. To carry out its pollution prevention and response duties under the Oil Pollution Act of 1990, MMS will add data on pipelines in state waters (see Chapter 6).

Office of Pipeline Safety

OPS has collected data on marine pipeline failures, in both OCS and state waters, since 1984:

- Operators of pipelines carrying hazardous liquids such as oil must report in writing (DOT Form 7000-1 [Appendix C]) any pipeline failures resulting in explosion or fire, loss of 50 or more barrels of hazardous liquid, escape to the atmosphere of more than 5 barrels per day of highly volatile liquids, death or serious injury, or property damage estimated at $5,000 or more.
- Gas pipeline operators are required to report "incidents" (events involving releases of gas, death or injury requiring hospitalization, or property damage estimated at $50,000 or more) in writing (DOT Form RSPA F 7100.2-1 [Appendix D]).

Because of the high cost of making pipeline repairs offshore, the property damage thresholds result in essentially all failures of OPS-or MMS-regulated marine pipelines being reported. Telephone reports in either case are made immediately to the U.S. Coast Guard's National Response Center (described below).

The two-page incident reporting forms used by the OPS request only the most basic and preliminary data about incidents (operator, location, numbers of deaths and fatalities, estimated property damage, estimated size of any spill, and apparent cause). They do not lend themselves to statistical interpretation, because they do not require precise enough information on the location and nature of damage, and because follow-up reports confirming initial estimates are often not completed. The agency does not publish separate safety statistics for marine pipelines. In addition to the incident reports, "safety-related conditions" such as material defects, corrosion, or undue loading or movement of a pipeline by events such as earthquakes must be reported. OPS intends to propose expanding the reporting form to collect more information (personal communication, Cesar DeLeon, July 27, 1993). Details of this proposal were not available to the committee.

The reporting thresholds have varied substantially over the years, making it hard to establish trends in rates of incidents (Woodson, 1991).

U.S. Coast Guard, National Response Center

The U.S. Coast Guard's National Response Center (NRC) has collected data on oil spills since 1974, under the Federal Water Pollution Control Act of 1973 and several subsequent laws, including the Comprehensive Environmental Compensation and Liability Act, the Clean Air Act, the Toxic Substances Control Act, and the Resource Conservation and Recovery Act. The NRC receives telephone reports of spills of oil or other hazardous substances that exceed thresholds established by the U.S. Environmental Protection Agency, and dispatches the necessary information to designated spill response teams. The reports cover all navigable waters of the United States.

For pipeline spills, the NRC is designated by OPS regulations as the recipient of immediate telephone reports. It began collecting these reports in 1982.

State Agencies

Few state agencies have made substantial efforts to collect safety data on marine pipelines until quite recently, preferring to rely on the OPS for data of this kind. Repeated inquiries by this committee at the Texas General Land Office (GLO) and the Louisiana Department of Natural Resources drew no response until mid-1993, when the GLO produced a printout of failures in Texas waters, without accompanying analysis. Louisiana provided no such information for the many miles of pipelines in its waters. California, with its 300 miles, is an exception; the State Lands Commission of California has recorded offshore pipeline failures since at least 1980 (Woodson, 1991).

PREVIOUS STUDIES

Several recent studies have been made of the marine pipeline failure data collected by the various regulatory agencies. The committee examined three in particular.

The Woodson Data Base

The most complete study yet of the available data on offshore pipeline safety was commissioned by the Marine Board of the National Research Council (Woodson, 1991). For the Gulf of Mexico OCS, the resulting data base records every failure of a gas, crude oil, or condensate pipeline reported to OPS, MMS, and the NRC between 1967 and 1990, in addition to 46 failures reported in an article by M. D. Reifel (1978). In all, the data base contains records of 1,047 events.

Woodson tabulates incident reports according to the following structure:

- Number of reported events per failure mechanism and per year;
- Number of reported events per failure mechanism and per month (thus accounting for weather patterns);
- Number of reported events per failure mechanism and per nominal pipe diameter;
- Number of reported events due to corrosion as a function of pipeline age; and
- Number of reported events per failure mechanism in buried and exposed pipelines.

The data base has significant limitations, reflecting the weaknesses of its data sources:

- Many of the reports compiled by Woodson are incomplete, with missing information on the causes of incidents, the ages of failed parts, and other important data.
- Because it is restricted to the Gulf of Mexico OCS, it leaves out incidents in state waters, nearer shore, which contain the oldest pipelines and those most exposed to collisions by vessels.

- Notably absent from this data base is information on the locations of failures (beyond specifying the the MMS lease blocks in which they took place), which would help highlight geographical patterns, such as the relation between offshore platforms and anchor damage (today poorly known).

The Woodson data base also excludes California. That state, with only about 300 miles of offshore pipeline, compared with the more than 20,000 miles in federal and state waters in the Gulf—is not critical to a statistical study of offshore pipeline safety.

Other Studies

J. S. Mandke (1990) of the Southwest Research Institute analyzed MMS pipeline failure data for the Gulf of Mexico (690 reported failures between 1967 to 1987). The aim was to relate pipeline failure trends to variables such as pipe size, failure location, nature of repair procedure, and reported failure cause. Mandke divided causes of incidents into five categories: material or equipment failure, operational problems, corrosion failures, storms and mudslides, and mechanical damage (including damage from anchors, fishing nets, and vessel hulls). Mandke's data, like Woodson's, are limited to the OCS. (In fact, his data are a subset of Woodson's.) However, his analysis provides useful insights about oil spills and other risks.

Larry Broussard (1992) of Tenneco analyzed pipeline failure reports to the OPS from 1984 to 1990, using similar categories to those of Woodson and Mandke. Broussard's data cover transmission lines in both state and federal waters.

CAUSES OF FAILURE

Reported causes of failures are not reliable; they are often determined by guesswork, without complete investigation or repair. Follow-up or "supplemental" reports are sometimes not made (U.S. Department of Transportation, 1989). In addition, different categories of causes cannot be regarded as entirely distinct, because of the likelihood of multiple failure modes. For example, a corrosion-weakened pipeline ruptured by storm or anchor damage would generally be reported as failing due to storm or anchor damage, not corrosion. (In fact, corrosion reports tend to decline after major storms [Woodson, 1991].) With these limitations in mind, however, it is possible to make some generalizations.

Causes of failure are categorized differently by the three analysts (Table 2-1). For comparison, they can be divided into the following broad categories:

- Corrosion (external and internal);
- Maritime activities (anchors, nets, trawls, and vessel contact);
- Natural forces (storms, hurricanes, and mudslides); and
- Other/unknown (including events attributed to "material failure").

It can be seen from Table 2-1 that the three data bases are roughly consistent in the percentages of failures attributed to each of these causes. The Woodson data base is the most comprehensive, and will be the basis of the following analysis, except where noted otherwise.

Corrosion—internal and external—is the most widely reported cause of failure (50 percent of the incidents whose cause is reported), followed by maritime activities (anchor

TABLE 2-1 Marine Pipeline Incidents, by Reported Cause (Numbers of Occurrences and Percentages of Totals)

	Percentage of total incidents attributed to each cause, by compiler and source of data (number of incidents per cause in parenthesis)		
Cause of failure	Woodson (MMS data, 1967-90)	Mandke (MMS data, 1967-87)	Broussard (OPS data, 1984-90)
Corrosion (internal and external)	50 (456)	50 (343)	45 (38)
Material failure	10 (94)	9 (63)	14 (12)
Third party—nets, boats	14 (124)	21 (138)	
Storms/mudslides	12 (106)	12 (82)	
Outside forces			31 (26)
Other or unknown	15 (136)	9 (63)	10 (8)
Total (may not add, due to rounding)	100 (916[a])	100 (690)	100 (84)

[a] Of the 1,047 incidents tabulated in the Woodson data base, only 916 included information on reported causes.

and net damage and vessel collisions) at 14 percent and natural forces (storms and mudslides) at 12 percent (Figure 2-1).

There appears to be no correlation between the product carried in the pipeline and the reported failure cause (Table 2-2). This result is intuitively satisfying for all major categories except corrosion; gas lines might be expected to have higher rates of internal corrosion, because the produced brines and other corrosive substances are less easily carried off by the product.

It is impossible to draw firm conclusions about the relative roles of internal and external corrosion, because more than one-third of the corrosion failure reports do not specify the location of corrosion. Mandke's (1990) analysis, however, shows that about 70 percent of corrosion failures occur in lines 6 inches or less in diameter, and that 78 percent take place at platforms, either in risers (vertical pipeline extensions from the seabed to the surface) or on the adjacent seabed. Industry experience suggests that many of these failures occur in production flowlines, in risers (through external corrosion in the splash zone or under clamps), and at the pipe bend where the riser meets the seabed (through internal corrosion on the pipe bottom). However, the data are insufficient to establish these patterns without doubt.

Relationships between failure rates and length of service cannot be established either. Such information would be extremely valuable in safety planning, and should be assigned a high priority in future risk assessment efforts.

CONSEQUENCES OF PIPELINE FAILURES

Like the causes of failures, the consequences are often inaccurately reported. Reports of incidents include preliminary estimates of the property damage or the size of oil spills, for example. These estimates are not always made by qualified observers. In any case, it is generally impossible to assess damage without carrying out detailed inspections and repairs. Depending on the agency involved and the willingness of the operator to file supplementary reports, these revised estimates may or may not find their ways into the official record (U.S. Department of Transportation, 1989).

Still, some broad conclusions can be drawn about the risks of different failure mechanisms.

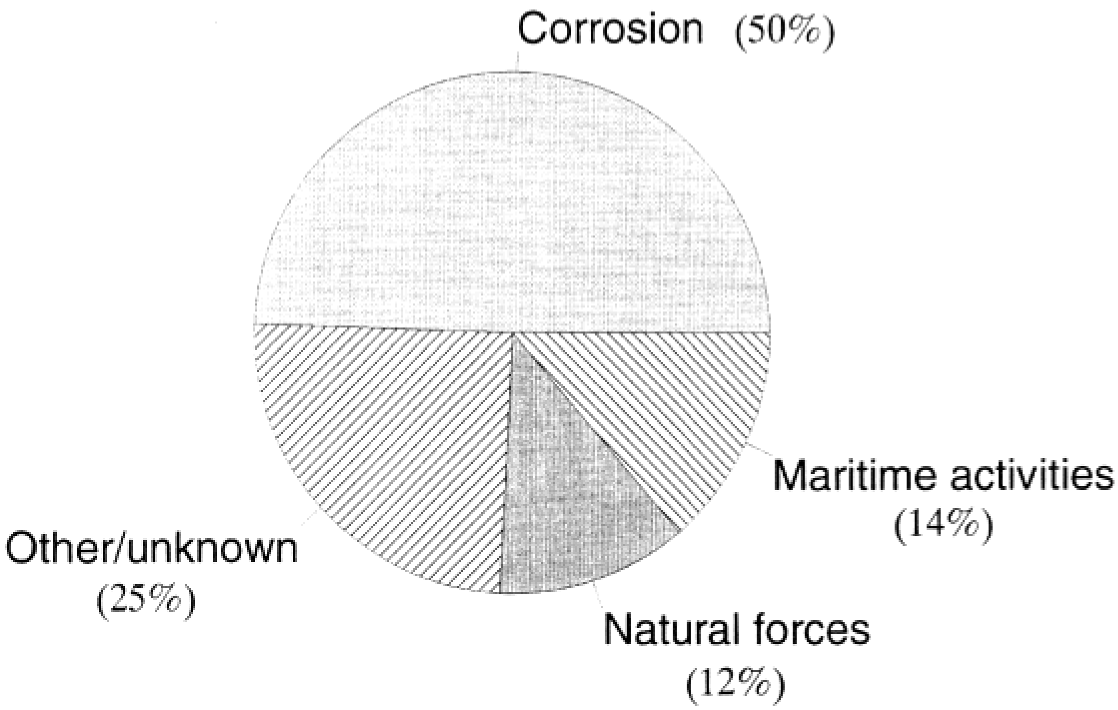

Figure 2-1 Pipeline failures, by reported cause.

TABLE 2-2 Reported Failure Causes, by Product Carried

	Percentage of failures attributed to each category of cause in:	
Reported cause	Oil lines	Gas lines
Corrosion	48	50
Maritime activities	14	12
Natural forces	14	8
Other/unknown	24	30
Total	100	100

Deaths and Serious Injuries

Fatalities and injuries are rare in connection with pipeline failures. (This committee excluded from its consideration injuries and deaths incurred in routine pipeline operations and maintenance unconnected with pipeline failures.) The committee has found only six cases since 1967 in which offshore pipeline failures were associated with deaths or serious injuries in the United States. The *Northumberland* and *Sea Chief* accidents, already described, resulted from vessel collisions with gas and gas condensate lines in shallow water. The Sonat/ Arco accident, also described earlier, resulted from the inadequate isolation of a platform from a gas pipeline undergoing repairs. Two serious injuries occurred in 1990 during repairs of the Sonat Sea Robin system (a gathering system

TABLE 2-3 Deaths and injuries associated with pipeline failures, by source, 1967-1990

Accident	Date	Number of fatalities	Number of injuries	Pipeline type
Placid, Eugene Island 296[a]	1975	3	0	Gas?[b]
Chevron, Ship Shoal 266[a]	1979	1	1	Gas condensate?[c]
Sea Chief	1987	2	1	Gas condensate
Northumberland	1989	11	3	Gas
Sonat/Arco, South Pass 60	1989	7	10	Gas
Sonat Sea Robin	1990	0	2	Gas

Source: Data from Minerals Management Service.
[a] Not reported in Woodson data base.
[b] Not specified in MMS data base, but circumstances (explosion during repair, no pollution) strongly suggest gas.
[c] Not specified in MMS data base, but circumstances (explosion during repair, more than 50 barrels pollution) strongly suggest gas condensate.

for multiple production pipelines), when a pig trap receiving door failed to operate correctly.[3] Two earlier incidents (in 1975 and 1979) involved pipeline repairs that resulted in fatal explosions.[4] Table 2-3 tabulates these deaths and injuries.

All of the deaths and injuries are associated with gas or gas condensate lines, which operate under pressure—often very high pressures—and can be violently explosive.

Pollution

The offshore oil and gas industry accidents and incidents produce surprisingly little pollution, compared with several other causes and sources noted earlier. Worldwide, offshore production accounts for about 1.6 percent of the oil released into the oceans by human activities (National Research Council, 1985). Failures of transmission and production pipelines are responsible for about 98 percent of the accidental releases from offshore production activities in U.S. waters, by volume (Alvarado et al., 1992).[5]

While corrosion is the most commonly reported cause of pipeline failures, it rarely results in large spills. Between 1967 and 1990, more than 95 percent of the pollution from pipelines on the OCS was due to maritime activities, which tend to produce much larger spills (Figure 2-2). And more than 95 percent of the pollution from maritime activities (90 percent of all marine pipeline spills, by volume) was due to anchor damage, as shown in Table 2-4. (A single 160,000-barrel spill in 1967, caused by an anchor drag, accounted for nearly two-thirds of all the pipeline spills in the Gulf OCS, by volume.)

Although some of the anchor damage has been attributed to supply vessels servicing platforms, the data do not permit comparing the anchor damage from vessels performing services for platforms with that from vessels more distant from platforms, which could be attributed to general maritime traffic. This information would be helpful in determining

[3] A pig trap is a fitting attached to a pipeline to launch or receive a pig (an internal cleaning, batch separating, or inspection device).
[4] The 1988 *Piper Alpha* disaster in the North Sea, which killed 167, should be kept in mind. In that event, an offshore platform was destroyed in a fire fed by gas from a connecting pipeline. Property damage came to $3 billion (Cullen, 1990; Paté-Cornell, 1993).
[5] The term "offshore production activities" includes not only drilling and production, but also pipelines and supporting services. It does not include transportation by tanker or barge.

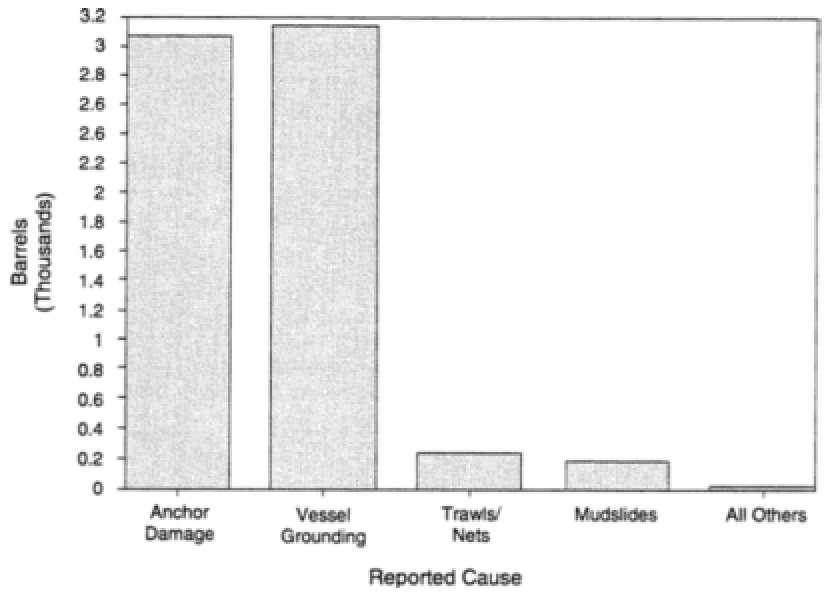

Figure 2-2 Average pollution amount per incident, by reported cause of failure.

TABLE 2-4 Pollution from marine pipelines, by reported cause of failures. 1967-90

Cause	Number of incidents	Pollution volume (bbl)	Average pollution per event (bbl)
Corrosion, total	456	5,882	13
External	186	105	< 1
Internal	115	5,649	49
Not designated	155	128	< 1
Maritime activities, total	124	241,345	1,946
Anchor damage	77	230,357	2,992
Vessel grounding	2	6,330	3,165
Trawls, nets	19	4,504	237
Other	28	157	6
Natural forces, total	106	3,930	37
Mudslides	20	3,886	194
Storms and other	80	44	< 1
Other or unknown	230	2,886	13

Source: Woodson (1991)

to what extent anchoring precautions or mooring systems at platforms would help reduce pollution.

The distribution of spill sizes is also important, because large spills are disproportionately likely to do significant environmental damage. On the Gulf of Mexico OCS, from 1967 to 1987, more than 80 percent of the pipeline spills were of 10 barrels or less, as shown in Figure 2-3 (Mandke, 1990). Only 20 pipeline spills between 1971 and 1990 on the OCS exceeded 50 barrels (Minerals Management Service, 1991, p. 9).

In the Woodson data base, the four largest spills—all caused by anchor damage, and totaling 211,047 barrels—accounted for 85 percent of the volume of pollution from pipelines. The top 11—all but one-of them caused by maritime activities and natural forces—produced 98 percent of the pollution. The remaining 1,036 pipeline failures were responsible for only 2 percent of the pollution, averaging just 5 barrels per failure.

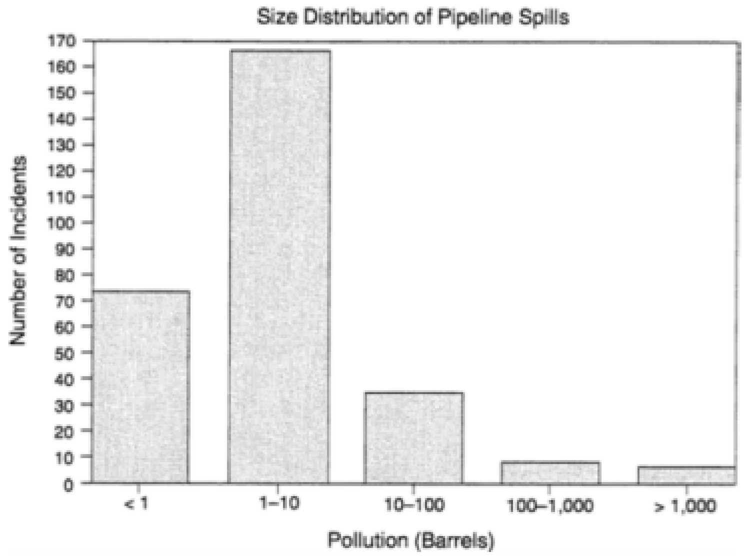

Figure 2-3 Size distribution of pipeline spills, 1967-1987 (Mandke, 1990).

Corrosion releases average less than 13 barrels, according to Woodson's data. (In fact, if one excludes a single 5,000-barrel release in 1973, attributed to internal corrosion, the average is more nearly 2 barrels.)

Economic Costs

The economic costs of individual pipeline failures, in terms of property damage, repairs, lost revenues, and deferred production, are hard to estimate from the pipeline failure data base. As noted earlier, the data base includes mainly preliminary estimates of property damage, which are highly unreliable, and often incomplete. However, the experience of Hurricane Andrew, in September 1992, suggests that large-scale disruptions of the marine pipeline network can be devastating. That storm shut in production for weeks in a large part of the Gulf of Mexico, damaging 393 pipeline segments, of which only 219 had been returned to service by the following March (personal communication, E. P. Danenberger, Minerals Management Service, May 13, 1993). (Some of the reduction in numbers is due to the fact that many segments were rerouted and reconnected to other segments in the same systems because intermediate platforms were destroyed.) While the safety and environmental consequences were minor (no deaths or injuries, about 2,000 barrels of pollution, 1,000 barrels of which were recovered), the repair costs, loss of production and pipeline revenue, and interruption of national energy supplies were heavy. The consequences were contained by the industry's longstanding practice of shutting down platforms and isolating pipelines on the approach of a severe storm.

Such disruptions, whether they take place—like Andrew's—over a few weeks and months or over years of slow deterioration caused by inadequate maintenance, must be avoided.

FINDINGS

Analysis of incidents involving marine pipelines is extremely difficult, owing to the inconsistency of data collection by the various federal and state agencies with safety jurisdiction, and the lack of a shared focus on safety planning in data collection. Only for the outer continental shelf are there any organized data on offshore pipelines. In particular, data are insufficient to establish relations between (a) corrosion and pipeline length of service, (b) anchor damage due to supply vessels working at platforms and that from other vessels, remote from platforms, (c) corrosion and the product carried, or (d) corrosion and location along the pipeline (on the riser, at the riser bend, or on the seabed).

However, analysis of the 1,047-incident Woodson (1991) data base does yield some important patterns:

- Corrosion, although it was the reported cause of nearly half of OCS pipeline failures from 1967 to 1990, produced only about 2 percent of the pollution from pipelines and no deaths, injuries, or damage to the property of third parties.
- Damage from vessels (and especially from anchors and groundings) is dramatically more significant as a source of pollution and other consequences, including deaths and injuries. Anchor damage alone accounts for more than 90 percent of the pipeline-related pollution on the Gulf OCS.
- A few incidents have resulted in the majority of consequences for public safety and the environment:
  - The 4 largest pipeline spills, all caused by anchor damage, accounted for 85 percent of the pollution from pipelines on the Gulf OCS between 1967 and 1990. The largest 11, all but one caused by vessels, produced 98 percent.
  - Six accidents (two vessel groundings and four repair activities) have resulted in all of the deaths and injuries.

Better efforts must be made to collect and assemble safety data. In the meantime, risk analysts must use the data that is already available.

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3

Risk Analysis: Hazards and Zonation

The lack of consistent and comprehensive data on the safety record of offshore pipelines is a severe challenge for safety planning. Yet modern risk analysis techniques can help make sense of the data, using inferences guided by expert opinions and physical models of the nature of the risks and their distributions in location and time. Risk analysis involves identification of failure scenarios, computation of probabilities for accidents or failures for each scenario, and assessment of the consequences of a failure or accident. Use of this techniques enables industry and its regulators to set risk management priorities more rationally, more cost-effectively, and more consistently. This chapter describes the broad structure of a quantitative approach—a mathematical model—that embodies those techniques.

Risk analysis, generally, is the science of estimating risks, so that priorities for their management can be developed. This analysis can provide information fundamental to the formulation of risk management strategies for industry, as well as the federal and state government agencies that have jurisdiction over the enforcement of pipeline safety regulations. The use of risk analysis results for risk management purposes permits identification of high-risk situations and assessment of their evolutions caused, for example, by variations in vessel traffic or by shoreline erosion. Risk levels, in turn, affect the needs for safety measures, including the frequency and extent of pipeline inspection, the depth of burial, and the need for resurveying pipeline locations.

In policy making, risk analysis provides guidance in developing and promulgating regulations, implementing public laws, establishing right-of-way corridors for pipelines, or formulating requirements for the design of pipelines, such as the capability for handling internal inspection devices. Occasionally, it may also be necessary to modify existing regulations about pipeline design, location, depth of burial, and other parameters based on physical changes that modify the risk patterns (including, as mentioned above, shoreline erosion and changes in the vessel traffic). These changes would appear in the long-term process of gathering data for a regular estimation and updating of the risks. New regulations guided by the risk analysis results need not be more restrictive, but they will be better targeted. Indeed, they should be more flexible to reflect the variations in the values of risk parameters such as water depth and pipeline density along the selected coastal zones.

In industry, risk analysis can support routine choices of resource allocations (e.g., inspector assignments, aircraft or helicopter inspection overflights, resurveys of lines, and frequency of internal pipeline inspections). While pipeline regulations establish general requirements, industry keeps some latitude to operate within the regulatory range. Based on the data base generated by risk analysis and regularly updated, the operators can set priorities that should allow more cost-effective risk management both at the policy and the industry level.

The objective of risk analysis is to focus the data and information that is available or readily attainable to make decisions about using resources in the most effective way to enhance pipeline safety. It is technically and economically impossible to reduce to zero the risks to individuals and to property, no matter how much government and industry are willing to spend. Yet an acceptable level of individual safety must be provided to vessel crews and platform workers, and the risk of marine pollution must be evaluated and controlled. Many potential safety measures can be considered, such as making more accurate maps of existing pipelines, burying exposed pipelines, inspecting and maintaining pipelines, and protecting pipelines against corrosion. In addition to technical measures, organizational measures can be considered, such as streamlining the regulatory system to make risk management strategies more coherent and cost-effective. None of these measures is 100 percent effective, and most are costly. Thus, a reasonable objective is to optimize the allocation of the current resources to obtain maximum safety, or to reach a specified safety target at minimal cost. The following questions then must be addressed:

- What is the current risk in the different areas?
- What can be done, and with what prospect for risk reduction?
- What are the costs of these measures?
- When can one consider that an acceptable safety level has been achieved?

This chapter outlines a risk analysis approach designed to compute the initial risk and the risk reduction benefits of safety measures. It also contains a set of safety goals for the management of marine pipelines. In both cases, data must be gathered and objectives specified by the agencies and the industry. Calculation of the risk involves both the probabilities and the consequences of different types of accidents in different geographic zones. The different dimensions of the risk results include a variety of consequences, expressed as the probability of human casualties, the amount of oil spilled (and the consequent environmental damage), and the property damage to pipeline owners and others. The risk reduction benefits can then be estimated for different options by computing the differences of the expected values of these consequences with and without the proposed measures.

The risk analysis model described here is a prototype, intended to be developed further. It involves five categories of accident or incident initiators ("initiating events"):

- A vessel's hitting an exposed pipeline;
- A vessel operator's dropping or dragging an object such as an anchor or a heavy tool on a pipeline;
- A pipeline's leaking because of corrosion
- A pipeline damaged by the forces of waves and disturbance of the sea floor in storms and hurricanes; and

- A pipe failure at the interface between platform and pipeline, caused either by overload (e.g., excessive internal pressures) or reduced strength (equipment deterioration).[1]

The probabilities and severities of incidents of the last category depend largely on the equipment and the mode of operation of each platform. This chapter focuses mainly on the first four accident types. In the risk analysis model, the last category (pipe failure at the site of a platform riser connection) is treated separately for each individual platform or type of platform, assuming that a probabilistic risk analysis has been performed for the platform/pipeline system.

The risk analysis model is designed mainly for the Gulf of Mexico. Clearly, the risk is higher in some areas of the Gulf than in others. The high-risk areas include zones of high density of pipelines, of high density of vessel traffic, of shallow waters where fishing vessels can collide with live gas pipelines, and the immediate vicinity of platforms. In addition, one may want to consider other types of regions, such as zones of severe erosion and shift of the sea floor, and zones that are most likely to be affected by hurricanes and storms. For simplicity it is assumed in this chapter that these phenomena affect the Gulf in a fairly uniform way and, therefore, do not require separate partitions. In fact, these risk factors can vary substantially from place to place. For example, seafloor shifts are more likely to occur in certain areas, such as those with steeper slopes or soft soil deposits at the mouth of the Mississippi River. The assumption of uniformity that is made here can be easily relaxed.

The risk analysis model thus relies on a zonation of the Gulf region by superposition of three maps: a map of water depth also showing the limits of the outer continental shelf (OCS), a map of vessel traffic densities, and a map of pipeline densities. In further development of the model, other types of zones may be added, such as areas of extremely weak sediments that are subject to fluidization when agitated, or additional navigation zones based on the drafts of different types of vessels. The result of this superposition is a finer partition of the region into "min-zones" defined by the local values of these three parameters. An alternative approach would be to compute the risk per mile of pipeline; but the risk posed by different segments of the same pipeline is not uniform because it depends, for example, on vessel traffic. The zonation approach was therefore preferred.

There is no need for a different set of safety regulations for each zone. Yet, some zones require higher safety levels than others, for example, because the vessel traffic density is higher there than elsewhere. The objective of this zonation-based risk analysis is to set priorities, first among zones according to their characteristics (e.g., vessel traffic density), and second among failure modes according to the relative risks involved and the costs of reducing them. For instance, it might become evident that further investment in corrosion protection may not be as cost-effective as other measures such as provision of moorings at platforms.

The use of risk analysis models based on zonation has proved useful in other cases to set priorities in risk management. For example, a risk-based zonation of the United States supports the seismic provisions of building codes (Applied Technology Council, 1982; Federal Emergency Management Agency, 1986; International Conference of Building Officials, 1982). These provisions are more stringent in California than in other regions

[1] Because codes and standards differ on whether the interface is at the top or bottom of the pipeline riser, this interface should be consistently defined to eliminate confusion in estimating risk.

of the United States. The benefits of these regulations were clear in the 1989 Loma Prieta earthquake where the losses, although tragic, were certainly lower than if the same earthquake had occurred in some other parts of the country. Another recent example, is the development, for NASA, of a risk analysis model of the heat shield of the space shuttle designed to compute the risk-criticality of the black tiles and to set priorities in maintenance operations (Paté-Cornell and Fischbeck, 1993a, 1993b). In that case, the surface of the orbiter was divided according to the density of debris that hit the tiles, the loads of heat and aerodynamic forces, and the criticality of the subsystems under the skin. The results showed that 85 percent of the risk was associated with 15 percent of the tiles. Priorities were set based on risk-criticality, and the recommendations were implemented to reduce the risk of loss of an orbiter.

DEVELOPING A PROTOTYPE MODEL: DECISION VARIABLES AND CRITERIA

Decisions

The risk analysis model outlined in this chapter is designed to support decisions among risk management measures. These decisions are closely linked to the geographic zonation of the area of concern:

- *Where to survey the pipelines*. Surveying the entire Gulf is not the most efficient way to allocate limited resources and efforts. For example, it is more important for fishing vessels to know the locations of the live, exposed gas pipelines in shallow waters than elsewhere.
- *Where to request inspection of a known pipeline (by what means and how often)*. Inspection is costly: divers as well as the use of inspection equipment are expensive and inspection operations may require interruption of production. The structural integrity of some pipelines is easier to establish than that of others. The consequences of oil spills also vary geographically because leaks from pipelines of large diameters close to the coastline are generally viewed as more damaging to the environment.
- *What repairs and other risk reduction measures to require for existing pipelines, given inspection results showing problems*. For example, when corrosion problems are indicated, which should be fixed, how, and how soon?

Because the location of the pipelines contributes to the possibility of damage, it affects the benefits of risk reduction measures:

- *Should old, empty pipelines be removed, and where?* The risks of human casualties are generally associated with live pipelines. The question is whether the possibility of property damage from collisions of fishing vessels with abandoned pipelines justifies their removal.
- *What preventive measures should be required for existing pipelines and for new pipelines?*

Regulations require burying exposed pipelines in shallow waters. Buried pipelines, however, become exposed when currents and storms cause erosion of the sea floor. Burying pipelines at a depth of three feet (generally the minimum standard for waters less than 200 feet deep) may be insufficient in soft soils where a greater depth may be desirable to avoid vessel collisions. The decision must be made based on the increments of costs and risk-reduction benefits of each additional foot of burial depth.

- *Should warning devices be required on fishing vessels and other boats when these devices become available*? It may be possible, for example, to develop devices capable of detecting a pipe's metallic mass with sufficient distance and accuracy to allow a slow fishing boat to turn and avoid frontal collision with an exposed pipeline.
- *What safety measures (procedures or equipment modification) should be required at the interface between pipelines and platforms?* Systems for isolating platforms from pipelines in case of serious platform emergencies have proven to be important safety features that should be located in such a way that they can be easily maintained and quickly or automatically activated in case of emergency.

Decision Criteria and Relevant Outcomes

The chosen outputs of the risk analysis model depend on the structure of the decision criteria (the maximum acceptable individual risk, the cost-benefit criterion when applicable, etc.). The corresponding risk characteristics relevant to the evaluation of different safety policies are the following:

- The overall probabilities of at least one casualty per year in different areas, and the maximum individual risk (annual probability of death) per individual exposed. This result allows ensuring basic individual safety (for example, a maximum individual risk of 10^{-4} or 10^{-5} per year, two or three orders of magnitude less than the probability of deaths per year for the population as a whole).
- The mean volume of oil spilled per year. This result allows checking that a criterion of acceptability (which may vary with the distance to the shore or other factors) is met. One important issue is the potential for environmental pollution. If pollution to the shore and wetlands is considered more serious than pollution at sea, one relevant result is the proportion of spilled oil that reaches the shore.
- The monetary damage due to collisions of vessels with empty or live pipelines. Other possible losses include damage to fishing nets and trawls.
- The repair costs of corrosion pits in pipelines (which can be decreased by corrosion prevention measures).
- The costs of the proposed risk reduction measures.

STRUCTURE OF THE RISK ANALYSIS MODEL (ZONATION)

The risk analysis approach for the area of interest (in this example, mainly off the coasts of Louisiana and Texas) is based on a zonation of the region according to the three parameters mentioned above: water depth, vessel traffic density, and pipeline density. These parameters determine the variation of the risks from place to place. The values of each parameter are divided into a few discrete ranges. The geographic area is then partitioned into minimal zones ("min-zones"), each characterized by the local values of the three parameters. Each min-zone (index i), is characterized by:

- the surface area in square miles;
- the density of pipelines indexed by j (1, 2, or 3) and, possibly, specific distributions

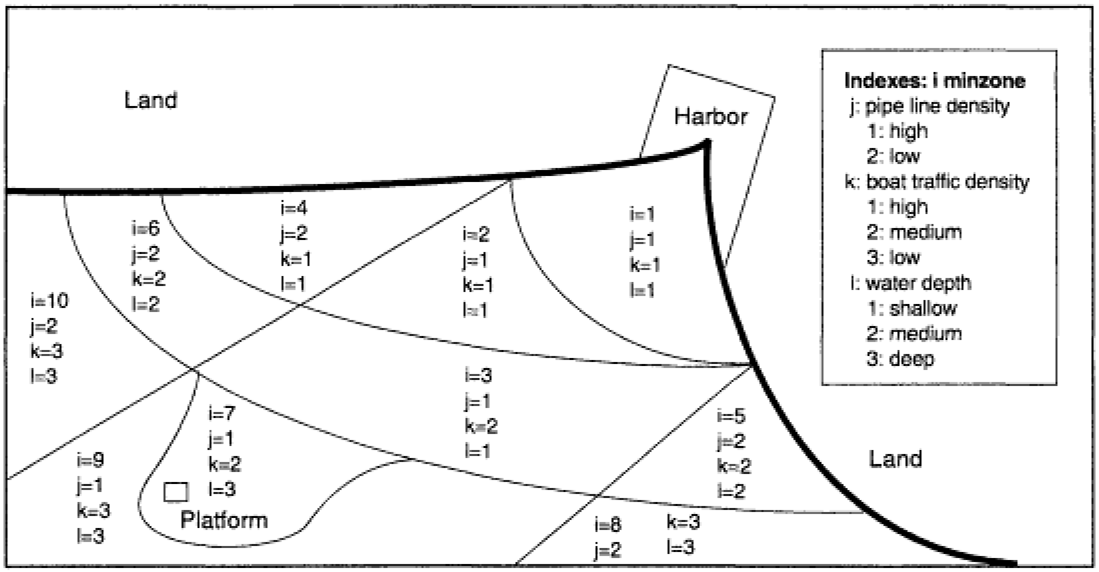

Figure 3-1 Partition of a hypothetical area according to water depth, pipeline density, and boat traffic density

of pipe sizes, ratios of old to new and inactive to live pipelines, as well as the proportion of those carrying gas versus oil or condensate (unless these characteristics are considered geographically uniform);

- the density of vessel traffic, indexed by *k* (1, 2, or 3), and possibly the types of vessels if there are significant differences in drafts;
- the water depth indexed by *l* (1, 2, or 3); and
- the number of platforms.

Figure 3-1 shows an example of such a min-zone partition for a hypothetical region.[2] A harbor is shown, to illustrate variation in vessel traffic density. (Additional parameters (e.g., the relative densities of old pipelines and new ones, or the distribution of pipelines by diameter) may be added if needed, resulting in a finer division of the area into min-zones.)

The risk for each min-zone is characterized by:

- the annual probability of at least one death in the min-zone, and the corresponding maximum individual risk (the annual probability of death in a pipeline-related accident for the most exposed individual);
- the mean amount of spilled oil per unit of surface and per year in the min-zone; and
- the mean annual property damage to pipelines and vessels.

[2] The zonation approach allows not only computation of the risks but also assessment of the costs of risk reduction measures. Many operations are more expensive in deep water, where putting the emphasis on design may reduce both the risks and the need for expensive inspection, maintenance, and repair.

The structure of the risk analysis model includes (a) initiating events (e.g., a vessel-pipeline collision) and their annual probabilities, (b) intermediate developments and their probabilities conditional on the initiating events (e.g., the probability of fire given a vessel-pipeline collision), and (c) the consequences (generally expressed as means or mean rates) of each accident sequence.

The five initiating events (denoted "IE") are as follows:

- For "offsite" pipelines (not in the immediate vicinity of platforms):
  - -IEa A vessel hits an exposed pipeline, a class of accidents that can lead to human casualties,
  - -IEb A vessel operator drops or drags an anchor or other object causing a breach in a pipeline,
  - -IEc A pipeline leaks due to corrosion, either at the site of a flange or in a pipe section (excluding the interface with platforms), and
  - -IEd A pipeline breaks and/or leaks due to damage caused by storms and hurricanes;
- For pipelines at platforms:
  - -IEe A pipeline fails at the interface with a platform due to excessive loads such as shocks or high internal pressures, and/or to reduced capacity due to a weakness of the equipment.

These five types of initiating events can be considered mutually exclusive. Their probabilities are defined for each min-zone as functions of the information shown in Figure 3-1: water depth and the densities of vessel traffic and pipelines. The risks associated with each initiating event can then be computed and summed over all accident types and all min-zones to assess the overall risk in the Gulf.

In general, the model can be made either simpler or more detailed, depending on the information needed. (The model's structure is outlined more thoroughly in Appendix E, along with details of the equations used.)

Choosing the Model's Complexity

The model outlined here is intentionally simple, and its structure is determined by the choice of the five initiating events described above. It represents a framework in which the values of several variables can be determined by the results of other models. Several key assumptions can be reexamined. First, mean values are used to replace full distributions of most random variables; some decision makers may want more detailed computations. Second, many of the probabilities of failures that are described here as input data can be obtained as results of classical reliability computations involving estimations of loads and capacities. Third, statistical data do not exist for some of the random variables, so that expert opinions are needed to do the analysis (for example, to assess the mean number of incident occurrences given the number on incident reports). In some cases, experiments can be performed to assess physical factors such as the rate of deterioration of a pipeline under specified circumstances. Fourth, some of the simplifying assumptions, such as a uniform ratio of different pipeline diameters or the independence of the different failure modes, may need to be reexamined (for example, to account for differences among operators in their degree of compliance with existing regulations or their inspection and maintenance policies).

The most difficult task will probably be the analysis of the risks at the site of platforms because the initiating events of accident sequences are numerous, and the systems are complex and different. Again, the choice of a level of analytical aggregation is determined by the resources available and the precision needed for the assessment of different safety policies. The intent of this chapter is to provide the general framework of a risk analysis model. Each variable can be analyzed further according to the circumstances.

Modeling Change Over Time

The approach presented here provides a means of deriving a snapshot of the situation. It does not account for the trends that will affect pipeline performance in the future. These trends can be included in the model by replacing simple values of the deterministic variables by functions of time, and random variables by stochastic processes (representing probabilities). At present, the trends include the following:

- Some of the facilities are aging (and presumably, deteriorating). At the same time, new facilities are installed with better technologies, such as improvements in anode protection and inspection facilities.
- New regulations, as they are enacted, tend to reduce the risks if properly implemented.
- At the same time, there is a significant rate of abandonment of pipelines (but it is smaller than the rate of abandonment of platforms).

In this simplified model, the length of service of a pipeline affects mainly two of the five identified failure modes: corrosion and pipe failure at the site of a platform. Although corrosion seems to occur at the same rate on old and new pipelines, its cumulative effects over time make older pipelines more vulnerable in the long run. Fatigue and repeated exposure to wave loads may also reduce the capacity of the pipelines to withstand hurricanes and storms.

All the dynamic effects listed above can be included in the model. This requires, at the minimum, an evaluation of the rates at which these phenomena are occurring. These rates of evolution, however, may not be constant, so that past statistics may offer only limited information. In the long term, evolution may be driven by external variables, such as the future price of petroleum on the world market, or the design and implementation of new government policies. Uncertainties about such future variables can only be described by expert opinions.

DATA SETS AND BIASES

As reported in Chapter 2, there are several data sets containing records of past pipeline failures, accidents, and oil spills. They are managed by different agencies, with little interagency coordination. These data bases cannot be used directly, because they are incomplete and contain substantial but unknown biases.

"De-biasing" such a data set requires assessing, for each category of events, the probability of incidents being reported, then inferring from the reports the likely actual rates of events per year and per category. The probability that an event of a given type in a given period was actually reported depends on the reporting process at that time, the incentives to report, and the probability and consequences of discovering an unreported event. This problem is similar to that of assessing the magnitude of a medical or a social problem based on reported cases when there are reasons to believe that some cases are not reported. The probabilities of events being reported, given that they have occurred, are best estimated by expert opinions. Even though expert opinions seem less reliable than so-called hard statistics, they may be more accurate.

Furthermore, the factors affecting pipeline failures are not constant. The probabilities of the different failure types are changing, and only experts can attempt to predict what they might be in the future under different scenarios. Therefore, when using the available data, the rates of changes (deterioration as well as improvement) must be incorporated in the analysis to allow predicting the effects of proposed safety measures.

Obviously, in the end, the risk analysis results will be only as good as the input data. As is almost always the case in risk analysis, the data needed for the computations outlined in this chapter and in Appendix E come from three sources:

- statistics from past reported incidents;
- physical models (involving vessel drafts, water depth, vessel speeds, corrosion mechanisms, etc.); and
- expert opinions (subjective assessments of probabilities based on experience).

One important source of information that needs gathering and exploiting whenever possible are data about minor incidents (such as contact with a pipeline that does not result in failure), because they enrich the small information base about rare events such as severe accidents.[3]

ESTABLISHING SAFETY GOALS

The risk analysis results could be used to support two kinds of management decisions: regulatory decisions (e.g., whether requirements for the removal of abandoned pipelines are warranted) and private decisions of the oil companies (e.g., the frequency of inspection and the technology to be used). Cost-benefit analysis can be used for these decisions, but only after a certain level of safety has been ensured for people who spend much of their lives on fishing vessels, supply and service boats, or platforms. What follows is a set of numerical safety goals based on a survey of current practices in the United States and abroad, and recently presented at a workshop of the Department of Energy (Paté-Cornell, 1992).

It is important to emphasize that zero risk is unachievable. Balancing costs and risk reduction requires finding an acceptable balance between economic efficiency and equity. Equity requires that all individuals be granted equal protection against risks inflicted on them by others. Therefore, a basic individual safety level must first be provided everywhere. Once this safety level has been ensured, additional safety measures may be

[3] In the first implementation of the model, there will be considerable uncertainties about the inputs. A first run can simply be based on means (e.g., of future frequencies of incidents derived from past incidents and expert opinions), as described in Appendix E. Uncertainties can be introduced in the analysis if desired, and described by probability distributions for these variables. Existing software allows computing the effect of these uncertainties on the risk results.

required in zones of high vessel traffic density and/or high pipeline density on a cost-benefit basis. Economic efficiency requires placing a ceiling on these additional safety expenditures per capita in the considered range of individual risks. Below a certain level of individual risk, no further safety measure is necessary because the benefits are negligible to the individuals concerned.

Economic efficiency is desirable to ensure the maximum risk-reduction benefit for a given safety expenditure. At some point, however, from the individual point of view, resources are better spent to increase investment and consumption (which can increase both longevity and quality of life) than for further risk reduction. Investing more resources to reduce low risks thus becomes counterproductive beyond a certain level of costs, even if one restricts the objectives to issues of individual safety and welfare. This maximum expense per capita to eliminate a low individual risk (divided by the risk magnitude) is sometimes referred to as "the value of life." For example, spending $2 per capita to eliminate a risk of 10^{-6} per year is sometimes referred to as a $2 million "value of life". Here, the relevant figure is this $2 "cost of human safety," i.e., an amount spent to eliminate an individual risk in the range of 10^{-6} per year.

Equity considerations require that no individual should be exposed to an excessive risk for reasons of economic efficiency; therefore, society may want to sacrifice some economic efficiency to achieve a more balanced allocation of risks. The proposed criteria thus include an upper bound, above which the risk to an individual is simply unacceptable and must be reduced or eliminated if at all feasible, regardless of the costs. It is only below this threshold that cost-benefit analysis is relevant.

Finally, there is a risk level that is so low as to be below regulatory or legal concern ("de *minimis*") simply because, in that lower range, the benefits of risk reduction are so small as to be negligible to the individual. Investing in risk management in this domain is wasteful, because it would divert attention and resources from more beneficial risk reduction measures.

In any case, an acceptable risk is not found simply by applying numerical criteria. It is instead the product of an acceptable decision process, in which risk analysis results and numerical safety goals are only parts of a larger context. For example, "voluntariness" and "informed consent" are key elements of the acceptability of risk. Therefore, it generally makes sense to require more stringent risk limits for the public than for workers of the oil and gas industry, who are presumably informed and compensated and assume the risks voluntarily. Obviously, this fact implies a responsibility of firms to inform workers of the risks they face.

Based on these principles and on the targets that have emerged in recent years from the safety debate (Paté-Cornell, 1992, 1994), the following risk strategy would be appropriate for marine pipelines:

- First, basic requirements and traditions of the best segments of the oil and gas industry should generally be satisfied; for example, proper inspection and maintenance, prompt reporting of incidents and spills, and prompt reaction to spill reports.
- Beyond that, safety measures should be adopted so that no member of the public, including those on fishing boats, or other vessels, is exposed to an individual risk greater than a threshold, for example, 10^{-4} or 10^{-5} per year of exposure (one objective being to reach this goal at minimum cost).
- Beyond that, further risk reduction measures should be adopted if they cost less than a specified "cost of human safety," for example, $20 per person per year to eliminate

a risk of 10^{-5} per year (cost-benefit criterion) or \$2 per person per year for a risk of 10^{-6} (a criterion sometimes referred to as "\$2 million per life").

- Finally, a *de minimis* individual risk threshold can be set, for example, at 10^{-7} per year per person.

In addition, cost-benefit criteria can be used to evaluate environmental protection measures. There is, however, no established criterion for assessing the benefits of environmental protection, and no observable consistency in the public's willingness to pay for a given level of protection.

It could well be that, for marine pipelines, the *de minimis* level is currently achieved. If this is the case, the model could suggest which improvements should be considered next if one wanted to provide still higher safety levels.

Again, these figures are not meant to represent universally acceptable risks; they are targets rather than absolute criteria. Precedents and economic arguments suggest, for example, that some of these targets could be relaxed by up to an order of magnitude for older pipelines that are not expected to be in service much longer. The risk analysis results and the safety targets are inputs into a joint decision process of the agencies and the oil and gas industry, which could lead to improvements in safety.

Some safety measures reduce both the risk to human life and the expected value of property damage. In this case, the reduction of the financial loss can simply be subtracted from the costs before doing a cost-benefit analysis based on human safety (in the range of individual risk such an analysis where is appropriate, as noted earlier in this chapter). Other safety measures decrease only property damage and should be adopted on a simple cost-benefit analysis basis. The risk analysis model allows computing the risk-reduction benefits by comparing the expected values of the losses with and without the proposed measures. When the options involve a continuous range (e.g., in determining the appropriate depth of burial of pipelines in shallow waters), such an analysis should be based on incremental costs and incremental benefits. In all cases, an appropriate discount rate should be used to account for the time value of money over the remaining expected lifetime of the equipment.

FINDINGS

Use of the risk analysis approach outlined in this chapter can help decision makers in industry and regulatory agencies identify the most risk-critical zones of the Gulf of Mexico for marine pipelines. They can then adapt their risk management strategies to the local conditions while providing a basic level of safety everywhere. Extensions of the model to the immediate vicinity of the platforms can also help the regulatory agencies to identify weaknesses in the components of the pipeline-platform interface and to choose appropriate and economical safety measures.

Risk analysis is a management tool applicable to both strategic planning and administration by industry, and policy making by federal and state governments. The risk analysis approach to safety standards for marine pipeline zones and safety decision support can be useful in the development and implementation of routine risk management activities. It permits setting priorities and improving cost-effectiveness in resource allocation, for example for inspection operation, the resurvey of pipelines, and decisions about rights-of-way for new construction.

The dispersion of the regulatory authorities and of the information gathering systems complicates greatly the risk management task. A common data gathering policy would permit merging reports from all sources in a single data base and would provide a clearer picture of the current situation and trends. Furthermore, a unified risk management strategy among the agencies would allow more consistency and cost-effectiveness while simplifying the task of industry operators.

To place marine pipeline safety priorities on a firm basis, it is necessary that data be gathered in a consistent format by the responsible agencies, stored in a central data base, and used in a risk analysis model based on the zonation approach presented in this chapter.

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4

Maintaining the Integrity of the Marine Pipeline Network

The offshore pipeline industry, since its first ventures into the Gulf of Mexico and the waters off California more than 40 years ago, has steadily improved its operating practices, with new materials, more robust designs, and more efficient techniques for construction, operation, and maintenance. Today it operates with confidence in waters as deep as 1,700 feet, with near-term plans for depths of 3,000 feet (Salpukas, 1993). Technology is being developed for pipelines in much deeper waters, up to perhaps 6,000 feet.

Despite this progress, the marine environment is a challenging one for pipelines, and maintaining their integrity requires vigilance. Repairs and inspection are costly for underwater pipelines, and the emphasis is accordingly on preventing damage and deterioration. Corrosion protection has advanced to a state at which pipelines may serve far beyond their original expected service lives (although isolated corrosion is still a troublesome and costly source of pinhole leaks). Leak detection programs use combinations of visual detection from boats and aircraft, automated metering of pressures and flows in pipelines, and monitoring of the flows in entire pipeline networks. Workers are highly trained to carry out routine operations and maintenance; more recently, enhanced training for emergency response has been mandated by regulators.

Much of the pipeline inventory has remained in use beyond its originally intended service life. About one-fourth of the pipeline mileage in the federal waters of the outer continental shelf is more than 20 years old, and the average age is rising steadily (Minerals Management Service, 1992). Pipelines in state waters are even older, with some dating from the early 1950s, when offshore pipeline construction began. Coatings, cathodic corrosion protection, and internal corrosion monitoring have improved substantially since then. Still, corrosion—especially internal corrosion—is inexorable, and requires continual inspection and monitoring. This problem is likely to grow more serious; as gas fields decline, gas pipelines will carry more liquids, and be potentially subject to increasing corrosion.

On the other hand, corrosion, while the most common reported cause of pipeline failures, presents relatively small risks. Corrosion failures tend to be small pinhole leaks, and are generally detected in time to prevent large losses of oil or gas. As noted in Chapter 2, the average oil pollution per corrosion incident is a little less than 13 barrels;

if a single anomalous corrosion leak of 5,000 barrels in 1974 is excluded, the average is about 2 barrels; the vast majority of oil spilled from pipelines is due not to corrosion, but to damage from vessels and their gear.

CORROSION CONTROL

Marine pipelines are constructed of high-strength carbon steels in several grades, depending on size, internal operating pressure, bending and longitudinal stresses expected during construction, and anticipated environmental conditions. All piping, materials, and fittings are specified to be consistent with industry standards, promulgated by technical societies such as the American Petroleum Institute and the American Society of Mechanical Engineers. OPS and MMS regulations specify minimum operating design and construction, post-construction, and testing standards for pipelines and components. Both agencies' regulations cite these industry standards frequently.

Corrosion may occur either internally or externally to a pipeline. It tends to occur at predictable locations. Internal corrosion in likely at low spots in pipelines and at riser elbows, where brine, bacteria, and other corrosive agents collect. External corrosion is most likely in the "splash zone" at the sea surface, where wave action may degrade cratings. Corrosion engineers take preventive measures that give priority to such high-risk locations.

Corrosion defects in pipelines develop gradually, and generally manifest themselves as small pinhole leaks, through which small amounts of product escape. A corrosion-induced failure is not a spectacular event. Escaping product is noticed on the surface as either large bubbles from gas lines (a small high-pressure bubble at pipe depth is seen as a large bubbling or "gas boil," at the surface) or a light oil sheen from liquid lines. Small leaks of this kind are easily detectable by routine helicopter overflight.

External Corrosion Protection

The marine environment is generally uniform and stable with respect to its corrosivity. Pipelines are protected against corrosion by bonded coatings. On larger diameter pipelines, which would otherwise float when empty or be subject to excessive displacement by waves and currents, a concrete weight coating is added to provide stability, and incidentally some mechanical protection from objects such as the anchors of small vessels. Specifications for corrosion-preventive coatings and their application and testing are available from several associations representing the pipeline industry and coating firms.

Both OPS and MMS regulations require corrosion preventive coatings. OPS regulations prescribe testing requirements and intervals for verifying the adequacy of such protection. The OPS regulations for gas pipelines (49 CFR 192) follow criteria of the National Association of Corrosion Engineers (now NACE International). Criteria for hazardous liquid (that is, petroleum) pipelines are less prescriptive, setting only general performance standards for internal and external corrosion control; in practice, however, corrosion protection practices are similar to those used for gas pipelines. MMS permits require operators to meet OPS design standards for corrosion prevention (30 CFR 250.152); the agency also maintains a data base of cathodic corrosion protection systems, so that operators can be notified when the systems need inspection.

To prevent the electrochemical process of external corrosion, marine pipelines use cathodic protection systems, which apply a small voltage to the pipe, either from an external power source or through the electrochemical reaction of two dissimilar metals using seawater as an electrolyte. The earliest type of cathodic corrosion prevention system (known as impressed current protection) used single-location, or "point-groundbed," anodes, powered by electrical rectifiers to provide protective current to the pipeline. The original system anodes are generally depleted after 10 to 15 years of service and replaced with new ones. A drawback of this system is occasional interruption of electric power, supplied by generators on platforms; although occasional brief interruptions are not harmful, the relative inaccessibility of the rectifiers can make outages more frequent and longer than desirable. The adequacy of corrosion protection—and in particular protection from external corrosion—at intermediate points, between anodes, is difficult to verify. For these reasons, impressed current systems are not often used today.

Today, so-called sacrificial cathodic protection is more common. It involves the use of anodes of a sacrificial material such as aluminum or zinc, electrically bonded and attached to the pipeline as clamp-on bracelets. These anodes are sized and spaced along the pipeline to provide uniform cathodic protection for at least 25 to 30 years, taking into account the anticipated extent of coating damage, the anode depletion rate, and other factors. One drawback of sacrificial systems is that depleted anodes cannot be as readily replaced as the single point anodes of the impressed current system. In addition, the anodes on smaller pipes, without weight coatings, may be damaged during pipeline installation, rendering them nonfunctional and reducing the safety factor built into the system. (On larger lines—the most common—the outer diameter of the anode is the same as that of the weight coating, making such damage unlikely.)

Thus, the maintenance problems associated with impressed current systems are eliminated, but replaced with other possible problems. Also, as with the impressed current systems, the adequacy of protection in the intermediate sections of pipelines may be questionable unless advanced techniques such as cathodic protection surveys by remotely operated vehicles (ROVs) are used. ROVs are already commonly used to assess the external physical conditions of unburied pipelines. Equipped with magnetic tracking devices and controlled from the surface, these vehicles follow the pipeline, providing visual surveys of the pipeline and bottom conditions along the route. New systems to record corrosion control data using ROVs have not yet achieved widespread use, but are increasingly accepted by the pipeline industry (Weldon and Kroon, 1992).

Conventional cathodic protection monitoring of offshore pipelines is generally conducted by measuring the pipe-to-electrolyte potential of the pipeline at easily accessible points, generally the platform riser and/or a point onshore. This technique produces data for only one or two points, so there is some difficulty in judging the protective status of the rest of the pipeline, which depends on such things as the condition of protective coatings and the integrity of anode-to-pipe connections.

There are two ways to get more information, whose merits depend on specific conditions of the pipeline, such as length and depth, water clarity, type of corrosion coating, whether or not the pipe is buried, and the type of corrosion protection used:

- Spot monitoring of the pipeline potential is generally limited to locations where other maintenance or construction activities are being carried out by divers. The locations of such work are independent of anode locations, which are potentially more valuable monitoring points. Still, the additional information can be useful in the absence of other monitoring opportunities.
- Close-interval potential surveys provide a nearly continuous plot of the pipeline potential. Towed "fish" or ROVs can be used to carry the monitoring equipment. ROVs,

which follow the pipeline more closely and consistently, are generally most effective. They also can carry video cameras, which reveal even minor coating defects (on pipelines that are not covered with sediments).

Internal Corrosion Protection

The phenomenon of internal corrosion is well understood by the pipeline industry, but requires increasing attention as pipelines and oil and gas producing fields age. In both gas and liquid lines, corrosive mixtures of foreign materials such as brine, drilling fluids, and bacteria from production reservoirs, not removed by production equipment, travel in the product stream. Metal loss from internal corrosion is generally concentrated at the bottoms of the pipe and at low spots, especially in gas lines because the corrosive substances tend to be heavier than oil or gas. In some cases, a combination of erosion and corrosion can occur. As more pipelines transport mixtures of produced fluids (oil, gas, and water), corrosion problems have become more complex, but they remain manageable.

The internal corrosion problem has grown more challenging in natural gas lines during the past 10 to 15 years, owing to changes in operating and economic conditions. At one time, gas accepted for purchase or transportation by many systems, was required to be dry (free of entrained liquid or liquid vapors of any type, including water, hydrocarbons, distillates, or condensates produced with the natural gas). Today pipelines are more likely to carry such liquids to shore, because of the value of the recovered liquids and the operational efficiencies of separation ashore, as well as the limited water disposal options offshore. Cooler temperatures around the pipeline on the ocean floor cause condensation of entrained liquid vapors, including water, resulting in formation of corrosive liquids (Darwin, 1992). Shifts of production to deeper waters will tend to increase condensation of many of these corrosive fluids, because pipelines will carry more mixed fluids longer distances from producing fields to treatment and separation facilities, and in cooler waters.

Internal corrosion is more difficult than external corrosion to locate and quantify, owing mainly to the relative inaccessibility of intermediate sampling points on offshore pipelines. Onshore, monitoring can be performed at valve sites, stations, instrument locations, and other points, to help isolate and locate active internal corrosion. Offshore there is typically no opportunity to establish monitoring points except at the originating platform. This location is of limited use in establishing the existence of corrosion downstream. It is far more desirable to have monitoring points at both intermediate and end points of a pipeline. Even under the best of circumstances, onshore or offshore, it may be difficult to determine where fluid velocities and pipeline profiles combine to allow water to drop out of the fluid, or to cause erosion of the pipeline; the chemistry of the fluid and the nature of entrained substances all affect internal corrosion activity.

Operators use various indirect means of monitoring internal corrosion. Fluids are often monitored continuously for corrosion products at both termini of pipelines. Small sacrificial pieces known as coupons, immersed in the flowing gas or liquid, can be removed to test for the extent of internal corrosion. The resulting analytical information is used as the basis for corrosion inhibitor injection programs and for scheduling cleaning runs by "pigs" carrying internal scrapers and brushes. Gas pipelines most commonly use corrosion inhibitors. Liquid pipelines can rely on the flow of the liquid to keep entrained water in suspension, thus limiting accumulation of corrosive substances on the walls of the pipe. Sometimes it is possible to obtain a general indication of the rate of corrosion activity in a pipeline system by monitoring the content of iron in water emitted from the pipeline system. A high iron content would indicate need for a detailed survey and remedial action. As production declines in some offshore fields, and liquid velocity drops to the point at which water settles out, internal corrosion control in liquid pipelines will be more important.

Cleaning pigs—hard rubber or inflatable plastic spheres or cylindrical devices that travel with the product flow—are often used to move foreign substances to a downstream location where they are removed from the system. The recovered material is analyzed to determine the adequacy of the internal corrosion control measures, including any chemical inhibitor programs in use. In many pipeline systems (mainly those with subsea connections with other pipelines), the use of pigs is difficult or impossible. Where feasible, it is an important means of increasing the effectiveness of internal corrosion control, used by most pipeline operators. It not only removes corrosive materials and gives operators information on corrosion activity in the pipe, but also brings corrosion inhibiting chemicals in better contact with the pipe surface.

Newer technologies have been developed to provide more precise identification and location of problem areas. In-line inspection (ILI) devices (also known as smart pigs), discussed later in this chapter, are suitable for some pipelines, but are limited generally by the physical characteristics of existing pipeline systems, such as tight bends, restrictions in subsea junctions, and the lack of room on platforms for pig launching and receiving equipment. Retrofitting may be difficult and expensive. Research is underway by the pipeline industry to reduce the length and weight and improve the accuracy of such devices.

Internal corrosion tends to occur fairly consistently in several distinct locations of offshore pipelines: in the bends at the bases of risers (pipes that connect seabed pipelines to platforms), where corrosive liquids tend to accumulate (especially in gas lines); and in small-diameter flowlines (pipelines connected directly to producing wells), where corrosive liquids and sand are contained in the unprocessed fluids. Knowledge of these patterns allows the targeted use of specific inspection measures and remediation techniques.

MAINTENANCE AND INSPECTION

Equipment and piping maintenance performed on marine pipeline facilities that are above the water line is very similar to that performed onshore. Maintenance procedures and inspection and calibration intervals are established based on the type of equipment involved, the potential consequences of failure, and the likelihood of various failure modes. The purpose of this preventive maintenance is to prevent equipment failure which could have adverse safety, environmental, operational, or financial consequences. Repairs are performed as needed, according to established procedures.

The same general principles apply to marine pipelines facilities on the seabed. However, access to equipment and piping on the seabed is more difficult, and special techniques are needed. Both inspection and maintenance can be performed by specially developed machines or specially trained divers. The sophistication of the work that can be performed on the seabed is limited, and submerged facilities are designed accordingly to minimize the need for access. Typically, the only pieces of equipment that are submerged are the pipe, tie-in valves, check valves, and some other miscellaneous fittings associated with subsea junctions. A combination of techniques is used for maintenance and inspection.

The interface of pipeline and platform is critical. Pipeline maintenance can expose platforms and platform personnel to unexpected hazards (Cullen, 1990; U.S. Department of Transportation, 1989). By the same token, platform activities can endanger pipelines (Minerals Management Service, 1991a, 1991b). Adequate communication and carefully specified procedures must be used for this work to be done safely and effectively.

External Inspection

External inspections of marine pipeline facilities are performed only as conditions warrant, for reasons of cost, safety, and environmental impact. Any diver-assisted operation carries risks of injury. The disturbance of sediments and the potential for damage to the pipe raises environmental issues. Cost issues arise when the anticipated benefits are not adequate in comparison to the costs incurred. Direct access to submerged pipelines is in any case limited, because the pipe is buried and/or covered by a corrosion-protective coating and sometimes a concrete coating (used to add weight to the pipe). External inspection is therefore limited primarily to situations where significant damage is suspected (as, for example, when a ship's anchor has been accidentally dragged near the pipeline) or when it is necessary to confirm the pipeline's location or burial status.

The inspection technique used depends on the results desired. For equipment that is submerged but not buried, divers or ROVs can make direct visual inspections. Even for equipment that is buried, it may be possible to uncover the piece of equipment or section of pipe (albeit at great cost) and achieve the same direct access or, in rare cases and in shallow water, even raise it to the surface for repair without disconnecting it.

Alternative methods of externally inspecting subsea pipelines use specially designed sonar or magnetic devices that are towed along or across a pipeline to give an electronic, rather than visual, indication of the pipeline's location and burial status. (See Chapter 5 for discussion of shallow water depth-of-cover inspections.) These indications are, of course, indirect; that is, the data must be interpreted and translated into useful information. Accompanying this indirect method of inspection are certain inaccuracies inherent with these techniques; however, these methods do have very definite and widespread applications offshore.

Internal Inspection

To determine the structural condition of a pipeline, operators use either pressure-testing, to reveal incipient leaks, or instrumented in-line inspection (ILI) devices (generally known as smart pigs) passed through the line to record data that indicates metal loss or certain other pipe characteristics. These measures complement the corrosion control and monitoring methods discussed earlier in this chapter, and are generally used together, to meet the circumstances of a particular pipeline and its operating conditions.

Pressure-Testing

Pressure-testing is commonly used to verify the integrity of pipelines after installation or repairs regardless of the system's age. The pipeline is filled with water and pressurized, generally to 125 percent of operating pressure (90 percent of the specified minimum yield strength), to reveal leaks and flaws.

As a routine inspection measure, pressure-testing has serious limitations, particularly offshore. First, it detects only flaws that are near critical size, and thus gives the operator little or no warning of impending failure. In addition, it generally requires shutting-in an entire field, and sometimes several fields. Pressure-testing must take its place among the inspection alternatives available to the operator, useful for certain purposes but not a broadly applicable means of assurance.

In-Line Inspection Devices

The use of in-line inspection (ILI) devices (more commonly referred to as smart pigs) to measure various physical characteristics of pipelines has continued to gain acceptance in the pipeline industry as the technology has developed and improved. A variety of ILI devices are used to provide information to pipeline operators, such as the types and locations of pipe anomalies, the radii and locations of bends, and even photographic images. Most carry instruments to measure either ultrasonic signals or magnetic flux leakage, which indicate metal loss. They carry their own batteries, tape recorders, and odometers. ILI services are now supplied worldwide by more than a dozen companies offering more than 20 types of smart pigs. These pigs are launched from special "launch traps," propelled by the transported oil or gas, and removed through "receiver traps."

Smart pigging technology has progressed significantly, and is likely to continue improving, driven by the needs of the pipeline industry (H. O. Mohr Research and Engineering, 1989). Technology development efforts are ongoing, both here and abroad.

Limitations of Offshore Use.

Most smart pigging in the United States has taken place in onshore pipeline systems, where smart pigs have earned a place among the various techniques available to operators to evaluate the long-term integrity of pipeline systems. However, the conditions of offshore pipelines are more challenging, and widespread use of smart pigs there will require substantial advances in technology. First, today's smart pigs are too big (about 8 to 12 feet long) to fit the vast majority of offshore pipeline systems in U.S. waters, with their varying pipe diameters and tight bends, restrictive subsea connections, and limited space on platforms for the needed pig launch and receiver traps. Conversion of these pipelines is rarely practical. As offshore oil and gas production moves into deeper waters, most new fields will rely on pipelines that tie in to the existing pipeline system, which will continue to limit smart pig use. In new and existing lines that run from platform to platform or from platform to shore with properly sized subsea tie-ins and without sharp bends, smart pigs may be accommodated.

The question of cost-effectiveness, though, will remain a real one. Even with marine pipelines that can accommodate smart pigs, the procedure is significantly less cost-effective offshore than onshore:

- The consequences of the corrosion failures and other minor leaks that could be prevented by smart pigs are smaller offshore, with no human safety or property damage impacts and generally minimal environmental impacts (see Chapter 2).
- The costs of smart pig surveys are significantly higher. Preliminary line cleaning is more difficult, and sometimes impossible, because of the heavier wax deposits that form in marine oil pipelines. Temporary launching facilities are more difficult and costly to install offshore. On existing pipelines, indicated defect locations are harder to establish, because the temporary magnetic mile markers placed on pipelines onshore for use in calibrating distance readings are not practical offshore (where their placement would be very expensive). (On new pipelines, it is possible to improve the accuracy of flaw location, for example, by installing permanent magnetic mile markers or using accurately located weld joints as mileage calibration data.)
- The costs of postsurvey inspections to verify indicated flaws are significantly

higher, because of both the inaccuracies referred to above and the inherently higher costs of access to pipelines offshore. Divers must be sent down and work barges used to locate, recover, and expose the pipe and verify and measure the pit. They often must work in zero visibility on pipelines with several inches of concrete weight coating; because reference magnets are not practical offshore, even the location from which to begin the search may be highly uncertain. The costs, which vary from several hundred thousand dollars to more than a million dollars for a single investigation, are about 50 to 100 times greater than a comparable investigation onshore. However, it is not necessary to make a detailed internal inspection of every indicated flaw. The operator has a range of alternatives for monitoring including pressure tests, reviews of pipeline operating records, and use of hydrocarbon sensing techniques.

- Other, "hidden," costs of smart pigging are higher offshore as well. Repairs may be made of flaws that might never have resulted in leaks if undiscovered. (Industry experience suggests that only 5 percent of the anomalies identified in smart pig surveys actually require repair, but 100 percent must be evaluated for severity, and some must be inspected visually.) Diving and other marine work are more dangerous than the activities required onshore, and jetting, uncovering, and retrenching pipelines disrupts the marine environment. Coating removal and repair may also do long-term damage to the integrity of the pipeline's coating system, creating problems elsewhere.
- Offshore systems have less operating flexibility in the event of a line blockage or lodged pig. There is no emergency storage capacity for oil offshore, and quick access to the problem location is impossible, so a single blocked line typically shuts in the production of dozens of producing platforms for days or weeks. Once a line is blocked, it generally cannot be cleared without some release of oil or gas to the environment.

All of these considerations favor alternative means of ensuring pipelines' integrity, such as the corrosion control programs described earlier in this chapter. The nature of corrosion activity offshore generally favors the use of corrosion monitoring techniques that are less effective onshore. The uniform conductivity of seawater, for example, removes some of the limitations of corrosion monitoring onshore, such as shielding due to disbonded coatings and localized corrosion due to severe soil conditions.

To be widely useful offshore, smart pigs must become more compact or "passable." To be cost-effective offshore, these devices must improve their accuracy and reliability, reducing the costs and uncertainties associated with anomaly verification in the offshore environment.

Recent Reports on Smart Pigging.

Two recent U.S. government reports have reviewed the technology of smart pigging (Research and Special Programs Administration, 1992; U.S. General Accounting Office, 1992). Both focused on onshore pipelines.

One of these reports, by the Research and Special Programs Administration (RSPA) of the U.S. Department of Transportation, used historical accident data in an economic feasibility study of the periodic use of smart pigs in both hazardous liquid and gas pipelines. It concluded that using smart pigs is cost-effective when only minor modifications to the existing pipeline are needed to accommodate them, and when one or more specific risk factors is present, such as proximity to a highly populated area, known corrosion or coating disbonding, or pipe deformation due to settlement or dredging activity. The cost-benefit analysis considered the safety, property damage, and environmental consequences of pipeline leaks as well as the costs of the periodic surveys. A key assumption was the presence of highly populated areas, so the benefits of smart pigging could more reasonably be expected to include safety and property damage effects. The study recognized that most pipeline leaks that would be prevented (small seeps due to isolated corrosion pits) have no safety or property damage consequences, and minimal environmental consequences.

The second report, by the U.S. General Accounting Office (GAO), focused more generally on the use, capabilities, and limitations of smart pig surveys in gas pipelines. It included a survey of the pipeline industry, state and federal regulators, and other sources. Most users, it found, question the accuracy of smart pig surveys in measuring and locating corrosion pits and other pipe anomalies; smart pig inspections must be supplemented by visual inspections of suspect areas of the pipe or other corrosion inspection, monitoring, or leak detection techniques.

Used in conjunction with other inspection techniques, the GAO report found, smart pigs can help identify potential pipeline defects and reduce pipeline leaks. But users believe that technological improvements are needed to permit smart pigs to more accurately measure the geometry of corrosion pits, which is vital to estimating their risk. In addition, smart pigs need to be further developed in their ability to detect other pipe defects, such as metal loss in weld zones and disbanded coatings.

The GAO report recommended that, as the Office of Pipeline Safety completes its studies and rulemaking on the use of smart pigs, it consider the capabilities, limitations, and costs of smart pig surveys. The GAO report itself did not attempt to quantify the potential benefits or costs. Nor did it discuss how to address survey inaccuracies and the other verification costs associated with follow-up visual inspections, although these items would need to be considered.

The conclusions of these studies are consistent with information presented to this committee by pipeline operators, which suggests that smart pig data were often hard to interpret, and in some cases erroneous (Bowles, 1992; Houston, 1992; Robinson, 1992; Winters, 1992). Although data obtained from smart pigs indicate the existence and relative magnitude of metal loss, the precise geometry of the pit or flaw cannot be established unless it is physically exposed. It is this geometry that is critical in determining the scope and need for repair.

The pipeline industry has begun construction of special test loops for smart pigs. These loops are made of pipe containing known defects of various geometries, and will be used to improve the evaluation of smart pig survey data. The results, however, may not be realized for several years.

The two government studies concentrated on onshore pipelines. As noted above, there are key differences between onshore and offshore systems that tend to reduce the applicability of smart pigs to offshore pipelines.

As the RSPA and GAO reports indicate, improvements in smart pig technology is needed before their net benefits will allow them to be used by pipeline operators more widely and routinely. At present, specific risk factors (such as population density) must exist for individual pipelines to warrant smart pig surveys. Offshore, with significantly higher survey costs and with little or no safety or property damage consequences, such risk factors must be even greater to justify the use of smart pigs. Even then, with the small number of offshore pipelines that can accommodate smart pigs, other solutions—such as the various corrosion monitoring measures described earlier in this chapter—are more practical in the vast majority of cases.

Alternative Inspection Measures.

Because corrosion tends to occur in certain distinct areas of offshore pipelines, such as risers and small well flow lines, specific local inspection measures and remediation techniques are generally more effective than the use of smart pigs that survey entire pipelines. In the case of flow lines, the use of smart pigs is precluded, because of their small diameters and the lack of means to install pig launch traps. For risers, inspections by divers or ROVs carrying ultrasonic thickness devices, or specially equipped tethered smart pigs can be used for these local inspections. Even in those cases, the emphasis is on corrosion prevention and corrosion control monitoring; metal loss is suspected only when identifiable risk factors exist.

As shown in Chapter 2, most pipeline leaks and corrosion failures result in small leaks that are readily detectable; the most significant pipeline ruptures and spills are caused not by corrosion, but by damage from vessels and their gear (see Chapter 5). Although pipeline operators' efforts to control corrosion do not prevent all releases, most have a strong economic incentive to maintain the long-term integrity of these valuable assets. Moreover, small leaks do not readily expand into large ones, according to industry observations and the failure data. Pipeline failure statistics since 1973 show only one spill of more than 50 barrels that was attributed to internal corrosion; that spill, which occurred in 1973, is estimated to have released 5,000 barrels. There have been no corrosion-related spills of that size since, probably because of monitoring by operators and increased regulatory attention to inspections by operators and frequent aircraft and helicopter observation to detect bubbles and sticks.

Inspection Requirements of Regulatory Agencies

Both the OPS and MMS require specific maintenance and inspection tasks to be conducted at set intervals. But agencies differ substantially in their approaches. The MMS inspection program is larger and more direct than that of OPS, with frequent visits to platforms and requirements for formal reports. OPS leaves inspection and maintenance largely to the operators, enforcing its safety requirements with periodic audits of company records.

Office of Pipeline Safety

OPS regulations require operators to conduct periodic visual surveys of offshore pipelines for leakage (no less than once per calendar year for gas pipelines [49 CFR 192.705] and 26 times per calendar year for hazardous liquid pipelines [49 CFR 195.412]). Inspection intervals for cathodic protection systems, valves, and other devices are also specified in OPS regulations.

OPS regulations (49 CFR 190.203) give the agency general authority to inspect pipelines and related records for compliance with applicable regulations. Such inspections are generally audits of companies' records. Regional Directors are responsible for scheduling these inspections. They are necessarily rather infrequent; OPS, for example, has only two full-time inspectors in the Gulf of Mexico, to cover more than 13,000 miles of pipelines, under the management of more than 160 different operators (personal communication, Jim Thomas, Office of Pipeline Safety, Southwestern Region, February 4, 1993). (By contrast, MMS has 70 inspectors in the Gulf OCS region, albeit with the more complex task of assessing the safety of both pipelines and platforms [Alvarado et al., 1992].)

The Pipeline Safety Act of 1992 (P.L. 102-508) requires the Office of Pipeline Safety to specify circumstances in which smart pigs or equivalent inspection technology must be used, and where facilities can be modified to accommodate such devices. Local population density and environmental concerns are critical factors to be considered.

Minerals Management Service

MMS requires pipeline operators to inspect pipelines regularly—at least monthly—for evidence of leakage. In addition, operators must conduct pipe-to-electrolyte potential measurements annually, to ensure the cathodic protection of pipelines equipped with rectifiers or anodes with life expectancies less than 20 years (30 CFR 250.155); results must be reported to the Regional Supervisor (30 CFR 250.158). Pipelines taken out of service for repair must be pressure-tested before being returned to service, and pressure-testing may be required if the Regional Supervisor has reason to believe the pipeline has been damaged or weakened (30 CFR 250.155).

Only in California, on the outer continental shelf, is the use of smart pigs routinely required by regulators of the Minerals Management Service; there, the pipelines are more recently installed, for the most part, with fewer connections and elbows to impede the passage of pigs. The corrosive hydrogen sulfide-rich crude there also demands more thorough internal inspection.

DETECTING AND LIMITING LEAKS

Leak detection options are varied, depending on operational and environmental conditions. Visual detection, during periodic overflights, is quite reliable (although slow) in fair weather, but wind-generated waves can obscure gas bubbles or oil sheens. Automated leak detection, using pressure or flow sensors, is in principle more sensitive and quicker, but in complex offshore networks, with multiple inputs and wide variations in flow, can produce unacceptable numbers of false alarms. In general, automated leak detection is less reliable for gas lines than for liquid lines, owing to the compressibility of gas.

A variety of systems is in place to prevent or limit leaks in case of pipeline failure, including emergency shutdown systems, flow restricting check valves, and pipeline isolating block valves. In the worst case, emergency isolation systems for platforms are needed in case of pipeline failures that threaten platforms. The 1989 fire and explosion on a Sonat/Arco platform in lease block South Pass 60, in which seven crew members died and ten were injured, with $70 million in property damage, would have been prevented by the use of such a system; in fact, such a system had been installed, but had not been added to the engineering drawings (U.S. Department of Transportation, 1989).

The Minerals Management Service (MMS) of the U.S. Department of the Interior has new authority to approve oil spill prevention and response plans, under the Oil Pollution Act of 1990; the MMS is considering standards that may address leak detection methods. In addition, OPS, under the Pipeline Safety Act of 1992, must prescribe requirements for leak detection methods and for emergency shut-in valves to minimize spill volumes.

Routine Operations

Production and transmission differ broadly in operating conditions, and present correspondingly different leak detection problems. Most marine production pipelines function very similarly to their onshore counterparts. Flowlines transport multiphase production (containing gas, oil, and water) to processing platforms. Gathering lines transport partially or fully processed product (i.e., separate lines for gas, oil, and water) to other platforms, where they are further processed or handled prior to injection into a transmission line. These lines and platforms are all owned and operated by the producer and are usually contained within a radius of several miles. Operating parameters are monitored locally at the platforms or at a central platform.

Marine transmission pipelines function more like gathering systems than like traditional point-to-point transmission lines on shore (Darwin, 1992). That is, they collect product from various production platforms and transport them to shore facilities for further transmission to refineries or distribution. Which platforms are tied in to a given pipeline system is determined mainly by proximity, the type of commodity transported, and available pipeline capacity. The federally mandated concept of open access requires that any producer can be tied-in to any compatible pipeline system that has available capacity. The typical result is that several producing companies from numerous locations inject simultaneously into a single pipeline company's system. The pipeline system operator monitors the operation by tracking key parameters, using instruments located at each injecting platform and at the shoreside receiving end of the pipeline. Monitoring instruments are rarely used at intermediate points on the pipeline or subsea tie-in points.

Producing platforms inject directly into the pipeline system, with units starting up and shutting down independently of one another. As a result, significant changes in flows and pressures occur. Since the pipeline systems were designed to transport the anticipated product, these transients are well within the operating range of the pipeline system. The only valve switching that occurs routinely is at the receiving end of the pipeline; therefore, offshore operations consist primarily of the monitoring of operating parameters such as pressures and flow rates, rather than the more complex line switching operations that can occur onshore. Except in emergencies, this continuous operation is interrupted only briefly (mainly for maintenance).

Most marine transmission pipelines and a growing number of production pipelines use SCADA systems, which allow them to be monitored and/or controlled from remote locations. The use of SCADA systems for marine pipelines has developed in conjunction with technological advances in data processing and communications. These advances have allowed data from remote locations to be more reliably transmitted to central locations for monitoring and processing. These capabilities have been in place onshore for many years. As transmission equipment becomes more compact and communications systems more reliable, new installations are designed and existing facilities retrofitted for more sophisticated SCADA systems. The degree of sophistication depends largely on the proximity of the monitored facilities to monitoring personnel. Thus, SCADA systems tend to differ depending on whether the pipeline functions as a transmission line (longer distances, multiple injections, and remote personnel) or a production line (shorter distances, single inputs, and manned facilities).

On transmission lines, key operating parameters (typically pressures and flow rates from sensors located at platforms) are monitored, displayed, and recorded at an offsite control center. In gas pipelines, temperature, free water, and water vapor may also be monitored. The status of key equipment—pumps on or off, valves open or closed—can also be monitored and displayed. The SCADA system is set to issue an alarm or a command signal, to keep operation within the desired limits. The controller or dispatcher monitors the displayed information and executes commands through the control keyboard while communicating with operating personnel at the platforms and other field locations as needed. The operation of a marine transmission pipeline system consists of this combination of computer and human system; the computer and equipment monitor conditions and hold them within desired limits, while the human sets desired limits and assesses operating conditions.

Marine production pipelines, by contrast, lend themselves typically to automated operation, with minimal human intervention. As a result, the more complex SCADA systems used on transmission pipelines are not required. Production flowlines tend to operate continuously at relatively constant flow rates and production gathering lines tend to be either "on" or "off," again operating at relatively constant flow rates. Only very limited data monitoring and transmission is required (unless production of more than one operator is commingled and must be metered for royalty purposes).

Complementary Leak Detection Techniques

Leak detection for operating marine pipelines typically involves a number of coordinated and complementary activities and systems, ranging from simple visual observation to sophisticated real-time, computer-based SCADA systems. Evidence of leaks is detected by periodic overflights of pipelines. On liquid pipeline systems, manually calculated daily line-balances (comparing the flows into the pipeline with those out) are made to reveal undetected losses. Finally, a range of sensor-and computer-controlled systems, including high- and low-pressure switches and SCADA-based setpoint-limit, rate-of-change, and line-balance systems, is available. Acting in concert, different combinations of these systems can maximize the effectiveness of leak detection capabilities and compensate for the others' weaknesses (Figures 4-1 and 4-2).

Visual Surveillance.

An important element of leak detection is accomplished through visual surveillance—both that done by design from oil field helicopters and supply boats, and that done by chance by routine marine traffic. This approach allows relatively small as well as large leaks to be detected, but may take days or weeks.

MMS regulations (30 CFR 250, subsection J) require visual inspection of the pipeline route from aircraft or visual inspection of the pipeline route from aircraft or surface vessels at best once each 30 days. These observations, generally made during routine traffic of personnel and supplies, have been an important means of leak detection and have worked well, according to MMS personnel (personal communication, Alexander Alvarado, Minerals Management Service Gulf of Mexico Region, March 11, 1994). Aircraft and vessel operators sighting a leak or spill are required to report the sighting.

Manual Line-Balance Calculations.

Another typical method, used for liquid pipelines, involves a manual comparison of volumes delivered into a given pipeline system versus volumes delivered out. These manual line-balance calculations are performed on a daily basis and require that each injecting platform operator call a central location each morning to report daily totals injected into each line segment. Totals are recorded and checked against the total delivered onshore. Discrepancies in these comparisons of volume in versus volume out trigger action. This system is capable of detecting relatively small, as well as large leaks, although not very quickly. It is less effective for gas lines, because of the greater compressibility of the fluid, and the presence of entrained liquids in the gas flow.

Automatic Leak Detection Systems.

Automatic leak detection systems rely on sensors and/or SCADA systems to identify and signal alarm conditions.

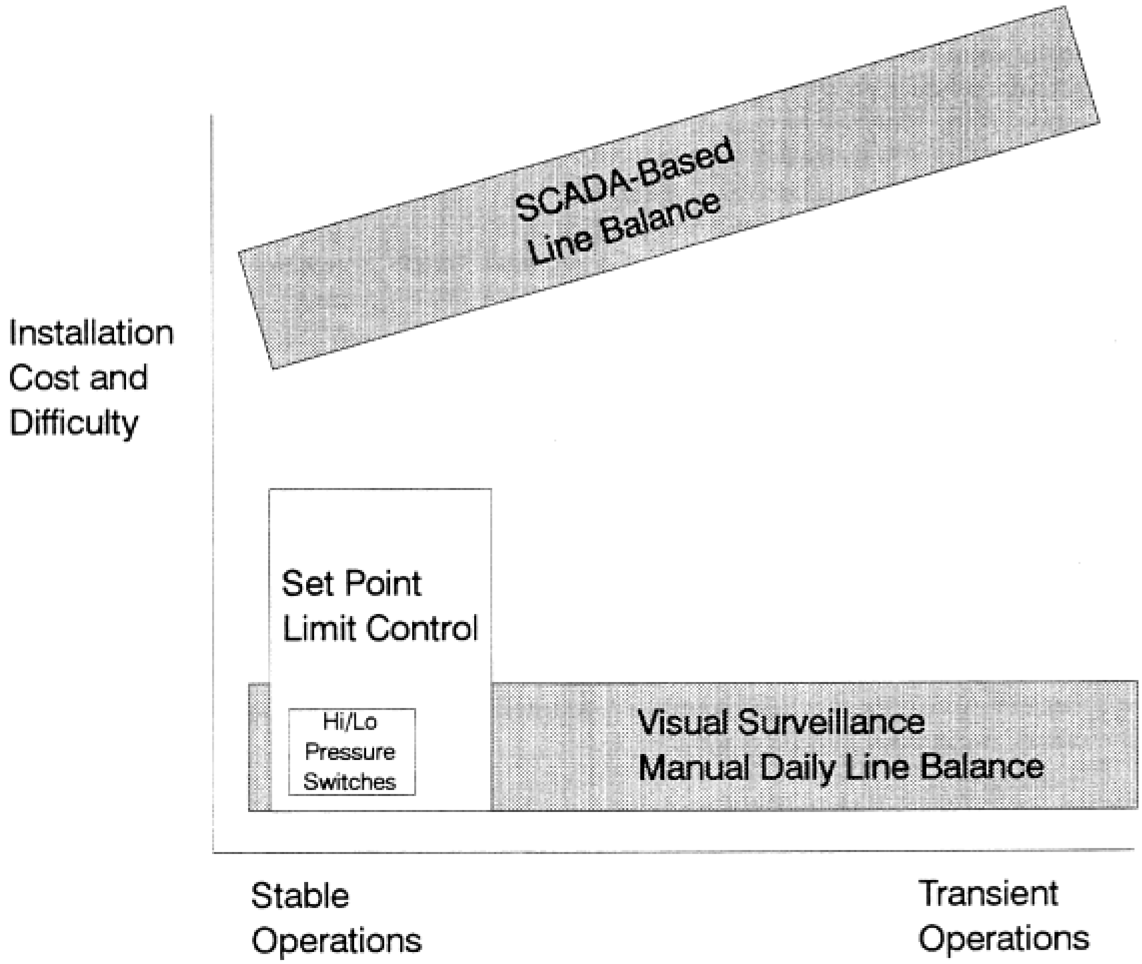

Figure 4-1 Schematic drawing comparing the advantages of different leak detection methods as functions of installation costs and relative stability of pressures and flows.

Setpoint-Limit Control Systems.

Setpoint-limit control systems establish limits on operating parameters such as pressures or flow rates, or (much less frequently) the rate at which they change, to identify upset conditions. These systems are quick to detect large leaks, but they require steady flows and pressures to operate effectively. The more variable a pipeline system's operating parameters and the greater the span between control limits, the less effective this type of system is in detecting leaks. Even when limits can be set extremely tightly on a pipeline system with steady flow and pressures, small to medium-sized leaks may not be detected because of system noise and the limits of equipment accuracy.

SCADA-Based Line-Balance Systems.

SCADA-based line-balance systems continuously compare volumes into a liquid pipeline systems with volumes out. Typically, a short-term (1 hour) and a long-term (24 hour) time period are used for these comparisons; a medium to large leak can thus be detected more quickly, but with adequate "accumulation" time to reveal small leaks too. (The High Island Pipeline System leak in 1988 totaled 15,576 barrels; the SCADA system, monitored with a 24-hour period, would have detected the

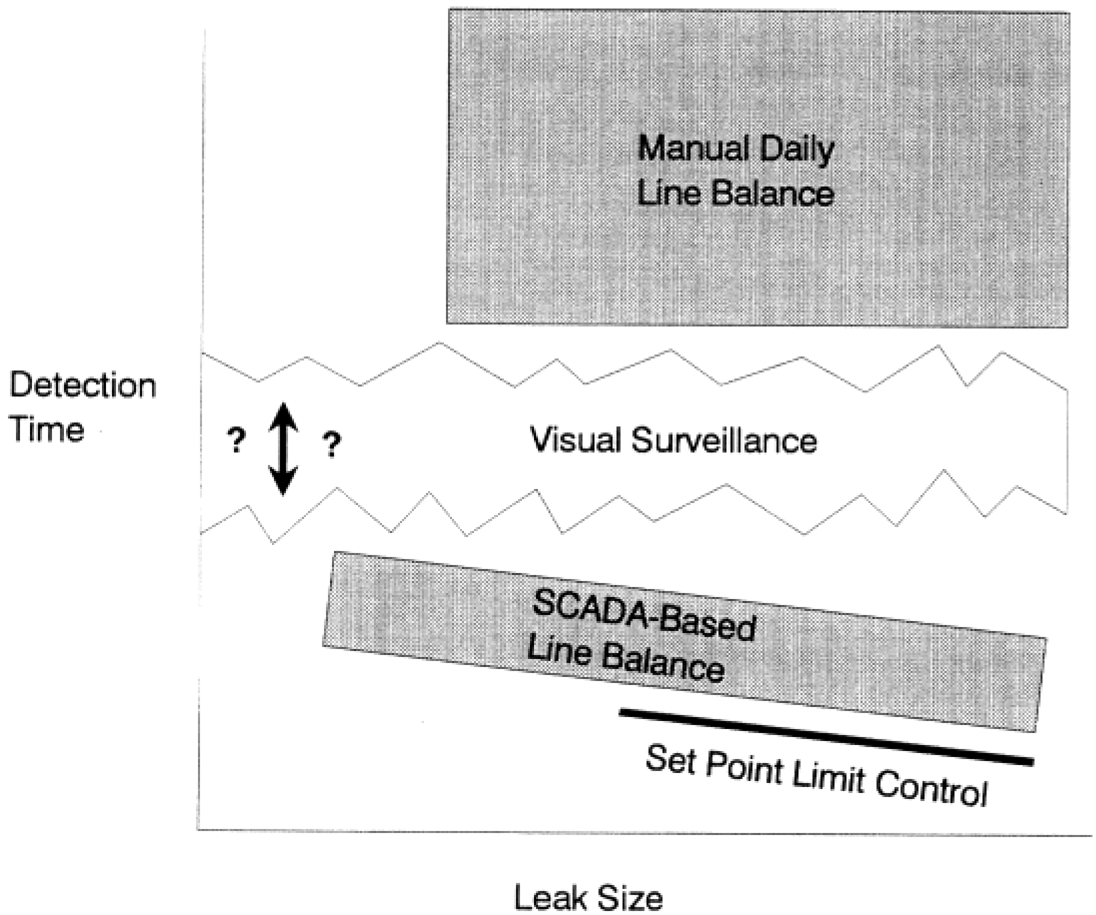

Figure 4-2 Schematic drawing comparing the advantages of different leak detection methods as functions of sizes of leaks and detection times.

leak much more quickly if monitored on an hourly basis.) These systems are relatively expensive to install and require metering devices on all inputs and outputs to a given pipeline system. Their application to marine liquid pipelines has only recently become practical, owing to reductions in equipment size and improvements in the reliability of data gathering and transmission equipment.

If the changing pressures, temperatures, soil and water characteristics, and liquid characteristics could be measured at close intervals along the pipeline, these calculations could conceivably be accurate enough to detect small leaks. In practice, however, these parameters cannot be practically measured in most offshore pipelines, and significant differences result between volumes metered in and volumes metered out. Operators must accept these smaller differences to maintain operations, but assess their trends over time so as to reveal possible smaller leaks. Small leaks are therefore not quickly detected by such systems.

TABLE 4-1 Leak detection methods compared

Leak Detection Method	Strength	Limitation
Visual surveillance	Detects small leaks as well as medium and large.	Monitoring is not continuous.
Setpoint-limit control	Quickly detects large leaks.	Requires steady flows and pressures.
Manual daily line-balance	Detects small to large leaks.	Performed only once per day; human error in calculations can occur.
SCADA-based line-balance	Detects small to large leaks, with speed and accuracy depending on the complexity of the pipeline system.	Threshold leak sizes must be exceeded; does not detect large leaks immediately; requires meters on all inputs and outputs.

TABLE 4-2 Applications of leak detection methods in different types of operations

	Leak detection method			
	Visual	Setpoint-limit	Line-balance[a]	
Pipeline operation	survey	control	Manual—daily	SCADA—continuous
Low-throughput, stable operations	X	X	X (Liquid)	
Low-throughput, transient operations	X		X (Liquid)	
Medium-throughput, stable operations	X	X	X (Liquid)	
Medium-throughput, transient operations	X		X (Liquid)	
High-throughput, stable operations	X	X		X (Liquid)
High-throughput, transient operations	X			X (Liquid)

[a] Can be used only where metering exists or can be readily installed.

Table 4-1 summarizes the strengths and limitations of the varied options under different conditions. Table 4-2 is a guide for determining which leak detection method is effective for a given type of operation.

Future Leak Detection Technology

In the short term, no substantially new technology for leak detection is on the horizon, although current technologies will be improved. Technological development in the area of leak detection methods is being driven by industry to address the limitations of existing methods. Statistical analysis of flow and pressure rates of change and modeling of system transients are developing areas are basically mathematical analyses of operating parameters. "Sniff" systems, commonly used onshore, consist of tracer tubes buried next to the pipelines, which continuously monitor the tube contents for the presence of hydrocarbons, thus indicating a pipeline leak; they presently have a very limited range (approximately 10 miles), and their effectiveness is compromised in the offshore environment due to the continuous decay of marine life which exudes hydrocarbons (Jolly et al., 1992).

Responding to Leaks and Other Emergencies

A variety of systems are in place to address emergencies associated with marine pipelines. Emergency shutdown systems, flow restricting check valves, and pipeline isolating block valves minimize or prevent leaks, and emergency response procedures and planning efforts mitigate the effects of leaks. In addition, personnel evacuation and facility security measures are initiated for approaching storms and hurricanes, and integrity verification checks are made prior to restarting a pipeline.

Emergency Shutdown and Platform Isolation Systems

Emergency shutdown systems on transmission pipelines include high-and low-pressure switches or automatic pilots and, where metering exists, high flow switches at the originating points. Additionally, an emergency shutdown capability exists locally on the platform and, in some cases, remotely from a central control center. For production pipelines, automatic "cascading" shutdown systems are used, with shutdown initiated by switches that sense pressures (or rates of pressure change) that are higher or lower than preset limits. Emergency shutdown capability exists at the platform, and, in some cases, on a nearby companion platform as well.

Manual, remotely operated, or automatic block valves at platforms and onshore facilities are used to isolate transmission pipeline systems. Check valves at most subsea tie-ins prevent backflow from the trunkline into a failed section of line. On production lines, automatic valves on platforms at either end of the pipeline are used to isolate the pipeline from the platform and, in the event of a platform incident, the platform from the pipeline. Pipelines that carry hydrocarbons aboard platforms represent sources of fuel that must be quickly isolated and protected from any and all emergencies which could occur within the platform's process and handling facilities. A platform's emergency shutdown and safety systems can be effective only if the platform can be isolated from the additional volumes of fuel that pipelines transport and contain (Cullen, 1990). The 1988 *Piper Alpha* accident in the British North Sea, which killed 167 crew members, and the 1989 South Pass 60 accident, which killed 7 and injured 10, were both platform fires in which inadequate isolation of platforms from pipelines containing gas was a contributing factor.

To isolate incoming and outgoing liquid, gas, and multiphase pipelines, operators typically use a flow-restricting device (FRD), located (and protected) to ensure long-term reliability. Ideally, these valves are located as close as possible to the boarding riser (the pipeline carrying product onto the platform), and placed above the splash zone, but below the operating decks of the platform. Typically, the devices are placed more than 12 feet above water level, and often much higher. However, subsea valves are sometimes used, after due consideration of the methods used both to actuate the valve and to periodically verify its operability. The FRD may be fail-safe, capable of operation with a total loss of power, air, hydraulic, and communications interface. The seats and seals are usually of fire-safe design, capable of withstanding extreme temperatures, and the FRD is protected against damage from physical contact, using a mechanical or structural barrier if required.

The FRD is either self-acting (that is, automatic) or is linked with the platform's emergency shutdown (ESD) system. FRDs can be remotely operated, but only if they are monitored continuously from a control center with fail-safe and immediate communications to indicate platform emergencies which would initiate immediate FRD actuation. In all of these cases, the boarding pipeline systems are designed to safely accommodate the pressure surges and flow stoppages which would accompany FRD actuation.

The FRD typically consists of a ball or gate valve on incoming and outgoing gas and multiphase lines and on incoming liquid lines. On outgoing lines, a check valve is deemed adequate, as long as it meets the other fail- and fire-safe criteria. For pipelines requiring continuous operation, even in the event of platform emergencies, consideration is sometimes given to "protected" or subsea emergency bypasses, which can be used safely throughout the duration of platform emergencies.

Regulatory Requirements

OPS regulations contain performance-oriented requirements for responding to abnormal and emergency pipeline conditions. In addition, there are prescriptive requirements for the design and annual inspection of overpressure safety devices which prevent operating pressures from exceeding 110 percent of their normal limit. The performance requirements cover methods of detecting and responding to abnormal conditions by monitoring pressures, flows, and other operational data. Response to abnormal or emergency conditions can involve performing an emergency shutdown, reducing operating pressures or flows, or other actions deemed necessary. Isolation valves are required at all pump stations, storage tank areas, lateral takeoffs, and at locations along the pipeline that will minimize damage or pollution due to a liquid pipeline release. It is left for the operator to determine which of these valves to tie-in to a control center or to an automatic emergency shutdown system. This determination is based upon, among other things, both the potential adverse and beneficial impacts valve closures and other operator actions could have on the safety of the pipeline system and other connecting laterals and platforms.

The OPS, under the Pipeline Safety Act of 1992, must issue regulations prescribing the circumstances in which operators of hazardous liquid pipelines must use emergency flow-restricting devices and other systems or procedures to detect pipeline ruptures and limit releases.

MMS regulations, like those of the OPS, generally set the performance levels required rather than requiring specific techniques. Certain shutdown equipment, however, is specifically required. Operators must install high- and low-pressure sensors or other acceptable leak detection systems on the upstream sides of all pipelines that connect with or cross production platforms. These systems are intended to automatically shut in leaking pipelines or production facilities. MMS Regional Supervisors may also require line-balance leak detection systems, which compare the volume of flow into a liquid pipeline at the production platform with the flow at the discharge (30 CFR 250.154).

MMS is considering requirements for further safety systems. A proposed regulation would require operators to install emergency shutdown valves on pipelines downstream from facilities in addition to those which board platforms (Alvarado et al., 1992). MMS considers it desirable that all offshore platforms, including the 70 to 80 under OPS jurisdiction, incorporate systems that automatically cut off hydrocarbon flows to and from platforms in emergencies (Alvarado et al., 1992). Chapter 5 discusses emergency shutdown systems.

It is important to note the absence from OPS regulations of the high-and low-pressure setpoint-limit sensors required by MMS. This apparent inconsistency is due to the basic operational difference between MMS-and OPS-regulated lines. As explained earlier, setpoint-limit systems are appropriate for shorter lines, with single inputs and outputs and stable flows and pressures (typical of MMS-regulated lines). Because of this stability of operation, fairly "tight" setpointlimits can be established. Small changes in operating conditions, normal in OPS-regulated lines, usually indicate abnormal conditions in typical MMS-regulated lines. In the case of longer lines with multiple input and output points and widely varying operating conditions, a more sophisticated alarm system is usually necessary. However, operators of producing platforms under MMS jurisdiction generally require OPS-regulated pipeline operators to install MMS-specified high-and low-pressure sensors and other safety devices before allowing the pipeline operators to install any facilities on the platforms.

Identifying and Notifying the Responsible Operator

As stated earlier, an important element of leak detection offshore is visual detection during scheduled surveillance and incidental observations associated with normal boat and helicopter traffic in the offshore oil and gas industry. As a result, the probability of a leak's being detected by a party other than the actual facility operator is high.

In cases in which leaks are discovered by parties other than the operators, significant periods of time can pass between the actual sighting and notification of the proper operator (National Transportation Safety Board, 1990; Alvarado et al., 1991). With no visual markers and no available locating techniques to help the observer of a surface sheen or other indication of a leak establish the identity and owner of a marine pipeline, attempts to notify the proper parties may be misdirected. In addition, phone or radio calls to platforms in the vicinity or to local agency offices may go unanswered or, if answered, may be of no help in establishing the operator(s) required to take action.

A similar potential for communication inefficiencies exist even once the proper operator is established. In many cases, the pipeline operator will not have the instantaneous capability of shutting down the facilities injecting into the pipeline system or of isolating the leaking segment (Alvarado et al., 1991; Howard et al., 1991; National Transportation Safety Board, 1990). Production facilities that inject into pipelines must be shut down in a properly sequenced fashion to preclude the development of pressure surges or other unsafe consequences on injecting production platforms. As a result, proper procedures for shutting down and isolating a leaking pipeline involve a series of phone calls to operators of all platforms which are connected to the pipeline system. In many cases, these platforms are unmanned or, if manned, personnel may not be able to respond immediately. As a result, time may be lost in attempts to initiate a timely shutdown due to these inefficiencies in the communications procedures. A more effective, standardized process of notification is needed.

A standardized reporting process could be used, possibly through a 24-hour attended center where notifications can be made by telephone, appropriate information taken, and the notice redirected to the various operators and agencies who must respond. Among pipeline and production facility operators, a "call wheel" or other similar process would allow operators to pass information along efficiently, so that system integrity checks can be initiated and the responsible operator identified. The notification center could use a standard checklist to capture as much valuable information as is available, allowing the information to be forwarded in a standardized reporting format. This information might include the block and/or coordinates of the spill location; the size and color of the sheen; the direction of travel of the sheen; the existence of marine vessels or platforms in the area; and the presence and nature of any gas bubbles.

Once the responsible operator was identified, the next phase of notification communications would begin. Operators in general and pipeline operators in particular, would need an efficient and reliable means of contacting operators of all connected facilities. Each operator might have 24-hour attended phone numbers for all operators of connected facilities, or equivalent means of immediately contacting all those operators who must take timely action. In addition, this process should include prompt notification to the proper office of all agencies involved.

Both phases of this notification process (spotter-to-center-to-operator and operator-to-platforms) should be exercised and reviewed periodically to ensure its proper implementation and effectiveness. During these exercises, critiques should be performed so that areas of needed improvement can be identified. In addition, as pipelines are transferred from one operator to another, a means of updating all spill notification and emergency response numbers should be incorporated. This updating of telephone numbers should be implemented concurrently with the transfer of ownership. Spill volumes can be reduced, and spill containment and cleanup efforts improved, with a streamlined and reliable spill advisement system.

FINDINGS

Corrosion, while the most commonly reported cause of pipeline failures, presents relatively small risks to the environment or human safety. Corrosion leaks offshore tend to be small, and they tend to occur in predictable locations in the pipes. Operators use a variety of complementary monitoring and control techniques to limit corrosion.

Smart pigs have great promise, but most offshore pipelines are not physically or operationally suited to their use. The accuracy of smart pigs in locating defects is also rather poor, and the penalties for inaccurate defect location are much higher offshore than onshore, because of the much greater cost of access to the pipeline.

A combination of complementary leak detection systems, suited to the individual pipeline system, is the is most effective approach.

The discoverer of a leak at the water surface often has no way of identifying and notifying the responsible pipeline operators in a timely way. Better notification systems are needed.

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5

Avoiding Outside Interference with Pipelines

Marine pipelines' most serious risks to human life and the environment have to do, not with corrosion, but with larger scale damage from anchors, fishing nets, and storm-induced failure of the supporting sediments (see Chapter 2). In shallow waters (less than about 15 feet), collisions of vessels with inadequately buried pipelines can kill (as shown by the *Northumberland* and *Sea Chief* cases, in which fishing vessels burned and crew members died after the vessels struck exposed pipelines in shallow water). In deeper waters, anchor and net damage has been responsible for more than 90 percent of the pipeline oil pollution recorded on the OCS between 1967 and 1990; the four largest spills—all caused by anchor damage, and totaling 211,000 barrels—accounted for 85 percent of the volume of pollution from pipelines during this period (see Chapter 2). At a minimum, the vessel may lose valuable gear, such as snagged nets or anchors.

No available sensor technology allows moving vessels to detect pipelines at a distance, and thereby avoid them. Satellite-based location technology is improving rapidly, but it is neither accurate enough nor widely enough used to be relied on. (In any case, pipelines—and especially older pipelines—are often not accurately charted.) It is therefore incumbent on the operators of pipelines to protect against interactions with vessels. In some cases, such as the anchoring of supply boats near platforms, improved communications between platforms and vessels can provide protection. In others—such as vessels that operate in shallow waters—adequate pipeline burial is the only satisfactory measure. For this reason, regulatory standards and sound engineering practice require pipelines to be sunk below the bottom in shallow waters (generally those less than 200 feet deep). The minimum depth of cover is set at 3 feet (18 inches in rocky soils). While loosely referred to as "burial," this procedure generally does not include covering the pipeline with sediments; currents are relied on to cover the pipeline in time.

The problem of burial is complicated in some parts of the Gulf of Mexico by the area's coastal dynamics, which feature large movements of sediments and a general pattern of shoreline erosion and retreat, modulated by storms. Pipelines near the shore, or crossing the shore, may become exposed as a result of this sediment movement. In some cases they may even work their way up from their original depth of cover unless they are adequately weighted or otherwise stabilized.

COEXISTING ACTIVITIES

The intensity of all types of offshore use increases near the coast, where water is shallowest and pipelines most densely distributed. A network of large- and medium-diameter transmission pipelines move production ashore from both nearshore and deepwater fields, and a profusion of smaller flowlines and gathering lines interconnect wells and platforms.

Except for large cargo vessels and tankers, and in the immediate vicinity of maintained channels, traffic in this area operates outside of any marked channels or fairways, traveling courses governed by the skills, prudence, and experience of individual skippers, who are often—usually, in the case of fishing vessels—unlicensed and without formal training, although they may be highly skilled and experienced.

Oil and Gas Field Activities

Serving the oil and gas fields in the Gulf at any one time are several hundred oil field supply vessels from 60 to 200 feet long; the numbers roughly parallel the level of drilling activity. These vessels work closely around rigs and other structures and must anchor in areas with high concentrations of pipelines (Reed, 1987).

Self-propelled and barge-mounted mobile drilling and workover rigs with extendable "jack-up" legs operate in shallow waters; in deeper waters, rigs use multiple-point mooring systems and anchors. The footings and anchors of these rigs can also crush or snag pipelines (Reed, 1987).

Fishing

Fishing vessels in even greater numbers ply the same waters. About 20,000 shrimping vessels, 20 to 200 feet long, operate bottom trawls that can make direct contact with up to a square mile of seabed in a single day (Baron-Mounce, 1991). Large shrimping vessels can trawl in water up to 500 feet deep, but the vast majority of shrimpers are smaller vessels that operate in waters less than 50 feet deep and can work in coastal bays less than 5 feet deep (Gulf States Marine Fisheries Commission, 1988).

About 50 menhaden purse seiners up to 200 feet long (commonly referred to as pogey boats) operate in shallow coastal waters. (There were about 80 operating during the late 1980s). Menhaden seiners are limited to daytime operations and excluded from bays and inlets. They work offshore of the Louisiana coast within 10 miles of land, where the menhaden schools are found in waters less than 80 feet deep. With drafts of about 14 feet, these vessels commonly maneuver in very shallow waters, to the point of stirring up bottom sediments with their propellers (Gulf States Marine Fisheries Commission, 1988).

Smaller longliners and other fishing vessels, both commercial and recreational, operate throughout the Gulf, often congregating around offshore oil and gas structures, which attract some species of fish.

Fishing vessels frequently snag their nets, trawls, and other gear on unseen obstructions on the bottom. A recent atlas of the sites of such "hangs" reported by shrimpers in the northern Gulf of Mexico includes the approximate locations of more than 7,500 sites where shrimpers have lost or damaged gear in water depths up to 300 feet (Graham, 1988). Of the reported hangs, 89 percent had no identified cause; 3 percent were thought to be caused by natural formations; and 4 percent were attributed to lost cargoes, ship and plane wrecks, anchors, and a variety of other human-made debris, exclusive of pipelines.

Fewer than 1 percent were attributed to pipelines. Of course, these figures give no real indication of the frequency with which pipelines damage fishing gear, because most pipeline hangs, fortunately, do not result in retrieval of recognizable pipeline sections or fittings or visible product loss.

To compensate for such losses, the state of Louisiana and the National Oceanic and Atmospheric Administration (NOAA) of the U.S. Department of Commerce each dispenses funds collected from the offshore oil and gas industry to fishermen who make plausible claims. The federal "hang fund" is in effect on the OCS, and the Louisiana fund in state waters. NOAA publishes the locations of these sites in the weekly Notice to Mariners; once a hang has been reported and noticed from a single location, no further compensation of fishermen for damage at this location is permitted. The Louisiana Fishermen's Gear Compensation Fund, operated by the Louisiana Department of Natural Resources, maintains no database of hang locations; claims are limited to $5,000 per incident, and to no more than three per year per claimant. From the fund's inception in 1979 until February 1993, 5,252 claims were filed, of which 4,084 were approved for payment, totaling about $6.8 million (Hinojosa, 1993).

Cargo and Other Traffic

Finally, the area is traversed daily by up to 20 large self-propelled cargo vessels and tankers, and a greater number of barge tows moving to and from ports on the Mississippi River, the Louisiana Offshore Oil Port (LOOP), Galveston, Beaumont, Lake Charles, Pascagoula and Mobile. Subsurface oyster shell reefs are also mined by dredging in central Louisiana bays and coastal waters. Vessel traffic statistics collected by the U.S. Army Corps of Engineers are difficult to interpret but provide an overall indicator of the level of activity in Corps-maintained waterways and at locks; in 1985 it was estimated that as many as 3 million vessel trips occurred in 24 northern Gulf of Mexico waterways between Pascagoula, Mississippi, and Beaumont, Texas (Reed, 1987).

NEARSHORE AND COASTAL DYNAMICS OF THE GULF OF MEXICO

The Gulf shoreline is constantly shifting. The northern Gulf, where both pipelines and vessel traffic are most concentrated, experiences rapid shoreline erosion in places and frequent severe storms, which may expose pipelines that were originally safely buried. Avoiding interference by vessels requires careful engineering and well-developed inspection and maintenance programs, in addition to care and skill on the parts of vessel operators.

Patterns of erosion and shoreline retreat vary dramatically. Along the Louisiana coast, shoreline retreat is generally rapid, as shown in Figure 5-1.[1] Along the Gulf Shore, however (Figure 5-1) retreat averages 60 feet (18 meters) per year on the barrier islands south of Houma and 12 to 18 feet (3.7 to 5.5 meters) per year along the western Louisiana and eastern Texas coasts. Storms can cause wave-and current-induced movements of nearshore bottom sediments, barrier islands, and shorelines that can affect the depth of burial and integrity of pipelines laid in waters less than about 60 feet deep (Tubman and Suhayda, 1976). As shorelines retreat, sediment is excavated from the shoreface, which can expose or undermine pipelines and other fixed structures (Williams et al., 1989).

[1] Figure 5-1 gives erosion or accretion rates in meters per year.

Areas that are more dynamic in terms of shoreline and sea bed sedimentation and erosion require the most attention from pipeline builders and operators and from vessel operators. The variability of shoreline retreat provides one means of classifying the northern Gulf of Mexico into geological regions that are meaningful to pipeline safety. Wicker and colleagues (1989) followed this approach, dividing the area into four regions, from west to east: the Texas Barrier Island System, the Strandplain-Chenier Plain System, the Mississippi Delta System, and the North-Central Gulf Coast System.

Texas Barrier Island System

From the Mexican border to Rollover Pass on Galveston Bay, extensive lagoons with relatively little riverine freshwater and sediment input lie behind large, continuous, sandy barrier islands. Shoreline retreat exceeds 12 feet (3.7 meters) per year only along the headland adjacent to eastern Matagorda Bay, except at the ends of barrier islands. Offshore, Holocene sediments, generally of sandy muds, form a veneer less than 3 feet thick overlying a highly oxidized and cemented Pleistocene clay formation (Anderson et al., 1992). Thicker Holocene sequences have filled valleys carved across the shelf by the Trinity and Sabine Rivers during lower sea level stands and are associated with large sand and shell banks thought to be relict coastal barrier islands (Siringan and Anderson 1991).

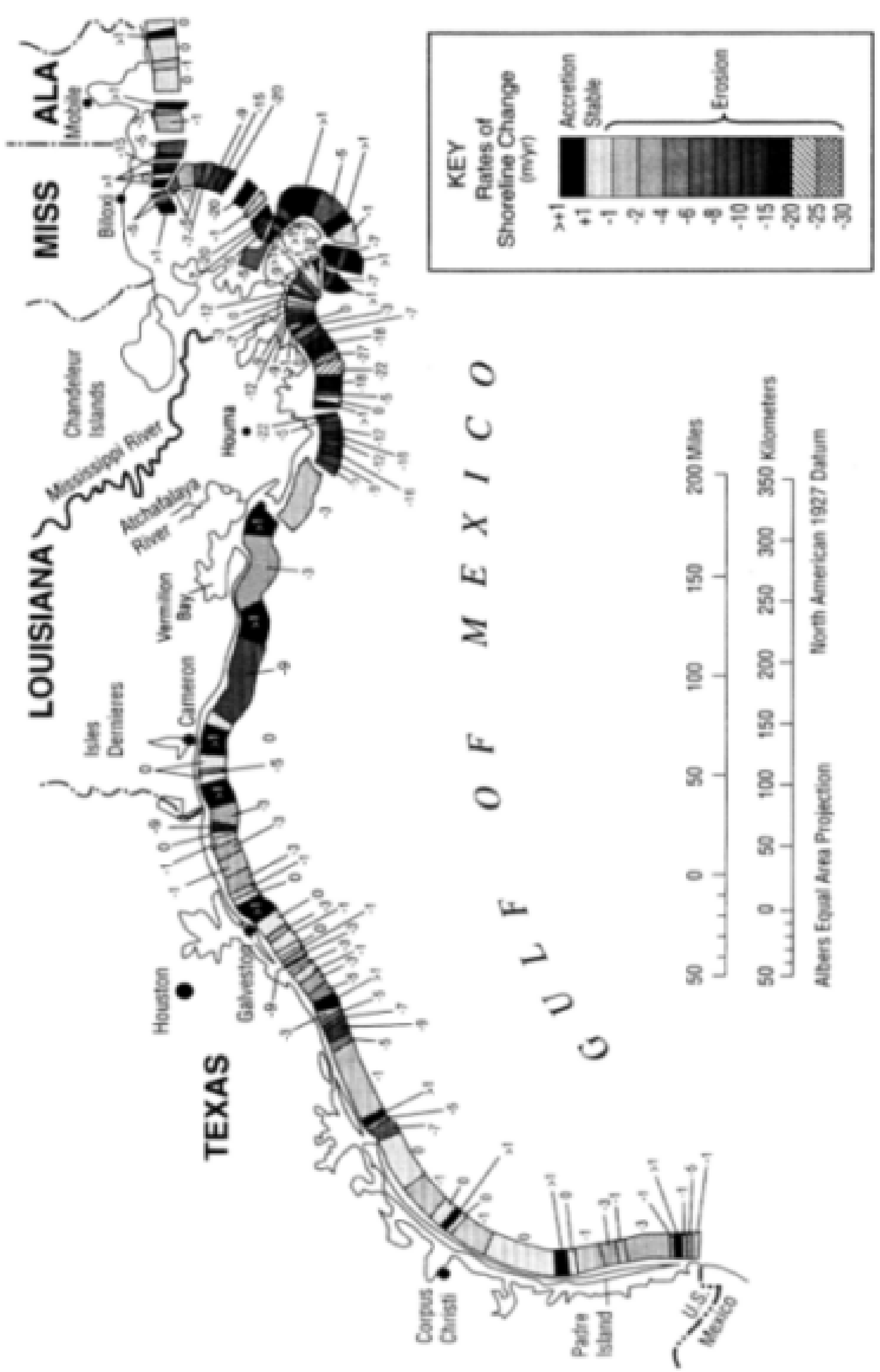
Shoreline dynamics are relatively predictable. The oxidized clay sea bed may be difficult to trench to uniform depths. Relatively low rates of shelf sedimentation may prolong natural filling of pipeline trenches and expose unburied pipelines to storm forces.

Strandplain-Chenier Plain System

Between Rollover Pass and Vermilion Bay, Louisiana, much of the shoreline consists of an eroding marsh scarp fronted by sandy and shelly beaches. Where beaches are well developed they are perched on marsh deposits. Inland, marshes are interrupted by older beach ridges with oak trees, known as cheniers (Russell and Howe, 1935). Shoreline retreat along much of this stretch averages 30 feet (9.1 meters) per year, although it is more stable at its eastern and western ends. Recently deposited sediments consist of silty clays in a seaward thinning wedge extending out to about the 30-foot depth contour (which lies as far as 20 miles from shore in the eastern section. As much as the upper 3 feet of these sediments can consist of unconsolidated fluid mud in a gel-like clay suspension, deposited by the sediment discharge of the Atchafalaya River and carried westward by coastal currents (Kemp and Wells 1987).

Elsewhere offshore, the shelf is relatively stable and receives little new sediment. The Pleistocene surface either outcrops or lies just beneath the mud line, as is true off of Texas. Deepwater corals and carbonate sediments are found locally on salt domes that rise above the sea bed in 200-to 300-foot water depths.

Rapid retreat of the shoreline and lowering of the shoreface can affect pipeline burial in this area. The presence of fluid mud deposits near shore may make it difficult to determine a true bottom position using traditional acoustic instruments, whether for the pipeline operator attempting to locate a permanent soil surface and comply with burial requirements or for the mariner seeking to ensure adequate clearance under the keel. In addition, wave loadings can fluidize muddy nearshore deposits, causing inadequately weighted pipelines to float upward from their buried positions, and reducing the shear strength of covering soils.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Cameron
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Atchafalaya River
Mississippi River
Houma
Chandeleur Islands
Biloxi
Mobile
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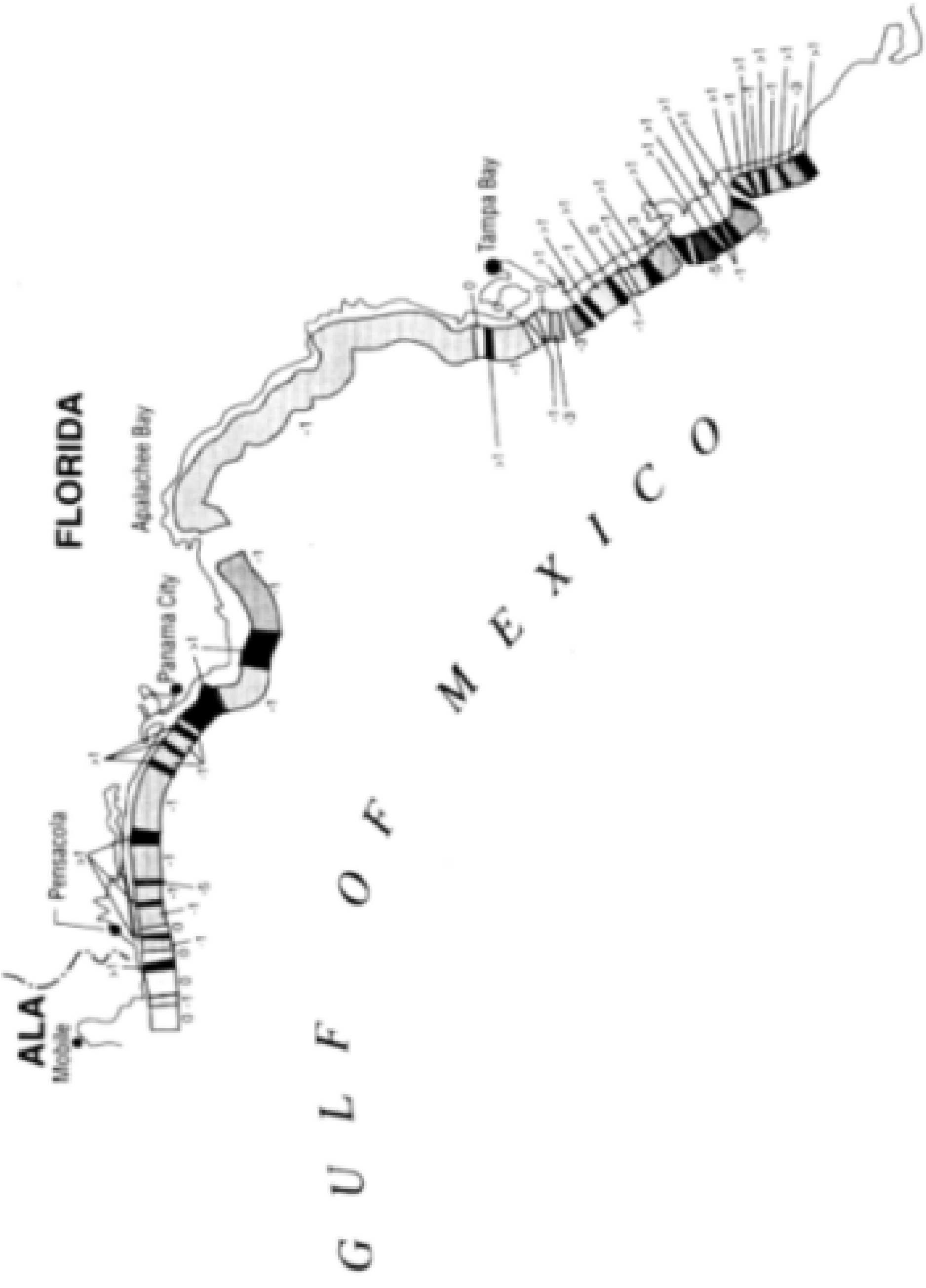

Figure 5-1 Map of the Gulf of Mexico shoreline, showing rates of shoreline erosion and accretion (meters per year). (Louisiana Geological Survey, 1991)

Mississippi Delta System

This system is a composite, including the Mississippi and Atchafalaya river mouths and the barrier island chains that outline the rest of the Louisiana coast east of Vermilion Bay. Except for short segments, virtually all of this shoreline is retreating at more than 18 feet (5.5 meters) per year. Land-building at the river mouths is occurring in Atchafalaya Bay, 5 to 10 miles inland of the Gulf coast, and to a lesser extent at the heads of some passes in the "bird foot" Mississippi delta. Land and inner shelf sand banks built during delta-building sequences of the Mississippi in the past 5,000 years take up much of the continental shelf, so that the mouth of the modern Mississippi is perched on the edge of the continental slope. Because of erosion associated with ancestral Mississippi River channels during lower sea level stands, and a general downwarping of the crust, the Pleistocene surface, which is largely exposed on the continental shelf to the west, lies 200 to 900 feet below the modern seabed throughout this area (Kolb and van Lopik, 1958). Muddy sands cover the shoreface and shelf, because most of the mud associated with discharge from the modern Mississippi is deposited off the continental shelf, while that from the Atchafalaya is retained relatively near shore and moves mainly to the west.

Extensive oyster reefs, no longer alive, front the coast immediately offshore of Atchafalaya Bay, but most of the rest of the shoreline outside of the bird foot delta itself is characterized by more or less continuous sandy barrier islands. The Chandeleur and Breton Islands east of the river mouth are moving landward, while the islands east of the delta, defining the seaward boundaries of the Terrebonne and Barataria estuaries, are narrowing and breaking up in place. Much of this deterioration is attributed to the high rate of subsidence of the deltaic plain, as the thick underlying column of Holocene sediment consolidates and compacts (Penland et al., 1985). New passes are formed through these islands with every major storm, and often do not seal in fair weather, because sand supplies are so limited.

Around the margins of the bird foot delta of the Mississippi, at the edge of the continental shelf, special conditions apply that can greatly affect pipeline safety in this area of concentrated oil and gas development. Unconsolidated mud accumulations, rapidly deposited during high river flows, move downslope in mass movements when disturbed by storm waves. Pipelines and structures in the path of such movements can be moved and otherwise exposed to severe stresses, which may cause failure. Pipelines in this so-called mudslide area are laid on the surface, so as to ride over the moving sediments, and are equipped with breakaway joints and check valves to limit damage and loss of hydrocarbons. (Because these areas are at depths of more than 200 feet, there is no requirement for burial.)

Inland of the barrier islands and bird foot delta, the highly organic sediments that make up the deltaic plain marshes are also experiencing subsidence that, when combined with global sea level rise, can total between 0.5 and 1 inch per year of "relative sea level rise" (Penland and Ramsey, 1990). As a result, coastal marshes are being converted to open water in Louisiana at rates as high as 40 square miles per year, and averaging about 28 square miles per year over the past 50 years (Dunbar et al., 1992). Pipelines and other structures that were constructed in the marsh are now exposed to wave forces. Mariners must find channels and navigate through waterways that retain few of the visible boundaries shown on charts. Most navigation channels crossing Louisiana's coastal plain have experienced substantial bank erosion, widening in some cases to more than twice the authorized channel dimensions (Wicker et al., 1989). Pipelines that were once buried beneath the land surface can protrude from the eroding banks of widening navigation channels and pose a hazard.

The Mississippi Delta System presents a variety of problems to pipeline engineers. Barrier island migration, breaching, and erosion on both bay and Gulf shorelines are unpredictable. Fine sand shoals offshore are prone to liquefaction. Mudslides and fluid mud complicate pipeline installation and maintenance around the bird foot delta. Loss of marshes in the interior of the coastal plain and generally unstable soils make channel margins unstable and prone to erosion.

North-Central Gulf Coast System

This system extends east from the mouth of the Pearl River along the Mississippi and Alabama coasts into Florida and shares many of the features of the Texas coast, including its relative stability. It is characterized by white sand beaches and large continuous barrier island chains. Shoreline dynamics can be relatively dramatic in the vicinity of tidal inlets, but despite a relatively high wave energy regime, shoreline retreat is generally less than 6 feet (1.8 meters) per year. Nearshore and shelf sediments are sandier than in the other provinces, and include shell, gravel and carbonate rubble (Shultz et al., 1990). Sediments in the shallow subsurface of the inner shelf were deposited by fluvial and coastal systems that developed on the shelf during Pleistocene sea level fluctuations and were reworked during subsequent sea level rise (Parker et al., 1992). Modern sedimentation on the inner shelf has been minor and is restricted to the vicinity of coastal bays and inlets.

Shoreline dynamics are relatively predictable. The sea bed may be difficult to trench to uniform depths where hard bottoms are found. Relatively low rates of shelf sedimentation may prolong natural filling of pipeline trenches and expose unburied pipe to storm forces.

PIPELINE AVOIDANCE TECHNIQUES FOR VESSELS

At present and for the foreseeable future, it will be impossible for moving vessels to avoid pipelines by detecting them at a distance. The next best method, highly accurate position location for vessels, is on the horizon. However, one must also know the positions of all pipelines in the vicinity, and pipelines in general do not appear on navigational charts with the precision necessary for vessels to thread their ways among them. Moreover, few coastal charts have been produced using recent highly accurate positioning offered by GPS (Global Positioning System). For vessel operators, adequate training can help avoid the more obvious hazards. Better communication between vessels and pipeline operators about the locations of some pipeline hazards could also be achieved. As a practical matter, avoiding interactions between pipelines and vessels will remain the task of the pipeline operator (generally by ensuring that pipelines are not exposed to vessels and their gear).

The Role of Technology in Pipeline Avoidance

No sensor technology is available for detecting pipelines at a distance. (Side-scan sonar is routinely used to locate pipelines under water, but is incapable of identifying a pipeline that lies ahead of a moving vessel.) Eventually, a forward-looking metal detector suitable for avoiding collisions with exposed pipelines might be approached by techniques being developed by the military. The perfection of a device that can distinguish a pipeline valve from a discarded appliance on the seafloor is certainly not at hand, and a device that produced too many false alarms would be useless, and would simply be disabled by operators. Further development by the military, followed by system simplification and major cost reduction, will be necessary before commercial applications are practical.

Position Location Techniques

The state-of-the-art in position-finding equipment is GPS, which uses satellite signals for determining a vessel's position at sea. This military system provides two levels of accuracy: the Precise Positioning Service (accuracy 17.8 meters) for military purposes and the Standard Positioning Service (accuracy 100 meters, owing to certain errors deliberately introduced into the satellite signal) for all other users. Besides indicating a vessel's location (latitude and longitude), most GPS terminals ate combined with simple calculators or computers that provide information on future positions (or way points), speed (based on elapsed time from the last location), and—when properly linked with the vessel's compass—the effects of currents and winds on the vessel's actual progress.

The U.S. Coast Guard's Differential GPS (DGPS) program, expected to be available in some areas by the mid-1990s, will offer nonmilitary users an accuracy of 8 to 20 meters (25-70 feet). DGPS terminals process the standard low-accuracy GPS signal in combination with the signals of terrestrial marine radiobeacons to correct errors inherent in the GPS service. The technique is already in proprietary use, for example by hydrocarbon exploration vessels. An accuracy of 8 to 20 meters is considered sufficient for cargo ships—the main intended beneficiary of the program—to navigate in harbors and harbor approaches. Ultimately, all coastal waters of the United States are expected to be covered (U.S. Coast Guard, 1992).

The GPS position of a vessel, of course, may be more accurate than the chart available to the mariner or the plotted position of a platform or pipeline. Improperly charted islands, headlands, and other fixed objects are a recurrent problem for mariners, but not surprising when one realizes that the surveys on which a chart is based may have been made a century or more ago, when celestial observations and accurate time were the sole basis for position determination.

In any case, most charts used by mariners do not show pipelines on the seafloor. Large-scale charts of harbors, estuaries, or rivers indicate pipeline and cable crossings, but seldom show the path of a pipeline or cable across a bay or along a channel. Detail and harbor charts often clearly indicate areas that are designated anchorages or prohibited zones, but generally do not indicate pipelines.

Integration of vessels' position-keeping system—presumably DGPS—with an electronic chart system that had a clear and nonfatiguing display would permit a warning light or buzzer to alert the operator to the vessel's arrival in a dangerous area. Current systems are limited to point, rather than zone, hazards, but "fuzzy logic" systems are being developed to correct this limitation. Danger zones would, of course, include platforms and/or rigs, but could also include pipeline junctions, fittings, or exposed sections of pipe. The electronic charts must be prepared and maintained, software written to integrate the charts with the DGPS signals, operators trained, and guidance provided for evasive or preventive actions.

Sophisticated GPS or DGPS systems with electronic charts will be used by contract service vessels only if they are required by OCS operators as conditions of obtaining contracts. It is unlikely that such systems will be economically justified for fishing vessels in the foreseeable future.

Avoiding Pipelines when Mooring or Anchoring at Platforms

The use of anchors by supply and service vessels in areas of dense pipelines or flowlines adjacent to offshore installations presents particular safety issues. In many cases, it may be difficult or impossible for a vessel operator to ensure that a dropped anchor will not strike a pipeline or flowline. In such conditions, permanent mooring equipment can often reduce the risk of damage substantially.

In other situations, where there is enough clear bottom area to make anchoring feasible, platform operators can give vessel operators detailed and timely information on the local pipeline and/or flowline network, with preferred anchoring areas clearly marked.

To simplify pipeline avoidance in these congested areas over the longer term, future pipeline installations can be placed together in well-defined "corridors," to the extent practiced.

Pipeline Location Data

Adequate maps of pipeline locations would, in principle, make it possible to inform vessel operators of areas in which pipelines might be encountered. Collisions of vessels with pipelines are confined to shallow waters, mainly under state jurisdiction, where data on pipeline location, ownership and condition have not been systematically collected and put in accessible and comprehensive data bases. Some of the necessary information has been assembled by the Minerals Management Service, and some by operators under Office of Pipeline Safety regulation, but it is incomplete, particularly in the shallow waters where it would do the most good.

MMS keeps a detailed data base of all pipelines on the OCS (including OPS-regulated pipelines) and their construction details. It is in the process of digitizing the as-built maps, and plans to incorporate accident data, net hang sites, abandoned lines, and other information on that geographical database. To carry out its responsibilities under the Oil Pollution Act of 1990 (see Chapter 6), the agency will add data on pipelines in state waters to this data base (personal communication, Alexander Alvarado, Minerals Management Service, February 3, 1993). The boundaries of MMS jurisdiction under the Oil Pollution Act, however, do not extend shoreward of the coastal barrier islands, so that bays and channels within that boundary will not be covered (personal communication, E. P. Danenberger, Minerals Management Service, December 2, 1993).

OPS requires pipeline operators to maintain their own detailed maps and records, of gas and hazardous liquid pipelines. These maps have not been incorporated in any central data base.

State requirements regarding mapping and facility data vary widely, but are generally inadequate for this purpose. Louisiana and Texas, the two states with the overwhelming majority of pipeline mileage, rely on operators to keep as-built drawings. California authorities have quite accurate information on pipeline locations for that state's small offshore pipeline mileage, but those pipelines are fewer, with less intricate interconnections, and do not present the same risks to vessels as the network of pipelines in the shallow waters of the Gulf.

Pipeline location data could be gathered relatively cheaply during periodic surveys, using data from the Global Positioning System (GPS). Elsewhere in this report the committee recommends periodic depth-of-cover surveys for pipelines in shallow waters, keyed to GPS locations. Such surveys, if required by all state and federal regulatory agencies, would in a few years produce the necessary location data. Assembling the data in a central data base would be a straightforward task.

The existence of a data base that accurately locates all pipelines would not in itself prevent collisions or pipeline damage. Effective use of this information could, however, reduce the likelihood of serious accidents. For example, a "one-call" notification system, modeled on those used for years by pipeline operators onshore to prevent damage by excavators, could use the data base to inform vessel operators planning operations in a given area of any local pipeline hazards. This notification system could be integrated eventually with the recommended pipeline leak notification system (see Chapter 4), which in turn would benefit from the pipeline data base.

Standards for Vessel Inspection, Licensing, and Training: Implications for Improving Pipeline Avoidance

The United States is a member of the International Maritime Organization (IMO), with the U.S. Coast Guard as its representative. The Coast Guard is responsible for negotiating and administering international conventions and enforcing the maritime laws of the United States with respect to the international conventions for inspecting seagoing vessels such as tankers, freighters, and passenger ships. The international conventions do generally apply to seagoing ships but uninspected vessels such as fishing boats and most of the smaller vessels that serve offshore oil and gas fields are subject to domestic standards. The convention articles, regulations, and resolutions, are designed to protect ships, their crews and passengers, the public, and the natural environment. They serve as guidelines for most national and state laws (although the states may impose more rigid, and in some cases slightly different, requirements in specific areas). The need for uniform standards for vessels on the high seas that call at foreign ports is obvious. Conformance with these standards is strongly supported by the insurance industry, which uses economic forces to encourage the use of proper functioning equipment and the licensing of operators.

Self-propelled drill ships, semisubmersible rigs, or other mobile offshore units, and most U.S. vessels operating in the world's offshore oil and gas fields are inspected vessels. The various IMO agreements do not necessarily apply in their entirety to these vessels, although lights, sound signals, flares, flotation devices, and fire prevention and fighting equipment usually do conform. Generally, however, domestic U.S. laws and U.S. Coast Guard regulations do conform with the IMO Convention on Standards of Training, Certification, and Watchkeeping for Seafarers (STCW).

Fishing boats and several classes of offshore service boats, and other vessels carrying fewer than six passengers for hire, are not required to be inspected. (Crews of offshore service and fishing vessels are not considered passengers; nor are personnel being transferred from shore to offshore rigs considered passengers for hire under the Passenger Vessel Safety Act of 1993.)

The persons in charge of uninspected towing vessels and uninspected passenger vessels are required to be licensed as Operators. To be licensed as an Operator of an uninspected passenger vessel, an individual must pass a written examination and document experience and citizenship. These licenses frequently limit the operator to a specific vessel size and operational distance from shore. At the very least, obtaining the license requires the mariner to learn the Rules of the Road and be able to answer various open-book questions.

Some companies, as well as the U.S. Power Squadron and the U.S. Coast Guard Auxiliary (both volunteer organizations), provide courses and training to help license applicants. It should be noted, that each license requires specific sea service (time served aboard a vessel) and that licensing requirements for offshore service operators are considerably more stringent than uninspected passenger vessel licenses.

Uninspected vessels in the offshore energy industry, such as offshore tugs, are generally operated, for insurance reasons, by persons with Master or Mate licenses, which are normally required only for operators of inspected vessels. At minimum, persons operating these uninspected vessels must possess a U.S. Coast Guard-issued Operator's license.

Fishing vessels are not required to be inspected, and their operators currently require no license. Congress and the U.S. Coast Guard, however, are considering means of ensuring that these vessels meet certain equipment and stability standards, and that their operators are competent.

There are no data showing that a person who can pass a license examination for uninspected vessels is a better seaman than a thoroughly experienced mariner with years of experience. The skills needed to anchor a work boat near a platform in the Gulf of Mexico without snagging a pipeline on an exposed fitting or the skills needed to successfully drag a double-rigged shrimp trawl across 20 miles of seabed while avoiding many miles of pipeline do not relate to those needed to pass a College Board exam. However, to take full advantage of new technology for vessel positioning, additional, possibly costly training may be necessary; but this training should be encouraged.

PIPELINE BURIAL

For structural stability and protection from outside forces such as vessels and storms, offshore pipelines in waters less than 200 feet deep are sunk beneath the bottom, in trenches. While loosely referred to as burial, this practice does not include covering the pipelines; the pipeline is lowered into the bottom by jetting, dredging, or plow methods, depending on local conditions. Generally currents are relied on to sweep sediments over the pipelines in due time. In cases in which natural sedimentation is inadequate, the pipeline may be covered by mechanical backfilling. Valves, lateral pipeline tie-in assemblies, and other pipeline appurtenances are protected from snagging trawls, nets, and anchors with pyramids of bags of concrete or other protective structures, or by lowering them as needed to prevent snags. The depth of burial required depends on local vessel traffic, soil and shoreline dynamics, and other engineering considerations.

Regulatory Requirements for Depth of Cover

OPS and MMS requirements for pipeline burial differ. OPS requires that pipelines installed offshore in water less than 12 feet deep must be placed at least 3 feet below the bottom in soil (18 inches in consolidated rock); in deepwater ports or navigable rivers and inlets, these depths are doubled (49 CFR 192.327, 195.248). The MMS requires that pipelines originating on the OCS be placed at least 3 feet beneath the bottom in waters less than 200 feet deep. (These regulations could conceivably leave a gap with no burial requirements between a 12-foot water depth and the beginning of the OCS, but normal pipeline construction practice involves burial from the shore to depths of 200 feet. In any case, pipelines that originate on the OCS, whether OPS-or MMS-regulated, are subject to the requirements of their MMS permits, which specify MMS burial requirements.)

Neither agency has a requirement for maintaining the required depth of burial. However, in 1990, Congress reacted to the *Northumberland* and *Sea Chief* accidents with amendments to the Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1671 et seq.) and Hazardous Liquid Pipeline Safety Act of 1979 (49 U.S.C. 2001 et seq.), directing the U.S. Department of Transportation to require operators to inspect all pipelines in less than 15 feet of water to identify and mark with buoys sections that were "exposed" or constituted a "hazard to navigation" (P.L. 101-599, "Improving Navigational Safety and Reducing Vessel-Pipeline Collisions"). In addition, the agency was required to establish a program of mandatory inspections. OPS issued the required regulations in December 1991, requiring operators to survey the pipelines and, by November 1993, to rebury to a depth of three feet any found with one foot or less of cover (49 CFR 192.612, 192.3). By March 1993, with more than 95 percent of the survey completed, only 24.4 miles of such pipe had been found, or 1.7 percent of the 1,456 miles surveyed (personal communication, Cesar DeLeon, Office of Pipeline Safety, March 11, 1993). OPS will consider the results of this survey in determining the need for a mandatory continuing inspection program.

The Pipeline Safety Act of 1992 (P.L. 102-508) extended inspection and reburial requirements to all offshore areas and inland navigable waters less than 15 feet deep (not only those in the Gulf of Mexico, as originally provided).

The committee has no information leading it to believe that the currently required initial cover depths and procedures are either adequate or inadequate. There has been no systematic study of the problem, to the committee's knowledge. Anecdotal evidence suggests that it may be not inadequate initial cover, but rather the loss of cover through erosion or fluidization of surrounding soils, that most often exposes pipelines to interference by vessels. Such was the case in the *Northumberland* and *Sea Chief* accidents. Regulators will need to assess the matter further, perhaps in conjunction with the periodic depth-of-cover surveys outlined later in this chapter. A sophisticated approach, taking into account local variations in shoreline and seabed dynamics, is likely to yield the safest and most cost-effective solutions. Pending the results of such a study, the currently specified initial depths must be considered adequate.

Engineering Considerations in Installation

Installation of a marine pipeline must take into account a variety of local conditions in addition to the minimum regulatory requirements, including soil characteristics, currents, vessel traffic, and the potential for erosion of the shoreline at shore crossings. These factors determine the initial burial depth, the amount of weight coating, and the need for any additional stabilizing features such as pipeline anchors or backfill. Figure 5-2 is a schematic drawing of the decision process involved.

The pipeline must be designed and constructed to maintain its initial depth of cover throughout its lifetime. It is recognized that a buried pipeline may tend to float up or sink down from its initial placement depending on its weight (including contents) and on the density and shear strength of the soil. As explained earlier in this chapter, certain current and wave conditions may "fluidize" soils in much of the northern Gulf to the degree that pipelines may float upwards if they are not adequately weighted or anchored. In major storms, susceptible soils may fluidize enough to present such problems at depths of 60 feet or more.

Erosion by ocean currents can cause other problems with pipeline cover and stability. Pipelines placed in trenches that run parallel to currents may be covered and stabilized by

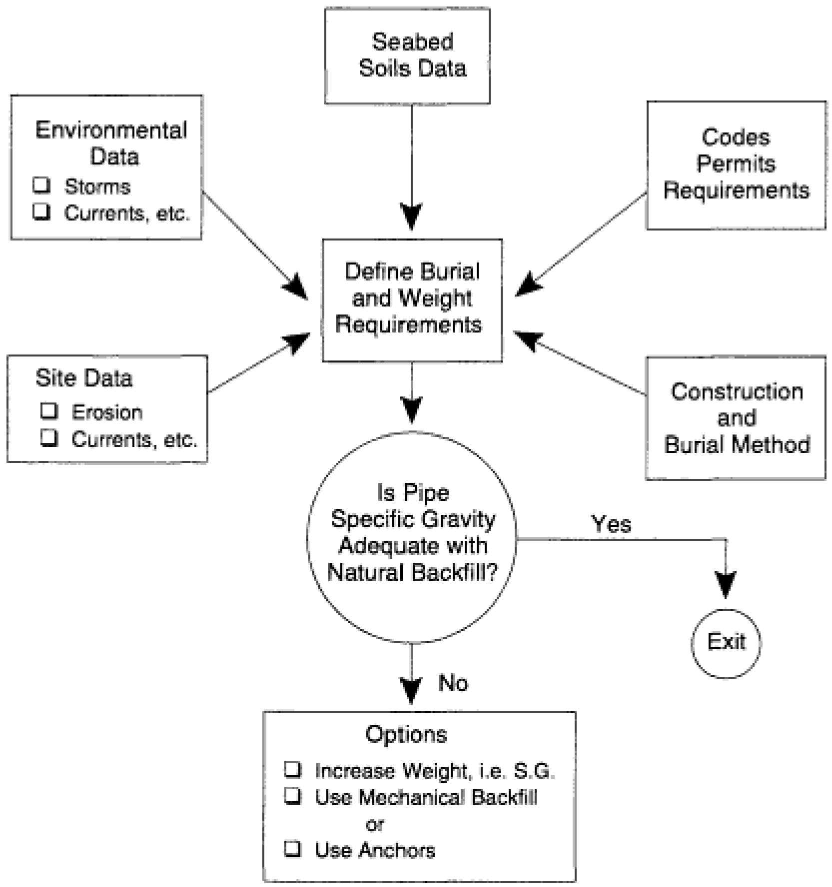

Figure 5-2 Decision process for burial and stability evaluation of a marine pipeline.

sediments very slowly compared with those that run more nearly perpendicular to currents (Mousselli, 1979; personal communication, A. H. Mousselli, July 20, 1993).

Prudent engineering practice involves thorough bottom surveys along pipeline routes, with soil core samples taken at regular intervals. The samples are analyzed for design parameters relevant to specific gravity, grain size, shear strength, resistance, and potential for fluidization. The information derived from such surveys helps in choosing pipeline routes, burial depths, and weight coatings.

Pipelines are inspected at the determined depth of cover by divers using water pressure gauges accurate to within 3 inches of depth. A gauge reading on top of the pipe in the ditch is compared with a second made to the side of the pipeline on normal firm undisturbed bottom, and readings are recorded by a crew on the surface in the dive boat. The two gauge readings tend to average the effects of surface waves. Measurements are almost continuous as the diver swims along the pipeline in the newly created trench. If adequate cover is not found, the burying equipment is required to make additional passes. Initial depth-of-cover information from the gauge readings may be correlated with Global Positioning System location data, to meet MMS and OPS requirements for "as-built" drawings.

One uncertainty in determining the depth of cover in practice is the fact that divers must establish the actual firm and undisturbed bottom, which can be quite indistinct in the unconsolidated sediments found in much of the northern Gulf. Designers of pipelines generally calculate the bottom's location according to a specific shear strength criterion for the soil. But divers test the soil's firmness merely by pressing downward with their gloved hands until they reach resistant soil, and rarely use any measure of shear strength. In practice, however, experienced divers are quite accurate, placing their bottom pressure gauges within about 10 percent of measurements made according to shear strength (personal communication, A. H. Mousselli, October 20, 1993).

Pipelines installed across shorelines through trenches can accelerate erosion and create currents and wave conditions that remove cover from pipelines. The directional-bore installation method, by which pipelines are installed underground, without trenching was proven in the early 1980s for river and canal crossings and pipeline installations that traverse environmentally sensitive areas, highways, and other areas where disturbance of the surface is undesirable. It is today required wherever possible by permitting agencies such as the U.S. Army Corps of Engineers and state coastal zone management commissions. It generally yields lower construction and maintenance costs, in addition to its safety and environmental advantages. Overall bore distances of as much as 5,000 feet are now commonly attainable in pipe diameters up to 36 inches. The pipeline generally crosses the beach at about 50 foot below the surface, and gradually approaches the normal design burial depth at a point well beyond the shoreline. The distance by which the shore end of the bore is set back behind the shoreline can be adjusted to take account of local rates of shoreline erosion.

Periodic Depth of Cover Inspections

Periodic surveys to ensure that adequate depth of cover is maintained are not generally made, although operators are required by MMS and OPS regulations to keep pipelines from being exposed. In many places in the Gulf, such surveys would simplify the problem of meeting that regulatory requirement. Initial depth-of-cover information, with Global Positioning System locations along the pipeline, could serve as a baseline for future depth-of-cover surveys. Because the sediment behavior and shoreline erosion are relatively predictable at different points in the Gulf of Mexico, surveys could be scheduled according to those factors, along with such other factors as the passage of major storms.

Table 5-1 summarizes the characteristics of the shoreline and seabed dynamics that are encountered in various regions of the Gulf of Mexico and identifies the pipeline safety issues associated with these dynamics. Table 5-2 identifies the types of inspection programs that are appropriate to these regions.

An accurate baseline depth-of-cover. record would be established for each pipeline in less than 15 feet of water, based either on the one-time depth-of-cover inspection required by OPS in 1991 (described earlier in this chapter) or on other recent inspections. The depth of 15 feet (enough to accommodate the drafts of large fishing vessels) was defined in the act of Congress mandating the one-time depth of cover survey (P.L. 101-599), based on testimony from the National Fisheries Institute and the American Shrimp Processors Association (personal communication, Cesar DeLeon, Office of Pipeline Safety, March 11, 1994). With such a baseline, subsequent inspections can measure changes in the depth of cover for each pipeline. Intervals between further inspections could be lengthened or shortened according to whether the depth is changing, and at what rate. (One might call this method of scheduling inspections "self-adjusting.")

A second depth-of-cover inspection would be performed within, perhaps, two years

TABLE 5-1 Shoreline and seabed dynamics affecting pipeline depth-of-cover inspection requirements

	Characteristics of dynamics		
Region	Shoreline	Seabed	Pipeline safety issue
Nondeltaic	Localized retreat.	Stable	Occasional exposures at shoreline; deposition on seabed
Chenier plain	Rapid and generalized retreat.	Very dynamic top layer of unconsolidated muds, less dynamic sublayer.	Storm-induced cover loss; gradual cover loss.
Barrier islands	Active dynamics primarily on islands and shoals.	Rapid to gradual generalized siltation; localized erosion and seabed shifting.	Rapidly changing shorelines and island/shoal crossings; storm-induced changes.
River mouth	Very rapid change; some retreat, some advance.	Slumping	Storm-induced slides.

TABLE 5-2 Depth-of-cover inspection needs for different shoreline and seabed regimes

	Shallow water inspection program	
Region	Without occurrence of storm	With occurrence of storm
Nondeltaic	Periodic monitoring of shoreline crossing.[a] If shoreline changes, then investigate near-shore depth-of-cover. Periodic inspection of depth-of-cover is not necessary.	Post-storm inspection of shoreline crossing. If shoreline changes, then investigate near shore depth-of-cover. Post-storm inspection of depth-of-cover is not necessary.
Chenier plain and barrier islands	Periodic monitoring of shoreline crossing.[a] Periodic inspections of depth-of-cover. If shoreline changes, then investigate near-shore depth-of-cover.	Post-storm inspection of shoreline crossing and depth-of-cover.
River mouth	Periodic monitoring of shoreline crossing.[a] If shoreline changes, then investigate near-shore depth-of-cover. Periodic inspection of depth-of-cover is not necessary.	Post-storm inspection of shoreline crossing and pipeline (in mudslide areas only).

[a] Monitored visually with biweekly route survey, but no less frequently than every three months.

of this baseline survey. Its results would determine the next inspection interval. If the depth of cover had remained relatively stable or increased, the inspection interval could be lengthened to perhaps four years in the chenier plain and barrier island regions of the Gulf of Mexico, or to eight years in the nondeltaic regions. On the other hand, if depth of cover is being gradually lost, subsequent inspection intervals would be the same or, if the loss appeared significant, could be shortened. Pipeline operators would determine the necessary inspection intervals. A maximum interval of, perhaps, 10 years should be established by regulation for the chenier plain and barrier island regions and 20 years for the nondeltaic regions. As a part of the ongoing enforcement and auditing effort, the regulating agencies should review operators' shallow water inspection programs, the results of both the baseline and subsequent surveys, and the operators' plans for extending, retaining, or reducing the inspection intervals.

This method would be altered in the case of significant storm activity near the pipeline. After a large storm, a post-storm inspection would be performed for those portions of pipelines in the storm path, as listed in Table 5-2. The initial choice of the storm magnitude that triggers a post-storm inspection, and the path width covered by the inspection requirement, could be based on the results of the MMS inspection program carried out after Hurricane Andrew, in 1992. Again, a self-adjusting approach could be used, in which storm magnitudes and path widths are increased or decreased based on the overall inspection results.

ABANDONED AND INACTIVE PIPELINES

Abandoned pipelines are often blamed for damage to vessels' anchors, hulls, and fishing gear. However, from the surface it is very hard to discriminate between a pipeline—active or abandoned—and the other kinds of debris and obstructions that litter the bottom in the Gulf of Mexico, such as sunken vessels, lost cargoes, and well casings. For this reason, there is very little information on accidents involving abandoned pipelines. The U.S. Coast Guard has a system in place, and research has been conducted, to log the locations of these "hang" sites and obstructions. Unfortunately, in the vast majority of the cases, there is no easy way to establish the nature of these obstructions. In addition, there are no readily retrievable statistics on the injuries and property damage which may have been associated with improperly abandoned pipelines in particular. Because of the broad scope of this problem and the lack of verifiable data upon which to base an analysis, this committee can only speculate on pipelines' contribution to this problem. Additional study is needed to address the larger issue of debris in offshore waters.

It is known, however, that abandonment of offshore platforms and well casings is increasing, as producing fields that have reached maturity are shut-in and their structures abandoned (Francois and Barbagallo, 1992). Oil and gas wells in coastal Louisiana waters are being plugged and abandoned at rates that in recent years have ranged between about 600 and 1,400 wells annually (Aldridge, 1993). Abandoned well casings and platform legs are required to be cut 15 feet below the seabed, and removed within a set time. The production lines associated with these shut-in wells and fields have no future use and are therefore abandoned. The transmission lines, however, will most likely continue to serve other fields, and possibly even newer, deeper water production as well. The extent of abandoned platforms and pipelines correlates directly with the original progression of oil and gas field development from coastal marshes to shallow waters to OCS waters. As a result, most of the lines now being abandoned are in the marshes and shallow, state waters of the Gulf of Mexico.

Abandonment involves the permanent and, for all practical purposes, irreversible process of discontinuing the use of a pipeline. The physical asset is abandoned in the truest sense of the word; no future use or value is attributed to it, and no attempts are made to maintain serviceability. Pipeline systems or segments that are not abandoned, but only idled, decommissioned, or mothballed, are considered to have the potential for reuse at some point in the future. The maintenance and inspection to be performed in these cases is a function of the probability of reuse, the cost and difficulty of remediation which may be required, and the potential impact of the in-place and idled facility on human safety and the environment.

Pipelines today are abandoned, under the regulations of the MMS and OPS, by removing hydrocarbons, filling the pipe with seawater, and capping and burying the ends to prevent them from snagging nets and anchors. Side-scan sonar, diver inspections, or test trawls with nets are required to ensure that burial was effective.

Pipelines are not physically removed unless they are identified as hazards to navigation or nuisances to the fishing or shrimping industries. Removal is costly, and has its own environmental and safety risks. Abandoned pipelines are not inspected regularly, but owners can be required to remediate any that are brought to their attention as hazards to navigation or nuisances.

There is no regulatory requirement at present for the surveillance or maintenance of cover over abandoned pipelines, unless they are determined to present hazards to navigation, interfere with commercial fishing, or unduly impede other uses of the OCS—in which case the owner may be required to remove or rebury the pipeline (Joint Task Force on Pipeline Safety, 1990). However, the Pipeline Safety Act of 1992 (P.L. 102-508) requires OPS to issue regulations requiring the lowering of offshore pipelines—active or abandoned—that represent hazards to navigation, and to study, and issue regulations on, the abandonment of underwater pipeline facilities.

Some states have their own specific abandonment requirements. Louisiana law, for example, requires removal of all abandoned nonburied facilities (except flow lines) in less than 20 feet of water, and the marking of unburied flow lines left in place after abandonment in less than 20 feet of water (Stolls, 1993).

A properly abandoned pipeline poses no risk to public safety or to the environment. However, past abandonment procedures—especially in state waters—were often not as scrupulous as today's. The extent of the problem is unknown. Additional study is warranted.

Much concern is expressed in Louisiana about the growing number of "orphaned" or abandoned production facilities in state coastal waters. Louisiana's Commissioner of Conservation reported in early 1993 that 63 facilities ranging from single-well caissons to multiwell fields complete with flowlines, production barges and tank batteries had been identified as "orphaned", that is, without a competent owner of record (personal communication, H. W. Thompson, February 11, 1993). An industry-sponsored fund has been established to pay for remediation of such facilities. The Louisiana authorities have not reported similar problems with transmission pipeline operators, however. Nor, to the committee's knowledge, has any other state.

FINDINGS

No conventionally available sensor technology allows moving vessels to detect pipelines at a distance, and thereby avoid them. Nor is satellite-based vessel positioning technology, used by itself, suitable to the task. It is therefore incumbent on the operators of pipelines to protect against interactions with vessels, through pipeline burial, and secondarily by establishing adequate communications and notification systems.

Adequate burial of a new pipeline requires a thorough bottom soil survey in advance, to determine the best route, the proper depth of soil cover, and the appropriate weight coating to keep the pipeline from floating upward in soils that may be fluidized by wave action.

From the human safety standpoint, it is particularly important to maintain pipelines at their intended depths of cover in water less than 15 feet deep (a depth that can accommodate the drafts of large fishing vessels). While there is a general regulatory requirement in some pipeline permits to ensure that pipelines remain adequately buried, there is no regulatory requirement to make the periodic depth-of-cover or "hang site" surveys necessary for this purpose. Such surveys, at intervals set by local shoreline and seabed dynamics and the passage of major storms, would improve the assurance of safety, especially on the shifting shorelines of the Gulf. From the environmental standpoint, it is important to eliminate potential net "hangs," where fishing gear may damage pipelines or pipeline equipment.

The committee is not aware of any systematic study of whether the currently required initial burial depths and procedures are either adequate or inadequate. Regulators will need to assess the matter further, taking into account local variations in shoreline and seabed dynamics and the results of the periodic depth-of-cover inspections recommended in Chapter 7.

A properly abandoned pipeline poses no risk to public safety or to the environment. An improperly abandoned pipeline can damage vessels and their gear. Reports by fishermen and others of such damage are difficult to confirm, owing to the lack of systematic data.

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6

Regulatory Jurisdiction and Enforcement

The primary federal jurisdiction over the safety of offshore oil and gas pipelines is shared by two agencies: the Office of Pipeline Safety (OPS) of the U.S. Department of Transportation (DOT) and the Minerals Management Service (MMS) of the U.S. Department of the Interior (DOI). OPS's authority is derived from its status as the agency responsible for pipeline safety, both offshore and onshore, under the Natural Gas Pipeline Safety Act of 1968 (49 U.S.C. 1671 et seq.) and the Hazardous Liquids Pipeline Safety Act of 1979 (49 U.S.C. 2001 et seq.). MMS regulates all aspects of mineral development, including oil and gas production, on the outer continental shelf (OCS), under the Outer Continental Shelf Lands Act of 1978 (OCSLA; 43 U.S.C. 1331). OPS's basic charter is to protect the public, property, and the environment. To those aims MMS adds a mandate to prevent waste and conserve OCS natural resources, taking into account all users and potential users of these natural resources. Under this authority, MMS issues permits for OCS platforms as well as for all OCS pipeline rights-of-way and easements.

State agencies also share in the safety regulation of offshore pipelines. They have direct responsibility for the safety of production platforms and associated production pipelines in state waters. They also may be certified by OPS to inspect for and enforce OPS regulations on federally regulated intrastate transmission pipelines, as described later in this chapter.

This sharing of safety responsibilities has resulted in some jurisdictional confusion and overlap. In addition, the involvement of multiple agencies has increased difficulty of coordinating in safety planning and data gathering, as discussed in Chapter 2.

Other agencies, at all levels of government, become involved in specific areas. The U.S. Army Corps of Engineers issues permits for pipeline crossings of navigable waterways, shorelines, and navigation fairways. It routinely informs other federal agencies of applications for such permits, and furnishes copies of permits to the National Ocean Service of the National Oceanic and Atmospheric Administration for referencing and charting. The U.S. Coast Guard regulates marine navigation generally, and may declare as hazards to navigation exposed pipeline segments or other subsurface obstructions. Finally, the Coast Guard, under the Port and Tanker Safety Act, conducts annual safety inspections of port facilities, including pressure-tests of dock loading lines, and may shut down facilities that fail to meet its standards (personal communication, Gary Chappelle, U.S. Coast Guard, Port Safety and Security Division, January 14, 1993).

While this chapter focuses on the roles of OPS and MMS, it also takes note of the interactions of other regulatory bodies.

FEDERAL JURISDICTION

Marine pipelines fall into two general categories for purposes of safety regulation: those that originate on or are located within the outer continental shelf (OCS), and those in state waters nearer to shore. On the OCS as of late 1992, MMS had jurisdiction over 3,934 miles of so-called production pipelines (those closely associated with production activities), and OPS over about 12,711 miles of transmission pipelines. In state waters, OPS has jurisdiction over transmission pipelines and the states over production platforms and related pipelines. OPS may certify a state agency to carry out inspection and enforcement of OPS regulations on intrastate transmission pipelines in the waters of that state, if state regulations are consistent with federal regulations; state agencies in Louisiana, Texas, Alabama, and California are certified for this purpose. A certified state agency may have additional or more stringent requirements as long as they are compatible with OPS requirements.

MMS regulation is carried out through a permitting program for all OCS pipelines (Pearcy, 1991). The agency issues permits for the installation, modification, or abandonment of pipelines throughout the OCS, under the Outer Continental Shelf Lands Act (43 U.S.C. 1334). (The only exception is a few miles of pipeline permitted by the Department of Transportation under the Deepwater Port Act of 1974 [33 U.S.C. 1501], which applies solely to the Louisiana Offshore Oil Port.[1]) The agency, in granting rights of way, is to ensure "maximum environmental protection by utilization of the best available and safest technologies, including the safest practices for pipeline burial" and "taking into account, among other things, conservation and the prevention of waste." MMS is responsible for ensuring that pipelines are maintained and operated in compliance with their permits, and conducts annual inspections of all offshore facilities under its permit jurisdiction (30 CFR Part 250, Subpart A). Using this permitting authority, MMS Regional Supervisors may impose requirements beyond those set out specifically in the federal regulations. If a pipeline originating on the OCS traverses state waters, MMS verifies that state agencies have reviewed the permit application (Joint Task Force on Pipeline Safety, 1990), but it does not inspect pipelines in state waters.

Division of Federal Jurisdiction

To prevent undue duplication of regulatory efforts on the OCS, the two agencies signed a memorandum of understanding (MOU) in 1976, setting out the following division of responsibilities (*Federal Register* , 1976):

[1] The Louisiana Offshore Oil Port (Loop) is a floating marine terminal in the Gulf of Mexico. It was permitted under the Deepwater Port Act of 1974 (33 U.S.C. 1501), which offered a "one-window" approach to permits and licensing through the U.S. Department of Transportation. It remains the sole facility permitted under that act. OPS regulates the pipeline portion of the facility, and the U.S. Coast Guard the offloading facilities (personal communication, Thomas James, Office of the General Counsel, Louisiana Offshore Oil Port, Inc., February 8, 1993).

> The DOT will establish and enforce design, construction, operation and maintenance regulations for those pipelines extending to the shore from the outlet flange at—(1)each facility where hydrocarbons are produced, or (2) each facility where produced hydrocarbons are first separated, dehydrated, or otherwise processed—whichever facility is further downstream, including on-line transmission equipment but not including any subsequent production equipment. The DOI will establish and enforce design, construction, operation, and maintenance regulations for offshore pipelines extending upstream from the outlet flange described earlier (under DOT responsibilities) into each production well on the OCS.

The intent of this MOU was to allow MMS to regulate those pipelines closely associated with oil and gas production ("production lines") on the OCS, while allowing OPS to regulate those pipelines associated with oil and gas transmission ("transmission lines").

Problems in determining jurisdictional boundaries in practice, and disagreements about regulatory priorities, have led the two agencies to review the MOU (Joint Task Force on Offshore Pipelines, 1990). As of August 1993, negotiations were still underway (personal communication, Carl Anderson, Minerals Management Service, August 3, 1993).

Some duplication of regulatory responsibilities certainly exists, owing mainly to MMS's broad permitting authority. The permits may, in turn, place operational or other requirements on OPS-regulated pipelines in addition to those imposed by OPS. In addition, there is some redundancy in the agency inspection process. MMS inspection activities for permit holders often bring to inspectors' attention violations of OPS, as well as MMS, regulations. Opinions from the Department of the Interior's (DOI) Solicitor's office, however, make it clear that DOI inspectors may not enforce DOT regulations (personal communication, Carl Anderson, Minerals Management Service, January 29, 1993).

In addition, OPS jurisdiction under the MOU extends to some field gathering lines more appropriately considered production lines (MMS's responsibility); producers in these cases must maintain parallel relations with both regulatory agencies.

The potential for duplication and conflict will grow as MMS assumes its new authority under the Oil Pollution Act of 1990 (P.L. 101-380). MMS authority under OCSLA applies only in waters of the outer continental shelf (OCS). However, under the Oil Pollution Act, as implemented by President Bush's Executive Order 12777, MMS is responsible for overseeing oil spill prevention and response activities for all offshore pipelines, in both state and federal waters.

New Authority for MMS Under the Oil Pollution Act of 1990

MMS responsibility for oil spill prevention and response is expanding. The Oil Pollution Act of 1990 (OPA 90), as implemented by Presidential Executive Order 12777, October 1991, gave the agency regulatory responsibility for ensuring spill prevention and response capability for all offshore pipelines, including pipelines in state waters.

OPA 90 amended and expanded the oil spill prevention and response requirements of the Federal Water Pollution Control Act (FWPCA), and transferred regulatory responsibility for oil spill prevention and response at offshore facilities from EPA to MMS and the states. MMS is preparing regulations to implement these acts, mainly through cooperative agreements with OPS and the states.[2]

[2] Offshore state waters, for the purpose of defining the application of the Oil Pollution Act of 1990, begin at an inshore baseline defined as the "coastal line" and extend seaward for three miles (three marine leagues in Texas). The coastal line demarcation excludes waters behind barrier islands and many inshore waterways. Thus, there are marine platforms and pipelines in these areas between state lands and the coastal line that do not fall within the application of the act.

Among other things, OPA 90 requires certification of the "financial responsibility" of offshore operators to the amount of $150 million, to meet potential pollution liability. The U.S. Coast Guard (USCG) in the past certified the financial responsibility of OCS facilities in federal waters, pursuant to the OCS Lands Act. That function has been transferred to MMS under OPA 90 and its implementing Executive Order.

MMS already enforces requirements for pipeline and platform spill prevention measures and oil spill response plans on the OCS. Under OPA 90 these requirements are being revised to meet the "worst case" discharge provisions of the law and are being extended to cover facilities and pipelines in both federal and state waters (other than the Louisiana Offshore Oil Port). The agency is seeking cooperative agreements with coastal states to ensure effective implementation of the new requirements, and is coordinating its rulemaking on oil spill prevention, oil spill response plans (OSRP), and financial responsibility with states to minimize administrative burdens on government and industry (Alvarado et al., 1992). It is also working with the states to determine the total mileage of pipelines in state waters that are affected by the new OPA and FWPCA requirements (Alvarado et al., 1992). Ultimately, MMS plans to add pipelines in state waters to its current map of all pipelines on the OCS (personal communication, Alexander Alvarado, Minerals Management Service, February 3, 1993).

A complicating factor under OPA is that state regulations for offshore pipelines are not preempted by federal oil prevention and spill response regulations. States may impose their own, more stringent requirements for liability limits, financial responsibility requirements, inspection and reporting requirements, and approval of response plans, and may establish their own spill response trust funds. In Texas, the Oil Spill Prevention and Response Act of 1991 imposes roughly the same requirements as the federal law (and, importantly, accepts federally approved response plans). In Louisiana, the Oil Spill Prevention and Response Act also followed the federal example in these respects. Neither Alabama nor Mississippi has passed any significant legislation covering offshore oil pollution. California passed a comprehensive law, the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act, two weeks after OPA 90 went into effect; the State Lands Commission and the new Oil Spill Prevention and Response office are in the process of issuing regulations to implement the act (Stolls, 1993). These state laws, like OPA 90, govern spills from tankers as well as pipelines.

STATE JURISDICTION

State jurisdiction over pipelines in offshore waters stems from a variety of authorities granted to states, in addition to the authority granted by OPS certification for pipeline safety regulation.

The multiplicity of state and federal agencies with authority over offshore pipeline safety holds the potential for inconsistencies in requirements, disparities in safety goals, differences in priorities, and redundancy of efforts. It also offers many areas of both mutual and parallel interest. State and federal cooperation and consistency are enhanced by formal cooperative mechanisms such as the OPS certification program already in place. Further coordination would be desirable.

State Regulation of Intrastate Production Pipelines

States have sole regulatory jurisdiction over production facilities and associated production pipelines in state waters (inshore of the boundary of the federal OCS, 3 miles—

or, in Texas, 3 marine leagues [about 10 miles]—from shore). These facilities, being in state waters, are not under the federal safety jurisdiction of MMS. Some states agencies, certified to enforce OPS regulations for transmission pipelines, simply apply the same regulations to the production pipelines under their jurisdiction. These regulations, however, were developed for transmission pipeline systems, and are frequently inappropriate to production pipelines, which tend to be smaller in diameter, to vary more in flow, and to carry more corrosive untreated fluids.

States would be well advised to consider adopting regulations for these production facilities based on the appropriate MMS practices. (There is no formal MMS-state relationship, comparable to the OPS-state certification relationship, to ensure compatible safety goals and regulations.) Formal agreements between MMS and state agencies could be adopted, to ensure the necessary protection. As noted elsewhere in this chapter, MMS and states are already developing agreements to enforce the Oil Pollution Act of 1990, and should build on these agreements in the area of pipeline safety. Such cooperation would ensure consistent interpretation and application of compatible regulations in OCS and state waters.

The primary intent of formal agreements between the MMS and states would be to induce the states to establish pollution prevention and safety standards that are at least equivalent to federal standards. Coordination between the MMS and participating states would occur during formulation of standards and preparation of agreements. Enforcement would be the responsibility of the states. At present, the Oil Pollution Act of 1990 provides authority for the establishment of memoranda of understanding between MMS and the states for oil spill prevention and response, as well as related aspects of operational safety. The act does not cover gas pipelines; new legislation would be required for the establishment of formal agreements for such pipelines.

One benefit of federal and state regulatory cooperation could be to establish a pipeline failure and accident data system, including common data formats and reporting process with a clear means of accessing data.

The Oil Pollution Act of 1990

States also have the authority, under the Oil Pollution Act of 1990, to apply pollution prevention and spill response and cleanup standards more stringent than those of MMS. MMS is seeking cooperative agreements with responsible state agencies so that states may administer prevention programs (personal communication, Alexander Alvarado, Minerals Management Service, May 13, 1993).

Coastal Zone Management Plans

States administer Coastal Zone Management Plans (under the federal Coastal Zone Management Act) to mediate among competing uses of the waters and shore. Pipeline operators must therefore obtain state permits in addition to those from MMS (and for pipelines crossing navigable waterways or coastlines, the U.S. Army Corps of Engineers and the U.S. Fish and Wildlife Service). Any activity affecting the coastal zone, including dredging or filling or resource extraction, must obtain a permit from the competent state agency (e.g., the Louisiana Department of Natural Resources). The permit process can be complex, with detailed descriptions of the activity and its purpose and specific plans for dredging and disposal of dredged materials. Additional permits may be required

TABLE 6-1 State agencies with jurisdiction over pipeline safety

	State agency jurisdiction					Federal agency with shared jurisdiction
Description	Alabama	California	Louisiana	Mississippi	Texas	
Coastal zone	CAB	CC	DNR-OCRM	DWC-BMR	GLO	None
Intrastate transmission pipelines	PSC-PS	SFM,[a] PUC[b]	DNR-PS	PSC-PS	RC-PS	OPS (preemptive)[c]
Production platforms & pipelines in state waters	PCS-PS,[d] OGB[e]	SLC, DOC-DOG	DNR-OGD	OGB	RC-PS,[d] RC-OGD[e]	None
Marine spill response and cleanup in state waters	DEM	DFG-OSPR	OSCO, DEQ	DEQ	GLO-OSPR	U.S. Coast Guard (nonpreemptive)[c]

[a] Liquid only.
[b] Gas only.
[c] preemption allows the state to imposed additional or more stringent requirements, so long as they are compatible with federal standards.
[d] Production pipelines only.
[e] Production platforms only.
NOTES: Alabama: CAB = Coastal Area Board; PSC-PS = Public Services Commission, Pipeline Safety Section; OGB = Oil and Gas Board; DEM = Department of Environmental Management. California: SFM = State Fire Marshall; PUC = Public Utilities Commission; SLC = State Lands Commission; DOC-DOG = Department of Conservation, Division of Oil and Gas; DFG-OSPR = Department of Fish and Game, Office of Oil Spill Prevention and Response. Louisiana: DNR-OCRM = Department of Natural Resources, Office of Coastal Restoration and Management; DNR-PS = Department of Natural Resources, Office of Conservation—Public Safety; DNR-OGD = Department of Natural Resources, Office of Conservation—Oil and Gas Division; OSCO = Oil Spill Coordinator's Office; DEQ = Department of Environmental Quality. Mississippi: DWC-BMR = Department of Wildlife Conservation, Bureau of Marine Resources; PSC-PS = Public Services Commission, Pipeline Safety Division; OGB = Oil and Gas Board; DEQ = Department of Environmental Quality. Texas: GLO = General Land Office; RC-PS = Railroad Commission, Transportation/Gas Utilities Division—Pipeline Safety; RC-OGD = Railroad Commission, Oil and Gas Division; GLO-OSPR = General Land Office, Oil Spill Prevention and Response.

from fisheries agencies, state health departments, and state environmental quality agencies.

Agency Roles

Because various agencies may be selected to administer the above authorities, several state agencies typically have jurisdiction over some aspect of marine pipeline safety within a given state. Table 6-1 gives some examples of the primary state agencies involved, and associated federal responsibilities.

RESOLVING DIFFERENCES BETWEEN FEDERAL ENFORCEMENT APPROACHES

Underlying the differences between MMS and OPS regulatory requirements, documented in several chapters of this report, are radically different approaches to enforcement. OPS leaves the inspection and maintenance of pipelines largely to the operators, enforcing its safety requirements with periodic audits of company records to ensure that operators meet OPS standards. These inspections are necessarily rather infrequent; OPS, for example, has the resources to assign only two full-time inspectors in the Gulf of Mexico, to cover nearly 13,000 miles of pipelines, under the management of more than 160 different operators (personal communication, James Thomas, Office of Pipeline Safety, Southwestern Region, February 4, 1993).

MMS inspectors, on the other hand, make periodic on-site inspections of pipeline maintenance and safety systems during annual inspections of offshore facilities, and spot inspections of construction and repair activities. During these inspections, all boarding, crossing, or departing pipelines are reviewed to ensure compliance with the terms of the MMS-issued permits (Alvarado et al., 1992). Regional Supervisors are responsible for scheduling these inspections. MMS has 70 inspectors in the Gulf OCS Region, albeit with the more complex task of assessing the safety of platforms along with that of regulated pipelines. (Alvarado et. al., 1992). Comparison of the inspection checklists used by the two agencies provides a partial explanation for this disparity. The OPS list contains 300 to 400 items, all pertaining to pipelines themselves. The MMS list contains about 700 items, only 30 of them pertaining to pipelines, suggesting that the vast majority of the MMS inspection focus is on nonpipeline matters such as production and processing operations, drilling and well workover operations, and fluid measurement.

OPS enforcement efforts and resources are focused mainly on onshore pipeline systems, and especially on those that present risks to public safety or unusual risks to the environment. MMS, in contrast, devotes its enforcement efforts and resources entirely to offshore operations.

Offshore, it should be remembered, the pipeline systems regulated by the two agencies present quite different management and safety issues. Production pipelines, regulated by MMS, are generally smaller than transmission pipelines, and they normally carry untreated, hence corrosive, fluids; their economic lives, set by the lives of the producing fields, are generally shorter than those of transmission lines. Transmission lines carry treated fluids from production processing platforms to shore; they operate at higher volumes and often must serve for periods of decades. Despite these differences, the disparity in enforcement effort between the two agencies is apparent.

OPS's enforcement emphasis for marine pipelines could be increased by either increasing the agency's offshore inspection resources or by giving another agency the task of carrying out OPS enforcement, through an interagency agreement. Assigning this role to MMS, which is already active in OCS pipeline safety regulation, would have benefits of logistical efficiency and the effective use of trained inspectors.

Pipelines regulated by the two agencies are physically and operationally connected. Logistically, an agency inspecting a facility under MMS jurisdiction may be able to inspect an OPS facility during the same visit. In addition, because the facilities are operationally connected, integrated inspections by a single agency would produce better evaluations of overall system integrity and safety.

Such an expansion of MMS's responsibilities would also be consistent with the Oil Pollution Act of 1990, which extends MMS authority beyond production operations on the OCS—the agency's traditional regulatory sphere—to cover all offshore oil and gas pipelines. Federal preemption by OPS would prevent this authority from displacing existing OPS regulations, but MMS's pollution prevention authority under the act could be exercised through MMS's integrated enforcement role for all offshore waters. MMS would thus enforce MMS regulations on MMS facilities and OPS regulations on OPS facilities.

An interagency agreement of this kind would include a process for jointly identifying and resolving concerns, investigating incidents, suggesting and discussing improvements in regulations, discussing safety objectives, and collecting and disseminating marine pipeline safety data.

A memorandum of understanding between MMS and OPS would be the most flexible and expeditious alternative for extending MMS's authority in the OCS. The alternative of amending public law through acts of Congress would be extremely cumbersome, involving at least four acts and several committees of the House and Senate.

FINDINGS

The varying missions, resources, and regulatory approaches of the federal and state agencies charged with ensuring the safety of offshore pipelines have led to both duplication and gaps in enforcement, and to a lack of coordinated safety planning and record keeping. Better coordination would offer both efficiency and better safety assurance.

The jurisdictional MOU between MMS and OPS, established in 1976, has not eliminated duplication and overlap of federal regulatory effort. A variety of specific regulatory requirements, discussed in other chapters of this report, remain unresolved. Better coordination is needed.

OPS cannot effectively oversee more than 160 pipeline companies, operating nearly 17,000 miles of offshore pipeline, with its present complement of only two full-time inspectors for the entire Gulf of Mexico. Unless the necessary resources are provided, other means of enforcement—presumably through an interagency agreement with the MMS—would be more effective.

State agencies, with regulatory jurisdiction over intrastate production pipelines, sometimes apply OPS regulations—devised for transmission pipelines, rather than regulations more appropriate to production pipelines.

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7

Conclusions and Recommendations

A reliable, safe, environmentally responsible pipeline industry is vital to the nation. First, and most immediately, a significant fraction of the nation's energy supply depends on uninterrupted operation. In the longer run, the offshore oil and gas industry in general could be dramatically affected by major pollution incidents or fatal accidents resulting from pipeline failures. The safety record of marine pipelines is good, but it should be improved, since society's willingness to accept risk seems to be decreasing. Transmission and production pipelines account for about 98 percent of all the oil spilled by outer continental shelf (OCS) oil and gas operations (not including transportation by tanker or barge).

This committee's assessment leads to the following conclusions and recommendations.

Pipeline failures and spills are reported to several different agencies, with different reporting formats and information requirements. The available data on failures of offshore pipelines are correspondingly incomplete. Most important, data for state waters is unavailable; even on the OCS, the lack of consistent reporting standards prevents detailed statistical analysis. It is important to improve the process of information gathering, to put risk management priorities on a sound and cost-effective basis.

The various regulatory agencies involved should develop a common safety data base, covering both state and federal waters, and should periodically review their data requirements. The focus should be on collecting, archiving, analyzing, and reporting safety data with the intent of improving design and operating regulations. The extended data base should include the information needed for risk and cost-benefit analyses. MMS, which has the greatest experience and resources in data gathering, should coordinate this effort.

Despite the incompleteness of the safety-related data, several important patterns can be discerned in the data base for the OCS:

- Corrosion, although it was the reported cause of nearly half of the 1,047 OCS pipeline failures recorded between 1967 and 1990, produced only about 2 percent of the pollution from pipelines.
- Damage from vessels (and especially from anchors and groundings) is dramatically more significant than corrosion as a source of pollution and other consequences, including deaths and injuries. Anchor damage alone accounted for 90 percent of the pipeline-related pollution on the Gulf OCS.
- A very few incidents have resulted in the majority of consequences. The 4 largest pipeline spills, all caused by anchor damage, accounted for 85 percent of the pollution from pipelines for both production and transmission, on the Gulf OCS between 1967 and 1990; the largest 11, all but one caused by vessels, produced 98 percent.
- Deaths and injuries are rare. Six incidents (two vessel groundings and four repair accidents) resulted in all of the deaths and injuries associated with pipeline failures.

Even in the absence of better safety data, it is possible to improve safety planning. Modern risk analysis methods, using incomplete data supported by inferences and expert opinion about the nature and distribution of risks, can clarify priorities for risk management. For example, the risks to human safety and to the environment due to failures of marine pipelines are not uniform across the Gulf of Mexico. Resources being limited, a risk analysis model that compares various risks by geographic zone would allow cost-effective risk management decisions that address safety everywhere and provide the basis for strengthening regulations in high-risk areas. The goal is a consistent risk management strategy that unites all of the regulatory agencies and pipeline operators in developing criteria for the reduction of human and environmental risks.

The committee recommends that safety regulations be based on sound risk analyses and cost-benefit analyses. Specifically, regulatory agencies should agree on a consistent risk management strategy to set priorities about human safety criteria, and about the use of cost-benefit analysis for the reduction of property and environmental damage. A zone-based risk analysis model, based on the zonation approach outlined in Chapter 3 of this report, should be developed on the basis of currently available information and regularly updated, to help determine whether regulations should be revised, strengthened, or relaxed, and assist in establishing priorities for the operational use of resources by both government and industry for enhancing pipeline safety (such as inspection coverage and frequency, use of internal inspection devices, and establishment of burial depths for areas having high erosion rates).

Enforcement of safety regulations, like information collection, reflects a lack of consistency among state and federal agencies. The enforcement programs of the OPS and MMS are radically different in approach and in scope. OPS inspection efforts are conducted primarily through periodic audits of company records. MMS inspection efforts consist of the periodic inspection of pipeline maintenance and safety systems (during annual inspection of offshore facilities) and spot inspections of construction and repair activities. There is also a dramatic difference in enforcement personnel; MMS assigns 70 inspectors to the Gulf of Mexico OCS region, while OPS assigns 2 inspectors. To some extent, these differences reflect differences in the safety issues faced by the two agencies, but it appears likely that OPS enforcement personnel are too few to adequately cover the nearly 13,000 miles of pipeline and more than 160 operating companies in the region that are under OPS jurisdiction.

To make better use of inspection resources and help integrate the enforcement of MMS and OPS marine pipeline safety regulations, the committee recommends that the enforcement of OPS regulations offshore be performed by the MMS, through an interagency agreement or redefinition of the memorandum of understanding that defines the jurisdictional division between OPS and MMS. Such a system would continue OPS's role in regulating offshore pipelines, while strengthening the application and enforcement of such regulations by bringing to bear MMS' greater resources.

Another regulatory discrepancy is visible in the MMS and OPS requirements for internal inspection of pipelines. MMS, under a law requiring the use of the "best available and safest technology," has established a general requirement for the use of in-line inspection devices (generally known as smart pigs) where practicable. OPS is studying the matter, under congressional mandate. The committee finds that the technology of smart pigs is progressing, and that these devices are seeing increasing use onshore. However, the vast majority of marine pipelines cannot physically accommodate smart pigs, and modification of pipelines generally would be uneconomic. In addition, the current devices are relatively inaccurate in locating flaws. Because the costs of verifying suspected flaws are much greater offshore than onshore, this inaccuracy is a greater handicap. The use of smart pigs offshore will not be widely practical until further technical improvements are made, especially in the reliability and accuracy of three-dimensional measurement of flaws and in the compactness and maneuverability of smart pigs themselves.

The committee recommends that marine pipelines already constructed be exempted from federal or state requirements for the use of currently available smart pigs for external or internal corrosion control. New medium- to large-diameter pipelines running from platform to platform or platform to shore should be designed to accommodate smart pigs whenever reasonably practical.

Pipeline operators and regulators should continue to assess developments in smart pigging technology and seek cost-effective opportunities for its use.

Detecting and limiting leaks quickly is nearly as important as preventing them in the first place. A variety of techniques is available. Periodic aerial surveillance can detect leaks of all sizes, but sometimes with a delay of days to weeks. Setpoint-limit control systems (which monitor changes in pressure or flow rates) can detect large leaks, but are not effective for pipeline systems with routinely varying pressures and flow rates. For liquid pipelines, manual or automated line-balance calculations (comparing volumes in with volumes out) can detect leaks of varied sizes; manual calculations are generally made only once per day, while automated calculations may be made more frequently (with substantial additional costs for the necessary monitoring and communications equipment).

Many leaks are first detected through visual sightings by parties other than the pipeline operators. The detector of a leak generally cannot identify the operator of the pipeline. Nor is there an agency or entity that can establish the responsible party in a timely fashion. The responsible operator in turn, once made aware of a leak, can have difficulty contacting in a timely manner all connecting pipeline and platform operators who must take action.

Pipeline operators should use a combination of leak detection methods to ensure timely detection of a broad range of leaks. Setpoint-limit control systems, where practical, should be used to provide quick detection of relatively large leaks. Line-balance calculations—either manual or SCADA-based—should be conducted at least daily, where practical, to monitor pipeline systems for small-to medium-sized leaks (which can be detected in this way with a time delay of 1 to 24 hours). Periodic visual surveillance (with a time delay of 1 hour to 2 weeks) should be used to detect very small leaks and those that have gone undetected by other means. The method chosen will depend partly on the product transported, the throughput of the pipeline system, the potential consequences of leaks in particular locations, and the nature of the pipeline system's operations (such as its relative stability of operating conditions and its location and accessibility by personnel).

MMS should coordinate an effort by appropriate federal and state regulatory agencies and industry to establish a system through which leaks detected by third parties can be reported to a single agency or notification center with continuous coverage around the clock. This one central location should have a comprehensive data base permitting easy identification of the operator of any marine transmission or production line based on the reported sighting location. All maritime entities should be encouraged to use this single reporting center. Pipeline operators, in turn, should have 24-hour telephone numbers or a means of immediately contacting all other pipeline and platform operators who must take action.

No sensor technology is available to permit moving vessels to detect nearby pipelines at a distance, and thereby avoid them. Location-determining technologies are too inaccurate. However, there are operational measures by which vessels can lessen the risks of inadvertently interfering with pipelines.

An obvious but difficult problem is the control of the mooring of supply' and service vessels in areas adjacent to offshore platform installations. A specific risk is that these vessels may drop anchors on nearby pipelines or flowlines, or interfere with pipeline risers. Clear communications between vessels and offshore platform operators would help avoid these risks.

In areas where supply and service vessels operate adjacent to fixed platform installations associated with high densities of pipelines or flowlines, permanent mooring systems should be considered. In other circumstances, platform operators should be required to provide detailed and timely information to vessel operators on the configurations of local pipelines or flowlines, so that the vessels can anchor in designated areas. To lessen the risks of damage further in those congested areas, new pipelines should be installed whenever practical in well-defined "corridors."

In shallow waters (generally less than 200 feet deep), the best protection against the interference of vessels and pipelines is burial of the pipelines, with enough weight coating to keep them in place. In the shifting, often unconsolidated coastal sediments and eroding shorelines of the northern Gulf of Mexico, however, achieving and maintaining adequate burial requires care and vigilance. Pipeline installation must take into account detailed knowledge of soils, currents, and shoreline processes, so the pipeline can be buried and weighted to keep it in place, even if its surrounding soils are fluidized by wave action.

The committee has no information leading it to believe that the initial burial depths required by regulatory agencies are either adequate or inadequate. Anecdotal evidence suggests that initial cover may be adequate, but loss of cover over time, through erosion or fluidization of surrounding soils, exposes pipelines to interference by vessels. Pending further study, the current regulatory standards for initial depth of burial must be considered adequate.

Much of the Gulf shoreline is eroding rapidly. This erosion may expose pipelines buried at installation, and can be accelerated by the trenching used to install pipelines across the shoreline. The directional bore method of installing pipelines under beaches without breaking the surface eliminates this problem, and is also attractive from the standpoint of construction and maintenance costs.

The need for periodic inspections of pipelines, to ensure that they do not lose cover or become exposed, is not addressed in standard industry practice or in regulations.

Geotechnical studies of soil conditions, with sampling at intervals determined by local site conditions,' should be required as a condition of marine pipeline construction permits. Soil core samples should be analyzed and interpreted for design parameters relative to weight, specific gravity, grain size, shear strength, and potential for liquefaction and fluidization. Permitting and regulatory agencies should work with industry to develop criteria for specific gravities of marine pipelines in varying soil environments.

To provide baseline data for subsequent depth of cover and bottom status surveys, newly installed pipelines should be surveyed at once and their depths of cover recorded, with reference to Global Positioning System locations. Maintenance of this baseline data should be required by the agencies issuing the construction permits.

All agencies involved in the permitting of pipelines crossing shorelines should require the use of the directional bore installation method wherever feasible.

In waters less than 15 feet deep (where interactions between vessels and pipelines may, albeit rarely, expose vessels and crews to fire and explosion), periodic depth of cover surveys in the Gulf of Mexico should be scheduled according to the specific local shoreline and seabed dynamics, and the passage of severe storms, according to the criteria outlined in Chapter 5 ("Periodic Depth-of-Cover Inspections"). In brief, a baseline depth of cover measurement should be established for each pipeline, and subsequent inspections should be made—at intervals determined by local shoreline and seabed dynamics and storms—to determine the direction and rate of change of the depth of cover. Later inspection intervals can *be lengthened or shortened according to this rate; this approach might be called "self-adjusting."*

Pipeline operators and regulatory and permitting agencies should conduct studies to determine the appropriate standards for initial depth of burial under various shoreline and seabed conditions, using the results of the recommended periodic depth-of-cover surveys.

Abandonment of marine pipelines will continue to increase as producing fields reach maturity and are shut-in. Most of these abandoned lines are in shallower state waters. A properly abandoned pipeline poses no risk to public safety or to the environment. Abandoned pipelines have not been reported to cause any loss of life or significant property or environmental damage. The current practice of remediating abandoned pipelines once they come to the attention of the operator is adequate. A more aggressive periodic inspection program is not warranted until, and unless, public safety or the environment is shown to be adversely affected.

Pipeline abandonment standards should include a requirement for a one-time inspection at the time of abandonment to verify that abandonment requirements were met. Removal, continuing surveillance, or periodic inspection of abandoned pipelines should be required only where unique public safety or environmental conditions exist, such as rapid coastal erosion in areas of high vessel traffic. Pipeline operators should take timely corrective action when they are made aware of problems caused by their abandoned pipelines. Remediation should be the responsibility of the owner or successors until or unless the abandoned pipeline is removed.

Appendix A

Biographies of Committee Members

MARK Y. BERMAN is Project Manager of the Capital Asset/Project Management Study within Amoco Production Company. He has held various positions with Amoco since 1973, including Research Director and other supervisory posts in offshore systems development, offshore structure engineering, and arctic engineering. He has broad experience with worldwide applications of offshore technology, including fixed platforms, compliant structures, arctic engineering, and floating drilling/production systems. He has served as chairman of Amoco's External Research Coordination Committee, which oversees hydrocarbon exploration and production-related research. He has participated in many American Petroleum Institute (API) committees, and is past chairman of the API committee on standardization (the design, construction, and operational standards). He holds a number of patents related to offshore technology. Mr. Berman was a member of the NRC Committee on Marine Structures, and served on the Committee on the Safety of Innovative Structures which completed its work in 1991. He is currently a member of the Marine Board. He received his M.S. in civil engineering from Kansas State University in 1973.

SALVATORE J. BELLASSAI is a consultant on pipeline engineering, construction, and corrosion control. Following retirement in 1986 and until 1991, he was a member of the Technical Pipeline Safety Standards Committee of the U.S. Department of Transportation. Previously, he spent 37 years with Transcontinental Gas Pipe Line Corp. His most recent position was vice president, engineering, with responsibility for design and construction of 12,000 miles of onshore and offshore pipelines and compressor stations. His other positions included manager of engineering, superintendent of marine construction, and project engineer in offshore pipelines. Mr. Bellassai received his B.S. degree in civil engineering from Worcester Polytechnic Institute.

ROBERT J. BROWN is chairman of the board of R. J. Brown and Associates, which he founded in 1969 and became a division of Kvaerner, Earl and Wright, Inc. in 1992. He has more than 36 years of experience in the offshore pipeline industry and is an international authority in the field. His pioneering work includes the development of new and innovative methods of pipeline installation, connection, and stabilization. Earlier in his career, Mr. Brown spent five years with Bechtel Corp., where his various responsibilities included research projects in deep water pipe-laying and design of offshore structures. Prior to that, he held various pipeline research and development positions in the United States and abroad. The author of numerous technical presentations and journal articles, Mr. Brown has been honored by the American Society of Civil Engineers for outstanding achievements in pipeline engineering. He received his M.S. in civil engineering from Stanford University.

JOHN M. CAMPBELL, JR., is a consultant and retired in 1993 as president and chief executive officer of John M. Campbell & Company where he served since 1981. The company offers consulting services to major oil companies, governments, and many other clients worldwide in engineering and economics, with special expertise in training for production/processing facilities and the economic analysis and management of petroleum investments. Previously, he held a variety of teaching and research positions in finance and economics at Florida State University, the University of Chicago, and elsewhere. Dr. Campbell has written or co-authored three books and numerous articles, papers, and technical reports. He received his Ph.D. in economics from the University of Oklahoma.

JOHN E. FLIPSE (NAE) is director emeritus of the Offshore Technology Research Center, Texas A&M University. He was the director from 1988 to 1991, while also serving as a professor of engineering. Previously, he served for five years as associate deputy chancellor for engineering for the entire Texas A&M University System. Prior to that, he was associate dean of engineering and, earlier, a professor of civil and ocean engineering. His industrial experience includes 11 years as chairman and chief executive officer of Deepsea Ventures Inc. He has written or presented dozens of papers and holds nine patents. Mr. Flipse is past president of the Marine Technology Society, and he has served as chairman, vice chairman, and member of the Marine Board. He earned his M.S. in mechanical engineering at New York University.

NORMAN HACKERMAN (NAS) is chairman, Scientific Advisory Board, the Robert A. Welch Foundation. He is president emeritus of Rice University, where he was president and a professor of chemistry for 15 years. Prior to that, he had a long and distinguished career at the University of Texas at Austin, where he served as president, and, earlier, held various positions including director of the Corrosion Research Laboratory for 13 years and chairman of chemistry for nine years. He has served on numerous national and state boards and committees focusing on various aspects of research and education. He has served on a dozen NAS/NRC panels and committees and is a past chairman of the Board on Energy Studies. He is the author or co-author of more than 200 publications. Dr. Hackerman earned his Ph.D. in chemistry from Johns Hopkins University.

G. PAUL KEMP is science and technology director for the Coalition to Restore Coastal Louisiana, after serving two years as executive director. Previously, he was project scientist and director, Coastal Sciences Unit, for Woodward-Clyde Consultants. Earlier, he held various positions as a hydrogeologist and geologist. His interests include wave/sediment interactions, coastal erosion processes, ecosystem modeling, estuarine geochemistry, and natural resources and science policy. Dr. Kemp has written or co-authored a number of book and journal articles, technical reports, and papers. He received his Ph.D. in marine sciences from Louisiana State University in 1986.

M. ELISABETH PATIO-CORNELL is a professor of industrial engineering and engineering management at Stanford University, where she has been a member of the faculty since 1981. Her areas of expertise include risk analysis, engineering reliability, and engineering and environmental risk management. She has been a consultant to major oil companies, federal and state governments, the World Health Organization, and numerous other clients on various aspects of risk analysis and environmental management. She has written numerous book chapters, journal articles, and conference papers, and she has given dozens of invited lectures. Ms. Pate-Cornell received her Ph.D. in engineering-economic systems from Stanford.

KENNETH H. STOKOE II is a professor of geotechnical engineering at the University of Texas at Austin, where he has been a member of the faculty since 1973. He has conducted extensive research in geotechnical engineering and has received many honors. He also participates in a variety of professional societies. He is a past member of the NRC's Geotechnical Board and was a member of the NRC Panel on the Assessment of the Defense Nuclear Agency's Program for Predicting the Response of Deep Underground Structures under Explosive Loading. He received his Ph.D. in civil engineering from the University of Michigan.

GARY L. ZIMMERMAN is a staff engineer-specialist for Shell Pipe Line Corp. He has worked for Shell in various capacities for 16 years. His current position involves public and environmental safety aspects of pipeline operations, including interpretation and implementation of federal and state pipeline safety regulations. He is responsible for developing associated corporate policies and positions; operating, maintenance, and emergency response procedures; system safety standards; and design and construction specifications. He also manages incident investigations and is involved in risk assessment. In past assignments, he has worked as project manager for pipeline construction projects both on shore and offshore, domestically and internationally, and has worked in several operational assignments. Mr. Zimmerman earned his B.S. in mechanical engineering at Ohio State University.

Appendix B

Minerals Management Service Serious Accident Reporting Form

US DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

Herndon (MS 4700)
MS 5200
MS 5034
MS 5260 (Orig)

ACCIDENT INVESTIGATION REPORT
OUTER CONTINENTAL SHELF

PART I. IDENTIFICATION DATA

1 LEASE IDENTIFICATION				2. DATE OF ACCIDENT
LEASE NUMBER OCS-G	AREA	BLOCK	COMPLEX ID	3 TIME OF ACCIDENT

4 DESIGNATED OPERATOR	4A OPERATOR ONSITE REPRESENTATIVE
5 CONTRACTOR	5A CONTRACTOR ONSITE REPRESENTATIVE
6 SERVICE COMPANY	6A. SERVICE COMPANY REPRESENTATIVE

7 TYPE OF STRUCTURE	8 WATER DEPTH	9 DISTANCE FROM SHORE

10 TYPE OF ACCIDENT(S)	11 INITIAL CLASSIFICATION OF ACCIDENT

PART II. SPECIFIC ACCIDENT DATA

1 NUMBER OF INJURIES	2 NUMBER OF FATALITIES	3 AMOUNT OF PROPERTY DAMAGE

4 WEATHER CONDITIONS AT TIME OF ACCIDENT

5 TYPE OF OPERATION BEING CONDUCTED AT TIME OF ACCIDENT	6 IDENTIFY EQUIPMENT INVOLVED IN OPERATION
	6A. NAME OF EQUIPMENT MANUFACTURER
7 IDENTIFY EQUIPMENT THAT FAILED	7A NAME OF MANUFACTURER OF EQUIPMENT THAT FAILED

8 PROVIDE MAINTENANCE AND/OR SERVICE HISTORY OF EQUIPMENT THAT FAILED

9 IDENTIFY SAFETY DEVICE THAT MALFUNCTIONED	9A. NAME OF MANUFACTURER OF SAFETY DEVICE(S) THAT SHOULD HAVE ACTIVATED TO PREVENT THE ACCIDENT

10 NAME OF PERSON(S) TITLE IMMEDIATELY RESPONSIBLE FOR THE OPERATIONS BEING CONDUCTED AT THE TIME OF THE ACCIDENT	11 NAME OF PERSON(S) IMMEDIATELY RESPONSIBLE FOR THE EQUIPMENT IN USE AT THE TIME OF THE ACCIDENT	12. WERE PICTURES TAKEN YES ☐ NO ☐
		13 WERE STATEMENTS TAKEN? YES ☐ NO ☐ ADD WITNESS STATEMENT AS ATTACHMENT

FORM MMS-2010 (FEB 1983) PAGE 1

PART III. NARRATIVE STATEMENT

1 DIRECT CAUSE OF ACCIDENT

2 CONTRIBUTING CAUSE(S)

3 DESCRIBE IN SEQUENCE HOW ACCIDENT OCCURRED

FORM MMS-2010 (FEB 1983) PAGE 2

3. Describe in Sequence How Accident Occurred: (Continued)

FORM MMS-2010 (FEB 1983)

PART IV. FIRE/EXPLOSION DATA

1 SOURCE OF IGNITION	2 TYPE OF FUEL	3. FUEL SOURCE

4 ACTIVITIES BEING CONDUCTED AT TIME OF FIRE/EXPLOSION

5 PROPERTY DAMAGED (IDENTIFY)	6 NATURE OF DAMAGE

7 WHAT PRECAUTION OR ACTIONS WERE TAKEN TO ISOLATE KNOWN SOURCES OF IGNITION PRIOR TO THE ACCIDENT?

8 DIRECT CAUSE OF FIRE/EXPLOSION.

9 NARRATIVE DESCRIPTION OF FIRE/EXPLOSION

PART V. HYDROCARBON RELEASE

1 VOLUME OF HYDROCARBON RELEASED	2 TYPE OF HYDROCARBON RELEASED	3 SOURCE OF HYDROCARBON RELEASED

4 APPEARANCE OF WATER	4A ESTIMATED LENGTH	4B ESTIMATED WIDTH	4C DIRECTION OF MOVEMENT	5 WERE SAMPLES TAKEN? YES ☐ NO ☐

6 STATUS AND TYPE OF CLEANUP EQUIPMENT ACTIVATED OR ON STANDBY?	7 ESTIMATED RECOVERY
	8 RESPONSE TIME

9 DIRECT CAUSE(S) OF RELEASE

10 NARRATIVE DESCRIPTION OF HYDROCARBON RELEASE

FORM MMS-2010 (FEB 1983) PAGE 3

PART VI. BLOWOUT

1 TYPE OF ACTIVITY (EXPLORATORY DRILLING, WORKOVER, ETC)

2 DRILLING DEPTH

3 MUD WEIGHT IN HOLE

4 MAKEUP OF DRILL/WORK STRING HOLE

5 LAST STRING OF CASING SET
DEPTH SIZE

6 BOP STACK AND CHOKE MANIFOLD
TYPE SIZE PRESSURE RATIO

7 MAKEUP OF DIVERTER SYSTEM INCLUDING VALVE TYPES

8 SUBSURFACE SAFETY DEVICE
TYPE DATE INSTALLED

9 INDICATE ANY HOLE PROBLEMS PRIOR TO BLOWOUT

10 KICK SIZE

11. MUD KILL WEIGHT

12 EVACUATION PROCEDURES

13. INITIAL SHUT-IN DRILL PIPE PRESSURE

14. INITIAL SHUT-IN CASING PRESSURE

15 WERE PERFORATIONS OPEN?
YES ☐ NO ☐

16 WAS WELL DIVERTED
YES ☐ NO ☐

17 WHAT WELL CONTROL PROCEDURE WAS USED?

18 DIRECT CAUSE OF BLOWOUT CEASING (BRIDGED, PUMPED KILL MUD, DRILLED RELIEF WELL ETC.)

19. DIRECT CAUSE(S) OF BLOWOUT OR DETERMINED CAUSE(S) OF ACCIDENT AS A RESULT OF INVESTIGATION

20 NARRATIVE DESCRIPTION (IN SEQUENCE) OF BLOWOUT

FORM MMS-2010 (FEB 1983) PAGE 4

PART VII. INTERNAL CONTROL DATA

1. IDENTIFY VIOLATIONS OF THE REGULATIONS AND OCS ORDERS

1A SPECIFY THOSE VIOLATIONS THAT MAY HAVE DIRECTLY OR INDIRECTLY CONTRIBUTED TO THE ACCIDENT

1B. IDENTIFY PREVIOUS REGULATIONS VIOLATIONS (SIMILAR OR RELATIVE TO THIS ACCIDENT) THAT WERE DOCUMENTED ON PREVIOUS INSPECTIONS

2 ACTION INITIATED (SUSPENSIONS OF PRODUCTION/DRILLING OPERATIONS, WARNING, OTHER) FOR EACH OF THE IDENTIFIED VIOLATIONS

3 CORRECTIVE ACTION RECOMMENDED BY THE OPERATOR (CHANGES IN EQUIPMENT, OPERATIONAL PROCEDURES, SAFETY DEVICES OR SYSTEMS, TRAINING OTHER)

4 IDENTIFY ANY "WAIVERS/DEPARTURES" THAT MAY HAVE BEEN IN EFFECT AT THE TIME OF THE ACCIDENT RELATIVE TO THE INCIDENTS

5 PREVENTATIVE ACTION RECOMMENDED BY INVESTIGATORS(S) MINERALS MANAGEMENT (PRIMARY AND SECONDARY SAFETY DEVICE(S) SAFETY ALERTS, NOTICE TO LESSEES, CHANGES IN THE OCS ORDERS AND REGULATIONS, OTHER)

6 FINAL CLASSIFICATION OF ACCIDENT

7 DATE INVESTIGATION WAS INITIATED

7A TIME

8 DATE INVESTIGATION WAS COMPLETED

9. TEAM MEMBERS (NO SIGNATURES REQUIRED)

10 SIGNATURE DISTRICT SUPERVISOR

FORM MMS-2010 (FEB 1983) PAGE 5

Appendix C

U.S. Department of Transportation Accident Report, Hazardous Liquid Pipelines

OMB No. 2137-004

Report Date

No. 7000-1
(DOT)

ACCIDENT REPORT-HAZARDOUS LIQUID PIPELINE

PART A—OPERATOR INFORMATION

1.) Name of operator ____________________

2.) Principal business address ____________________

____
(city) *(state)* *(zip code)*

3.) Is pipeline interstate? ☐ yes ☐ no

PART B—TIME AND LOCATION OF ACCIDENT

1.) Date: *(month)* *(day)* *(year)* ____________________

2.) Hour *(24 hour clock)* ____________________

3.) If onshore give state *(including Puerto Rico and Washington. D C.).*
and county or city. ____________________

4.) If offshore, give offshore coordinates ____________________

5.) Did accident occur on Federal Land? ☐ yes ☐ no
(See instructions for definition of Federal Land.)

6.) Specific location *(If location is near offshore platforms. buildings. or other landmarks, such as highways, waterways, or railroads, attach a sketch or drawing showing relationshp of accident location to these landmarks)*

____
____
____

PART C—ORIGIN OF RELEASE OF LIQUID OR VAPOR. *(Check all applicable items)*

1.) Part of system involved:
☐ line pipe ☐ tank farm ☐ pump station

2.) Item involved: ☐ pipe ☐ valve ☐ scraper trap ☐ pump
☐ welding fitting ☐ girth weld ☐ tank
☐ bolted fitting ☐ longitudial weld

Other *(specify)* ____________________

3.) Year item installed ____________________

PART D—CAUSE OF ACCIDENT

☐ corrosion ☐ failed weld ☐ incorrect operation by operator personnel
☐ failed pipe ☐ outside force damage
☐ malfunction of control or relief equipment.
☐ other *(specify)* ____________________

PART E—DEATH OR INJURY

1.) Number of persons killed. __________
__________ Operator employees __________ Non-employees

2.) Number of persons injured. __________
__________ Operator employees __________ Non-employees

PART F—ESTIMATED TOTAL PROPERTY DAMAGE

$ __________

PART G—COMMODITY SPILLED

1.(Name of commodity spilled: ____________________

2.) Classification of commodity spilled:
☐ Petroleum Petroleum product ☐ HVL or ☐ Non-HVL

3.) Estimated amount of commodity involved
______ Barrels spilled ______ Barrels recoverd

4.) Was there an explosion?
☐ yes ☐ no

5.) Was there a Fire?
☐ yes ☐ no

INSTRUCTIONS: Answer sections H, I, or J only if it applies to the particular accident being reported.

PART H—OCCURRED IN LINE PIPE

1.) Nominal diameter *(inches)* ______ 2.) Wall thickness *(inches)* ______
3.) SMYS *(psi)* ______ 4.) Type of joint: ☐ welded ☐ flanged ☐ threaded ☐ coupled ☐ other
5.) Pipe was ☐ Below ground ☐ Above ground
6.) Maximum operating pressure *(psig)* ______
7. Pressure at time and location of accident *(psig)* ______
8.) Had there been a pressure test on system?
☐ yes ☐ no
9.) Duration of test *(hrs)* ______
10.) Maximum test pressure *(psig)* ______
11.) Date of latest test ______

PART I—CAUSED BY CORROSION

1. Location of corrosion
☐ internal ☐ external
2. Facilty coated?
☐ yes ☐ no
3 Facilty under cathodic protection?
☐ yes ☐ no
4. Type of corrosion
☐ galvanic ☐ other *(Specify)*
______

PART J—CAUSED BY OUTSIDE FORCE

1. ☐ Damage by operator or its contractor
☐ Damage by others
☐ Damage by natural forces
☐ Landslide
☐ Subsidence
☐ Washout
☐ Frostheave
☐ Earthquake
☐ Ship anchor
☐ Mudslide
☐ Fishing Operations
Other ______

2. Was a damage prevention program in effect
☐ yes ☐ no
3 If yes, was the program
☐ "one-call" ☐ other ______
4. Did excavator call?
☐ yes ☐ no
5 Was pipeline location temporarily marked for the excavator?
☐ yes ☐ no

PART K—ACCOUNT OF ACCIDENT

NAME AND TITLE OF OPERATOR OFFICIAL FILING THIS REPORT

______

______ Telephone no. *(Including area code)*

______ Date

Appendix D

U.S. Department of Transportation Incident Report, Gas Transmission and Gathering Systems

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $1,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $200,000 as provided in 49 USC 1678 Form Approved OMB No 2137-0522

US Department of Transportation
Research and Special Programs Administration

INCIDENT REPORT – GAS TRANSMISSION AND GATHERING SYSTEMS

Report Date ______
No ______ (RSPA)

PART 1 – GENERAL REPORT INFORMATION *SEE INSTRUCTIONS*

1. a. Operator's 5 digit identification no /_/_/_/_/_/
   b. Name of Operator ______
   c. ______ Number and Street
   d ______ City, County, State and Zip Code
2. Location of Incident
   a. ______ City and County
   b ______ State and Zip Code
   c Mile Post/Valve Stat. ______
   d. Survey Station No ______
   e Class Location
      Onshore ☐ 1 ☐ 2 ☐ 3 ☐ 4
      Offshore ☐ ______ area ______ block number
      State ______ or Outer Continental Shelf ______
   f Incident on Federal Land other than Outer Continental Shelf
      ☐ Yes ☐ No
3. Incident Type
   ☐ Leak ☐ Rupture ☐ Other
   Rupture Length *(feet)* ______
4. Reason for Reporting
   ☐ Fatality Number /_/_/_/ persons
   ☐ Injury requiring inpatient hospitalization Number /_/_/_/ persons
   ☐ Property damage/loss Estimated $ ______
   ☐ Operator Judgment
   ☐ Supplemental Report
5. Elapsed time until area was made safe
   /_/_/ hr /_/_/ mn
6. Telephonic Report
   /_/_/ mo /_/_/ day /_/_/ yr
7. a Estimated Pressure at Point and Time of Incident *(PSIG)* ______
   b Maximum allowable operating pressure *(MAOP) (PSIG)* ______
   c MAOP established by.
      (1) Test pressure ______ *(PSIG)*
      (2) 49 CFR §192 619(a)(3) ☐
8. Time and Date of the Incident
   /_/_/_/_/ hour /_/_/ mo /_/_/ day /_/_/ yr

PART 2 – APPARENT CAUSE

☐ Corrosion *(Continue in Part A)* ☐ Damage by Outside Forces *(Continue in Part B)* ☐ Construction/Material Defect *(Continue in Part C)* ☐ Other ______

PART 3 – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE INCIDENT *(Attach additional sheet(s) as necessary)*

PART 4 – ORIGIN OF THE INCIDENT

1. Incident Occurred On
   ☐ Transmission System ☐ Gathering System
   ☐ Transmission Line of Distribution System
2. Failure Occurred On
   ☐ Body of Pipe ☐ Fitting, Specify ______
   ☐ Mechanical Joint ☐ Other, Specify ______
   ☐ Valve ☐ Weld, Specify ______ *(girth, longitudinal, fillet)*
3. Material Involved
   ☐ Steel ☐ Other Specify ______
4. Part of System Involved in Incident
   a Part
      ☐ Pipeline ☐ Regulator/Metering System
      ☐ Compressor Station ☐ Other ______
   b Year installed /_/_/_/_/

PART 5 – MATERIAL SPECIFICATION

1. Nominal Pipe Size /_/_/_/_/ in
2. Wall Thickness /_/_/_/_/ in
3. Specification ______ SMYS /_/_/_/_/_/
4. Seam Type ______
5. Valve Type ______
6. Manufactured by ______ in year /_/_/_/_/

PART 6 – ENVIRONMENT

Area of Incident
☐ Under Pavement ☐ Above Ground
☐ Under Ground ☐ Under Water
☐ Other ______

PART 7 – PREPARER AND AUTHORIZED SIGNATURE

______ *(type or print)* Preparer's Name and Title ______ / ______ Telephone Number

______ Authorized Signature and Date ______ / ______ Telephone Number

Form RSPA F 7100.2 (3-84)

PART A – CORROSION

1. Where did corrosion occur?
   - ☐ Internally
   - ☐ Externally

2. Visual Description
   - ☐ Localized Pitting
   - ☐ General Corrosion
   - ☐ Other ______________

3. Cause
   - ☐ Galvanic
   - ☐ Other ______________

4. Pipe Coating Information
   - ☐ Bare ☐ Coated

5. Was corroded part of pipeline considered to be under cathodic protection prior to discovering incident?
   - ☐ Yes Year Protection Started /__/__/__/__/
   - ☐ No

6. Additional Information

PART B – DAMAGE BY OUTSIDE FORCES

1. Primary Cause of Incident
   - ☐ Damage resulted from action of operator or his agent
   - ☐ Damage resulted from action by outside party/third party
   - ☐ Damage by earth movement
     - ☐ Subsidence
     - ☐ Landslide/Washout
     - ☐ Frost
     - ☐ Other ______________

2. Locating information *(for damage resulting from action of outside party/third party)*
   - a. Did operator get prior notification that equipment would be used in the area?
     - ☐ Yes Date received /__/__/ mo /__/__/ day /__/__/ yr
     - ☐ No
   - b. Was pipeline location marked either as a result of notification or by markers already in place?
     - ☐ Yes Specify type of marking ______________
     - ☐ No
   - c. Does Statute or ordinance require the outside party to determine whether underground facility(ies) exist?
     - ☐ Yes
     - ☐ No

3. Additional Information

PART C – CONSTRUCTION OR MATERIAL DEFECT

1. Cause of Defect
   - ☐ Construction ☐ Material *(describe in C.4 below)*

2. Description of Component Other than Pipe

3. Latest Test Data
   - a. Was part which leaked pressure tested before incident occurred?
     - ☐ Yes Date of Test /__/__/ mo /__/__/ day /__/__/ yr
     - ☐ No
   - b. Test Medium ☐ Water ☐ Gas ☐ Other ______________
   - c. Time held at test pressure /__/__/ hr
   - d. Estimated test pressure at point of incident *(psig)* ______________

4. Additional Information

Appendix E

A Risk Analysis Approach

The risk analysis approach outlined in Chapter 3 is designed to assess the current risks of marine pipeline operations and the risk reduction benefits of different kinds of safety measures. It is, therefore, structured to account explicitly for the variables that could be affected by certain improvements, technical and managerial. The approach is a prototype model, with a generalized architecture. It can be expanded further if needed. For example, the model is based mainly on means of random variables; in actual studies the whole distributions may be relevant. Some of the input variables can be obtained by more detailed models involving, for instance, computations of loads and capacities. Some of the failure modes (e.g., at the interface between risers and platforms) will require full probabilistic risk analyses (PRAs) that are only outlined here. This prototype model, however, can be implemented. It may be sufficient in some cases and can provide a basis for initial sensitivity analyses.

As outlined in Chapter 3, this model is based on a zonation of the considered area by superposition of three maps (water depth, vessel traffic density, and pipeline density). Other types of zones may be introduced following the same pattern, to account, for instance, for geological properties of the seafloor. Five types of initiating evens are considered here: collisions between vessels and pipelines, dropped objects and dragged anchors, corrosion, effects of storms and hurricanes, and incidents at the interface between platforms and risers.

The input data of the model presented below are of three kinds: direct results of statistical data base analyses (after "de-biasing" if needed to account for the possible underreporting of certain types of incidents in the past); results of other models that need to be developed separately; and expert opinions to fill information gaps when the necessary data are unavailable at decision time, unobtainable by observable statistics (e.g., densities of uncharted pipelines), or possibly obtainable from complex models but at a greater cost than justified by their information value. For example, direct data provide frequencies of observed and reported collisions between vessels and pipelines. Physical and probabilistic models can be developed to assess the occurrence and progression of corrosion on poorly maintained pipes. Expert opinions will be needed to evaluate the average vessel traffic density or the average size of the crews in specified zones.

STRUCTURE OF THE RISK ANALYSIS MODEL (ZONATION)

The risk analysis model for the area of interest (in this example, mainly off the coasts of Louisiana and Texas) is based on a zonation of the region along the three parameters mentioned above: water depth, vessel traffic density, and pipeline density. Each parameter is divided into a few discrete ranges. The geographic area is then partitioned into minimal zones ("min-zones"), each characterized by the local values of the three parameters.[1] The structure of the risk analysis model includes (a) initiating events (e.g., a vessel-pipeline collision) and their annual probabilities, (b) intermediate developments and their probabilities conditional on the initiating event (e.g., the probability of fire given a vessel-pipeline collision), and (c) the consequences (generally expressed as means or mean rates) of each accident sequence.

The risk for each min-zone is then characterized by:

- The annual probability of at least one death in the min-zone, and the corresponding maximum individual risk (the annual probability of death in a pipeline-related accident for the most exposed individual)
- The mean of the amount spilled per unit of surface and per year in the min-zone and the mean annual property damage to pipelines and vessels.

Zonation of the Region

The area of interest is divided into min-zones defined by the superposition of three different partitions:

- *Pipeline density*. A map showing zones of known or assessed pipeline density (e.g., two or three zones) as well as offshore platforms and their input and output pipelines is needed (Figure E-I). Several other factors may be needed on this map, including the relative densities of old pipelines and new ones, of large pipelines and small ones, of live pipelines and inactive ones, and of buried pipelines and exposed ones. To a first approximation, it may be sufficient to assume uniform ratios of old to new and live to inactive pipelines, and a uniform distribution of pipe diameters. Obviously, such assumptions should be checked; for example, around new platforms, the density of pipelines is high, most pipelines are live, and those that are new are less likely to experience corrosion leaks.
- *Vessel traffic density*. Also required is a map showing a few different zones of vessel traffic density, as well as the platforms and the density of vessel traffic around them. Fishing takes place wherever the water depth is sufficient. One can expect, however, to find greater traffic density near harbors or in the most favorable fishing areas. These areas include, for shrimp, the zones surrounding the platforms.
- *Water depth*. Finally, a map showing different water depth contours is needed (e.g., 0-10 feet, 10-20 feet, 20-50 feet, more than 50 feet). The water depth can be compared with the drafts of different types of the vessels likely to circulate in the area. Also dependent on the water depth is the impact of the waves on bottom sediments and the effects of storms and hurricanes on submerged pipelines.

[1] Several noncontiguous min-zones can have the same set of index values. They are treated here as separate min-zones to allow simple analysis of the effects of hurricanes and storms as described later.

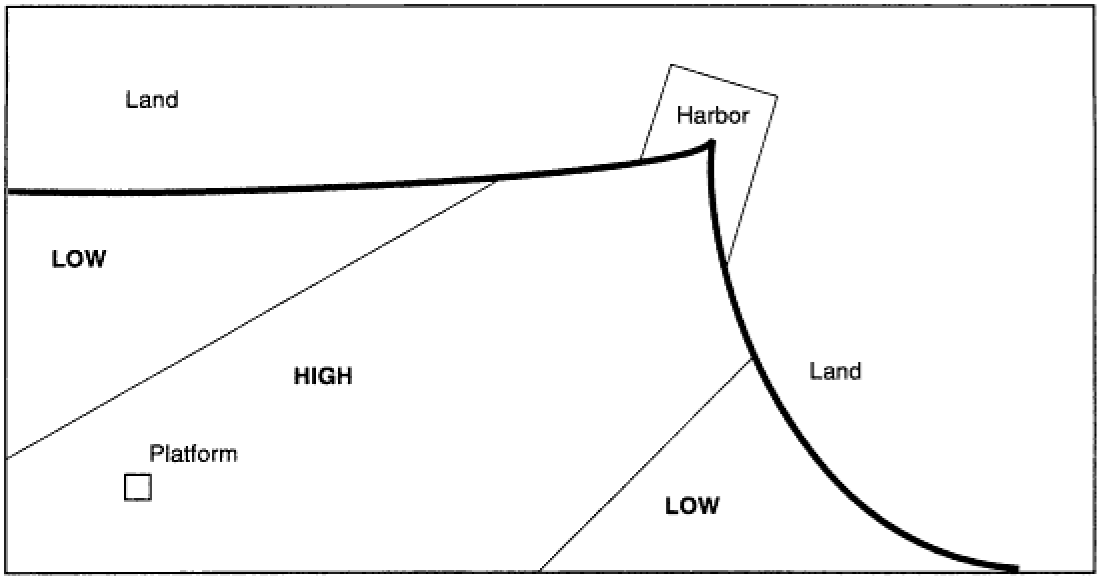

Figure E-1 Hypothetical map of pipeline density.

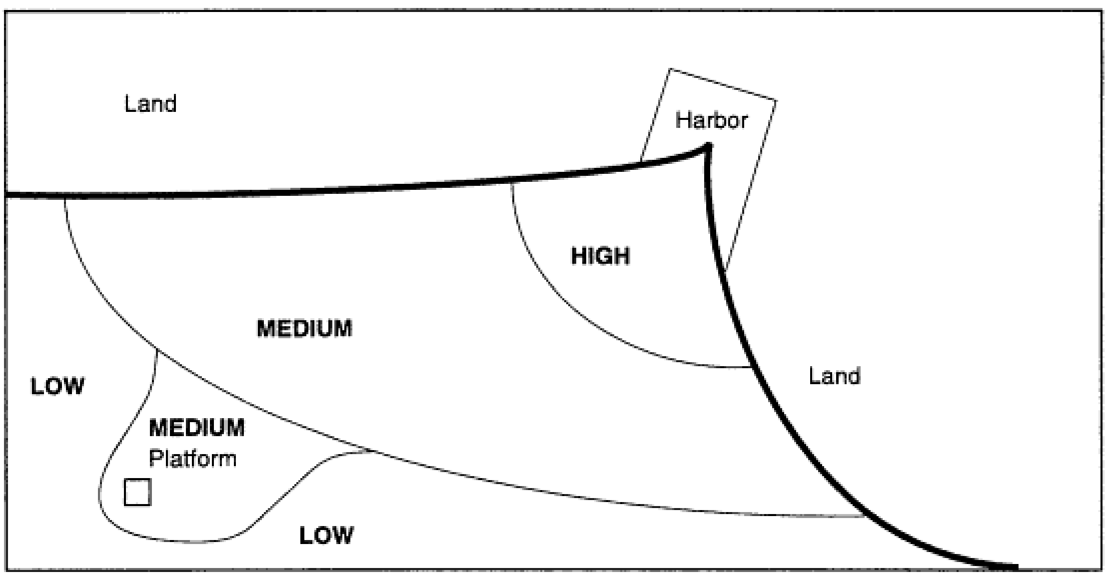

Figure E-2 Hypothetical map of vessel traffic density.

The superposition of the three maps in Figures E-I, E-2, and E-3 leads to the zonation shown in Figure E-4. This zonation is characterized by what are called here the corresponding "min-zones", i.e., the minimal zones that result from the partitioning of the region. What is shown here is a hypothetical region. A harbor site was assumed because the vessel traffic is more likely to be high in its vicinity. The characterization of the zones (e.g., high, medium, low) is totally hypothetical and for illustrative purposes only.

Each min-zone (index *i*) is characterized by:

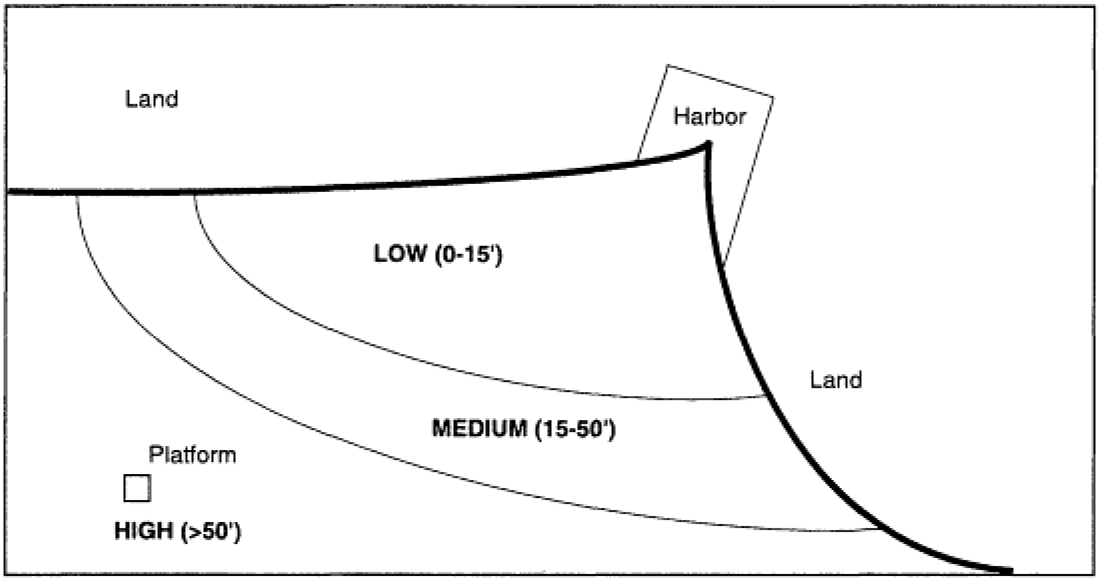

Figure E-3 Hypothetical map of water depth.

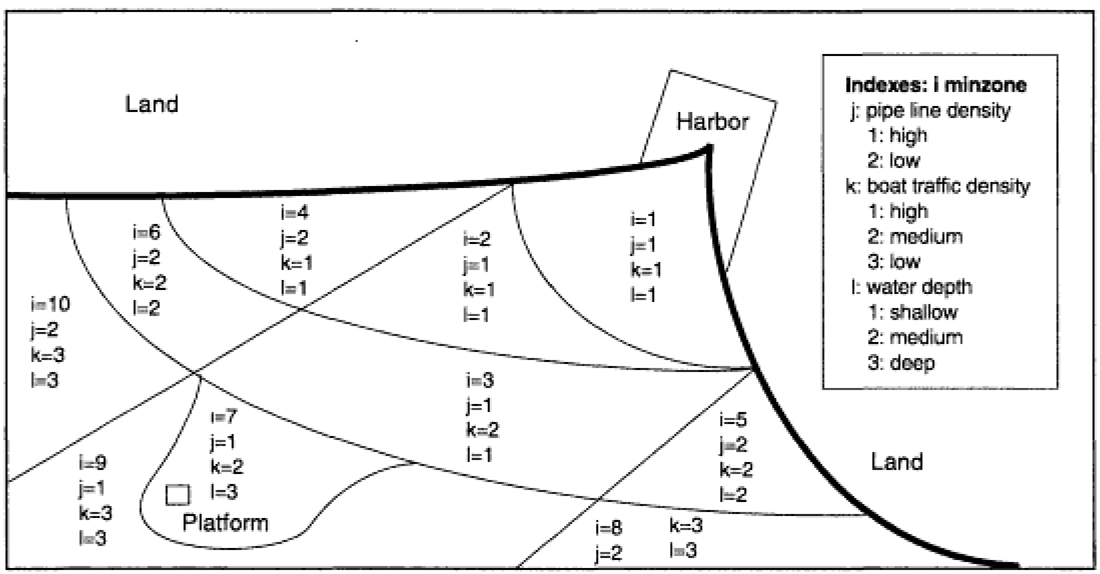

Figure E-4 Partition of a hypothetical area according to water depth, pipeline density, and vessel traffic density.

- The surface area in square miles
- The density of pipelines indexed by *j* (1, 2, or 3) and, possibly, specific distributions of pipe sizes, ratios of old to new and inactive to live pipelines, as well as the proportion of those carrying gas versus oil or condensate (unless these characteristics are considered geographically uniform)
- The density of vessel traffic, indexed by *k* (1, 2, or 3) and possibly, the types of vessels if there are significant differences in drafts

- The water depth indexed by *l* (1, 2, or 3)
- The number of platforms.

Initiating Events

The five initiating events (denoted "IE") are as follows:

• For "offsite" pipelines (not in the immediate vicinity of platforms):

IEa: A vessel hits an exposed pipeline, a class of accidents that can lead to human casualties.

IEb: A vessel operator drops or drags an anchor or other object causing a breach in a pipeline

IEc: A pipeline leaks due to corrosion

IEd: A pipeline breaks and/or leaks due to damage caused by storms and hurricanes

• For pipelines at platforms:

IEe: A pipeline fails at the interface with a platform due to excessive loads such as shocks or high internal pressures, and/or to reduced capacity due to a weakness of the equipment.

These five types of initiating events can be considered mutually exclusive. Their probabilities are defined for each min-zone as a function of water depth and the densities of vessels and pipelines. The risks associated with each failure mode can then be computed and summed over all accident types and all min-zones to assess the overall risk in the Gulf. In particular, one can compute independently the mean annual number of human casualties, and the mean annual volume of oil spilled due to leaks (which depends on the size of a hole in a live oil pipeline of specified diameter for a given spill duration).

Structure of the Risk Computation for Each Min-Zone

For each min-zone and for each initiating event, the risk is characterized by (a) the probability of at least one death per year in the min-zone (and the maximum individual risk), (b) the mean volume of oil spilled per year, and (c) the average annual property damage to vessels and pipelines. The structure of the model (data, dependencies and outputs) for each initiating event is outlined in the following sections.

Initiating Event a (IEa): Collision Between a Vessel and a Live Pipeline, Remote From Platforms

The main concern about vessels striking pipelines is the possibility of human casualties on board if the pipe transports gas. In this case, an explosion can follow, possibly causing heavy damage to the vessel and injuring or killing its occupants. If the pipe carries oil, the consequences for human life are much less severe: the vessel and the pipeline may suffer some damage and some oil may be spilled, but to the extent that the event is noticed and its location is known, the response time can be short and the amount of spillage generally small.

The annual probability of at least one casualty in min-zone *i* in any given year depends on (a) the probability distribution of the annual number of collisions between vessels and exposed live gas pipelines in min-zone *i* and (b) the conditional probability of at least one death given a collision between a vessel and a gas pipeline of diameter m ($P_m(D|C)$). The annual probability of a vessel-pipeline collision depends on the densities of pipelines and of vessel traffic, on the water depth in min-zone *i*, and on the proportion of live, exposed pipelines. The term $P_m(D|C)$ depends on the probability that a pipeline of diameter m carries gas, on the mass of the vessel, and on its speed at the time of the collision.

The individual risk for the most exposed people on vessels depends on the average annual number of casualties in vessel-pipeline collisions in min-zone *i*, and on the number of people who incur most of the risk (the "most exposed" individuals), generally those on board fishing vessels that navigate in shallow waters.

The mean annual volume of oil spilled depends on the mean annual number of collisions, and on the average volume spilled in a collision between a vessel and a live oil pipeline (which for a given event depends, among other factors, on the size of the pipeline breach and on the response time to stop the flow).

Initiating Event b (IEb): Impact of Dropped or Dragged Anchors and Other Objects, Remote from Platforms

For this kind of incident, the main concern is the amount of oil spilled. If the pipeline carries gas, the ignition source is generally far removed from the site. The mean annual volume of oil spilled depends on the mean annual number of impacts of various objects (mostly anchors) on live, exposed pipelines transporting oil and the mean amount of oil spilled per event.[2] The annual number of impacts depends on the density of vessel traffic, the density of live pipelines, and the proportion of pipelines that are exposed and transport oil in the different specified ranges of diameters. The mean amount of oil spilled per event depends, among other factors, on the probability that the impact of a dropped or dragged object causes a breach in the pipeline, the mean size of the breach, and the response time (spill duration).

The model can be simplified by assessing directly the mean amount of oil released conditional on object impact. The reason for making the equations more detailed is that some safety measures are meant to improve spill detection, thereby decreasing the spill duration and improving the response.

The mean annual financial loss due to pipeline damage can be computed by simply multiplying the mean annual number of incidents by the mean property damage per impact. (Note that only immediate damage is accounted for here; a pipe may break later due to a dent that did not cause immediate rupture.)

Initiating Event c (IEc): Corrosion of Pipelines Transporting Oil, Remote from Platforms

Oil leaks due to corrosion are generally much less serious than those due to dropped or dragged objects such as anchors. One important policy issue is the cumulative effects

[2] An alternative here is to compute the annual probability of a large spill.

of corrosion with the age of the pipelines. Also, when corrosion results in leakage, the leak dection time is critical to the amount of oil spilled. If the flow of the spill is too small to be noticeable by pipeline operators (through either electronic monitoring or visual surveillance), the spill can last for some time before measures are taken to stop it.

The mean annual volume spilled depends on the mean number of corrosion holes per year in min-zone *i* (allocated among buried and exposed pipelines), which itself depends (cumulatively) on the age of the pipelines and on the maintenance and management policies of the oil companies, the mean size of corrosion holes (which determines the mean spill rate, given the pressures in the pipes), and the mean duration of spills per event. The observation delay may depend on the distance to the shore (the closer, the more visible). The total amount of oil spilled per year is obtained by summing the amounts of oil spilled for all sizes of the breaches, pipe diameters, and spill durations.

The model can be simplified by considering only the frequency of occurrences of corrosion holes in each min-zone (as a function of the pipeline density) and the average amount released for each corrosion incident. Again, in this simplified form, the model allows computing the benefits of preventing corrosion, but not the benefits of earlier detection through better inspection and maintenance programs, which may themselves be cost-effective safety measures. The model can also be expanded to include the rate of deterioration of corrosion breaches and therefore, to allow computation of the benefits of earlier detection. To do so, a simple analysis of the corrosion process over time may be required. If the mean amount of oil spilled per event is the only result of interest, however, the mean time to detection for different types of pipelines (e.g., each diameter range) might be sufficient. The model could also be expanded to include corrosion of gas pipes; however, the environmental and safety consequences of these events are not considered high.

Initiating Event d (IEd): Effects of Storms and Hurricanes, Remote from Platforms

The severe wave forces of storms and hurricanes can disturb the sea floor, cause mudslides, expose buried pipelines, and damage exposed (unburied) pipelines. The effect of the waves on the pipelines depends on the energy involved, which in turn depends on the water depth. It is assumed, in this simplified model, that the distribution of occurrences of storms and hurricanes is uniform over the Gulf region. Each of them, however, affects a particular area.

The mean annual amount of oil spilled from leaks due to storms and hurricanes depends on the frequency of storms and hurricanes in the Gulf, the mean size of the area affected by each event, the distribution of event severity levels (measured, for example, by the wave heights), the water depth (which determines the energy of the waves and their effects on the sea floor given the event severity in the area affected), the pipeline diameters and densities in the considered min-zone (which determine the sizes of the breaches and the magnitudes of the spills), and the mean spill duration.

For this failure mode, there are clear event dependencies (e.g., the same event can affect several adjacent min-zones); but if one focuses only on averages, the mean of the total amount of oil spilled per year can be obtained by multiplying the average total amount of oil spilled per storm by the mean annual number of storms, regardless of geographic correlations.

Initiating Event e (IEe): Pipeline Failure, Near Platforms

This class of initiating events is a large one, which includes pipe ruptures under normal loads due to corrosion, rupture of normal pipes due to excessive loads such as overpressure, the impact of dropped or dragged objects, heat loads due to fire, or the blast of explosions initiated elsewhere in the platform system. It also includes the effects of storms and hurricanes at the site of the connection between platforms and risers. This class of accident initiators is therefore much more complex than the previous ones.

A complete analysis of the reliability of the pipelines at the interface with the platforms involves computation of the probability that the annual extreme value of the load (a random variable described by its probability distribution) exceeds the pipeline capacity (described by another random variable). Accidents initiated on the platform constitute, in turn, initiating events for the failure of the pipelines at the interface with the platform. An example of such cases is the *Piper Alpha* accident in the North Sea, where the riser from platform Tartan failed at the interface with the *Piper Alpha* under the heat loads generated by fire on the deck. Other accident initiators occur in the pipelines themselves (e.g., corrosion leaks).

Altogether, the set of initiating events IEe can be subdivided into five categories' (a) leaks due to corrosion of a pipeline at the interface with the platform, (b) leaks due to the impact on a pipeline of a dropped object or a vessel (e.g., fishing vessels or service and supply boats) at the site of a platform, (c) pipeline failures due to a large and sudden increase of pressure (caused by human error, equipment failure, or an explosion originating at platform equipment), (d) pipeline failure under severe, sustained fire load, and (e) pipeline failure due to the effects of hurricanes and storms.

Each class of accident initiators requires a probabilistic risk assessment, possibly a partial analysis focusing on the components of interest. In principle, each of these accident sequences must be studied starting from the platforms configuration, its functions, and its operating procedures, including inspection and maintenance. In practice, the analysis can be simplified by computing or estimating based on global accident data, the rates of occurrences per (generic) type of platform. The number of casualties due to each type of initiating event is influenced by the nature of the event, its frequency, its severity, whether the pipe carries oil or gas, further developments (such as fires and explosions), and the number of workers exposed. The mean annual amount of oil spilled also depends on the nature of the incident/accident initiator, on the detection time, the diameter of the pipe, the pressures, and the time to response. The property damage (as well as the number of casualties) depends in large part on whether or not the pipeline rupture results in fires, explosions, or further failures that can affect the rest of the platform.[3]

NOTATION

EV(X):	Expected value (mean) of a random variable X
p(E):	Probability of an event E
p(E|Y):	Conditional probability of E given Y
EV(X|Y):	Expected value of X given Y

[3] Only fixed platforms are considered in this section. Mobile drilling units are not included because there are fewer of them (less than 5 percent of the total platform and rig total in the Gulf of Mexico).

Of the following notations, some represent indexes, some are events (e.g., vessel-pipeline collision), some are random variables, some are means of random variables, and some are probabilities.

Characteristics of Min-Zone i

i: Index of min-zone = {j, k, l} (pipeline density, vessel traffic density, water depth indexes for min-zone i)

a_i: Proportion of exposed pipelines in min-zone i

b_i: Proportion of live pipelines in min-zone i; b_i may depend on a_i

g_i: Proportion of live pipelines transporting gas or liquefied gas in min-zone i (1-g_i transport oil); g_i may depend on a_i

S_i: Surface of min-zone i in square miles

F_i: Average number of people on vessels in the most exposed group in min-zone i (i.e., personnel on fishing vessel or service vessels more than 150 days per year), based on average number of fishing or service vessels and average size of crew

Characteristics of Pipelines

m: Index of pipe diameter ranges

d_m: Discretized distribution of pipe diameters, i.e., proportion of pipelines of diameter in ranges indexed in m. Examples:

$$m = 1 \quad \text{diam} < 2'' \Rightarrow d_1 = 10\%$$
$$m = 2 \quad 2'' < \text{diam} < 5'' \Rightarrow d_2 = 25\%, \text{ etc.}$$

(This distribution is assumed to be independent of the min-zone. The model can be easily modified to include different diameter distributions in different zones.)

Collision Between Vessels and Live Exposed Pipelines

C: Collision between a vessel and an exposed pipeline

C_i: Mean number of collisions per year and per square mile between a vessel and an exposed pipeline (live or empty); c_i depends on j, k, 1 and a_i

C_i: Mean number of collisions per year in min-zone i between a vessel and an exposed pipeline

EX: Explosion (or sudden fire) following a collision between a vessel and a live gas pipeline

P_m (EX|C): Probability of explosion (or sudden fire) given a collision between a vessel and a live gas pipeline in the diameter range m

NEX_i: Mean annual number of explosions or sudden fires caused by vessel/pipeline collisions in min-zone i

D: Event defined as follows: at least one human death occurs due to an explosion or a sudden fire in a specified collision

p(D): Probability of at least one human death in an explosion or a sudden fire in a specified collision

NDEX: Mean number of casualties on board given an explosion or sudden fire caused by a vessel/pipeline collision

NDC_i: Mean annual number of casualties in all vessel/pipeline collisions in min-zone i

OD: Event defined as follows: at least one death occurs in a given year in the Gulf in vessel-live pipeline collisions

$P_i(D)$: Annual probability of at least one human death in min-zone i due to collision between a vessel and a pipeline

SP_m: Mean spilled volume following a collision of a vessel with a live pipeline of diameter m transporting oil

XCO_i: Mean volume of oil spilled per year due to collisions between vessels and exposed live pipeline transporting oil in min-zone i

PDCL: Mean value of the property damage (to vessel and pipeline owners) per collision between a vessel and an exposed live pipeline given that there is no fire or explosion

PDCX: Mean value of the property damage (to vessel and to pipeline owners) per collision between a vessel and an exposed live pipeline transporting gas given that an explosion occurs

PDCE: Mean value of the property damage to vessels per collision between a vessel and an exposed empty pipeline

PDC_i: Mean value of total annual property damage due to collisions between vessels and exposed pipelines in min-zone i

$IR_i(D)$: Individual risk per year in "offsite" pipelines of min-zone i (away from the immediate vicinity of platforms) assuming that the risk of casualty is borne mostly by the regular service vessels' and fishing vessels' crews and that no one takes extraordinary additional risks

Object Impact (Mostly Dropped and Dragged Anchors)

O: Impact of an anchor or other dropped object on a live exposed pipeline

o_i: Mean annual number of object impacts on live exposed pipelines per square mile of min-zone i as a function of j, k, l, a_i and b_i

O_i: Mean annual number of object impacts on live exposed pipelines transporting oil in min-zone i

q: Index of breach diameter ranges in object impact incidents

Oh_q: Occurrence of a hole of diameter q caused by object impact on a live pipeline

$P_m(Oh_q|O)$: Probability of a hole of diameter q (discretized distribution) conditional on impact of object on a live exposed pipeline in the diameter range m

t_r: Spill duration ranges (Example: t_1: <1 day; t_2: from 1 to 5 days; t_3: > 5 days)

$p(t_r|O, oh_q)$: Probability of oil spill of duration t_r (discretized distribution over different time intervals) conditional on impact of object on a live exposed pipeline and a hole of diameter q

$X(oh_q, t_r)$: Average amount of oil spilled in each range of spill duration t_r from a pipeline, through a breach of diameter range oh_q

XDO: Mean amount of oil spilled per object impact

XD_i: Average amount of oil spilled per year in min-zone i due to dropped anchors or impact of other objects

PDO: Mean value of the property damage per event (an impact on live exposed pipelines of dropped objects including anchors)

PDO_i: Mean value of annual property damage due to impact on live exposed pipelines of dropped objects including anchors in min-zone i

Corrosion Holes

CHE: Occurrence of a corrosion hole in an exposed pipeline

CHB: Occurrence of a corrosion hole in a buried pipeline

ch_i: Mean annual number of corrosion holes in live pipelines per square miles of minzone i (depends on pipeline density)

CHE_i: Mean annual number of corrosion holes in exposed live pipelines transporting oil in min-zone i

CHB_i: Mean annual number of corrosion holes in buried live pipelines transporting oil in min-zone i

c: Index of corrosion hole diameter ranges when detected and fixed

d_c: Corrosion hole diameter ranges when detected and fixed

NCE_{icm}: Mean annual number of corrosion holes in exposed oil pipelines of diameter m, that reach diameter c (discretized) in min-zone i

NCB_{icm}: Mean annual number of corrosion holes in buried oil pipelines of diameter m, that reach diameter c in min-zone i

$P(d_c|CH)$: Probability that a corrosion hole reaches diameter d_c conditional on occurrence on a pipe before it is detected and fixed

$P(d_c|CHE)$: Probability that a corrosion hole reaches diameter d_c conditional on occurrence on an exposed pipe before it is detected and fixed

$P(d_c|CHB)$: Probability that a corrosion hole reaches diameter d_c conditional on occurrence on a buried pipe before it is detected and fixed

$P(t_r|CHE, d_c)$: Probability of oil spill duration t_r conditional on corrosion in a live exposed pipeline and a hole that eventually reaches diameter d_c

$P(t_r|CHB, d_c)$: Probability of oil spill duration tr conditional on corrosion in a live buried pipeline and a hole that eventually reaches diameter d_c

$XCE(d_c, t_r)$: Mean volume of oil spilled through a corrosion hole of final diameter d_c in a live exposed pipeline before the problem is detected and fixed

$XCB(d_c, t_r)$: Mean volume of oil spilled through a corrosion hole of final diameter d_c in a (live) buried pipeline before the problem is detected and fixed

XCE_i: Mean amount of oil spilled per year through corrosion holes in exposed live pipelines transporting oil in min-zone i

XCB_i: Mean amount of oil spilled per year through corrosion holes in exposed buried pipelines in min-zone i

XC_i: Mean annual amount of oil spilled through corrosion holes in both exposed and buried pipelines in min-zone i

RE_i: Mean annual cost of repair of corrosion holes in pipelines in min-zone i

REE_{cm}: Mean cost of repair of a corrosion hole of final diameter c in an exposed pipeline of diameter m

REB_{cm}: Mean cost of repair of a corrosion hole of final diameter c in a buried pipeline of diameter m

Hurricanes and Storms

H: Occurrence of a storm or a hurricane

NH: Number of hurricanes per year in the Gulf of Mexico

$p_{NH}(nh)$: Probability of occurrence of nh hurricanes or storms per year anywhere in the Gulf of Mexico

s: Levels of severity of storms and hurricanes (from s=0, no effect, to a chosen S_{max})

$P_i(s|H)$: Probability distribution of the local severity s (wind speed) of a storm or hurricane affecting min-zone i conditional on occurrence of H anywhere in the Gulf. Severity levels are discretized into a few ranges. They determine forces on exposed pipelines. These forces depend, in part, on the water depth in the min-zone. It is assumed for simplicity that the effect of any H is uniform over the min-zone.

NHB_i: Mean annual number of pipeline breaches due to storms and hurricanes in min-zone i

$P_i(nb|H, s)$: Probability that a storm or hurricane of severity s that affects min-zone i causes nb breaches in marine pipelines in min-zone i (depending on the pipeline density and the water depth)

XH_i: Mean amount of oil spilled per year in min-zone i due to damage caused by storms and hurricanes to live pipelines transporting oil

XH: Mean volume of oil spilled in a breach caused by a storm or a hurricane in a live pipeline transporting oil in min-zone i (assumed here to be averaged over pipe diameters, severity of the damage to the pipe and detection time)

RH_i: Mean annual cost of repair of breaches in pipelines due to storms and hurricanes in min-zone i

RH: Mean cost of repair of damage to pipelines due storms and hurricanes for all events and types of breaches

Risk at the Sites of Platforms

z: Index of platforms in min-zone i (depends on i)

v: Index of initiating events at the site of the platform

IE_v: Initiating event of index v:

v = 1: breaches due to pipe corrosion at the interface with the platform,

v = 2: breaches due to the impact on a pipe of a dropped object or a vessel (e.g., fishing vessels or service and supply vessels) at the site of a platform

v = 3: pipe failures due to a large and sudden increase of pressure (which can be caused by human error, equipment failure, or an explosion originated in platform equipment)

v = 4: pipe failure under severe, sustained fire load

v = 5: pipe failure due to the effects of hurricanes and storms.

N_{zv}: Mean annual number of occurrences of initiating event IE_v at the site of platform z

$p(D|IE_v)$: Probability of at least one death conditional on the occurrence of initiating event IE_v on platform z (PRA result)

$p(D_z)$: Probability of at least one death in any given year on platform z in an accident involving the pipelines

N_z: Average number of workers on platform z

ND_z: Expected annual number of deaths on platform z

ND_{zv}: Expected number of casualties in each accident of type v on platform z

X_{vz}: Mean amount of oil spilled conditional on occurrence of initiating event IE_v on platform z (PRA result)

PD_{vz}: Mean property damage conditional on the occurrence of initiating event IE_v on platform z (PRA result)

XP_i: Mean amount of oil spilled per year due to pipeline failure at the site (or in the vicinity) of platforms in min-zone i

PDP_i: Mean property damage per year due to pipeline failure at the site (or in the vicinity) of platforms in min-zone i

$P_i(DP)$: Probability that at least one death occurs in any given year due to pipeline failures at the site (or in the vicinity) of a platform in min-zone i

$IR_{z(i)}(DP)$: Individual risk (annual probability of death) for platform workers in accidents involving pipes at the site of platform z(i) in min-zone i

COMPUTING THE RISK FOR MIN-ZONE I

The risk is computed first for each class of initiating events (denoted IEa, IEb, IEc, IEd, and IEe), then added for all types of initiating events. It is assumed that these initiating events are mutually exclusive and that their effects are additive. It is also assumed that the ratios of live-to-empty, buried-to-exposed and gas-to-oil pipelines are independent of other factors, and uniform across min-zone i. This assumption may have to be reexamined in actual applications, and the equations may have to be modified accordingly.

IEa: Collision Between a Vessel and an Exposed Live Pipeline Carrying Gas

To model the risk of loss of lives in vessel-pipeline collisions, one can use an influence diagram similar to that shown in Figure E-5. An influence diagram is a directed graph whose nodes represent random events or random variables characterized by probabilities and probability. distributions.[4] An arrow between two nodes means that the probabilities characterizing the second node depend on the value of the first one. For example, the number of human casualties depends on the occurrence of an explosion or a sudden fire, which requires (1) that a collision occurs, (2) that the pipeline is live, (3) that it transports gas, and (4) that the diameter of the pipe (therefore the amount of gas involved) is sufficient.

The mean annual number C_i of collisions in min-zone i between vessels and exposed live pipelines transporting gas depends on the surface of the min-zone, the collision rate per square mile and the proportions of pipelines that are live and transport gas (it is assumed here that these two ratios are independent):

$$C_i = S_i \times c_i \times b_i \times g_i \qquad \text{Eq. 1}$$

The mean annual number of explosions (or sudden fires) due to collisions between vessels and exposed pipelines in min-zone i depends on the total number of collisions, the distribution of pipe diameters, and the probability of explosion given collision in each diameter range. Note that this equation assumes that the probability of collision is independent of the pipe diameter.

$$NEX_i = C_i \times \sum_m \left[d_m \times p_m(EX|C) \right] \qquad \text{Eq. 2}$$

The annual probability that at least one death occurs in min-zone i in explosions or sudden fires due to vessel/pipeline collisions is about equal to the product of the number of explosions and the probability of at least one death given that an explosion occurs

[4] Schachter, R. D. 1986. Evaluating influence diagrams. *Operations Research* 34(6).

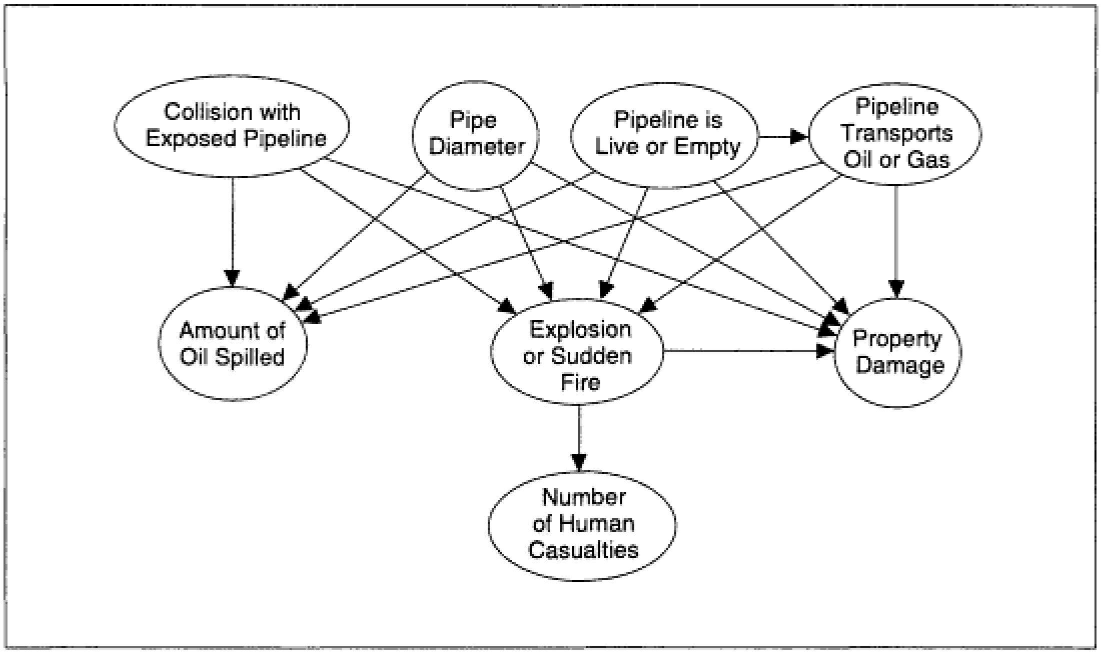

Figure E-5 Influence diagram for assessment of the risks involved in vessel/pipeline collisions.

following a collision. It is assumed here that p(D) is small, and that the type of vessel is not a major factor in the term p(D); otherwise, the computation should be done for the different vessel types.

$$p_i(D) \approx NEX_i \times p(D) \qquad \text{Eq. 3}$$

The mean annual number of deaths in explosions or sudden fires due to vessel/pipeline collisions in min-zone i is the product of the average number of explosions by the average number of deaths per explosion (the latter can be either inferred from existing statistics, or computed as the result of a model involving different types of vessels).

$$NDC_i = NDEX \times NEX_i \qquad \text{Eq. 4}$$

Assuming that the risk of casualty is mostly borne by the service vessels' and fishing vessels' crews (F_i people in min-zone i), and that risk avoidance behaviors are fairly uniform (e.g., no one actually seeks contact with the pipelines), the individual risk for fishing vessel crews in min-zone i (annual probability of death in collision accidents for the most exposed individuals), is approximately:

$$IR_i(D) = NDC_i / F_i \qquad \text{Eq. 5}$$

The result of Equation 5 is the ratio of the annual expected value of the number of casualties in min-zone i to the number of individuals exposed. Therefore, it represents an individual risk per year of life in which the individual may spend only one fifth of the year on the vessel. It is not a risk per year of exposure.

The mean value of annual property damage to vessel and pipeline owners due to collisions between vessels and exposed pipelines in min-zone i is the sum of the property damage for the three following cases: the pipeline is empty, the pipeline is live and there is no explosion, the pipeline is live and there is an explosion:

$$PDC_i = \left[S_i \times c_i \times (1-b_i)\right] \times PDCE + \left[S_i \times c_i \times b_i - NEX_i\right] \times PDCL + NEX_i \times PDCX \qquad \text{Eq. 6}$$

The mean spilled volume per year due to collisions of vessels and exposed live pipelines transporting oil in min-zone i is the sum of the spills over all ranges of pipeline diameters:

$$XCO_i = S_i \times b_i \times c_i \times (1-g_i) \times \sum_m \left[d_m \times SP_m\right] \qquad \text{Eq. 7}$$

IEb: Oil Spills due to Dropped and Dragged Anchors (or Impact of Other Objects)

The analysis is based on the events and random variables described in the influence diagram of Figure E-6. It is assumed that the main effect is the spill of oil and the property damage to live pipelines.

The mean annual number of impacts of dropped and/or dragged anchors or other objects on live, exposed pipelines transporting oil in rain-zone i is:

$$O_i = S_i \times o_i \times (1-g_i) \qquad \text{Eq. 8}$$

This equation assumes that oil and gas pipelines are equally likely to be hit.

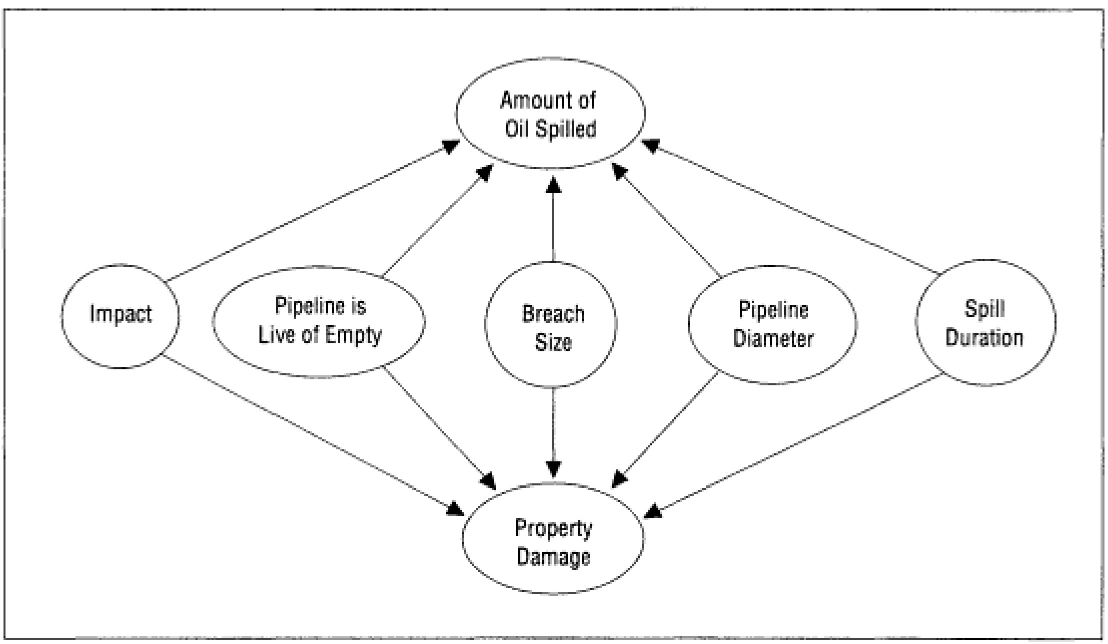

Figure E-6 Influence diagram (for assessment of the risk to pipelines due to dropped and dragged anchors (or impacts of other objects).

The mean amount of oil spilled per object impact given diameter of pipe, size of breach, and spill duration is the sum for all values of these three variables (considered here independent) of the amount of oil spilled under each scenario:

$$XDO = \sum_{m}\sum_{r}\sum_{q}\left[X\left(oh_q, t_r\right)\times d_m \times p\left(t_r \middle| O, oh_q\right)\times p_m\left(oh_q \middle| O\right)\right] \quad \text{Eq. 9}$$

The mean amount of oil spilled per year in min-zone i due to impacts of dropped and/or dragged anchors or other objects on live exposed pipelines transporting oil is the amount spilled per event multiplied by the number of events:

$$XD_i = XDO \times O_i \quad \text{Eq. 10}$$

Similarly, the mean value of the annual property damage due to impacts of dropped and/or dragged anchors or other objects on all live exposed pipelines in min-zone i is the product:

$$PDO_i = O_i \times PDO \quad \text{Eq. 11}$$

IEc: Corrosion of Pipelines Transporting Oil

The simplified model used here relies on the events and random variables described in Figure E-7.

The final size of the corrosion hole is a variable of the model because it would be affected by inspection policies that would allow earlier detection of corrosion and shorter oil spill durations.

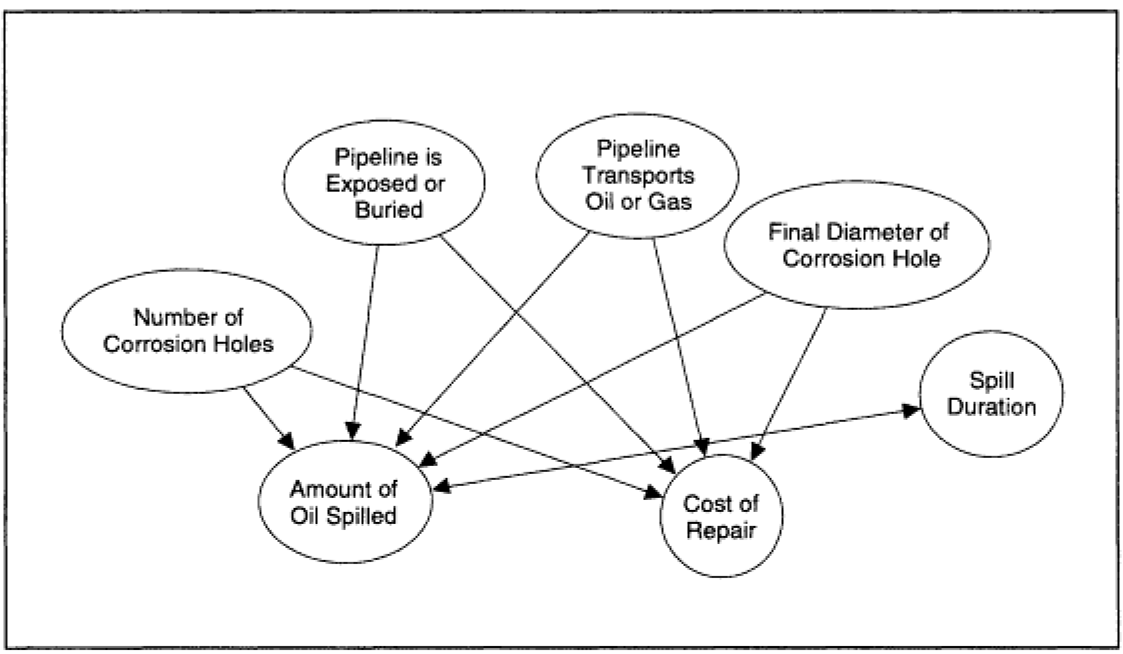

Figure E-7 Influence diagram for assessment of the risk due to pipeline corrosion.

The mean annual number of corrosion holes in *exposed* live pipelines transporting oil in min-zone i is the product:

$$CHE_i = S_i \times ch_i \times a_i \times (1 - g_i) \qquad \text{Eq. 12}$$

The mean annual number of corrosion holes that reach diameter c (discretized) in exposed pipelines of diameter m, transporting oil, in min-zone i is:

$$NCE_{icm} = CHE_i \times p(d_c | CHE) \times d_m \qquad \text{Eq. 13}$$

The mean annual amount of oil spilled through corrosion holes in exposed live pipelines transporting oil in min-zone i is sum of the amounts of oil spilled for all pipe diameters, sizes of corrosion holes, and spill durations:

$$XCE_i = \sum_m \sum_r \sum_c \left[NCE_{icm} \times XCE(d_c, t_r) \times p(t_r | CHE, d_c) \right] \qquad \text{Eq. 14}$$

The same computation can be performed for corrosion holes in buried pipes (although the quantities spilled may be very small: it may take years before a leak develops and one may choose to skip equations 15 through 17).

The mean annual number of corrosion holes in buried live pipelines transporting oil in min-zone i is:

$$CHB_i = S_i \times ch_i \times (1 - a_i) \times (1 - g_i) \qquad \text{Eq. 15}$$

The mean annual number of corrosion holes in buried pipelines of diameter m transporting oil, that reach diameter c (discretized) is:

$$NCB_{icm} = CHB_i \times p(d_c | CHB) \times d_m \qquad \text{Eq. 16}$$

The mean amount of oil spilled per year through corrosion holes in buried live pipelines in min-zone i is the sum of the amounts of oil spilled for all scenarios (pipe diameters, sizes of corrosion holes, and spill durations):

$$XCB_i = \sum_m \sum_r \sum_c \left[NCB_{icm} \times XCB(d_c, t_r) \times p(t_r | CHB, d_c) \right] \qquad \text{Eq. 17}$$

The mean total annual amount of oil spilled through corrosion holes both in exposed and buried pipelines in min-zone i is thus the sum:

$$XC_i = XCB_i + XCE_i \qquad \text{Eq. 18}$$

The mean annual cost of repair of corroded oil pipelines, both exposed and buried (costs of fixing corrosion holes excluding the costs of corrosion protection) is a function both of the diameter of the pipes and of the size of the corrosion holes:

$$RE_i = \sum_m \sum_c \left[NCE_{icm} \times REE_{cm} + NCB_{icm} \times REB_{cm} \right] \qquad \text{Eq. 19}$$

(One may want to add a similar equation for gas pipelines).

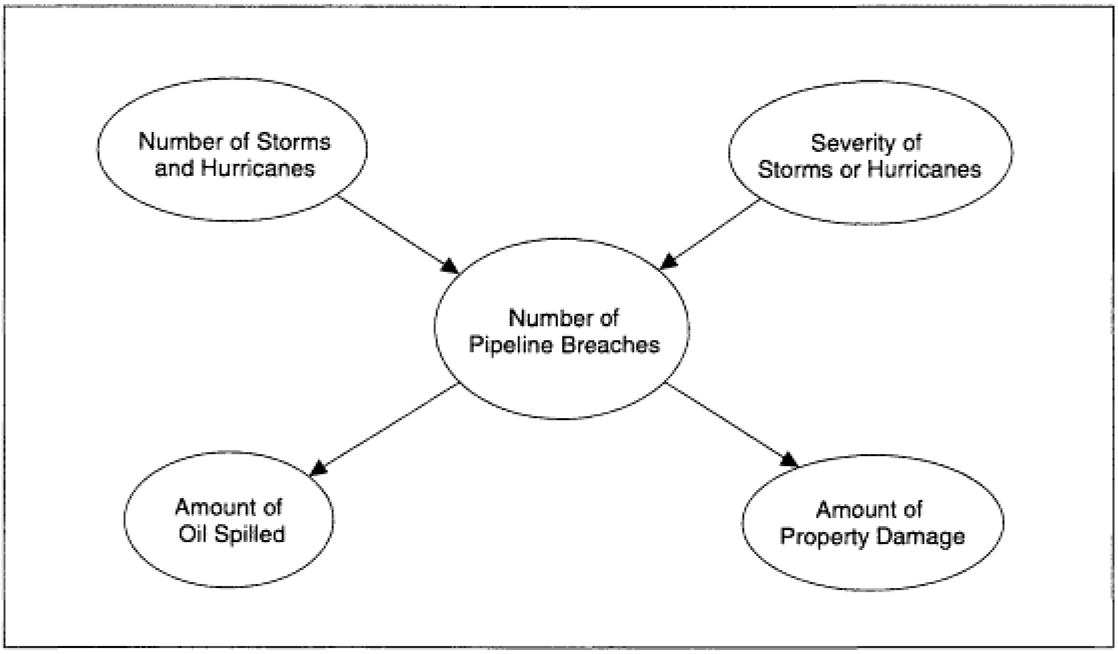

Figure E-8 Influence diagram for assessment of the risk to pipelines due to severe storms.

IEd: Storms and Hurricanes

The very simplified model developed further can be represented by the influence diagram of Figure E-8. This model can be developed further if needed by including the size of the area affected by an event (random variable), the diameter of the damaged pipelines, the duration of the spill, etc.

The mean annual number of pipeline breaches due to storms and hurricanes in min-zone i is obtained by summing their joint distribution over the number of storms, their severity given that they occur, and the number of breaches per storm of given severity:

$$NHB_i = \sum_{nb}\sum_{nh}\sum_{s}\left[nh \times p_{NH}(nh) \times p_i(s|H) \times nb \times p_i(nb|H, s)\right] \qquad \text{Eq. 20}$$

The mean annual amount of oil spilled due to breaches in pipelines caused by hurricanes and storms in min-zone i is obtained by restricting this number to live pipelines transporting oil, and multiplying the result by the mean amount spilled per event:

$$XH_i = NHB_i \times b_i \times (1 - g_i) \times XH \qquad \text{Eq. 21}$$

Similarly, the mean annual amount of property damage (costs of repairs of the live pipelines damaged by storms or hurricanes) in min-zone i is:

$$RH_i = NHB_i \times b_i \times RH \qquad \text{Eq. 22}$$

In addition to direct damage, hurricane and storms may also expose pipelines that were previously buried thus increasing the probability of vessel collision in the future (and therefore the results of the analysis of IEa). This effect is not included in this simplified model but can be added in a more complete version.

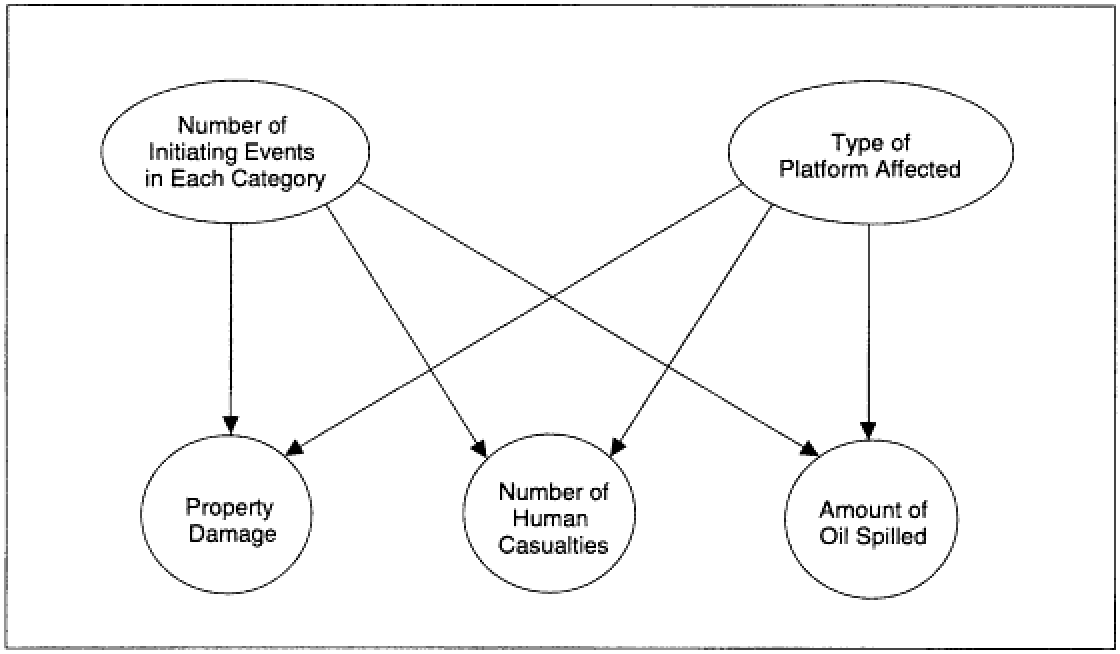

Figure E-9 Influence diagram for assessment of the risk due to accidents and incidents at the interface between pipelines and platforms.

IEe: Accidents and Incidents Involving Pipelines at the Site of a Platform

It is assumed here that either a preliminary PRA has been performed, accounting for the specific configuration of each platform and pipeline system, or that global rates of different categories of incidents have been assessed for different types of platforms. For initiating events involving, for instance, severe sustained fire loads across the whole platform (of the type of the Piper Alpha accident), a full (albeit simplified) PRA may be needed. It is also assumed that initiating events on a given platform are mutually exclusive, and that pipe failures across different platforms are independent.

The structure of the model is presented in the influence diagram of Figure E-9. For each type of platform, the full PRA allows computing the probabilistic link between initiating events and consequences.

The probability of at least one death in any given year on platform z in an accident involving the pipelines is one minus the probability of no death on platform z for all possible initiating events:

$$
\begin{aligned}
p(D_z) &\approx 1 - \prod_{v} \left[1 - N_{zv}\, p(D|IE_v)\right] \\
&\approx \sum_{v} N_{zv}\, p(D|IE_v)
\end{aligned}
\qquad \text{Eq. 23}
$$

The probability that at least one death occurs in any given year due to pipeline failures at the site (or in the vicinity) of a platform in min-zone i is thus:

$$
\begin{aligned}
p_i(DP) &= 1 - \prod_z \left[1 - p(D_z)\right] \approx \sum_z p(D_z) \\
&\approx 1 - \prod_z \prod_v \left[1 - N_{zv}\, p(D|IE_v)\right] \\
&\approx \sum_z \sum_v \left[N_{zv} \times p(D|IE_v)\right]
\end{aligned} \quad \text{Eq. 24}
$$

The expected annual number of casualties at the site of a given platform is:

$$
ND_z = \sum_v \left[N_{zv} \times ND_{zv}\right] \quad \text{Eq. 25}
$$

The individual risk (annual probability of death) for a year of a worker's life on the platform is approximately:

$$
\begin{aligned}
IR_{z(i)}(DP) &\approx ND_z / N_z \\
&= \sum_v \left[N_{zv} \times ND_{zv} / N_z\right]
\end{aligned} \quad \text{Eq. 26}
$$

The mean total amount of oil spilled per year due to pipeline failure at the site (or in the vicinity) of platforms in min-zone i is obtained by summing the amounts spilled over platforms and types of initiating events:

$$
XP_i = \sum_{z(i)} \sum_v \left[N_{zv} \times X_{zv}\right] \quad \text{Eq. 27}
$$

Similarly, the mean total property damage per year due to pipeline failure at the site (or in the vicinity) of platforms in min-zone i is:

$$
PDP_i = \sum_{z(i)} \sum_v \left[N_{zv} \times PD_{zv}\right] \quad \text{Eq. 28}
$$

OVERALL RISK

The annual probability of at least one casualty in the Gulf due to pipelines away from platforms (explosions or sudden fires following collisions between a vessel and an exposed live pipeline transporting gas) is one minus the probability of no casualty:

$$
p(OD) = 1 - \prod_i \left[1 - p_i(D)\right] \quad \text{Eq. 29}
$$

The upper bound of the individual risk across min-zones for vessel crews in the Gulf is the maximum of individuals risks over all min-zones:

$$
Max(D) \approx \operatorname*{Max}_i \left[IR_i(D)\right] \quad \text{Eq. 30}
$$

The mean amount of oil spilled per year due to pipeline failures caused by any of the five considered accident initiators (vessel collision, dropped objects, corrosion, storms and hurricanes, pipe failure at the site of a platform) is the sum of all amounts of oil spilled over the different types of initiating events considered here:

$$EV(X) = \sum_i \left[XCO_i + XD_i + XC_i + XH_i + XP_i\right] \qquad \text{Eq. 31}$$

Because the environmental damage caused by oil spills may depend on the distance of the spill to the shore, one may want to compute separately the amount of oil spilled in shallow waters. The sum of Equation 31 is then restricted to the values of index i corresponding to the values of index 1 (water depth) of particular concern.

Similarly, the mean annual amount of property damage (including costs of repair of corroded pipelines) in the Gulf due to pipeline failures caused by any of the five considered accident initiators (vessel collision, dropped objects, corrosion, hurrianes and storms, and pipe failure at the site of a platform) is the sum:

$$EV(PD) = \sum_i \left[PDO_i + PDC_i + RE_i + PDP_i\right] \qquad \text{Eq. 32}$$

TABLE OF REQUIRED DATA

Again, it is important to remember that the model presented above is a prototype describing the architecture of what can be a much more complex analysis. The form of the data may be adjusted to the need of information to support specific decisions or to simplify the task of gathering appropriate statistics or expert opinions.

Maps:

- Water depth
- Vessel traffic density
- Pipeline densities
- Platform sites

Pipeline diameters:

- Ranges of pipeline diameters
- Discretized distribution of pipe diameters, i.e., proportion of pipelines in each specified diameter range. The model assumes that this distribution is independent of the min-zone; if this is not the case, the equations can be modified.

Data for Each Min-Zone

General characteristics:

- Surface in square miles
- Proportion of exposed pipelines
- Proportion of live pipelines (may depend on the previous number)
- Proportion of live pipelines transporting gas or liquefied gas (the rest transport oil)
- Average number of people on vessels in the most exposed group (i.e., personnel on fishing vessel or service vessels more than 150 days per year), based on average number of fishing or service vessels and average size of crew

Collisions between vessels and live exposed pipelines:

- Mean number of collisions per year and per square mile between a vessel and an exposed pipeline (live or empty)
- Probability of explosion conditional on a collision between a vessel and an exposed live pipeline transporting gas in each diameter range
- Expected number of casualties given that an explosion occurs following collision (this number is a function of the type of vessels that operate in the min-zone, and can be derived from the probability distribution of the number of casualties in collision-related explosions)
- Probability of at least one death due to explosion or sudden fire in a collision between a vessel and an exposed live pipeline transporting gas in each diameter range (can be derived from the probability distribution of the number of casualties in collision-related explosions)
- Mean spilled volume following a collision of a vessel with a live pipeline of given diameter transporting oil
- Mean value of the property damage per collision between a vessel and an exposed empty pipeline
- Mean value of the property damage per collision between a vessel and an exposed live pipeline transporting oil or gas given that no explosion or sudden fire occurs
- Mean value of the property damage per collision between a vessel and an exposed live pipeline transporting gas given that an explosion or a sudden fire occurs

Object impact:

- Define ranges of sizes for diameter of breaches
- Define ranges of spill duration
- Mean annual number of events (impacts on live exposed pipelines of dropped objects including anchors) per square mile
- Probabilities of breaches of specified diameters (discretized distribution) conditional on impact of object on a live exposed pipeline
- Probabilities of oil spills of specified duration (discretized distribution over different time intervals), conditional on impact of an object on a live exposed pipeline and a breach of specified diameter. (If the amount spilled is simply proportional to the spill duration, can be replaced by the mean spill duration and the mean amount of oil spilled per event.)
- Average amount of oil spilled as a function of the range of spill duration and the diameter range of the breach. (If the amount spilled is simply proportional to the spill duration, can be replaced by the mean spill duration and the mean amount of oil spilled per event.)
- Mean value of the property damage per event

Corrosion holes:

- Define ranges of sizes of corrosion holes
- Define ranges of spill duration
- Mean annual number of corrosion holes in live pipelines per square mile of min-zone i. This figure can be derived, for example, from the number of corrosion holes per mile of pipes, the pipeline density, and the surface of the min-zone.
- Probabilities that corrosion holes eventually reach specified sizes

- Probabilities of specified oil spill durations through corrosion holes of specified final sizes in live exposed pipelines
- Probabilities of specified oil spill durations through corrosion holes of specified final sizes in live buried pipelines
- Mean volumes of oil spilled through corrosion holes of specified final sizes in live exposed pipelines
- Mean volume of oil spilled through corrosion holes of specified final sizes in (live) buried pipelines
- Mean costs of repair of a corrosion hole of specified final size in an exposed pipeline of specified diameter
- Mean cost of repair of a corrosion hole of specified final size in a buried pipeline of specified diameter

Hurricanes and storms:

- Define ranges of storm severity characterized, for example, by the maximum wind speed
- Probabilities of occurrences of different numbers of hurricanes or storms per year *anywhere* in the Gulf of Mexico
- Probability distribution of the local severity in min-zone i given that an event occurs anywhere in the Gulf
- Probabilities that a storm or hurricane of given severity causes different numbers of breaches in marine pipelines in min-zone i given that min-zone i is affected
- Mean volume of oil spilled in a breach caused by a storm or a hurricane in a live pipeline transporting oil in min-zone i
- Mean costs of repair of damage to pipelines due storms and hurricanes for all types of events and breaches

Risk at the site of platforms:

- Define different classes of platforms. For each class, it is assumed that a PRA or similar type of analysis has been performed, to obtain the probabilities and the consequences of different types of accidents characterized by their initiating events and their consequences.
- Define five classes of relevant initiating events:

— Breaches due to pipe corrosion at the interface with the platform,
— Breaches due to the impact on a pipe of a dropped object or a vessel (e.g., fishing vessels or service and supply vessels) at the site of a platform
— Pipe failures due to a large and sudden increase of pressure (which can be caused by human error, equipment failure, or an explosion originated in platform equipment)
— Pipe failure under severe, sustained fire load
— Pipe failure due to the effects of hurricanes and storms.

- Mean annual number of occurrences of initiating events of each type at the site of each class of platform
- Probability of at least one death conditional on the occurrence of each type of initiating event on each class of platform (PRA result)
- Average number of workers on each class of platform

- Expected number of casualties per type of accident and class of platform
- Mean amount of oil spilled per type of accident and class of platform (PRA result)
- Mean property damage per type of accident and class of platform (PRA result)

Appendix F

Sources of Briefings and Discussions

Tommy Allen, National Marine Fisheries Service Loan Program, St. Petersburg, Florida
Alexander Alvarado, Minerals Management Service, Gulf of Mexico Region, Metairie, Louisiana
Carl Anderson, Minerals Management Service, Herndon, Virginia
Larry Atwell, Office of Pipeline Safety
William Bertges, Office of Pipeline Safety, Washington, D.C.
Larry J. Broussard, Joe C. Bowles, Jr., and Robert H. Winters, Tenneco (pipeline inspection and corrosion control)
Gary Chappelle, U.S. Coast Guard, Port Safety and Security Division
E. P. (Bud) Danenberger, Minerals Management Service, Herndon, Virginia
Robert C. Darwin, Shell Oil Company, Houston, Texas
Cesar DeLeon, Office of Pipeline Safety, Washington, D.C.
Bruce Donnell, marine pipeline consultant, Lafayette, Louisiana
Gary Graham, Texas A&M University
Bill Hidalgo, Oil and Gas Marine, Morgan City, Louisiana
Mariano Hinojosa, Louisiana Department of Natural Resources, Baton Rouge
Jim Houston, Transco Energy, Houston, Texas
Robert Jones, Southeast Fisheries Association, Tallahassee, Florida
Fred Joyner, Office of Pipeline Safety, Southern Region
Buddy Kerry, Tidewater Marine, Morgan City, Louisiana
Mary McDaniel, Texas Railroad Commission, Division of Pipeline Safety, Austin, Texas
Jimmy Martin, B&J Martin, Inc., Galliano, Louisiana
Melinda Mayes, Minerals Management Service, Pacific Region
Albert H. Mousselli, Applied Offshore Technology, Houston, Texas
Ed Ondak, Office of Pipeline Safety, Western Region
Frank L. Parks, U.S. Coast Guard, Washington, D.C.
Shea Penland, Louisiana Geologic Survey, Baton Rouge, Louisiana
William Prosser, U.S. Coast Guard

Donald E. Pryor, National Ocean Service, National Oceanic and Atmospheric Administration
John T. Robinson, Mobil Exploration and Producing U.S., Inc., Houston, Texas
James Sides, John Chance and Associates, Inc., Lafayette, Louisiana
Ted Smith, Edison Chouest Offshore, Galliano, Louisiana
Charles E. Smith, Minerals Management Service
Schuble J. Tenney, Jr., John Chance and Associates, Inc., Lafayette, Louisiana
James Thomas, Office of Pipeline Safety, Southwest Region
H. W. Thompson, Louisiana Department of Natural Resources, Baton Rouge
Jack Wilcox, Office of Pipeline Safety, Southwest Region
Jack Willis, Zapata Haynie Corporation
Jack Willock, Office of Pipeline Safety
Ross Woodson, consultant