PROCEEDINGS of the INTERNATIONAL WORKSHOP on

OFFSHORE PIPELINE SAFETY

held on
December 4-6, 1991
New Orleans, Louisiana, U.S.A.

PROCEEDINGS OF THE INTERNATIONAL WORKSHOP ON OFFSHORE PIPELINE SAFETY

held on
December 4-6, 1991

at the
Doubletree Hotel, 300 Canal Street, New Orleans, USA

Edited by
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Sponsored by:

Minerals Management Service
US Department of the Interior

Office of Pipeline Safety,
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TERMS OF REFERENCE

A pressing need in the world offshore industry throughout the next decade, is felt to be the design, safety assessment and repair/rehabilitation, of offshore pipelines, both for new and existing installations. A co-operative international workshop was therefore held, in one of the centers of world pipeline activity, in order to facilitate improved understanding and safety assessment of offshore pipeline safety.

The overall purpose was to discuss current practice, progress, desirable future activities and key future directions in the field of offshore design and management, as well as safe practice in the offshore pipeline industry. It was also designed to bring together the various parties active in the field of offshore pipelines, to form a written record of the major issues at the present time, and to provide definition of areas for management and research focus.

The international steering committee identified eight special topics as being of particular importance, and these were as follows:

- Design, analysis and installation issues for integrity
- Evaluation of system integrity, limit state design issues, reliability assessment
- Internal monitoring (pigging, coupons, nondestructive testing, etc.)
- External surveillance (divers, remotely operated vehicles, acoustic location, etc.)
- Routine operation & maintenance issues (including corrosion control and leak detection)
- Abnormal operations, emergency and storm response, underwater morphology
- Repair & rehabilitation problems
- Deep water considerations-design, inspection, repair and rehabilitation

Participation included representatives of the gas and petroleum industry, consulting firms, offshore contractors, manufacturers and fabricators, government agencies, and academic and research institutions from many countries. Keynote addresses were also invited from prominent industry and government figures. Meetings were then held in separate working groups, to discuss each of the above special topics in more detail.

This report provides the written record of the invited papers and the subsequent results and conclusions of each of the working groups, as well as some independent contributions. The views expressed are not necessarily the views of the sponsors, the editor, or the individual working group chairmen. These proceedings are intended primarily to document the presentations and discussions that took place at this workshop, for the benefit of the engineering community at large.

ACKNOWLEDGMENTS

Many people contributed to the successful outcome of the workshop. Most particularly these included the international steering committee, which advised in setting up the program and identifying the working group topics:

Steering Committee

R. Ayers,	Shell Development
L. Broussard,	Tenneco Pipeline
S. Davis,	Exxon Production Research
C. Deleon,	Office of Pipeline Safety
A. Desai,	Brown & Root
W. Dunlap,	Texas A&M University
D. Halsey,	Minerals Management Service
D. McKeehan,	Intec Engineering
D. Morris,	Texas A&M University (chairman)
C. Nelson,	McDermott International
G. Powell,	University of California at Berkeley
J. Price,	Calolympic Engineering
G. Raborn,	R.J. Brown and Associates
C. Smith,	Minerals Management Service
W. Sparger,	Transcontinental Gas Pipeline Corp.

A large measure of credit for giving the meeting an initial picture of the main issues, belongs also to the keynote speakers, who devoted their time to an excellent series of presentations to the meeting:

Keynote Speakers

Roger Pearcy	Minerals Management Service
Cesar Deleon	Dept. of Transportation
Alan Adams	UK Pipeline Branch, London
Jack Clarke	CCORE, St. John's
Bob Brown	R.J. Brown & Associates
Harvey Mohr	H.O. Mohr Research & Engr.
Andrew Palmer	Andrew Palmer & Associates
Stelios Kyriakides	University of Texas at Austin

Thanks are also due to the chairmen of the working groups, for overseeing the individual workshop sessions, for bringing introductory material and encouraging participation, and most importantly for documenting the findings of each working group. These proceedings are in large measure the result of their efforts. They are:

Working Group Chairmen

Dave McKeehan, Intec, Houston
Stelios Kyriakides, University of Texas at Austin
Sergios Barbas, Exxon Production & Research
Tom Zimmermann, Center for Frontier Engineering, Edmonton
John Adams, Pulsearch, Calgary, Canada
Paul Moss, British Gas, Houston and UK
Paul Sucato, Oceaneering, Houston
David Weinhoffer, Sachse Engineering, Houston
Jim Houston, Transco, Baton Rouge
Mark Williams, Chevron Pipeline, New Orleans
John Bomba, R.J. Brown, Houston
David Phillips, J.P. Kenny, UK
Gary Vogt, Guillot-Vogt, New Orleans
Albert Barden, Nowsco, UK
Ray Ayers, Shell Development, Houston
Jesse Wilkins, McDermott International, New Orleans

Many local people also contributed to the smooth running of the arrangements, including Alex Alvarado and the staff of the New Orleans office of the Minerals Management Service, and Beth Amadon and the staff of the New Orleans Doubletree.

Last but not least, none of this would have happened without the participants, who made it all possible.

SUMMARY

On December 4, 5, and 6, 1992, an International Workshop on Offshore Pipeline Safety was held at the Doubletree Hotel and Conference Center in downtown New Orleans. It was attended by experts from the petroleum and offshore industry, consulting firms, government agencies, and academic and research institutions.

The purpose of the meeting was to discuss current practice, progress, and future directions in the field of safe management and design of offshore oil and gas pipelines. Recent experience and case studies were included.

Invited papers were presented by representatives of government agencies in the US and the UK, from a government laboratory in Canada, from consulting engineers active around the world, and from universities.

Eight working groups were then formed on topics previously identified as of special importance. These groups met for over a day in the parallel sessions led by co-chairmen who were charged with leading discussion and recording the results. Participants were free to attend more than one session if desired. The final reports of each working group were subsequently prepared by the chairmen, and these form the central body of these proceedings.

Key issues identified on the following topics, include:

DESIGN AND INSTALLATION ISSUES FOR INTEGRITY:

- The desirable depth and diameter of trenching practices needs to be investigated. A better understanding is required of the influence of currents on pipeline stability

- Study the value of protection devices, notably batter and embedment, against risk of fishing

- Shore approach practices need to be examined

- Studies of span correction practices are needed, as well as static span rectification procedures, and annual maintenance programs

- Collapse under installation loads is a major problem. Effect of reeling, local defects, and manufacturing processes all play an important role.

- Riser design procedures for large diameter pipe are not established. Should try to minimize needs for wall thicknesses greater than 1 inch.

- Bottom current information is sorely lacking - an industry wide data base should be established

EVALUATION OF INTEGRITY, RELIABILITY ASSESSMENT:

- Task force work is required to develop a limit state design document

- The pipeline industry can use reliability based design methods - limit state codes are in existence in Canada and Europe. US codes are still allowable stress based, although industry is using more advanced methods

- Experience has been good - few design related failures

- Task force activities (e.g. committees B31.4 and 31.8) should coordinate activities with existing efforts in Europe and Canada

- Recommended Practice documents can be developed first by using reliability methods for specific problems

- Existing codes need to be examined to determine current reliability and safety levels provided

- Reliable methods are required to assess the integrity of older pipelines.

INTERNAL MONITORING

- A growing array of internal monitoring tools is now available to industry, which in many cases could benefit from being fully aware of current capabilities

- The cost of one-off inspections is still sufficiently high to deter many potential users, especially small companies. If the unit cost could be dropped enough, then regular inspection might become accepted as a cost effective routine activity.

- Special problems still include the detection of corrosion, especially localized, and under sour service conditions. Stress sulphide cracking in welds and parent metal needs to be investigated

- The effect on welding of residual magnetism has become an issue - maximum allowable values need to be established.

- In addition to more sophisticated internal tools, the use of air or nitrogen for pressure testing could be expanded

EXTERNAL SURVEILLANCE

- Issues can be divided into the following categories: coastal zone/shallow water/deep water; steel pipe;flexible pipe; pipe survey/leak detection.

- Vehicles available for carrying instrumentation can be categorized as: divers/ROV's/tracked crawlers/surface vessels/aircraft/towed arrays/towed sleds.

- Instrumentation utilized are primarily: magnetometers/gradiometers / acoustics (sonar, sub-bottom profilers)/conventional optics (video cameras, direct visual)/unconventional optics (laser line scan)/CP probes

- Key decision making criteria in the design and selection of the above are: water depth/depth of pipe burial/burial medium/geographic location/ economics/type of pipeline/pipeline coating/existing route documentation/ nature of problem and client deliverables.

- A major emphasis should be placed on good pre-site surveys.

- Key industry requirements are to define the position of the sea-bottom precisely.

- Inspection continuity needs further clarification with regard to regulatory bodies.

- More precise correlations need to be established between internal pipeline damage and the need and nature of external repair intervention

- Autonomous vehicles (AUV's) are a promising new technology, but industry needs to direct the educational and research institutions that are currently the leading factors in AUV development

- Unconventional optics should be supported more, with increased R&D into development of laser line scan systems.

ROUTINE OPERATIONS AND MAINTENANCE ISSUES

- Special technologies are now available to assist with routine operations and maintenance - these include the Chirp Sonar, the Innovatum, and the Diver Probe

- Reliable methodology is required for the verification of depth of cover

- The overlap of responsibilities between the MMS, DOT, and Coast Guard should be clarified, and ideally simplified

- The geographic definition of the Gulf of Mexico and inlets needs to be clarified.

- A mutually satisfactory definition of a "soupy bottom" needs to be established.

- An integrated approach to corrosion control of pipelines would be desirable, taking into account both service under atmospheric and immersion conditions.

- Both line balance and pressure point analysis methods can be further developed for leak detection purposes.

- Abandonment of pipelines, and dealing with previously abandoned pipelines, has become a major industry problem.

- Movement of pipelines under pressure should be further studied.

- Reburial of pipelines should be further studied.

- Pipeline data base access should be actively maintained and expanded.

- Adequate training of pipeline operators is an industry-wide problem.

ABNORMAL, EMERGENCY AND STORM RESPONSE

- Case histories have emphasized the importance of proper location of ESD valves, and in the routing of lines from risers.

- Data transmission to personnel needs to be improved, to alert operators to drops in line pressure leak detection sensing systems.

- The Clean Gulf Association will have an effect on emergency response, but the requirements are not clear at present, nor is it known if the Association will include pipeline operators.

- Optimum operation procedures of offshore pipelines through storm should be studied, and possibly redefined.

- The definitions of allowable discharge need to be clarified, especially for extreme events.

- Improvements in leak detection technology would have a major effect on abnormal and emergency response. This could be a candidate for a Joint Industry Project.

- Continued operator training is vital if emergency response is to be improved.

- OPA requirements need to be defined.

- Availability of an accessible database would help planning operator response.

- Further research is needed into oil spill recovery.

- Dispersant approvals should be better co-ordinated.

- Open ocean bio-remediation is a promising new technology for emergency response, but needs major development still.

- Spill clean-up and treatment in general could be the subject of a Joint Industry Proposal.

REPAIR AND REHABILITATION PROBLEMS

- Major differences exist in repair techniques, between oil and gas pipelines, in large part because of the large volumes that must be vented to repair a gas pipeline.

- The usefulness of nitrogen purging of gas lines was pointed out, although even this does not guarantee that a line is perfectly safe, due to vaporization of local liquids. Further improvements of isolation techniques are desirable.

- Nitrogen foam techniques show promise, although development of water removal methods may have to be considered to prevent gas hydrate formation

- Pipe freezing has been used successfully on land, but is not viable offshore at present due to the difficulties involved and the possibility of hydrate formation afterwards.

- Hydrotesting of completed works should be encouraged.

- Further research and development of high differential pig train technology to provide a pressure factor of safety is desirable.

- Differences in OCS regulations exist in California with regard to provisions for smart pig installation and leak detection, and these should be harmonized with other areas.

- Rehabilitation techniques for lack of cover or proper protection need to be developed.

- Location and requirements for emergency shut down valves is now addressed by legislation, but may need further study.

- Protection from falling objects of risers and pipelines adjacent to platforms needs to be emphasized.

- Many repairs can now be performed by small dive vessels, due to utilization of fittings that do not require underwater welding.

- The use should be encouraged of fittings that can be pressure tested and/or inspected with ultrasonics prior to putting a pipeline back into service.

- Diverless repair is increasing, and new installations should be designed to allow diverless intervention.

- It would be desirable to develop ROV repair to include spool piece repair of pipelines.

- Repair techniques in general need to address the increasing age of most pipeline networks, and the fact that many pipelines are operating beyond their originally intended design lives.

DEEP WATER CONSIDERATIONS

- Design principles for deepwater pipelines are in many cases similar to shallower waters, but costs and installation risks are far higher.

- Long unsupported pipe spans caused by irregular bottom conditions are a special area of concern.

- Deep on-bottom connection technology still has to be proven.

- The depth record at present is 2500 ft., but long-term projects envision depths of 6000 ft. or more.

- Current ANSI/ASME based design codes do not provide design procedures for collapse, and it is usually up to the designer to select an appropriate design method.

- J-lay pipelaying techniques are more conducive to deepwater design and is considered safer, but costs need to be reduced.

- Present survey techniques cannot accurately predict the number, length, or height-off-bottom, of spans to be expected when crossing an irregular sea bed.

- Additional research is needed on the magnitude, duration and extent of hurricane induced currents, and their influence by sea floor topography.

- Development of effective low cost vibration suppression or pipe support braces is encouraged.

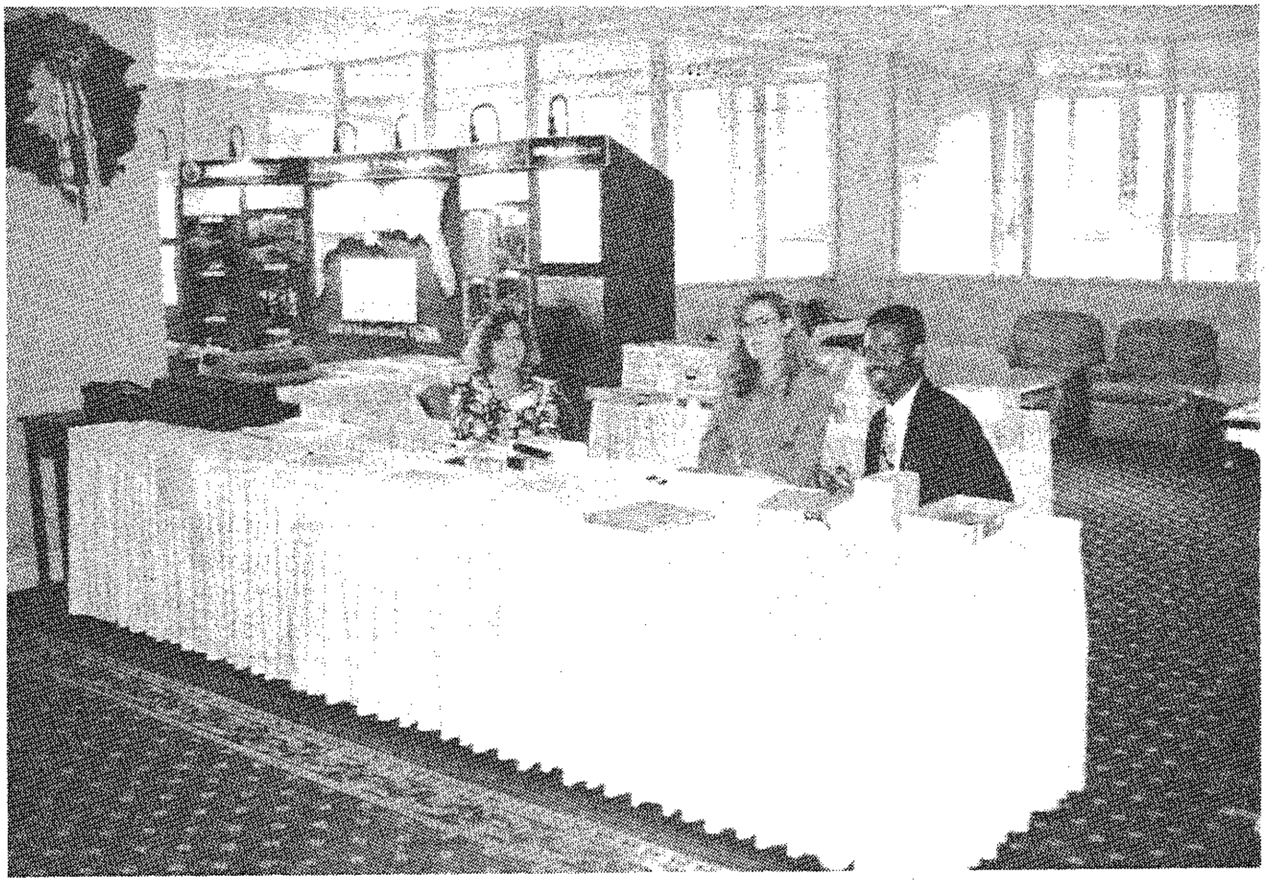
- Further developments in deepwater repair capabilities are expected. This will require major investments in tools and equipment.

- Research on vortex-induced vibrations due to loop currents is in progress, and should be supported.

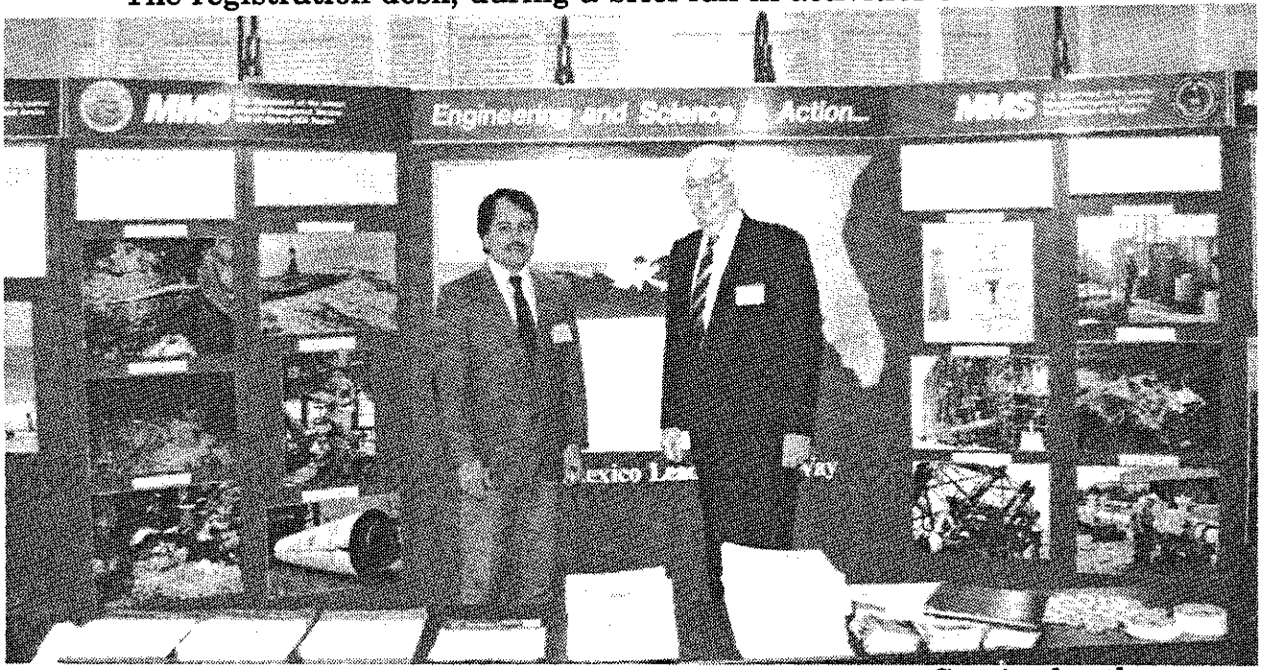
- Flexible pipe use will grow, although it is not specifically addressed in current US codes.

- Care must be used in using micro-alloyed low-carbon steel pipe, because it may be too brittle for reel pipelaying of thickwalled pipe, and research opportunities exist in this area for metallurgists.

PHOTOGRAPHS OF THE MEETING



The registration desk, during a brief lull in activities on the second floor.

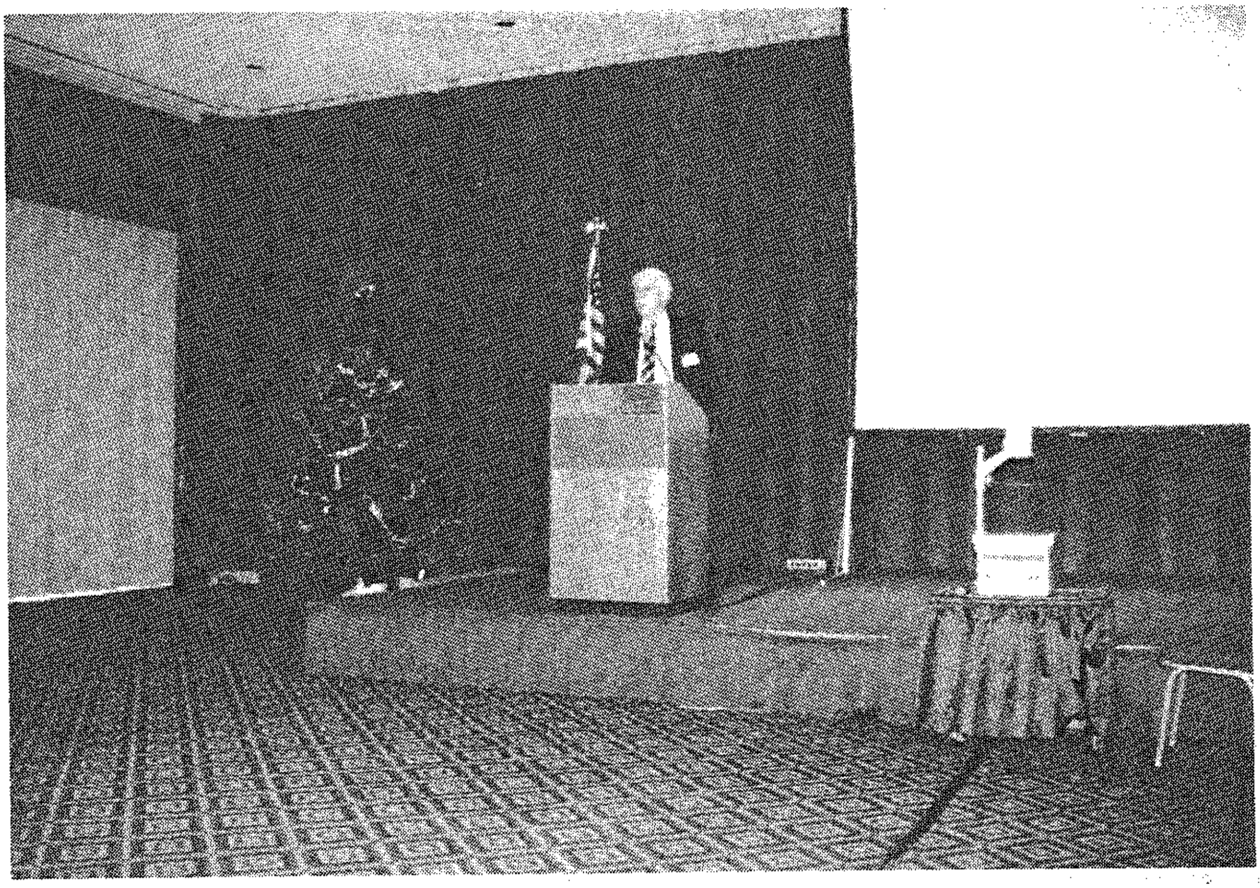


Part of the display area - the Minerals Management Service booth, manned by two stalwart representatives (Alex Alvarado and Henry Bartholomew).

Participants assembling for the main session in the International Ballroom on the sixteenth floor of the Doubletree Hotel.

The steering committee chairman, Derek Morris, introducing speakers at the front podium.

Delegates returning from a coffee break



The closing address being delivered by Henry Bartholomew

WELCOMING REMARKS - CITY OF NEW ORLEANS

Dot Bondurant, New Orleans Chamber of Commerce

Dear Visitors:

Welcome to the Crescent City!

New Orleans has always been known for its fun, its variety of entertainment, its food, music, history, charm, and warm hospitality. Frenchmen and Spaniards, pirates and generals, European royalty and Southern belles alike have all bowed to the fascination of the Queen of the Mississippi. This meeting will give you the opportunity to experience all of this, and more.

But first, by way of introduction, you need to be introduced to a few local phrases. One word you will hear a lot is "Cajun". This refers to French settlers of "Acadia" (present day Nova Scotia in Canada) who resettled in South Louisiana around 1755. Their descendants now number nearly one million. Originally called Acadians, this formal designation has largely yielded to the now familiar contraction, "Cajun".

They contributed to the most famous part of New Orleans - the "French Quarter". New Orleans' fabled Vieux Carre is a never-ending delight for visitors, natives and newcomers alike. For shopping, dining, entertainment or just the pleasures of walking and watching, there's no place like it in the world. The architecture of the French Quarter is world-famous, with lush, hidden courtyards and wrought-iron balconies. Several historic homes are now "house museums," giving a wonderful peek at the way New Orleans lived in centuries past.

On Royal Street, you'll find some of the city's finest antique shops and marvelous art galleries. In fact, the entire Quarter is a shoppers delight! Discover handcrafted jewelry and gifts, fashions from antique collections to the most avant garde, gourmet treats to enjoy on the spot or take home as gifts, even rare books and museum reproductions.

On Bourbon Street, the mood changes with the all-night excitement of jazz clubs, burlesque revues, night club shows and music, music, music! Music is everywhere in the French Quarter, from street-corner musicians to Preservation Hall, where many of the jazz pioneers still perform.

Perhaps the heart of the French Quarter is Jackson Square where people have gathered for centuries. St. Louis Cathedral, the Cabildo and Presbytere, and the Pontalba apartments surround the beautiful square graced by Andrew Jackson on his horse, and the other buildings of the Louisiana State Museum group offer fascinating glimpses into New Orleans history.

At Jackson Square, the French quarter meets the Mississippi. You'll see paddlewheelers, ferries and tugboats side by side as New Orleans once again demonstrates its fascinating combination of history legend and a vital future. The river is of course the main artery of the community, and is 2,300 feet wide at Canal Street. Depths at the bank vary from 30 to 60 feet; at mid-stream from 100 to 240 feet. Over 300 billion gallons of water pass Canal Street each day. The levees harnessing the river are the finest in the world, and the Port of New Orleans has ranked as high as the second busiest in the world with cargo value approaching $8 billion.

If other means of transportation fascinate you, try riding a street car. The St. Charles Avenue line is the oldest, continuously operating street railway in the world. In 1985, it celebrated its 150th birthday. The 35 cars in service on the 13.2 mile route date back to 1924-most replacement parts must be handcrafted. Dare not call it a trolley - it's a streetcar, please.

Each year, our city celebrates Mardi Gras, the annual festival with colorful parades and masquerade balls that makes New Orleans the most popular party spot in the nation. The name is a French phrase meaning "Fat Tuesday" - the day before Ash Wednesday, the first day of the Lenten season. Locals use the term interchangeably with "Carnival", Latin for "farewell to the flesh". The first street parades date back to 1872. Now, approximately 60 private organizations (called "Krewes") stage street parades over a two week period leading up to Fat Tuesday. The final day sees "Rex, King of Carnival" lead his entourage through a million masked and frolicking subjects.

For the guest with an inclination to shop, hundreds of stores and restaurants are within walking distance at Jackson Brewery, Millhouse and the Riverwalk development.

The blend of nationally recognized stores and local specialty shops, festival marketplaces and major retail centers, antique shops and art galleries add to the City's colorful character. And, if you are visiting from another country, please look for the "Louisiana Tax Free Shopping program. Louisiana is the only state in America offering international visitors sales tax waivers on purchases made here.

All the ingredients for an exciting experience are right here in New Orleans. Enjoy the romantic setting, the great food and the incomparable jazz that makes it famous. You'll experience all the excitement of the South's most European city in New Orleans. There's hot jazz and cool blues on Bourbon Street.

Laissez les bon temps rouler!

KEYNOTE ADDRESS I

Roger Pearcy
Gulf of Mexico OCS Regional Director
Minerals Management Service
US Department of the Interior
New Orleans, Louisiana

"PERSPECTIVES ON OFFSHORE PIPELINE OPERATIONS"

Introduction

This address will endeavor to give a brief overall perspective of US offshore pipeline operations, particularly in the Gulf of Mexico, which represents by far the most extensive area of pipeline operations in this country, if not the world.

The Outer Continental Shelf (OCS) Lands Act, as amended, gives the Minerals Management Service (MMS) the authority to regulate offshore pipeline operations to ensure that they are conducted in a manner that protects life, property, and the marine, coastal, and human environment and minimizes conflicts with other uses of the OCS. In the exercise of this authority, the MMS has issued regulations (30 CFR 250, Subpart J) that contain specific requirements to ensure that OCS pipeline operations are safe and provide for protection of the environment.

The Department of Transportation (DOT) also has responsibility for offshore pipeline operations. A Memorandum of Understanding, which is in need of updating, was signed in 1976 and defines the respective areas of responsibility to avoid duplication of regulatory effort. However, the MMS reviews and approves all OCS pipeline applications.

In the Gulf of Mexico, the MMS has a Regional office in New Orleans and four District and two Subdistrict offices located along coastal Louisiana and Texas. The Regional office is responsible for reviewing the pipeline applications, including those for installation, modification, and abandonment, whereas the District offices are responsible for conducting onsite pipeline inspections. These inspections are usually by trained and/or helicopter inspection where required. At present, MMS in the Gulf of Mexico has 52 inspectors and 13 helicopters at its disposal to conduct all inspections, including pipelines. The MMS inspects all aspects of pipeline operations including installation, safety equipment, repairs, and abandonment's.

There are at present about 20,000 miles of pipelines approved in the Gulf of Mexico OCS (for statistics from 1984-1991, see Figure 1). Over 97 percent of all OCS liquid production and 100 percent of all OCS natural gas production is transported to shore by pipeline (Figure 2 gives statistics on daily production for the OCS during the past five years).

With this background, I would like to discuss the following topics, which contain issues of primary importance to the offshore pipeline industry and government regulators.

Safety

The importance of safe operation of the offshore pipeline system cannot be over-emphasized. It is instructive to note that in the period 1964 to 1989, 49% by volume of all the offshore oil spills over 1000 barrels came

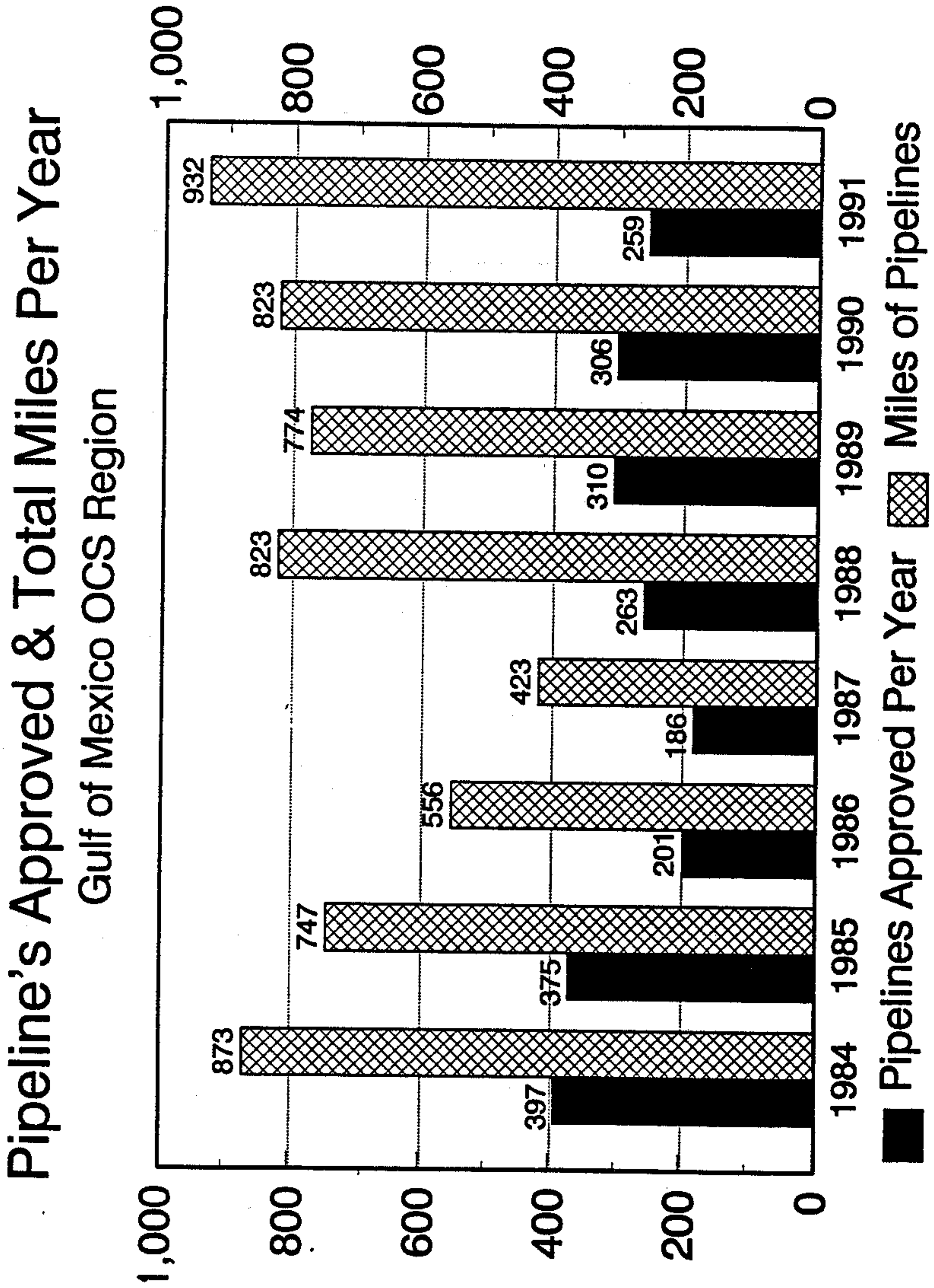


Figure 1 - Pipelines Approved and Total Miles per Year

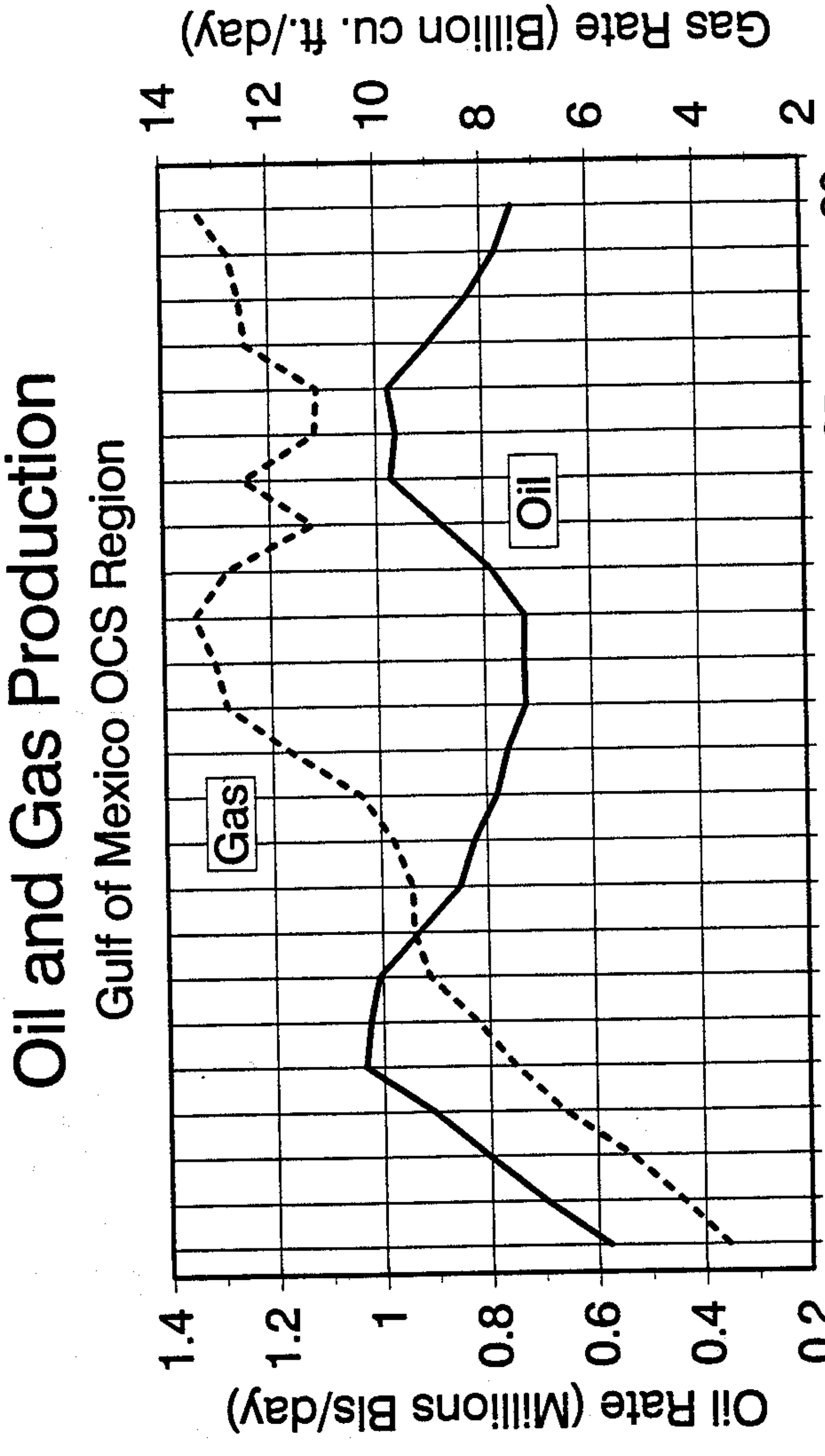


Figure 2 - Daily Oil and Gas Production

from pipelines. However in the period 1981 to 1990, this figure jumped to 97.3% by volume of all the offshore oil spills over 1000 barrels. In large part, this increase reflects the greatly increased usage of pipelines as a means of transporting hydrocarbon products.

Three incidents that concern offshore pipelines have occurred recently and have caused MMS and DOT to assess pipeline safety requirements.

One incident involving a fire, fatalities, and a severely damaged platform occurred when workers were in the process of repairing a pipeline in the Gulf of Mexico. This repair operation was necessitated by damage caused to a subsea tie-in by anchor chains.

Another incident occurred when the inventory of natural gas pipelines fed an ongoing fire resulting in numerous fatalities and the total destruction of a platform in the North Sea. This will be discussed further in a following keynote address by the head of the U.K. Pipelines Inspectorate, Alan Adams.

Finally, several crew members were killed in the Gulf of Mexico when their fishing vessel struck and ruptured a 16-inch natural gas pipeline. Within three to five seconds the vessel was engulfed in flames. Eleven of the fourteen crewmen died in the accident - two in the explosion and fire, and nine by drowning.

As a result of these accidents, MMS and DOT are considering the following:

1. The requirement that certain pipeline repair operations not be conducted until approval is obtained from the MMS. At present, the MMS only requires notification of proposed pipeline repairs. After notification, MMS determines whether or not to require the submittal of detailed repair procedures.

2. The requirement that shutdown valves be installed on pipeline risers at a location where they will provide greater protection to a platform.

3. The requirement that pipelines in water depths 15 feet or less be inspected to ensure that proper cover is being maintained.

Environmental Protection

The MMS remains concerned about the protection of the environment from the effects of oil spills from offshore pipelines. For example, the MMS is currently reviewing an application submitted by Texaco Pipeline Company for an oil pipeline that is proposed to traverse the buffer zone between the East and West Flower Garden Banks, which are awaiting official designation as a marine sanctuary. The MMS is considering imposing measures that will minimize the potential for detrimental effects to these sensitive biological features from pipeline operations, including the rerouting of the pipeline.

The Oil Pollution Act of 1990 requires that the MMS issue regulations to establish procedures, methods, and equipment and other requirements to prevent and to contain discharges of oil from offshore facilities, including pipelines. In this regard, the MMS is preparing a Notice to Lessees and Operators that will require that all pipeline right-of-way holders in the Gulf of Mexico prepare and submit oil-spill contingency plans, provide for training of the oil-spill response team, and conduct drills that simulate an actual oil spill.

Deep-Water Operations

Offshore operations in the Gulf of Mexico are occurring in deeper and deeper water depths (Figure 3 shows deep-water discoveries). New and unconventional technologies are required for the pipelines, which will carry production from deep-water facilities. I hope that this workshop will investigate some of these technologies. Are the J-lay and bottom-tow pipeline installation methods adequate for the conditions that will be encountered in deep waters? Further, are techniques available for the repair of deep-water pipelines?

Aging Pipelines

For oil spills greater that 1,000 barrels resulting from OCS operations, statistics from 1964 to 1989 show that pipelines were responsible for 49 percent of the total oil spilled. Additionally, from 1981 to 1990, statistics show that 97.3 percent of oil spilled as a result of OCS operations came from pipelines. These facts, coupled with the aging of offshore pipelines (see Figure 4), indicate the need for better leak detection.

This workshop can help to identify areas where additional leak detection research is needed. I encourage joint government and industry efforts to investigate promising technologies such as volumetric comparison and acoustic and chemical leak detection. The MMS is sponsoring research to identify and evaluate new methods for rapid leak detection in offshore pipelines.

Burial and Protection

At present, MMS regulations require at least three feet of cover for pipelines installed in water depths less than 200 feet and for all valves regardless of water depth. However, several recent incidents have occurred because soil erosion or deteriorating covers have exposed pipelines and valves to damage from external forces. Some of these incidents have resulted in oil spills of several thousand barrels. Studies need to be

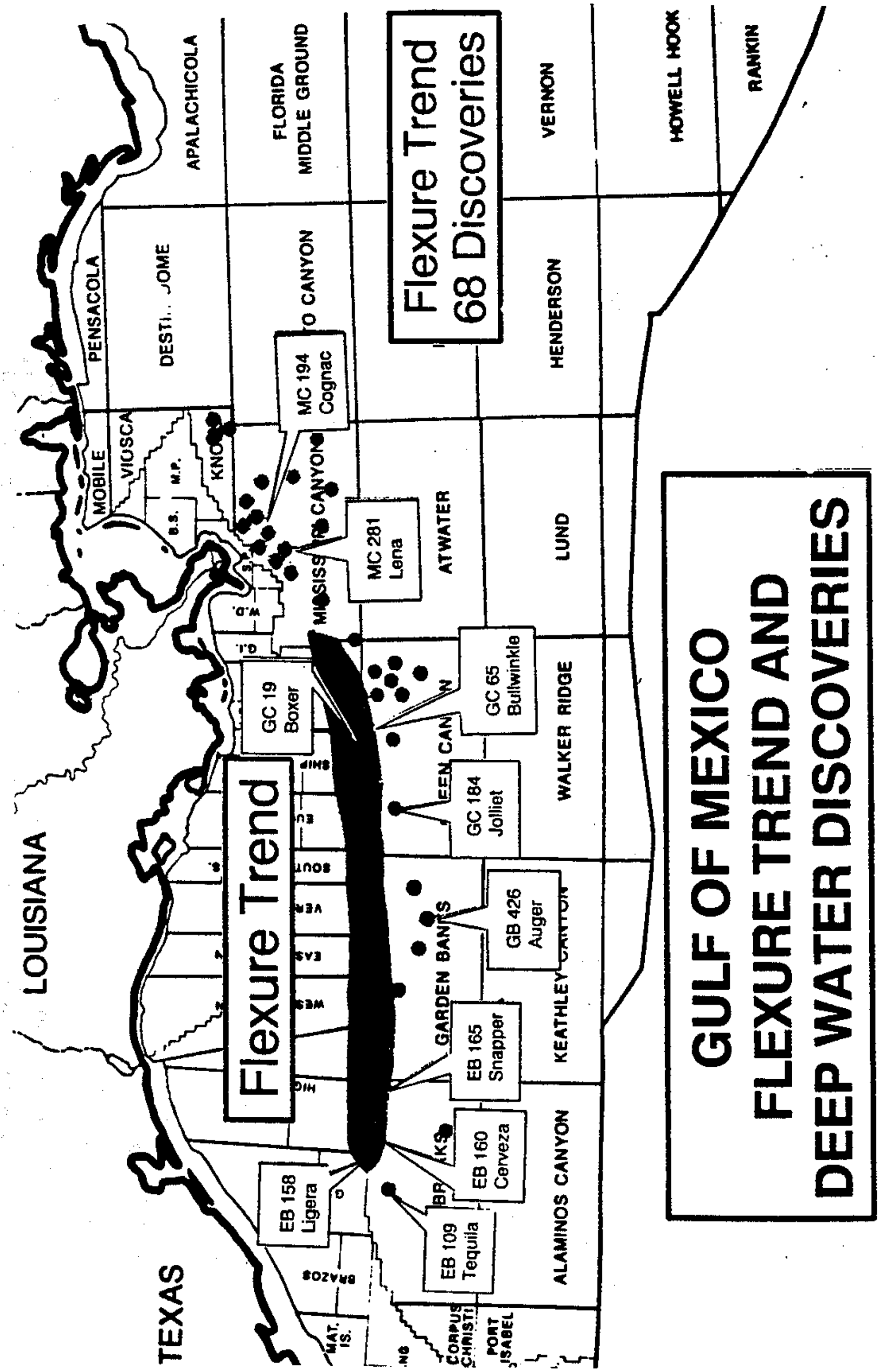


Figure 3 - Deep Water Discoveries in Gulf of Mexico

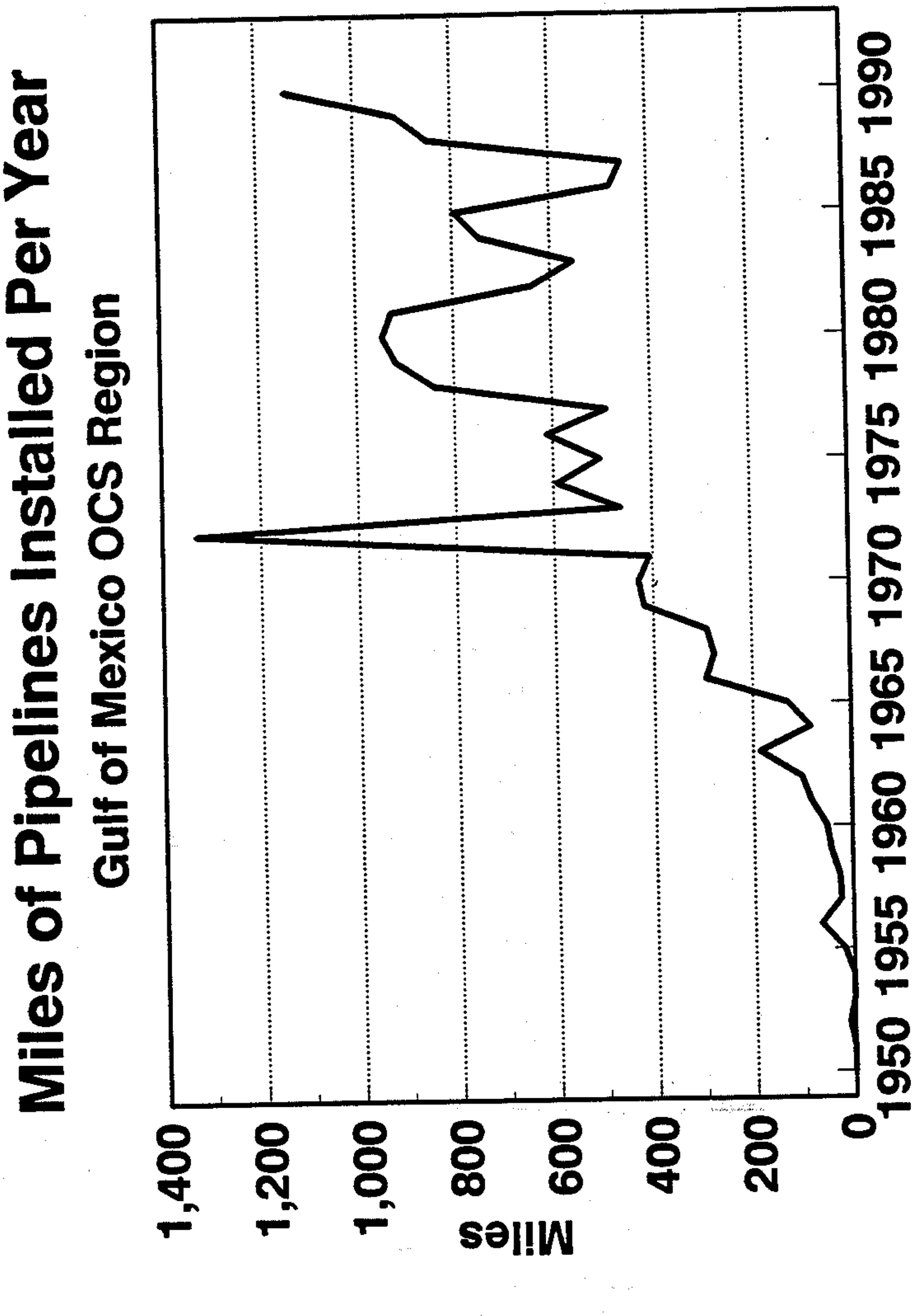


Figure 4 - Pipeline Mileage by Date of Installation

conducted on the effect of different types of domes, and of ways of ensuring proper cover for valve SSTI assemblies. Several incidents have occurred involving uncovered valves or lack of cover due to deteriorating sand bagging.

One previously mentioned incident occurred during operations to repair a subsea tie-in damaged by an anchor chain. I hope that this workshop will address methods to ensure proper burial and cover and inspection procedures to ensure that existing pipelines and valves do not become exposed where they can be damaged or pose a threat to other uses of the OCS.

Conclusion

I am looking forward to the discussions of the eight different working groups and the conclusions and results from each group. Through this joint effort from government, industry, academia, and research institutions, pipeline safety and environmental protection can be assessed and improved for both existing and new pipelines.

KEYNOTE ADDRESS II

Cesar Deleon
Director, Office of Pipeline Safety
Research and Special Programs
Administration
US Dept. of Transportation
Washington, D.C

"OFFSHORE PIPELINE MANAGEMENT"

Introduction

In the United States safety regulations for offshore pipelines are shared by the Office of Pipeline Safety in the Research and Special Programs Administration (RSPA) and the Minerals Management Service (MMS). The MMS regulates the flow lines and production lines, including issuance of rights-of-way, on the outer continental shelf (OCS), while RSPA regulates gathering and transmission pipelines on the OCS and on state waters. The U.S. Army Corps of Engineers also issues rights-of-way.

Recent Developments

Two significant offshore accidents resulted in considerable public and Congressional concern. The first accident occurred on July 24, 1987, when the fishing vessel SEA CHIEF struck and ruptured an 8-inch diameter natural gas liquid pipeline. The natural gas liquids were ignited resulting in the death of two crewmen. Another accident occurred on October 3, 1989, when the fishing vessel NORTHUMBERLAND struck and ruptured a 16-inch natural gas pipeline about one-half mile offshore of Sabine Pass, Texas. Eleven crew members died as a result of the ignition of the gas.

Legislation

As a result of these accidents, Pub. L. 101-599 was enacted on November 16, 1990. Pub. L. 101-599 amended the Natural Gas Pipeline Safety Act of 1968 (NGPSA) (49 U.S.C. 1671 et seq.) and the Hazardous Liquid Pipeline Safety Act of 1979 (HLPSA)(49 U.S.C. 2001 et seq.), which are administered by the RSPA. The law requires that not later than 18 months after enactment or 1 year after issuance of regulations, whichever occurs first, the operator of each offshore gas or hazardous liquid pipeline facility in the Gulf of Mexico and its inlets shall inspect such pipeline facility and report to the Department on any portion of a pipeline facility which is "exposed" or is a "hazard to navigation." Therefore, this initial inspection must be completed by May 16, 1992 or 1 year after issuance of regulations, whichever comes first. This requirement shall apply to pipeline facilities between the high water mark and the point where the subsurface is under 15 feet of water, as measured from mean low water.

In accordance with Pub. L. 101-599, hazardous liquid gathering lines of 4 inch nominal diameter and smaller are excepted from this inspection. The Department may extend the time period for compliance with this inspection requirement for an additional period of up to 6 months for gas transmission pipeline facilities, or up to 1 year for hazardous liquid pipeline facilities. The law provides that any inspection of a pipeline facility which has occurred after October 3, 1989 (the date of the Northumberland accident) may satisfy the inspection requirements if it complies with the pertinent requirements in the final rule.

Pub. L. 101-599 requires the Department to establish standards on what constitutes an "exposed pipeline facility," and what constitutes a "hazard to navigation." The law requires that pipeline operators report to the Department, through the appropriate Coast Guard offices, potential or existing navigational hazards involving pipeline facilities.

As a result of the inspection, an operator of a pipeline facility who discovers any pipeline facility which is a hazard to navigation in water 15 feet deep or less as measured from mean low water, must mark the location with a Coast Guard approved marine buoy or marker and notify the Department.

The law provides for criminal penalties for persons who willfully and knowingly damage, deface, remove, or destroy the marine buoy or marker. Pub. L. 101-599 also requires the Secretary of Transportation to issue regulations requiring each gas and hazardous liquid pipeline facility that has been inspected and found to be exposed or that constitutes a hazard to navigation, be buried within 6 months after the condition is reported to the Department.

Furthermore, Pub. L. 101-599 requires that not later than 30 months after enactment of the law, or May 16, 1993, the Secretary shall, on the basis of experience with the initial inspection program, establish a mandatory, systematic, and, where appropriate, periodic inspection program of offshore pipeline facilities in the Gulf of Mexico and its inlets.

An NPRM was published on April 29, 1991 (56 FR 19627). RSPA received 27 comments in response to the NPRM. The comments were appropriately considered in the development of the final rule, which was published on December 5, 1991.

The final rule makes the following revisions to Parts 190, 191, and 192. Changes similar to those made to Part 192 are also made to Part 195.

<u>Final Revisions - Part 190</u>

Section 190.229 is amended by revising paragraph (d) to read as follows: S 190.229 (Criminal penalties generally)

(d) Any person who willfully and knowingly defaces, damages, removes, or destroys any pipeline sign, right-of-way marker, or marine buoy required by the NGPSA, the HLPSA, or the HMTA, or any regulation or order issued thereunder shall, upon conviction, be subject, for each offense, to a fine of not more than $5,000, imprisonment for a term not to exceed 1 year, or both.

Part 191

Section 191.27 is added to read as follows:

S 191.27 Filing offshore pipeline condition reports.

(a) Each operator shall, within 60 days after completion of the inspection of all its underwater pipelines subject to S 192.612 (a), report the following information:
(1) Name and principal address of operator.
(2) Date of report.
(3) Name, job title, and business telephone number of person submitting the report.
(4) Total number of miles of pipeline inspected.
(5) Length and date of installation of each exposed pipeline segment, and location, including, if available, the location according to the Minerals Management Service or state offshore area and block number tract.
(6) Length and date of installation of each pipeline segment, if different from a pipeline segment identified under paragraph (a)(5) of this section, that is a hazard to navigation, and the location, including, if available, the location according to the Minerals Management Service or state offshore area and block number tract.

(b) The report shall be mailed to the Information Officer, Research and Special Programs Administration, Department of Transportation, 400 Seventh Street, S.W., Washington, D.C. 20590.

Part 192

Section 192.1 is amended by adding paragraph (b)(3) to read as follows:

S 192.1 Scope of Part. (b)(3) Onshore gathering of gas within inlets of the Gulf of Mexico except as provided in S 192.612.

In section 192.3, definitions of "Exposed Pipeline", "Gulf of Mexico and its Inlets", and "Hazard to Navigation" are added in appropriate alphabetical order as follows:.

S 192.3 Definitions

"Exposed Pipeline" means a pipeline where the top of the pipe is protruding above the seabed in water less than 15 feet deep, as measured from the mean low water.

"Gulf of Mexico and its Inlets" means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet, as measured from the mean low water.

"Hazard to Navigation" means, for the purpose of this part, a pipeline where the top of the pipe is less than 12 inches below the seabed in water less than 15 feet deep, as measured from the mean low water.

Section 192.612 is added to Subpart L to read as follows:

S 192.612 Underwater Inspection and Re-Burial of Pipelines in the Gulf of Mexico and its Inlets.

(a) Each operator shall, in accordance with this section, conduct an underwater inspection of its pipelines in the Gulf of Mexico and its inlets. The inspection must be conducted after October 3, 1989 and before November 16, 1992.

(b) If, as a result of an inspection under paragraph (a) of this section, or upon notification by any person, an operator discovers that a pipeline it operates is exposed on the seabed or constitutes a hazard to navigation, the operator shall:

(1) Promptly, but not later than 24 hours after discovery, notify the National Response Center, telephone: 1-800-424-8802 of the location, and, if available, the geographic coordinates of that pipeline;

(2) Promptly, but not later than 7 days after discovery, mark the location of the pipeline in accordance with 33 CFR Part 64 at the ends of the pipeline segment and at intervals of not over 500 yards long, except that a pipeline segment less than 200 yards long need only be marked at the center; and

(3) Within 6 months after discovery, or not later than November 1 of the following year if the 6 month period is later than November 1 of the year the discovery is made, place the pipeline so that the top of the pipe is 36 inches below the seabed for normal excavation or 18 inches for rock excavation.

Other Legislation

Recent legislation introduced by Louisiana Congressman Billy Tauzin (H. R. 1489) and companion legislation introduced by Louisiana Senator John Breaux (S. 1593) would recognize the authority of DOT to regulate abandonment of natural gas and hazardous liquid pipelines and underwater pipeline facilities. The proposed legislation requires the pipeline industry to conduct a record search to determine which and in what locations underwater pipelines have been abandoned, as well as to report all future abandonments. It directs DOT, in cooperation with the industry, to conduct a study of underwater pipelines and to report back to Congress its findings and recommendations.

Regulatory Projects

The following regulatory projects that would affect offshore pipelines are currently being developed by RSPA:

Qualification of Pipeline Personnel

Training and qualification standards would be proposed for personnel involved in the operation, maintenance, and emergency response of gas and hazardous liquid pipelines.

Maps and Records; Inventory

As part of a continuing policy to adopt similar requirements for gas and hazardous liquid pipelines where appropriate for safety, this proposed rule proposes to equalize as far as possible the requirements that gas and hazardous liquid pipeline operators keep maps and records to show the location and other characteristics of pipelines. Operators would also be required to keep an inventory of pipe and annually report specific parts of these inventories to RSPA.

Gathering Line Definition

This rulemaking action proposes a clearer definition of "gathering line" in the gas pipeline safety regulations in order to eliminate confusion in distinguishing these pipelines from transmission pipelines in rural areas. This rulemaking will also eliminate confusion in distinguishing gathering pipelines from production pipelines, including flow lines.

Reporting of Drug Testing Program

This proposed rulemaking will propose that the results of the drug testing program for pipeline personnel be reported annually to RSPA. A program for alcohol testing may also be proposed.

KEYNOTE ADDRESS III

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"U.K. EXPERIENCE IN OFFSHORE PIPELINE MANAGEMENT"

Introduction

This Address reviews the historical growth in offshore pipelines in UK waters and discusses their operational incident record. Particular attention will be paid to the Piper Alpha disaster and to the work that has been - and is being - done to reduce the chance of similar accidents in the future. Finally, the talk will reflect on the future prospects for offshore pipelines in the UK and on how government and industry can work together to face the new challenges.

The Growth In Offshore Pipelines In U.K. Waters

It is now nearly a quarter of a century since the first UK offshore pipeline came into operation in 1967. That first pipeline - linking BP's West Sole gas field in the Southern Basin to the UK mainland on the East Yorkshire Coast was a relatively modest 40 mile long, 16 inch diameter system, which nevertheless heralded a revolution in the gas supply industry in the UK. Soon after West Sole, the Leman and Hewett pipelines came into use bringing more gas into Bacton on the Norfolk coast.

The early 1970s saw further gas pipelines in the Southern Basin (including the Indefatigable and Viking systems); whilst the mid. and late 70s were dominated by the new oil systems in the Central and Northern Basins, including: - the Ekofisk pipeline to Teeside, - the Forties system to Cruden Bay in Scotland, - the Piper system to Flotta in the Orkneys, - the Brent and Ninian Systems to Sullom Voe in the Shetlands. The one new major gas system was the Frigg system which came into operation in 1977.

During the 1980s, the focus of pipeline activities switched back to gas with new systems for the Esmond, Cleeton, Thames and North Valiant fields in the Southern Basin, while the principal new pipelines in the Central and Northern basins were the Fulmar and Brent gas systems. Many of these pipelines were routed and sized with the prospect of acting as gas gathering systems for other fields in the future. In the last two years, major new gas pipelines have been constructed to serve the Miller and Beryl fields, while the old Forties oil pipeline has been replaced with a new, larger, system.

Today, there are in total over 100 major offshore pipelines in the UK sector of the North Sea, with a combined length of over 4,000 miles and with more than 80% of them larger in diameter than the old West Sole pipeline. In addition to these major systems, there are over 400 smaller pipeline systems, with a combined length in excess of 1,000 miles. Without doubt, therefore, the UK sector of the North Sea is now truly a mature pipeline province.

I would now like to discuss the operational incident record of these pipelines and to highlight some areas where improvements could and should be made to reduce the risk of leakage from pipelines.

Operational Incidents In The North Sea

In 1990, a study of incidents involving North Sea offshore pipelines, was completed by Advanced Mechanics and Engineering Limited on behalf of the UK Offshore Operators Association and with the active support of the regulatory bodies in the UK, Norway, Holland and Denmark. So far as the UK is concerned, pipeline owners have, since 1977, been required by Regulations to report their incidents and this incident data was made available by the Pipelines Inspectorate as part of the input material to the study.

The resulting comprehensive historical database of pipeline incidents in the North Sea covers some 600 pipelines, having a total length of around 7,000 miles. This represents about 65,000 mile-years of pipelines and 6,000 riser-years of operating experience.

Before reviewing the results of this study, I should explain what is meant by an "incident". This has been defined as an occurrence which directly results or threatens to result in loss of containment of a pipeline. Occurrences which did not actually damage a pipeline have been excluded from the database which means that "near misses" such as wrecks or mines discovered in the vicinity of a pipeline have not been covered. Similarly non-significant corrosion defects have not been included, but those causing leakage or requiring remedial work have been captured in the database.

For the purposes of the study, very small diameter lines (such as umbilicals) and very short lines (such as "jumpers" associated with subsea completions) have also been excluded from the database.

In total, there have been 145 incidents - 94 on steel pipelines, 12 on flexible pipelines and 39 on pipeline fittings such as flanges, connectors and valves. Of these incidents, 63 resulted in loss of containment - 24 on steel pipelines, 11 on flexibles and 28 on fittings. The message here is that flexibles in particular are prone to leakage when damaged.

Steel pipelines represent the overwhelming majority in the North Sea and therefore I am going to concentrate on these when considering the important factors of the location and cause of incidents. Figure 1 shows the basic data. So far as location is concerned, 58 of the 94 incidents have occurred on the pipeline risers and in the 500 metre safety zones around the platforms and 16 of these led to loss of containment. A further 32 have occurred in the mid-line sections and 8 of these led to leakage. There have been only 4 incidents in the shore approach areas and land sections and none led to loss of containment.

	Riser	Safety Zone	Midline	Shore Zone	Land	Total
Anchoring	-	11 (5)	7 (-)	-	-	18 (5)
Impact	9 (-)	6 (1)	12 (4)	-	1 (-)	28 (5)
Corrosion	11 (1)	4 (2)	3 (3)	-	-	18 (6)
Structural	5 (1)	1 (-)	2 (-)	-	-	8 (1)
Material	5 (1)	2 (2)	1 (1)	-	-	8 (4)
Nat. Hazard	-	1 (-)	4 (-)	3 (-)	-	8 (-)
Fire/Explosion	1 (1)	-	-	-	-	1 (1)
Construction	-	-	2 (-)	-	-	2 (-)
Other	1 (1)	1 (1)	1 (-)	-	-	3 (2)
Total	32 (5)	26 (11)	32 (8)	3 (-)	1 (-)	94 (24)

Incidents resulting in loss of containment shown in brackets

Figure 1 - Cause and Location of Steel Pipeline Incidents

Incident Causes

When we look at the causes of these incidents, it is clear that the most common ones are impact (with 28 incidents), anchoring (with 18 incidents) and corrosion (also with 18 incidents) collectively accounting for two-thirds of all causes. We also have information on incident location and cause, which I am not proposing to discuss in detail, but I do want to highlight certain elements.

On the riser and in the safety zone, the impact and anchoring incidents have almost always been "self-inflicted" by the pipeline or platform owner. The worst culprits are the supply vessels that service the platforms, but there have also been incidents from diving support vessels and various construction vessels. It is obvious that owners must work harder at managing their operations more safely - by looking at all the ways and means of controlling the potentially hazardous situation that exists each and every time a vessel is operating in the vicinity of an offshore platform.

In the mid-line area, the great majority of impact and anchoring incidents have been caused by third parties - most of them from fishing vessel trawl boards and anchors. The last fifteen years have seen big improvements in the impact resistance of concrete weight coatings and so the newer pipelines can usually cope well with trawl-board interactions. However, the older pipelines and the smaller diameter ones not requiring a concrete coating for stability, do not benefit from such good protection. Perhaps the way forward here, is to try harder with the flow of information between the offshore oil industry and the fishing industry. Is it out of the question to consider making available cheap - or even free - pipeline maps for the fishermen?

Incidents due to corrosion have most often occurred in the riser and safety zone areas (15 out of 18). For the riser, corrosion has mostly been external, which reflects the arduous operating environment through the air/water interface. There has been only one riser leakage incident due to corrosion, which I believe reflects the industry's good practices in external riser inspection and maintenance schemes. Elsewhere, internal corrosion has been the sole problem and has mostly led to leakage, which I suspect is because the corrosion processes have largely been undetected. If the Industry is to identify reliably significant corrosion defects and to deal with them before they develop into leaks, then much greater use of intelligent pigging will be necessary.

I hope some of these observations have given food for thought for Working Groups 2, 3 and 4.

Although the database identified only one incident due to fire and explosion, that incident led to the Piper Alpha disaster, which deserves special consideration in this Address.

The Piper Alpha Disaster

On 6th July 1988, the Piper Alpha platform in the UK North Sea was totally destroyed by fire and 167 lives were lost. Without doubt, this was the worst offshore accident anywhere worldwide. The UK Government acted quickly to set up a Public Inquiry, presided over by Lord Cullen and with the twin remits to establish the causes of the disaster and to make recommendations to avoid similar accidents in the future. The Inquiry commenced its work in January 1989 and deliberated for over eighteen months. Lord Cullen finally published his Report in October 1990.

So far as the causes were concerned, the report essentially confirmed the findings of the technical investigation carried out previously in 1988 by the Department of Energy. These were that a fire started in a platform module; most probably as a result of a leak from a condensate pump which had been started up, despite having a loose connection on the pump delivery. The relatively small initial release of flammable material was then quickly followed by a series of explosions and fires, culminating after some 20 minutes in the rupture of a gas pipeline riser, the engulfment of the platform by fire and, eventually, its total destruction.

Thus, what had started as a relatively minor incident, escalated rapidly into a major catastrophe. The root causes appear to have been concerned with poor liaison between the maintenance and operations teams on the platform and weaknesses in the safety management system that were in place, particularly the permit-to-work system.

While the offshore pipelines connected to the Piper Alpha platform had not caused the initial event, their combined gas inventory of some 18,000 tonnes was the main factor in the total destruction of the platform.

At an early stage during the technical investigation by the Department of Energy, it became apparent that the configuration of the pipeline risers and their associated safety valves, was less than ideal. The risers were routed through the centre of the platform, before terminating at the pig traps, whilst their emergency shut-down valves were located very close to the pigtraps. Thus, loss of containment from the risers virtually anywhere on the platform would result in an uncontrolled release of the entire contents of the pipelines, since the ESD valves would be ineffective in limiting such a release. Had the ESD valves been located further down the risers, at or below cellar deck level, then it was very probable that the scale of the incident would have been limited to a major, but not catastrophic, event.

Pipeline Riser Re-evaluation

These considerations were immediately discussed with the Industry who were quick to accept that a review of all existing pipeline risers was necessary, with the objective of installing new ESD valves, or relocating existing ones, where these valves were non-ideally located. New regulations came into force in July 1989 and the Industry were given until the end of 1990 to complete the task. Of the 400 pipeline risers affected by the regulations, over 200 required new or re-located ESD valves.

This major project represented a challenge to both Government and industry and accordingly the Pipelines Inspectorate had to gear itself up rapidly for the task ahead. A dedicated project team was set up late in 1988 to review operators' proposals for all 400 pipeline risers. Not only were we concerned with the location of ESD valves, but we were also very much concerned with the safety aspects of the decommissioning and recommissioning operations. The key activities here were the safe isolation of the working area prior to intervention into the pipeline and suitable assurance of the fitness for purpose of the new components introduced into the pipeline.

Operators were, quite naturally, reluctant to decommission and purge out entire pipelines, particularly when very large gas lines were to be modified. In principle, the Pipelines Inspectorate had no objection to the use of temporary isolation systems in order to limit the decommissioning activity to the disturbed portion of the pipeline. However, we did expect operators to ensure that such systems contained adequate redundancy and independency, that procedures were developed to monitor location and sealing capabilities, and that systems should be tested and proven before being used put to serious use.

These views were made known to the industry through our "Safety Notice" system, which had the desired effect of stimulating the urgent development of more reliable pipeline plugs and other types of isolation systems. One such system will be described later by Mr Albert Barden of NOWSCO in Working Group 7. I am very pleased to say that, with one exception, this major programme of pipeline intervention work was carried through without any incidents or dangerous occurrences.

Use of Subsea Isolation Valves

Quite apart from the issue of ESD valves on pipeline risers, we also in 1988 requested the Industry to consider the practicability of installing Subsea Isolation Valves on their pipelines. In a number of cases, especially where large inventory gas pipelines were connected to offshore platforms having accommodation modules co-located with pipeline risers, the pipeline owner decided to proceed with the retrofitting of SSIVs.

The rationale here was usually that, despite the extremely small probability of the SSIV being needed as a back-up to the ESD valve, the potential consequences of a riser failure were considered to be intolerable and therefore the cost of an SSIV was justified. To date some 50 SSIVs have been fitted in UK waters.

Other Cullen Report Recommendations

The Cullen Report made over 100 recommendations and it would not be appropriate in this Address to attempt to review all of them; but I do wish to touch on some of those having an impact on offshore pipelines: -

Above the water line, it proposed that more be done to ensure the survivability of ESD valves and risers in extreme conditions. Development work on protection systems is underway through a number of joint industry research projects, in which we are participating, and these projects are now yielding benefits in enabling critical components to be more resistant to fire and explosion.

Below the water line, the report suggested that ways should be found to reduce the cost of SSIVs, so that they could more readily be adopted as reasonably practicable. The biggest costs with SSIVs lie, not with the cost of the valve itself, but with the cost of protection and, in the case of retrofitted systems, the costs of de-commissioning and re-commissioning. It is therefore these areas that need targetting if we are to cut the total costs of SSIVs without compromising safety. May I suggest that these aspects be discussed further in this Workshop, perhaps in Working Groups 1 and 7?

It was also suggested that studies should be carried out to devise ways of reducing the number of pipeline risers on platforms. This area demands progress, not only with subsea pipeline connections - particularly piggable ones - but also with subsea processing, metering and control systems. Perhaps these are further areas for discussion at this Workshop?

Possibly the most important aspect of the Cullen Report is its thinking concerning the approach to the management of safety offshore - that safety consciousness should permeate right through the organisation from top to bottom. This thinking is equally as valid for offshore pipelines as it is for the offshore platforms.

Prospects For The Future

During the 1990s, the prospects for offshore pipelines centre on: -

- the development of smaller gas and oil fields, with their tie-back to existing pipelines or platforms. These developments mean, among other things, the likelihood of more subsea completions, subsea hot-taps and retro-fitted pipeline risers.

- the development of new fields with harsher operational pipeline conditions, such as high temperatures, or high carbon dioxide or hydrogen sulphide concentrations in the transported fluids.

- the increasing tendency for unseparated fluids to be transported as multi-phase mixtures of oil, water and gas.

All of these developments, of course, present technical challenges for the industry and also have considerable safety implications. Recent pipeline research and development work in the UK has been addressing many of these issues. Increasingly, we have seen this work being carried out in the form of joint industry projects, with shared funding from both the oil and gas companies and from Government.

One recent example has been the project to develop a hot tapping system for deepwater gas and oil pipelines. This project was jointly funded by six oil and gas companies, together with Government, and Comex Houlder Limited acted as the project contractor. The project focused on the engineering and safety issues associated with working in a hyperbaric environment at a water depth of around 150 metres and included a substantial amount of validation testing of the equipment and procedures developed during the course of the project.

A further example has been the upheaval buckling project which addressed the responses of high temperature pipelines to thermally-induced loads. This project was also multi-funded and Shell International acted as project contractor. A predictive upheaval buckling model has been developed which can be used to produce an economic engineering solution to the upheaval phenomenon.

One other notable joint industry project has concentrated on the susceptibility of pipeline steels to hydrogen-induced and sulphide stress corrosion cracking. The objectives were to assess the suitability of both new and existing pipeline steels for sour gas service and to improve laboratory testing methods for the prediction of operational behaviour. A programme of full-scale tests has been completed by British Gas, acting as project contractor. The final development of more realistic laboratory tests is currently underway as a follow-on project.

The clear message from these - and many other - pipeline R & D projects is that both Government and industry can and should work together successfully to provide safe and economic solutions to new engineering challenges.

Inspection using Intelligent Pigging

One of the major issues for the industry will centre around the extension of operating life of many of the older pipeline systems. A number of operators are beginning to consider the abandonment of their platforms, whilst retaining their pipeline systems to service other field developments. Here, internal inspection by intelligent pigging will be the key to demonstrating the continued fitness for purpose of these systems. A number of pipeline operators have quite recently started to use intelligent pigs and we in the Pipelines Inspectorate will continue to encourage them and others to do so.

Concurrently, as various organisations realise the potential market for the provision of intelligent pigging services, the number of suppliers is increasing. As the range of commercially available intelligent pigs grows, it should become possible to use them as routine inspection tools for all those pipelines where loss of containment would otherwise have significant safety or environmental consequences.

Conclusions

I hope that some of these observations will stimulate discussion at this Workshop, and look forward with great interest to hearing the results of the deliberations in the Working Groups.

KEYNOTE PRESENTATION 1

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"DESIGN FOR SAFETY IN NORTHERN WATERS"

Introduction

Within the context of this presentation northern waters are considered to be those regions which are either invaded by or covered by ice for at least part of every year. As yet there has been no major oil or gas pipeline constructed in northern waters. A trial pipeline has been built at Drake Point for the Bent Horn oilfield in the Arctic Islands and serves the purpose of demonstrating the feasibility of the design and construction techniques to service a particular oilfield (Palmer et al., 1979).

Design in Northern Waters

The major difference between the design of pipelines in northern waters and the design of pipelines in other marine environments is the presence of ice and in many locations, permafrost. Terrestrial pipelines have been built in permafrost regions in North America, the USSR and China. Many problems that have to be dealt with on land are identical to those that will be encountered offshore. The same techniques to mitigate these problems will need to be employed. The major difference in offshore permafrost is the very stable boundary condition that exists. Permafrost offshore tends to be discontinuous and mostly relic but high ice content permafrost can be encountered and would have to be taken into account in the design of pipelines.

A great deal has been written on the design and safety of pipelines in permafrost terrain for the past several decades and this body of experience continues to grow. However, there is no experience with pipelines in ice scoured terrain and that will be the main focus of this presentation.

During the coming decade it is very likely that both oil and gas pipelines will be constructed in northern waters. There are a number of likely candidate sites in North America but there are also potential sites in the arctic regions of the USSR and Scandinavia. The potential problems and design requirements associated with the presence of ice and permafrost are common to all of these regions.

Ice Scour

Evidence of ice scour of the seabed or ice gouging as it is often called has been found in many regions throughout the Arctic and has been well documented. However, it is not difficult to predict where such scour could be experienced even though no evidence has been documented as yet. Figure 1 shows areas in the northern hemisphere where ice scoured features have been documented in the literature and also those areas where one would expect scour marks to exist based on glacial history and present conditions. Ice scours that have been found are both relic and modern.

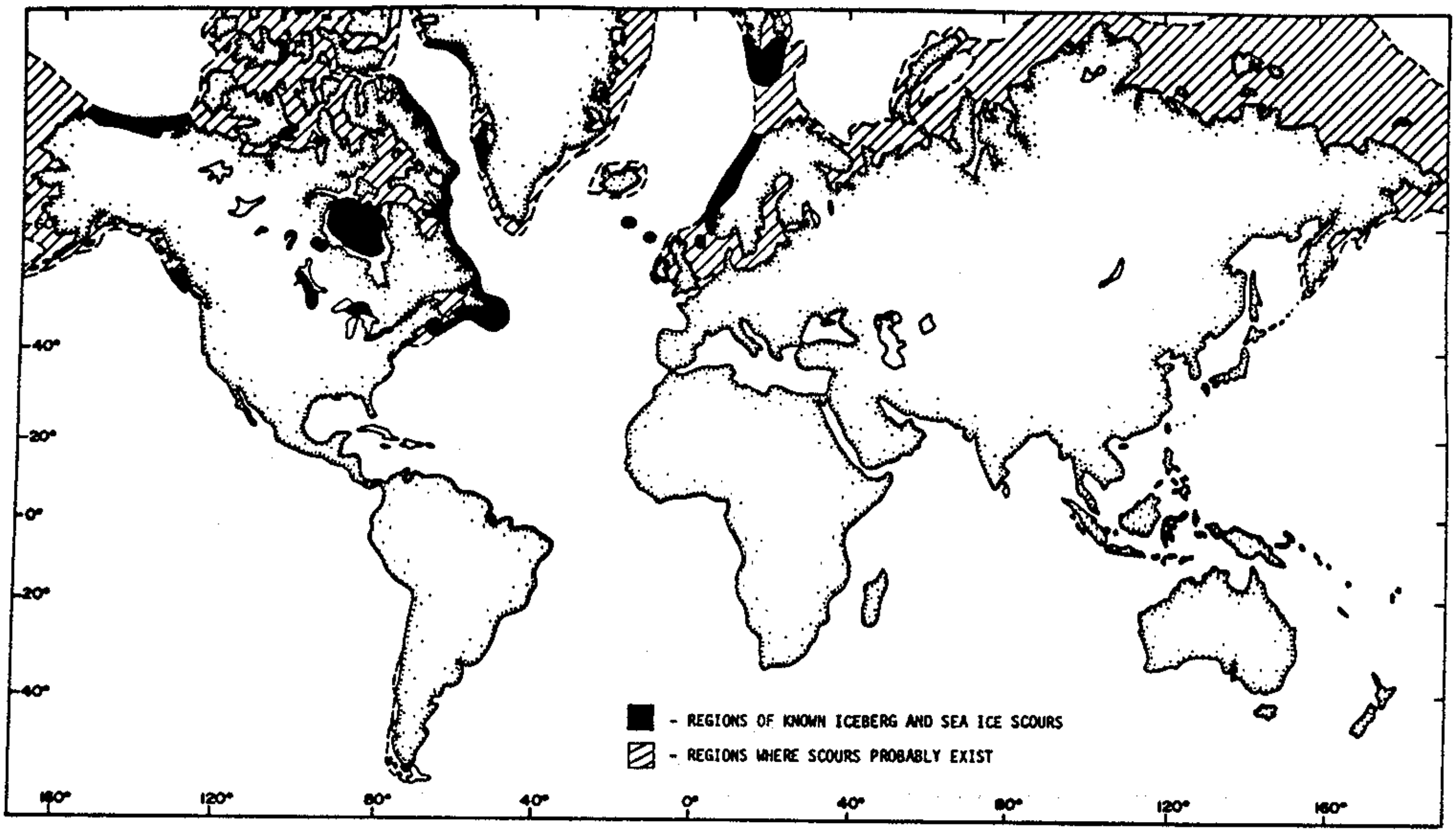

Figure 1 Areas of probable and known ice scours (Diagram courtesy of C.M.T. Woodworth-Lynas, C-CORE).

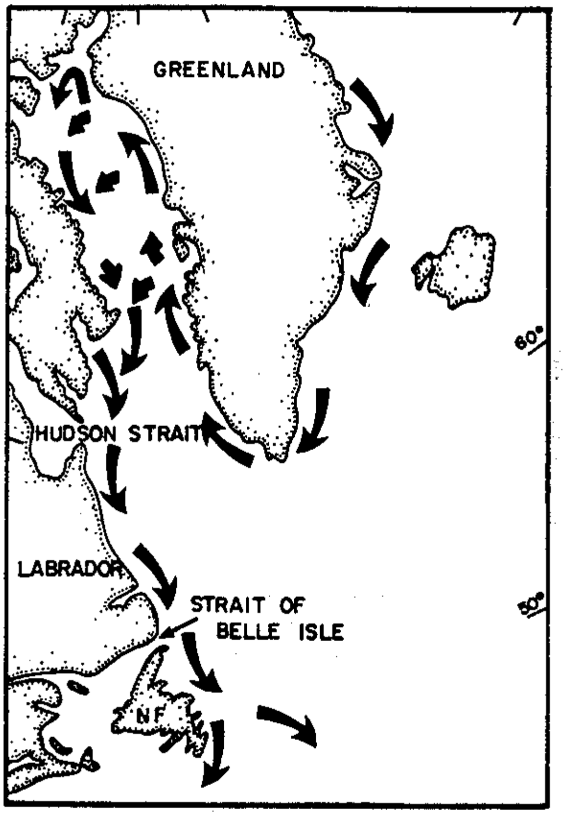

Figure 2 Drift Pattern for Canadian East Coast Icebergs.

One of the problems that faces a design engineer at this time is to determine what are the main characteristics of a modern day scour. Many of the deep scours which have been discovered are relic and could not occur under present conditions. However, as yet, a reliable method of proving the age of ice scour has not been applied to studies of ice scoured terrain.

It is very clear that a pipeline either has to be designed to resist impact by ice or it has to be located below the maximum depth penetrated by the ice. However, it may not be sufficient simply to design the pipeline to be below the depth of the scour. The sub-scour deformation of the ice scoured soil must also be known and must be taken into account when designing the pipeline.

Determining the maximum depth of scour is relatively straight forward but the sub-scour deformation is much less predictable at the present time. Several studies have been carried out in an attempt to assess the sub-scour deformation and major projects are ongoing at present with the same objective (Poorooshasb et al, 1989; Been, 1990; Poorooshasb and Clark, 1990; Paulin et al, 1991).

Ice Occurrence In Northern Waters

Ice scour in the Arctic may be caused by icebergs, by keels associated with pressure ridges, by ice islands, etc. (Hnatiuk and Wright, 1983). The most common features that present the design challenge are icebergs and the ice keels of pressure ridges. Figure 2 shows the main flow of icebergs around Greenland and off eastern Canada. The Grand Banks is the only area currently under development for oil production where the presence of icebergs is a design consideration. At present, no major pipelines are being designed for this area but the development will include a collection system local to the gravity based platform which may be affected.

The number of icebergs invading the Grand Banks region varies extensively from year to year. In 1966 zero icebergs flowed past the 48th parallel whereas in 1984 a record number of 2202 was recorded (El-Tahan, 1989). Although statistics are not yet available it is very likely that a new record was set in 1990/91. However, the statistics do not present the full picture if one considers how icebergs deteriorate and calve producing several smaller icebergs, growlers or bergy bits.

Table 1 illustrates the classification of icebergs commonly in use and their relative size. Figure 3 shows an iceberg off the coast of Labrador splitting in two. Other icebergs in the immediate vicinity at the time this photograph was taken suggested that the 9 million ton iceberg was probably part of an even larger berg which had split into several smaller icebergs by the time the photograph was taken.

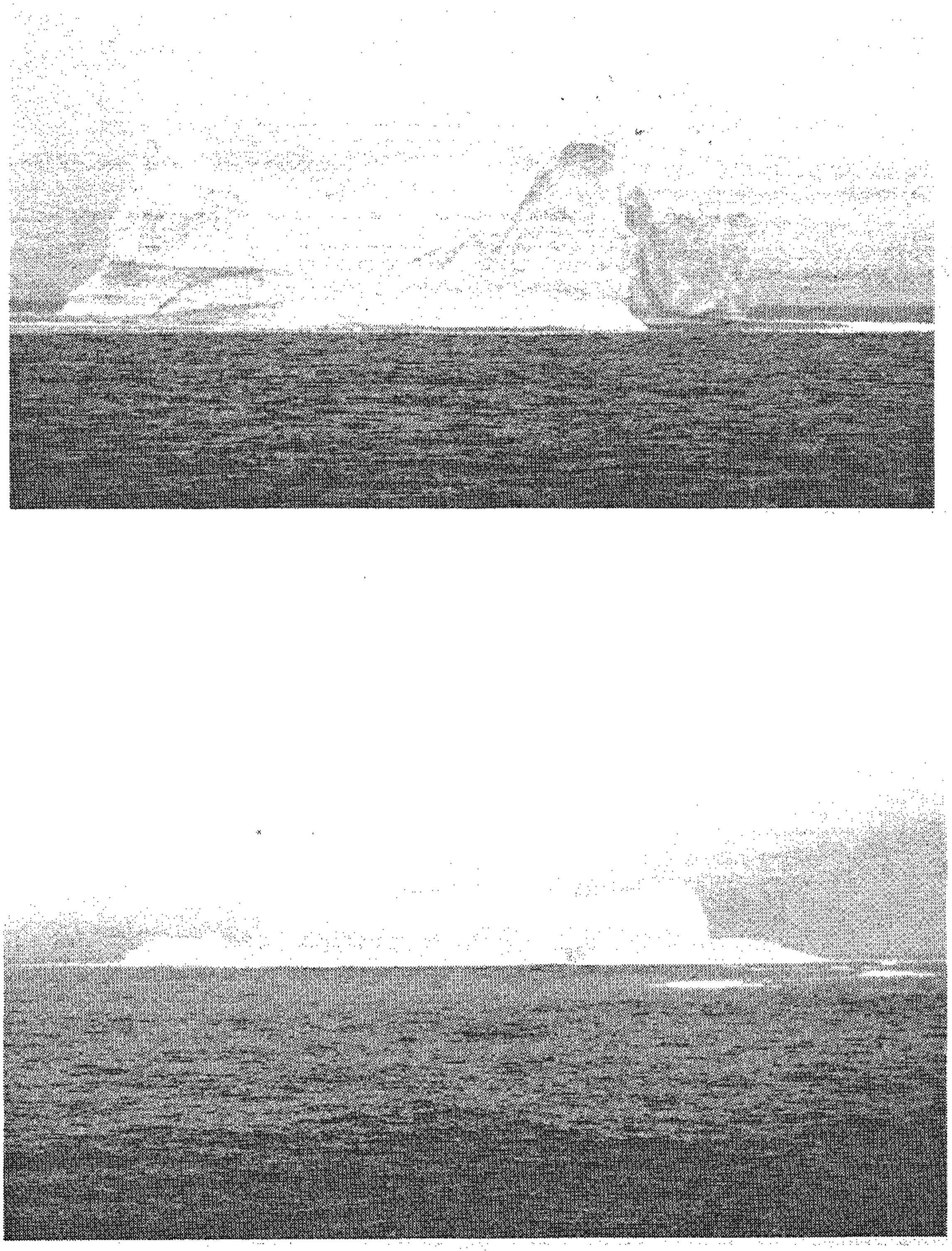

Figure 3 Iceberg Splitting Sequence off the Coast of Labrador.

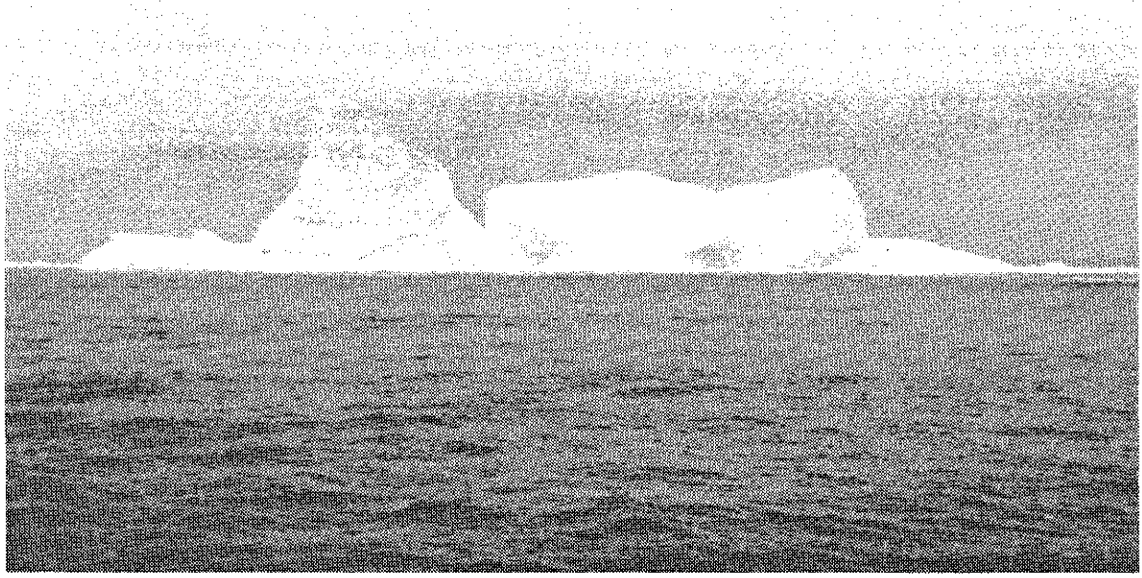

Figure 3 Iceberg Splitting Sequence off the Coast of Labrador (continued)

Table 1 Size Classification of Icebergs Used by the Grand Banks Operators (GBO) and the International Ice Patrol (IIP)

Iceberg Size	Code Used	Iceberg Height (m)	Length (m)	Approximate Weight (tons)
Growler	GG	under 1	under 5	1,000
Bergy Bit	BB	1-5	5-15	10,000
Small	SB	5-15	15-60	100,000
Medium	MB	16-50	60-120	2,000,000
Large	LB	51-75	120-220	10,000,000
Very Large	VB	over 75	over 220	over 10,000,000

NOTE: In IIP size classification, growlers and bergy bits are combined under "growlers'.

Pressure Ridges

In the Arctic, sea ice which is driven onto itself will tend to pile up creating a pressure ridge which has a keel extending below the water surface. Pressure ridges are driven primarily by ocean currents and secondarily by wind, wind generated currents, and loading from other ice. These pressure ridges are classified into either first year or multi-year pressure ridges.

These ridges, and thus their keels, can grow to a very large size and therefore, if they enter shallow areas, they might ground and scour. A large pressure ridge has been described in the literature in which the ridge was 150m in length, had a sail height of 11m and had a keel depth over 31m (Wright et al., 1978).

Figure 4 illustrates a typical series of ice keels in the Arctic. The keels are associated with pressure ridges which gradually build up and depress the below water component of the ridge.

Ice Scour - What It Looks Like

Figure 5 is a picture of a sidescan mosaic of an extensively scoured seabed off the coast of Labrador. This figure illustrates most of the types of scours that can occur. For example, it shows the long linear scours with typical U-shaped cross-sections - the so-called "chatter mark" scour caused

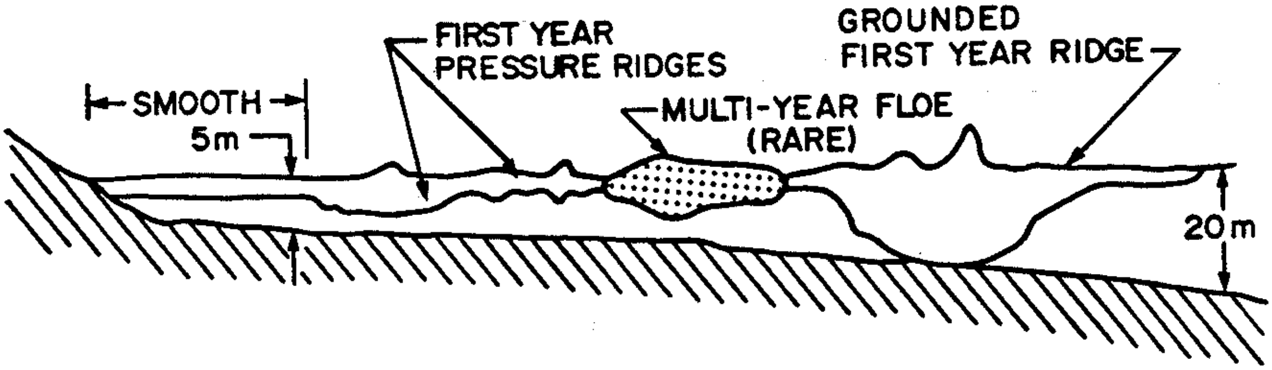

Figure 4 Typical Winter Ice Conditions, Beaufort Sea (After Croasdale, 1977).

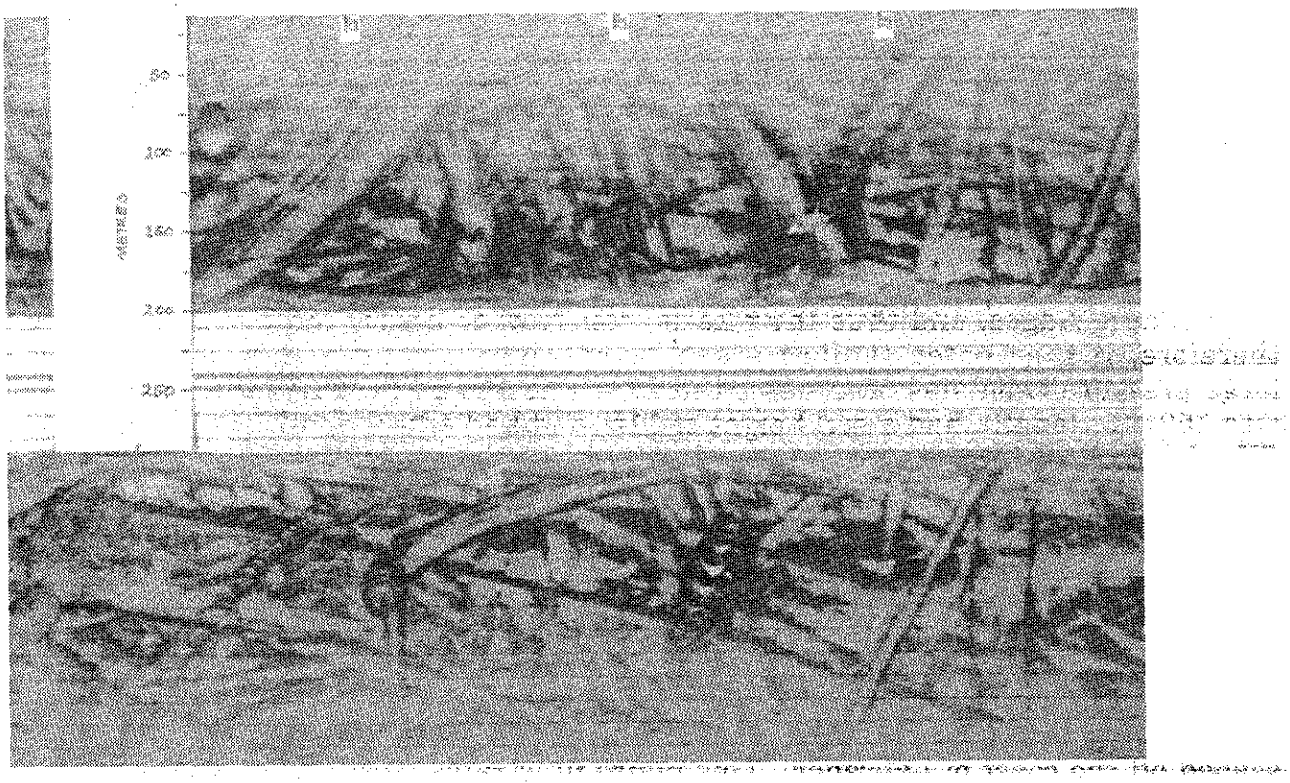

Figure 5 Sidescan Mosaic from the Coast of Labrador.

by an iceberg lightly grounded which wobbles along on the bottom, and a "crater chain" scour caused by an iceberg that is very close to being totally buoyant but bobs up and down as it moves along creating a small crater each time it touches the seabed. Localized pits are also caused when an iceberg impacts the seabed and remains stationary, and these can also be seen in the figure.

Figure 6 is a sidescan mosaic of a very large scour where the iceberg has come to rest and wallowed, creating a large berm around it, and then moved off. Icebergs can change direction very rapidly. The gouges may run for tens of kilometres or they may occur in a very localized pit. The same scour can be traced upslope and downslope while maintaining the same shape over many kilometres (Woodworth-Lynas et al, 1986a).

Figure 7 illustrates schematically the ice scour process for a pressure ridge keel and for an iceberg in the presence of an ice pack. Although it is often stated that the processes of scour by a pressure ridge keel and scour by an iceberg are very different, and indeed there are differences, there is strong evidence to suggest that much of the iceberg scouring that we see off the east coast occurs in the presence of an ice pack with the major driving force coming from the ice pack. This would account for very rapid changes in the direction of motion of very large icebergs which would not occur if they were being driven only by currents and winds.

Indeed, an examination of the relatively few scours found towards the southern end of the Grand Banks reveals that they are not nearly linear, and show evidence of short periods of scour followed by stationary periods. Many of the scours have a wandering type of track rather than the more definitive linear features that might be associated with icebergs being driven by an ice pack. There are many years in which the ice pack does not invade the southern Grand Banks, and when it does, the ice is usually greatly fragmented and very weak (Ladanyi et al., 1991).

Ice Scour Studies

Research on iceberg scours at C-CORE started in 1978. A comprehensive review of what was known at that time and a number of observations on speculative aspects of the ice scour process were presented in a C-CORE Report (Gustajtis, 1979). At the same time, research on ice scours off the east coast of Canada was being carried out by the Atlantic Geoscience Centre (AGC) as well as a number of oil companies.

The research program on ice scours at C-CORE since then has the following sequence:

1) the collection of phenomenological data

2) analysis of side scan sonar mosaics

Figure 6 Sidescan Record Showing Pit Created from a Rotating Iceberg.

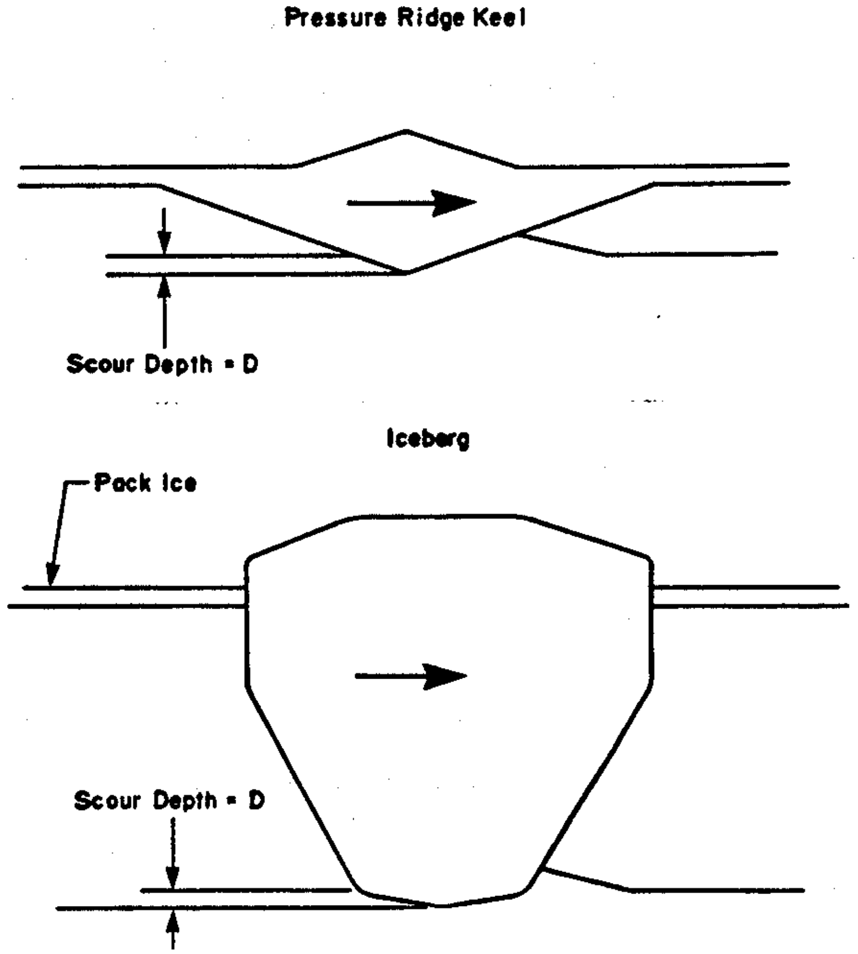

Figure 7 Ice Scour Process for a Pressure Ridge Keel and for an Iceberg in the Presence of an Ice Pack.

3) direct observations of scours from manned submersibles

4) initiation of studies of relict scours in the Canadian Arctic and Lake Agassiz, Manitoba

5) direct observation of small scale scour events with icebergs up to 50 tonnes on the flood plains of the St. Lawrence River, and

6) laboratory modelling of the scour process.

Each of these will be briefly described in the following sections:

Collection of Phenomenological Data

This work was initiated in 1978 and continues today. Several reports have been issued (for example, Lewis and Barrie, 1981; Woodworth-Lynas and Guigne, 1990). The studies have defined the morphology of the scours and have provided a significant amount of information on the rates of occurrence. Similar work has been carried out in the Beaufort Sea (Hnatiuk and Wright, 1983).

These works have provided a reasonably good basis for determining the average depth of scour, the maximum depth of scour, and the rate of occurrence. The ongoing studies include surveys for repetitive mapping to improve the data base. Nevertheless, there is a good body of data available for both the east coast of Canada and the Beaufort Sea that can be used to determine the potential risk of exceedance of scour beyond a certain depth.

In addition, on the east coast of Canada, a study of scours that occurred both upslope and downslope has been carried out (Woodworth-Lynas et al., 1986a). This has been very informative in that it has shown that scour morphology remains relatively constant over changes in relief of up to 15m. It is clear that an iceberg which maintains a relatively consistent shape and depth of scour while riding up and down slopes of up to 15m change in elevation must produce a significant variation in pressure acting on the seabed.

Analysis of Side Scan Sonar Mosaics

Side scan mosaics have been analyzed to gain better insight into the dating of the scours in addition to the studies of scour morphology. The dating work is carried out by starting with a modern scour of known time and tracing back through scours that it crosses. Analysis has also been made of preferred direction. Figure 8 shows the tracks of iceberg scours taken from a side scan mosaic from the Saglek east study area, Saglek Bank, Labrador.

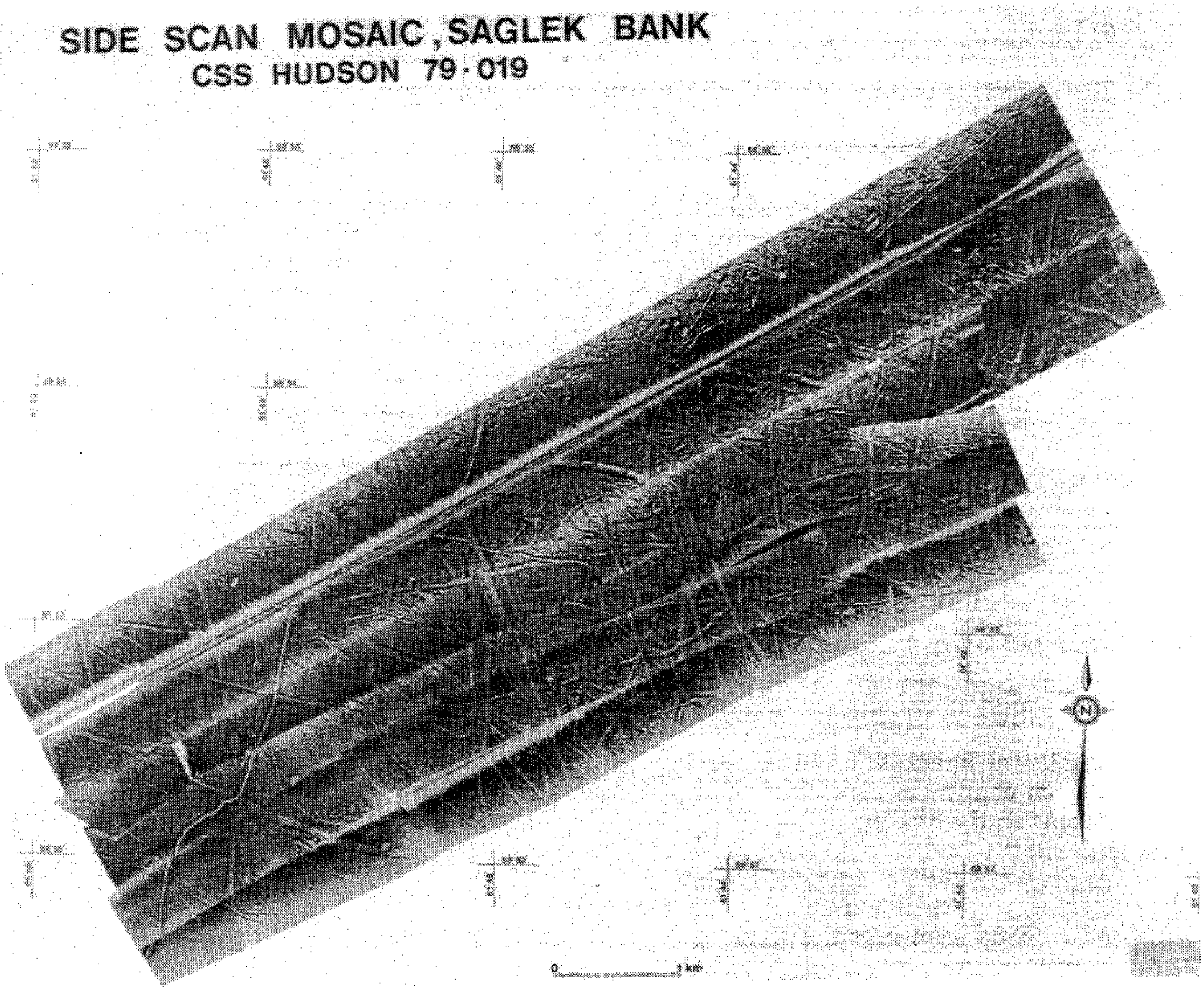

Figure 8 Sidescan Mosaic from Saglek Bank, Labrador.

These scours have been analyzed, and the resulting rosette is shown in Figure 9 (Woodworth-Lynas et al., 1986a). This rosette shows a preferred orientation in the East-West direction and a secondary preference in the North-South direction. This information can be very useful in selecting pipeline or cable routes (Clark et al., 1987).

The analysis of the occurrence of ice scours off the coast of Labrador indicates that approximately 4% of the seabed is scoured every year (Woodworth-Lynas and Barrie, 1985). It then follows that 80% of the seabed would be reworked after 40 years or 99% of the seabed after 113 years.

Direct Observations of Scours from Manned Submersibles

Dives on iceberg scours have been made in cooperation with AGC scientists in the Department of Fisheries and Oceans submersible PISCES as well from the HMCS CORMORANT using the SDL-1 submersible. These direct observations have been very useful in developing a fuller understanding of scour morphology and failure mechanisms. In addition, the dives have confirmed that there is considerable attrition of the ice as it scours the seabed.

Figure 10 shows a relatively fresh scour with large pieces of ice still embedded below the scour surface. Reconnaissance of the scours indicates a large number of melt out depressions where ice had been embedded during the scour process. It is thus very clear that the ice fails as the soil fails so as to produce the most efficient shape providing the least resistance to the advancing ice.

Although icebergs have an infinite variety of shapes and keels, the long linear scours have a relatively consistent shape. That shape is approximately a U-form. Many other types of scours can also be found on the seabed as previously illustrated.

Initiation of Studies of Relict Scours

Relict scours were first studied on King William Island. At that time cross trenches were cut through an iceberg scour and a terminal scour to examine the subscour and infill features (Woodworth-Lynas et al., 1986b). The soil at this site consisted of a very heterogeneous till-like material with very little clay binder.

The most interesting feature revealed in the excavation was the infill of relatively fine sand. At that time a model was suggested that involved the winnowing of sand that subsequently settled back in the scour after the iceberg had passed. This may well be the case but other mechanisms may also account for the sorting. The presence of permafrost did not allow excavation to the bottom of the zone affected by the scour.

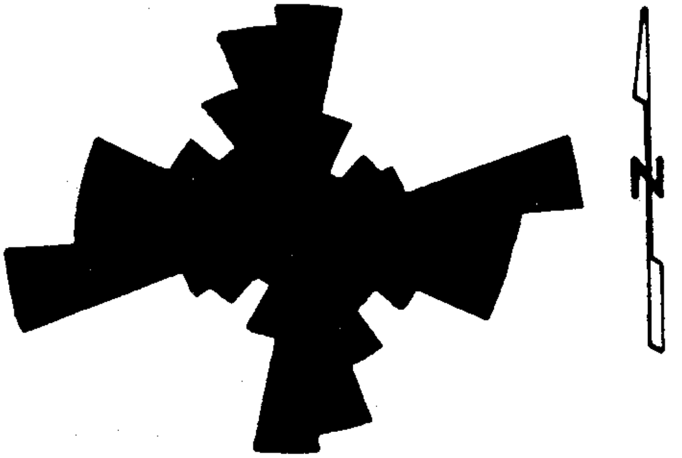

Figure 9 Scour Direction Rosette from Figure 8 (After Woodworth-Lynas et al., 1986a).

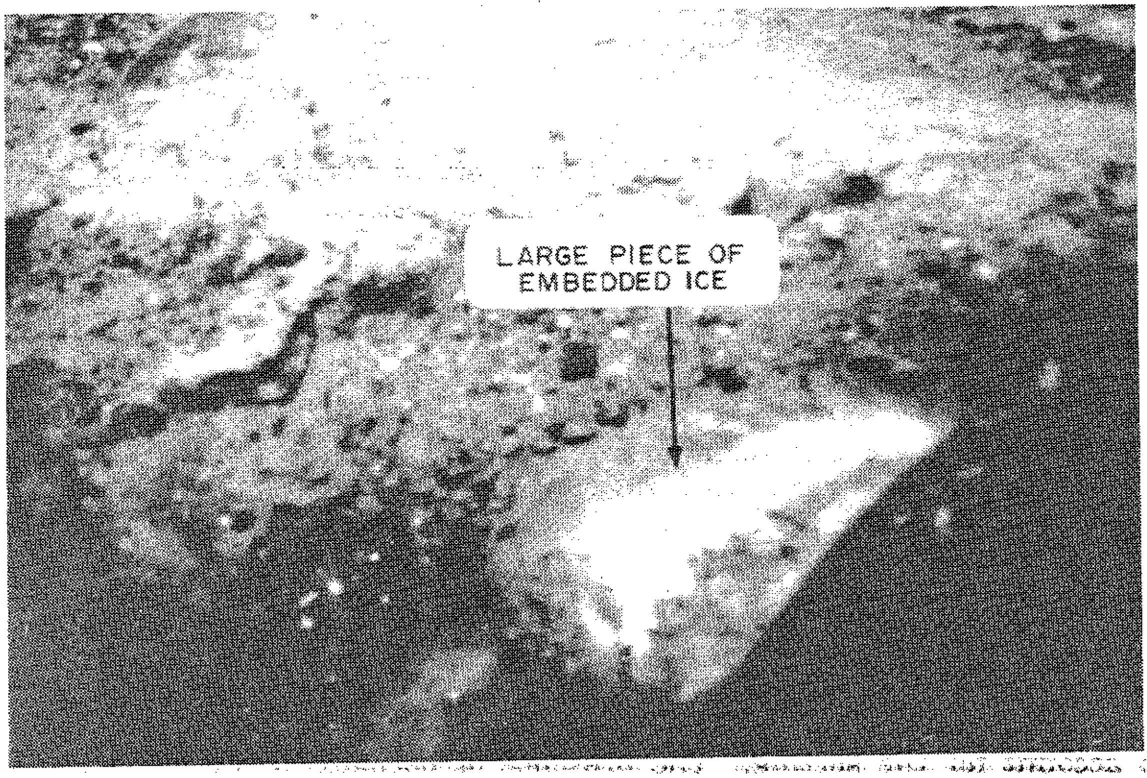

Figure 10 Relatively Fresh Scour with Large Pieces of Ice Still Embedded Below the Scour Surface

These studies were then extended in the Canadian Arctic. The most comprehensive relict scour study undertaken has been the study initiated in 1986 at the Lake Agassiz scour field near Lorette, Manitoba. Figure 11 shows an aerial photo of the scour tracks that can be seen.

These scours were created by icebergs from the continental ice sheet which bordered glacial Lake Agassiz about 9000BP. The water depth at that time has been inferred to be about 100m. The sub-soil at the site consists of a highly plastic clay which at the time of the scouring events had previously been subaerially exposed for over 300 years (Woodworth-Lynas and Guigne, 1990).

As a result, the clay was over consolidated and was able to develop well-defined shear planes. With this particular clay, a highly polished fabric is developed after a minor amount of shear dislocation along a shear plane. The fieldwork has revealed very definite and well-defined shear planes that suggest a Prandtl-type failure wedge (Terzaghi, 1943) directly underneath some of the iceberg scours. These features strongly suggest a bearing capacity failure in the soil mass below some of the scours.

Direct Observation of Small Scale Scour Events

These observations were made on icebergs up to 50 tonnes in size on the flood plains of the St. Lawrence River. Two field programs have been carried out in the St. Lawrence Estuary to observe small scale iceberg scours. An example of scour tracks is shown in Figure 12. Excavations have been made through some of the scour tracks, and subscour soil failure features similar to those revealed in the relict scours have been indicated.

The soil on the flood plain is much weaker than that of the relict scours but the depth of disturbance has been determined by making small scale vane shear tests. The disturbed soil is much weaker than the undisturbed soil surrounding it. These observations tend to confirm the sub-scour failure mechanism observed for the relict scours in glacial Lake Agassiz.

Laboratory Modelling

Laboratory modelling has been carried out at Memorial University in a specially designed scour tank. The overall tank consists of two compartments, both of which can be flooded with water and one of which can also include wave action.

Previous modelling work relevant to ice scour has been carried out by several researchers and the results have been reported in the literature (Harrison 1972; Chari, 1979, 1980). In addition, proprietary work has been sponsored by various oil companies (Fenco Ltd. 1975; Golder Associates Ltd. 1989). Other proprietary studies have been carried out by industry and the results have been made available to C-CORE.

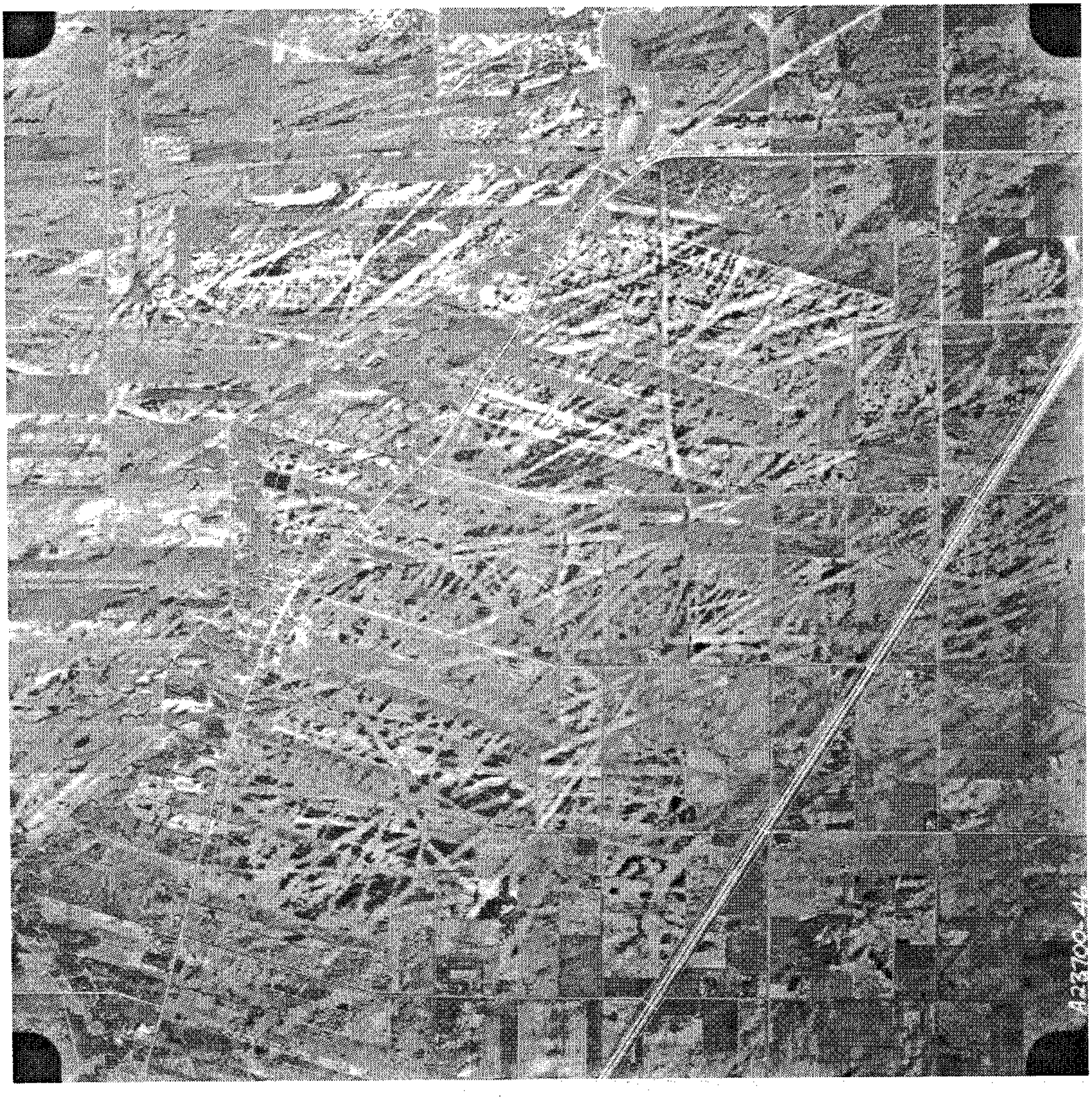

Figure 11 An Aerial Photograph of the Lorette Region in Manitoba. The Road in the Photograph is the Trans-Canada Highway. North is to the right.

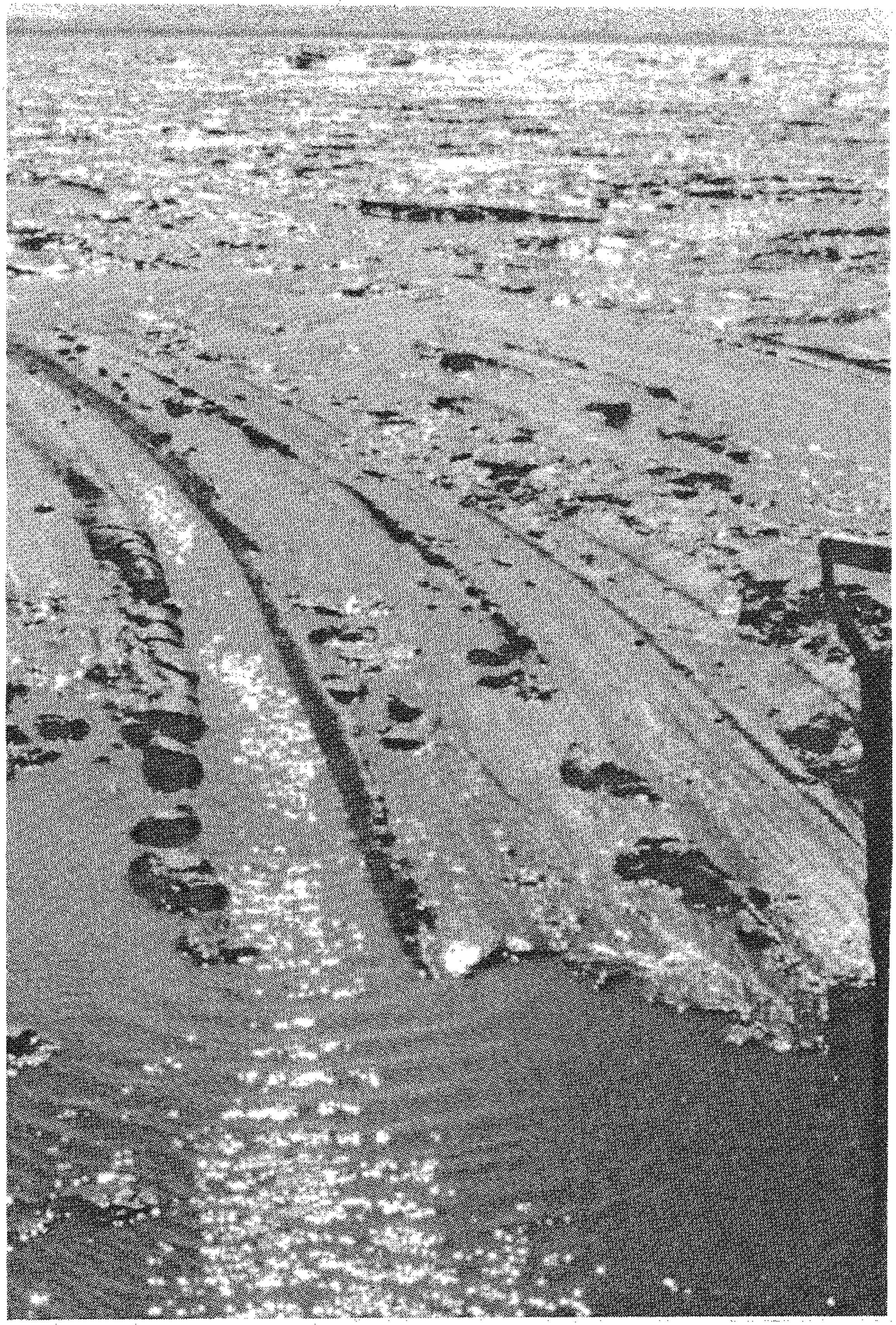

Figure 12 A Typical Scour in the St. Lawrence (After Poorooshasb and Clark, 1990)

Previous laboratory modelling led to the concept of the iceberg as a rigid indentor and of a ploughing action with very little vertical force acting on the seabed. The phenomenological data, and in particular that recorded from the studies of relict scours and the direct observations of small scale scours, have suggested that the vertical force may be sufficient to cause failure and displacement of the soil below the scour. These observations were used in designing the scour tests conducted in the iceberg scour tanks at Memorial University.

The first set of experimental tests conducted by C-CORE was carried out in gravity consolidated silt. In these small scale model tests, the model was allowed to pitch and heave while scouring the test bed, increasing the number of degrees of freedom of the model from previous work. The purpose of these experiments was to measure and observe subsurface deformations below the scoured test bed, shown by the displacement of horizontal layers of find sand. Also, the pore pressure response during scouring was recorded, as it was an indication of the depth to which scouring affected the testbed. The surface morphology of the scour was also measured and recorded. Although these tests were pilot studies to assess the model iceberg and investigate the appropriate scour depth for testing, a considerable amount of useful information was obtained (Poorooshasb et al., 1989).

A comprehensive model test program was carried out during 1989 in a sand bed which was prepared at two different densities. This work was sponsored by the Canada Oil and Gas Lands Administration and has been reported extensively elsewhere (Poorooshasb, 1989; Poorooshasb and Clark, 1990). The soil was instrumented so that the sub-scour displacement could be determined after the scouring event. Instrumentation consisted of small steel ball bearings whose course could be tracked, as well as flexible lines of solder placed across the scour track at various depths below the maximum scour depth. In addition, the iceberg was instrumented with pressure cells so that the stress on the soil at the bottom of the scour as well as the stresses on the attack face of the model could be measured.

A fixed scour cut depth was set and the stress variation was measured through the course of the test. In each test, the model scoured through a loose sand and a denser sand. The different densities for the two sections were obtained by varying the height and horizontal speed at which the sand was rained down from a hopper to the test bed. A total of four tests were carried out during this experimental program.

More recently an extensive series of tests has been carried out in both dry sand and submerged sand (Paulin, 1992). The tests done during this series were a continuation of the sand tests conducted by Poorooshasb (1989) and again the measurement of subscour displacements was the primary objective. Secondary objectives included the measurement of pressures and forces on the model, and the measurement of the stress response of the soil during loading.

The four tests were conducted using the same iceberg model geometry in order to examine the repeatability of the process. The last two tests were conducted in a submerged test bed so that the results from dry and submerged tests could be compared. The sand test bed was prepared at a low relative density and a model with a small attack angle (with respect to horizontal) was used because previous work had shown that the greatest subscour displacements were measured in loose sand with the same type of model (shallow attack angle). The completed test bed dimensions are shown in Figure 13.

One of the findings of the one gravity test programs is that the vertical load is typically in the range of 1 to 1.5 times the horizontal load for a keel with a shallow angle of attack (15 degrees). If the soil properties are known, the maximum horizontal load required to create a given scour can be reasonably calculated from passive earth pressure theory. Thus, the vertical load can be indirectly estimated and an assessment of potential subscour deformation can be made based on soil mechanics theory.

Figure 14 shows the depth of subscour displacement for a loose sand and for a somewhat denser sand. These results are for an attack angle of 15 degrees. These tests have confirmed that the most important factors that influence subscour deformation are the soil strength and the attack angle of the keel.

Centrifuge Modelling

There are problems in modelling soil/iceberg interaction (or other geotechnical problems) in the laboratory at one gravity because all the laws of similitude cannot be followed. Some of these problems arrive from trying to scale sediment grain size, density, and shear strength. These difficulties in modelling at one gravity may be avoided through centrifuge modelling, in that correct soil conditions may be established in the model, both in terms of the effective stress level and the stress history.

Centrifuge tests are currently ongoing to investigate the ice scour process (Paulin et al., 1991). Figure 15 shows a possible centrifuge model to investigate ice scour. The tests are being conducted on Cambridge University's beam centrifuge at an acceleration of 100 gravities (1:100 scale) and in kaolin clay. Data is being obtained on the effects of scouring, including changes in pore water pressure, soil deformations, and model pipeline deformations. The resulting scour from one of the centrifuge tests is shown in plan view in Figure 16.

Pressure Ridge Ice Scour Experience (PRISE)

The Pressure Ridge Ice Scour Experiment is a joint industry project with the objective of developing a reliable design technique that will result in a safe and the most cost effective pipeline possible in ice scoured terrain.

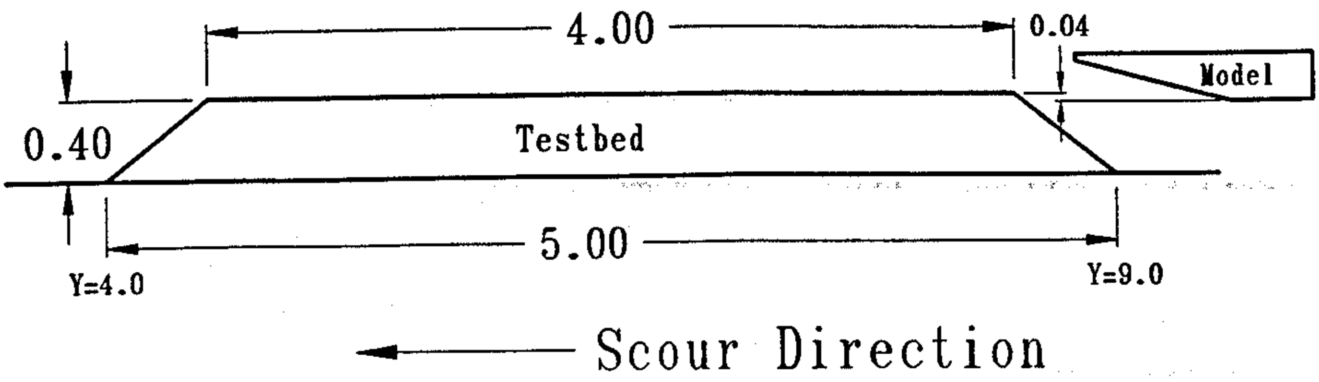

Figure 13 Completed Sand Testbed Dimensions (After Paulin, 1992).

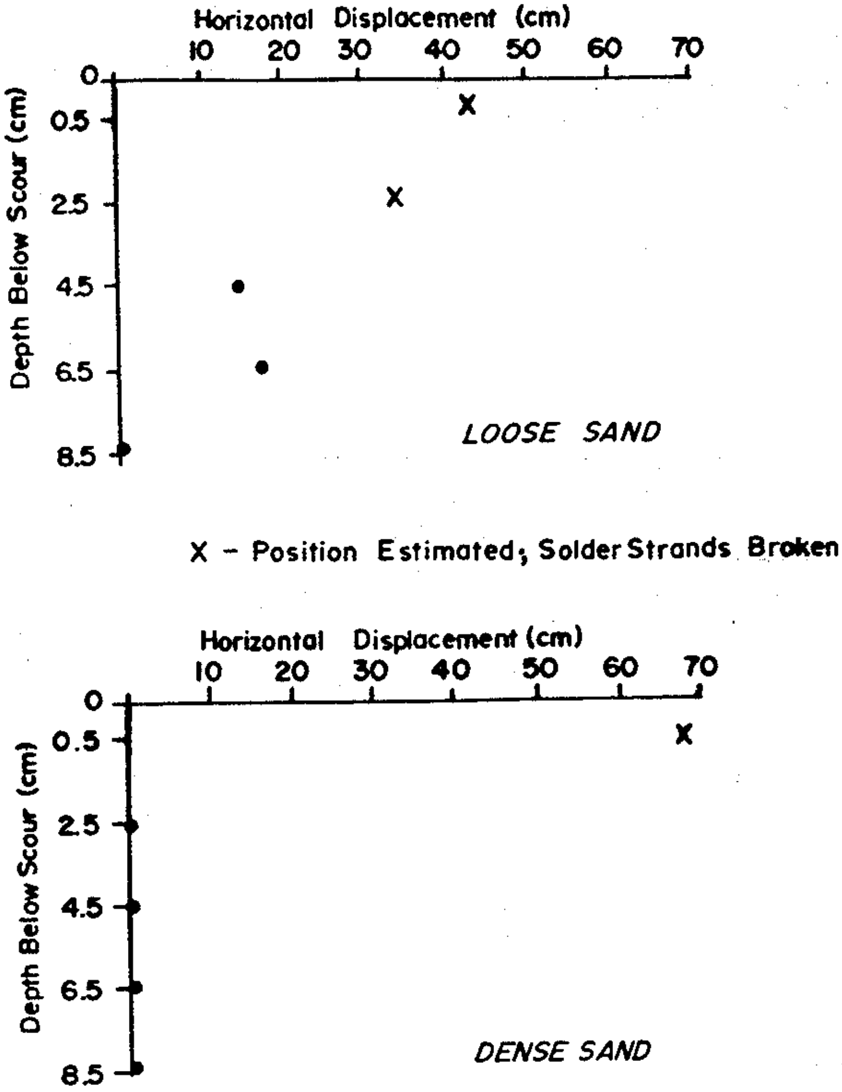

Figure 14 The Variation of Axial Displacement with Depth Below the Scour Cut Depth. For Loose and Dense Sands.

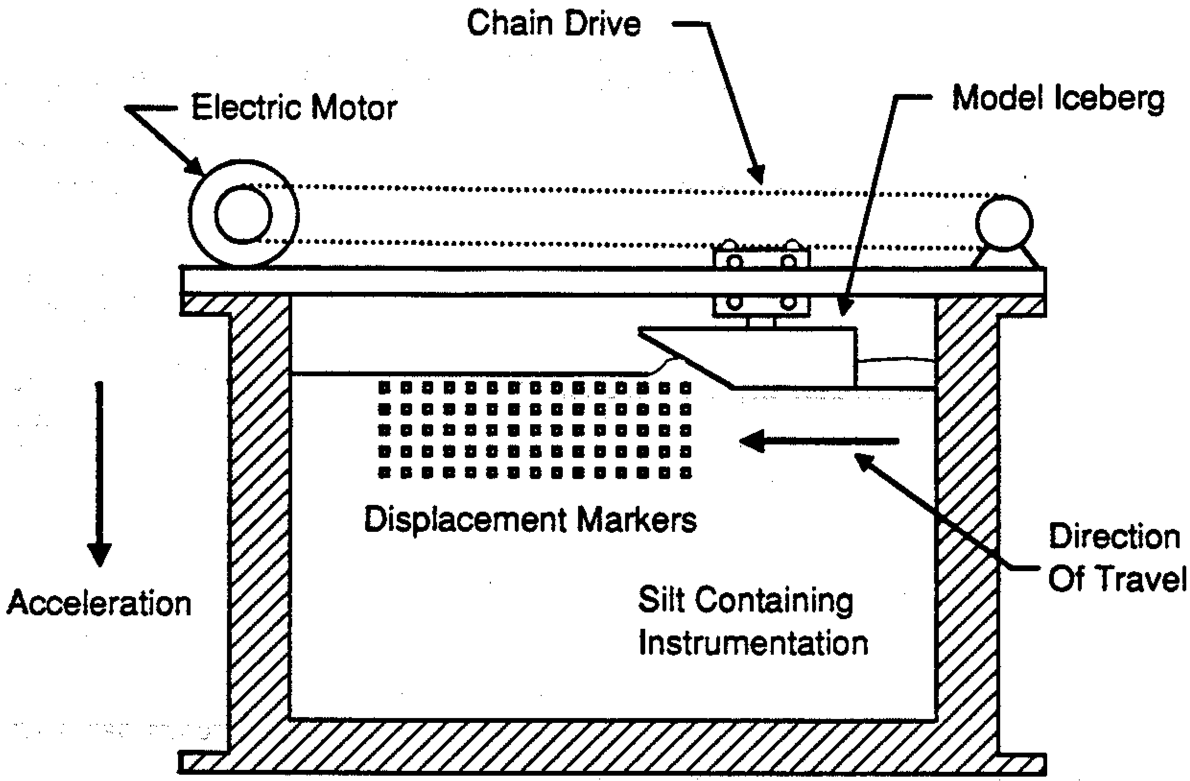

Figure 15 Possible Centrifuge Model to Investigate Ice Scour (After Poorooshasb and Clark, 1990)

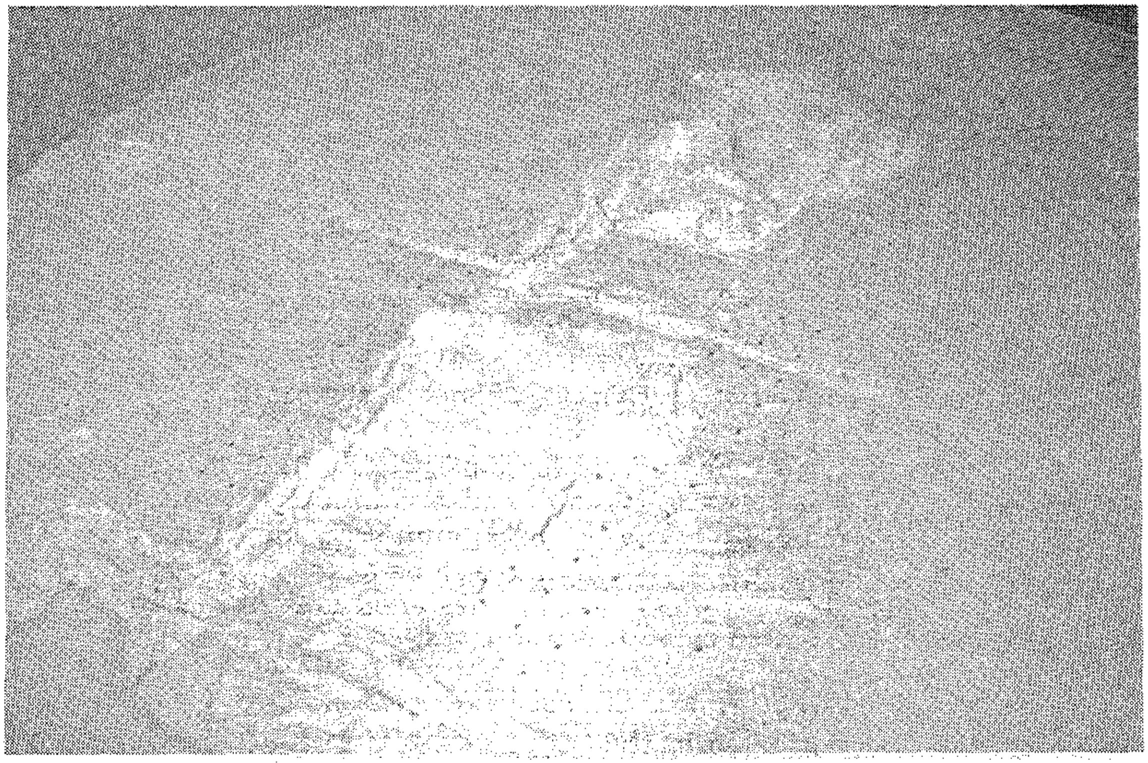

Figure 16 Resulting Scour From one of the Centrifuge Tests Conducted at Cambridge University. The Scour took Place From Bottom Left to Upper Right (Photo Courtesy of P. Lach, C-CORE.)

The project consists of laboratory modelling, theoretical investigation, and field observation of pressure ridge scouring of the seabed, the primary objective of which is the analysis of the stress changes and soil deformations under pressure ridge keels.

There are several phases to the project, including the development and testing of innovative measurement techniques, laboratory modelling under one gravity and under centrifuge accelerations, the development of a mathematical model, the full documentation of one or more scour events in the field, and the burial and monitoring of a test pipeline section in an area of the Arctic susceptible to scour. The project was initiated in September 1990 and is scheduled for completion by 1993-94.

Conclusions

At the present time, the design of pipelines in ice scoured terrain would predominantly rely on empirical methods based on phenomenological evidence. The design however would not take into account the sub-scour deformation which is an important consideration for any pipeline structure in northern regions.

Examination of a variety of model tests and observations of small scale scours suggests that for relatively weak soils the pipeline should be placed at least at a depth of twice the maximum depth of modern scour below seabed. Even at that depth some soil deformation would occur but it is very likely that the pipeline could be designed to resist that deformation and accommodate the stresses transmitted through the soil. Dense soils which are sufficiently strong to resist bearing capacity failure from the relatively high iceberg loads may not experience subscour deformation.

Centrifuge modelling has shown that the physical features that have been observed both in modern ice scoured terrain and in relic scours, can be replicated in a laboratory (Paulin et al, 1991). The most important aspects of ice scour are the attack angle of the ice and the strength of the soil. When the vertical load associated with the ice exceeds the bearing capacity of the soil, a bearing capacity failure occurs beneath the scour.

In strong soils, the vertical force associated with the iceberg scouring the seabed may not be sufficient to cause subscour deformation, in which case burial immediately below the maximum scour depth may be adequate. Burial depths in weaker soils may have to be at least twice the scour depth below the seabed level unless they are designed to resist extensive subscour deformation.

Recent model studies suggest that the vertical force exerted by a scouring iceberg may be in the range of 1 to 1.5 times the horizontal force required to create the scour. This needs to be verified by further testing and analysis but it does suggest that it may be possible indirectly to determine the maximum vertical load if the shape of the worst scours in a region and the soil properties are known.

Further verification of forces associated with iceberg or pressure ridge keel scouring is required. This should be achieved through the PRISE project currently (1991-92) underway.

Acknowledgements

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KEYNOTE PRESENTATION 2

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Houston, Singapore, London & Zug

"EMERGENCY SHUTDOWN SYSTEMS"

Introduction

A recent accident has shown the obvious advantage of using subsea valves to limit backflow in case of a pipeline failure on or near a platform. Before this time subsea valves had been installed as an afterthought and they infrequently reached the initial engineering phase for efficient integration into a pipeline system.

One method commonly used is, after the pipeline system has been installed, to post position a spool piece with its various valving arrangements in a single package, followed by the placement of a protective framing cover and rock dumping around the periphery of the box. This technique has serious negative cost implications because of the large spreads and excessive offshore time required. In most offshore installations the size of spread and time required to execute a specific element of work directly impacts on the cost of installation. Obviously, smaller spreads used for shorter periods can reduce installation costs.

The towing techniques of pipeline installation lend themselves quite well to the method of pipe makeup onshore, where the complete assembly is fabricated, tested, launched, towed, and tied in as an integrated element. This paper discusses some novel approaches using existing state of the art technology which will make it possible to install these valves within acceptable risk levels and at a lower capital cost.

Review

With the installation of long distance, large diameter gas transmission lines there is always the problem of total line bleed down at a point of rupture. During the 1940's and 50's the line lengths between valves was in the range of 15 miles at operating pressures of 600 to 800 psi. A failure would destroy an area of 150' radius and devastate an area of 500' radius. In the 1970's and 80's much longer distance, larger diameter and higher pressure lines were installed offshore with no intermediate valves with a tremendous increase in the stored energy. This radius of potential danger is increased dramatically by virtue of the volumes of stored energy.

In all cases offshore, the main gas transmission lines initiate at a platform and, in some cases, terminate at another platform or onshore. These initiation and termination locations are extremely important from the standpoint of potential energy releases and catastrophic failures with loss of facilities and lives. The use of valves in the lines near the platforms is an excellent means of product containment in the event of rupture near a platform.

Figure 1 shows the two principal types of valves with their various modes of operation. These include the check valve which automatically closes when backflow in the pipeline is detected. In fact there appears to be a nominal location for these subsea pipeline barriers which in the event of a rupture will shut in the main transmission line with a minimum of blow down between the subsea barrier and the top of the platform riser. Studies have shown that there is an optimum length of line between the valve and the riser based on the volume of gas stored in this area and the time required for burning gas, at its ambient temperature, to cause structural and bulkhead failure on the platform.

From a cost of installation standpoint, a valve at the top of the riser is ideal except that very little protection is available in the event of a riser or pipeline failure near the platform. On the other hand, a barrier valve set at some distance from the platform provides safety from the entire pipeline load coming back to the platform. The main drawback is the larger additional cost required to place a valve at a considerable distance from the platform, especially by conventional methods.

Another factor that is important is the type of barrier that the engineer should recommend in terms of reliability, operation, maintenance and repair. Obviously a single in-line check valve is the easiest to install but has little flexibility in terms of maintenance, repair, or replacement without considerable interruption to service. The next level is the combination of two valves which permits the operator to isolate the main transmission system and repair the primary valve. The other extreme is a complete side valve assembly with the ability to shut in and replace the main line valve with no interruption to service and the ability to pig through the system without shut-down.

The real question then becomes; what, where, when and how to install for the most acceptable operation at lowest risk and at the lowest capital cost.

Subsea Barriers

For a better understanding of the potential for operating the systems, a knowledge of the equipment components (Figure 1) is important. Basically these include the check valve which automatically closes when backflow is detected. The other valves include remote and/or diver controlled ball valves in both the open and closed positions depending on their specific mode of operation.

The speed of closure becomes an important factor if rupture occurs near the riser. As long as the valve is open, or partly open, backflow continues fueling the burning gas plume with destructive effect. As time continues, it rapidly reduces the life expectancy of the structure and the bulkheads between the fire and the personnel and equipment. With this combination of valving equipment available, there is a wide variety of conditions under which the system can be operated.

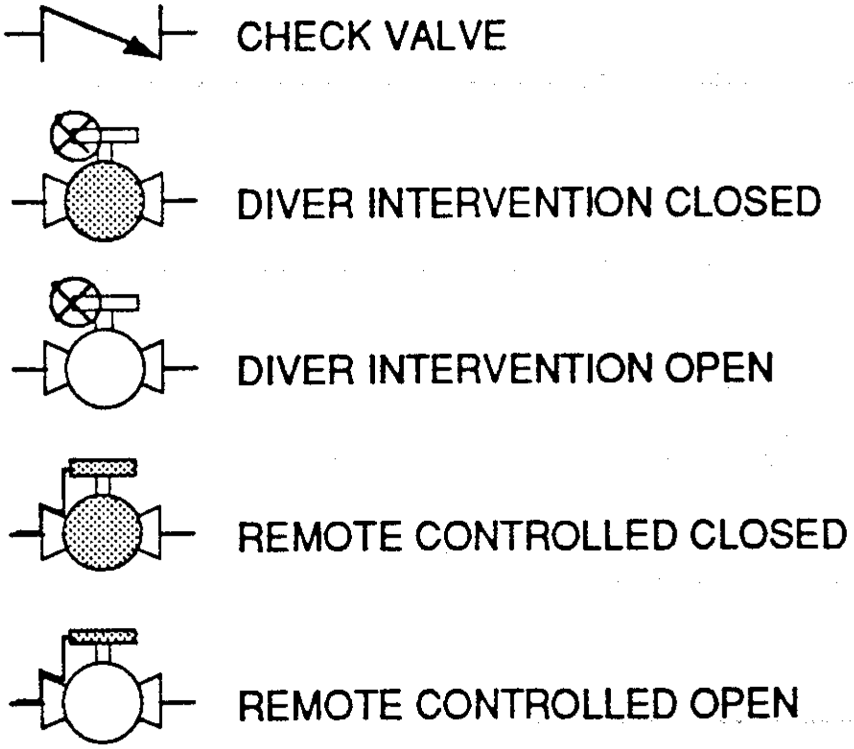


Figure 1 The various valve arrangements and operating modes

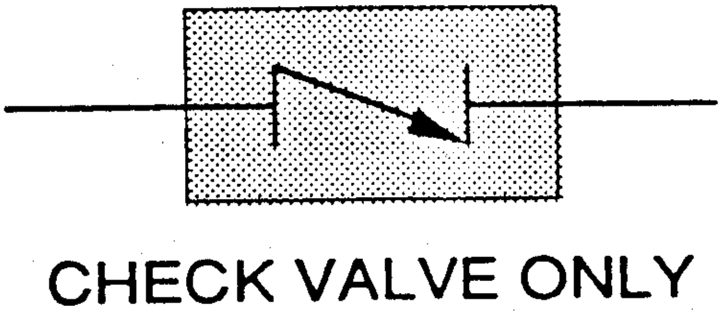


Figure 2 The minimum system using a check valve in a protective box, backfilled

The most simple, but least flexible is the single check valve (Figure 2) with which very little can be done. The other arrangements are more flexible from an operation standpoint but their reliability is reduced as each new valve component is added. The system most commonly installed to date (Figure 3) is the combination of a check valve with a ball valve immediately down stream. The other extreme includes a valve system that permits the central ball valve to be removed without interruption to pipeline service (Figure 4). It is also a question of how much insurance is required. The more complex and larger the system, the greater the initial cost for the materials, especially for the installation.

The distances of the ESD ("emergency shut-down") valve from the structure vary widely. In some cases they are near the riser and in others up to two and one half miles distant. The problem with the ESD valve being at a long distance is, in the event of a rupture, the line pack between the valve and the platform can have considerable storage prior to the discharge.

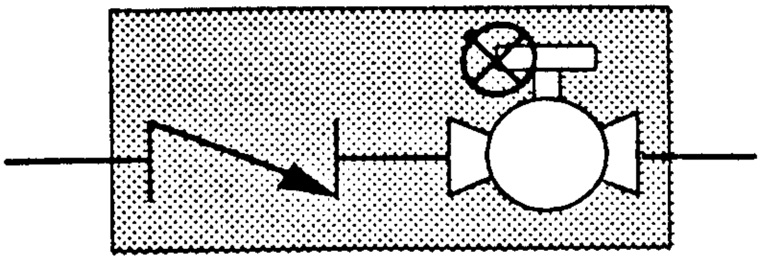
Lately a more rational approach has been developed taking into account the structure's ability to withstand "over heat" from a ruptured, ignited line at a specific distance from the platform. This accounts for: total line length, line pack, line pack between ESD valve and platform, prevailing winds, potential gas plume, and the time that the structure can withstand this "over heat" before degradation of the structural members becomes critical. Considering these factors there appears to be an optimum distance for positioning of these barrier valves.

Installation Cost Factors

The cost for offshore construction is a direct function of: the size and weight of equipment being installed, its complexity, time for installation, water depth, and spread size. Obviously a light structure with a small spread and short installation time can be very cost effective. The objective of this section is to discuss the various alternatives and to focus on the factors which can influence the methods and procedures which have the greatest impact on the installed costs. Installation costs for the ESD valves have ranged between $ 10 and 17 million plus the extra ancillary equipment, i.e. the controls, umbilicals and external protection.

Offshore companies vary widely in their operating philosophy in terms of perceived risk and built-in redundancies. For example, some companies prefer to have systems with backup safety for repair and replacement of the ESD valves, considering such factors as in-line valves which could leak, requiring extra bleed down capability between the valves. Ball valves are available which have the potential for removal and replacement of their cores or specifically for replacement of their seals.

How the redundant valves are controlled is another factor to be considered (usually either by remote or diver operation), as well as the methodology as to which valves are open and closed during normal operat-



CHECK AND BALL VALVE

Figure 3 A check and ball valve designed to permit the check valve to be worked on without depressurizing the main section of line to the next section of line.

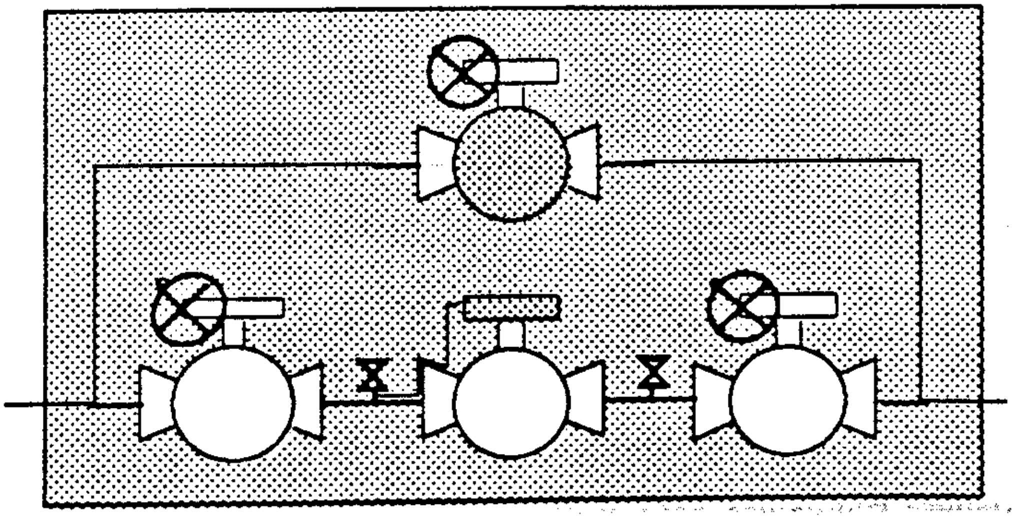


Figure 4 The maximum valve arrangement and versatility permitting complete valve repair or removal while maintaining the pipeline system in operation. It also permits pigging while maintaining full operation of the pipeline.

ing conditions, testing, pigging and valve cycling for seal lubrication. The depth at the facility becomes very important if divers are used for valve operation, although this becomes less of a factor if ROV intervention is planned and utilized.

Present Installation Methods

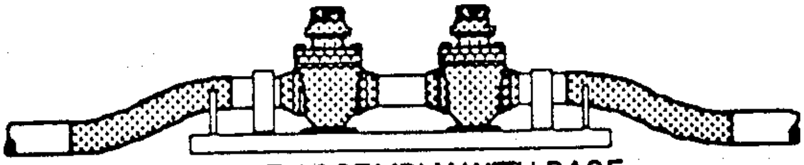
For the systems installed to date, the type of post installation method that is being employed is to fabricate the ESD valve and base assembly on shore with framing (see Figure 5) for the valve assembly components, then to: transport it to the site, shut the operating line in, bleed it down, elevate the existing pipe section onto sleepers, remove a section of the line, lower the valve assembly spool piece into the gap, align and hyperbarically tie-in the spool piece section, remove the supports, lower and place the cover assembly on the frame, jet the valve assembly and framing to grade, install and connect the control umbilicals, test and place backfill protection material over the assembly and pipeline. Naturally the size and complexity of the ESD has a direct impact on the size of spread and requirements for handling equipment. Again, the larger spreads cost more.

The installation of the covers over the valve assembly and framing is a delicate operation because of the hydrodynamic forces involved during the lowering operation. Under static conditions the cover assembly with a properly located C.G. is stable but will rapidly lose stability as the lowering is started. This is caused by the very large plan area of the cover and its interaction with the water. At a low vertical velocity, during lowering process, the added mass and lift component are large and generated below the C.G. which destabilizes the system. The effect is for the cover assembly to roll and sway around and along the longitudinal axis of the cover. This is also exaggerated by vessel heave resulting in high impact loads in the rigging. In several cases rigging failure has occurred causing considerable damage, delays and cost overruns.

Method of Installation

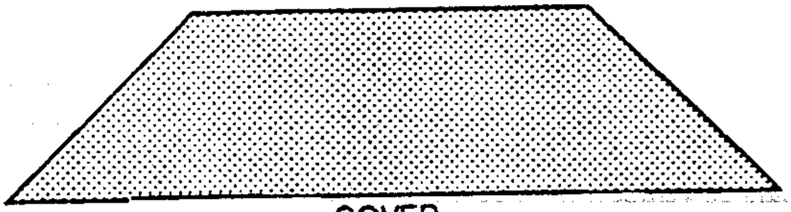
Recently several installations, by the tow method, have shown that this method has potential for incorporating large structures on the lead end of bundled lines which were installed prior to the pipeline launching, during the launching, towing and final positioning. Both the bottom and mid-depth tows have shown this versatility. In the case of Placid for the Green Canyon Block 29 export line installation, the lead sled was planned for a manifold system for future tie-ins. It weighed 130 tons in air and was roughly twenty four by forty eight feet in plan and twelve feet tall.

The Placid project utilized the bottom tow method from the Matagorda peninsula, 80 miles southwest of Houston, to the Green Canyon area some 450 nautical miles to the east, approximately 130 miles south of New Orleans (see Figure 6). The method employed by Placid was to make

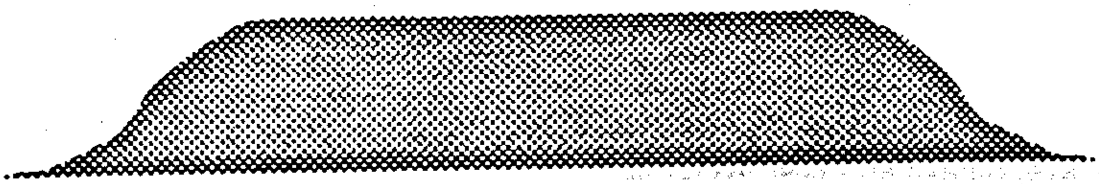


VALVE ASSEMBLY WITH BASE

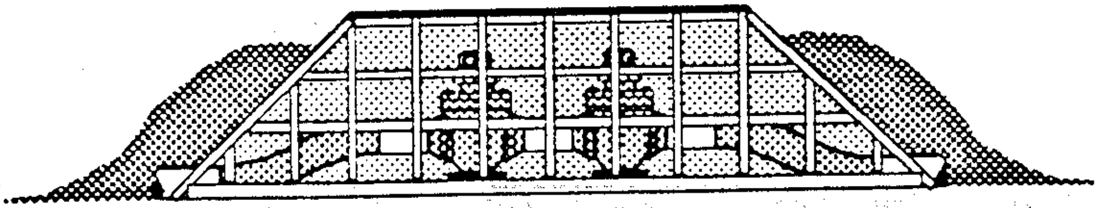
FRAMING



COVER



BACKFILL



CUTAWAY FINAL

Figure 5 A cut away view of a valve assembly showing a tandem check and ball valve on its base, the structural framing, the cover, the back filled periphery of the box, and a cut away view of the entire assembly.

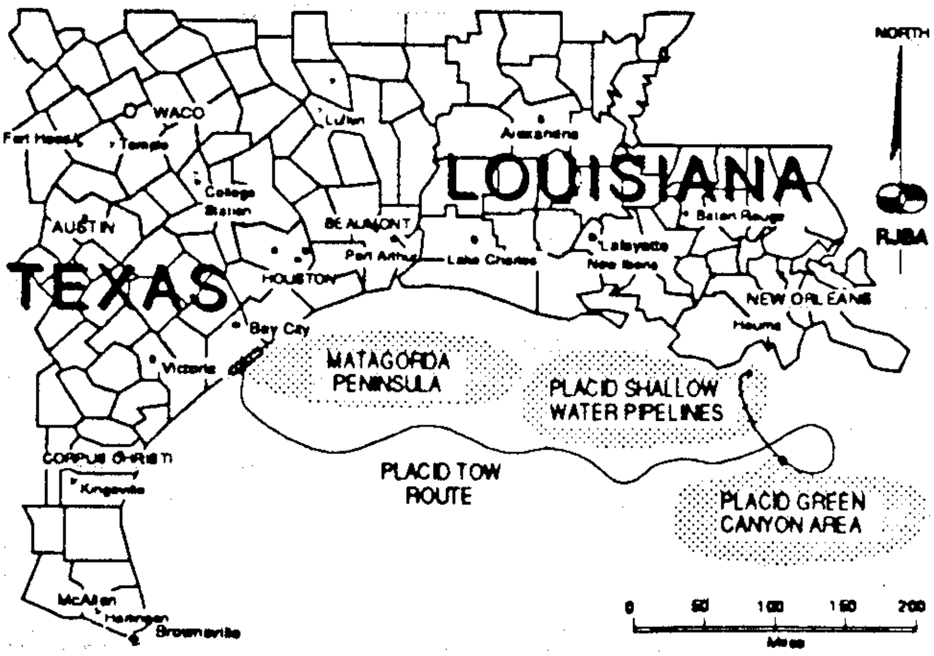


Figure 6 The Placid tow route between the Matagorda peninsula and the Green Canyon Block 29 field. The tow route length was 450 nautical miles and the pipeline passed through depths of 3000 feet during the tow.

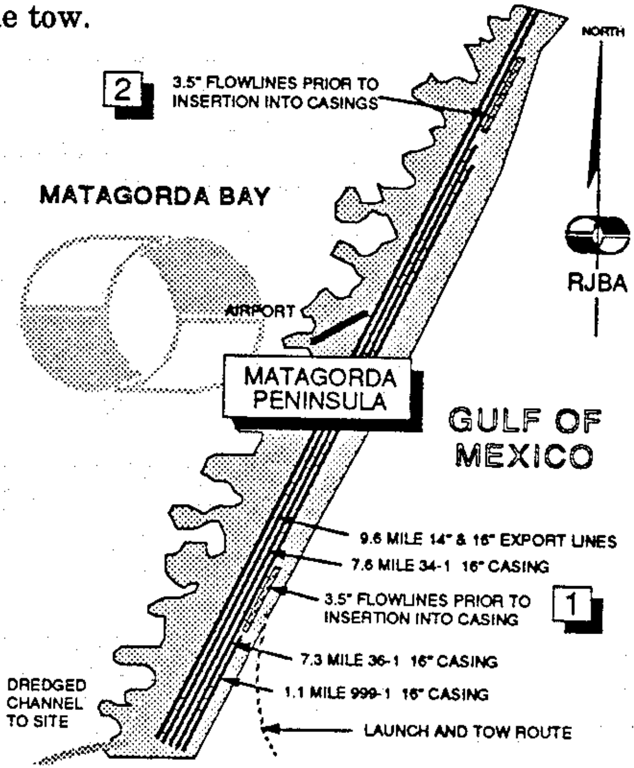


Figure 7 The Matagorda pipe make-up site where the Placid Green Canyon flowlines and export lines were made up and launched, towed, and positioned prior to their diverless connection. The line lengths varied from fifteen to 1.8 kilometers.

the pipe up in a continuous string, install the sleds, test and execute a lateral launch (Figure 7). The longest section launched was 9.5 miles in a single length.

The interesting aspect of the Placid project was that the maximum spread size and cost for the launch, tow and positioning including a tow and survey vessel was $ 30,000/day including fuel. The tow vessel was on long term charter and used only when available and had no associated downtime. Obviously, a spread cost of this magnitude, for a relatively short period, will have a low installation cost.

In this case the tow can be made up with the ESDV assembly placed some 900 feet from the tow head (Figure 8). This figure also shows the tow vessel being utilized as a launching vessel with an anchor deployed off the bow for providing the reaction force to deflect the lead pipe end offshore during the initial launching. During the installation process, proper management of the vessel's launching and towing loads is necessary to minimize the amount of equipment, and again, the cost. Figure 8 shows the force balance between the initiation of pipe launching and the start of the towing.

During the start of the pipe launch the primary load is to move the cable which, in the case of Placid, was 150 tons. As the deflection process progressed the cable load reduced as the length of cable out shortened and the amount of pipe deflected increased. During the launching process the load is continually being reduced to approximately one half the starting load, and prior to the initiation of the actual tow. The launch process and load combinations are site sensitive and can vary considerably depending on the type of foreshore approach.

The pipe, during its final phase of launching (Figure 9), is continually cradled into the water, over its entire length, by sidebooms and, similar to Placid, cranes walk the complete ESDV assembly into sufficiently deep water to achieve its launch buoyancy. Figure 10 shows the onbottom towing configuration with the tow vessel, towing cable, tow head, pipeline, valve assembly, and pipe tail. The pipe system could be several miles long depending on how far the pipe end is to be placed from the platform to avoid interference in the vicinity of the platform. Careful attention is given to the ESDV buoyancy in terms of water depth and displacement.

For example, the net weight is reduced as the depth of submergence is increased. The engineer must determine the depth of water that the ESDV system must reach prior to the pipeline initiation of tow. Another factor is the off bottom towing mode (Figure 11) of the side valve assembly, which must remain stable during the launch, tow, and final positioning. There are several sites on the Scottish Coast that could be used for either a transverse or lateral pipe make-up and launch. The transverse launch is limited to lengths of 3 miles in single pieces by virtue of the availability of land.

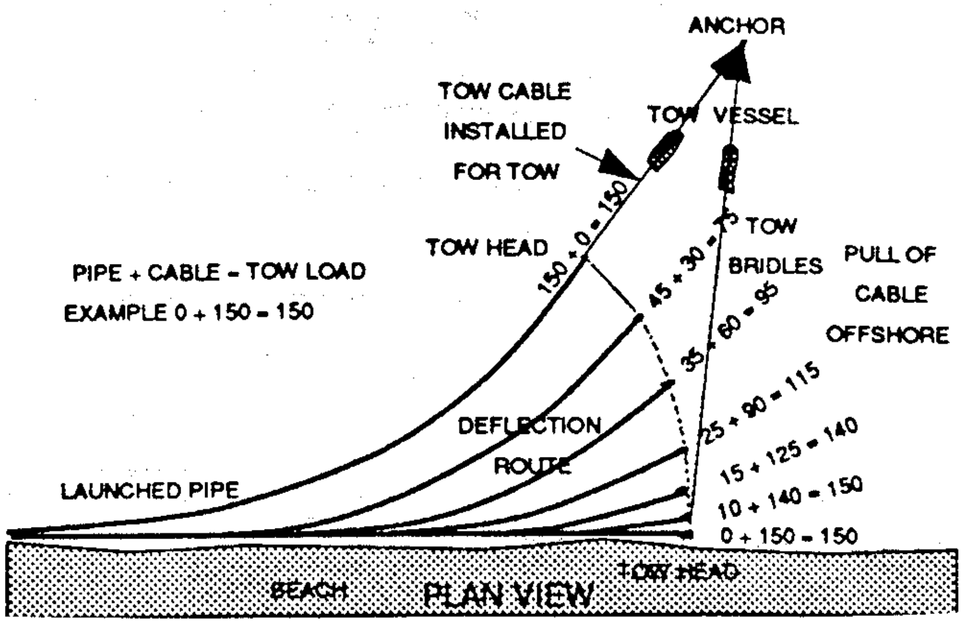


Figure 8 The loads required to launch the pipeline system laterally offshore, prior to the towing process.

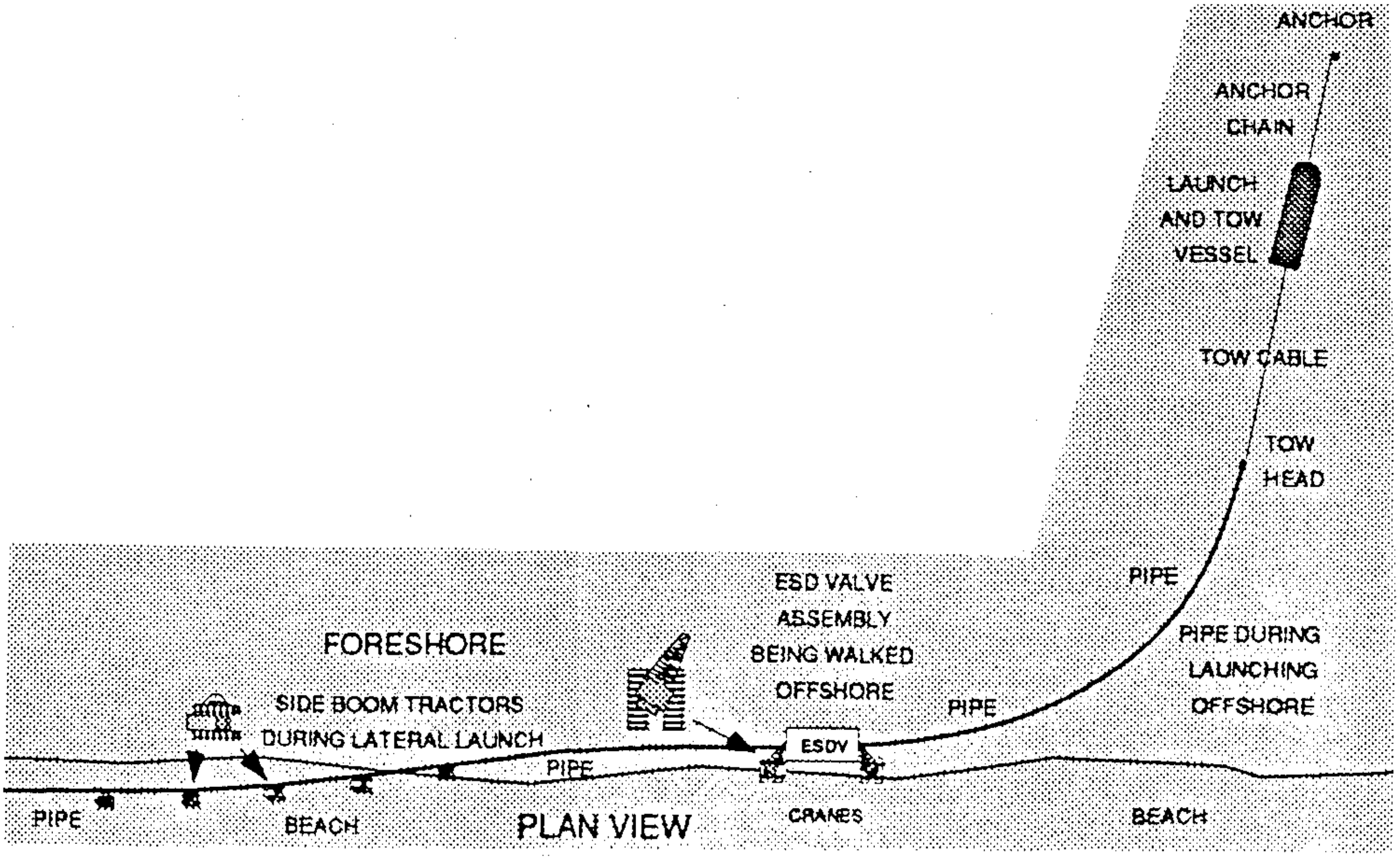


Figure 9 The lateral launching process where the lead sled at the pipe end is deflected offshore and the valve box is carried into the water prior to the pipe section getting under way.

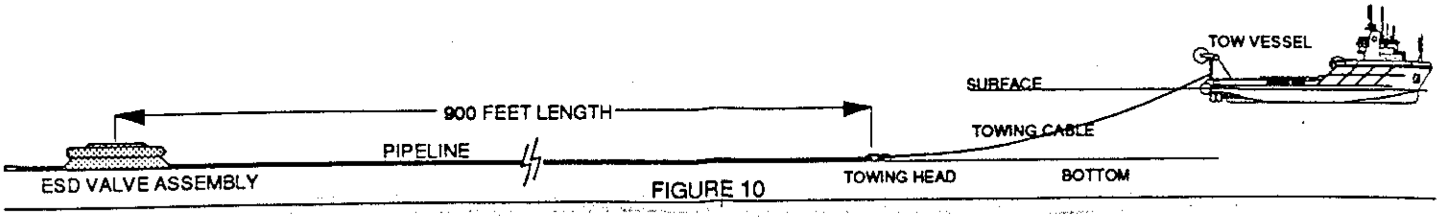


FIGURE 10

Figure 10 A profile view of the tow vessel, pipe, and valve assembly.

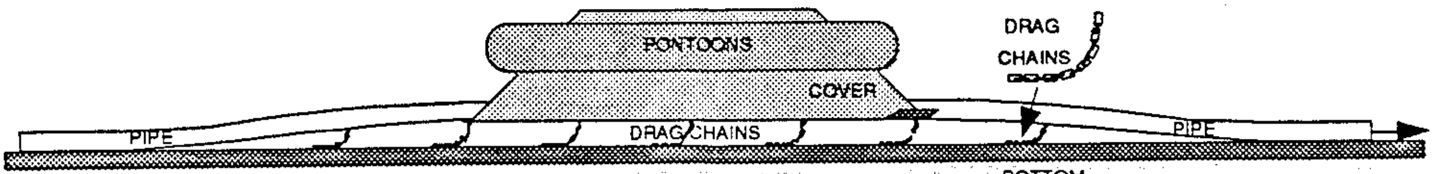


FIGURE 11

Figure 11 An elevation view of the valve box floating off the sea bed with drag chains maintaining the correct height.

Methods Cost Comparison

For the purpose of illustration we assume that a 36 inch line is to be installed with an ESD valve arrangement five hundred feet from a platform and, because of congestion around the platform, a total line length of 3 miles is required. A 900 series dual ball valve is used in a single containment chamber (Figure 12) with protective cover and rip rap backfilled around the periphery. The towing mode could be either of the tow methods with the pipe on bottom or mid-depth (CDI method). Figure 13 shows the chamber assembled configuration for towing with the complete valve assembly on the skid base with the framing, cover and pontoons in place.

The experience with the Placid 130 ton sidevalve assembly towing indicates that a tow velocity between 4 to 6 knots is feasible. Special care in addressing the towing stability is important from the hydrodynamic standpoint of the system. In fact, in a case of this type, the author recommends a model towing test to confirm stability at the speeds anticipated.

For comparison purposes, a cost matrix has been prepared (Table 1) which defines the different elements of work required for each of the ESD installation methods. The costs are based on installation during the good season with normal down time related to weather, and no extra downtime for interference and delay of other operations. The main difference for the valve fabrication is that the complete assembly can be made up in a single unit for the installation process. The unit's post installed system requires individual components which are heavier for assembly in the field. The tow method difference is a cost savings of approximately $500,000.

The largest saving is in executing most of the work on shore which avoids: lifting existing line onto grout bags, cutting existing line, hyperbaric tie-ins, connecting umbilical, lowering existing line off grout bags, lowering the cover assembly onto the base and jetting the assembly into bottom. The difference is a cost saving of approximately $ 4,500,000.

Conclusions

With the experience that has been accumulated over the last decade in terms of the need for additional protection for offshore platforms, the advances in marine pipeline construction, the design and installation of manifold systems; the following has been concluded:

- The use of ESD valves for protection systems should be seriously considered for lines with high capacity potentials of stored energy.

- The ESD valve system's function and operation can vary considerably depending on the complexity of the manifolding system employed.

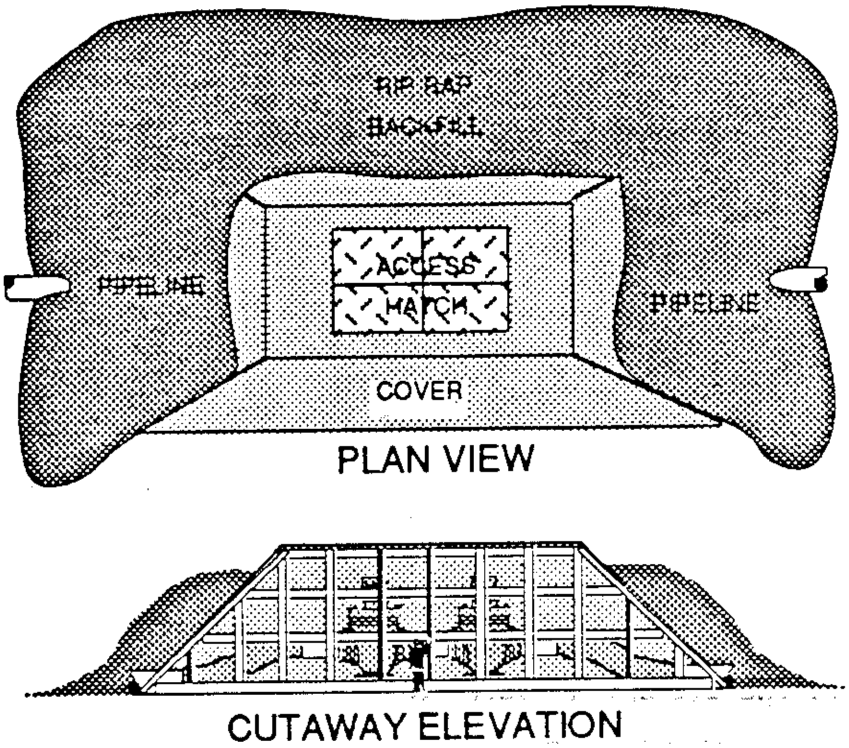


Figure 12 A plan and elevation view showing a cutaway of the assembled box with the valves in place.

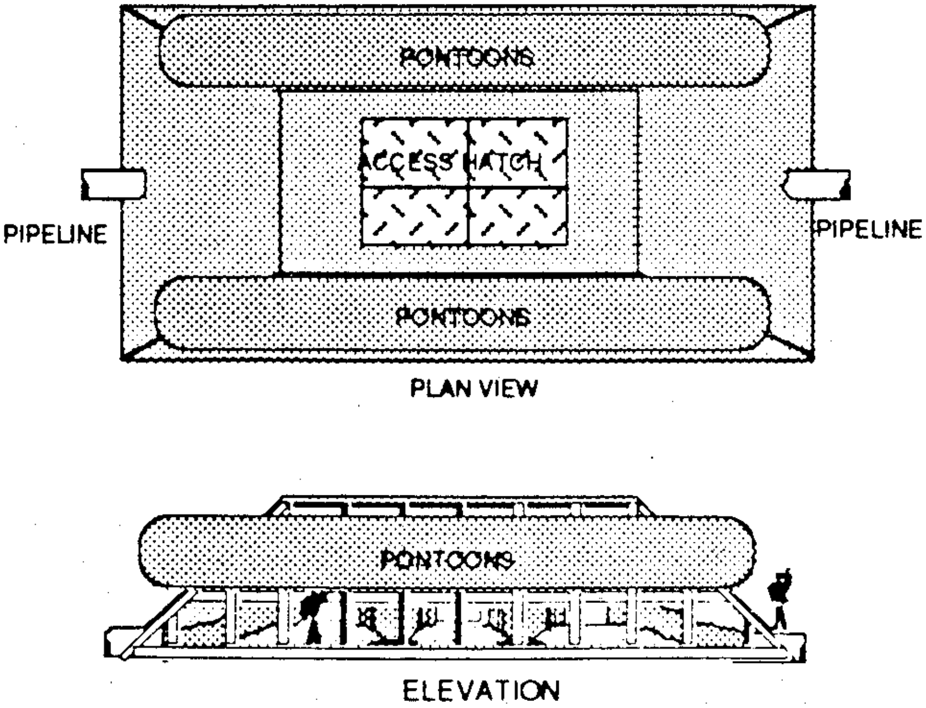


Figure 13 A plan and side view of the ESD valve box assembly with the auxiliary buoyancy for the launch, tow and positioning process.

COST ELEMENT	METHOD	
FABRICATION	POST INSTALLED	INSTALLED BY TOW
Valve Assembly Makeup	same	same
Protection Framing	1,400,000	1,200,000
Cover	2,200,000	1,900,000
Lifting Slings	40,000	nr
Valves	same	same
Sub Total	3,640,000	3,100,000
INSTALLATION		
Subsea Assembly	260,000	260,000
Launch and tow	nr	136,000
Lifting existing line onto grout bags	600,000	nr
Cutting existing line	425,000	nr
Hyperbaric Tie-ins	1,600,000	nr
Connecting umbilical	170,000	nr
Lowering existing line off grout bags	260,000	nr
Lower cover assembly on to base	680,000	nr
Jetting assembly into bottom	425,000	nr
Rock dumping	same	same
Sub Total	4,420,000	396,000
COMPARATIVE COST $	8,060,000	3,496,000

Note: nr not required

Table 1 The comparative cost of the conventional method of ESD valve assembly installation versus the towing technique.

- The most simple system is a single inline check valve. This is by far the lightest and least complex to install. However, it has the least versatility in terms of operation, maintenance and repair.

- The more complicated systems with additional valving and manifolding become less reliable in terms of potential for valve damage and leakage during the operational life of the system.

- The ESD valve systems require protection in the form of a protective structure and backfill around and over the structure to protect from dragging anchors, fishing boards and dropped objects.

- The conventional method of construction, by installation of a spool piece with framing and backfilling later is very costly and requires additional offshore installation time.

- The smaller the valve assembly, the lower the offshore construction cost because of the smaller handling equipment, lower day rate and less time required offshore.

- The installation of the cover over an installed spool piece can be very risky because of the inherent instability in a cover structure caused by its shape, location of the C.G.and the added mass loads developed during the lowering process.

- The bottom towing method for pipeline installation with a valve assembly in the line is technically feasible and can be cost effective.

- The method proposed in this paper is state of the art by virtue of a manifold system of 140 tons in a nine mile pipeline length having been towed for distances up to 450 nautical miles on the sea bed.

- The cost of installation can be reduced by a factor of two to three when using the towing technique versus the conventional spool piece method.

- The cost of installation by the towing technique is affected by the route length, towed section length, and method of tow employed, i.e. pipe on bottom, mid-depth or on the surface.

- If the tow distance is long and the pipe section length is relatively short (less than five kilometers), then the mid depth (CDI) method of tow can be used and is cost effective.

KEYNOTE PRESENTATION 3

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H.O. Mohr Research & Engineering
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"RESPONSE TO UNDERWATER PIPELINE EMERGENCIES"

Introduction

Any operator of subsea pipelines will undoubtedly agree that the probability of a line leak or failure is an inescapable reality. Having accepted this, the issue becomes one of preparing for a failure and subsequent repair. This thought must be carried one step further to define the failure/repair as an unscheduled repair - a repair that must be made on an emergency basis. The degree to which an emergency exists or is defined depends on such factors as the operator's basic philosophy, pipe size, water depth, the line's relative importance to other lines, and the revenue that is lost due to downtime.

In recent years, an extremely sensitive consideration has entered the equation - that of possible pollution. In fact, in some areas the operating company must show regulatory agencies documented plans for repairs of a subsea pipeline before permission is given for constructing the planned pipeline.

The "bottom line" is that prudent operators of subsea pipelines must determine how to address unscheduled repairs; the repair of a pipeline on an emergency basis. Numerous operators of subsea gas transmission lines in the Gulf of Mexico have recognized their vulnerability and need for a repair plan. Several of the operators collectively examined their ability to respond to emergency failures/repair capabilities. This initial assessment was informally organized by Tennessee Gas Pipe Line Company (Houston).

Virtually all operating companies had some form of repair capability. Based on the initial assessment, numerous operating companies of gas transmission lines unanimously agreed that they should jointly conduct a feasibility study to determine how they could collectively improve their ability to respond to the emergency failures of their lines.

Feasibility Study

Houston-based H. O. Mohr Research & Engineering, Inc. (MOHR), as an independent consultant, was authorized in May, 1977 to make the feasibility study. At that time, there was no formal organization of the interested gas transmission companies.

However, eleven companies had expressed a strong desire to establish a joint repair program (Table 1). The organizing representatives from each company were on a vice president level. This group became the executive committee (EC).

MOHR prepared a detailed outline of the proposed study. All participating companies were requested to prepare a listing of their subsea pipe line sizes, water depth, lengths, and pipeline location identification. The companies also could include river crossings and lines in lakes and harbors. The lines listed were referred to as dedicated lines.

TABLE 1

COMPANIES INTERESTED IN REPAIR PROGRAMME

1. Columbia Gulf Transmission Company
2. Eagleton Engineering Company
3. Michigan Wisconsin Pipeline Company
4. Natural Gas Pipeline of America
5. Southern Natural Gas Company
6. Tennessee Gas Pipeline
7. Texas Eastern Gas Pipeline Company
8. Texas Gas Transmission Corporation
9. Transcontinental Gas Pipeline Corporation
10. Trunkline Gas Company
11. United Gas Pipeline Company

TABLE 2

MILEAGE IN PROGRAM

6"	298.77
8"	422.69
10"	506.82
12"	910.89
14"	67.36
16"	860.66
18"	128.17
20"	819.40
24"	756.57
26"	264.03
30"	771.55
36"	352.80
	6,159.72 Miles

Since the study was to be technical in nature (equipment and technique evaluations), each participating company appointed a technical representative from their company to monitor the study. This group became the technical committee (TC).

Objectives

After the basic pipeline information was received from each potential participant, the actual engineering/feasibility study was started. The objective of this project was to determine the most time responsive and cost effective method(s) for providing emergency stand-by repair capability for subsea gas pipelines operated in the Gulf of Mexico by a group of gas transmission companies.

The scope of the project included the study of all mechanical repair devices and all subsea welded methods to repair lines and then recommending a system(s). The scope also included a cost analysis of the resulting program initial cost, representative operating costs and an equitable procedure for cost distribution to the participating companies. Another consideration that had to be addressed was to define the mechanics for keeping the emergency stand-by repair program in a constant state of readiness for an indefinite time period.

As noted in the above description of the study scope, the first task was to ask the interested gas transmission companies to prepare a listing of all line sizes (steel grades and wall thicknesses), pressure ratings, lengths, and method of identification (name, block number, etc.). These were then consolidated into a master sheet which served three functions. One function was to maintain records of lines dedicated to the program. The second function was to prepare specifications for the selection of repair devices; and the third function was to serve as a basis for cost distribution.

Based on the pipeline sizes submitted by each potential participant, line sizes from 6-5/8 inch through 42 inch were included.

Table 2 is a listing of various line sizes currently in the program and the miles for each line size.

Repair Method

One of the more critical tasks of the study was the selection of the repair method(s) for an emergency stand-by program. This task was divided into two considerations - to determine the surface/subsurface support equipment requirements and to select the repair devices/techniques.

It was decided that surface/subsurface support equipment should not be placed on stand-by or be a part of the program. The reasoning is that diving support vessels, divers, etc. are generally available within an acceptable time frame.

The main focus of the study was the selection of repair devices/techniques which could be placed on stand-by. Accordingly, the two basic approaches to the repair of subsea pipelines were studied in detail; the use of mechanical pipeline connectors and the application of subsea hyperbaric welding.

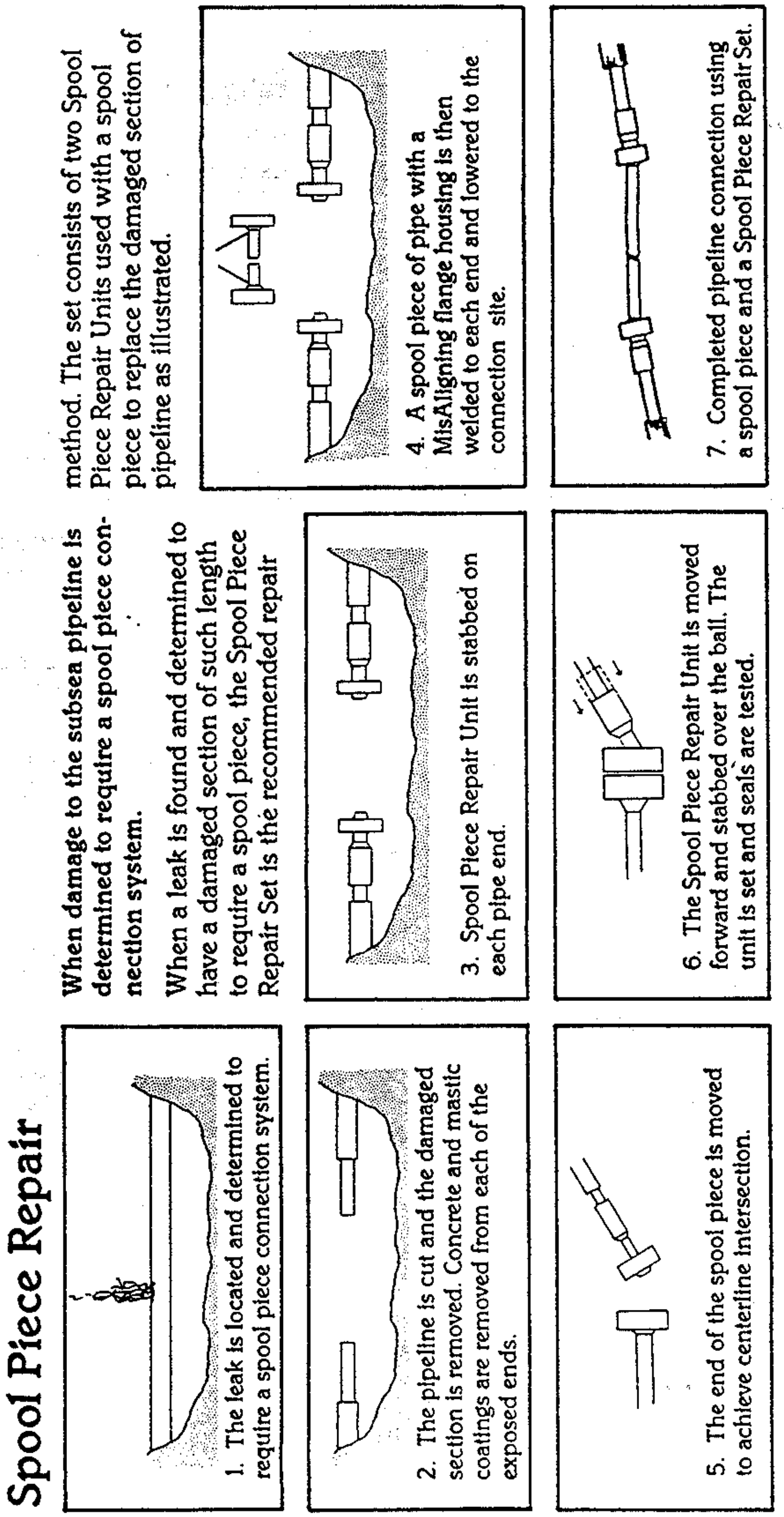
When the study was made in 1977, there were eight (8) suppliers of mechanical connectors and nine (9) suppliers/contractors for subsea hyperbaric welding for pipeline repair. Based on detailed evaluations of all repair options, it was concluded that mechanical connectors should be used rather than hyperbaric welding. The primary reason was that mechanical connectors can be stored for an indefinite time period and their installation can be performed by virtually any diving contractor in a cost effective manner.

It is important to note that the meaning of "repair" at the time of the study meant the capability to remove a damaged piece of pipe and install a spool piece. (The use of repair clamps for isolated damage was introduced later.) The basic sequences of the operation to install a spool piece are shown in Figure 1. Figure 2 illustrates a single connector and ball joint (courtesy of HydroTech Systems, Inc.).

Selection of Suppliers

The next step was the selection of suppliers and how many connectors should be placed on stand-by. The study resulted in two recommendations; to use connectors from two manufacturers and to stock three connector assemblies for each line size as shown in the configuration illustrated in Figure 2. Accordingly, connectors were supplied by Gripper, Inc. (Houston) in sizes from 6-5/8 inch through 16 inch and HydroTech (Houston) supplied connectors in sizes 20 inch through 36 inch. Three connectors for 42 inch lines were also supplied by HydroTech but were purchased outside the program by ANR Pipeline. They are stored and maintained with the entire inventory.

In studying the repair methods, it was recommended that subsea handling frames be purchased as part of the above inventory. The purpose of the handling frames was to manipulate the subsea pipelines (for alignment, etc.) and to position the connectors onto the pipeline ends. As an example, a single 36 inch connector including a ball joint (as shown in Figure 2) weighs in excess of 30,000 lbs. A single HydroTech manipulating frame as shown in Figure 3 was recommended to install connectors through 16 inch. A three member manipulating frame system as shown in Figure 4 was recommended to install connectors in sizes through 42 inch. Figure 5 shows photographs of actual frames and the initial connector inventory.



Spool Piece Repair

When damage to the subsea pipeline is determined to require a spool piece connection system.

When a leak is found and determined to have a damaged section of such length to require a spool piece, the Spool Piece Repair Set is the recommended repair method. The set consists of two Spool Piece Repair Units used with a spool piece to replace the damaged section of pipeline as illustrated.

1. The leak is located and determined to require a spool piece connection system.

2. The pipeline is cut and the damaged section is removed. Concrete and mastic coatings are removed from each of the exposed ends.

3. Spool Piece Repair Unit is stabbed on each pipe end.

4. A spool piece of pipe with a MisAligning flange housing is then welded to each end and lowered to the connection site.

5. The end of the spool piece is moved to achieve centerline intersection.

6. The Spool Piece Repair Unit is moved forward and stabbed over the ball. The unit is set and seals are tested.

7. Completed pipeline connection using a spool piece and a Spool Piece Repair Set.

Figure 1 Installation of a Spool Piece

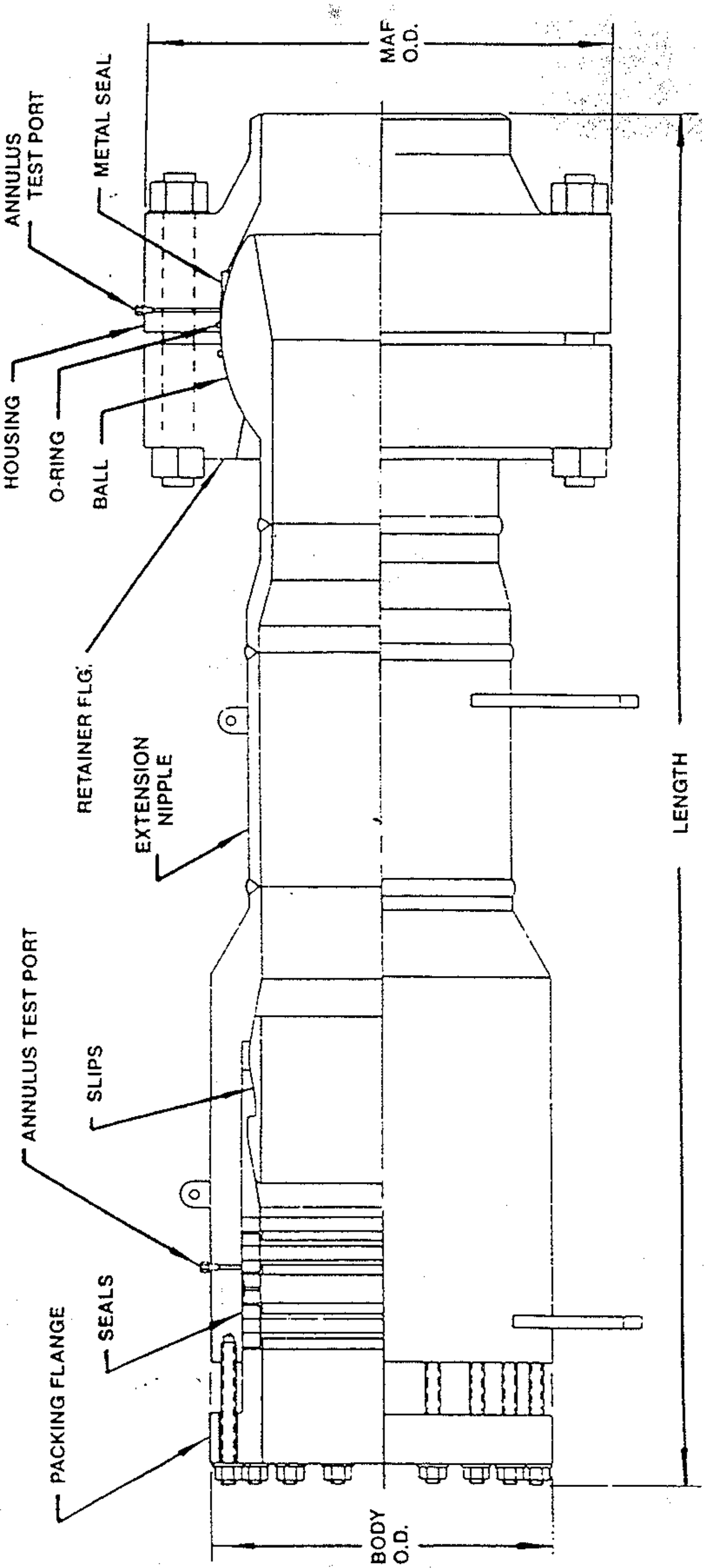
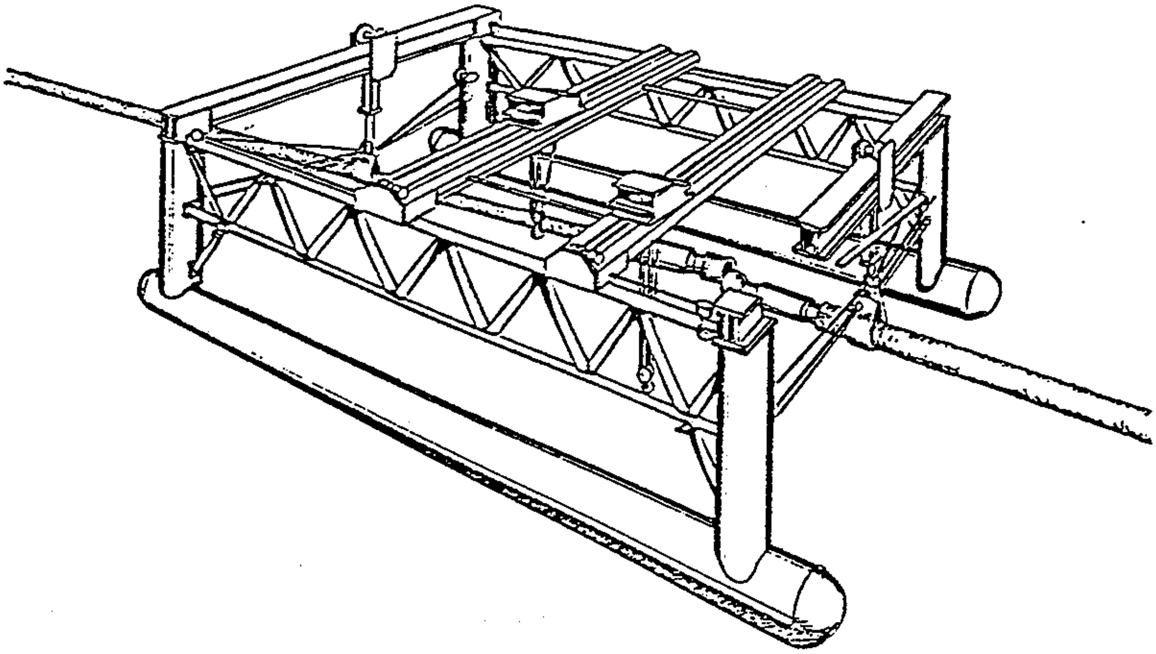
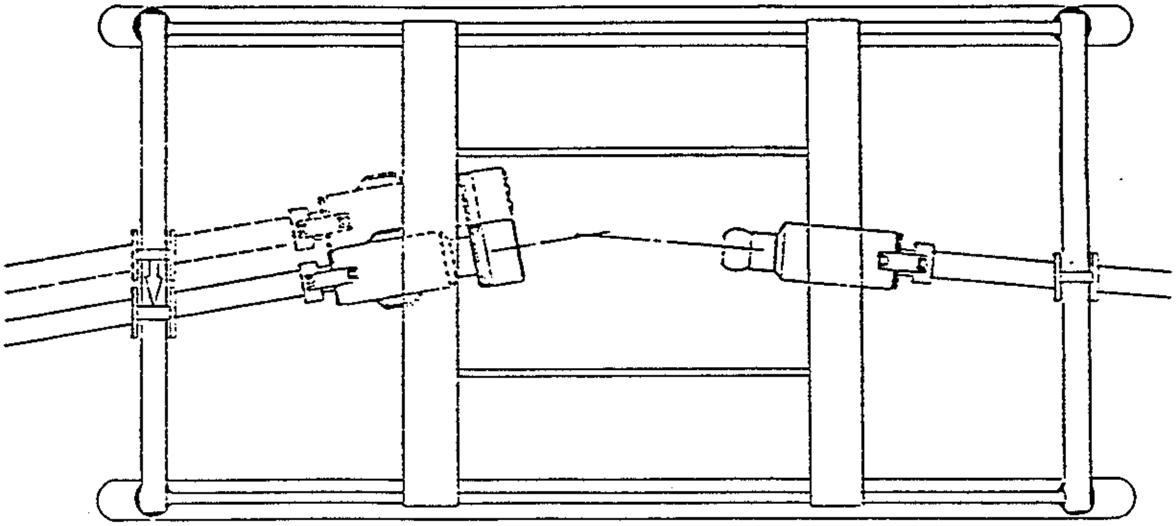


Figure 2 Configuration of Connectors





PLAN VIEW

Figure 3 Hydrotech Manipulating Frame

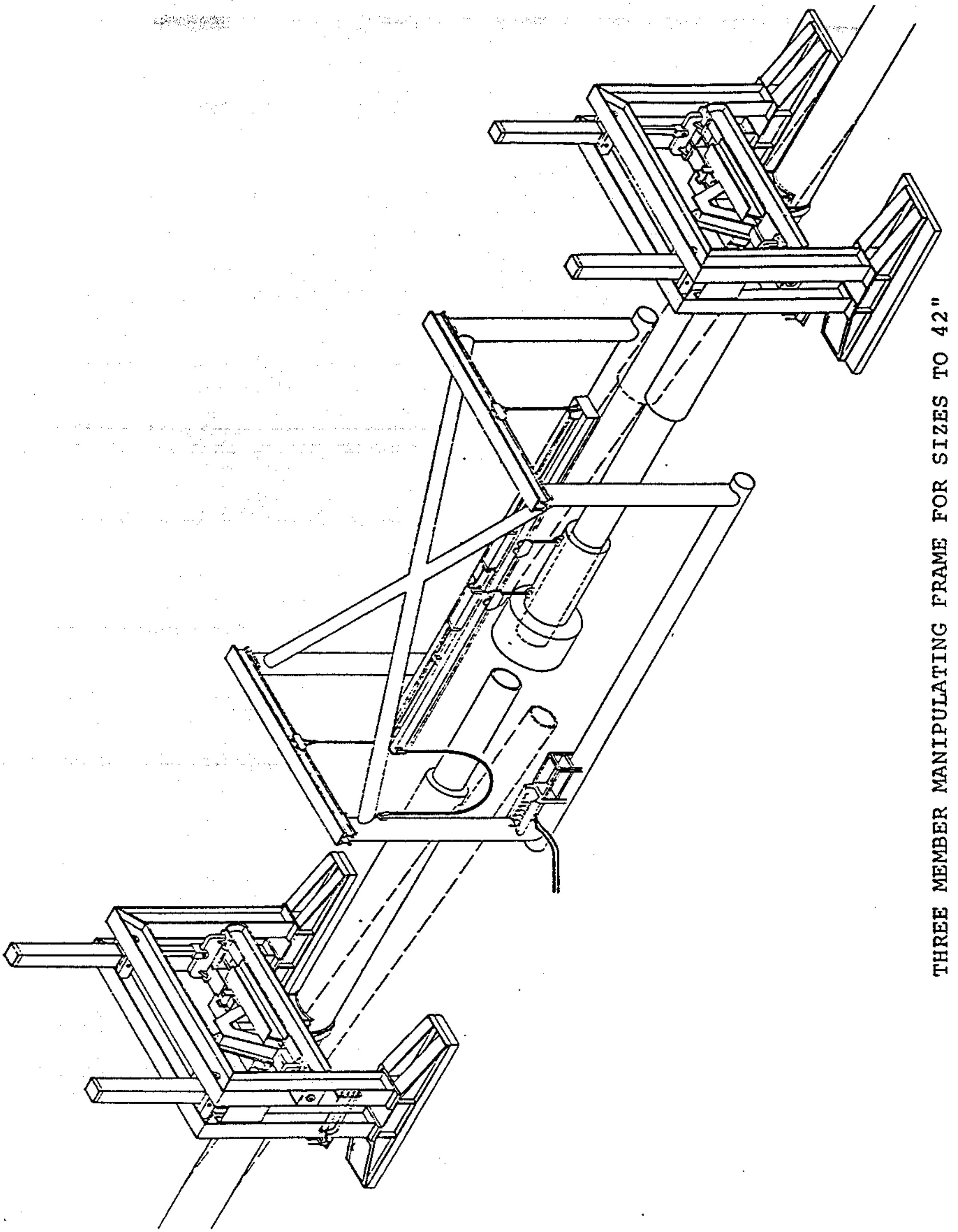


Figure 4 Three Member Manipulating Frame

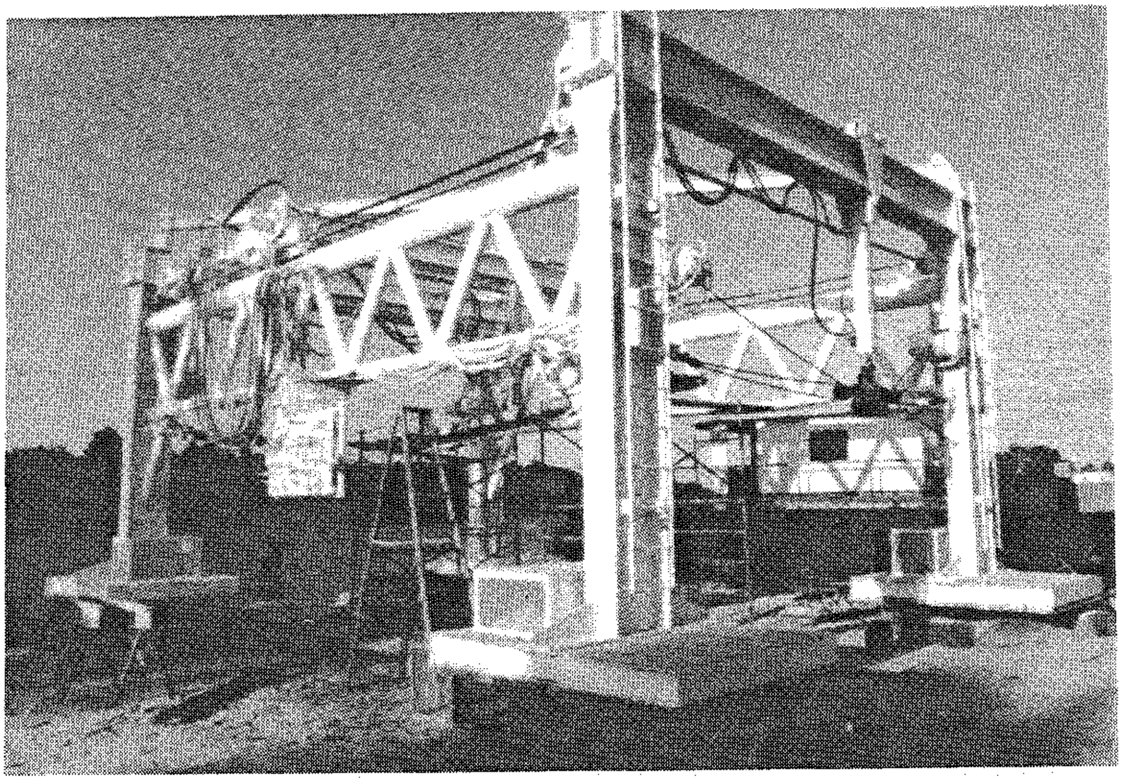


Figure 5 (a) B.M.F. (BOTTOM MANIPULATING FRAME).... Only frame required to install a 16-inch and below diameter connector. Capable of handling pipe ends and connector stabbing.

Figure 5 (b) STABBING FRAME....Designed to handle connectors up to 42-inch. Used in conjunction with "H" frames to install connectors over 16-inch in diameter

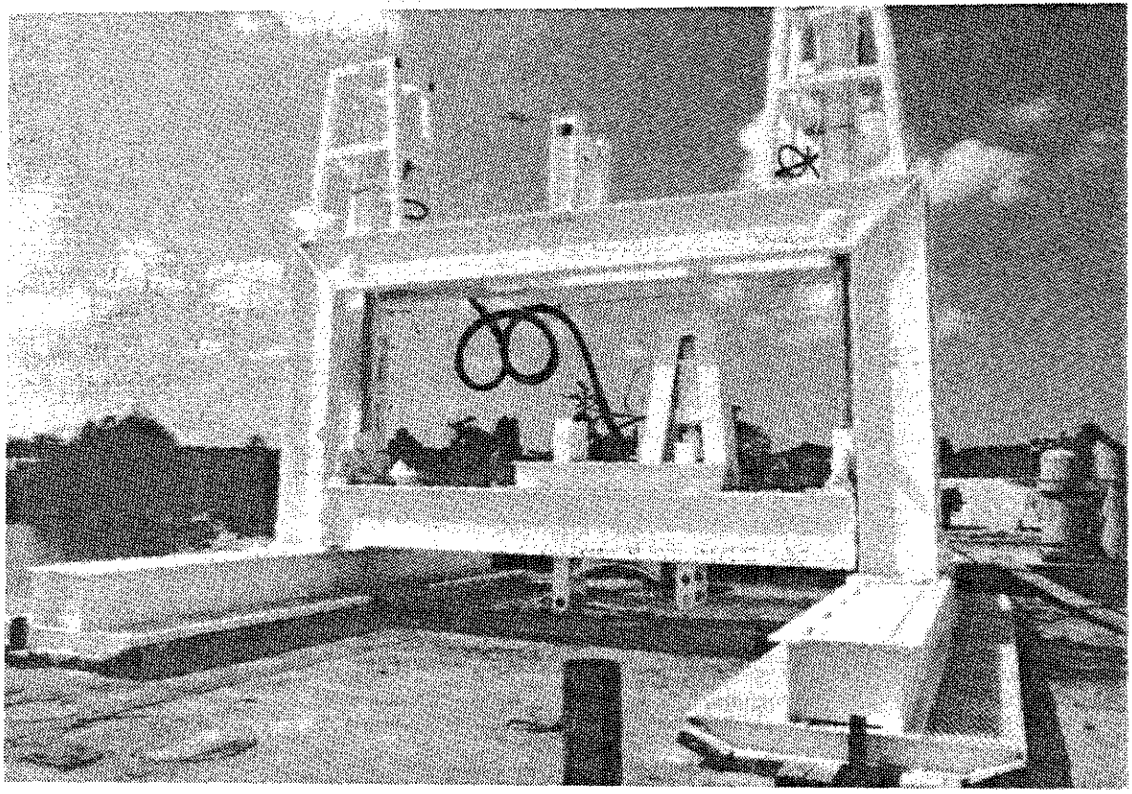


Figure 5 (c) "H" FRAME....Designed to manipulate pipes up to 42-inch in diameter. Maximum lifting load is 80 tons.

Figure 5 (d) Project Inventory of all pipeline connectors as of November 14, 1979.

Connector Storage and Manipulating Frame Storage

The study recommended that a warehouse be selected to store the connectors in Houston. The basic criteria was that the facility have proper circulation (remain reasonably dry), have minimum ozone (no electric motors, etc.) and overhead lifting capacity to 40,000 lbs.

It was recommended that the subsea manipulating frames be stored dockside somewhere along the Louisiana coast. This was necessary because the size and weight of the frames prohibited transportation along highways.

Cost Distribution

In order to properly administer the proposed program, it was important that a method be developed to divide the initial fixed costs and the variable monthly operating costs. The system must be equitable, simple, easily understood and flexible (easy to change).

The method proposed as a result of the study was a straightforward, logical system. It is illustrated by referring to Table 3 and explained as follows:

- List the fixed, stand-by equipment costs for each pipeline size. NOTE: A sample set of data has been entered into the 12-3/4" size for illustrative purposes.

- List the length of each pipeline size that each participant has. Then calculate the percentage each participant operates as shown in Table 3. If a participant does not have a particular pipe size, a zero will be shown.

- Use the group percentage figure to determine how much cost each participant should absorb for each pipeline size.

- Add the total costs of all the pipeline sizes that each participant will absorb to arrive at the total cost for each participant.

- Add the total stand-by tool costs in the program.

- By using the data from the two previous steps above, calculate the total percentage of fixed, stand-by tool costs that will be absorbed by each participant. This gives the fraction of total ownership by each participant.

The above process then establishes a percentage of participation for each company in the overall program and that percentage will be used to distribute the variable program costs, such as management fees, storage, taxes, inspection, etc.

PIPE SIZE	TOOL COSTS	PARTICIPATING COMPANIES											TOTAL MILES
		A	B	C	D	E	F	G	H	I	J	K	
6-5/8													
8-5/8													
10-3/4													
12-3/4	115,170	50 (7.9) 9,098	20 (3.3) 3,801	75 (11.9) 13,705	80 (12.7) 14,627	60 (9.5) 10,941	110(17.5) 20,155	60 (9.5) 10,941	25 (4.0) 4,607	90(14.3) 16,469	29 (4.6) 5,298	30 (4.8) 5,528	629(100)
14													
16													
18													
20													
22													
24													
26													
28													
30													
36													
42													
TOTAL	$												
% PARTICIPATION													

MILES OF 12" LINE

% OF TOTAL 12" LINES IN PROGRAM

THE COST OF THE 12" TOOLS THAT WILL BE PRORATED TO EACH COMPANY

TOTAL STAND-BY TOOL COST

TOTAL COSTS THAT WILL BE PRORATED TO EACH PARTICIPANT

% OF TOTAL STAND-BY COST OF EACH PARTICIPANT

Table 3 - Project Cost Proportioning

When the program was started, each participating company purchased (one time cost) the percentage of each tool group as a fixed asset. Then, on a monthly basis, each participant is invoiced a monthly operating fee that is prorated according to the percent participation in the program as defined on the bottom line of Table 3.

If a company withdraws a tool from inventory, then the user company must replace the tool. (The replacement process is administered by MOHR as part of the program management duties.)

Formal Organization of the Program

The study was presented to a group of 11 gas transmission executives and technical representatives during August, 1977. All recommendations were accepted and the companies agreed to organize a formal, legally binding group. Basic philosophies for the program were agreed upon.

Legal and accounting committee representatives were appointed from the participating companies to prepare the necessary contracts for the jointly owned and operated emergency stand-by repair program. This was accomplished from September, 1977 to July, 1978 and the program came into formal existence on July 1, 1978. At that time 15 gas transmission companies operating in the Gulf of Mexico elected to participate in the program. It was designated the R.U.P.E. Co-ownership Project (Response to Underwater Pipeline Emergencies). H. O. Mohr Research & Engineering, Inc. (MOHR) was contracted to administer and manager R.U.P.E.

Immediately after the R.U.P.E. Co-ownership Project was officially formed, MOHR placed orders for the connectors and handling frames. The first connectors were delivered by March, 1979, with the remaining connectors and all subsea handling frames completed by September, 1979.

The connectors and clamps were tested to 3,250 psi. Complete files and material traceability are maintained on each connector by MOHR. A formal, periodic inspection is made by MOHR and the tool manufacturer.

The connectors are stored in Houston, in a special warehouse constructed in Houston by MOHR for that purpose. The handling frames, because of their large physical size, were stored in Amelia, Louisiana.

History and Current Status of the Project

Immediately after the R.U.P.E. inventory was in storage, participants began to use the inventory. A participant, however, is not obligated to use the inventory when they experience a line failure.

During the first year of existence, R.U.P.E. proved to be so effective that at the first annual meeting in 1979 of the Executive, Technical, and Accounting Committees, the Technical Committee recommended that the inventory be expanded. This included the purchase of one additional connector for most line sizes (capability to make two spool piece repairs) and two repair clamps for most line sizes (to make isolated repairs).

Figure 6 shows a typical repair clamp. Figure 7 illustrates the basic steps to install a clamp over an isolated damage in a pipeline. Clamps are purchased from four (4) suppliers.

As stated above, R.U.P.E. currently has sufficient connectors to make two spool piece repairs for most pipe sizes. Additionally, two repair clamps are maintained for most pipe sizes. Figure 8 shows typical photographs of the range of connector sizes. Table 4 summarizes the value of the inventory maintained for each pipe size and the total value of the R.U.P.E. inventory. The value does not include the subsea manipulating frames which were disposed of during 1990.

Recent Trends

R.U.P.E. has added several new members, including one in Australia and one in Greece for a total of 17 participants at this time, which are shown in Table 5. Numerous companies have expressed an interest in joining R.U.P.E.

The annual operating budget of R.U.P.E. is approximately $200,000, including approximately $100,000 of fixed expenses such as ad valorem taxes and warehouse rental.

Based on the improvements in subsea handling equipment and availability, R.U.P.E. decided during 1990 to dispose of the subsea handling frames illustrated earlier. Another consideration was to reduce operating and maintenance costs.

Some interesting trends became evident during the 13 years of R.U.P.E.'s existence. For example, during the first 6 to 7 years of operation, numerous connectors and some clamps were used. However, during the past 3 to 4 years, virtually all inventory withdrawn has been repair clamps.

During the earlier history of R.U.P.E. there was a high level of construction activity in the Gulf of Mexico. This activity always results in mechanical damage to pipelines by work barges, etc., thereby necessitating spool piece repairs (use of connectors). After the downturn in production in 1986, numerous repair clamps were used each year. This was primarily due to reduced capacity (velocity) in the gas lines and liquids settling which caused isolated corrosion.

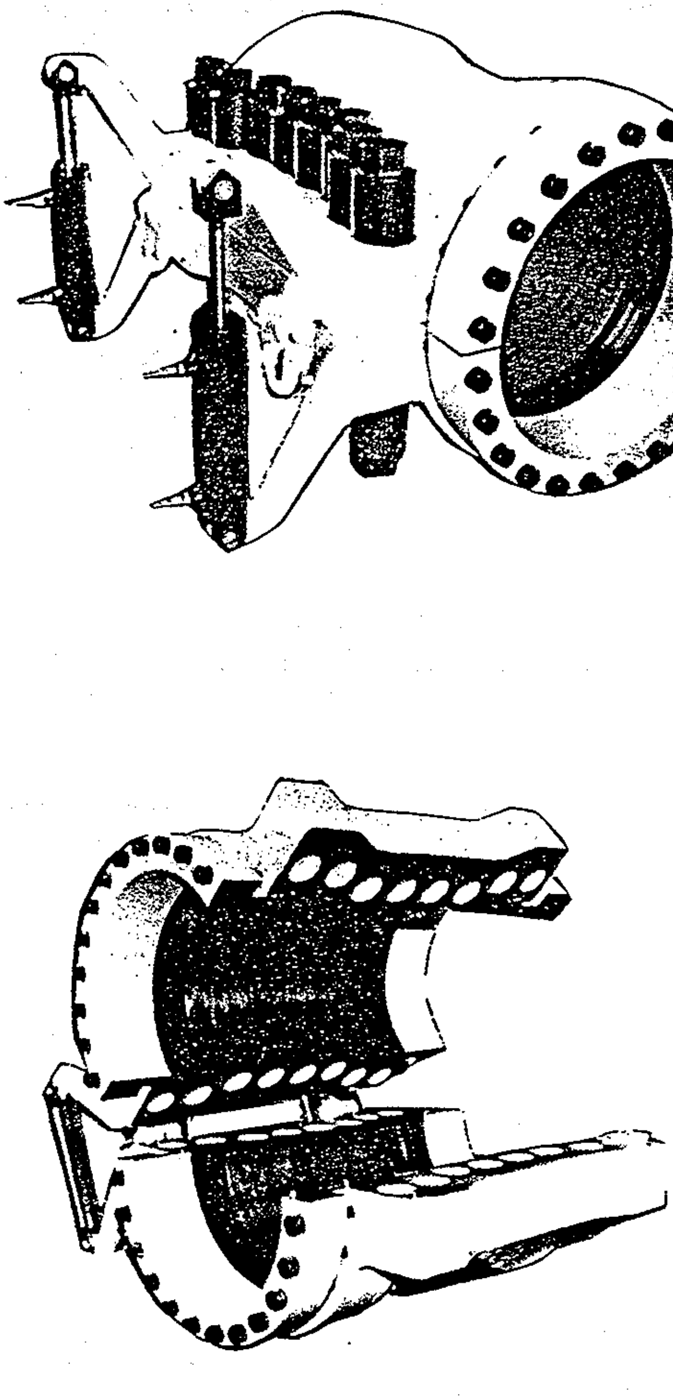
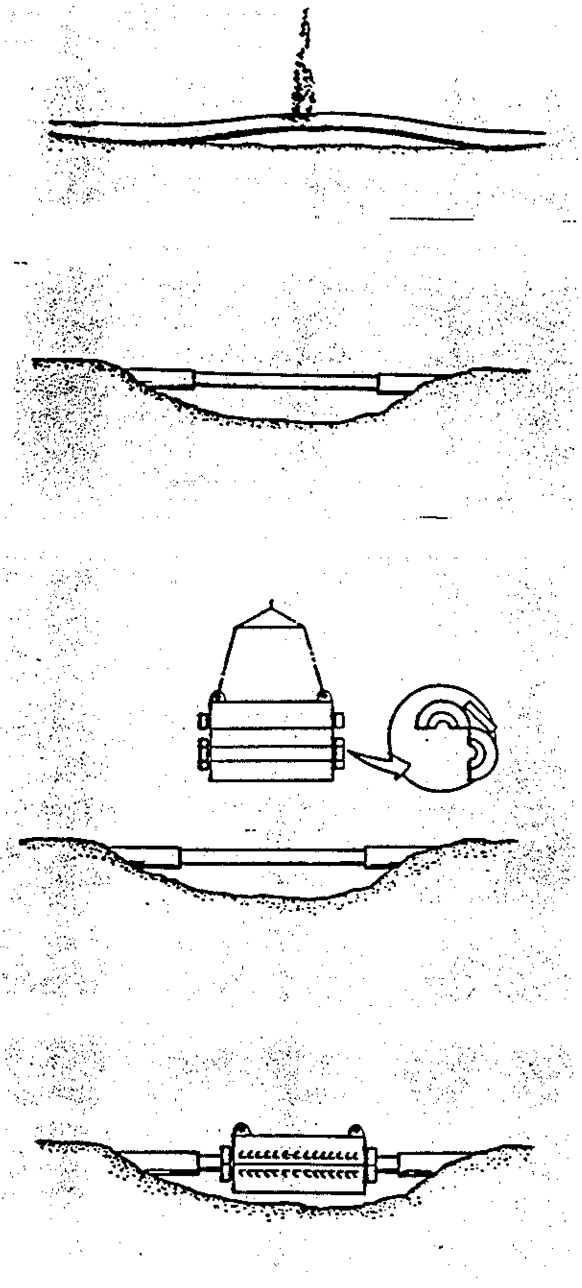


Figure 6 - Typical Repair Clamp



The leak is first located and determined to be less than one pipe diameter, and the axial strength of the pipeline has not been significantly reduced.

The area is jetted and the concrete and somastic coating are removed from the damaged section of the pipeline.

The Clamp is lowered into position and placed on the pipeline.

The Clamp is set, and the seals are tested through the annular cavity between seals if the pipeline is not punctured. When required, this annular cavity is filled with epoxy grout for additional protection and stability.

Figure 7 - Procedure to Install a Repair Clamp

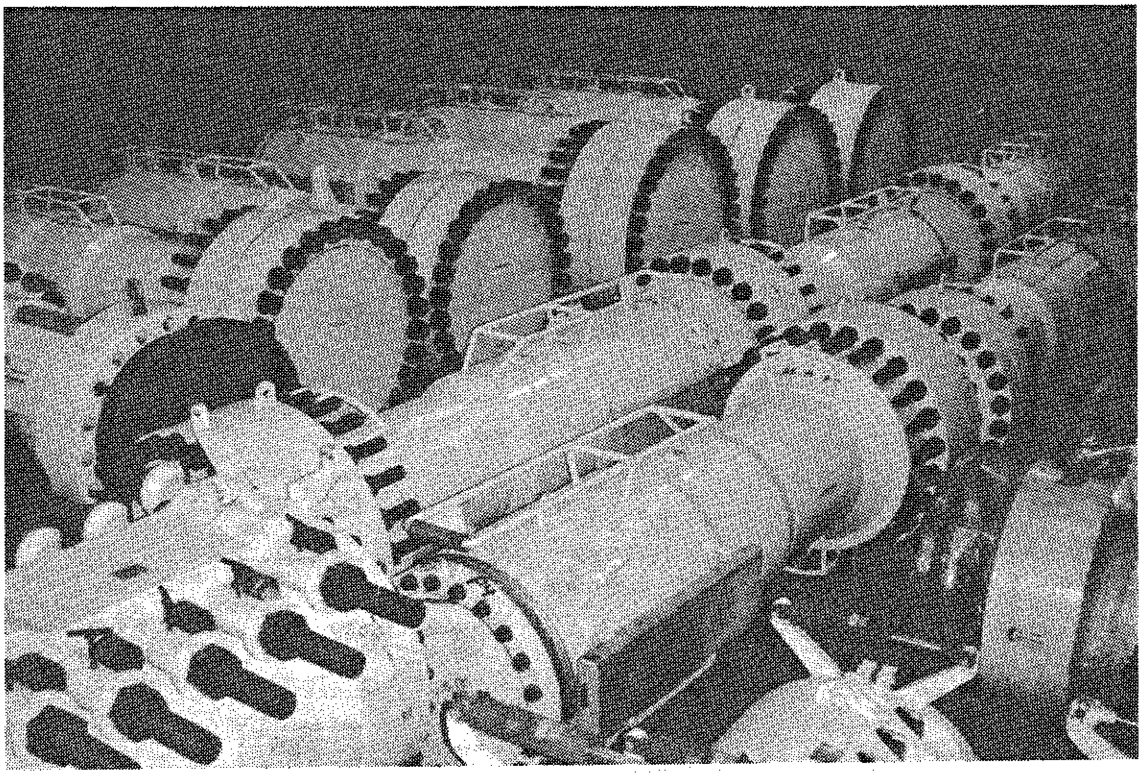


Figure 8 (a) Large Connectors and Clamps

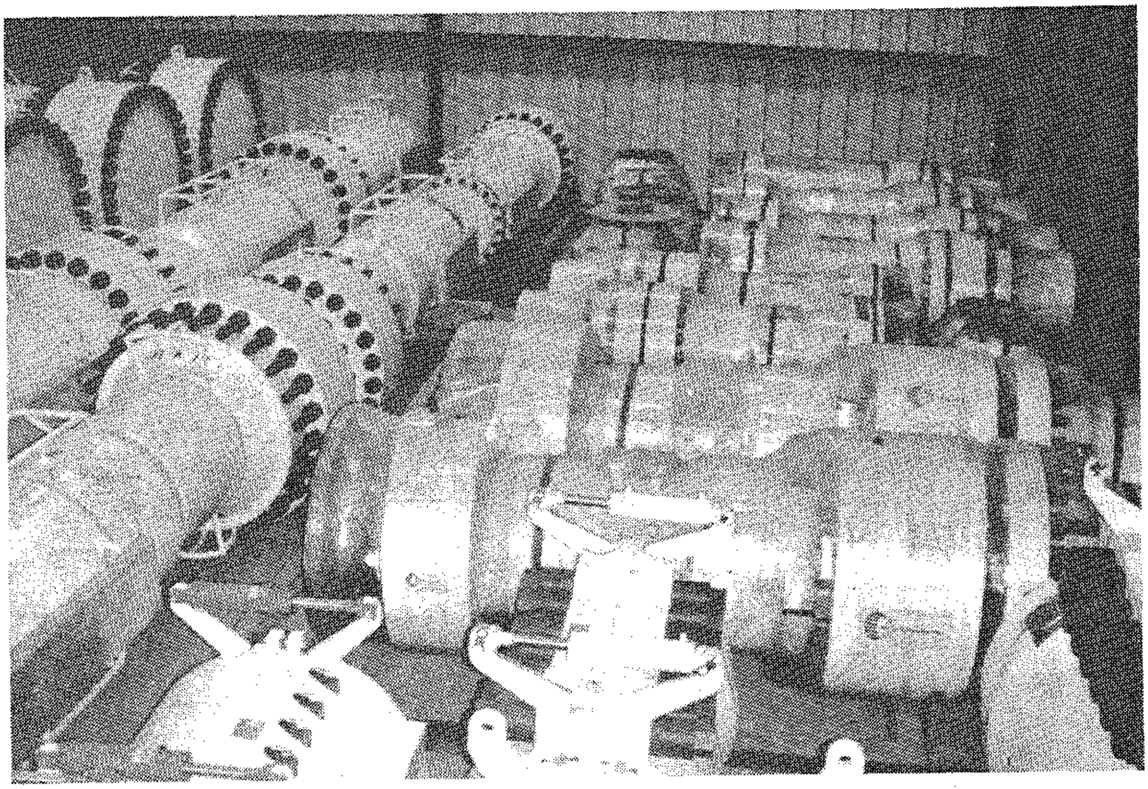


Figure 8 (b) Large Connectors and Clamps

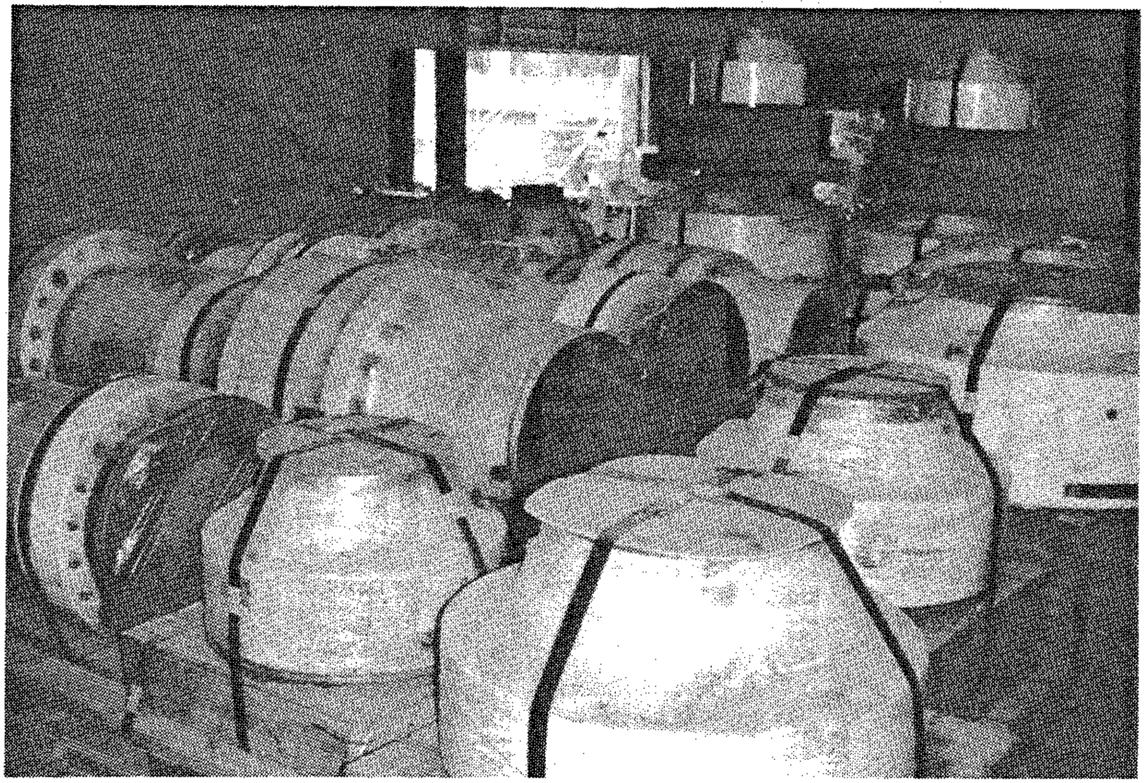


Figure 8 (c) Intermediate Size Connectors

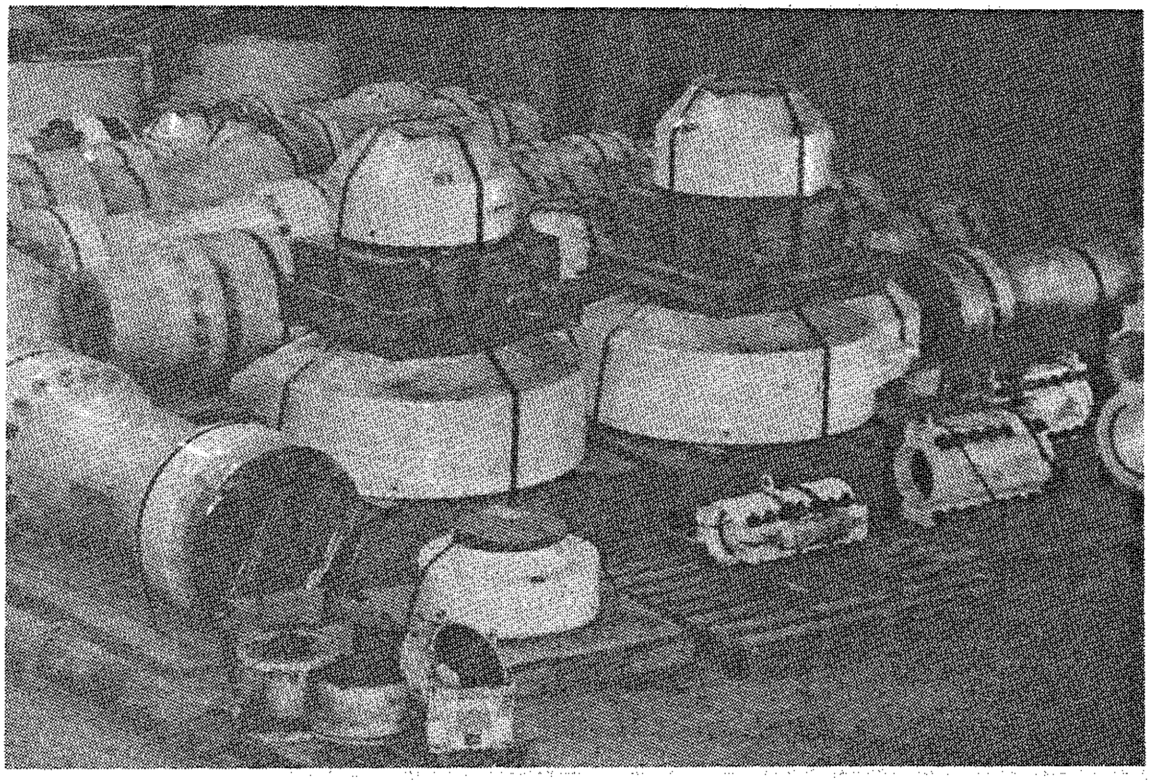


Figure 8 (d) Small Connectors and Small Clamps

TABLE 4

Table 4 - Pipeline Mileage/Dollar Amount

SIZE	MILEAGE	$ AMOUNT
6"	298.77	81,584
8"	422.69	108,410
10"	506.82	124,462
12"	910.89	220,745
14"	67.36	187,652
16"	860.66	331,165
18"	128.17	243,692
20"	819.40	456,004
24"	756.57	783,950
26"	264.03	869,018
30"	771.55	1,033,160
36"	352.80	1,004,500
	6,159.72	5,444,342

Table 5 - Participants in R.U.P.E.

ANR Pipeline
Columbia Gulf
Enron Corp.
Esso Australia
High Island
Natural Gas
North Aegean Pet.
Seagull Energy
Sea Robin
Southern Natural
Stingray Pipeline
Tennessee Gas
Texas Eastern
Texas Gas
Transco
Trunkline
United Gas

Conclusions

The R.U.P.E. program was organized in 1977 as a joint effort to make available from a common inventory, pipeline repair connectors and clamps on a 24 hour basis. A total of fifteen U.S.A. companies and two foreign companies participate in R.U.P.E. By jointly funding such a program, the ability to maintain a large inventory of repair devices is economically very attractive.

The inventory is maintained in Houston, Texas USA. The program is administered by H.O. Mohr Research & Engineering, Inc. The R.U.P.E. program remains open for participation by any operating company, worldwide, that shows financial responsibility. Fees to join R.U.P.E. depend on the size/miles of line dedicated to the program by the individual participants. So far the program has served its intended function - to provide repair devices to the participating companies on a 24 hour basis.

KEYNOTE PRESENTATION 4

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London, England

"FUTURE NEEDS FOR INTEGRITY EVALUATION"

Introduction

Pipeline operators are coming to have a heightened awareness of the need for integrity monitoring and evaluation of pipeline systems both during design and whilst in service. Several factors contribute to this trend.

The first is the growing realisation that the pipeline network is aging. In the UK sector of the North Sea, only a very few pipelines were built before 1970, but there were bursts of construction activity in the mid-1970s and early 1980s. Many of those lines will soon be 20 years old, and some operators have discovered that their condition is less than perfect, in some cases through internal corrosion and in others through damage to risers, weight coatings and anti-corrosion coatings. The costs of intervention for repair or remedial work are rising as a result of the increased level of construction activity planned for the next five years. Pipeline operators need to make informed and objective decisions concerning the condition of a pipeline, as to where intervention is required and over what timescale.

The second factor is the desire to keep pipelines operating beyond their original intended design lives which may arise for two reasons:-

- Developments in reservoir modelling and enhanced oil recovery have lead to upgrading of the reserves and extending the life of existing oilfields.
- New fields can often most economically be produced through short pipelines linking them to existing platforms, utilising trunklines to shore or storage and tanker export facilities. When tied in to fields which are nearly depleted, the new field is then the economic justification for the continued operation of the old pipeline.

If the line is to continue in service, the operator must convince himself, his partners, and the regulatory authorities that it remains in acceptable condition to continue to operate safely.

A third factor is external pressure, from national governments, local governments and environmental pressure groups. Their sensitivity is heightened by pipeline accidents, such as the tragic failures in California and the Gulf of Mexico which caused loss of life. Sensitivity is also increased by incidents such as the Prince William Sound oil spill and the Piper Alpha disaster. This is possibly unfair, since they were not pipeline failures, though in the Piper Alpha instance rupture of the pipelines leading to the platform did contribute to the severity of the fire that followed the initial explosion and loss of the platform.

The UK has fortunately been spared fatal incidents in recent years, but there is no cause to be complacent, and one accident could radically change the public perception of the pipeline industry. Awareness has already increased as a consequence of the leakage of a hot oil pipeline near Liverpool, at Bromborough in 1989, which occurred as a result of external corrosion following displacement of the external coatings. A video taken by the local fire brigade showed a fountain of oil on the foreshore, and was repeatedly broadcast on evening television; a prosecution followed. That incident is described in a Department of Energy report [1].

Finally, consciousness of the availability of sophisticated integrity monitoring and inspection systems naturally increases the market for them. Availability of a technology creates its own demand. Since the mid eighties more research has been focused upon internal inspection and corrosion detection than any other form of pipeline inspection. The result is a wider range of inspection tools and sensor technologies. Operators certainly recognise the risk of criticism if they do not apply the most modern technology that exists.

Formal safety assessment (FSA)

The approach to design and operation of offshore facilities and pipeline systems is changing in response to the recommendations made by Lord Cullen in the report on the Public Enquiry into the Piper Alpha disaster [2]. It has been proposed that prescriptive regulations should be phased out, being gradually replaced with objective goal-setting regulations. These require that the Operators demonstrate the safety of each installation and its associated pipeline systems, by preparing a Formal Safety Assessment, (FSA).

For the pipeline and riser systems a Quantitative Risk Assessment, (QRA) is carried out for use in the FSA. The evaluation examines the hazards to, and consequences of, pipeline failure as an integral part of the design process covering the following areas:-

- Overpressure from facilities
- Internal corrosion
- Ship collision with risers
- Dropped Object and trawl-board impact
- Analysis of potential hydrocarbon release

It is planned that the assessments are carried out in two stages - on completion of conceptual engineering; and following detailed design, several months prior to start-up. This will include proposals for extending the service life or alternative use of pipelines.

Once accepted by the Health and Safety Executive (HSE) it is planned that the safety case will be a "living document that can form the basis of a more telling system of inspection, including periodic major audits". [3] There is currently no standard or procedure for the preparation of safety assessments, other than that proposed by the UK Offshore Operators Association, (UKOOA). [2] The approach is intended to set targets for safety and reliability, and will encourage innovation and the application of new technology. The industry will have to be prepared to respond to this requirement which will require a more rigorous and consistent approach to integrity evaluation than has been prevalent up to now.

Integrity evaluation

More stringent requirements for safety assessment will place emphasis upon means of monitoring and evaluating the performance of the system as a whole. Assessment will be continued throughout the life of the system using a planned inspection programme, which may be optimised reflecting the results of previous surveys.

To determine the condition and make an assessment of the integrity of a line in service requires examination of a number of factors:-

- the design criteria and methods used
- as-built material and construction records
- remaining wall and localised corrosion damage
- pipeline geometry, denting and bending
- external coatings and CP system performance
- pipeline support, cover and stability
- on-line integrity monitoring systems

Each of these factors cannot be reviewed in isolation since their combined effect may influence the integrity of the system. Experience from the Russian pipeline network, for example, indicates that the combination of stress and corrosion defects has been the cause of failure in the majority of cases [5].

Currently there is no single internal or external inspection device which can acquire all of the data required to carry out such an assessment. It should also be noted that the quantity of data is substantial and the application of probabalistic methods requires advanced computation. Computerised pipeline management systems have been developed but these are generally specific to a particular manufacturer and inspection technique. A future requirement is a system which will integrate inspection data from a number of sources allowing an overall analytical assessment.

Leak Detection and monitoring of flow conditions

For most pipelines the primary means of on-line integrity monitoring is based upon flow measurement, i.e. comparing the measured flow at either end of the pipeline. The integration of the Pipeline Integrity Monitoring System, (PIMS) with the emergency shut-down system requires accuracy and speed of detection to ensure isolation and containment. This method obviously detects massive leaks, and these can generally be located by observations from ships and helicopters. For small leaks, the detection of very small differences between large quantities is inevitably difficult. Even if the accuracy could be pushed to 0.1 per cent, this still represents 300 bopd in a 300 mbopd oil pipeline. The location of leaks is also problematic, particularly in gas pipelines where it is not currently possible.

There is therefore a need to detect and locate leaks directly. Acoustic methods are promising, above all for gas pipelines, where even a very small high-pressure gas leak is an efficient generator of sound. The sound is transmitted through the pipe wall and efficiently radiated into the water. It can be detected and analysed by accelerometers attached to the outside of the pipeline (in routine monitoring) or by towed arrays of hydrophones in acoustic surveys.

The increased transportation of unprocessed reservoir fluid in two-phase flow is another area where acoustic methods are also extremely promising for flow monitoring. This is important where the operator needs to be informed of changes in flow conditions such as the approach of slugs, retrograde condensation, or the onset of hydrate formation. Many modes of two-phase flow generate sound through the radial oscillations of bubbles as they respond to pressure changes, and calculations show that the sound is between 1 and 10 kHz, in the audible range. This could be monitored using microphones attached to the pipeline risers.

Corrosion Problems

Corrosion damage has been observed in a number of lines during routine inspection and, excluding external influence, is the most common cause of failure . Corrosion has been responsible for 42% of the reported pipeline failures involving leakage, in the Gulf of Mexico [5], and 20% of those in the North Sea [4]. Among published examples are internal corrosion damage to the first Forties pipeline, and external corrosion in the Alaska Pipeline and in the Bromborough incident described above. Corrosion damage is probably present and as yet unrecognised in many other lines.

Internal Corrosion

Advanced internal corrosion is commonly linked to a change in the pipeline operating conditions. The following changes may lead to accelerated corrosion and compromise the integrity of the line:-

- The tie-in of new facilities to existing pipelines can significantly increase the risk of corrosion due to higher levels of acid gas, CO_2 and H_2S, which were not taken into account in the original design or material specification.
- In waterflood reservoirs, during the later years of production, microbial action can lead to souring of the produced fluids. Souring can cause cracking of piping and components, particularly at high temperatures, and is difficult to inhibit and monitor.
- The operating temperatures of production flowlines will tend to rise with increasing water-cut which can lead to accelerated corrosion.

The change in composition or temperature can alter or remove protective layers of corrosion product which have built up on the pipe surface, leading to an increase in the corrosion rate. When considering a change in service, several operators have found that the material of existing pipe is unsuitable for its intended future service and have been forced to down-rate the system or pursue alternative means of transportation.

As future lines are required to operate at temperatures of 80 degrees C (180 degrees F) and beyond, there is greater uncertainty over material performance and hence the integrity of the line. The use of empirical formulae used to estimate corrosion rates at elevated temperatures has been the subject of much debate. Several operators have adopted CRA or clad linepipe while others have opted for heavy wall, intensive inhibition and advanced monitoring systems such as the use of Thin Layer Activation corrosion probes.

External Corrosion

External corrosion reflects the combined breakdown of the pipeline external coating and the cathodic protection system in response to chemical and biological effects, and to soil stress. The evaluation of the condition of the coating and CP system is integral to a pipeline condition assessment. Experience from lines operating in the North Sea has lead to an evaluation of existing coating systems and cathodic protection design criteria.

Both protection potential and current density requirements are now more stringent than when many pipelines were originally installed. Due to degradation of the coatings or depletion of the CP system several operators have undertaken costly intervention to install remote anode sleds allowing extended pipeline operation.

As with internal corrosion, operation of pipelines at high temperatures places demands upon the coating and CP system:-

- a recent paper points out that the service we expect from a pipeline coating is equivalent to cooking it in a pressure cooker for thirty years. Currently available coatings are limited to a maximum temperature of 120 degrees C.
- for buried flowlines, where the anodes are expected to operate at similar temperatures to the line, a reliable cathodic protection is not available. Zinc anodes suffer intergranular corrosion above 50 degrees C, while aluminum alloys tend to passivate above 80 degrees C.

Operation of pipelines at high temperatures will require the development of new pipeline coatings and means of providing cathodic protection. Due to the perceived uncertainty with these systems, a higher level of inspection and monitoring will be required.

Corrosion Inspection

Integrity monitoring needs to detect many kinds of corrosion damage, among them general loss of wall thickness, general or localised corrosion at low points (often associated with water), generalised pitting, and localised pitting, particularly at bends and valves. Ideally corrosion monitoring ought to be part of the initial design of the pipeline, so that the broad picture given by corrosion monitoring can be combined with the detailed information given by local corrosion measurements, intelligent pig runs, external CP readings and by geometry surveys.

Since the mid eighties more research has been focused upon internal inspection and corrosion detection than any other form of pipeline inspection. The result is a wider range of inspection tools and sensor technologies. A clear requirement for the future is a means of handling the large quantities of data and evaluating the results of inspection surveys.

External damage

After corrosion, external damage is the greatest potential hazard to offshore pipelines. Some damage has an immediate effect such as impact on marine pipelines by vessels, anchors and trawl-gear. Monitoring of the pipeline itself cannot do anything to eliminate severe incidents of this kind, which reflect the pipeline's external environment. However in the case of the line struck by a fishing boat in the Gulf, mentioned previously, external survey might have revealed the exposure of the line.

This too is a potential application for technology, which might replace the present crude and expensive external surveys by towed fish or ROVs. For example, it is certainly possible to imagine a pipeline which would detect interference from a dragging anchor in the platform safety zone and could alert an operator, or trigger a warning device, before severe damage or rupture occurs.

Some kinds of external damage do not produce immediate catastrophic consequences, but lead to trouble later. Dents alone do not substantially reduce the strength of a pipeline, but dents combined with gouges or corrosion defects are much more serious. The dent flexes in response to pressure fluctuations, and alternating bending stresses lead to rapid extension of any cracks present at the gouge root.

Detection of dents by intelligent pigs is already routine, and is linked with wall-thickness measurements that can pick up gross gouging, but the combination with detection of cracks is harder to achieve particularly if they are oriented in the longitudinal axis of the line.

Sediment transport, scour and pipeline spans

A marine pipeline may be exposed to the effect of large changes in seabed level produced by sediment transport: for instance, a pipeline can be half-buried before a storm, and after the storm it may be completely exposed. These changes are important because they determine the future stability of the line and its response to later storms, and because they may expose it to other kinds of damage. Part of integrity evaluation is to determine how the changes are occurring, and if they represent random changes in response to storms or a continuing progressive deterioration in stability.

As a result of general sediment transport or localised seabed scour, pipeline spans may develop. Spans in marine pipelines may be a threat to safe operation, because of fatigue damage induced by vortex-excited oscillations, because of overstress, and because of the risk of hooking by fishing trawls. These are real possibilities, although the severity of the problem has often been exaggerated. Under North Sea conditions, some recent work suggests that hooking is unlikely and that overstress cannot lead to a limit state condition.

Vortex-induced fatigue is possible, at least in shallow areas where wave-induced seabed velocities play a part in exciting oscillations, and the limiting acceptable length can be determined by a straightforward fatigue calculation. In other geographical areas where the seabed bottom topography is much rougher, however, much longer spans can occur, and may be accompanied by various kinds of oscillation and by severe bending at the ends.

This indicates that the monitoring requirement is for the detection and measurement of spans, coupled if possible with a direct measurement of natural frequency. Trials have shown that it is practicable to measure the natural frequencies of spans in submarine pipelines, by attaching accelerometers and carrying out spectral analysis of the movements. The accelerometers in the trials were externally attached using an ROV. The measured natural frequencies were significantly lower that those predicted theoretically, indicating longer span lengths may be allowable.

Conclusions

Aging of the existing pipeline network and the desire to extend service lives or re-use lines will require an operator to ensure that they remain in an acceptable condition to operate safely. The design and operation of pipelines in the future is going to be regulated by more stringent legislation. This will require the use of new materials, better inspection tools and more rigorous methods of integrity evaluation.

Apart from the obvious incentives, in the case of the extended service of existing pipelines, there are economic benefits for future developments in terms of:

- increased availability of the system;
- planned and optimized inspection and maintenance;

- minimising the requirement for emergency intervention for remedial works or repair;

- the industry being perceived as a safe "environmentally acceptable" energy source.

Finally, during the short history of the industry, it has shown its ability to adapt to change, for example developments in deep water and harsh environments. The technology to improve reliability and safety is either available or being developed, and will certainly be employed in the near future given the benefits which they accrue.

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WORKING GROUP REPORT 1

- *Design and installation issues for integrity*
  Dave McKeehan, Intec, Houston
  Stelios Kyriakides, University of Texas at Austin

Introduction

This report reflects the discussion among representatives and specialists in the offshore pipeline industry on the subject of pipeline design and installation. The focus is on aspects related to safety and performance.

The number of participants varied during the two-day session, but was typically 20 to 25. The composition of the working group was as follows:

50%	Oil/gas offshore operating companies or their affiliates
20%	Engineering
15%	Regulatory
10%	Independent consultants
5%	Academic

Preamble

Safety engineering as part of pipeline design and installation is a serial process: each step of the development is advanced to the level of quality necessary to provide a secure foundation for the next step. For example, poor choice of material may impose design penalties which result in a buckling failure during installation even if installation procedures are carefully planned.

Recognizing the traditional sequence of activities which take place during a pipeline project, the discussion explored six topics in sequence, each with a discussion leader:

- Design Criteria (D.S. McKeehan)
- Codes and Design Practice (H.M. Wilkinson)
- Line Pipe Materials (R.A. Teale)
- Spanning and Stabilization (P.K. Shaw)
- Installation (S. Kyriakides)
- Protection and Trenching (W.R. Mahone)

The format for each discussion included a 10-minute opening remark by the designated lead member of the six-person panel, followed by an hour discussion among the members of the workshop. Although consensus was not always achieved, the points discussed were noted and formed the basis of this summary report. The workshop results comprise a blend of viewpoints.

Design Criteria

At the start of an offshore pipeline project, relevant environmental and operational data are assembled to provide a basis for the design criteria.

The discussion topics selected by the panel included:

- Route Survey Requirements
- Data Sources
  - Bottom Current Data
  - Bathymetry and Seabed Morphology

Raw data are the framework for establishing appropriate design criteria. Quite often, surface data, which are easier to obtain than bottom currents or seabed morphology, are used to estimate bottom conditions. For example, wind and wave induced current models are frequently applied to estimate bottom currents. While this is a useful technique, the working group notes that bottom current magnitude has a significant impact on stability requirements, particularly in deep water where wave induced velocities have minor impact. Much of the bottom current data are in proprietary archives and are not readily accessible for design.

For hydrodynamic stability design, particularly in deep water, the availability of such data would be beneficial in defining necessary stabilization. The working group recommends that an industry-wide data base of current data be set up in a format similar to that of the presently available Synoptic Summary of Marine Observations (SSMO) which provides surface wind and wave information.

In addition to operating companies, oceanographic research organizations such as Texas A&M University and the University of Miami who have data from long-term moorings in the Gulf of Mexico should be invited to contribute in either a raw data, processed data or manuscript form. The data base should be sponsored by a regulatory agency such as the MMS and limited to data obtained by conventional oceanographic instrumentation such as Savonius rotor or Vector averaging current meters. Quality control and maintenance of the data base would be performed by the sponsor.

Current Industry Practice and Design Codes

Discussion during this session reflected the following areas:

- Use of strain instead of stress criteria in certain conditions
- Riser hoop stress criteria
- Breakaway joints
- Use of pneumatic (air or nitrogen) testing in place of hydrostatic testing

Stress Versus Strain Criteria

The use of strain criteria reflects engineering recognition of limit state theory. In practical application, the use of limit state criteria requires the pipeline to perform satisfactorily under all potential exposure conditions. For example, in deep water, the ability to resist collapse depends on factors poorly related to stress, but highly correlated to ovality and strain. The strain environment is less defined in terms of allowable values and requires specific information on pipe properties. These are generally unavailable to the designer until after material procurement and testing.

The ability of a pipe to resist burst is determined by yield strength, ultimate tensile strength, and the nature of the stress-strain curve. As a convenient device, hoop stress as calculated by Barlow's Formula, is traditionally used to prove internal pressure capacity. While this works effectively for conventional material and pipe properties, the simplified hoop stress value is not representative of the true failure mode of burst.

Longitudinal Stresses

Longitudinal stresses are covered in the governing codes; however, using "stress" as the only controlling criteria unnecessarily restricts the designer in the construction, operation and maintenance of pipelines. The acceptance and use of "strain" limits, when the consequences of such yielding are not detrimental to pipeline safety and operation, gives an opportunity for the designer and installer to provide more economic, yet safe, pipelines.

On a number of occasions, the operating pressure of a present-day pipeline has had to be reduced, with consequent loss of throughput, to satisfy a condition where "longitudinal stress calculations indicated the line would be overstressed", i.e., exceed 80 percent of theoretical yield, when, in reality, there was absolutely no danger of failure due to the limiting nature of the configuration. A pipeline experiencing high longitudinal stress due to bending can safely be operated at normal operating pressures when further bending is limited and noncyclic in nature.

This condition is referred to as being "displacement controlled bending as contrasted with load controlled" in Ref. 1. "Load controlled" is experienced in low tension suspended spans, but even there displacement control may become the controlling factor as the sagbend picks up additional supports.

Restrained Versus Unrestrained Piping

An adequately restrained pipeline, experiencing an operating pressure causing the combined stresses to exceed the presently recognized "stress" limits, will simply "yield" to an extent that the longitudinal stresses are relieved - the same result as making a standard field bend. When the supports are such that further displacement cannot occur in the same plane, there are no adverse effects of such yielding as long as the bending is within the capabilities of the pipeline welds and there is insufficient external pressure to cause pipe collapse.

Influence of Permanent Bending Stress on Burst Pressure

Extensive burst testing, performed at Shell's Westhollow Research Center as well as other sites, shows no correlation to pipe bending. Rupture occurs as often outside the bend-affected area as it does within that area.

Displacement Controlled Riser Design

Two existing displacement controlled methods of riser installation utilize the principles noted above. The J-tube method, extensively employed, and the "bending shoe" method, used sparingly, both rely on the "alternative strain limit" theory of design. The combined stress, as defined in present-day literature, is considerably exceeded, but further displacement of the pipe in the bending plane is limited by the configuration of the supports and no adverse effects are experienced.

The working group discussed these aspects in context with the present ANSI/ASME B31.8 piping code. It was concluded that the present wording opens the opportunity to use strain criteria, but could be extended to include specific strain limits. This would primarily apply to those conditions in which the pipe was either bent during installation or installed in a state of residual bending stress.

The benefit of using strain criteria over stress criteria is that a more accurate picture of the risk of failure and accordingly a safer pipe design is achievable. The disadvantage is that more pipe-specific data are needed and a number of load conditions must be evaluated by sophisticated methods such as finite element analysis or laboratory tests. An area where this methodology will have direct impact is tie-ins by lateral deflection which leave residual bending stress in the pipe. Recognition of the lack of effect of bending stress on burst capacity would potentially simplify the tie-in requirements since this is a displacement controlled geometry.

Riser Hoop Stress

For large diameter risers, the working group recommended a design factor of 0.6 x SMYS for hoop stress instead of 0.5 x SMYS. The rationale is that wall thicknesses exceeding one inch are difficult to weld and their use may be uneconomical and may introduce failure mechanisms related to weld geometry and metallurgy.

Break-away Joints

The working group addressed the extent of use of break-away joints, or load limiting devices at platforms. The consensus was that the practice was limited to areas where known risks exist. Such risks did not necessarily include anchor damage, but were associated with mud slides or natural occurrences of pipeline movement.

Use of Pneumatic Testing

The working group noted that air or nitrogen is presently authorized only for Arctic pipelines because of the risk of freezing. However, this testing method is practiced in Brazil and has proven useful in gas laterals where pigging is impractical. In deep water, pigging poses potential procedural difficulties particularly if a diverless tie-in is employed. In these circumstances, the extension of the present codes to permit greater latitude in pneumatic testing would reduce some of the complexity associated with present hydrostatic testing of gas lines. Because of compressibility, the procedure must allow adequate time for obtaining pressure and temperature data to correct the internal pressure.

Line Pipe and Materials Performance

To date, many hundreds of thousands of miles of submarine pipelines have been installed, with most of the early installations being in the Gulf of Mexico. Despite the lack of sophisticated testing methods and expertise in materials engineering available then, the designers of early pipelines can take credit in the fact that there have been very few in-service failures even though many of these lines are over 20 years old and well past the original design life. However, failures do occur: in 1989, the US Department of Transportation reported that Natural Gas Transmission and Gathering Pipelines incidents resulted in 22 deaths and property damage of over $20,000,000. One of the largest spills was in Texas when an ERW land pipeline made in 1947 split at the seam; and possibly the most spectacular and deadly failure was when the fishing vessel Northumberland hit a 16-inch OD offshore pipeline near Sabine Pass.

Discussion during the session addressed:

- Yield and tensile stress
- Materials availability
- Weldability
- QA/QC
- Material toughness
- Resistance to sulfide stress cracking

Yield and Tensile Stress

Line pipe materials having yield stresses in the range of 70 to 80 ksi are becoming available. While this trend has benefits in material savings, the group discussed several design-related aspects of these higher grade materials.

The development of high strength, high toughness line pipe steels in the X-65, X-70 and X-80 grades is of interest because the technology used to increase strength and toughness also increases the yield/tensile (Y/T) ratio. There is concern that the use of steels having high Y/T ratios might result in unanticipated safety risks resulting from a reduction in toughness and ductility at high strain rates. API 5L requires a maximum Y/T ratio of 0.85, except for X-65 over 0.375-inch wall thickness when 0.90 is allowed and 0.93 for X-80 grade material.

The designer must allow for the impact of these higher ratios in the analysis of burst and, to some extent, in the analysis of post-buckling behavior. Maintaining the hoop stress criteria as 72 percent of yield will result in lower safety factors on burst for materials with higher Y/T ratios. This implies that higher grades may be under designed in terms of the ratio of operating pressure to burst pressure. Accordingly, procedures which account for this variation are warranted for the higher strength materials. This recommendation is consistent with the remarks of several attendees who proposed greater emphasis on limit state analysis.

Materials Availability

Pipe material in API grades B to X-70 is readily available from US or Canadian pipe mills, manufactured by either seamless, ERW or submerged arc welded processes. The overall quality properties and weldability of these materials is also more than adequate for most pipeline design requirements. However, none of the North American pipe mills have the capability of producing high strength TMCP steels, which have now become the standard material of use in the North Sea pipelines.

High strength X-80 pipe material is currently being offered by some US pipe mills and by most of the European and Japanese mills. Test data would indicate that X-80 pipe material can be used for offshore pipelines to reduce material and installation costs, but that automatic GMAW welding must be specified and the service product needs to be sweet, as heat affected zone hardness below 250 Hv cannot be produced in X-80.

In addition to higher strength materials, electric resistance welded (ERW) and spiral welded pipe are being used, provided proper consideration is given for QA/QC. A recent example of 10.75 x .409 inch ERW pipe installed by the reel method in Vancouver was cited (Ref. 3).

Weldability

The principal aspects of weldability in pipeline steels is control of the following considerations, which are discussed in the next three sub-sections:

- Heat affected zone hardness
- Hydrogen induced cold cracking
- Arc/weld pool stability

Heat Affected Zone Hardness

With conventional pipeline steels, the reduction of hardness levels to below 250 Hv to avoid SSC is possible even when using low heat-input automatic welding procedures, provided the chemistry is tightly controlled and the carbon level kept low. When low hardness levels are required, it is essential to keep the pipe material PCM value below 1.6 and the carbon equivalent (CE) value below 0.38, for automatic welding.

Manual stick welding can produce heat affected zone hardness values of 250 Hv, with higher PCM/CE values, but the pipe material composition is the most significant factor in controlling heat affected zone hardness. The TMCP type steels are excellent in producing low heat affected zone hardness and should be specified if HAZ hardness is of concern.

Hydrogen Induced Cold Cracking

Hydrogen cracking associated with cellulosic pipeline welding electrodes in the 1950s and 1960s is not a problem with modern pipeline steels until the pipe grade exceeds X-65. Although there is ample hydrogen, the nonstructure of modern pipeline materials is not normally susceptible to this form of cracking. However, with X-70, cracking can be a problem and with X-80 it is almost assured. Pipelines made of X-70 or X-80 grade need to be welded using a low hydrogen process, if the risk from hydrogen cracking is to be eliminated.

Arc Weld/Pool Stability

It has now been established that when calcium or other rare earth elements are added to a steel to provide sulfide shape control, they can have an adverse effect on welding by altering the short arc transfer frequency. With calcium contents exceeding 40 PPM, weldability trials need to be performed if automatic GMAW is to be used.

Magnetism will also disturb arc/weld pool stability, especially when manual stick welding is being used. Modern steels appear to be more prone to magnetism and arc blow, possibly due to their cleanliness, so pipe ends need to be checked to ensure any residual magnetism is less than 20 gauss. This is particularly true for high nickel alloys.

On major pipeline projects, weldability tests need to be performed on a typical sample of the pipe to be welded. These tests need to be carried out by a contractor (rather than the pipe mill) utilizing the same weld procedure and consumables to be used in production.

Quality Assurance / Quality Control (QA / QC)

The quality assurance and quality control requirements for pipe material have evolved over the years from a set of simple mechanical tests and a quick hydrotest, to the implementation of elaborate testing inspection and quality assurance programs. The extent of testing and inspection will vary depending on the type of pipe being produced and/or the intended service.

Obviously, a plain API 5LX-52 seamless pipe to transport liquids need not be subjected to the same type or extent of tests needed to control the quality of an X-80 gas line or sour service pipeline. However, regardless of service and extent of testing, all of these quality control items have not been controlled by a comprehensive quality assurance program. With the recent introduction of API Q1 Specification for Quality Programs, the industry now has a standard for quality assurance.

It was agreed that an aggressive QA/QC program fills an important position in the safety chain. This effort should include materials inspection at the mill as well as cross checking and review during the design stage. As a reflection of this trend, several operators are establishing hazardous operations review teams whose function it is to independently evaluate designs with respect to installation and operational safety prior to startup.

Pipe Material Toughness

The need for adequate pipe material toughness has been well established and amply demonstrated by a number of spectacular pipeline failures in the Middle East. Currently, most material specifications require Charpy V-notch testing and some also require CTOD or wide plate tests as an additional requirement, but acceptance criteria vary considerably.

The specified toughness values have increased significantly over the past few years and test temperatures have been lowered. Still, advances in pipe material manufacture have kept pace with these requirements and most modern pipeline materials exhibit very high levels of notch toughness.

Pipe Material Resistance to SSC

The combination of significant stress levels and significant levels of hydrogen sulfide in a pipeline can result in sulfide stress cracking (SSC). Although failures have been infrequent, SSC has progressed to failure in a few cases. The increasing frequency of the transportation of natural gas containing levels of hydrogen sulfide, which may lead to SSC and unanticipated pipeline failure, has led to the development of pipeline steels that are resistant to SSC. These steels are normally evaluated by a number of small scale laboratory corrosion tests or full scale tests such as the CAPCIS test, and the NACE TM-01-77 solution.

While these tests tend to rank material performance compared to other materials, they are too conservative and do not appear to predict accurately the materials performance in service. Frequently, materials that have survived sour gas services for 10 to 20 years cannot survive the current corrosion test requirements.

Spanning and Stability

The long-term safety of a marine pipeline is often dependent on the interaction between the pipe and seabed. In calm areas, the pipe is hydrodynamically stable with relatively light weight and seabed contact is uniform. Of more concern, however, is the more energetic environment usually found in the wave zone. In addition, the presence of high steady currents may result in scour, exposed pipe and vortex induced oscillation. For this reason, two span environments are recognized: the wave zone where pipe cyclic behavior is in the 6 to 8 second range and the high steady current environment where behavior is governed by scour and vortex shedding.

The cost to install remedial span correction measures is a significantfactor in determining the optimum design. For active seabeds, an annual program may be the most cost effective method of protecting the pipe. In such conditions, annual survey and installation of concrete mattresses has proven effective. For irregular, but less active seabeds, the industry practice is to stabilize the pipe as part of initial construction by rock dumping, concrete mattresses, grout bags, mechanical supports and anti-scour mats.

The preference for which support systems to install depends on region. Rock dumping and anti-scour mats have been used successfully in the North Sea. Grout bags have been used in the Gulf of Mexico. Mechanical supports have proven cost effective in deep water.

Recent research has focused on methods of assessing the potential for fatigue damage of spanning pipelines (Ref. 4). This includes wave induced stresses in shallow water and vortex shedding dynamics in deeper water. The consensus was that this remains a very subjective area as the designer must have access to reliable data on currents, waves and soil conditions.

Laboratory research on the vortex shedding mechanism and the fatigue of line pipe materials has progressed to the level where the true risk can be established for a specific environment. The present guidelines are over simplified and provide over conservatism in areas where fatigue is not a concern while allowing under design in critical areas (Ref. 5). The group's consensus was that fatigue is an aspect of pipeline design that could benefit from the use of limit-state criteria. For example, the fatigue life could be a factor of five on the service life.

Installation

Discussion on this subject addressed the areas of ongoing research which have a direct role in improving safety. Since this does not have a direct impact on the ability of the pipe to meet pressure containment requirements, the primary research programs are tending toward the investigations of the effects of external-loads on collapse.

The effect of various external load or geometry variations on collapse failure has been the subject of recent research. While the results are proprietary, the programs discussed included the influence of:

- Dents
- Residual ovality
- Method of manufacture
- Tension

Prior work (Refs. 6. 7 and 8) has consisted of both empirical and analytical treatments of the collapse problem. Recent advances in the predictive analysis of the post buckling behavior of pipe (Ref. 9) suggest that conservatism of 10 to 20 percent is incorporated in the present methodology. This has a progressively more significant effect in deep water where the added steel weight requires greater tensions and thereby compounds installation difficulties.

The use of buckle arrestors was discussed as a deign alternative to heavy wall. In this scenario, the wall thickness is adequate to prevent initial collapse, but not propagation of the buckle, should collapse occur. A considerable amount of laboratory investigation has been directed at buckle arrestor design and efficiency. While these have been included as part of numerous pipeline designs, only one actual occurrence of a propagating buckle being arrested in this manner was noted by the working group.

The use of high D/t ratios in shallow water is generally warranted. However, reference was made to the collapse failure of large diameter loading lines. This exemplified the fact that external pressure effects during installation when the line is empty should be evaluated even for shallow water when diameters are large.

Protection and Trenching

Discussion topics included protection of valves and pipe.

Protection of Valves

For valve protection, the use of open frame structures are presently not permitted in the Gulf of Mexico due to concern for hooking and engagement of fishing gear on anchors on the structure. Experience in the North Sea suggests that open structures are effective with frame geometry (angle) and embedment depth being more significant factors than closure in reducing fouling.

Both valves and pipelines are potential hazards to fishing equipment. Most participants agreed that greater coordi-nation between the fishing and pipeline industries would reduce the loss of nets. While no representatives of the fishing industry were present, it was commented that a data base of pipe locations would be a step in reducing loss of equipment. This is potentially attractive in view of advances in accurate satellite based positioning systems which would allow coordinate data to be used effectively.

Pipeline Protection

Opening discussion addressed the major types of damage that can occur to a pipeline in shallow and deep water. In shallow water, marine traffic and fishing activities can be dragged over or against the pipeline.

The resulting damage, depending on the anchor/trawlboard weight and travel direction, can be between a loss of weight coating to complete pipeline rupture and separation.

Merchant ships have a reasonable pattern and anchoring depth in shallow water. Platform support and construction vessels must be accounted for due to their close proximity of the mooring system to platforms in shallow water. Dropped objects are another means of damaging a pipeline, but this is generally limited to locations near the platform or construction vessel.

Deep water damage to pipelines is primarily due to trawlboard and support/construction vessels. Anchor wire rope and chain sawing along with fishing activities are major concerns to these pipelines.

The present practice by operators is to protect the lines out to a distance of 200 to 500 ft from the platform. This is to ensure safety from dropped objects and anchors. In addition, operators have policies on anchoring restrictions. To improve the reliability of protection several suggestions were made.

Trenching practices, particularly the requirement for 3 ft cover to a depth of 200 ft are based on sometimes anecdotal information and should be compared with data acquired over the last 20 years to provide a more performance-oriented rationale. This would specifically include stability, fishing risk and the influence of diameter on required depths to which lines must be trenched.

The present practice of protecting the pipe in the shore approach is inconsistent. Industry practice varies on the depth of trench and length extending above the mean water level. Superior long-term protection has been associated with techniques which result in the least anomaly to the shoreline. This is often difficult to achieve and has resulted in the use of rip-rap, twin jetties, directional drilling, dredging and backfilling. The recommendation was made to attempt to improve shore approach design by adopting a more consistent set of performance criteria. As a start for this effort, the historical performance of various techniques should be documented for industry review.

Conclusions and Recommendations of the Working Group

The group consensus was that present design practices for offshore pipelines are safe and tend toward the conservative side.

The group noted that the scientific understanding of pipe behavior and failure modes was, in several areas, ahead of field practice. This was most apparent in the distribution between the limit-state approach and presently used allowable stress methods. The research on combined loads (axial, bending, external pressure and internal pressure) indicates that present practices in areas such as spanning and installation are over conservative while the present hoop stress criteria for burst becomes nonconservative as material grades increase. While the traditional methods are easy to apply and safe, the group encourages the inclusion of limit state methodology into selected areas of present practice such as containment, installation and span analysis.

The following areas of study were considered beneficial to improve consistency within the industry or to improve the foundation for design for more demanding service.

1. Survey of worldwide trenching practices regarding influence of depth, diameter and damage mode on required trench depth and/or backfill.

2. Study of the effectiveness of valve protection devices to establish influence of angle, type of structure and embedment.

3. Survey of shore approach practices to improve under-standing of long term performance in specific environ-ments.

4. Survey of span correction practices with a comparison of one-time versus annual maintenance.

5. Continued study of pipe collapse under various installation loads. This includes the effects of reeling, local dents, manufacturing process and installation process.

The following conclusions were made regarding the present design codes and practices:

1. Establish allowable residual magnetism in pipe and its effect on welding. This is directed at high nickel alloys.

2. Expand the allowable use of air or nitrogen in lieu of water for pressure testing.

3. Establish an industry wide data base for bottom currents.

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WORKING GROUP REPORT 2

- *Evaluation of integrity, reliability assessment*
  Tom Zimmerman, Center for Frontier Engineering Research, Edmonton, Canada
  Serghios Barbas, Exxon Production Research Company, Houston, Texas

Introduction

This working group had as its terms of reference the evaluation of reliability and the assessment of system integrity. The meeting focused its attention on three areas of pipeline technology:

- Evaluation of Structural Integrity;
- Limit States Design; and
- Reliability Assessments.

For each of these areas, the group addressed issues related to the state of current technology, on-going research, and future research and development needs.

In addition, two formal presentations were made. The first by Dr. Torbjorn Sotberg of SINTEF, addressed the subject of "Reliability Assessment of Submarine Pipeline Systems". The second by Dr. Thomas Bubenik of Battelle, addressed "Recent Developments in Pipeline Integrity Assessments". The substance of these presentations is included at the end of the proceedings, in Theme Papers 6 and 7 respectively.

Major Issues

The major issues discussed by the working group, pertaining to reliability-based design and structural integrity evaluations, revolved around the following key questions:

- Do we want current industry practices to change?
- Can the pipeline industry use reliability-based methods?
- Are methods available to assess the structural integrity of older pipelines?

During the working group's discussions, many different opinions were expressed, however, several comments, related to each of these issues, were endorsed by the group as follows:

Should Current Practice Be Changed?

- New design methods must be implemented to address all relevant failure modes, as the pipeline industry moves to new, more demanding applications (deep water, arctic environment, higher operating pressures and temperatures, etc.). Current design codes do not explicitly consider many potential failure modes.

- Industry should proceed cautiously in implementing new methods, to ensure that good practice is preserved, and sound engineering judgment is not lost.
- Loading conditions and failure modes specific to offshore pipelines need to be recognized.
- Design codes must evolve to keep pace with new technology and new applications.

Are Reliability-Based Methods Usable?

- Yes; reliability analyses are useful for specific problems, and for helping to develop limit state codes, but should not be mandatory for use.

Can Such Methods be Used for Older Pipelines?

- There has been good progress, particularly in evaluating methods for assessing corroded pipe integrity.
- Various problems still exist: (1) many older lines cannot be pigged; (2) some evaluation methods are still very conservative.
- The biggest problem relates to determining the location of damaged areas, and making reliable assessments regarding the integrity of damaged regions for complex loading situations (i.e. when axial, bending and cylic loads are present in addition to pressure loads).

State of Practice

The working group felt that it was possible to summarize the current state-of-practice in the offshore industry, as follows:

- There has been good experience with existing codes and practices to date; there have been few design related failures; existing integrity monitoring programs implemented by industry have worked well.
- It was recognized that practice varies throughout the world; some countries and companies being more advanced than others with respect to design methods and integrity evaluation methods.

- Limit state codes are currently under development in Europe (Holland, Norway, Denmark and Britain) and Canada.
- In general, industry (by necessity) is using more advanced methods other than those provided in existing codes, and supplementary design criteria to prevent failure modes not addressed by the codes. Code development must follow industry's lead.
- New design codes should be flexible enough to allow designers to use the best available methods, data, and criteria for preventing potential failure modes especially failure modes not explicitly addressed by the codes.

Recommendations

Two days of discussions and presentations enabled the working group to agree on the following four recommendations:

- The technical committees for Standards B31.4 and B31.8 should set up Task Groups to develop a limit state design document.
- The activities of the Task Groups should be coordinated with parallel existing efforts in Europe and Canada.
- Consideration should be given to the development of Recommended Practice documents to provide guidance for using limit state and reliability methods.
- Existing codes should be examined to determine what current reliability and safety levels are being provided. This will help set target reliability levels for Limit State Code development.

Key Participants

Although attendees were free to contribute to several sessions, the prime input to this working group was based on the following key participants, with affiliations listed as follows:

Tom Zimmerman	Centre for Frontier Engineering Research
Serghios Barbas	Exxon Production Research
Tom Bubenik	Battelle
Torbjorn Sotberg	SINTEF, Norway
Steve Shirt	Oceaneering-Solus Schall
Carl Langer	Shell Development Company

Mike Mitchell	MMS Santa Maria CA. Dist.
David Halsey	MMS Herndon, VA
John Gregory	MMS Herndon, VA
Don Perkins	National Research Council - Marine Board
Vagner Jacobsen	Danish Hydraulic Institute
Jasper Price	Pulsearch/Nowsco
Chris Gaines	Exxon Co., U.S.A.
Ivor Ellul	Scientific Software Intercomp, TX
Frank Dezzutto	Shell Offshore, Inc.
Kevin Williams	AME Ltd., UK
Frank Gonzales	ARCO Pipe Line Co.
Paul C. Cheng	Tenneco Gas

WORKING GROUP REPORT 3

- *Internal monitoring*
  John Adams, Pulsearch, Calgary, Canada
  Paul Moss, British Gas, Houston and U.K.

Introduction

The group attendance varied from approximately 15 to 20 people during the discussions. The breakdown of those attending was as follows:

Pipeline Operators	10-15
Contractors	4-6
Government	2-6

There was generally good audience participation and there were widely varying opinions on most subjects. The discussion topics for each agenda item were as follows;

Current industry practice

Safe practice

Technologies available

Results (significance and accuracy)

Future needs

The agenda below was followed during the group discussion session:-

- Introduction
- Corrosion and construction damage
- Caliper, location, deformation and movement assessment.
- Depth of cover, integrity of weight coating
- Crack detection
- Pigging operations
- Conclusions

The following comments are indications of the items discussed, although they are not necessarily conclusions of the group as a whole. In general there was little or no offshore experience in the Gulf of Mexico and hence much of the discussion related back to the onshore US or North Sea practice.

Corrosion and Damage Inspection

Corrosion of the riser in the splash zone was felt to be one of the primary concerns for offshore lines. Several operators voiced the opinion that the main body of the pipe would remain defect free. Other operators disagreed pointing to statistical information supplied in Alan Adams keynote address.

Operators voiced the opinion also that the results of pigging must be of sufficient accuracy that would justify the cost of field verification and repair. This was held to be true for both mechanical damage and corrosion/metal loss damage. There was differing opinion as to what constitutes sufficient accuracy. One operator submitted an accuracy analysis of the results of conventional magnetic flux leakage tools showing that in general results did not reach specifications. This analysis is attached, in figure 1.

The accuracy of corrosion inspection surveys was further examined with a variety of concerns being voiced. It was stated that there were various accuracies and types of tools available for corrosion and geometrical defect determination. The services range from the cheaper qualitative pigging assessment to the accurate quantitative assessment of pipelines. Most people present believe that there were no deficiencies in the available technologies although cost might become an issue.

Caliper, Location and Deformation Assessment

The location of a defect and its exact nature were considered critical when one considered the cost to go out and perform offshore repairs. Many points were raised as to methods of accurately locating the defect in the offshore environment and it was generally felt that this was an area which required more work.

The same point for mechanical (geometrical) tools outlined above applies. The technology varies dramatically - however there appears to be no requirement beyond the current most technically advanced tools.

In addition to the inspection, the operators were interested in the cause and prevention of defect occurrence and one operator suggested that preventative action negated the requirements for inspection.

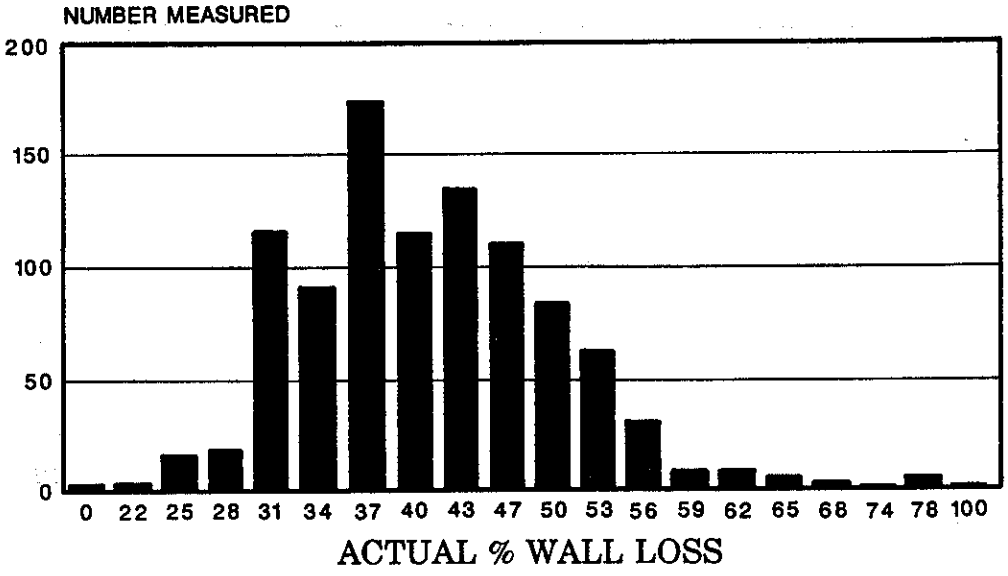
Operators felt that Quality Assurance and Control during the construction and the continuous use of inhibitors prevented defect initialization and reduced the number of failures.

FIGURE 1 - PIPELINE INTERNAL INSPECTION

ACCURACY OF MAGNETIC FLUX LEAKAGE TOOLS

DATA BASE:	900 pipeline miles - several pipelines Flaw categories based upon calibration digs 1000 flaws reported as > 50% wall loss Actual wall loss based upon accurate measurements
RESULTS:	Average wall loss = 40% 80% of flaws < 50% wall loss

DISTRIBUTION OF REPORTED FLAWS
ACTUAL VS REPORTED >50% WALL LOSS



BLIND INTERPRETATION RESULTS:

Calibration digs are not always economical, such as, for offshore pipelines. Less accurate logs result when only blind interpretations can be made in such cases. As an example, blind grading of wall loss versus actual wall loss has varied as follows:

REPORTED	ACTUAL
< 25%	0 - 45%
- 50%	0 - 65%
> 50%	0 - 75%

Life extension, re-certification, and fitness for purpose were all felt to be important reasons for conducting inspection programs. It was also felt however that the US pipeline regulatory community is just beginning to adopt new codes and standards that will allow for some of the assessment which will be necessary.

Depth of Cover

Depth of cover and integrity of concrete weight coating were discussed. There is technology available to provide this service by pigging, however there seemed to be no interest from Gulf of Mexico operators although the technology is in service in the North Sea.

Crack Detection

Crack detection was discussed and most operators felt that it was not a problem for offshore lines. One operator discussed the detection of girthweld cracking in a North Sea gas pipeline and the fact that the pig data together with destructive testing data was used to determine a fitness for purpose for the line. For other types of cracks it was felt that the available inspection technology was not fully developed. Two service companies gave an account of their current crack detection programs and discussed EMAT and Elastic Wave technology.

There was no conclusion as to the recommended frequency of inspection due to the lack of experience in the US offshore. Although a number of operators conducted a regular onshore inspection program through the use of a risk assessment algorithm there was skepticism that this could be applied offshore. It was generally concluded that frequency of inspection is based on a wide number of variables including but not limited to:

- product
- temperature
- pressure
- construction method and material of the pipe
- environmental impact of pipeline leak
- assessment of cathodic protection
- corrosion/leak/damage history
- age
- coating type and integrity
- type of maintenance and cleaning program
- sea floor stability
- regime around the pipeline and riser

Pigging Operations - General Problems

The following points were raised with regards to the operational considerations, namely:

Many offshore lines in the Gulf of Mexico were felt to be unpiggable due to varying diameter, lack of launch and receive facilities, tight bends and the sub sea termination of some lines in connection to other lines. Pigging service companies felt that most of these problems except for the last one could be overcome, although at substantial cost.

Cleaning of the pipeline was felt to be important. Again, the technology exists in many forms from mechanical pigging to chemicals and the operator must choose where applicable.

Operators expressed concerns with respect to having to make costly platform modifications (to allow for pigging) and expressed concern over the safety when asked to perform "hot work" modifications.

Conclusions

There are no hard and fast conclusions from the discussions as a wide variety of differing opinions were expressed. Generally, it was felt that the experience in the US was limited and the operators were only beginning to evaluate their options. Education and exposure is obviously required. The North Sea experience as presented by Alan Adams would appear to support the position that inspection of offshore pipelines is desirable, and to encourage dedicated efforts to be made by the operators to determine the frequency and type of inspection technology utilized.

It was also the general feeling of the discussion group that every pipeline is different and that it would be hard if not impossible to create a general rule determining the type and frequency of inspection. The responsibility then clearly rests with the operators and via their maintenance, operations and financial departments to determine their own needs.

WORKING GROUP REPORT 4

- *External surveillance*
  Dick Frisbie, Oceaneering, Houston
  David Weinhoffer, Sachse Engineering Houston

Introduction

This workshop group concentrated on the discussion of current practice, instrumentation, and future research/operational directions associated with external pipeline surveillance. The extent of the workshop group was broadened to include both survey and leak detection surveillance associated with all types of pipe (rigid and flexible) in the following offshore areas:

- coastal zone
- shallow water
- deep water

Coastal zones include all the beach transition areas including the shallow nearshore underwater section, the wave surf section, and the above ground section. Shallow water areas basically include those within safe diver depth. Deep water areas include those beyond safe diver operations which require some type of special manned (JIM suit, WASP unit, etc.) or unmanned (ROV) intervention equipment.

Instrumentation Deployment

Existing equipment and deployment techniques for offshore pipeline surveillance are fairly diverse and routinely used by offshore operators. The specific equipment and deployment selection is primarily based on the specific requirements of the required operation and task. Specific deployment methods, platforms, and vehicles utilized for the deployment of surveillance equipment include:

- Divers and other manned intervention equipment
- Remotely Operated Vehicles (ROV's)
- Tracked surface crawlers
- Surface work vessels
- Aircraft
- Towed arrays
- Towed sleds

Whenever possible, manned intervention or direct visual observation is preferred. Obviously, this is because any problem can usually be unambiguously confirmed and/or repaired without further mobilization of additional equipment.

Surveillance Equipment

Specialized surveillance equipment can be categorized into several basic classifications:

- Magnetometers/Gradiometers
- Acoustics
- Conventional Optics
- Unconventional Optics
- Cathodic Protection Probes

Magnetometers and gradiometers are passive instruments which detect the natural or enhanced magnetic fields around ferrous pipelines. They are primarily used in the location and tracking of pipelines.

Considered acoustic equipment is active instrumentation which emits, detects and measures reflected sound waves. Types of this equipment include basic tracking sonars including side scan sonar, and subbottom profilers. The primary use of this equipment is location and tracking of pipelines. Use of passive acoustic emission transducers for detection of both stressed pipe defects and incipient leak detection is not currently considered practical from both economic and location accuracy viewpoints. The only acoustic instrumentation which can monitor buried pipe is the subbottom profiler which must be deployed transversely across the projected pipe track yielding a single data point for each crossing.

Conventional optics includes both direct visual contact by the human eye, and the use of various video cameras. Camera instrumentation may include either the use of direct optical umbilical links to the surface, or remotely operated cameras which store exposed film for later development. The use of cameras which remotely store rather than transmit visual documentation is awkward unless an alternative method of providing corresponding positional information is available.

The category of unconventional optics is included basically to cover the use of a newly developed laser line scanning system. This system provides a continuous visual representation through the use of a continuously scanning laser light beam. The visual display provides much greater independence from underwater lighting and turbidity conditions than conventional optic systems. At present, this product is offered only through one manufacturer.

Use of cathodic protection (CP) probes is widely used for pipeline monitoring to ensure adequate levels of impressed current for arresting marine corrosion. This method of corrosion control surveying on a periodic basis is a widely accepted monitoring technique.

Instrumentation Selection Criteria

The workshop participants identified a number of critical items which are instrumental in determining instrumentation and delivery method selection. Most of these items are interdependent and include:

- Overall inspection requirements
- Exact client deliverable specifications
- Existing pipeline documentation
- Water depth
- Depth of pipe burial
- Burial medium
- Type of pipeline (rigid vs flexible)
- Pipeline coating
- Geographical location
- Economics

The first three items are critical criteria and must be clearly identified prior to instrumentation and delivery vehicle selection. First, the overall inspection requirements must be clearly defined (ie. whether route survey, leak detection or confirmation, corrosion monitoring, etc.). Second, the client's deliverable requirements must be addressed (ie. whether continuous or discrete survey points, allowable distance between survey points if discrete, accuracy of survey, etc.). Third, all existing pipeline documentation related to the desired survey should be collected and fully reviewed. For example, if a corrosion survey is desired, past survey information and accuracy should be reviewed along with any new areas where crossing pipeline contact may be present. Also, if the pipeline is part of a labyrinth system of crossing lines such as in coastal areas, all information related to crossing system routes must be reviewed.

The next five items relate to technical concerns which directly impact potential equipment selection and mode of delivery. The final two items determine the ability to perform the work with the resources (equipment and money) available.

Major Issues/Problem Areas

Diverse, well-proven instrumentation methods and practices exist which allow a wide selection array for any desired pipeline surveillance requirements. Often, more than one sensor output is required to provide meaningful surveillance data. Additionally, both the in-situ site conditions or survey equipment limitations may dictate use of various sensor units.

Two survey equipment selection issues are critical. The first pertains to the need of the client to clearly delineate the objectives of the pipeline survey and the specification of the final end product. As noted in the previous section, lack of adequate definition in these areas can easily result in performance of a survey which may not fully provide all essential information. The second related issue pertains to the need for the contractor to fully understand the full extent of survey requirements in order to properly and competitively quote cost effective work.

Each of the above noted issues can be fully addressed if a pre-site inspection survey is performed prior to bidding. The sole purpose of this survey would be to determine the key parameters relevant to bid preparations. Some of these include:

- Extent of pipe burial
- Number, extent, and relationship of all adjacent pipeline systems along the entire pipeline survey route
- Potential obstructions or hindrances to performance of the work (eg. ship channel traffic, fishing areas, kelp beds, etc)
- Review of all construction history and past surveys for information on any additional unknown anomalies or peculiarities which could impact survey equipment selection (eg. pipe coatings, special mid-pipeline tie-ins, etc)

Inconsistent data interpretation between various surveillance equipment and intermittent survey records must be reconciled after each new survey.

During the workshop, many contractors indicated that they would rather no-bid potential work than provide a lump sum cost for some inspection work without a pre-site survey. Workshop participants representing various service contractors were unanimous in this conclusion. Inspection work on a time and materials basis would always be performed. However, this may not be either desirable or feasible within limited inspection funding allocations.

One point made during the workshop sessions was that with recent corporate downsizing many service companies/contractors were assuming more the additional role of consultants rather than independent subcontractors. Pipeline service companies desiring such harmonious relationships may tend to carefully protect that association by assuming a more conservative bidding approach rather than risk potential cost overruns to achieve the desired inspection goals.

Required Industry Directions

There are three workshop identified key areas in which the pipeline industry should take the lead with regard to external surveillance issues:

- Bottom definition
- Correlation to internal surveillance data
- Inspection continuity clarification

The area of bottom definition as noted here relates to pipe burial. Recently enacted legislation defines definite burial depths but does not provide guidance on what constitutes the reference benchmark. For example, many Gulf of Mexico areas have extremely soft, "soupy" bottom sediments which essentially hold no strength and are littorally transient. The idea of referencing the bottom to a specific, measurable soil strength was discussed as a potential definition solution. The final selection criteria should be developed with input from all concerned parties including regulatory agencies, installation contractors, survey contractors, and concerned petroleum and pipeline operating companies. A quick resolution should be achieved to ensure continuity with recently passed legislation.

Industry also needs to provide guidance in developing methods for correlating work between internal and external surveillance inspection reports and actual external repair intervention. The desire to confirm/repair leaks or external defects found through an internal pigging inspection can be both difficult and potentially costly if the line is either buried or coated with concrete. The idea of providing periodically placed buckle arrestors, whether needed or not, on newly installed lines would provide one possible method of correlation between "smart" pigs and external survey records. Again, guidance should be provided from a consortium of parties as noted in the previous paragraph.

The final area in which the pipeline industry should provide assistance is with inspection continuity between the various regulatory bodies and concerned industry principals. This assistance should take the form of guidance so that independent regulatory agency responsibility leads to clear, non-competing inspection regulations.

Future Research Activities

Two clear research areas were identified for further work in external pipeline surveillance:

- Use of deep water autonomous vehicles (AUV's) for basic underwater surveys

- Further research in development of laser line scan systems

Autonomous Underwater Vehicles

This technology is currently in the developmental stage. AUV's are differentiated from current unmanned, deepwater ROV work systems in that there is no umbilical or tether to the surface which implies independent use from existing surface support equipment. AUV prototype systems are severely restricted in several areas including power, manipulative capability, the ability to identify and discriminate objects, and the ability to accurately know their position. Current AUV work is being performed solely through college and research institutions. These institutions have received no direction from potential industry users to help focus their development.

The potential advantage for deepwater pipeline inspection work with AUV's is that their use could possibly result in substantial surface support spread savings. Short duration tasks (5-6 hours) requiring only localized, fly-over searches could be preprogrammed into system memory. Results from onboard instrumentation could be recorded within the AUV for later analysis. The pipeline industry needs to utilize this resource for potential deepwater inspection assistance.

Towed Laser Line Scan Systems

Existing conventional camera systems are severely limited in differentiating open ocean objects further than about 10 feet away. Any natural turbidity or near bottom sediment disturbance further restricts even the best conventional camera systems.

The Towed Laser Line Scan System (LLSS) is a high resolution optical seafloor imaging tool designed for acquiring very detailed large area surveys of the seafloor in a rapid cost effective operation. The LLSS is capable of detecting centimeter sized objects at ranges two to five times those of conventional underwater camera and light systems. When incorporated into a towed vehicle for underwater surveys, the LLSS can provide inspection coverage at speeds up to six knots with swath widths up to 120 feet.

The operation of the LLSS is based on the latest advances in laser scanning technology. The laser scanning process can be described as the construction of an image from a rapidly acquired series of spots on the seafloor. Each spot is sequentially illuminated by a laser beam with a diameter of approximately that of a pencil. This imaging technique eliminates nearly all unwanted back-scattered light permitting the increased imaging range with higher resolution.

The LLSS is compactly packaged in a rugged pressure housing integral to the towed vehicle. Acquired data is transmitted via a coaxial cable in the tow umbilical to the monitoring and recording station on the surface survey vessel. The signal outputs are monitored and recorded in real time and the survey operator can periodically adjust scanning parameters as needed. The actual survey operations are conducted like those performed by conventional sidescan sonar systems. That is, overlapping track lines are run over the survey area to guarantee 100% coverage.

Known commercial applications verifying system capabilities include nuclear power plant intake/exhaust inspections, outfall pipe surveys, and pipeline pre-lay route surveys. The system is currently marketed by a single vendor.

Supporting Information

Further material on specific aspects of external surveillance of offshore pipelines are contained at the end of the workshop proceedings based on presentations, by McBride-Ratcliff & Associates on "An Integrated Geophysical Approach to Pipeline Location and Depth of Burial Surveys", by Shell Oil Company on practices and experiences in the Gulf of Mexico, and by John E. Chance & Associates, in Theme Papers 2, 3 and 4 respectively.

WORKING GROUP REPORT 5

- *Routine operation & maintenance issues*
  Jim Houston, Transco, Baton Rouge
  Mark Williams, Chevron Pipeline, New Orleans

Introduction

This working group identified a broad range of subjects relating to the safe operation of offshore pipelines which could only be briefly summarized here.

Pipeline Regulations

With the advent of new regulations governing the depth of burial of shallow water pipelines, the topic was discussed at length during the conference. As with any new regulations, questions regarding the clarification of the new rules have been plaguing the pipeline companies. The main points of this discussion were as follows:

- An industry standard should be set regarding clarification of the definition of "sea bottom" prior to an arbitrary government ruling.
- Methods of re-burial of shallow pipelines should be addressed by the industry.
- Education of fishing boat operators should be included in a comprehensive damage control program.
- Definition of "inland waters" should be clarified.

Industry participants discussed the relative merits of several different methods of determining depth of cover, including Innovatum, Chirp Sonar, and Probing with Divers. It was agreed that new methods and procedures should be developed to ensure the safety and integrity of our aging offshore pipeline system, especially in the area of proper monitoring for corrosion control. Offshore corrosion control maintenance can be broken into two categories: external and internal.

External Corrosion

External corrosion control on offshore pipelines is generally monitored by reading pipe to electrolyte potentials at the initiation and terminus of pipeline risers at accessible platforms. New methods of performing offshore close interval cathodic protection surveys should be further utilized to ensure the integrity of the pipelines and coatings at all points in between.

Onshore, this challenge has been met by the development of a special "light" wire which can be trailed behind the reader for (literally) miles. Offshore, the light wire method is ineffective due to the harsh conditions imposed by sea, swell, and wave action. Heavier wires have been tried with limited success, again due to the difficult conditions encountered. However, remote vs. close electrode continuous survey techniques have been developed and proven to be effective offshore.

New methods of spot checking pipe to electrolyte potentials on the pipelines between platform locations would also help to ensure the integrity of these aging lines and coatings as well as to make sure that all requirements for pipe to electrolyte potentials are being met. It is worth noting also, that coating pipe and nut joints only, tends to concentrate corrosion at the joints.

Well coated pipelines offshore which are placed under cathodic protection undergo extremely long periods of polarization before pipe to electrolyte potentials reach a stable level. This process can take weeks to months depending upon the coating condition, bonds to foreign structures, and local conditions. Conversely, depolarization can take months as well. This phenomenon creates a difficult situation when testing for the 100 mV depolarization criteria for cathodic protection on the pipeline system offshore.

Methods are available to quickly de-polarize the pipeline system. One such method is to throw current to the pipeline, thereby making it anodic to another structure for a short period of time. This and other methods could prove detrimental to the pipeline system in the long run and have not been used on anything but a test basis. Industry continues to investigate the possibility of different criteria for cathodic protection of offshore pipelines under these circumstances as well as new methods of testing for cathodic polarization.

Pipe Isolation

Most offshore pipelines are insulated from platforms utilizing conventional insulating flanges as are used onshore. These flanges have proved generally reliable in this type of service. Underwater however, at underwater tap locations and foreign line tie-ins, a completely different situation exists. It has proven difficult to effectively insulate pipelines at underwater tap locations thereby requiring that two or more pipelines be cathodically protected as a unit. Foreign structure bonds are periodically inspected for pipe to electrolyte potential and current flow.

Onshore, the situation described above would be considered a foreign structure bond. Offshore, this situation creates a condition that is extremely difficult to check for either potential or current flow due to its location. It might be desirable to modify the regulations to take into account the "real world" conditions encountered offshore. Also research could be initiated to bring to light new methods of effectively insulating pipelines at underwater tap locations.

One extreme option might be to form an industry consortium to look into the possibility of protecting all offshore pipelines and structures in the Gulf of Mexico as a single unit, thereby eliminating the need for isolating devices.

External Corrosion at Risers

One of the most common areas for corrosion failures offshore is on the pipeline risers. Many coating materials have been used on pipeline riser "splash zone" areas, some with more success than others. Research into new materials, and/or better methods of applying existing materials in a maintenance program could lead to a reduced failure rate on these systems.

Non-Destructive Testing

Non destructive testing methods for determining the integrity of offshore pipelines, especially on pipeline risers have been used with some success by adapting ultrasonic, X-ray, hardness testing, and smart pigging methods used onshore to offshore work. There are however, no standards for using these methods in the offshore environment. This subject could be a complete workshop in itself and certainly bears further examination. Further development of these techniques will help improve integrity monitoring and long term reliability of offshore pipelines.

Other Issues

In addition to the above, the following issues were raised as areas requiring further review and development:

- Possible use of rust converter systems.
- Paint application techniques and preparation offshore.
- Techniques to retrofit or remediate cathodic protection systems.

Internal Corrosion

The control of internal corrosion is becoming more difficult as producing wells age and produce more saltwater. Bacteria influenced corrosion is becoming an ever increasing problem as gas and fluid velocities decrease, allowing water to stagnate in these lines. Technology for monitoring and control of these microbiologically influenced internal corrosion problems is in its relative infancy (relative to external corrosion control) and certainly merits further research. Specifically, claims have been made by various industry personnel regarding new methods of monitoring for bacteria without opening the pipeline for water samples. Such a method may utilize a corrosion probe-type instrument. At this time, these claims have yet to be borne out in practice. Research, or a joint industry committee may investigate these claims for validity.

It is accepted throughout the industry that an effective pigging program will reduce internal corrosion problems by removing liquids, sludge, and scale from the inside of the pipeline. Pigging also cleans the internals of the line allowing any chemical corrosion inhibitor utilized to perform its job properly. Some pipelines are not piggable, of course, due to the configuration of ells, the existence of T bars at tie-ins, or a number of other reasons. There are existing methods of dealing with some of these problems such as dissolving pigs, which may allow the pigging of some lines with T bars installed. Research into other possibilities or ways to clean and purge the pipeline may turn up other innovative methods, thereby enhancing internal corrosion control on an industry wide basis.

Internal Lining

Industry uses plant applied corrosion resistant internal linings on some new pipelines where appropriate. To some extent in-situ coatings have been applied on existing pipelines with varying degrees of success. The in-situ method of internal corrosion control is so expensive and of questionable effectiveness as to make it impractical for longer and larger pipelines. Internal coatings are also subject to scour in two-phase lines. New technology in the area of interior linings that could substantially improve reliability, could bring prices down and make this a more viable method of internal corrosion control on a large scale.

Regulatory Overlap

Most industry workshop participants expressed concern over the division of responsibility between DOT and MMS in the Gulf of Mexico and the possibility of contradictory regulations or overlapping inspections from the two. It would behoove industry as well as both agencies to present a clear, concise set of standards showing the division of responsibility and the interests of each, resolving apparent inconsistencies in regulatory requirements. Ideally pipelines under DOT jurisdiction should follow DOT standards only, and likewise for MMS pipelines, not both.

Leak Detection

Pipeline operators establish, maintain, and verify the overall integrity of their pipeline systems. Additionally, Federal and State regulations and various industry standards are intended to reinforce and strengthen this effort. An effective leak detection system is one of the many elements of a complete line integrity system designed to prevent and - through early detection and timely emergency response - mitigate releases. As a result, pipeline operators continue to improve and implement leak detection technologies.

With the advent of increasing environmental awareness on the part of the public, leak detection, especially in product lines, has taken on a new importance. Existing methods of leak detection on product lines could usefully be improved. This applies particularily to methods used to detect offshore leaks on natural gas pipelines which include bubble observation and rough volume calculations. There will always be problems in calculating volumes to the accuracy which would indicate small leaks, especially in product lines where the environmental impact of even a small leak over an extended period could be severe.

Basic leak detection methods that have been in widespread use include visual surveillance, pressure/flow set point alarms, volume (in/out) balance over set time intervals, and various concepts of rate-of-change. New methods of on-line, real-time leak detection monitoring tools including software-based pipeline models are being developed, requiring further research and testing to define their capabilities, limitations, and specific application. Some specific areas for further study include:

- Monitoring of non-steady state situations.
- Effective leak location techniques.
- Two phase and gas monitoring technologies.
- Effects of instrument accuracy on capabilities.
- Effects of modeling accuracy on capabilities.
- Future potential of non-traditional methods such as acoustic and fiber optics - based systems.

Supporting Information

Additional material on "Corrosion Control Survey Methods for Offshore Pipelines" is contained in Theme Paper 1 by Clark Weldon and David Kroon of Corrpro Companies, at the end of the workshop proceedings.

WORKING GROUP REPORT 6

Abnormal, emergency & storm response

David Phillips, J.P. Kenny, U.K.
John Bomba, R.J. Brown, Houston

Introduction

Most progressive defects on damage to a pipeline and riser system may be, and usually are, detected during routine operation and inspection. Corrective action options to stop progressive deterioration of the pipeline on the supporting seabed can be determined in a planned and orderly manner and carried out as a part of normal, planned, routine maintenance. On the other hand, cases of more severe damage require an immediate response.

Pipeline damage can be broadly grouped into four categories:

- Internal (corrosion and erosion);
- External (anchor, anchor wire on fishing gear damage, corrosion, and, in the case of a riser, accidental vessel impact);
- Environmental (such as scouring or destabilization by storm conditions, mud slides or seabed instability ie sand waves, liquefaction);
- Deficiency (design, material or installation faults).

The level of damage severity, therefore the urgency of the response, can vary significantly for each category and is complicated by the fact that the damage itself is not visible. The decision making process to assess whether damage can be left for the next planned maintenance or immediate intervention is necessary, requires experienced and informed judgement.

This workshop established a basic framework for developing an "Abnormal Event Response Capacity or Capability" from initial detection, through the decision making process for remedial action, to the implementation of corrective measures, the subsequent recording of all events which have taken place, and the planning of measures to mitigate future occurances.

The workshop session focused on a range of issues in the context of an abnormal or emergency response scenario, and included the following:

- Definition of potential damage causes;
- Initial damage detection or cause for alarm;
- Physical location of damage;
- Evaluation and decision processes;
- Required intervention;

- Ability to mobilize emergency response; longer term mitigation against re-occurrence;
- Update of records;
- Case histories.

The following sections begin with a general discussion of material related to all responses. This is followed by sub-sections for Abnormal Response, Emergency Response, and Storm Response.

Current State of Practice

General

The current state of practice as regards industry-wide response to abnormal, emergency, and/or storm situations is adequate but no readily visible consistency between the approach of individual operating companies to these situations is apparent.

Department of Transport (DOT) regulations are specific in their requirements. These direct company policies and operational procedures to ensure an understanding of abnormal operations/situations before returning a system to service. "Keep it shut down until the upset is understood by everybody!" seems to be the general policy.

The Oil Pollution Act requires each company to have a spill contingency plan in effect.

The manner in which the Gulf of Mexico pipeline system developed, with its multitude of subsea tie-ins, generally precludes the use of inspection pigging. Some of the newer systems, particularly those which carry significant amounts of CO_2 and H2S, are designed for smart pigging.

Abnormal Situation Response

Current Department of Transport (DOT) regulations are specific. Operational procedures and company policies are now in place to ensure understanding of the abnormal operation before returning to service. Gulf of Mexico operator policy is to keep everything shut down until the upset causing the abnormal situation is thoroughly understood. No additional legislation or regulations are required. Limited annual inspections of pipeline systems are carried out, but not to the extent of other areas such as the North Sea.

Emergency Response

The Clean Gulf Association and the individual pipeline operating companies have developed separate plans for Emergency Response to spills.

Storm Response

The current practice for named storms in the Gulf of Mexico is to abandon all manned offshore platforms, waiting until the last minute to close the valves and pull out.

Problem Areas

General

It has been reported that 50% of the leaks in the Gulf of Mexico are pipeline related and lead to over 90% of total spill volume.

Abnormal Situations

The primary concern is operator response to an abnormal situation. His inadequate understanding of the problem may result in his interpreting the data available to him incorrectly. Because some important data may be lacking, or something completely unknown may have occurred, an operator's response may not be correct.

Leak detection systems currently in use are generally inadequate. In addition, most of the subsea tie-ins are not piggable with ordinary pigs, particularly with smart pigs.

Emergency Situation Response

A primary concern of the pipeline operators is that OPA requirements are unknown, therefore, the following questions arise:

- Will Clean Gulf procedures, etc. apply as far as OPA requirements are concerned?
- What will be the definition of "worst case discharge"?
- Will Clean Gulf be opened up to other than producing companies - eg., pipeline operating companies?

Storm Response

Producers with automated facilities will want to maintain production through a storm. Major problems are:

- Will the pipeline system have the same capabilities?
- What is needed to operate a pipeline system in a storm?
- Is lack of access to an area during a storm enough of a reason not to operate?
- How dependable is the emergency shut down (ESD) system and the leak detection system?
- What are the consequences if something happens?
- How does one close valves quickly?

Industry Needs

General

The "off the record" discussions which took place during the Workshop Sessions between operators and regulatory agency personnel was enlightening to all parties. Everyone stressed the need for better communications between operators and agencies.

Abnormal Response

The primary need expressed during the workshop is "continued operator training", ultimately leading to better understanding of his job and how to cope with unusual situations.

Emergency Response

The primary industry need is resolution to the questions raised under Emergency Problem areas. This would facilitate development of plans for producers and pipeline operators to work together in an economically efficient manner, avoiding needless duplication yet covering all eventualities.

Storm Response

As under Emergency Response, the primary industry needs are answers to the questions raised under problem areas.

Research Needs

General

Better leak detection systems and reliable emergency shut down (ESD) valves would improve response capabilities. Better methods of training operating personnel to understand what the data they do receive really means are also suggested.

Abnormal Situations

The primary research need identified during the work shop is definition of ways of providing better data, and in a usable (understandable) form, to the operator for his use in evaluating what is actually happening. Additional research into leak detection and reporting techniques is needed. Particular attention should be given to multi-phase flow leak detection.

Emergency Response

The current research into oil spills (containment and recovery techniques, dispersants and bio-remediation) should be accelerated and approval for the use of dispersants and bio-remediation should be granted.

The "best" location for ESD valves should be determined.

Storm Response

No separate research needs were identified during the workshop sessions.

Implementation and Application

General

All Workshop participants agreed that leaks are not acceptable from any point of view (ie., from a financial, safety, or an environmental standpoint). There was general agreement that leak detection technology should be developed further through Joint Industry Participatory (JIP)/Regulatory Agency Studies. This is particularly important in view of regulatory requirements for response planning. If the real problems related to implementation of leak detection systems (for instance, multiphase flow leak detection) and the real accuracy, repeatability and reliability are known by all parties, meaningful progress is achievable in a carefully thought out development program.

In general, there is an obvious safety bias in pipeline system operators' policy statements. A safe system is a reliable system. OPA compliance requirements may impact implementation of the studies, procedures, plans, etc. discussed in this and possibly other workshops.

Abnormal & Storm Situations

The implementation and subsequent application of the results of the research will lead to the continued improvement of operator training and of data communication.

Emergency Response

Pipeline operators and regulatory agencies should work together on definitions and plan requirement. In addition, both should support research on oil spill cleanup and treatment.

WORKING GROUP REPORT 7

Repair & rehabilitation problems

Gary Vogt, Guillot-Vogt, New Orleans
Albert Barden, Nowsco, U.K.

Introduction

The scope of this group was to address pipeline repair and rehabilitation problems in the areas of current regulations, leak detection, decommissioning, repair techniques and hardware with an emphasis on safety. The methodology used in the preparation of a pipeline for a repair and subsequent recommissioning in a safe manner was presented. This group considered the industry needs and future directions for the repair and rehabilitation of pipelines.

General Comments

The working group found it necessary to settle on a list of objectives and specific items to be addressed during the session due to the broad range of topics associated with pipeline repair and rehabilitation problems. The consensus of the working group favored this approach in order to stay focused on the assigned topic.

The consensus of topics was as follows:

- Current Regulations
- Decommissioning/Isolation
- Repair Hardware/Techniques
- Diverless Repairs
- Industry Needs

Currrent Regulations

Mr. Frank Patton with the MMS Gulf of Mexico OCS Region gave a presentation on current MMS regulations regarding pipeline repairs. The sections in the April 1991 Notice to Lessees (NTL) regarding pipeline repair requirements were discussed along with other general requirements of the MMS.

Operators are required to give immediate notification of a pipeline leak with the OCS number and the Pipeline Segment Number to the MMS and other governmental agencies such as the Coast Guard and D.O.T. A detailed procedure for cutting the pipeline must be submitted to the MMS for their review. The MMS will give acceptance of procedures, not approval. Also a detailed report of the pipeline leak should then be submitted within thirty days to the MMS. Test charts acquired during the pipeline repair must also be submitted to the MMS upon completion of the repair.

The MMS has put together a Safety Review Task Force as a result of accidents involving platforms and pipelines in the North Sea and the Gulf of Mexico. This task force is reviewing the present regulations and will recommend changes if required. Areas where significant changes are being implemented involve platform risers. Protection of the riser from falling objects is required by minimizing above water horizontal sections of the riser pipe. Riser guards are required for protection of the riser at the water line, and on bottom pipe protection by burial or alternative methods is being addressed for areas around platforms.

Valve Location

The location and requirements for emergency shut down (E.S.D.) valves for risers is another item of importance. The location of the E.S.D. valve in the riser pipe can be critical to the successful operation of the valve in an emergency situation. Many E.S.D. valves have been installed on platforms, at a location where the valve may be subject to damage from an explosion or fire and rendered useless. Many operators install the valve in a protected area, either on the vertical section of the riser or as close to the vertical section as possible. Minimizing the exposed section of the riser between the water line and the E.S.D. valve is encouraged.

Some E.S.D. valves have been installed near the top of jacket elevation approximately (+) 12'-0" to protect the valve from fires or explosions. This location has some inherent risk that must be considered. One problem with this location is the extreme exposure of the valve and the operator to the severe elements encountered in the splashzone area. A complete risk analysis should be performed considering the vulnerability of the valve, serviceability or manual operation of the valve during storms and life expectancy and reliability of the valve at this location.

The additional risk associated with valves located in the splashzone area and the probability of a problem with the valve do not appear to justify the splashzone area as the preferred location. The optimum location in most cases appears to be on a sub-cellar deck away from the production or in the vertical run of the riser with an access platform installed just below the lowest production deck of the platform.

Other Issues

Another area discussed was the verification of pipeline burial and the rehabilitation of areas where lack of cover was discovered on the pipelines. Notification to the MMS is also required when operators discover foreign lines near crossings and subsea tie-ins that do not have adequate cover. The shallow water and beach areas are of greater concern due to recent accidents involving pipelines without proper cover or protection. The verification and rehabilitation of pipeline burial is addressed in new legislation.

Drug testing personnel for repairs to lines in service is required to be in accordance with D.O.T. part 199. It was noted that the regulations are different for drug testing on a new installation.

A difference in the 0.C.S. regulations in California was discussed. The MMS in California are requiring operators to design and install pipelines so that Smart Pigs can be run through the lines and a system for minor leak detection is a requirement.

Decommissioning/Isolation

Mr. Albert Barden with Albert Barden Consultancy gave a presentation on the decommissioning and isolation of a pipeline based upon his experience in the North Sea. This is documented in more detail in Theme Paper 5 at the end of the workshop proceedings. In 1989 new guidelines were issued to the North Sea Oil/Gas Industry by the Department of Energy Pipeline Inspectorate requiring the installation of emergency shut down (E.S.D.) valves. These valves were to be installed on top sides and subsea. The purpose was to minimize the loss of product from the pipeline in the event of a top side failure.

Two basic scenarios exist that can be used to prepare the pipeline for this work to be carried out in a safe manner i.e.:

Scenario One -

Isolate and displace all the product from the pipeline using an inert medium, usually water or nitrogen. Carry out repairs to the pipeline, followed by recommissioning operations using dry air, nitrogen, methanol swabbing or vacuum drying.

Scenario Two -

Provide localized isolation adjacent to the working area, leaving the work site safe, while the remaining section of pipeline still maintains product. This work can be carried out by one of several methods i.e. the use of:

(a) high differential pig trains

(b) remote controlled pipeline packer tool

(c) pipeline freezing

(d) nitrogen foam inerting

(e) pipe stopple operations

The options available for doing this and the method of determining the most suitable solution depend upon a number of factors:

- type of product
- length and diameter of the line and hence volume of product involved
- facilities for disposal of product
- time available for operations
- space availability at operational location restricting equipment deployment

Bearing these factors in mind, various scenarios can now be considered and the advantages and disadvantages of alternative solutions examined.

Oil Pipelines

Oil pipelines represent a simple problem when compared to gas lines. The volume of product required to depressurize the line is very small. For small volume lines, the simplest solution is to displace the product with water, allowing the work to take place under safe conditions. It is prudent to utilize a low pressure isolation device in the form of a sphere or stopper to ensure that any vaporization of hydrocarbon does not come into contact with the work site.

For larger volume systems, the pipeline can usually be isolated locally to prevent having to displace all the product from the lines. This can be done by displacing one or more pigs down the riser and onto the seabed with water.

Under both scenarios, testing of the completed works is easily performed by hydrotesting. On completion of the work, the pig can be propelled back to the work site by displacing with oil from the far end or, by launching another pig, the train can be pushed to the far end.

Gas Pipelines

On gas lines, we have to vent off large quantities of gas to reduce the pressure in the line. If water is introduced into the line, we have in most instances to dry the line in order to recommission it, in order to prevent hydrate formation and minimize corrosion.

Nitrogen purging can be done; however due to vaporization of condensate, etc., even nitrogen does not guarantee the line perfectly safe. A local isolation is usually required to prevent vaporized liquids from coming into the work site area.

High Differential Pig Train

The pig train concept utilizes proven basic technology in the form of bi-directional pigs and with an in-built factor of safety from the number of pigs being used. Two types of pigs have been developed:

1) High sealant pigs to provide an interface

2) High differential pigs to provide a pressure factor of safety

Most pig trains are designed to hold back 7 to 10 bar of head. Pipelines with condensate have experienced a smaller differential due to the condensate acting as a lubricant around the pigs.

Diesel gel is used to increase sealing efficiency in the pig train. A slug of glycol is also injected and the level of glycol closely monitored in order to detect any movement of the pig train.

Remote Pipe Freezing

The system has been developed to provide a method of producing an isolating plug of a frozen liquid in a pipeline at a location remote from the major items of equipment.

Pipe freezing is not recommended for offshore use due to the difficulties involved and the possibility of hydrate formation afterwards.

Nitrogen Foam

Nitrogen foam is produced by blowing nitrogen gas through a surfactant/water mixture which is closely regulated to obtain the ideal expansion ratio. Nitrogen foam can be mixed and then injected into a pipeline or vessel to suit the requirements of the operation to be performed. Consideration may have to be given to removal of the water upon completion of the operation by drying.

Methanol Drying

Methanol is used to condition a pipeline before the introduction of natural gas. Methanol is an alcohol that is readily mixed with water and is used to remove and replace the water from the pipe wall to prevent hydrate formation.

Repair Hardware/Techniques

Mr. Lee Avery with Big Inch Marine Systems and Mr. Rex Mars with Oceaneering gave presentations on pipeline repair hardware and techniques.

Repair hardware is readily available from the manufacturers and from organizations such as Response to Underwater Pipeline Emergencies (R.U.P.E.). Inventories of fittings for most pipeline diameters are in stock or can be made available at short notice.

There are various types of fittings that can be used to perform a pipeline repair. Each of the different types of fittings have qualities that may benefit an operator depending on the nature of the repair. The forged-on fitting and a mechanical grip type connection are widely used in the industry. Many fittings have variable sealing surfaces such as polymers and/or metal to metal seals. The type of seal that is chosen should be considered depending on the application and product flowing through the pipeline.

These type of fittings do not require welding which has been known to cause many accidents involving pipeline repairs. Many of the fittings can be pressure tested and/or inspected with ultrasonics prior to putting the pipeline back into service.

Many repairs can now be performed by smaller dive vessels due to the utilization of these fittings. The pipelines do not have be moved in most cases, eliminating the need for a larger construction vessel. The other advantage is that the dive vessel can usually respond more quickly if required.

Installation of most repair fittings is relatively quick and easy. The decommissioning and preparation of the pipeline for the repair, normally requires additional time and planning. The removal of the pipeline coating is also a time consuming process.

Riser repairs have been of particular interest due to the hazards of working in the proximity of a platform. Additional safety precautions such as using stopple fittings to isolate the repair area are being used. Some of the stopple fittings are used with a vent in case of a pressure build-up. The stopple is installed in the pipeline below the repair area with a section of pipe connected to the fitting. The vent pipe runs out of the riser pipe to a designated location. This can be an important safety item, although precautions should be taken regarding the location of the vent piping. The repair is then implemented and the stopple fitting is then removed.

Diverless Repairs

Mr. Cliff Chamblee with SonSub, Inc. gave a presentation on diverless pipeline repairs. Due to the increasing water depths of pipeline installations and current limitations on diving depths there is a need for a practical diverless repair operation. As these operations are developed and proven, the use of diverless repairs may become attractive to shallow water operations. The safety aspect alone is a great incentive to use diverless techniques for any of the offshore operations. Many of the new installations are being designed for diverless intervention.

The main tool for a diverless repair is the Remotely Operated Vehicle (R.O.V.). The R.O.V. can be used for many different operations of a repair. It can be used to locate the repair with the help of sonar, pipe tracking equipment, leak detection equipment and video displays.

One type of diverless repair performed to date involves span rectifications. The use of an R.O.V. to install various types of supports under a pipeline span has been performed successfully. Grout bags and structural steel supports have been used to support the pipeline. The most effective use of these varies with the terrain. Grout bags are limited to a five degree slope of the bottom conditions. Special mats used for scour protection are being considered as a potential means of repairing small spans in a pipeline.

Another type of repair performed by an R.O.V. is the installation or retrofitting of anodes to a pipeline. Anode pods are attached to the pipeline with a clamping device. This appears to be an effective method, however the long term contact for the connection may be a problem.

A spool piece repair of a pipeline, typically performed by divers, has not been done by an R.O.V. to date. Tests have been performed utilizing the R.O.V. to perform the jetting, cleaning, cutting and fitting installation operations. The use of a dredging system for jetting and a 30,000 p.s.i. water blaster for coating removal has been applied to offshore projects. Visibility is one of the operational problems associated with this technique. New cameras and sonar equipment have improved this situation.

The proposed methods for cutting a pipeline with an R.O.V. are the grit entrained cutting method, the modified Wachs saw and special explosive shape charges.

Industry Needs

Throughout the Workshop the participants shared their experiences and ideas. The vast knowledge from different parts of the world regarding safe industry practices should be co-ordinated so that everyone can be aware of available technologies. The reciprocal exchange of ideas and information is vital to our industry. The awareness and use of integrity monitoring and inspection systems should reduce the number of pipeline repairs and accidents.

As governmental participation and policy making increases in our industry, the need for additional interaction by our industry with regulatory agencies is necessary. Most governmental agencies welcome the participation by industry because of its vital importance.

The need for additional research and new techniques to safely and effectively perform a repair is required. Due to the instability and economy of our industry, many research programs have been cut. The fact that our pipeline network is aging, increased construction of pipelines and the decision to keep pipelines operating beyond their original intended design lives, should encourage our industry to continue to develop advanced systems for pipeline repairs. Tragic accidents and environmental consequences are unacceptable. Prevention of accidents by using the most advanced technology to improve reliability and safety of our pipeline systems should be the goal of our industry.

WORKING GROUP REPORT 8

- *Deep water considerations*
  Ray Ayers, Shell Development, Houston
  Jesse Wilkins, McDermott Intl., New Orleans

Introduction

This working group considered the unique aspects of deepwater pipeline design, installation, operations and repair. The purpose of this group session was to establish the state of the art of deepwater pipelines, based on discussions of deepwater pipelining experience, and to identify the various research programs that have been conducted, or are in progress, to advance the state of the art.

Industry Experience

For the purposes of this discussion, the distinction between deepwater and shallow water will be drawn at 1000 feet. This represents a practical but not absolute limit for diver-assisted operations. But much of the technology normally associated with deepwater has either evolved from or is migrating to shallow water; layaway flowlines and diverless subsea connections are two examples. On the other side of the line, diver-assisted pipeline operations have been performed in over 1000 feet (Jolliet); and one research center in Germany says experiments have shown divers can safely perform useful work at depths to 2000 feet.

We count about fifteen pipeline and flowline systems installed to date in deepwater, not counting the sixteen layaway flowlines installed offshore in Brazil. The 20-inch Transmediterranean Gas Pipeline system in 2000 feet of water, installed over ten years ago in the Sicilian Channel, is one of the earliest deepwater installations, and still among the most noteworthy because of the extreme water depths and large pipe diameters represented.

Most industry deepwater activity has occurred in the Gulf of Mexico and in the Campos Basin, offshore Brazil. Gulf of Mexico systems include Southern Natural's recent 20-inch gas pipeline installation in 1220 feet, Conoco's Jolliet TWLP development in 1760 feet, Placid's Green Canyon 29 development in 2370 feet, and Shell's Bullwinkle oil and gas lines in 1350 feet of water. The water depth record for a deepwater pipeline or flowline is currently held by Petrobras in Brazil with 8-inch steel flowlines installed in water depths close to 2500 feet using the reel ship, Apache.

There is also considerable near term activity with several deepwater pipeline projects either underway or on the drawing board. Most of this activity remains concentrated in the Gulf of Mexico and includes Exxon's Zinc/Alabaster development in water depths to 1500 feet, the Enserch 441 subsea development in 1525 feet, and Shell's Auger TLP in 2860 feet. Outside the Gulf, Exxon recently installed the Santa Yenez pipeline system in the Santa Barbara Channel in water depths to 1300 feet.

Overall, these and other projects demonstrate that the oil and gas industry has had successful, albeit limited, experience with the design, installation, and operation of pipelines in deepwater.

Over the longer term, operators are considering pipeline and flowline systems for water depths to 6000 feet, mainly in the Gulf of Mexico. As yet, we are not aware of a project committed beyond 3000 feet. In many respects, this frontier represents a significant step-out from past experience, particularly with installation technology. The majority of deepwater lines to date have been installed by conventional laybarge methods, but new and less conventional methods such as J-lay and towing will be more prominently used to install steel pipelines in these depths, particularly larger diameter lines, say over 12-inches.

Concerning deepwater pipeline research activities, perhaps a dozen Industry sponsored research projects on installing and repairing pipelines in water depths to 3000 feet have been conducted over a 20 year time period. Major accomplishments were documented in the mid 1970's with Shell's 2 1/2 year long joint industry research project "Deepwater Pipeline Feasibility Study"[1] involving 36 oil and gas and service companies. Other more recent Shell industry programs include:

- 1986 Deepwater Pipeline, Flowline and Risers - I[2]
- 1987 Deepwater Pipeline, Flowline and Risers - II[3]
- 1988 Repair Program - I[4]
- 1990 Repair Program - II[5]

Industry research on offshore pipelines by the AGA Pipeline Research Committee has been strongly focused on deep water technology. Recent work includes:

- Pipe Collapse Design[6]
- Capabilities/Limitations of S-Lay[7]
- Mechanical Connections for J-Lay[8]
- Diverless Clamp Pipe Repair Development[9]
- ROV Capabilities[10]

Working Group Activities

The session began with a historical overview[11] of deepwater pipelines constructed to date, as well as joint industry research progress, delivered by Ray Ayers, session chairmen from Shell. Next, Dale Reid from Exxon and David Gray from Diverless Systems Incorporated made presentations of their company's views on the state of the art and issues regarding deepwater pipelines. A group discussion then ensued, which considered specific topics within the areas of deepwater design, installation, operations and repair.

The texts of presentations by Ray Ayers (Shell), Don Barry (Shell), Dale Reid (Exxon), and Jay Wilkins and Gary Harrison (McDermott) were integrated into this report, along with results from discussions which took place during the rest of the 8-hour-long-meeting. Table 1 contains a list of potential discussion topics from which the topics of greater interest were chosen. David Grays' presentation, representing a diverless subsea operations perspective, is included as Appendix B.

TABLE 1- DEEPWATER DISCUSSION POINTS

Design

- Normal operating loads
- Hurricanes and loop currents
- Materials
- Code requirements
- Pipe buckling/collapse
- Construction loads
- Row considerations
- Valves
- Suspended spans
- Branch connections
- On-bottom stability
- CP and coatings
- Breakaway joints

Installations

- Site survey
- S-lay vs J-lay, reeling
- Buckle arrestors
- Positioning on a row
- Initiations and terminations
- Pipe joining process
- Tensioning
- Abandonment and recovery

Operations

- Leak detection
- Gas vs oil
- Intelligent pigging
- Emergency and storm response

Repairs (during operations)

- Leak detection
- Dented pipe
- Clamps for pinhole leaks
- Major spool piece repairs

Deepwater Design Considerations

The design principles governing deepwater pipelines are essentially the same as those for shallow water--deepwater pipelines just cost a lot more. Because of cost considerations, there is greater incentive to remove unnecessary conservatism, while still ensuring safe designs.

The current design codes do not distinguish between deepwater and shallow water pipelines. However, we see incentives to improve certain areas of existing criteria in order to address real failure modes, instead of simple stress limits, and to ensure consistency in levels of safety. This approach, often referred to as limit-state design, will not be belabored here, except where it touches deepwater-related issues.

Probably the most important design consideration is collapse. In order to prevent hydrostatic collapse, deepwater pipelines are designed with diameter/wall thickness (D/t) ratios of 25 or less compared to 25-60 for shallow water pipelines. However, over-specification of wall thickness may preclude the selection of a more economic installation method or utilization of locally available contractor equipment. Both the choice of installation method and equipment can be sensitive to pipe weight.

The ANSI/ASME based design codes do not provide design procedures for collapse although other recognized design practices such as the DNV guidelines do. It is up to the designer to select an appropriate design method and apply appropriate levels of conservatism or factors of safety for collapse.

Fortunately, considerable industry research has been performed over the last ten years, aimed at determining and verifying collapse pressures for low D/t pipe. Considerable data has been obtained that addresses effects on collapse due to ovality, eccentricity, dents, and installation loads. Research has also focused on buckle propagation behavior and buckle arrester design. As a result of several joint industry research studies, notably those sponsored by Shell, Battelle, and the Pipeline Research Committee of the American Gas Association, sufficient analytical and experimental data is now available to safely and reliably guide designs.

Pipe Spans

One significant challenge to deepwater pipeline design will be pipeline routing. Deepwater pipelines cannot be easily laid in a straight line because of fault scarps, irregular carbonate topography, hydrate mounds, potential land slide areas, chemosynthetic communities or other problems. Detours on the order of several miles may be required to avoid these problem areas.

J-lay pipelay, as opposed to S-lay and tow methods, is more conducive to shorter bottom spans, due to the low on-bottom horizontal tension in the pipe, as it is laid on the sea floor. Because of the lower bottom tension, J-lay can more readily route the pipeline around on-bottom obstacles. However, even with significant detours, irregular seafloors will cause some pipeline spanning to occur. Large pipeline spans may require remedial support to avoid structural problems, including fatigue due to vortex induced vibrations.

Present survey techniques cannot accurately predict the number, length or height of spans to be expected when crossing an irregular sea bed. Also very little data or knowledge is available concerning the magnitude, duration or extent of hurricane induced currents or the effects of these currents on surrounding sea floor topography. Spans can be corrected after pipeline installation, provided that the height of the span is not too great; however, the cost can become very expensive. Some techniques for span correction are presented in Appendix B.

Additional research is needed on the magnitude, duration and extent of hurricane induced currents and the effect of sea floor topography on these near bottom currents. Also, development of effective low cost methods for vibration suppression and pipe support are encouraged.

Installation

Over ninety percent of all offshore pipelines have been installed using conventional (S-lay) laybarges, including the Transmed pipeline system mentioned earlier. Alternative installation methods such as reeling and towing have also been used successfully in deepwater, although to a much lesser extent than conventional S-lay. The choice of installation methods is considered to be job specific. At this time, there is a cost incentive to extend the use of conventional S-lay vessels and methods into deeper water. In deeper waters, however, S-lay becomes technically and economically unfeasible, and installation options are limited to J-lay or towed systems.

J-lay installation and towing are potentially the most technically and economically attractive methods for installing steel pipelines greater than 12 inches in diameter, in water depths beyond about 2000 to 3000 feet. Towing was successfully used for the installation of Placid's Green Canyon 29 flowline and pipeline bundles. J-lay has not yet been used in deep water; Shell plans to demonstrate industry's first application with the installation of their Auger TLP in 1993. Although J-lay has not yet been used for a major pipeline, it is considered to be safer than S-lay for future deepwater applications. This is due in part to the lower horizontal tension requirements and the ease of dynamic positioning as opposed to cumbersome deepwater mooring systems.

The use of limit state design (ultimate failure state) methods rather than stress-based criteria will allow better use of the structural capacity of the pipe and its material properties during installation. Accordingly, there is an incentive to use a strain-based rather than stress-based installation criterion for deepwater pipelay. This should help remove unnecessary conservatism currently recognized in existing criterion. Thick-walled pipe can be bent well into the plastic range without risk of failure. Reel pipelay and J-tube installation are applications where plastic deformation of the pipe routinely occurs, without harming the pipe.

For an operator, the leading installation issue is determining the economic applicability and technical limits of the four installation methods:

- S-lay
- reeling
- towing
- J-lay

Applicability is sensitive to water depth, pipe size, and pipeline design. Take for example a 12-inch pipeline in 2500 feet of water, which could be installed by any of these four methods. The questions are:

- which is the lowest cost method
- how does the choice of method affect pipeline and tie-in designs
- what technology improvements would help to further reduce installed cost.

Industry research continues to study ways to reduce installation costs. Areas under investigation include extending the applicability of conventional laybarges and reeling technology to deeper water, and improving J-lay productivity through the use of automatic welding or mechanical pipe connectors in lieu of manual welding. Although the basic installation technology exists, contractor equipment and capabilities are very limited due to the few jobs available.

In the final analysis, a pipe failure during construction due to buckling or dropping, etc., may have economic consequences for the owner or the contractor, but has no safety or environmental consequences. Consequently, the choice of installation method alone does not necessarily affect the ultimate safety of the pipeline.

Flexible pipe installation by the reel method will also see increasing use in deepwater where there is technical and economic justification over steel pipe. Applications include pipeline and flowline risers, jumper tie-ins to subsea facilities and export pipelines. Flexible pipe is still an emerging technology that is not specifically addressed in the U.S. design codes. However, industry has had successful experience with flexible pipe for relatively benign riser and flowline applications in both shallow and deep water.

Connections

Whereas divers are often employed to facilitate pipeline tie-ins in shallow water, diverless connections are almost exclusively used in deepwater. Diverless connection methods include J-tube pulls, direct pull-in or deflection tie-ins, vertical stab and hingeover, layaway, flexible jumpers, and various diverless spoolpiece methods.

Subsea connections generally represent the most critical of all operations associated with deepwater pipeline installation. However, this technology should be considered both proven and reliable as demonstrated in several shallow water (Shell/Esso's Underwater Manifold Center, Esso Australia's-Bass Strait Platforms) and deepwater (Placid's Green Canyon 29, Exxon's Santa Yenez Unit) applications.

As in all areas related to deepwater pipelines, there is a significant incentive to reduce connection costs. One way this can be achieved is by relying less on expensive connection designs and operations involving large, complex tool packages deployed from drilling vessels, which represents the current industry state-of-art. One promising technology is the use of so-called passive alignment connection hardware, which utilizes portable tools deployed and operated with the assistance of ROV's. This method will be employed on Exxon's upcoming Zinc template installation in 1992.

Diverless connection technology is also seeing more use in water depths within diver reach due to lower connection costs, diver safety considerations, and improvements in ROV capabilities. One example is Sante Fe's recent Garden Banks Block 224 subsea development where the layaway technique was used to install a subsea tree, flowline and umbilical in 745 feet of water.

Repair

Pipeline repairs will be more difficult and expensive in deepwater. Shallow water repairs are typically performed using divers to install split-sleeve clamps, and spoolpieces. In water depths beyond diver reach, remote operated tool packages, special connection hardware and ROV-based repair procedures need to be developed and used.

The risk of pipeline damage in deepwater is very low and we are not aware of any in-situ repairs that actually have been performed on a deepwater pipeline, beyond diver depths.

An operator would want to be able to respond quickly to a repair need. To achieve such a capability may require significant development, testing, and preinvestment in tools and equipment. The level of this effort depends on factors such as line size, water depth, and whether or not the line is concrete coated. To help reduce the operator's own investment in a standby capability, there is good potential that some industry sharing of repair tools and equipment will come about, particularly as more and more pipelines are installed in deepwater. Until such tools become available, the option of recovering and re-laying a portion of the pipeline remains the most viable option for deepwater.

No off-the-shelf diverless repair system or single contractor repair capability currently exists. The exceptions are two deepwater repair systems that are dedicated to a few large diameter pipelines in the Norwegian North Sea and the Transmed system.

There are three categories of repair:

- Repairs during installation, say for handling the contingency of a wet buckle
- in-situ repairs of small leaks
- in-situ repair of major pipeline damage.

Repairs during installation are the easiest to deal with since the lay vessel is likely to be available to make repairs, and has one free pipe end to work with. Special tools are still necessary to cut, dewater, and retrieve the pipeline to the surface.

In-situ repairs of small leaks and some temporary repairs can probably be handled with a split-sleeve clamp adapted to diverless installation. More significant repairs, say due to third-party damage, would require something like a spoolpiece repair utilizing available mechanical connectors and swivels. As an alternative to on-bottom repair, Shell recently developed a surface lift and layover technique where most repair operations are performed on the water surface after cutting and retrieving the pipe ends.

We are aware of a number of ongoing research efforts in deepwater repair, and we expect to see further significant developments in repair strategies and contractor capabilities as more and more lines are installed in deepwater.

Corrosion Protection

Deepwater pipelines must be designed and operated to avoid both internal and external corrosion. Anode and coating designs should be sufficiently robust. Pipeline operations should include pigging to remove settled fluids in gas pipelines and to control water in oil lines. Any potential problems with corrosive fluids should be controlled by proper choice of pipe material during design, possibly augmented by chemical injection in the fluid stream. There is a need to review the MMS offshore corrosion failure data to find the root causes of pipeline mid-line corrosion to ensure that the causes of past failures are adequately addressed in deepwater failures. There appear to be differences in failure statistics and causes depending on whether the line is transporting oil or gas.

Inspection

A discussion ensued concerning the applicability and use of intelligent pigs to detect flaws and corrosion damage in offshore pipelines. Points raised during the meeting were as follows:

- Accurate detection and location of local pipeline defects is currently beyond the state-of-art for offshore pipelines.
- Deep water will make location of local defects even more difficult.
- Inspection pigging technology is relatively mature, but is used more in the North Sea than in the Gulf of Mexico, and only then for gauging the general condition of the line rather than searching for any local defects.
- Making any pipeline inspection piggable will add to the complexity and cost of the pipeline (and riser) system and reduce or eliminate the possibility of subsea pipeline branches or connections.

Appendix A contains written remarks prepared and distributed to the group by D.W. Barry of Shell, which are germane to the subject.

Safety Valves

Subsea safety valves on gas pipelines can be used to protect an offshore platform from potential damage due to a rupture of the gas export pipeline (including platform piping and riser). The group appreciated the value of safety valves in general, but felt that subsea valves would be extremely difficult (cost isn't the big issue) to install and maintain (using diverless methods). There are concerns with their long-term reliability and the maintainability of safety valves in general. One solution is to place them in the riser where they are accessible.

Conclusions

The Deepwater Considerations Working Group evaluated design, installation and operations unique to deep water (over 1000 foot depths). Experience has been gained with recent pipelines/flowlines to 2500 feet (Placid, Brazil) and deeper projects are underway (Auger). Numerous private and joint industry research programs have been conducted over the last 20 years relevant to deepwater pipelines.

The design principles for deepwater pipelines are the same as for shallower waters, but costs and installation risks are higher. Specific areas of concern are

- long unsupported pipe spans caused by irregular bottom conditions,
- pipelay cost/risk considerations,
- subsea connection issues,
- repair difficulties and costs,
- line integrity and inspection, and
- safety valves.

In summary, with proper design, careful installation, and with prudent operations, deepwater pipeline systems will be safer, but certainly more costly than those in shallower waters.

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APPENDIX A - INSPECTION CONSIDERATIONS

by

D. W. Barry
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The Pipeline Safety Reauthorization Act of 1991 as proposed will require intelligent pigs to be run in pipelines in environmentally sensitive areas. If offshore is judged to fit into this category and intelligent pigs are required to be run, serious problems should be expected. Although these tools have been used and developed for over twenty years, their flaw detection and discrimination capabilities still leave a great deal to be desired.

Accuracy of assessing the depth of wall loss due to corrosion depends upon knowledge of the geometry of the flaws. The lack of flaw geometry knowledge makes it necessary to perform "calibration digs" to get any meaningful data from the run. Calibration digs require excavation of the pipeline and measurement of flaw dimensions at locations where flaws are indicated by the tool. Even with calibration digs, defects reported to be greater than 50% wall loss have been found to be less than 25%.

Calibrating intelligent pig runs in shallow water offshore pipelines will be difficult and extremely expensive. Calibrating runs in pipelines beyond diver depth is judged to be impossible.

Another detriment to this requirement is the following: Many deep water fields are expected to require very lengthy pipelines to reach any present infrastructure. An intelligent pigging requirement makes it impossible to connect different size pipelines together sub-sea. This would necessitate each deep water facility to install its own separate pipelines all the way to a shallow water infrastructure, which would be very expensive; or would require all new pipelines to be brought onboard existing deep water platforms with an inherent reduction in safety to the pipelines and the platforms.

APPENDIX B - DIVERLESS SUBSEA OPERATIONS PERSPECTIVE

Diverless or ROV support of Deepwater pipelines can be summarized in three basic areas:

1. Pre-installation site surveying
2. Installation support to the lay process
3. Repair during pipeline operation

Pre-installation site surveying:

The industry standard for deepwater pipeline routes is for the ROV to fly the right-of-way doing a detailed bathymetry contour map. Subsea ROV support for site surveying is adequate for current requirements. Most considerations are economic related rather than technical issues of competence. Typical capabilities rest primarily on the positioning/surveying company - generic ROV support is competent in all arenas.

Installation support to the lay process:

Subsea support for pipeline installation can be broken down into three categories:

1. Survey and support of as-laid pipeline
2. Survey and support of tie-in activities
3. Correction of anomalies occurring during the lay process
    a. Wet buckle recovery
    b. Span supports

Survey Support

Typical ROV support includes a vessel, surveying team, 24 hr. ROV crew and bathymetry capability. As noted earlier, ROV support for survey and positioning requirements is competent and considerations are economic, not technical capability.

Tie-in Support

Various methods for diverless subsea tie-ins have been used. These include:

-J-tube pull
-Bottom tows plus deflection

-Surface lay plus deflection
-Hinged surface connection to tree and lay away
-Connection via dogleg spool piece

Typical subsea tasks include:

Support laydown in target area: No technology development required for survey inspection aspects. Abandonment and recovery aspects are similar to Wet Buckle Recovery (see later discussion).

Running and connection of pulling cables, subsea: To date, efforts have been based on surface tow methods. Offshore operations this winter plan subsea ROV based towing methods. Technology requirements are pending these operations.

Monitoring of deflection: Similar to surveying and pipelay support inspections - no development required.

Pull-in and locking of pipeline to connector fixture (surface or subsea winches): Surface winches with subsea routing of cables through sheaves and guides is the norm. Subsea wenching offers significant advances and economic advantages but is unproved - technology development could improve willingness to utilize subsea options.

Pipeline connection and seal test: See later discussion on pipe repair for similarity. Deflection operations this winter may also contribute track record experience.

Operation of support valves and other functions: Subsea operation of valves and other special functions is in its infancy from an offshore experience standpoint. These operations are becoming increasingly common. This is an area where major developments and capabilities have developed over the past two or three years, but most of the hands on experience has been limited to tank testing. It is significant that operators are now willing to place contingency requirements of this nature as the responsibility of diverless methods. Additional development is required and is evolving as diverless intervention increases its capabilities.

Contingency backups: As noted in the previous discussion, this is an area of increasing diverless involvement and should be expected to grow in the near future. Support of technology development is required to continue this growth.

Anomaly Correction

ROV support of wet buckle recoveries (installation of a recovery head, either: external, internal, or saddle types) has undergone significant developments and testing over the past two years. However, because of the similarity of tasks to the pipe repair discussion of the following section, it will not be discussed in this section.

Span Supports

Span supports is an area where additional technical improvements are needed. To date, most span supports are of two types:

1. Grout bags/sand bags
2. Mechanical "jacks"

Grout bags are the industry standby. They are typically derived from shallow water diver type installations. Grout bags are limited in their height considerations - too small or short a support and the bag and deployment means cannot be positioned under the pipe; too high or tall, and the bag becomes too massive at the base. Practical limitations suggest that grout bags are most attractive for spans of between 2' and 8', with up to 10' feasible but not desirable. Grout bags are also very slope sensitive - more than a 5 degree slope and the bag may be unstable on its foundation. Spans are usually caused and found in areas of sudden and significant slopes. Deployment of grout bags, both from the surface support requirements, and from the subsea standpoint are also challenging.

Mechanical jack type supports have been used recently, on hard bottoms, and on spans of much larger heights than grout bags. They do not have the same mud mat area nor stability. They are much less expensive in total support cost, based primarily on a much lower installation cost. Any resistance to their use has focused on the resistance of pipeline operators to install any mechanical device which is attached to the pipeline.

The Gulf of Mexico span supports typically must be installed in areas of very soft bottom (100 psf or less shear strength), on slopes of 5 to 15 degrees, and supporting heights of 2' to 15'. Technical development of alternative concepts should be considered such as piles with mechanical clamps, better grout support configurations, and bipods.

Repair during operation:

Due to economic considerations, repair of pipelines by diverless methods have been the subject of many years of study, and in several instances, the outlay of tremendous amounts of funds to inventory a diverless capability for pipe repair. ROV's have undergone tremendous improvement in recent years in both capability and reliability. They are now competent in tasks that even three years ago were not generally accepted as ROV capable.

However, much of these capabilities are test and tank proven, but not offshore operationally experienced. Actual experience is required in an offshore environment, and for this, the financial responsibilities will have to be shouldered, preferably in a test environment, without the added pressures of operational downtime.

Repairs actually start with leak detection and leak location. Existing capabilities are crude at best and additional development and adaptation to the deepwater environment is needed.

There are three basic types of pipe repair:

1. Wet buckle recovery (from installation damage)

2. Clamp repair for pinhole leaks

3. Spool piece repair for major damage

For the purpose of this discussion, the tasks required for support of each of the three types are similar, and will be discussed only as a generic spool piece repair.

A typical spool piece repair scenario consists of a major task in support of the repair process. Each task will be discussed below in minimum detail to define the current state-of-the-art and whether further development is required.

Pollution control: Once a leak has been located, what pollution control requirements will be required? If a gas leak, probably none, but if oil is leaking, can production be continued if the leakage can be controlled? Even if the pipeline is shut in - how will leaking fluids be controlled, contained and collected until the pipeline has emptied? A limited capability has been explored on the West Coast due to its extreme environmental sensitivity, but further development is required here.

Select repair site: Similar to survey support and inspection, no development required here.

Rough cut: The classic approach for a rough cut has been shaped charges. Recent environmental concerns suggest that shaped charges may not be an acceptable cutting method in future years. A "first cut" mechanical method must be developed. Recent land/tank testing has demonstrated alternatives which include a mechanical guillotine saw, and grit entrained abrasive jet cutting. Further work is needed.

Sling old spool: While not an easy task, this is within the current capabilities of ROVs to perform.

Pipe elevation, exposure and stabilization: Dredging by ROV is current technology. Pipe elevation by jacking or lift bags has no track record, but the detailed steps have been performed in other operations and can be assumed to be state-of-the-art. Stabilization, depending upon the requirements, is very similar to span supports and while development is needed in the span support area, previous operations have demonstrated the ROV capability to successfully perform these operations. No development required in this area.

Coating removal: This requirement can be expanded to include all coatings including FBE and PE. The area of coating removal is perhaps the biggest area where development is required. Even with divers, coating removal is a process that takes days; diverless operations, if based on existing technologies, are limited to high pressure water blasing, and compliant grinders.

Make clean cut: This is an area where significant development and tank testing have occurred recently. No underwater operational experience has occurred however, and additional experience is needed. As noted under rough cut, the primary candidates are a mechanical guillotine saw and abrasive jet cutting.

Pipe end preparation: Operational experience with compliant grinders is growing and a case can probably be made for existing technology being available to accomplish the dressing of a pipe end. Weld bead removal must also be considered and is included within the scope of this task. There is no existing track record for diverless removal of a seam weld and development is required for this operation.

Spool measurement: Spool measurement can be by two existing methods: high resolution sonar can measure lengths of 40', with both pitch and yaw angles to acceptable accuracy's; mechanical taut wire methods also exist that can acceptably measure lengths and pitch/yaw angles; for very high accuracy measurements, acoustic arrays can be used, if the economics can be justified.

Connector and spool piece installation: both tasks have been lumped under a single heading. A generic description that would include the other repair cases (wet buckle recovery-recovery head installation; pinhole leak-split sleeve clamp) is positioning of a high mass object to precise requirements on or around a pipeline (end). This is an area where recent developments have expanded the state-of-the-art. Tank testing has demonstrated the ability to place a 2000 lb. mass, buoyantly support inside, over the end of, or over the top of a pipeline, in a satisfactory manner (clearances are of the order of 1" or larger). Additional development is required to accomplish the same task with much larger masses, when clearances are of the order of .1" or less.

Test pipeline: The implied task here is a seal test for the various connectors and their seals. It is assumed to be a hot stab hydro type test for which sufficient track record exists. No additional development is required for this task.

Repair Equipment

It should be noted that repair connectors are unique designs, few of which have ever been built, tested, or installed in typical service. Diverless installable connectors are very expensive, and usually require 3-6 months to manufacture, as they often have not been detail designed in all pipe sizes. Consideration should be given to the nature of the connector design: type of seal, redundancy, etc.; diverless requirements for installation support; actuation means to lock the connector to the pipe and to set the seals. No stock of such connectors is available.

As a final statement, few of the tools required for support of a diverless pipe repair exist off-the-shelf. If built, tooling is unlikely to be available to callout requirements. An ROV capable of supporting the heavy requirements of such pipe repair, is also probably not available on a callout basis. The exact definition of such an ROV is debatable, but probably of the heavy work class, with a minimum of 50 HP and dual manipulators.

THEME PAPER 1

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Corrpro Companies

"CORROSION CONTROL SURVEY METHODS FOR OFFSHORE PIPELINES"

Introduction

Construction, operation and maintenance of offshore pipelines and other facilities is tremendously expensive. The consequences of an offshore corrosion failure can be devastating. For these reasons, cathodic protection has become a universally applied technique for mitigating corrosion on marine pipelines.

Marine pipelines are typically provided with cathodic protection by bracelet anodes of zinc or aluminum. Impressed current systems at platforms or onshore are also used, as well as hybrid systems which employ a combination of the two techniques.

Whatever the method of applying cathodic protection, the primary concern is arresting corrosion. For cathodic protection to be effective in arresting corrosion, a properly planned program of monitoring, inspection and maintenance is essential.

The most widely accepted method of evaluating cathodic protection on pipelines and structures is through the use of potential measurements. Potential measurements on offshore pipelines have traditionally been recorded only at readily accessible locations such as platform risers, wellheads, and test stations located near shore. Divers can be used to take potential measurements on submarine pipelines at discreet locations, but this procedure is much too costly to use extensively. Monitoring of pipeline cathodic protection only at platforms or shore installations provides limited information. It is possible that serious corrosion can be occurring on a pipeline even when potentials at a riser or test station satisfy the criteria for cathodic protection.

Corrosion surveys and inspection of offshore pipelines are particularly important at this stage in the development of our offshore petroleum resources. Many existing offshore pipelines are reaching the end of their cathodic protection system design lives. Decisions must be made as to if and/or when additional cathodic protection must be retrofitted to prevent corrosion failures. The data provided by corrosion surveys and inspection plays a key role in this decision making process.

The relatively recent industry move into "deep" water has also had a tremendous impact on corrosion control practices. Deep water pipelines present new challenges for design, maintenance, inspection and retrofit of corrosion control systems. The advent of the remotely operated vehicle (R.O.V.) which has become commonplace, has radically altered corrosion survey and inspection practices.

Probably the single most important development in the last several years with respect to offshore corrosion survey and inspection methods is the use of computers. Computerization of survey data acquisition, processing and management has provided the means for development of the state of the art corrosion control techniques used today. These include close interval pipeline surveys, modeling of platform cathodic protection and inspection data management systems.

The purpose of this paper is to present an overview of corrosion control survey techniques in use today for monitoring of offshore pipelines.

Towed Vehicle/Trailing Wire Pipeline Survey

The Towed Vehicle/Trailing Wire potential survey is one of the most widely used methods for monitoring cathodic protection levels along offshore pipelines. The survey is performed by making a test connection to the pipeline at an accessible location such as an offshore riser or onshore test station. Alternatively, the survey may be performed with a test connection to a stationary electrode placed on the sea floor at a location where the pipeline potential is known. A silver/silver chloride reference electrode is towed above the pipeline from a vessel while maintaining the test connection. The pipe-to-electrolyte (P/E) potential is measured and recorded on board with a computerized data acquisition system. The potential is displayed on a video terminal and plotted on a graphics printer (1) (see Figure 1).

Typically, a surface positioning system such as Syledis or Star-fix is used to position the survey vessel. The surface positioning system may be electronically integrated with an acoustic positioning system. Together, the integrated positioning systems provide towed fish position relative to the as-built coordinates of the pipeline. Where as-built coordinates are accurate, an integrated positioning system allows the towed fish-to-pipeline distance to be maintained within ~15 meters, in most cases.

In shallow water, a portable marine magnetometer may be used to locate the pipelines which are then marked at regular intervals using temporary buoys. The survey is performed by following the line of buoys with the survey vessel. Downline position may be approximated using wire distance or more accurately using electronic distance measuring equipment.

The foremost objective of this type of survey is to determine the general level of cathodic protection relative to the N.A.C.E. criterion of -800 millivolts to Ag/AgCl. Figure 2 shows a typical P/E potential profile. Study of the profile shows an elongated depression in potential values associated with an apparently bare or poorly coated tap value. Note that the effects of the bare area are recorded over approximately 4,000 feet centered at the tap valve. This smooth shape is typical of potential profiles recorded using the towed fish/trailing wire method and is due to the low resistivity of the seawater and the averaging effect caused by the "semi-remote" nature of the towed fish.

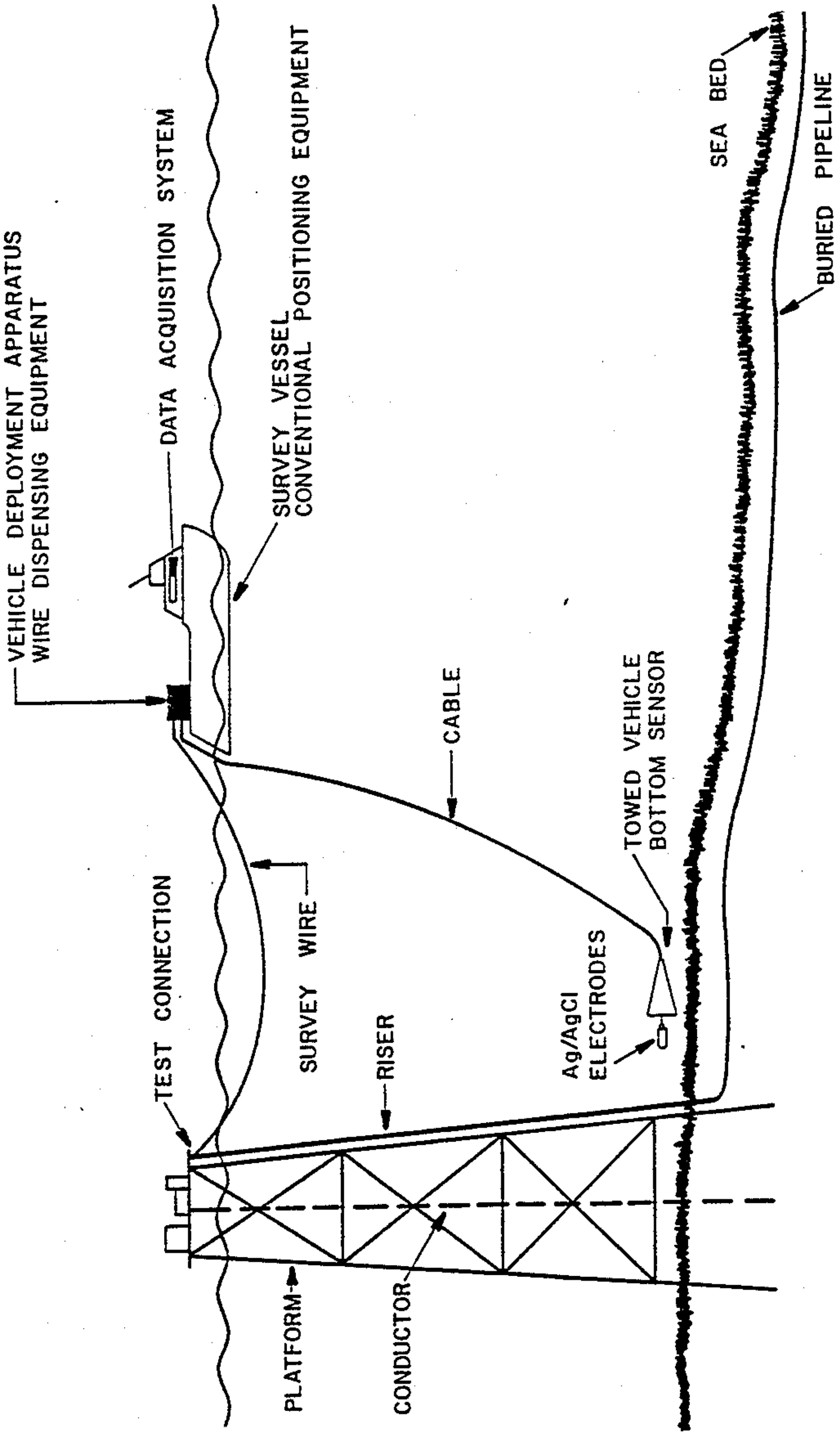

Figure 1 - Diagram of Towed Vehicle/Trailing Wire Pipeline Survey

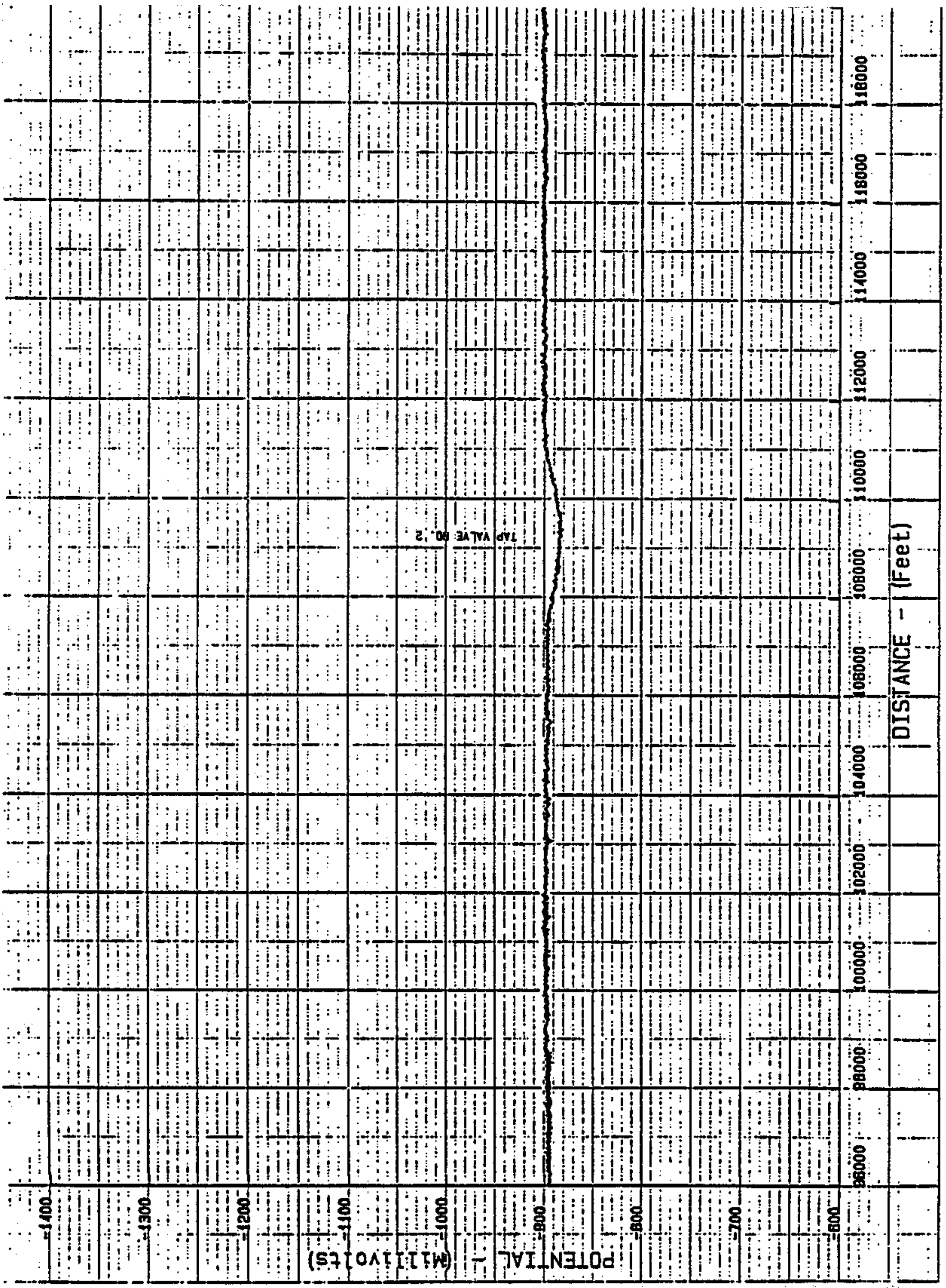

Figure 2 - P/E Potential Profile - Towed Fish Survey

The towed fish/trailing wire survey can also provide information to determine magnitude and direction of long line currents, electrical interference and current requirements.

When used on pipelines equipped with an impressed current system, the current source (s) is typically interrupted at frequent intervals to provide both current "on" and "off" profiles. On pipelines receiving impressed current, the technique is typically more sensitive to local potential variations than on galvanically protected pipelines. This is due to stronger electrical field gradients and the remote nature of the impressed current source.

The primary concern voiced regarding the towed fish/trailing wire survey method is the effect of electrode position relative to the pipeline. The true path of the towed electrode is an elongated "S" pattern, back and forth over the pipeline, as the survey vessel constantly corrects its course to follow the pipeline. Vertically, the electrode is typically maintained within 1 to 5 meters above the sea floor.

Collection and analysis of several thousand miles of close interval potential data over the last 15 years from both towed fish and R.O.V. assisted techniques, in addition to field tests have yielded the following information:

1. On a well coated pipeline equipped with bracelet anodes, anomalies such as individual anodes and areas of minor coating damage are typically detected only when the measurement electrode is within approximately 3 pipe diameters from the anomaly. The poorer the coating quality, and thus presumably the higher the anode output, the greater the electrode-to-structure distance at which an anomaly is detectable. Except in brackish or fresh water, and/or pipelines receiving impressed current, anomalies such as bracelet anodes and minor coating flaws are not detected using the towed fish/trailing wire technique. Depending on coating quality and depth of burial, these anomalies may be detected using R.O.V. aided techniques.

2. When electrode position is maintained within approximately 15 to 20 meters, which is generally the case using the towed fish/trailing wire method, "long line effects" such as those caused by areas of major coating damage, electrical interaction between the pipeline and continuous platform jackets, and large "point" current sources such as anode sleds or impressed current sources are readily detected.

3. Comparison of data collected using the towed fish/trailing wire method with data recorded using an R.O.V. aided method on the same pipelines, has shown that the overall measured potential levels were approximately the same (+20 mV). The primary difference was in the detection of anomalies such as minor coating flaws and individual bracelet anodes. Fortunately, in seawater and saturated muds, where resistivity values are very low compared to land based pipelines, protective current

from bracelet anodes is easily delivered to coating flaws several thousand feet away. This effect, coupled with minimal electrolyte IR drop at the cathode caused by low resistivity, results in potential profiles on typical submarine pipelines that show little localized variation in potential at coating holidays, even with the measurement electrode located within 1 to 3 pipe diameters from the pipeline.

Evaluation of over 330 kilometers of close interval potential data recorded during R.O.V. aided cathodic protection surveys in the Gulf of Mexico, Gulf of Suez, West Africa, and U.S. West Coast showed 53 anomalies indicative of coating holidays. Of these anomalies, 52 exhibited P/E potential shifts less than 10 mV., with one coating flaw at a flange showing a 15 mV. shift. Discussions with other pipeline operators who have run R.O.V. assisted surveys generally support these findings.

This information is valuable for the purpose of interpreting the "semi-remote" potential profiles obtained from towed fish/trailing wire surveys. For example, if the general potential level on a pipeline is -830 mV to Ag/AgCl, as measured using the towed fish/trailing wire technique, the probability of localized potential values being less than -800 mV. is very low. Analysis of data from both towed fish/trailing wire and R.O.V. assisted techniques shows that, with the exception of potential spikes at anodes (detected by R.O.V. surveys only), most potential variations occur over large distances. These include effects associated with electrically continuous jackets and pipelines, general coating and anode deterioration, and attenuation of P/E potential as distance from an impressed current source increases.

The primary difference in the nature of the data provided by towed fish/trailing wire and R.O.V. assisted surveys relative to the "gross" effects noted above is that the R.O.V. aided survey provides electric field gradients and visual information from sacrificial anodes. Of course, on buried pipelines where close access to anodes is impossible, the value of the electric field gradient data is often limited.

R.O.V. Assisted Remote Electrode Survey

The most commonly used R.O.V. assisted survey method is the Remote Electrode Survey. This technique has been popular in the North Sea for nearly ten years and is used as a component of many pipeline inspections or surveys.

The remote electrode survey measures the potential between a Ag/AgCl electrode positioned just above the pipeline and a "remote" electrode located near the water's surface above the pipeline. This measurement is used in conjunction with direct contact P/E potential measurements at anodes and other accessible locations to produce a continuous P/E potential profile. A schematic of the remote reference electrode survey is shown in Figure 3.

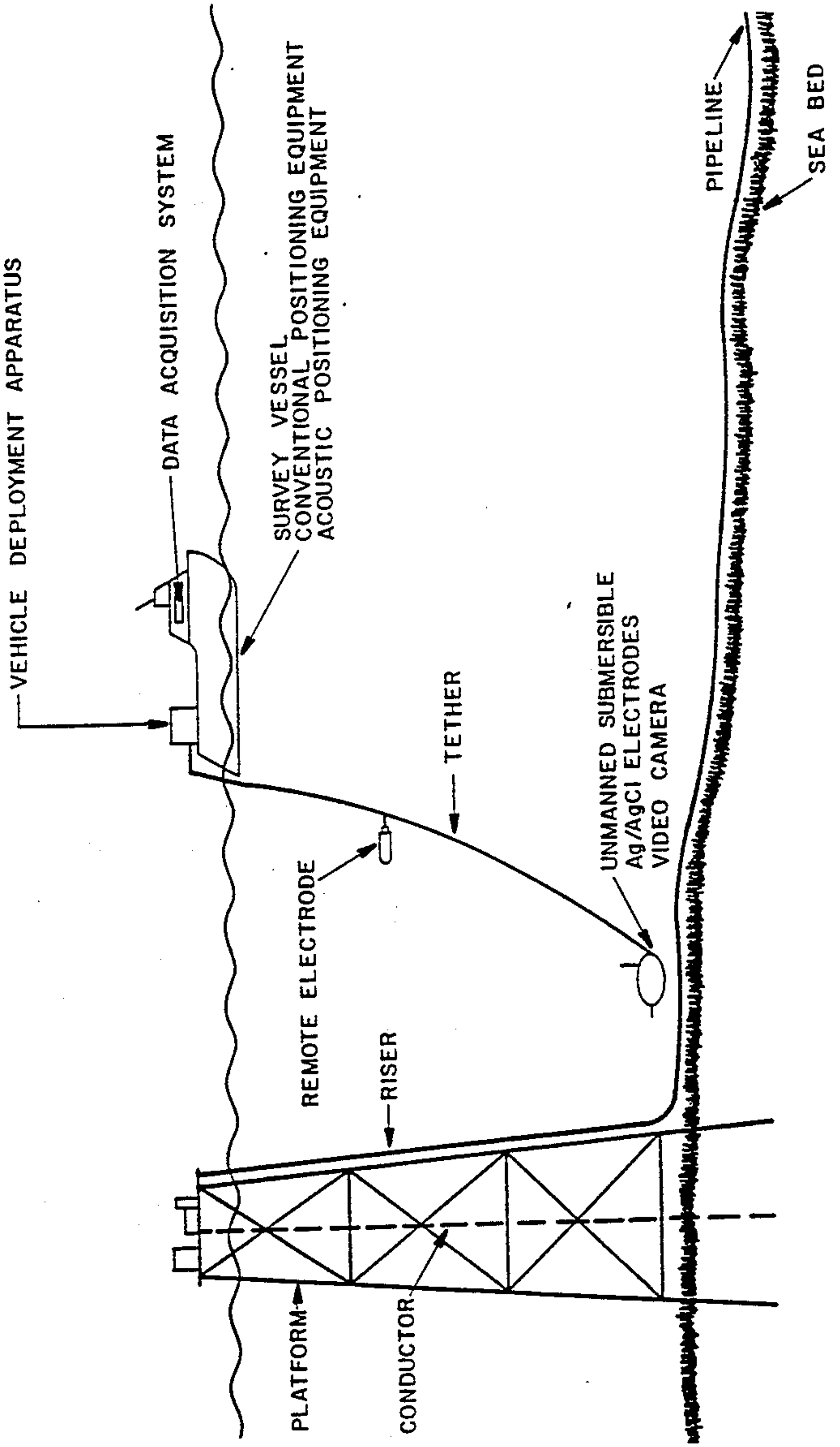

Figure 3 - Diagram of R.O.V. Assisted Remote Electrode Survey

At the start of a remote electrode survey, a direct contact P/E potential is measured at an accessible location such as a bracelet anode. Simultaneously, the potential between the electrode close to the pipe and the remote electrode mounted on the submersible umbilical is recorded. This establishes the fixed voltage offset between the pipe potential and remote earth. The two electrodes are then moved down the pipeline and the potential between the electrodes is continuously recorded. The P/E potential at any particular point on the pipe is the P/E potential recorded by direct contact, plus the voltage offset between the dose and remote electrodes at the point of direct contact, minus the potential between the remote and close electrodes at the particular point.

Reading location is typically determined using conventional electronic surface positioning (ship location) interfaced with underwater acoustic positioning (R.O.V. location) and, in some cases, pipe tracking equipment. Position fixes are electronically entered into the cathodic protection survey data stream at fixed intervals and at anomalies. The survey data is later plotted versus pipeline stationing to provide a detailed continuous potential profile. A short section of typical data is shown in Figure 4. Study of the data indicates the presence of two functioning bracelet anodes and two poorly coated field joints.

The primary advantage of the submersible technique is the increased sensitivity to minor changes in potential assuming that the measurement electrodes can be maintained within approximately 2 to 5 pipe diameters of the pipeline. The exact distance at which anodes and other anomalies are detected varies and is, of course, a function of coating quality and anode activity, as noted earlier. The survey provides a detailed P/E potential profile, pinpoints the location of problem areas, and provides information concerning the cause of a problem. The R.O.V. assisted potential surveys are ideally performed in conjunction with electric field gradient (cell-to-cell) measurements. This provides even greater resolution of anomalies and aids in the interpretation of the P/E potential data. Note that on buried pipelines where burial depth exceeds 2 to 5 pipe diameters, anodes and minor coating flaws may not be detected.

The remote electrode technique has distinct advantages over the towed fish/trailing wire technique relative to sensitivity to detailed anomalies. However, due to the requirement that the surface (remote) electrode be truly remote from electric fields associated with the pipeline and other structures, the technique has limited applications.

The remote electrode technique is a reliable technique for measurement of pipe-to-electrolyte potential on a submarine pipeline only where the following conditions exist:

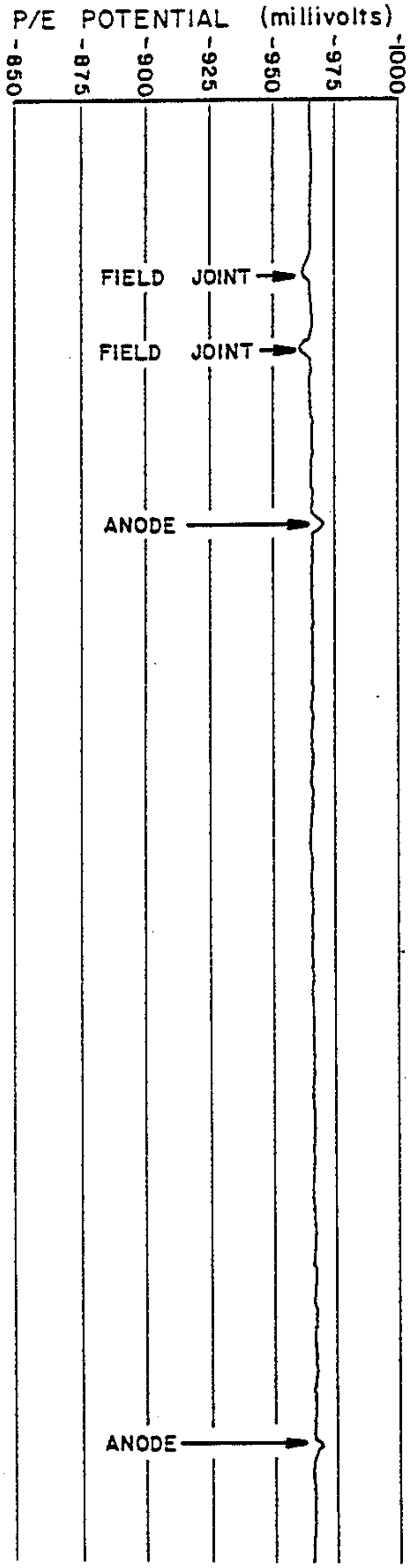

Figure 4 - Typical Potential Profile - R.O.V. Assisted Survey

1. The "remote" reference electrode is maintained at a distance of at least 25 meters from the R.O.V. mounted "close" electrode. This typically limits its use to water depths in excess of 30 meters.

2. The "remote" electrode is truly remote from all electric fields associated with the survey vessel and/or cathodically protected production platforms associated with pipeline risers. Experience has shown that a minimum distance of 200 meters from platforms must be maintained in order to achieve accurate results.

3. Direct contact potential measurements are made at a minimum of five kilometer intervals for correction of remote electrode potentials. This is necessary to account for drift in remote electrode potential caused by 1) long line P/E potential variations, 2) variations in salinity and temperature from surface to the bottom, 3) electrode instability, and 4) effects of stray current from the surface vessel. Ideally, direct contact calibrations should be made at 1 to 2 km intervals.

4. On long sections of buried pipelines, the potential of the remote electrode to a stationary electrode is continuously monitored.

5. The pipeline is not receiving cathodic protection current from an impressed current source.

If performed correctly, this technique will accurately account for most variations in "remote" electrode potential. Note however that the technique is only as good as the quality of the stationary electrode and the insulation of the wire used to maintain the connection with the electrode. It is recommended that the fixed electrode be deployed at a maximum of 10 kilometer intervals to ensure that the calibration is not adversely affected by telluric interference or other measurement errors.

These limitations are well documented by research bodies such as Det Norske Veritas (2) and also by most companies regularly engaged in the survey of submarine pipelines. Based on these requirements, the remote electrode technique is best suited for survey of unburied or partially buried pipelines in water of over 30 meters depth, equipped with a galvanic cathodic protection system.

R.O.V. Assisted/Trailing Wire Pipeline Survey

This technique uses the same principles as the towed fish/trailing wire survey, but an R.O.V. is used to carry the measurement reference electrodes along the pipeline instead of a towed fish. Figure 5 illustrates the technique. Note that the R.O.V. is only used as a vehicle for the reference electrode. All wire handling and data acquisition are performed on board the support vessel which is connected to the R.O.V. by a tether.

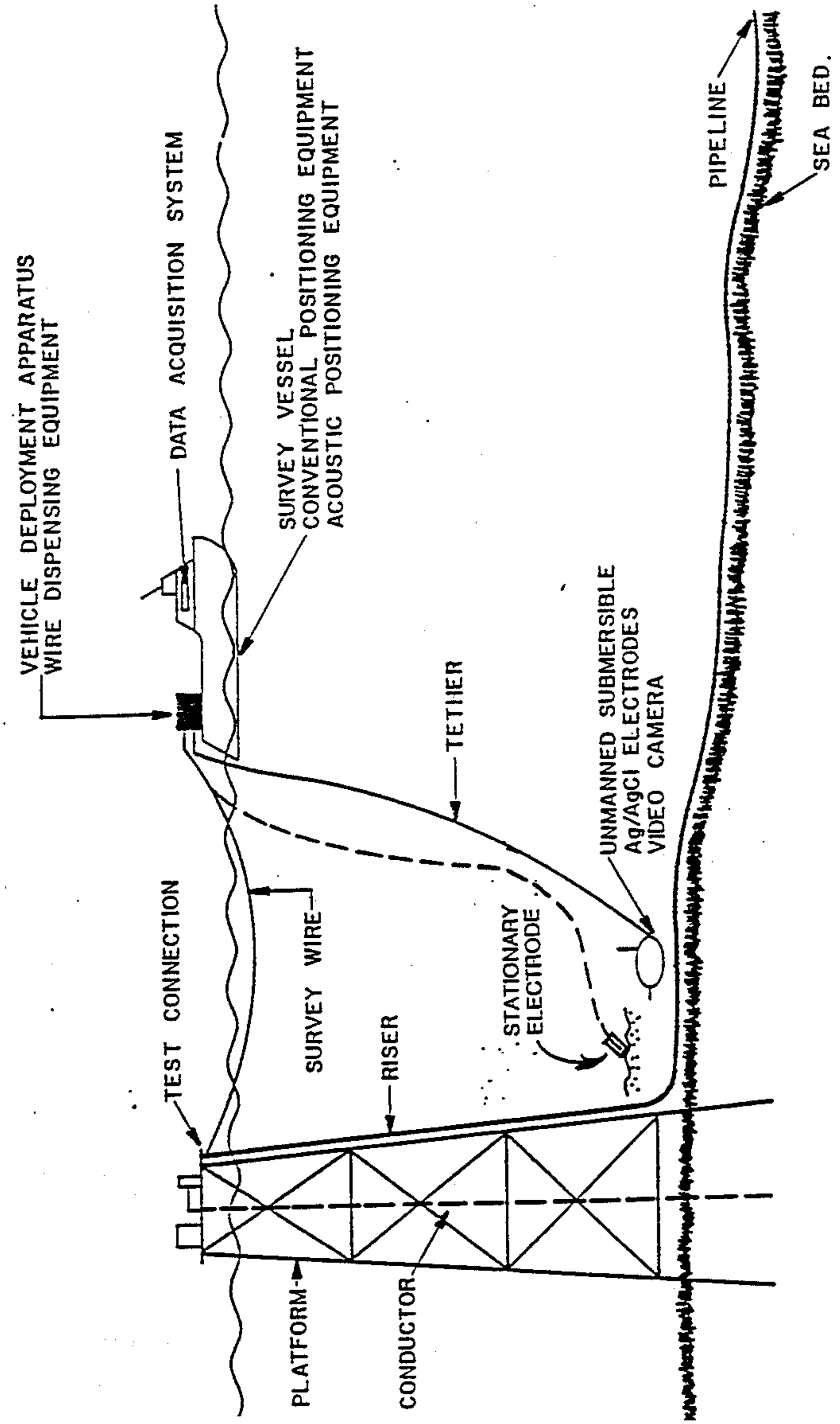

Figure 5 - Diagram of R.O.V. Assisted Trailing Wire Survey

With respect to R.O.V. positioning, electric field gradient measurements and data acquisition, the techniques are the same as those described above for the R.O.V. Assisted Remote Electrode Survey.

Unlike the remote electrode method, the R.O.V. assisted trailing wire survey uses a test connection directly to the pipe or to a stationary electrode on the sea floor. A direct connection to the pipeline is typically used when the survey run commences at or near a riser.

If the survey is started at a location on the pipeline not readily accessible to a riser or other above water test point, the procedure is modified. Instead of making a connection to the pipeline, a weighted Ag/AgCl reference electrode attached to a disposable wire is lowered to the sea floor near the pipeline. The location of this electrode is not important since it serves simply as a fixed voltage source. The inspection vehicle, equipped with a metallic contact probe and reference electrodes, records a potential measurement at the closest accessible test location which is generally a bracelet anode. The potential is recorded between the pipeline and the stationary electrode on the sea floor. This potential value is entered into the computer as a fixed offset.

The survey then proceeds by continuously measuring the potential between the fixed electrode and the moving electrode mounted on the vehicle. The pipe-to-electrolyte potential at any point along the pipeline is simply the starting potential plus the stationary to moving electrode potential value at that point. As would be expected, this technique yields a potential profile identical to one recorded using a physical connection to the pipeline (3).

The primary advantage of the trailing wire technique over the remote electrode technique is its wider range of applications. Since a fixed reference is used as a stable electrode, instead of a moving "remote" electrode, fewer direct contact measurements are required. This makes this technique better suited for survey of continuous or intermittently buried sections of pipeline. Additionally, use of a fixed reference makes R.O.V. assisted surveys on pipelines in shallow water, and equipped with impressed current, feasible.

The chief disadvantage of the trailing wire survey is that additional equipment and personnel are required. This includes the trailing wire, wire dispensing equipment and personnel to tend the wire.

The most technically and economically feasible method of surveying many pipelines is to utilize a combination of the remote electrode and trailing wire techniques. The remote electrode technique is used for unburied or partially buried sections of pipelines while the trailing wire method is used adjacent to platform jackets, and on continuously buried and shallow water sections.

Electric Field Gradient Survey

Electric field gradient (E.F.G.) measurements are usually made in conjunction with potential measurements obtained using an R.O.V. E.F.G. measurements are made by measuring the potential of two electrodes placed at a known distance apart in a plane perpendicular to the pipeline. This is typically accomplished by mounting two or more electrodes on an R.O.V., aligned so that they are normal to the pipeline, as the R.O.V. proceeds along the pipeline. The electrodes may be spaced from a few inches apart to over two feet apart depending on the equipment.

One operator uses a rotating "T sensor" with two electrodes to measure E.F.G. The sensor is rotated to eliminate errors caused by electrode potential drift over the course of a survey. The operator claims precision of up to 1 micro-volt/cm using this technique. (4)

A typical plot of E.F.G. measurements on a weight coated pipeline with bracelet anodes is shown in Figure 6. Electric field gradient measurements are used to detect changes in current density and direction at all points along a pipeline. This allows detection of anomalies such as nonfunctioning anodes, coating holidays, and defective field joint wraps which may not be detected by P/E potential measurements. E.F.G. also provides data useful for rough estimation of current densities associated with anodes (current output) and coating holidays. Please note, however, that due to the complex nature of the pipeline environment and the E.F.G. measurement, accurate calculation of anode output is extremely difficult, if not impossible, using existing survey techniques, particularly on partially or totally buried pipe. A number of variables must be considered in this calculation including electrolyte resistivity, degree of anode burial and anode sensor geometry.

E.F.G. measurements are also useful for determining location and relative severity of coating holidays, and for locating disfunctional anodes. The measurements can also provide a useful comparative estimate of anode outputs. E.F.G. measurements are most valuable when used in conjunction with P/E potential surveys or with direct P/E potential readings taken at frequent intervals along pipelines.

Conclusions

All of the survey methods discussed above have been used extensively and are constantly being modified and improved. The choice of the method, or combination of methods, is dependent on a wide range of factors including water depth, water currents, location, depth of burial, size or length, cathodic protection system age, and cost. The requirements of each individual pipeline or structure will help dictate the method to be used. In general, the following guidelines are offered:

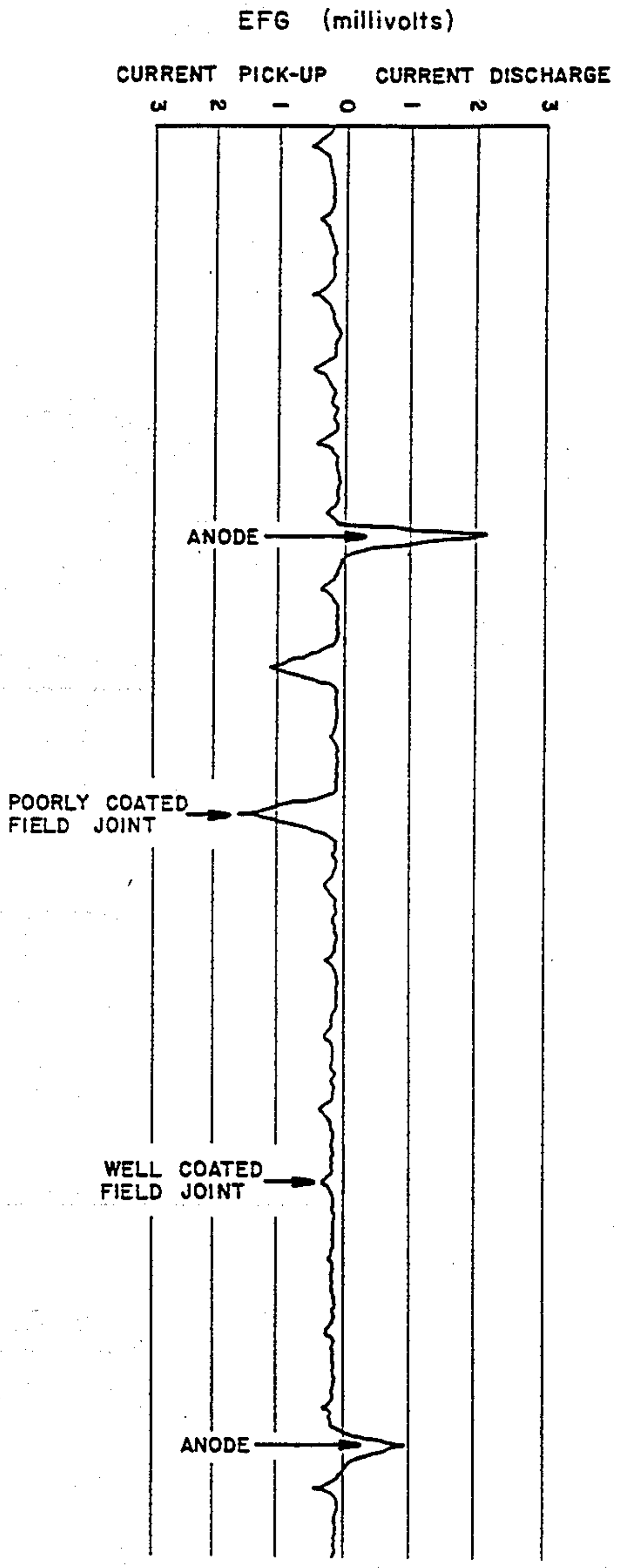

Figure 6 - Typical Electric Field Gradient Profile

Towed Fish / Trailing Wire

1. Economical.
2. Measures overall P/E potential level and locates major anomalies on most buried and unburied pipelines.
3. Not sensitive to minor anomalies such as bracelet anodes and minor coating damage.
4. Used for buried and/or shallow water pipelines where R.O.V. assisted techniques are not well suited.

R.O.V. Assisted Remote Electrode

1. Provides a detailed cathodic protection profile, particularly when used in conjunction with E.F.G. measurements.
2. Requires periodic direct contact potential measurements for accurate results. Best suited for unburied pipelines in water exceeding 30 meters depth.
3. Easy to combine with R.O.V. inspection operations.

R.O.V. Assisted Trailing Wire

1. Provides detailed cathodic protection profile, particularly when used in conjunction with EFG measurements.
2. More accurate than remote electrode survey for continuously buried and/or shallow water pipelines.
3. Requires additional personnel and equipment for wire dispensing operation.
4. Suitable for use on pipelines equipped with impressed current.

Electric Field Gradient

1. Used in combination with the R.O.V. Assisted Remote Electrode or Trailing Wire techniques to obtain detailed information on relative anode current outputs, size and location of coating flaws, and integrity of field joint wraps.
2. Most effective where sensor to pipeline distance is maintained at less than 2 to 5 pipe diameters.
3. Calculation of anode current outputs based on EFG values is generally not reliable due to multiple variables including electrolyte

resistivity, anode-to- sensor orientation and distance, and anode geometry.

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THEME PAPER 2

McBride-Ratcliff & Associates
Houston,
Texas

"AN INTEGRATED GEOPHYSICAL APPROACH TO PIPELINE LOCATION AND DEPTH OF BURIAL SURVEYS"

Introduction

Public Law 101-599, passed in November, 1990, requires that operators of pipelines in the Gulf of Mexico and its inlets inspect all pipelines in water depths less than 15 feet prior to May 16, 1992. In a Notice of Proposed Rule Making by the DOT, published in the April 29,1991 Federal Register, the following proposed requirements were detailed:

- If an exposed pipeline or a pipeline that represents a hazard to navigation is discovered during the survey, it must be marked with a Coast Guard approved buoy and a notification made to the DOT within seven days of discovery.

- Exposed pipelines or pipelines representing a hazard to navigation must be reburied within six months of discovery.

- Both natural gas pipelines and hazardous liquids pipelines (crude oil, products) are included in the regulations.

- Gathering lines in the inlets of the Gulf will be included in the regulations.

Final rules were published December 5, 1991 in the Federal Register and extended the pipeline inspection deadline to November 16, 1992.

McBride-Ratcliff and Associates, Inc. (MRA) are one of the leaders in conducting shallow water pipeline location and inspection surveys to meet the requirements mentioned in the above paragraphs. In addition, as part of an inspection package, it is possible to perform the necessary engineering associated with lowering pipeline shore crossings. This is only required if an exposed or navigation hazard pipeline is identified during the inspection survey.

Pipeline Location Techniques

The following equipment and techniques are routinely used for location of existing pipelines in shallow water zones. Since there is not a 100% effective, practical, single system that can accurately map the location and depth of pipelines, the multi-sensor approach is used for near shore surveys. The following systems are specifically tailored for use in shallow beach/surf zones and in water to depths of 30 feet or more.

Equipment

Magnetometers

The Geometrics 866 Marine Proton Precession Magnetometer is used with marine towfish and responds directly to the pipeline steel. This system has a microprocessor controlled console with recorder/printer which permits an analog chart and digital recording for real-time, on-board analysis.

The Geometrics 856 Magnetometer is a smaller hand held portable unit which is used for land or shallow water applications. It also has an option allowing use as a differential gradiometer by using two sensor heads with a separation between heads for pinpoint accuracy.

Gradiometers

Two models of Schonstedt gradiometers are routinely used for pipeline location. The smaller hand held GA-528 unit is used for land and shoreline search applications. This unit produces an audible signal over steel pipes. The Model GAV-20 Marine Gradiometer is used with a towed underwater sensor and has both meter and audio indications when passing over steel pipelines.

The Innovatum triple gradiometer system uses three fluxgate gradiometers plus a double axis sensor for heading orientation. The use of three magnetic sensors allows a computer generated 3 dimensional depth and direction orientation of the pipeline. The sensors are mounted on an open tow sled constructed of aluminum and P.V.C. with lead weighting. A Hewlett Packard computer and screen display indicate the depth of pipe and orientation with respect to the 3 sensors and heading sensor.

Pipeline Profiler

A new, advanced technology "chirp" acoustic profiler system is used for profiling in shallow water to produce an echo track of the pipeline location as well as thickness of sediment burial. This profiler uses a frequency modulated sweep from 1.8kHz to 10kHz and digital auto correlation of output to received signal to produce superior penetration and pipeline sensitivity as compared with standard, single frequency profilers. The system has no ringing interference problems which are often found with single frequency pinger systems in shallow water applications.

The use of a broad frequency sweep also is more effective for producing an optimum reflection over a broader range of pipeline sizes and bottom materials. The resulting record display over an offshore oil or gas pipeline locates and defines burial of pipelines. The pipeline is highlighted with a characteristic pattern of sharp diffraction curves and high amplitude (red colored) reflections. Burial depth is determined by the measured depth to the diffraction peak below the sharp seabed interface reflection. An example of a typical record is shown in Figure 1.

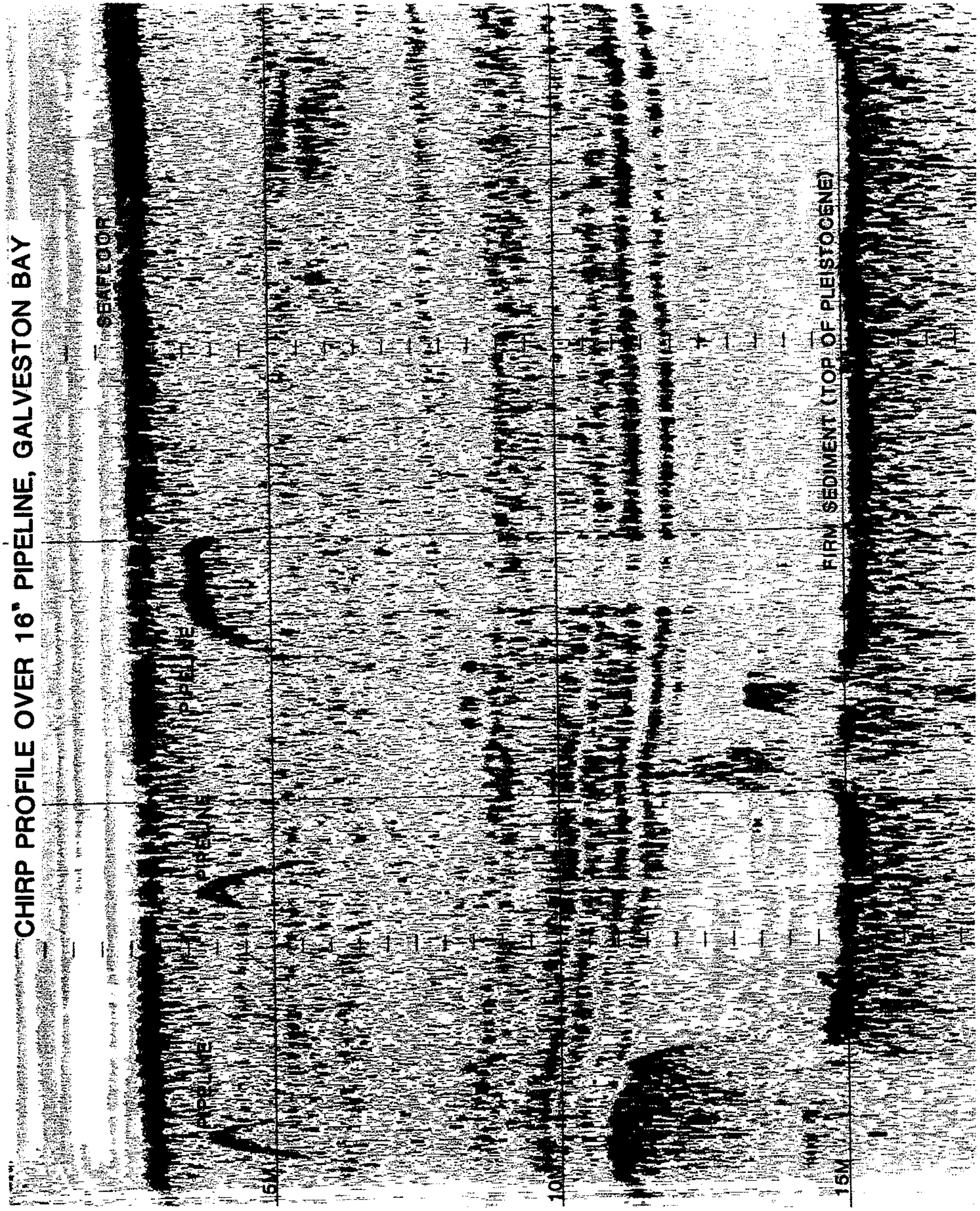

Figure 1 - Typical Record of Acoustic Profiler System

Side Scan Sonar

A Klein Hydroscan side scan sonar system is used for detecting pipelines exposed at the mudline. A special, 500 kHz "fish" is used for added resolution. The fish is capable of improved detection of smaller objects and differentiation of a pipe reflection from an anchor scar or trench.

Fathometer

Various units are used for water depth measurements along survey track lines. The data, when combined with continuous positioning, are used to develop bathymetric charts of the areas.

Tidal Observations

Bathymetric surveys are produced using available tidal data. In remote or confined survey areas recording tide gauges are used to obtain tidal datum for the survey.

Direct Probe

For a Water Jet Probe, a centrifugal pump attached to a 1" steel sectioned pipe with P.V.C. probe is used to probe down to the top of a pipeline. This unit can be rapidly deployed from the side of the survey boat and quickly penetrates normal coastal sediments. It allows a positive correlation by physical contact detection.

For a "T" Bar Probe, a conventional hand "T" Bar is used for probing in the shoreline zone. A long aluminum pipe attached to a probe is used in soft sediments in water depths to 15 ft where the jet probe is not required.

Soil Sampling

The direct probe equipment can be adapted to obtain soil samples for examination and geotechnical laboratory testing along the pipeline alignment. Such geotechnical data will be essential to the development of relocation engineering if such remedial treatment is determined to be necessary. Additional soil data is available from the Chirp Profiler. The profile records show subsurface reflection layers in color with color coding correlated to reflection strength.

Pipeline Survey Procedures

Shallow draft survey boats are used for the pipeline tracking vessel. Large inflatables, pontoon boats, and conventional small cabin cruisers have been used in this application. Maneuverability and safety for operation within the shallow surf zone are important factors to consider.

Generally, a reconnaissance run is made over an area using magnetometer and side scan sonar to determine if the pipeline is exposed and to establish pipeline locations. The coordinates of the pipeline location are entered into a computer with visual monitor after the reconnaissance coverage. These coordinates are continuously updated with additional location fill-in data as the survey progresses. The Chirp Profiler is used with a tight zig-zag survey pattern to establish exact location and burial depth of the pipeline. A magnetometer is mounted on a stinger pole in front of the vessel bow, and the Schonstedt gradiometer is towed a short distance behind the survey boat. The gradiometer produces an audible signal to alert the helmsman to turn back across the pipeline. Thus the pipeline is closely bracketed to facilitate accurate detection of the Chirp pipeline reflection.

If the chirp profiler is effective in producing a detectable echo over the pipeline, other instrumentation is not required. The Innovatum and marine Schonstedt gradiometers are much slower mapping methods. These devices must be slowly towed over the pipeline with sensor sleds dragging the seafloor.

Occasionally, depth calibration with the jet probe is required to check depths indicated by the chirp profiler. Generally, the chirp profiler depth determinations will be within 10% of direct probing results. The Innovatum is almost as accurate, and is not limited by difficult to penetrate soils such as organics. However, the Innovatum System is slower and more complex to operate.

Survey positioning is done with electronic systems such as the Artemis system, Micro-Fix, Laser-Trak, and Polar-Fix. MRA is presently evaluating new satellite GPS systems , but the accuracy of available systems is not yet considered adequate for this application.

Conventional survey crews are generally used to re-locate or re-establish station coordinates on existing pipelines, if stations are not readily available, and if known triangulation stations are within reasonable traverse distances. If this is impractical, satellite G.P.S. equipment and translocation can be used to re-establish survey station coordinates with adequate accuracies. This can be done either before or after a pipeline location study is done, depending on timing constraints.

Resurveys

After the pipeline surveys are completed, onshore monuments are established for future resurveys of the line. The monuments facilitate positioning the survey systems for subsequent studies. These re-location monuments are tied into the appropriate survey systems used by the pipeline companies.

Remedial Work

Since it is desirable to have a short response time between discovery of an exposed or navigation hazard pipeline and completion of the remedial work necessary to rebury the pipeline, it is essential that work begin immediately after discovery. This can usually be achieved within a six month period including permitting, design, bidding, and construction activities. It is possible to commence after the exposed pipeline is discovered, or the remedial services can be made part of the overall inspection process, to take effect only when an exposed or navigation hazard pipeline is identified. The latter option is suggested as it takes maximum advantage of the short, six month implementation period and allows coordination of engineering design data with the pipeline survey activity.

Typical activities required for the completion of the remedial work necessary to rebury a pipeline, would include the following tasks:

- Establish inspection specifications and additional specialized inspection requirements such as subsea girth weld and heat affected zone inspection for older pipelines.

- Provide permitting assistance and coordination with permitting agencies, fish and wildlife agencies, and other regulatory groups.

- Collect and interpret historic shoreline erosion records to assist in selecting the length of extra burial onshore.

- Perform computerized analyses of stress associated with lowering. This information is used to determine if there is sufficient slack available for lowering and to establish limitations on the amount of lowering which can be permitted on each pass of the lowering spread.

- Develop procedures for lowering and restoration of cover.

- Prepare bid packages for construction contractors and assist in bid evaluation.

- Inspect field operations of contractor during construction to ensure compliance with specifications and procedures.

- Provide as-built drawings showing lowered profile.

THEME PAPER 3

Shell Oil Company
Houston, Texas

"EXTERNAL SURVEILLANCE OF PIPELINES IN THE GULF OF MEXICO - SHELL OIL COMPANY PRACTICES AND EXPERIENCES"

General Considerations

The most obvious form of external surveillance of pipelines is visual observation. In the Gulf of Mexico this is severely constrained by water and soil conditions. In shallow waters zero visibility persists throughout the water column. In blue water areas, the slightest on-bottom activity in support of pipeline maintenance or installation instantly stirs up a visually impenetrable cloud of fine sediments.

Another constraint is the need for positioning. A defect in a pipeline is always a relatively miniscule singularity. A crack, corrosion pit, leaking flange or even a severed section is small in the context of the overall alignment. Surveillance is of little value unless you can find and reoccupy a given target. This gets more complex with increasing water depth. It takes a great deal of time, technology and funds to deploy an integrated surface and subsurface positioning system.

Apart from helicopter overflights, we do not believe any of the presently available external surveillance methods would be effective for monitoring line integrity. It is more than a little difficult to find a defect even when you know you have a problem!

Helicopter

Shell pipelines are inspected by helicopter both periodically and with random overflights. Most of Shell's lines are oil lines and very small releases from these are highly visible on the ocean surface. A layer only a few atoms thick will produce a visible sheen that can be investigated further. Aerial observation of the ocean will reveal losses that are far below the threshold of the most sophisticated line integrity systems.

A shortcoming of aerial observation is that sheens cannot be seen during the hours of darkness. Even if they could, no one is flying during those hours. Prudence dictates that night helicopter flights be limited to only the most dire emergencies.

Sidescan Sonar

Acoustic sonar has been used to inspect pipelines after a problem was found to exist. In at least one case damage due to an anchor drag was revealed. In another case a good sonar record was obtained of a flowing oil leak. A shortcoming of sidescan is that reoccupation of a target can be difficult. The sonar fish is typically towed, and cross currents can make the position of the fish ambiguous.

Scanning Sonar

Scanning sonar has been used on at least two occasions to find the precise locations of oil pipeline defects. Scanning sonar and divers can be deployed simultaneously. After finding the defect by acoustic observation, the diver can be directed to the precise damage location. He can then jet out the pipe, secure down lines, find the defect, and repair the defect. All this can be done in zero visibility.

Scanning sonar can register very small leaks. In one case the sonar was set up and trained on a subsea tie-in near which a helicopter had spotted a sheen. Nothing was visible for an hour or so, but then a pressure transient caused a puff of crude to escape from a loose flange. The scanning sonar registered the short lived result and a diver was directed to the exact point of the release.

Diver

In the case of new, jetted down pipelines, divers are used to probe the line and confirm adequate jetting. Divers are used for as-built inspections of risers and subsea tie-ins. In repair situations, divers are used to confirm unambiguously defects and make repairs.

Remotely Operated Vehicles (ROV)

In the simplest form of ROV surveillance, remote operated vehicles are used to visually inspect pipelines and observe installation operations. Typical tasks are observation of pipe progress into J-tube entries and flying an untrenched line after construction to assess position, condition and span lengths.

ROV's are also used as platforms for non-visual instruments.

CP Potential Survey

Instruments for measuring cathodic protection voltages have been used to assess sacrificial anode activity. Two kinds of measurements were taken: (1) the strength of low voltage electric fields in the vicinity of the pipeline and (2) actual pipe potential as measured with a probe making electrical contact with the pipe.

Magnetometer

This instrument is towed behind a boat and can be used to locate buried pipelines. It responds to ferrous structures.

Gradiometer

This instrument is essentially two magnetometers in tandem with its output corresponding to magnetic field gradient. It has been deployed by diver to find deeply buried lines. Shell has used triple gradiometer arrays to assess pipeline burial. The arrays have been deployed on both ROVs and towed sleds.

THEME PAPER 4

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John E. Chance & Associates
Lafayette, Louisiana

"EXTERNAL SURVEILLANCE - THE END PRODUCT"

Introduction

External surveillance utilizes many sensors - acoustic, electromagnetic, optical and physical. Unfortunately a single sensor generally only provides one or perhaps two items of information which are usually in isolation of other items.

Such isolated sensors are of little use to the end user. For example, a video record without annotation which can be cross referenced to another sensor is of little use. Supposing a free span is observed, it is of little use if the position and extent of the span is unknown. Similarly a CP system uncorrelated to distance down line is of limited use. While these statements appear obvious, it is surprising the number of occasions where a vast suite of equipment appears on the dockside with no one really having much idea of what is to constitute the final product. Although each individual component may be working to specification the total work product is lacking.

Definition of the Problem

What causes this problem? Firstly, the actual aim of the survey is often ill defined. Most often a single criterion such as span determination is listed with little mention of the other sensors required in order to make a comprehensive survey. Similarly the sensor itself may be poorly defined. Span identification and measurement have been deemed in some RFQ ' s to be achievable using a single camera on a vehicle with nothing else. The resulting video of a vehicle flying down a line in the middle of the screen is useless for detection of spans. It could be argued that the contractor should advise the client when his specification is unclear, but it must be remembered that the contractor must appear competitive and if the client requests a single video camera then the contractor is loathe to offer split head profiles and or boom mounted cameras as inclusion of these systems will probably make the bid non-competitive.

On a similar basis, a contractor may not fully understand the additional requirements needed to accomplish a task. In the case of depth of burial surveys, the pipe detection system is not the be all and end all - rather it is a component part of a system which includes position and sea bed determination.

A second factor involved in poor performance is a lack of detailed specification of what entails the final work product.

The client needs to detail specifically what is required in light of what the end use is. Phrases such as "all work records shall be submitted" deserve a box of video tapes and some field notes.

Management Considerations

What can be done to provide a usable end product? In a multi facet survey the client needs to consider who is the prime contractor. The ROV contractor probably has the largest dollar value share and so, commercially, should be lead contractor, but do they actually perform the data collection, collation and presentation? In the Gulf of Mexico probably not, as that is often the role of the survey contractor. The problem arises when the survey contractor is not brought into the loop until the later stages. This is not to suggest that the survey contractor should take over as lead. The North Sea has shown enough survey contractors who tried such work being badly hurt financially. The point is to make the survey contractor more involved at an earlier stage.

The client also has to decide to what end use the data is going to be put. Does it require paper maps, or video coordinate listings? Or would, in the case of repetitive inspections, only changes be noted.

The goal of obtaining the correct end product can be summed up under the concept of quality assurance and is basically understanding

- What does the client really want?
- How can it be best obtained cost effectively?
- Is what he is given at the end what he though he wanted?

To achieve this is a client and contractors responsibility - almost equally shared.

Conclusions

There are many exciting, innovative tools to be used in the field of external surveillance, but in general terms they cannot be used in isolation. As an industry, we must remember to consider our total requirement and all that goes into it, and to make sure we get what we really wanted in the first place.

THEME PAPER 5

Albert Barden
NOWSCO U.K.
England

"REPAIR AND REHABILITATION OF SUB-SEA PIPELINES"

Introduction

In 1989 new guidelines were issued to the British sector of the North Sea Oil/Gas Industry by the Department of Energy Pipeline Inspectorate requiring the installation of emergency shut down valves (E.S.D.) These valves were to be installed on top sides/sub-sea, the purpose being to minimise the loss of product from the pipeline in the event of top sides failure.

Two basic scenarios can be used to prepare the pipeline so that this work can be carried out in a safe manner notably:-

- Scenario One - Isolate and displace all the product from the pipeline using an inert medium, usually water or nitrogen. Carry out repairs to the pipeline, followed by recommissioning operations using dry air, nitrogen, methanol swabbing or vacuum drying.

- Scenario Two - Provide localised isolation adjacent to the working area, leaving the work site safe, whilst the remaining section of pipeline still maintains product. This work can be carried out by one of several methods i.e. the use of:

(a) high differential pig trains

(b) remote controlled pipeline packer tool

(c) pipeline freezing

(d) nitrogen foam inerting

(e) pipe stoppling operations

(f) hot tapping

The options available for doing this and the method of determining the most suitable solution depend upon a number of factors:

- type of product
- length and diameter of the line and hence volume of product involved
- facilities for disposal of product
- time available for operations
- space availability at operational location restricting equipment deployment.

Bearing these factors in mind, various scenarios can now be considered and the advantages and disadvantages of alternative solutions examined.

Oil Lines - General

Oil pipelines represent a simple problem when compared to gas lines. Firstly, the volume of product required to depressurise the line is very small, meaning we can work with a totally depressurised system without wasting product. Secondly, if the line is decommissioned and flooded with water, there are very few problems associated with recommissioning, as the water can usually be handled in the production facilities.

The options for oil lines are therefore relatively straightforward and depend usually on the volume of product involved.

For small volume lines, the simplest solution is to displace the product with water, allowing the work to take place under safe conditions. Even when all the product has been displaced, it is prudent to utilise a low pressure isolation device in the form of a sphere or stopper to ensure that any vaporisation of hydrocarbon from wax, etc., does not come into contact with the work site, particularly if welding is going to take place.

For larger volume systems, the pipeline can usually be isolated locally to prevent having to displace all the product from the lines. This can be done by displacing one or more pigs down the riser and onto the seabed with water. It is important in this scenario to evaluate the differences in elevation of the two ends of the line, taking into account the differing static heads caused by having one end of the line full of oil and one full of water. Again a secondary isolation is usually installed after cold cutting at the new valve location and prior to welding.

Under both scenarios, testing of the completed works is easily undertaken by hydrotesting. In the second case, this can be carried out with the isolation pig still in position so that product is still kept well away from the new work being tested.

On completion of the work, the pig can be propelled back to the work site by displacing with oil from the far end or, by launching another pig, the train can be.pushed to the far end.

Gas Lines - General

On gas lines, the problems associated with the valve installation are much greater. Firstly, we have to vent off large quantities of gas to reduce the pressure in the line. Secondly, if we introduce water into the line, we have in most instances to dry the line in order to recommission it, in order to prevent hydrate formation and minimise corrosion. This is both costly and time consuming. It is therefore only really feasible to flood and decommission short pipelines of small diameter.

Nitrogen purging the pipelines can also be very expensive on larger sized lines. Due to vaporisation of condensate, etc., even nitrogen does not guarantee the line perfectly safe. A local isolation is usually required, in the form of a sphere or stopper, to prevent vaporised liquids coming into the work site area.

The alternative to this, particularly on longer trunk lines, is to carry out a local isolation. Several techniques have been examined for carrying out this type of isolation, which will be discussed later. Let us now consider the techniques used.

Scenario 1 (a) DECOMMISSIONING PIPELINES BEFORE REPAIR

Oil Pipelines - as previously described.

Gas Pipelines - nitrogen is used as a purging medium because it is an easy and cheap way of achieving the objective. Purging to decommission a gas pipeline is normally carried out by one of two methods depending upon the product being removed from the pipeline:-

Free Volume Purging

This is the basic method used to remove gas from the pipeline. Where possible the gas should first have been reduced in pressure to as low a value as practical. Nitrogen is then introduced at one end, the gas being either vented or flared to atmosphere at the receiving site. A volume of approximately three times the value of pressure in the pipeline will be required to remove gas from the pipeline; although in practice only half that volume will be used to achieve a 99 percent nitrogen purge, providing the speed of the purge can be controlled to approximately 12ft/second.

Nitrogen Purging using a Pig as a Separator

Whilst in practice the free volume purge would suit the majority of gas/nitrogen purges, a pig may be used as a buffer between the gas/nitrogen. This method is used to remove any condensate or compressor oils from the pipeline that would not be achieved with a free volume purge. It is a more reliable method of purging pipelines and, whilst the amount of nitrogen used is increased due to the differential pressure required to propel the pig, it can be a "quicker" operation especially on longer pipelines, due to a smaller interface.

Scenario 1 (b) RECOMMISSIONING PIPELINES AFTER REPAIR

Oil pipelines - as previously described.

Gas pipelines - the following points must be observed:

Requirement for Dryness

The presence of water, or moisture in any operational pipeline will, under certain circumstances, cause major problems due to hydrate formation, internal corrosion or cracking.

In sweet gas pipelines, the presence of water can usually be adequately dealt with by propelling slugs of methanol through the pipeline during recommissioning, as this will prevent hydrate formation.

In oil pipelines, water presence can normally be treated successfully by the introduction of chemical inhibitors to prevent corrosion.

In sour gas pipelines, it is necessary to remove all free water from the pipeline prior to commissioning to prevent corrosion or cracking occurring. This water is eventually evacuated by propelling pigs through the pipeline using compressed air. However, even in the most successful dewatering operations, there is always some free water left in the pipeline comprising of a film of water adhering to the internal wall of the pipe. The film thickness will depend on the roughness of the steel and whether or not the pipeline has been internally coated. An average thickness of water will on an uncoated pipe be on the order of 0.1mm. The most used technique for achieving dewatering is vacuum drying, although air drying will also be discussed, as follows.

Pipeline Drying with Air

Following completion of repair and hydrostatic testing, the pipeline is gross dewatered using compressors complete with after coolers and driers.

During the drying process foam pigs are driven through the pipeline at regular intervals. These foam pigs have three duties:-

1. They absorb superfluous water (up to 80% of their volume).

2. They distribute the residual water as a uniform thin film on the surface of the interior wall so that it can evaporate faster.

3. Pools of water at low points are removed.

Experience has shown that, depending on the state of the internal pipe wall, between 0.8 and 1.2 pig runs are necessary per kilometre of pipe length.

To determine the state of dryness inside the pipeline, the moisture content of the air discharging at the receiving end is measured. The most suitable measure of dryness is in this case the dew point temperature. The dew point temperature of a gas is the temperature at which the gas is saturated with water vapour at the given pressure (in this case 1 atmosphere) - in other words the temperature to which the gas must be cooled before condensation of the water vapour begins to take place.

The dryness process inside the pipe does not occur uniformly or simultaneously along the whole length of the pipe. On the contrary, drying takes place in a drying front which moves down the pipe from the inlet to the outlet, forming a relatively sharp boundary between the dry up-stream section of the pipe and the wet down-stream section.

The moist air which is discharged from the pipe at the receiving site is initially saturated with water vapour, and hence the dew point temperature corresponds to the temperature of the discharging air which is itself at ground temperature. The dew point temperature only begins to fall when the drying front nears the end of the pipe. At about this time, the foam pigs begin to drive large quantities of dry dust from the pipeline. Initially the dew point falls rapidly to about - 20 degrees C, but thereafter the decrease occurs very much more slowly. After the required dew point temperature has been reached at the end of the pipe, the pipe is dry along its entire length.

Nitrogen Drying

As with air drying, following repair and hydrostatic testing the pipeline is usually gross dewatered with air before nitrogen drying commences. As with air drying, foam pigs are again used, with similar dryness tests carried out.

Table 1 lists the advantages and disadvantages of Nitrogen and Air Drying.

Table 1 - Comparison of Drying Methods

NITROGEN	AIR
Oxidisation of cleaned pipework will be subsequently reduced.	Oxidisation of cleaned pipework will be rapid.
Gas flow rate is variable to entrain and search out pockets of water.	Flow rate may be limited, and maximum flow rates could be lower than equivalent sized nitrogen units.
Rapid pressurisation to any pressure to enable repetitive compressor cycling and optimise the diffusion and entrainment of moisture.	Pressure limited to 150/200 psig unless a special is obtained.
High temperature gas to achieve less localised acceleration of drying.	Gas temperature ambient or
Liquid supply of nitrogen.	No supply problems.
Dew point -60 degrees C.	Dew point -40 degrees C.
Requires experienced operators to control, operate, maintain the unit.	Equipment relatively simply to operate and maintain.
No additional purge required.	Nitrogen required to purge prior to introduction of hydrocarbons.

Methanol Swabbing

Methanol swabbing is a method used to condition a pipeline before the introduction of natural gas. After the pipeline has been hydrostatically tested followed by gross dewatering, the free water remaining on the pipeline wall has to be removed.

Methanol is an alcohol that is readily mixable with water and therefore, is used to remove and replace the water from the pipe wall. Any water/methanol remaining in the pipeline will be of sufficient strength to prevent hydrate formation on the introduction of natural gas.

The methanol swabbing exercise is usually carried out in accordance with British Gas Specification BGC/PS/PC although variations to this specification may be necessary to suit specific operations.

In general two methanol slugs are used, each slug being contained between pigs. The amount of methanol varies according to the diameter and length of the pipeline. A fifth pig is used behind the second methanol slug and acts as an interface with the commissioning medium as well as collecting any methanol left behind by the other pigs.

Nitrogen is used in front of the pig train and between the two methanol slugs and the fifth pig. The volume of these nitrogen slugs is such as to prevent air/methanol mixturing and to allow each methanol slug to be received in the receiving trap independent of each other. Figure 1 shows a typical pig train for a methanol swabbing operation.

The pig train is then propelled to the receiving site and each slug of methanol received separately. Samples from each methanol slug are taken and analysed by measuring its specific gravity. These measurements are compared to the specific gravity of methanol used at the injection phase. The success of the operation is usually measured by the difference in the percentage of methanol by weight before and after the operation.

Vacuum Drying

Vacuum drying is the removal of free water from a pipeline by reducing the pressure in that pipeline, under controlled conditions, using portable vacuum equipment.

The principle of vacuum drying is that water will boil and give off steam (water vapour) at any temperature, providing the pressure is reduced accordingly. The pressure at which the water will boil is termed the saturated vapour pressure. At atmospheric pressure of 1013.25 m. bar, water will boil at 100 degrees C, whereas at 12.00 m. bar, for instance the same water will boil and hence turn to water vapour at 10 degrees C. If maintained at this pressure and temperature, all the water will eventually turn to water vapour leaving no free water present.

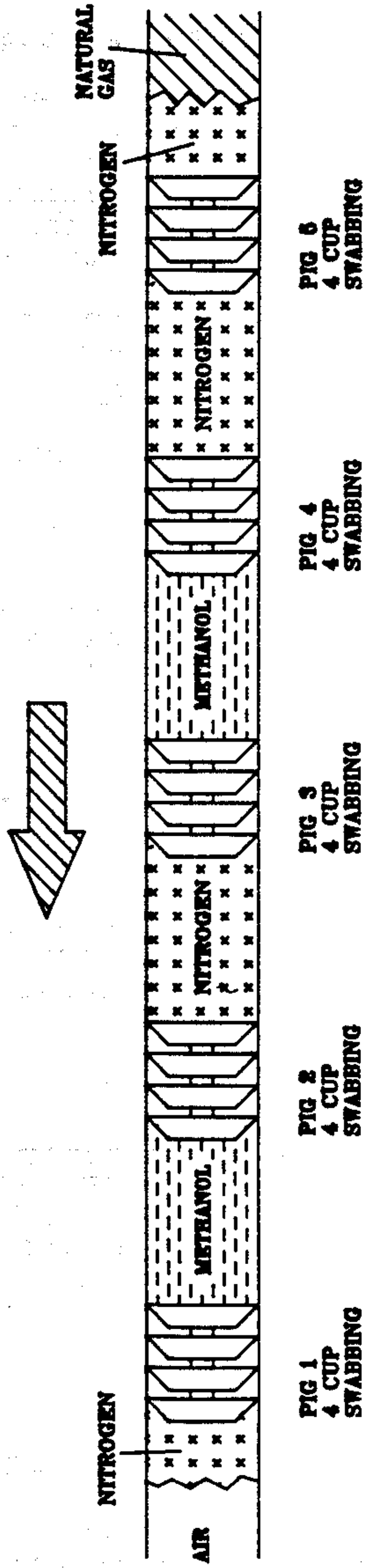


Figure 1- Typical Pig Train for Methanol Swabbing

Therefore in a pipeline or a system the criterion is to reduce the pressure to a value at which the environmental or ambient temperature of the system will cause the free water to boil and to maintain this pressure until all the water has been converted into water vapour. Once this has occurred, most of the water vapour can then be removed from the system by reducing the pressure still further, thereby inducing a flow of water vapour through the pipeline towards the vacuum equipment, usually situated at one end of the pipeline. The amount of water vapour removed, and the final dryness, depends upon the pressure level the vacuum equipment can achieve.

The vacuum drying process is shown graphically in figure 2 and consists of three separate phases:-

Phase 1 - Evacuation

During this phase the pressure in the pipeline is reduced to a level where the ambient temperature of the pipeline will cause the free water to boil and change to water vapour. This pressure level corresponds to the saturated vapour pressure of the free water in the pipeline which is dependent upon the ambient temperature of the pipeline.

The approximate pressure value is calculated in advance but is easily recognized on site by a fall in the rate of pressure reduction, which is noted from the plot of pressure against time.

At some convenient point in time a leak test is carried out by stopping the vacuum equipment and observing the pressure for a minimum period of four hours. Any "air in leaks" on flanges, fittings, or the like, are rectified at this time.

Phase 2 - Evaporation

Once saturated vapour pressure has been reached, then evaporation of the free water into water vapour will commence. During this phase, the vacuum equipment is carefully controlled to maintain the pressure at a constant level until all the free water has been converted into water vapour. This phase may take several days to complete, depending on:

(1) the amount of water to be evaporated

(2) the size of the vacuum equipment

(3) the ambient observed on site by a noticeable decrease in pressure.

At this time it is prudent to carry out a "soak test" to ensure that all the free water has in fact evaporated. The vacuum equipment is temporarily isolated from the pipeline, usually for a period of 12 hours and a careful note made of the pressure. If all free water has evaporated then

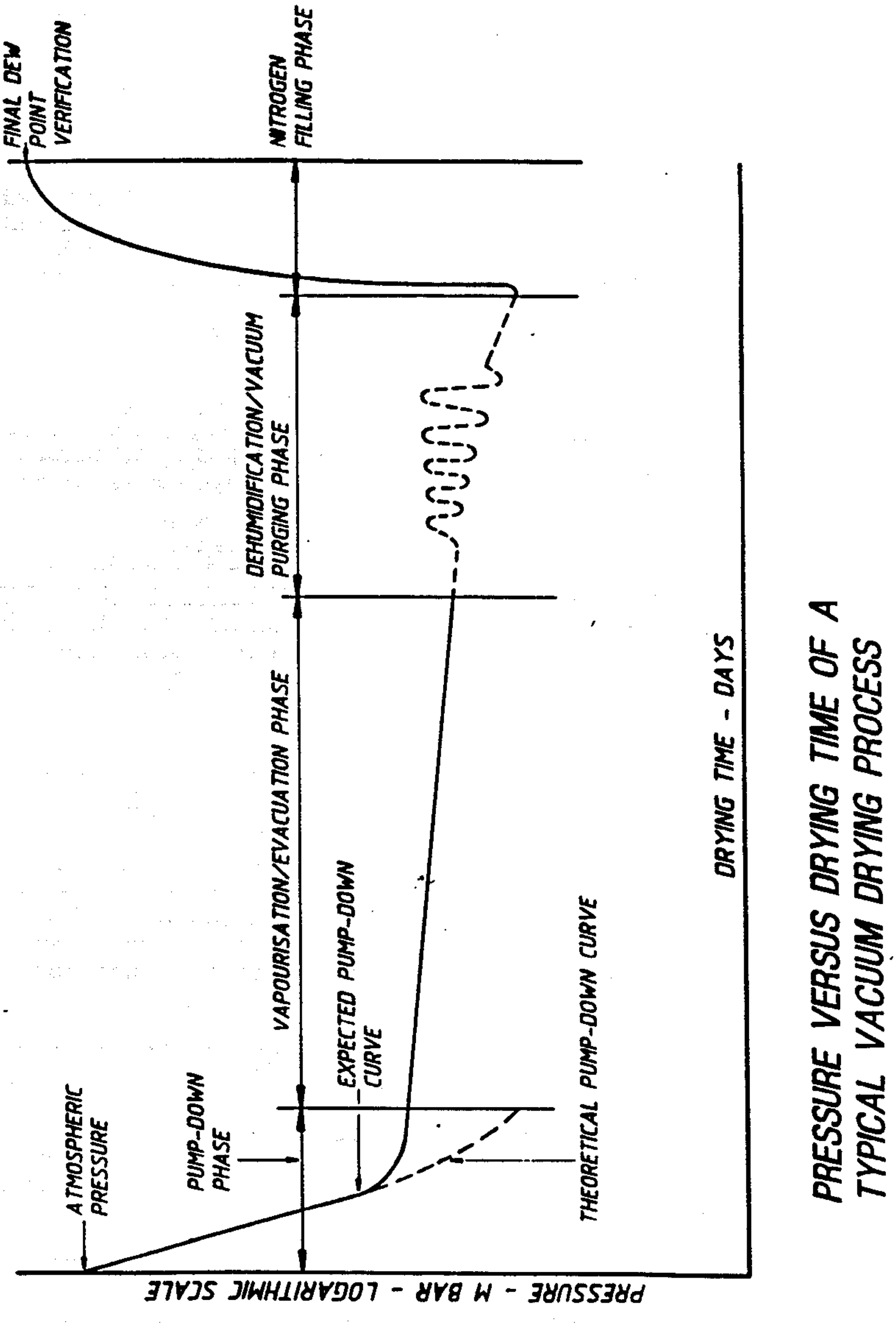


Figure 2 - Pressure Time Curve for Vacuum Drying

the pressure will remain constant and the final drying phase can commence.

An increase in pressure, however, will indicate that some evaporation is still taking place, in which case the vacuum equipment must be re-started to maintain the pressure level at which the water will evaporate. Once it is observed that the pressure is constant then the vacuum equipment is isolated and the final drying phase can be commenced.

Phase 3 - Final Drying

Once the free water has been converted into water vapour, the majority of it must be removed from the pipeline in order to reach the required dryness level. This is achieved by reducing the pressure in the pipeline still further, which has the effect of drawing the water vapour out of the pipeline through the vacuum equipment. Obviously the more water vapour removed then the drier the pipeline will become.

During this phase a careful watch is kept on the slope of the final drying line to ensure that it follows the calculated value, since a shallower slope would indicate the continuing presence of some free water still remaining in the pipeline, and careful control of the vacuum equipment would need to be exercised.

What is Dryness?

The dryness of a pipeline is measured in terms of dew point, which is the temperature at which mist or dew will begin to form. A convenient method of measuring dew point is to use an instrument called a mirror hygrometer where the water vapour is passed across a polished surface, which is slowly cooled until dew forms. The temperature at which the dew forms is the dew point of the water vapour and is normally expressed in degrees centigrade. The drier the air, the lower the temperature at which dew will form.

In terms of a pipeline being vacuum dried, the lower the pressure in the pipeline, the lower the dew point will be since, as the pressure is decreased from the evaporation pressure level, so the quantity of water vapour removed increases. For instance, at a pressure level of 2.62 m.bar, the equivalent dew point of the pipeline would be - 10 degrees C. If the pressure were further reduced to 1.04 m.bar, then the dew point would be - 20 degrees C.

For sour gas pipelines, a dew point level of - 20 degrees C is generally considered to be adequate and the 1.04 m. bar pressure level required to achieve this dew point is readily attainable using the portable vacuum equipment described.

Proving the Dryness

Immediately following the final drying phase, an air purge using atmospheric air under vacuum is carried out to prove the dryness of the pipeline. It is possible, under certain circumstances, for a small amount of free water to still remain in the pipeline. Usually this water will have turned twice due to the chilling effect of the vacuum drying process and may not be apparent during the soak test and final drying phase.

Atmospheric air, which has a dew point in the region of + 15 degrees C, is allowed to enter the pipeline through a valve at the remote end from the vacuum equipment until the pressure has risen to a pre-determined and calculated level. The pre-determined level is such that the dew point of the atmospheric air will drop to the final dew point level required in the pipeline (e.g. - 20 degrees C). This is due to the fact that as the atmospheric air enters the pipeline it expands into the vacuum thereby lowering the dew point.

Once the pre-determined pressure level has been reached, the vacuum equipment is started and that pressure level maintained. This has the effect of drawing atmospheric air through the pipeline under vacuum at a relatively constant dew point equal to the final dew point required. At some point in time the atmospheric air, now under vacuum and at a dew point of, say, - 20 degrees C will reach the vacuum equipment and will be drawn through it. Careful monitoring of dew point at both ends of the pipeline is made and a comparison made.

If there is no free water remaining in the pipeline, then the dew point at the vacuum equipment end will be the same as the dew point at the remote end. However, if there is any free water present, then the dry air passing through the pipeline under vacuum will absorb the water hygroscopically. The air purge operation must then continue to remove the remaining free water until the dew point at both ends are equal, at which time, purging is discontinued. The pipeline has now been vacuum dried to the required dew point level and the dryness proved. Purging and commissioning can now proceed.

Purging and Commissioning

Once the dryness has been attained and proved the pipeline is ready for commissioning. Whilst it is possible to introduce the sour gas directly into the vacuum, it is better to relieve the vacuum using dry nitrogen to some agreed positive pressure before gas is introduced.

PRIMARY DYNAMIC SEAL INTENDED PIG TRAIN POSITION

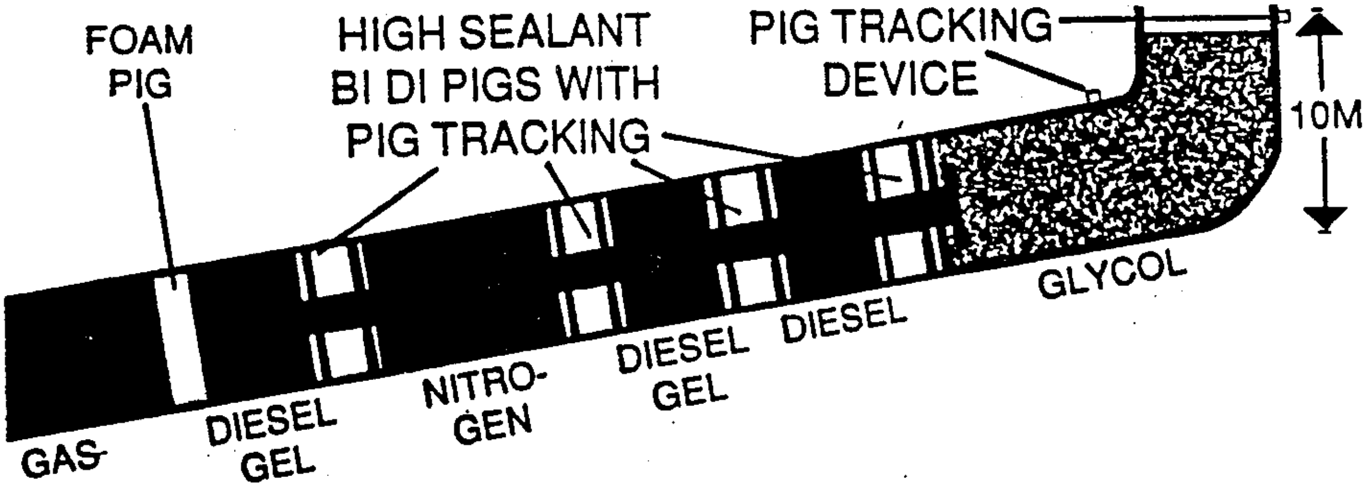


Figure 3 - Diagram of Pig Train

Scenario 2 LOCALISED ISOLATION OF PIPELINES

High Differential Pig Train

This system was developed to meet the short time period available for the operations. The pig train concept was seen as utilising proven basic technology in the form of bi-directional pigs and with an in-built factor of safety from the number of pigs being used. Trials were carried out to develop two types of pigs:-

- a high sealant pig to provide the main gas interface
- a high differential pig to provide a factor of safety in the event of either inadvertent pressurisation of the line, or rupture of the line, which could cause it to fill with water and pressurise.

A test loop was built to simulate conditions in the pipeline. This consisted of a section of light wall pipe, a section of heavy wall pipe and a 90 degree bend. Various disc configurations were tested on a standard bi-directional pig body. Different oversized discs were used in varying configurations to try to achieve the best combination of either, sealing characteristics or, high differential characteristics without damage to the discs or the pig body. Many combinations were initially tested, from the original bi-di configuration up to the point where the force across the pig was so great that the discs tore under stress. Eventually an optimum disc configuration was found, where no damage occurred to the pig and the maximum differential pressure (DP)/sealing capability achieved.

Subsequent testing of pigs on other pipework systems has led to further development of this initial concept. Unfortunately, from the operator's point of view, it has become clear that the suitability of a particular pig for providing a high DP is unique to the size of the pipe involved and the difference in wall thickness. For example, a high DP pig developed for a 24" pipe will not give similar results at 36" because, as the area of contact on the pipe wall changes, the relative distance between the disc support flange and the pipe wall is different and hence, the deformation of the disc is altered.

Different wall thicknesses have an even more marked effect on DP capability, as one might imagine. DPs obtainable in pipe of constant bore are more than halved in the pipe configurations where there is a half inch difference in wall thicknesses due to the damage caused by heavier wall pipe.

If reproducible results are required in the field, then tests will be required to establish the particular figures for a given set of pipeline parameters.

Topsides Isolation for Valve Installation

On this initial topsides isolation, the pig train was designed using the following parameters:

- the front part of the train would aim to provide the main interface to prevent migration of gas towards the work site;
- the second part of the train would provide the differential holding capability, which would provide a large factor of safety in the event of inadvertent pressurisation, or pipeline rupture. This would be achieved by two means; firstly by using high DP pigs and secondly, by using slugs of liquid between the pigs to create a static head should the pig train start to move up the riser.

With this in mind, the following pig train was developed. Due to the short period of time involved, only four pigs were available from the client and there was not time to order additional pigs. Consequently, a foam pig was used at the front of the train. This was simply to contain a slug of diesel gel which would increase the sealing efficiency of the first pig. A large slug of nitrogen would then provide an inert buffer to minimise the risk of any gas diffusion through to the second half of the train. The second portion of the train was made up of three high DP pigs, separated by slugs of liquid.

The first of these was diesel gel to increase sealing efficiency and the second was diesel. The length of these slugs was calculated to give 90 linear metres of liquid, or approximately 7 bar of head. A diagram of the pig train is shown in Figure 3.

It was intended that the pig train should be positioned just beyond the bottom riser bend. A slug of glycol would then be injected, such that the level of glycol could be closely monitored in order to detect any movement of the pig train. In practice, this proved difficult to achieve, as the varying speed of the pig train when propelled with nitrogen did not allow sufficient control of the train. However, this did not affect the efficiency of the pig train or the outcome of the operation.

After launching the pig train into a fully depressurised line and venting off the pressure behind the pigs, the pig train was allowed to stabilise before cold cutting the line. A secondary barrier in the form of a modified sphere with by-pass monitoring facilities was then installed prior to the welding work beginning. The Pipelines Inspectorate requirements for testing of the new works had a significant impact on the way the valve assembly was installed.

These indicated that all flanged joints should be leak tested at 1.1 MAOP, whereas a minimum number of new welds could be inspected by 100% NDT. This meant that in order to avoid pressure testing the whole line, the flanged valve had to be pre-tested with flanged pup pieces already in place, rather than welding in the two flanges offshore and then bolting in the new valve.

In practice, the differential pressure across the pig train in the offshore phase was slightly less than that anticipated from the trials; this may have been due to condensate present in the line. The pressure required to 'flip' the entire train to return it back to the platform on completion of the operation was 10.8 bar. Combined with the static head of diesel available, this meant that the pig train would have held back a DP of up to 18 bar.

Isolation for Installation of Sub Sea Valves

Following the success of the high DP pig train for pipeline isolation for topsides valve installation, its application for subsea valve installation was studied. The application for subsea works introduced several new factors into the pig train design concept. Figure 4 shows a diagram of the concept.

Firstly, because the construction work would be carried out subsea, it was necessary to launch the pig train with water to provide the necessary working environment for the divers. This would be advantageous for control and positioning of the pig train, as water is largely incompressible and easy to meter. It would, however, mean that some method of recommissioning the pipeline would be required.

The design premise for the pig train was also altered by the construction work being subsea. It was always intended that the pipeline would be vented down to static head pressure subsea, i.e. approximately 13 bar. With the pig train in position and the pipeline cut, the pig train would be in dynamic balance, with 13 bar gas pressure on one side and 13 bar static head on the other.

The differential pressure capability of the pig train would only come into play in an emergency situation. Initially, this was taken to be inadvertent pressurisation from the far end with gas moving the pigs towards the divers. However, this was found to be highly unlikely as, in this case, gas injection was not possible. Further examination of the system gave a worst case scenario of a topsides leak or rupture at the far end leading to pipeline depressurisation.

The full static head would then be acting across the pig train and the divers could potentially be sucked into the pipeline if the pig train moved. It was therefore, decided that the pig train should be designed to hold the full static head pressure (13 bar gauge) plus a factor of safety. Due to the cumulative nature of the DP across the pigs, the factor of safety required can be relatively low, because in losing one pig, for example due to damage,

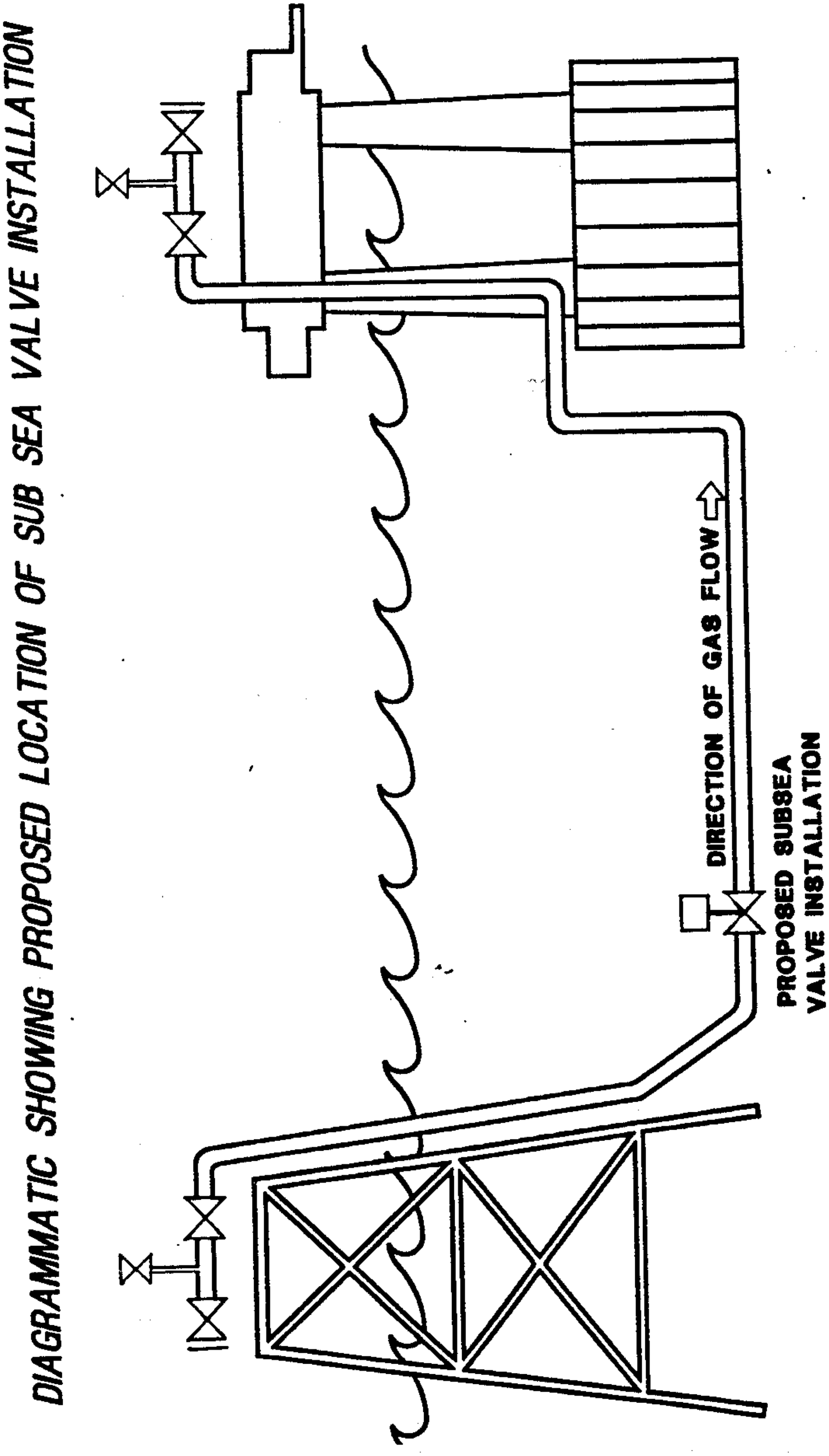


Figure 4 - Diagram of Subsea Valve System

we only use a small percentage of the entire system capability. The design requirement for the pig train was therefore set at 15 bar.

The use of nitrogen within the pig train also required careful consideration. Whilst slugs of nitrogen were desirable to minimise diffusion of gas along the train, their use would create other problems. When launching the pig train for topsides isolation into a pipeline at zero pressure, it had been possible to vent off the residual nitrogen pressure after launching the first two pigs. Launching the second part of the train had only compressed this to approximately 0.1 bar.

In the subsea case, this would not be possible when launching against a pressure of 13 bar. The nitrogen slugs would therefore act as springs with the potential of pushing the pig train back towards the work site after reduction of the launch pressure to static head pressure.

Examining the pressure profiles across the pig train, and the positioning of the nitrogen slugs, became an important part of developing the pig train.

With an half inch difference in wall thickness between thick and thin wall, the DP capability of the pigs was relatively low. A comprehensive testing programme was undertaken to evaluate the effect of wear on the pigs and their long term liquid retention capability, as well as disc material compatibility tests with the various fluids with which the pigs would be in contact (bearing in mind contact would last up to sixty days).

The pig train was designed with three pigs at the front, separated by slugs of nitrogen. Again, the main purpose was to minimise the diffusion of gas towards the work site. These were then followed by four slugs of recommissioning fluid trapped between high differential pigs. A further eight high differential pigs separated by slugs of inhibited water would complete the train. A standard bi-di would be added at the rear of the train to remove the hyperbaric spheres on the way out. The lengths of all the liquid slugs were sized to give the necessary spacing when receiving the train, to ensure that none of the train left in the line would be in the other ball valves. A diagram of the pig train is shown in Figure 5.

Pipeline Packer (Remote)

At the present time two types of mechanical plugs are available. The first is a tethered plug whose setting is controlled via a hydraulic umbilical and where the hydraulic pressure is continuously monitored in the tool to ensure the pig remains set against the line pressure. The second tool is a remote controlled pipeline packer, which does not have an umbilical or other connnection to the outer surface of the pipe. The tool is designed to negotiate 3D bends and is launched conventionally from the pig trap and displaced to the required position in the pipeline, where command signals

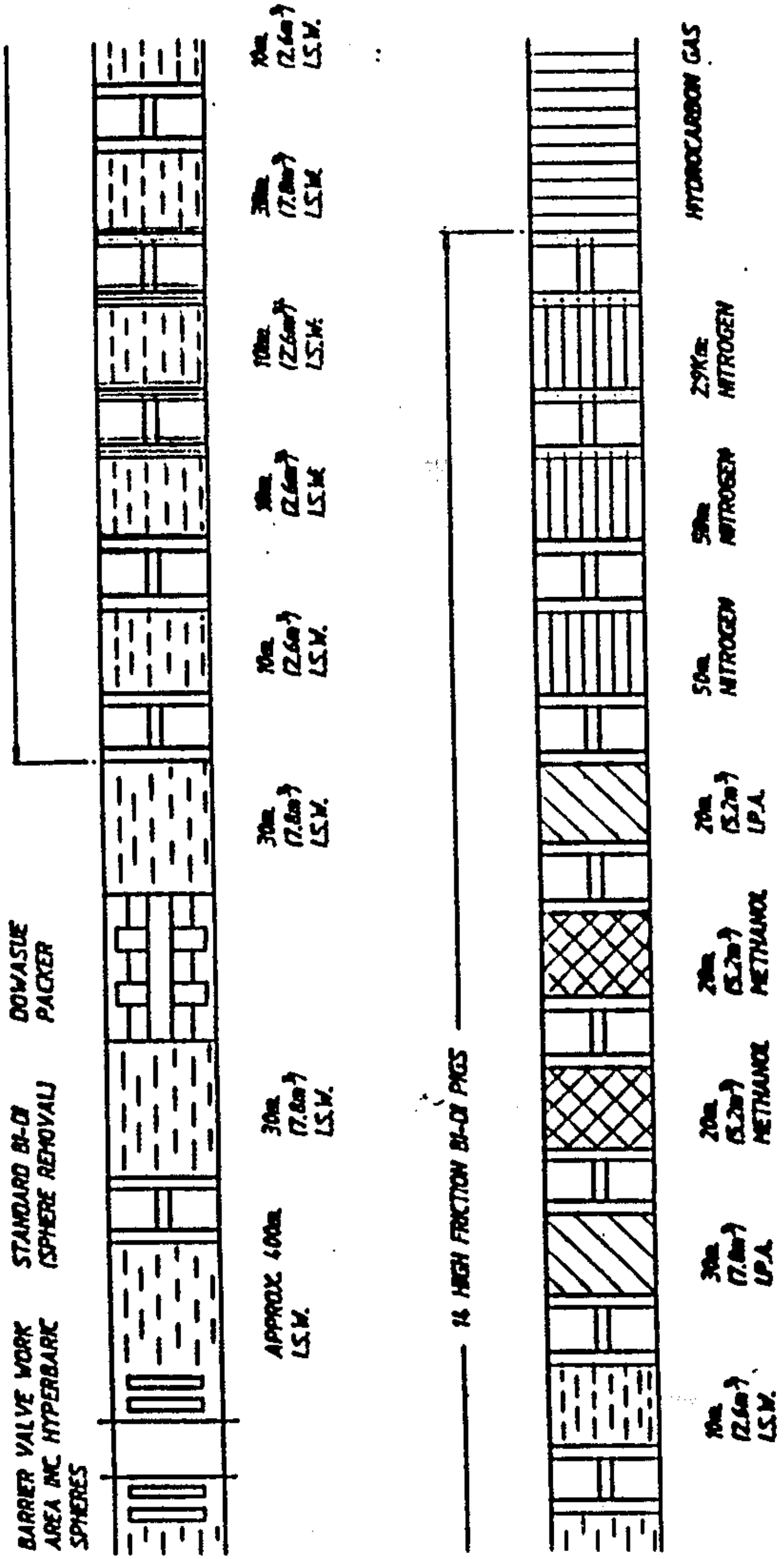


Figure 5 - Pig Train for Pipeline Isolation

are given to the tool. These coded signals set and unset the tool, as well as interrogate it regarding its condition.

The packer is available in sizes of 10" and above and has an established track record. As the result of field experience, significant modifications to the tool have been made over the years and these modifications ensure safe, reliable and repeatable setting of the tool.

The tool also has a number of back-up systems to ensure that should the tool not release at the time required, then over pressure systems disengage the setting mechanisms and release the tool from the pipeline. Once the tool has been released it is pigged throughout the line with the flow, and retrieved like a conventional pig.

To set the tool, the setting mechanism is only activated once the signal has been correctly received. Once received, the onboard electronics open valves releasing pneumatic energy to act upon the hydraulics. The hydraulics then ensure that the mechanical seal which isolates the line and the brake shoes which hold the pig in position against high differential pressure, are pushed firmly into contact with the pipewall, thereby safely sealing the pipeline.

Both the seal and the brake shoes are ribbed so that if a wax deposit is present on the pipewall it can be penetrated to effect good contact with the pipeline itself. The brake shoe surfaces are also covered with a slightly softer material to ensure that the forces applied by the hydraulics onto the surface of the pipewall do not deform or damage the surface of the pipe, e.g. if the tool is set on a weld the brake shoes form around it with no detrimental effect to the sealing abilities.

Once the packer has been set, the tool can be tested to ensure that it is actually sealing. This can either be done by pressure testing from one side of the packer or, bleeding down the pressure on the other side and monitoring the pressure using specially designed pressure monitoring pigs both upstream and downstream of the packer.

Communicating systems have also been developed to enable communications with the packer to be carried out during its operational setting and release period. Again pressure monitoring ahead and behind the packer is undertaken, as well as registering the hydraulic pressures inside the vehicle. These are all monitored and the information passed to the outside of the pipeline.

On completion of the job the packer is unset and displaced from the pipeline. Prior to the release, pressure should be equalised across the tool. Once this has been achieved the command signals are given for the tool to be unset. Should for any reason the tool fail to unset, an increase in pressure to a predetermined level from the on-pressure holding end causes the tool to automatically unset. Once the tool has been unset it can be pigged from the pipeline and retrieved conventionally from the pig trap.

Remote Pipe Freezing

The system has been developed to provide a method of producing an isolating plug of frozen liquid in a pipeline under precise temperature control, and enables the freeze to be applied at a location remote from the major items of equipment. Figure 6 shows a diagram of the general principles.

The system comprises a freeze skid which uses liquid nitrogen to cool a refrigeration medium through a counter current heat exchanger. The refrigeration medium is pumped through insulated hoses to a jacket which is placed around the pipeline.

The refrigerant temperature is controlled via a Eurotherm Controller which compares the temperature of the refrigerant leaving the heat exchanger with a set point temperature input by the operator. Should the refrigerant temperature differ from the set point temperature, the controller sends a signal to an actuated valve which allows more or less nitrogen to pass through the heat exchanger. This system allows precise control of the refrigeration temperature, typically to +/- 1 degree C. The low temperature limit of the freeze skids is - 65 degrees C, this limit being imposed by the minimum working temperature of the refrigerant pumps.

The freeze skid incorporates two refrigerant pumps, one working and one standby. During the operation the liquid end of the standby pump is opened up to the refrigerant and is cooled down with the working pump. This allows a rapid change over, should the working pump fail. The refrigerant pumps are driven by nitrogen gas supplied through an Ambient Vapouriser. A 7 bar nitrogen tank is required in order to provide the necessary drive pressure for the pumps.

Other than an electrical supply for instrumentation, the vapouriser and nitrogen tanks are the only additional equipment required to operate the system. The skid together with instrumentation and control equipment is suitable for use in Zone II areas, when the instrument readout and control panel are sited in a safe area.

For pipe diameters up to 20" and jacket lengths up to 2D, a simplified jacket can be used where up to three stainless steel braided hoses are wrapped around the pipe. Once in position the refrigeration medium is circulated and the hoses sprayed with water. When the jacket has a good ice covering, sheet insulation is wrapped around the jacket. This simple form of freeze jacket is only applicable to above water applications. It may be possible to extend the use of this type of jacket to 24 inch diameter, however, this will need review for particular cases.

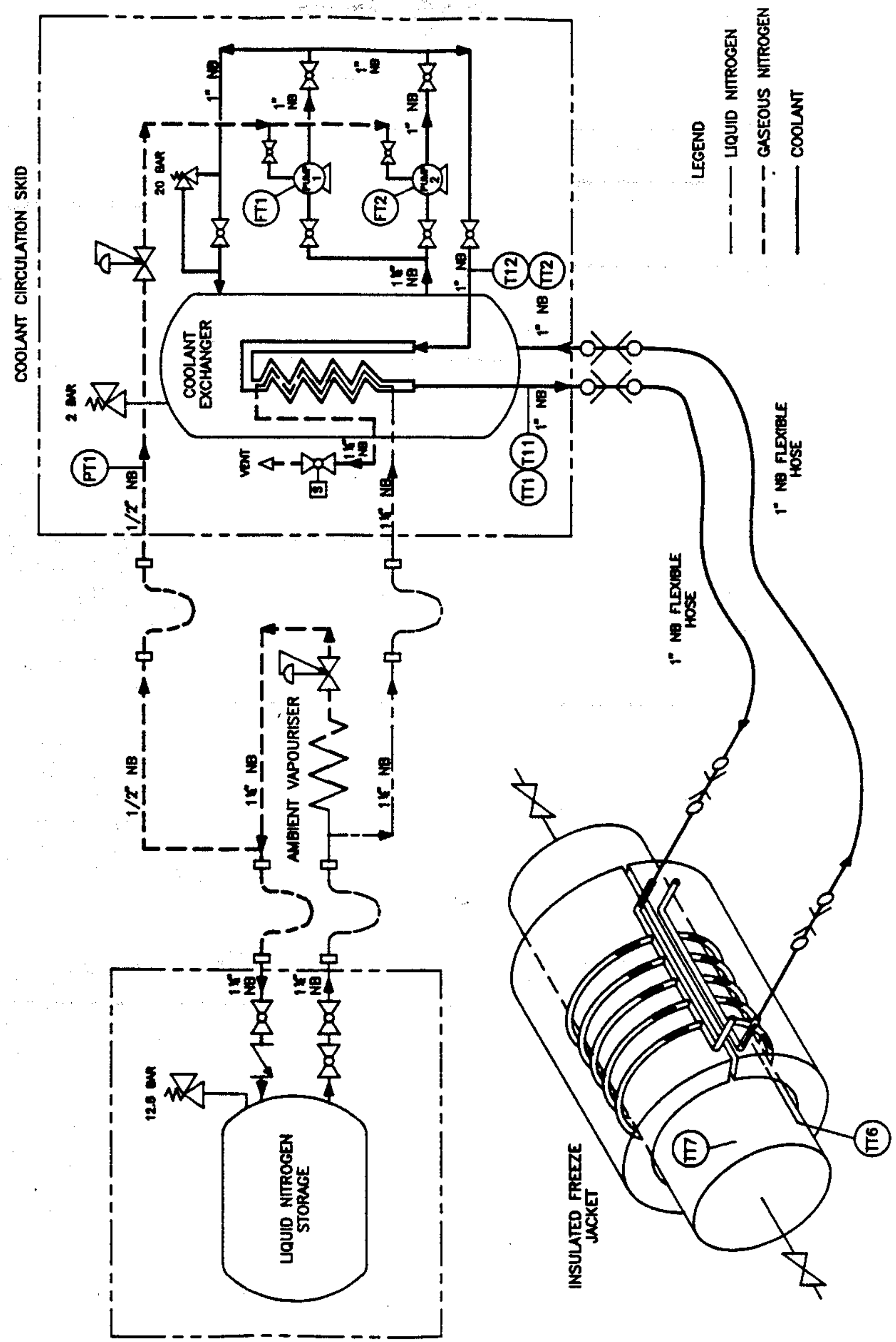


Figure 6 - Diagram of Pipe Freezing

For subsea applications or for pipe diameters above 24" a more complex jacket arrangement is required. The cooling matrix for the more complex jacket consists of an inlet and return header which are orientated longitudinally along the pipe. Between the two headers a number of braided hoses are run around the pipe circumferentially. The cooling matrix is fixed inside a stainless steel housing with sheet insulation between the matrix and the stainless steel skin. The jacket is built in four sections hinged longitudinally to allow easy placement of the jacket around the pipeline. The jacket is held in place by load binders which have been found to provide a simple method of attachment, easily manipulated by divers.

What medium can be frozen?

Except for early inconclusive trials using a hydrocarbon gel, the fluids we have frozen have been salt water, fresh water and gelled water. It must be recognized that the lowest temperature attainable with the remote freezing technique is - 60 degrees C and thus liquids with low freezing points (e.g. crude oil) will be less readily frozen with this technique when compared with the very low temperatures utilised in more conventional liquid nitrogen freezing.

In what maximum pipe diameter can an ice plug be formed?

The maximum diameter we have frozen during the development of the remote freezing technique is 30", under no flow conditions. Trials are to be undertaken at the end of April on 34" diameter pipe. As the diameter increases, convection currents within the pipe increase, which in turn result in longer freezing times. There will be limiting values of pipe diameter and ambient temperatures above which the freeze will never close.

In order to reduce the effects of convection currents, tests were undertaken using a gelling agent to increase the viscosity of the water forming the plug. These test proved successful with a 50% reduction in freezing time.

How long does it take to freeze a plug?

Typical times are as follows:-

Bare Pipe	(Ambient temperature 15 deg. C) (Pipe wall temperature - 50 deg. C)
8" dia. in air	5.5 hrs fresh water freeze
20" dia. in air	34 hrs fresh water freeze
20" dia. in water	24 hrs fresh water freeze
30" dia. in water	72 hrs fresh water freeze
30" dia. in water	36 hrs gelled water freeze

30" dia. in water, using gelled water as the freeze plug medium and with a simulated corrosion coating beneath the freeze jacket, 55 hrs.

What differential pressures can a freeze plug resist?

The theoretical maximum differential pressure (P) is dependant on the length of the freeze plug (L) the diameter of the pipe (D) and the shear strength (F) at the ice/metal interface, the relationship being $L/D = P/4F$. For an ice plug in a steel pipe with $F = 65$ psi this expression becomes $L/D = P/4 \times 65$psi.

In practice it has been found that this is a conservative estimate. It is thought that differential contraction causes a slight necking effect at the longitudinal centre line of the plug which provides an additional resistance to movement of the plug, e.g. for an ice plug of $L/D = 1.5$ the theoretical maximum differential pressure is:- $1.5 \times 4 \times 65 = 390$ psi. In practice a 1.5D plug in a 20" pipe has been subjected, during trials, to a differential pressure of 1000 psi without failure. This is only one trial and requires substantiation.

It is intended to carry out further trials to allow maximum differential pressure to be predicted with greater accuracy.

Is the steel permanently damaged by the low temperatures involved?

No, steel does become more brittle at low temperatures, however, this is a temporary effect and the steel properties will revert to normal on warming. The degree of embrittlement depends on temperature and therefore, the relatively high temperatures used in Nowsco's remote circulation technique cause less temporary embrittlement than other pipe freezing techniques.

What precautions must be taken prior to or during freezing?

The area over which the freeze is to be effected needs to be chosen with some care. Due to the temporary increase in brittleness, cracks above a certain size in a weld or in the adjacent heat affected zone will tend to propagate spontaneously as the material cools. The maximum allowable crack length is dependant on the pipe material and upon the temperature. With the relatively high pipe wall temperatures made possible through the remote freezing technique this maximum allowable crack length can be quite large. However, freeze plugs should be located away from circumferential welds and any seam welds should preferably be ultrasonically tested prior to instituting a freeze.

Again, because of temporary embrittlement, whilst at low temperatures the area of the freeze plug should be stressed as little as possible - in particular shock loads should be minimised.

The freeze should also be placed as far as possible from the work area. Where this is not practicable, thought should be given to reducing stresses as much as possible. For example, rusted nuts on a flange should be freed and then retightened individually before initiating a freeze to obviate the need for the use of flogging spanners whilst the freeze area is at a low temperature.

As the plug freezes, the expansion of the water as it changes phase to ice will cause an increase in pressure in any water contained in the system at each side of the plug. Care must be taken not to allow the pressure to exceed the MWP of the pipeline. Wherever possible the free length of the pipework between the plug and a valve or blind should be such that the MWP cannot be exceeded. Where this is not possible some arrangement must be made to relieve the excess pressure.

What is the maximum distance between the circulation skid and the plug?

The distance between skid and freeze plug is limited by pressure drop in the circulation hoses and heat gain through the hoses. With the existing 1" ID hoses, pressure drops limit the distance to about 150m. Should greater separation be required then larger diameter hoses can be used. However, these hoses are expensive and before quoting greater distances, consideration must be given to heat transfer through the hoses.

Nitrogen Foam Inerting (NFI)

The shutdown of operations on a system requiring modifications often requires hot cuts to be made. These systems may still contain flammable hydrocarbons from vessels or pipework and NFI is used to prevent air from entering the system when the cuts are being made.

Nitrogen foam is produced by blowing nitrogen gas through a surfactant/water mixture which is closely regulated to obtain the ideal expansion ratio (i.e. the ratio of gas to liquid volume). In use the foam closely resembles a detergent bubble formation. When a section of foam breaks down, either due to the application of heat or pressure, then nitrogen is liberated and flows out of the cut under the pressure of the bulk foam, thus always maintaining inert conditions. Figure 7 shows a schematic diagram of a typical foam inerting operation.

An important part of the foam inerting service is the detailed preparation of a job programme. This document details the procedure to be followed with reference to isometric drawings, showing the geometry of the system. This is very important, so that any dead legs are identified and the foam injection and venting points carefully selected to ensure maximum safety of the Foam Inerting Service. On a complex system it may be necessary to decommission the system by a nitrogen purge prior to carrying out the foam hot work.

High Expansion Foam

The expansion ratio has a direct effect on the viscosity of the foam. Within limits, the wetter the foam the more it will behave like water, flowing into corners and following the contours of the vessel or pipeline without leaving voids. Therefore, when a vessel is filled with high expansion foam, the foam will stack up towards the filling point. It will not easily flow around obstructions and may leave voids or areas of a vessel unfilled.

One of the major problems found with high expansion foam, is the very accelerated decay rate caused by the application of heat. This makes it more difficult to maintain positive pressure necessary inside the vessel or pipeline. When cutting into a vessel, the only positive indication of foam is when it is seen to flow from the cut behind the cutting torch or from a vent point downstream from the cutting area. If the expansion ratio of the foam is too high, or if it becomes dry or less stable through drainage, it can be completely destroyed by heat and consequently no foam is seen to emerge. The ideal foam is one that will flow without voiding and is resistant to decay both from the application of heat and from normal drainage.

Nitrogen foam can be mixed and then injected into a pipeline or vessel to suit the requirements of the operation to be performed. A further point for consideration is whether the system being worked upon can accept a water base. Consideration may have to be given to removal of the water upon completion of the operation by drying. Figure 8 shows typical use of a foam inerting operation.

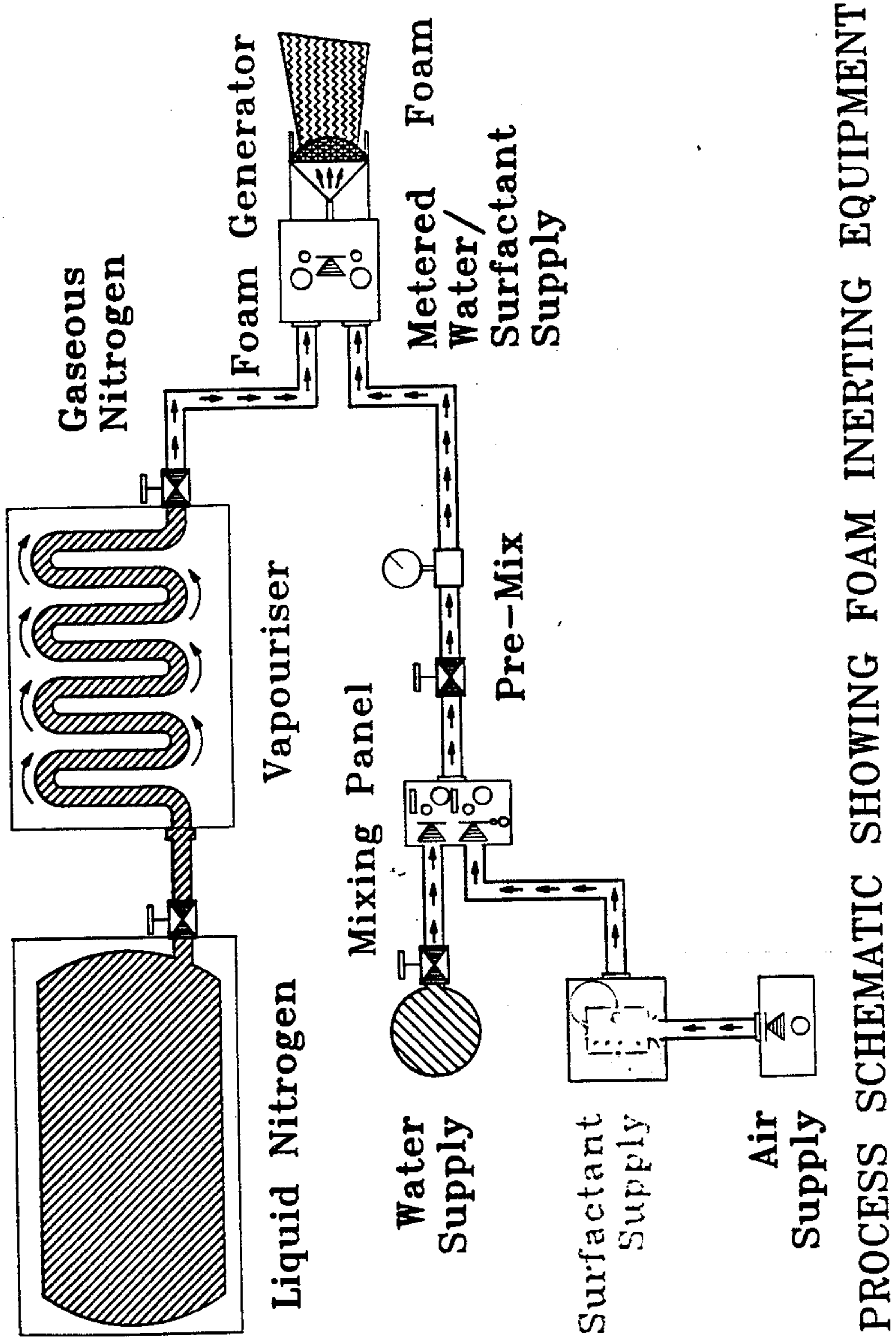


Figure 7 - Diagram of Foam Inerting System

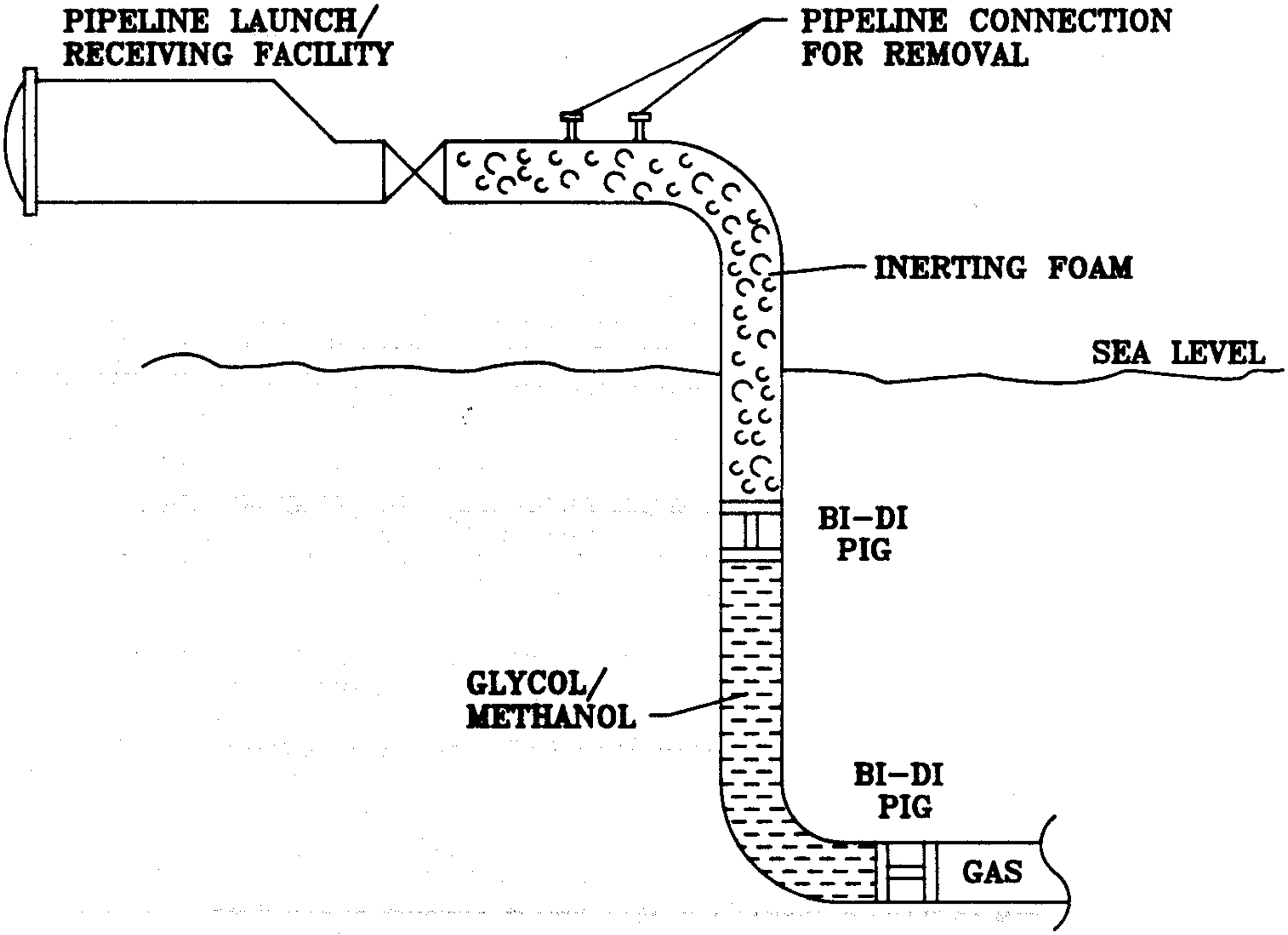


Figure 8 - Typical Foam Inerting Operation

Pipe Stoppling Equipment

A subsea hot-tapping system has recently been developed to enable large diameter pipelines to be hot-tapped in cold deep waters typical of the North Sea.

The cost of developing offshore oil/gas fields measured by Capital Expenditure per recoverable costs has declined. This is largely due to use of existing infrastructure of platforms and pipelines throughout the North Sea.

One technique which allows existing pipelines to be maximized is hot-tapping. This technique also allows for lines now being laid for future gas gathering to be constructed without the need to anticipate size and position of future tie-in points, which can be added as and when required.

Hot-tapping has been used on land lines for many years and to a lesser extent on sub-sea lines in the Gulf of Mexico and the Middle East, albeit on low specification lines with low product flow and often in shallow water.

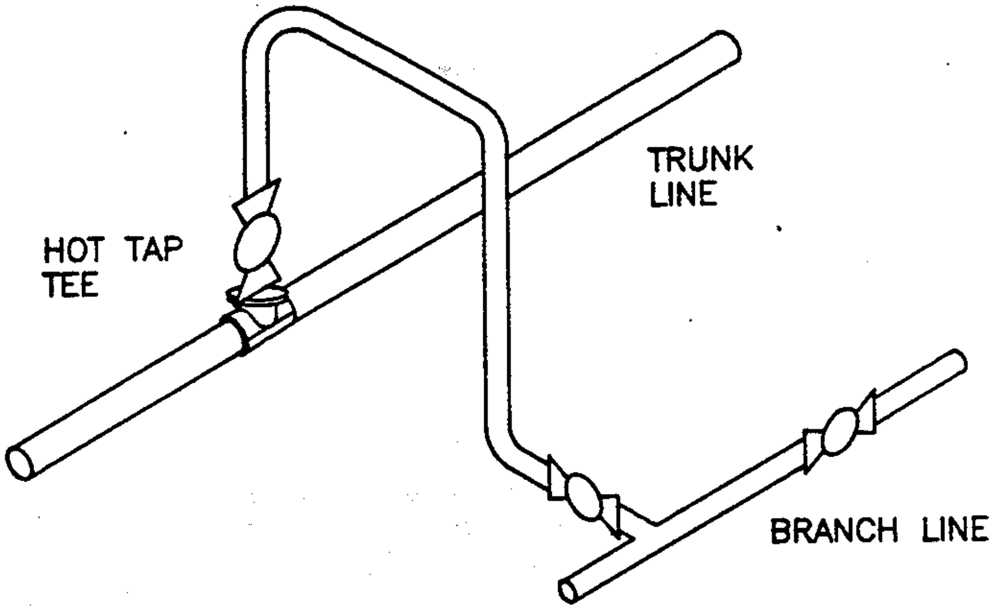
In previous attempts to carry out a hot-tap in the North Sea, it was necessary to stop the flow in the line to achieve the weld. This meant that full economic advantage of the technique was not realised. This prompted the need to develop a technique applicable to sub-sea lines in this environment.

Two further applications of hot-tapping in the North Sea (in addition to the use of tying-in a new branch line), are that the system plugging feature could be used to by-pass a redundant platform, and could also be used to remove a line section for inserting a new safety valve 'Y' piece etc. Figure 9 illustrates the principle of the application.

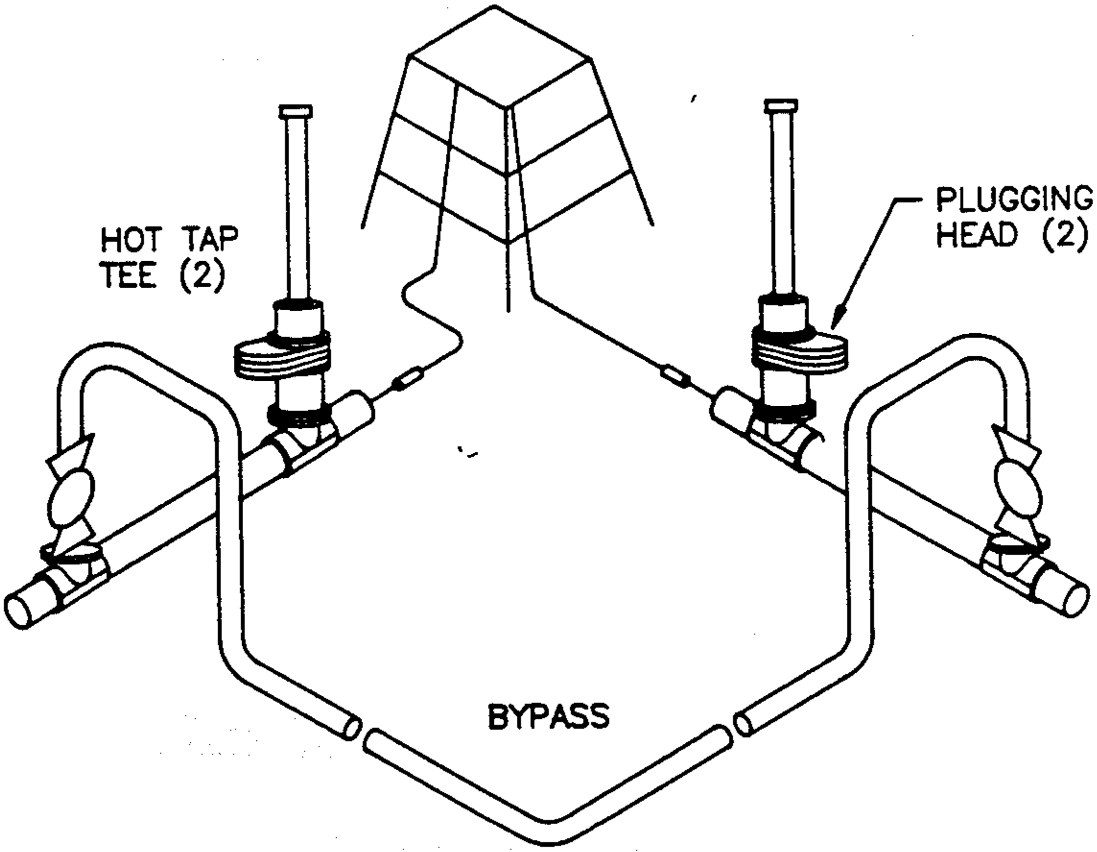
Two types of welded tie-branch configuration are used, firstly the direct branch in which the gas sealing weld is a full penetration weld at the junction between branch and main line. The second utilizes a split tee in which the gas seal requires circumferential fillet and longitudinal welds. These are illustrated in Figure 10.

It was necessary to find a method to pre-heat the weld area which would allow the tee to be installed with a high quality long lasting weld. Standard hyperbaric methods of pre-heating sections of pipelines such as resistance heating are quite incapable of overcoming the large heat losses resulting from product flow. Therefore, welding temperatures are achieved with the pipe being heated locally by induction from an inventor power source.

An essential element in welding on sub-sea lines is proving of the Procedures and Welder Qualification in a surface hyperbaric chamber.

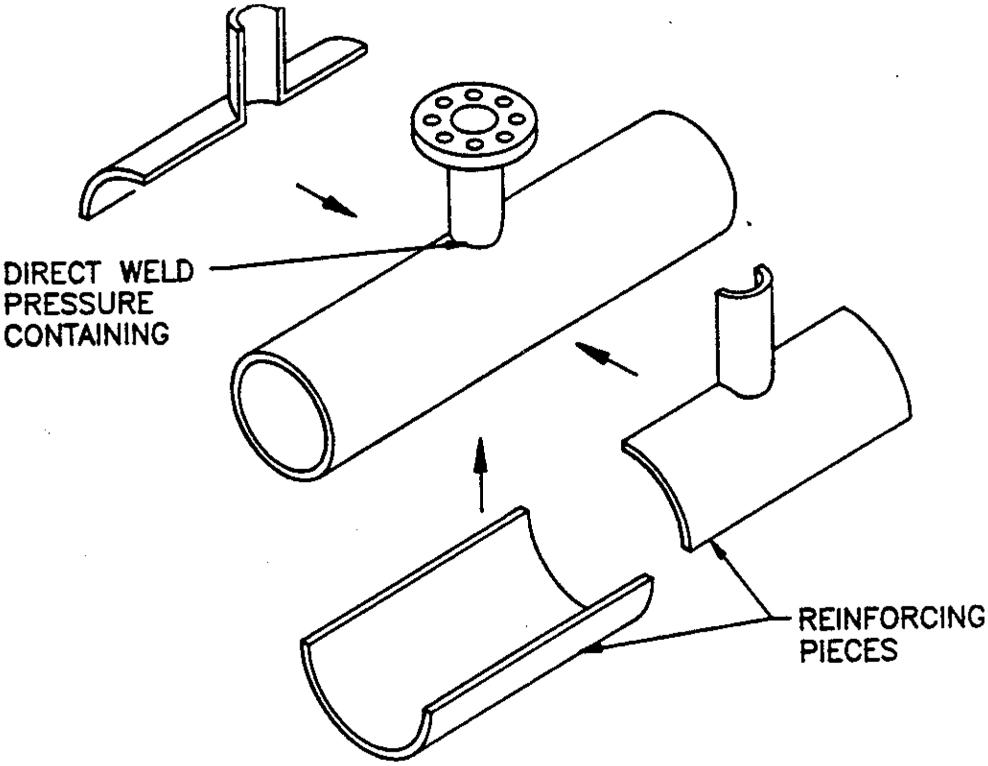


BRANCH LINE TIE-IN

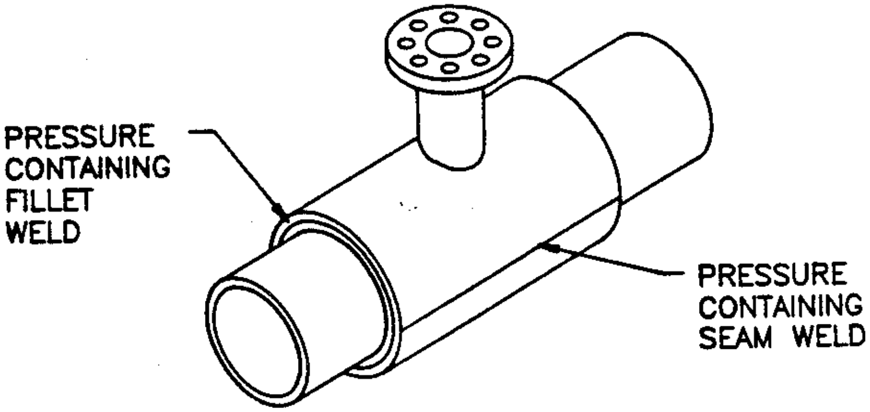


PLATFORM BYPASS

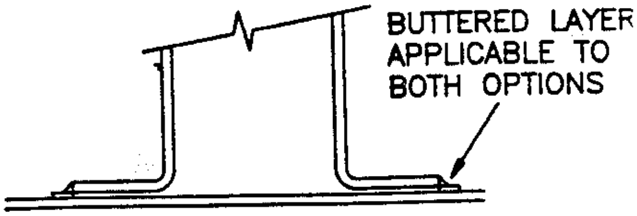
Figure 9 - Illustration of the Use of Branch T's Hot Tapped into an Existing Subsea Pipeline



BRANCH PIPE WELDED DIRECTLY



TWO PIECE SPLIT 'T'



Two types of welded 'T' branch configurations. Direct welding allows more accurate inspection. Buttering layers are applicable to either case to improve weld quality.

Figure 10 - Alternative Types of Branch Configuration

This is straightforward for normal pipeline tie-in where two pipe ends are butt welded. Welding on live, it is necessary to reproduce in the list section the exact heat loss as if the weld were made on the actual sub-sea gas/oil line. A thermal simulation was developed to accurately produce heat loss/transfer representing a pipeline with flow.

From this, information and data were obtained on temperature profiles either side of the coils for different flow rates, wall thicknesses and power levels of coils. Computer predictions to measure temperature profiles on either side of the coil were performed.

The critical nature of hot-tap welding requires careful control at all stages with emphasis being placed on adequate pre-qualification. To make the system work it is necessary to develop:-

- New systems that are safe to operate by divers in dry hyperbaric or wet modes of operation.

- Handling equipment/Procedures for operation of hot-tapping.

- Pipeline isolation equipment, where appropriate.

Hot-Tapping and Stopple Plugging Application

Basic Steps to make a Hot-Tap - Once the tee complete with lack-o-ring (LOR) flange has been welded to the pipeline, a full bore valve is mounted onto the flange. A tapping machine (TM) is then mounted to the flange and after opening the valve the cutter attached to the TM is lowered through the valve to cut a hole in the pipeline. The cutter retains the coupon cut which is then withdrawn through the valve, before closing the valve. The TM is then removed. Figure 11 shows the principle of the operation.

Basic Steps for a Stopple Plugging Operation - A full bore sandwich valve complete with by-pass spool and hot-tapping machine is bolted onto the lock-o-ring flange as shown in Figure 12. This is carried out to both sides of the section of pipeline to be received/repaired. The temporary by-pass pipeline is then mounted to the spool adaptors and the hot-taps made. With the temporary by-pass now on stream the sandwich valves are closed and the hot-tapping machines removed. A stopple-plugging machine is then bolted to the sandwich valve which is opened to allow the plugging head to be lowered into the pipeline. These plugging heads act as a temporary block valve, the flow being diverted through the by-pass.

The isolated section between the plugging heads can then be vented and/or purged before cutting or removal in readiness for the insertion of a 'Y' piece, or a sub-sea isolation safety valve.

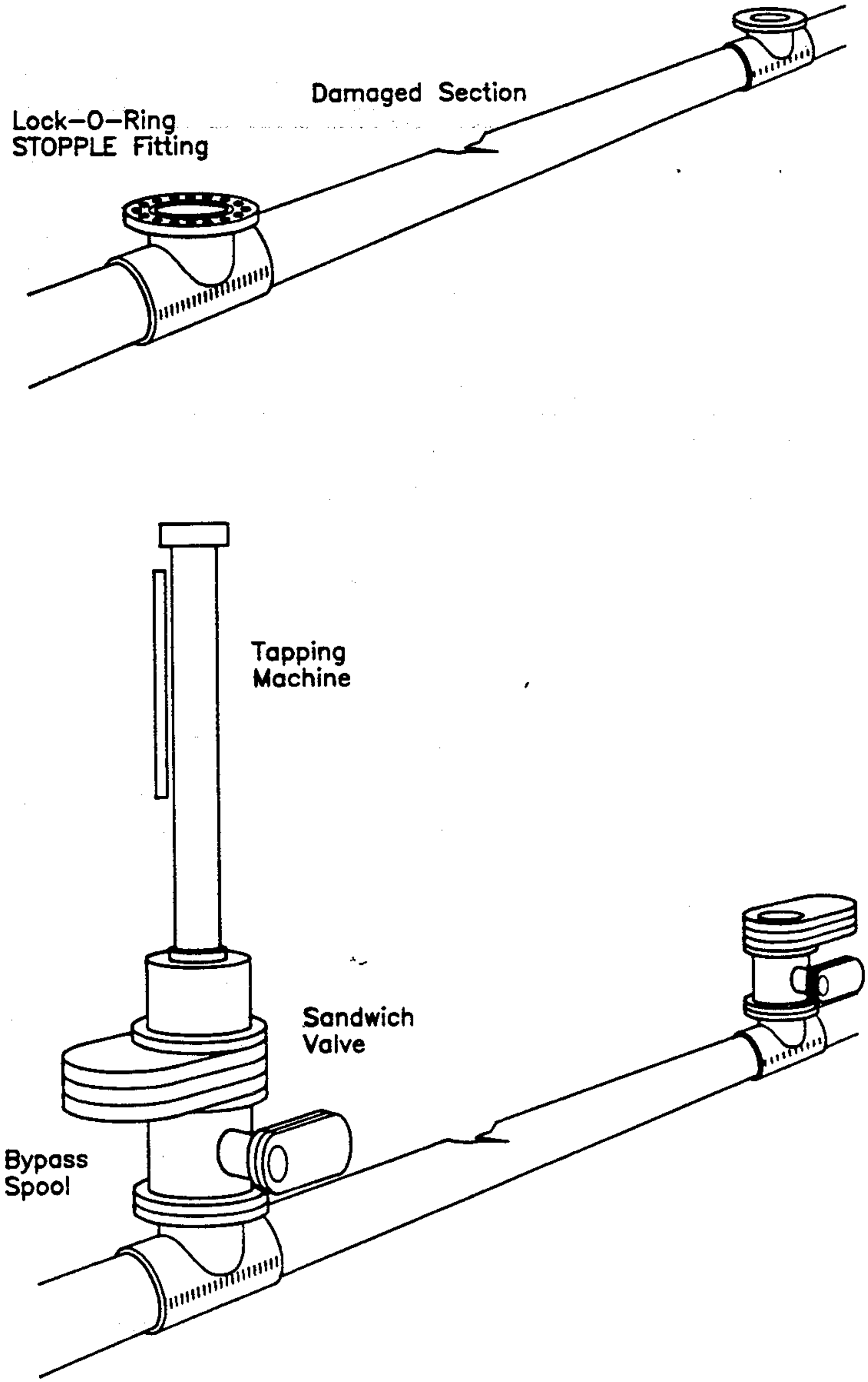


Figure 11 - Basic Steps to Make a Hot -Tap on Stream

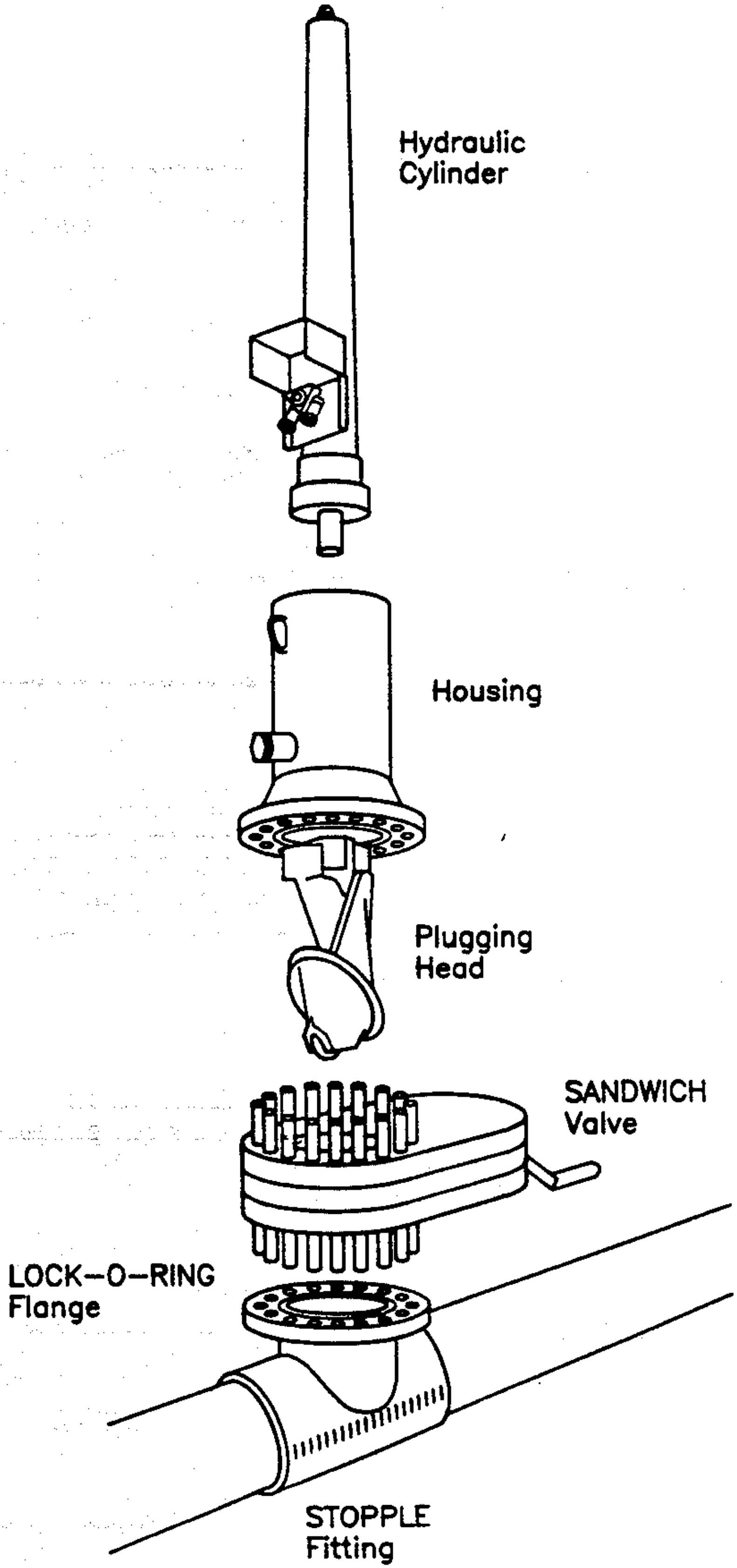


Figure 12- - Typical Set-Up of a Stopple Plugging Operation

Secondary Barrier

Within the hot-tapping programme, it is also considered necessary to develop a secondary seal barrier system, particularly to ensure the safety of the diver/welder working in a habitat over the end of the severed line.

The secondary barrier is inserted in the cut line between the stopple and habitat. It must be a positive safety device and is thus designed to withstand full line pressure that may leak past the primary seal. This secondary barrier usually takes the form of a bi-directional pig.

The barrier pig features four independently activated seals and a bleed system to prevent pressure building up between primary and secondary barriers. Access is available to the annuli between the two seals which is filled with an inert gas that may be monitored and sampled as required. This monitoring of the atmosphere in the second annulus ensures complete safety of the diver/welder from hydrocarbons.

It is necessary to remove the secondary barriers in cases where.the final configuration does not allow direct access, i.e. as with the installation of an emergency shut down valve. On completion of the tie-in, the pressure in the seals can be released by two methods. This is done either by an acoustic release system, or by a differential pressure system whereby once the pig has a certain differential pressure across it, it will de-activate the seals. The pigs are then propelled in the pipeline to the receiving site. These secondary pigs went through extensive testing to prove their capabilities and were able to withstand in excess of 15 bar differential pressure without leakage.

Acknowledgements

I would like to thank Mr. Blair Albers General Manager Nowsco Well Service Europe & North Africa for the support and facilities provided in the writing of this paper, to Comex U.K. Ltd. for allowing me to take extracts from a paper on Hot-Tapping for North Sea Gas' New Options, T.D. Williamson S.A. for their approval to use extracts from a paper on Hot-Tapping and Stopple Plugging Application for ESV System, to A.J. Barden of McKenna & Sullivan for permission to use extracts from his paper on Pipeline Isolation Design Developed for North Sea Applications, to Pipeline Engineering for the supply of pipeline internal gauges, and to Nowsco Well Service Ltd., Canada for permission to use extracts from a presentation on the Pipeline Packer Tool and Nitrogen Freezing.

THEME PAPER 6

Torbjorn Sotberg
SINTEF
Norway

"RELIABILITY ASSESSMENT OF SUBMARINE PIPELINES"

Recommended practice in Norway in the reliability assessment of offshore pipelines, is summarized on the following pages, based on a viewgraph presentation made at the workshop.

CONTENT

- ○ Introduction
- ○ Structural Safety Measures
- ○ Reliability Analysis
- ○ Definition of Limit States
- ○ Uncertainty Analysis
- ○ Safety Assessment
  - target safety - implied safety - calibration
- ○ Application Examples

WHY RELIABILITY METHODS?

- ○ Reliability studies for future design
- ○ Reference to fixed offshore structures
  - large scatter in component reliability
  - overinvestment

WHY RELIABILITY METHODS?

- ○ Application of Reliability Methods
  - consistent treatment of uncertainties
  - tool to include new research results
  - to identify area where further data would be beneficial
  - address safety in areas facing new technological challenges
  - to evaluate optimal design - target safety
  - to calibrate design equations

STRUCTURAL SAFETY MEASURES

Deterministic: (traditional)	safety factor, f_s load factor, λ partial factor, γ
Probabilistic:	safety margin, M reliability index, β failure probability, P_f reliability, $R = 1 - P_f$

DETERMINISTIC SAFETY MEASURES

- ○ Safety factor, f_s (usage factor)
  - stress based design $\sigma_{al} \le \sigma_{pl} = \frac{\sigma_{ul}}{f_s}$
- ○ load factor, λ
  - acting on applied load $Q_d = \lambda Q_R$

DETERMINISTIC SAFETY MEASURES

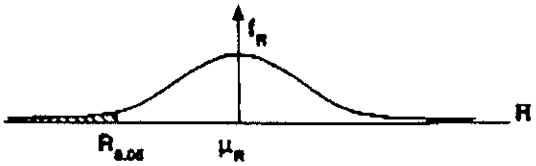
- ○ Partial factors, γs
  - load and resistance factors $\phi_i R_i \le \sum_i \gamma_i S_i$

characteristic resistance R_k(5%)

characteristic load S_k (95%)
$S_k = \mu_s(1 + k_s V_s)$, k_s = 1.65 (normal)

- ○ Lack of invariance
  - uncertainties not explicitely accounted for
  - definition of loads and resistance

SAFETY FACTORS - CHARACTERISTIC VALUES



Definition of characteristic resistance / load effect

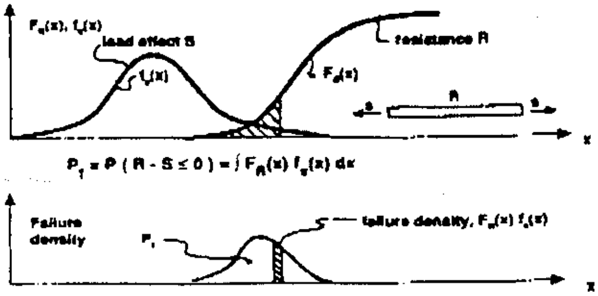
$$R_k = \mu_R (1 - k_R V_R)$$

$$S_k = \mu_S (1 + k_S V_S)$$

Normal distributed k_R = 1.645 (no. of std. dev.)

○ characteristic safety factor $\lambda_k = R_k / S_k$

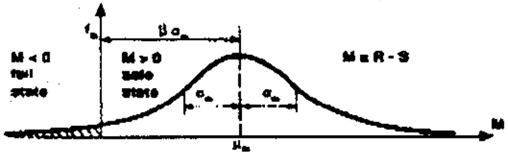
FUNDAMENTAL R-S CASE, SAFETY MARGIN



$P_f = P(R - S \leq 0) = \int F_R(x)\, f_s(x)\, dx$

Safety margin $M = R - S$, $P_f = P(m \leq 0)$

SAFETY MARGIN - Independent / normal (R, S)

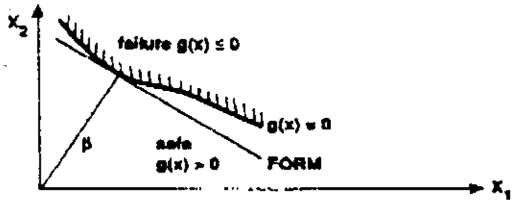


$Pf = P(M < 0) = \Phi(\frac{-\mu_m}{\sigma_m})$, $z = \frac{M - \mu_m}{\sigma_m}$, N (0, 1)

$\beta \overset{def}{=} \frac{\mu_m}{\sigma_m} \rightarrow P_f = \Phi(-\beta)$

Reliability index, β (distance mean value to failure point)

RELIABILITY INDEX - General case



Limit state g(x)
> 0 safe state
= 0 limit state
< 0 failure state

continue ....

RELIABILITY INDEX - General case

Procedure:
- transformation N(0 , 1)
- calculation of distance β

FORM - linearization of g (x), $P_f = \Phi(-\beta)$
SORM - quadratic approximation of g(x)

Alternative: Simulation methods

EVALUATION OF PARTIAL COEFFICIENTS

Design value: $x_i^* = F_{xi}^{-1}(\Phi(z_i^*))$

$= \mu_{xi}(1 - \alpha_i \beta V_{xi})$

Specified value: x_{sp} (characteristic value)

$x_k = \mu_{xi}(1 - k_x V_{xi})$

Partial coeff: $\gamma_i = \frac{x_k}{x_i^*}$

RELIABILITY APPROACH

Limit states g(x)
> 0 safe state
= 0 limit state
< 0 failure state

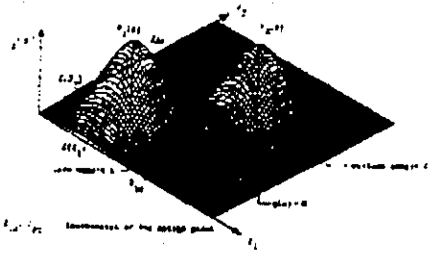
Failure probability $P_f = \int_{g(x)<0} f_x(x)\, dx$

Two approaches:

1 Analytical, transformation methods
FORM, SORM → reliability index β

2 Simulation methods
Monte Carlo (MC) → failure probability P_f
Importance sampling

IMPORTANCE SAMPLING PROCEDURE

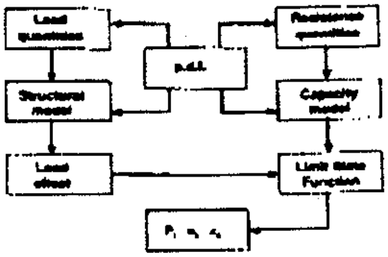


METHODS OF SAFETY CHECKING

Level 1
Characteristic values + safety factors γ
γ calibrated by level 2 and 3 methods
traditional code level, design check

Level 2 / 3
P_f calculated directly, "exact" (3), approximate (2)
uses information about uncertainties

RELIABILITY ANALYSIS



Procedure:

- Establish Limit State Functions / Failure Modes
- Determine Load Conditions / Quantities
- Determine Capacity Models / Resistance Quanities
- Uncertainty Analysis
- Reliability Calculations, P_f, α_i and z_i
- Calibrate Design Formats

DEFINITION OF LIMIT STATES

○ **Analytical formulation of the failure mode**

Typical classification:

SLS - **Serviceability Limit State**
(yielding, ovalization, excessive displacement etc)

ULS - **Ultimate Limit State**
(buckling, collapse, fracture and overload)

FLS - **Fatigue Limit State**
(high / low cycle fatigue damage accumulation)

UNCERTAINTY ANALYSIS

○ **Model uncertainty inherent in g(x)**

○ **Uncertainties associated with x**

- **parameter uncertainties**
- **model uncertainties**

UNCERTAINTY SOURCES

- Ocean environment - short term model
  - long term distribution
- Wave kinematics
- Hydrodynamic forces
- Soil resistance forces

(Wave kinematics, Hydrodynamic forces, Soil resistance forces } model uncertainties)

- Pipe / soil parameters
- Structural modelling
- Statistical uncertainty (time domain)
- Pipeline capacity versus failure modes

MODELLING OF UNCERTAINTIES

- Distribution function
- Mean value / Bias
- cov

→ input in reliability calculations

SHORT TERM SEA STATE MODEL

- Jonswap model wave spectrum, H_s and T_p
- Constant current velocity, V_c

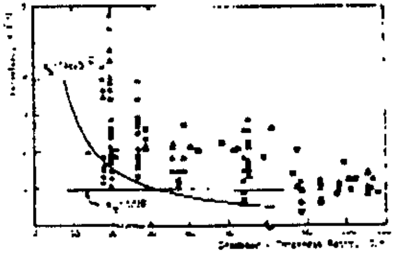
⇒ deterministic parameters

LONG TERM SEA STATE MODEL

- Parameters H_s, T_p and V_c
- Significant wave height, H_s = Weibull
- Peak wave period, T_p = Lognormal
- Steady current velocity, V_c = Weibull
- Correlation H_s - V_c

LOCAL BUCKLING - f_c

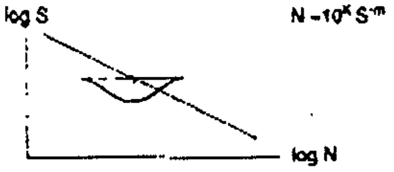
- Limit load failure / Bifurcation failure



- f_c - lognormally distributed, cov = 25 %

FATIGUE FAILURE - K, Δ

- High cycle, S-N curves



K - normally distributed

- Damage accumulation, Miner-Palmgren

$$D = \Sigma n_i/N_i < \Delta$$

Δ - lognormally distributed, cov = 35%

TARGET SAFETY LEVELS

- ○ **Implied safety in present codes**
- ○ **Failure statistics**
  (reliability of existing pipelines)
- ○ **Consequences of failure and failure type**
- ○ **Effect of inspection and repair**

TARGET ANNUAL FAILURE PROBABILITIES (NKB)

Class of failure (structure)	Consequence of failure: Less serious	Serious	Very serious
I **Ductile with reserve capacity**	$P_F = 10^{-3}$	$P_F = 10^{-4}$	$P_F = 10^{-5}$
II **Ductile without reserve capacity**	$P_F = 10^{-4}$	$P_F = 10^{-5}$	$P_F = 10^{-6}$
III **Brittle instability**	$P_F = 10^{-5}$	$P_F = 10^{-6}$	$P_F = 10^{-7}$

TARGET FAILURE LEVELS - PIPELINES (ULS)

Failure mode	Installation pr installation	Testing pr first test	Operation pr year
Crack-type	$P_F = 10^{-3}$	$P_F = 10^{-3}$	$P_F = 10^{-5}$
Ductile (buckling)	$P_F = 10^{-3}$	$P_F = 10^{-2}$	$P_F = 10^{-4}$

DESIGN PRINCIPLES

- Direct application of reliability analysis
- Limit state design (calibrated)
  - characteristic design values
  - partial safety factor

LIMIT STATE EQUATION

$$g(z) = R_c/\gamma_m \qquad \sum S_{ci}\gamma_i = 0$$

R_c - characteristic resistance
S_{ci} - characteristic load effect (type i)
γ_i - load *effect* factor (type i)

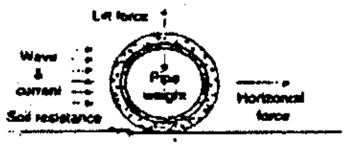
CALIBRATION

- Specify characteristic design data
- Define partical factor, (γ_E, γ_F, γ_m)
- Define limit state equation
- Iterate to find optimal set of γ_s, $g(z) = 0$

APPLICATION - Examples

- ○ **On-bottom Pipeline**
  - **excessive displacement** (stability)
  - **yielding failure**
  - **ultimate condition** (buckling)
- ○ **Wall thickness design** (design pressure)
  - **yielding, ultimate and fracture limit states**

TRADITIONAL PROCEDURE



• Hydrodynamic forces	- Morison
• Soil resistance	- Coulomb
• Static balance	

REVISED DESIGN PROCEDURE

- Based on new models
- Limited pipeline movements
- Additional limit states
- Safety evaluation / Cost optimal

NUMERICAL STUDY - DATA BASIS

- Generalized Probabilistic Design
- Two water depths, 30m / 80m
- 4 failure modes

30m: $H_{s1} = 5.1$ m, $H_{s100} \sim 7.1$ m, $\rho_{HT} = 0.33$
80m: $H_{s1} \sim 8.7$ m, $H_{s100} \sim 12$ m, $\rho_{HT} = 0.57$

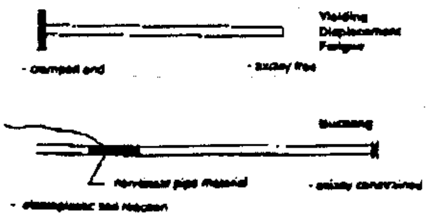
Current velocity:	$V_{cw} = 0.6$ m/s (Weibull)
Pipe diameter:	$D = 1.25$m / 1.20m (Normal)
Soil density:	$D_r \sim 0.35$ (Lognormal)
Yield strength.	$\sigma_y = 463$ MPa (Lognormal)

15 - 20 random quantities

LIMIT STATE FUNCTIONS

- Displacement: $g_1(z) = Y_T - Y(z)$
- Yielding: $g_2(z) = \sigma_y - \sigma_i(z)$
- Buckling: $g_3(z) = \varepsilon_b - \varepsilon(z)$
- Safety level: According to failure data and type/consequences of failure
- Seviceability: (1+2) $P_f = 10^{-2} - 10^{-3}$
- Ultimate: (3) $P_f = 10^{-4} - 10^{-6}$

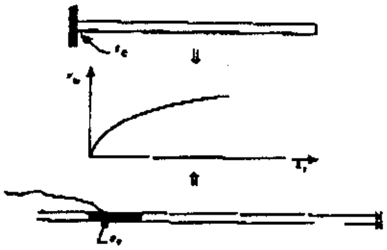
STRUCTURAL MODELLING - f_m



- f_m - normally distributed, cov = 25 %

PLASTIC STRAIN - RELIABILITY CALCULATION

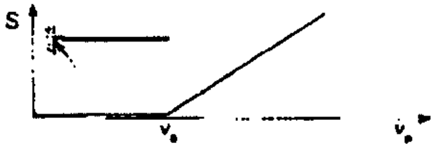
- Transformation



- Given for specific case

FATIGUE DAMAGE CALCULATIONS

- Dynamic stress range



- Flow velocity amplitudes - Rayleigh
- Stress distribution

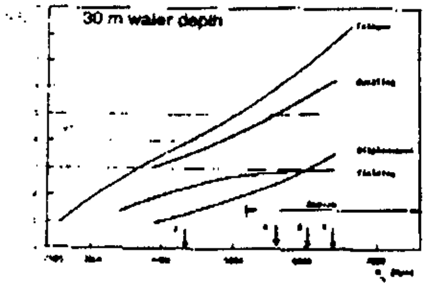
$F_s(S) = 1 - \exp[-2(S/k + V_r/U_s)^2]$

→ Closed form solution for D

RELIABILITY CALCULATION

- Failure probabilities
- Sensitivity factors
- Design point
- Evaluation of methods
- Limiting failure mode

LIMITING FAILURE MODE



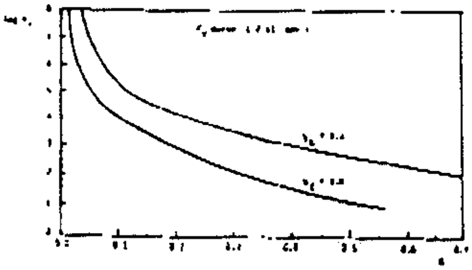
- Comparison of methods

YIELDING FAILURE MODE

- $g(z) = \sigma_y - \sigma_{eq}(z)$
- Wave loading dominate (75-80%)
- Model and statistical uncertainty (20-25%)
- Current loading insignificant
- Yield stress variability without effect
- Effect of functional load uncertainty low
- Method 1 / 2: $P_f(1) > P_f(2)$ (20-30%)
(Wave dominate / non-linear response)

CALIBRATION - FLS

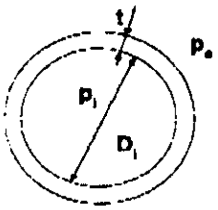
- S-N curves (-2 to -3 σ)
design curves shifted 2 σ
- Utility factor Δ (0.3 / 0.1)



CONCLUSIONS & RECOMMENDATIONS

- Methods for safety assessment have been outlined
- Procedures tailored to present application
- Sensitivity to wave loading is high
- Model and statistical uncertainty important
- Effect of functional load variability small
- Design principles - two approaches
- Reliability calculation procedures efficient for present application
  - generalized to cover all relevant failure modes
- Revision of design criteria for future application

WALL THICKNESS DESIGN - Differential Pressure



- ○ **Hoop stress $\sigma_h = (p_i D_i - p_e D_e) / 2t$**
- ○ **Alternative design equations** (Barlow-, thin-wall formula)
- ○ **Safety margin ?**

DEFINITION OF LIMIT STATES

- ○ **Yielding limit state, onset of first yielding (SLS)**
- ○ **Ultimate limit state, flow stress and strain hardening**
- ○ **Fracture limit state, fracture failure considering external damage / construction defects**

The limit state function g(x) expressed in terms of the random variables, x

YIELDING LIMIT STATE

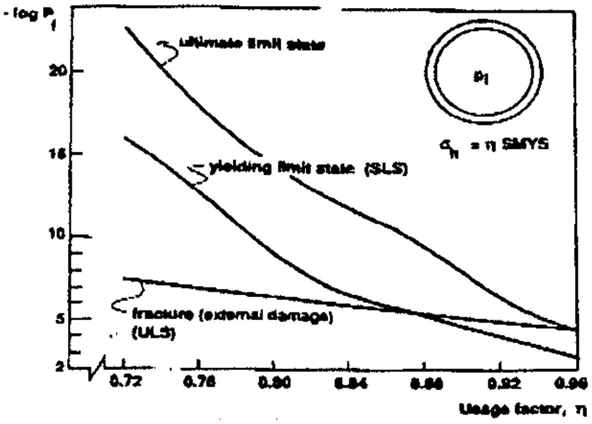
Random variable	Distribution	cov %	Sensitivity
Yield strength, σ_y	LN	4	56 %
Operating pressure, P	N	3	17 %
Diameter, D	N	0.2	≈ 0.1
Wall thickness, t	N	2.5	27 %

FRACTURE LIMIT STATE - External Damage

Random variable	Distribution	cov %	Sensitivity
Operating pressure, P	N	3	2.0
Diameter, D	N	0.2	0
Wall thickness, t	N	2.5	4.6
Flow stress, σ_{flow}	LN	4	0.6
Model uncertainty	N	5	6.6
Charpy energy, C_v	LN	10	2.3
Notch depth, a	EXP	100	80.9
Notch length, 2c	EXP	100	3.0

Dent depth, H_p (deterministic, 50 mm)

FAILURE PROBABILITY VERSUS USAGE FACTOR



CONCLUSIONS

- ○ **Probabilistic assessment of wall thickness** (pressure)
- ○ **Appropriate limit states formulated** (Yielding, ultimate and fracture)
- ○ **Uncertainty measures estimated**
- ○ **Findings:**
  - **fracture limit state dominant**
  - **traditional design check gives a very high safety margin**

THEME PAPER 7

Tom Bubenik
Battelle
Columbus, Ohio

"RECENT DEVELOPMENTS IN PIPELINE INTEGRITY TECHNOLOGY"

The state of the art in several key pipeline integrity areas is summarized on the following pages, based on a viewgraph presentation made at the workshop. The work presented represents recent Battelle efforts, under various sponsorships.

OFFSHORE INCIDENT DATA

1984-1989

(FROM DOT/OPS INCIDENT DATA)

	#	%
CORROSION	28	41
OUTSIDE FORCE	26	38
CONSTRUCTION	6	9
MATERIAL	5	7
OTHER	4	6
	60	100

CURRENT ANALYSIS OPTIONS

CORROSSION
- ASME B31G
- EFFECTIVE AREA METHODS (E.G., "RESTRENG")

MECHANICAL DAMAGE
- MAXIMUM DENT DEPTH GUIDELINES
- VARIOUS PUNCTURE FORMULAS
- FRACTURE INITIATION GUIDELINES

CRACKING
- CHARPY-BASED PROPAGATION GUIDELINES

COMMENTS ON CURRENT ANALYSIS OPTIONS

- GENERALLY DEVELOPED FOR ONSHORE GAS LINES
- LARGELY EMPIRICAL OR "SEMI" EMPIRICAL
- RESTRICTED TO EMPIRICAL DATABASE REGARDING
  - EXTERNAL LOADINGS
  - PRESSURE VARIATIONS
  - GEOMETRY
  - MATERIAL PROPERTIES

INTEGRITY ISSUES

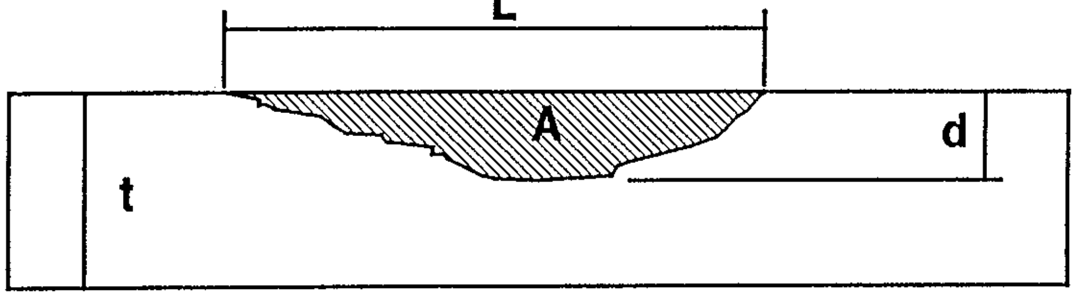
1. Damaged Pipe Analyses
2. Repair Methods
3. Bending Limit States
4. Hydrotest Guidelines

B31G Model

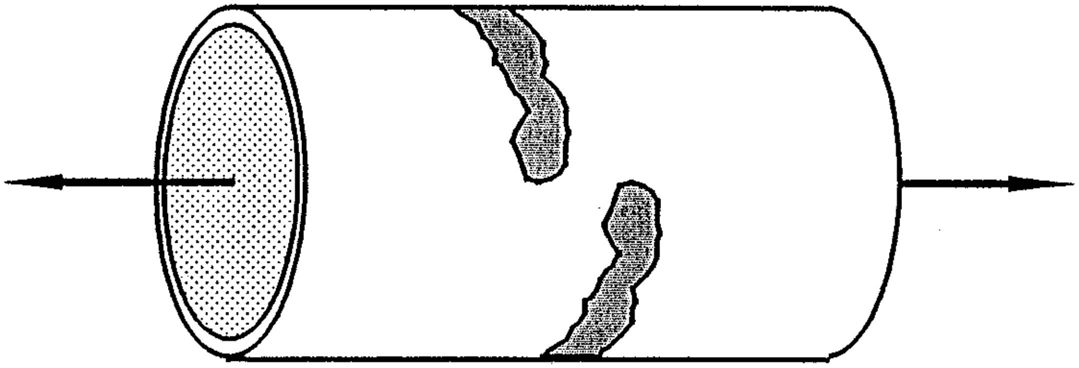
B31G BASICS

$$\text{Failure Stress} = \text{Flow Stress} \frac{1-A/Ao}{1-(A/Ao)/Mt}$$

where $A \sim 2/3\ Ld$
$Ao = Lt$
Mt = 'Folias' factor = $f(L, \text{Diameter}, t)$



PROBLEMS WITH CURRENT PROCEDURES

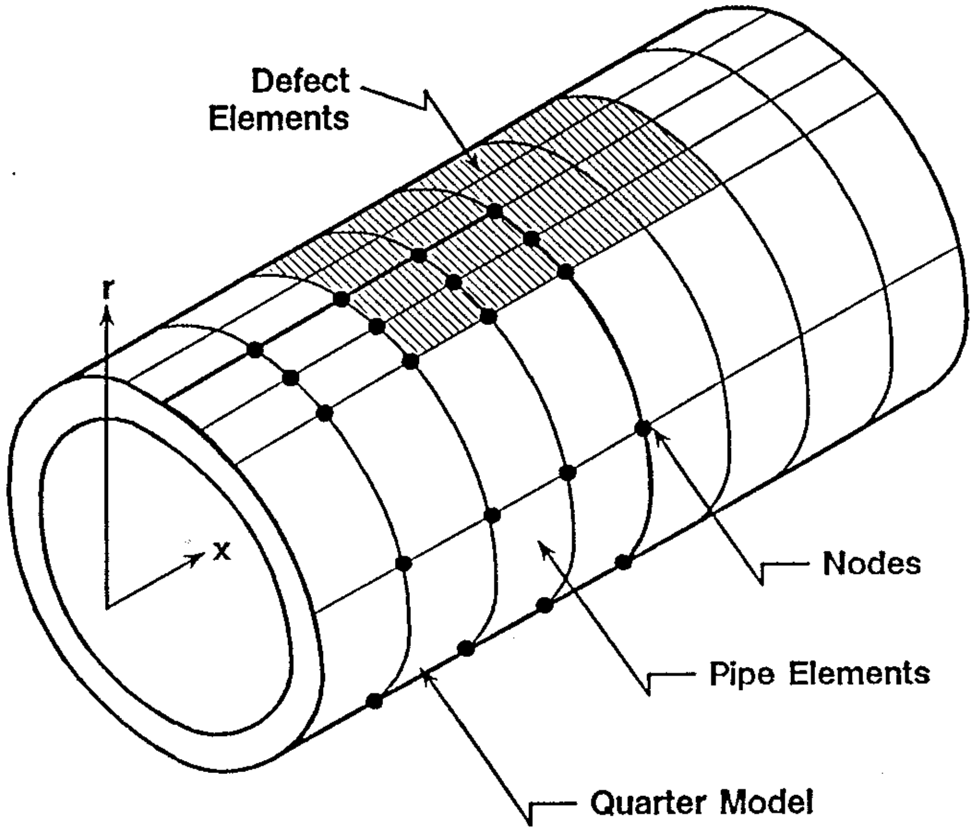


Axial Loads
Circumferential Corrosion
Interaction between Corrosion Patches

Battelle's Hybrid Shell - FE Approach

- Full 3-D solution of Flugge's shell equations for corrosion patch geometry
- PC based FE solution methodology with unique, accurate infinite order elements
- Simplicity and accuracy allow rapid solution for exploratory and parametric investigations

Finite Element Mesh for Battelle Model

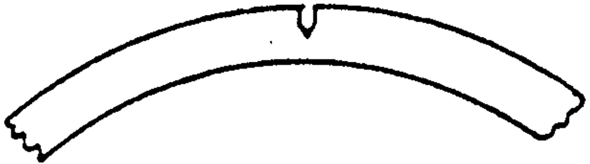


CORRODED PIPE QUESTIONS

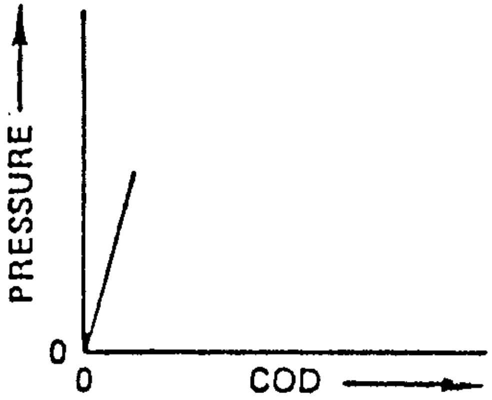
- How important are future developments to cover
    - circumferential corrosion
    - multiple areas of corrosion
    - corroded fittings
    - sharp corrosion

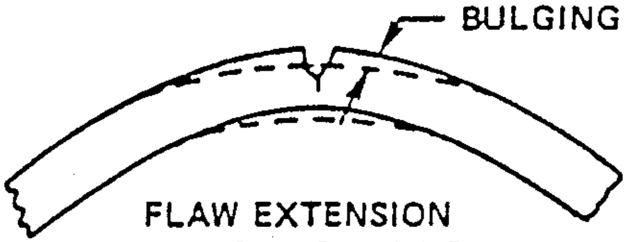
- In what format should future guidelines be
    - nomographs, similar to ASME B31G
    - software, similar to RSTRENG
    - finite-element procedures

DEFECT BEHAVIOR

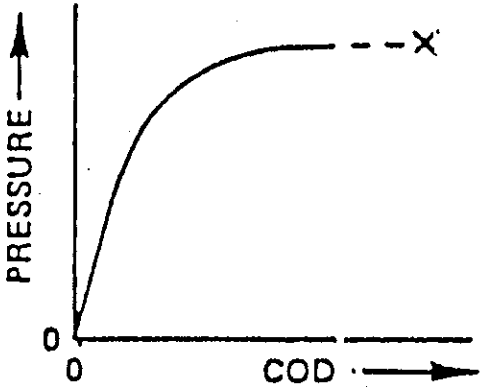


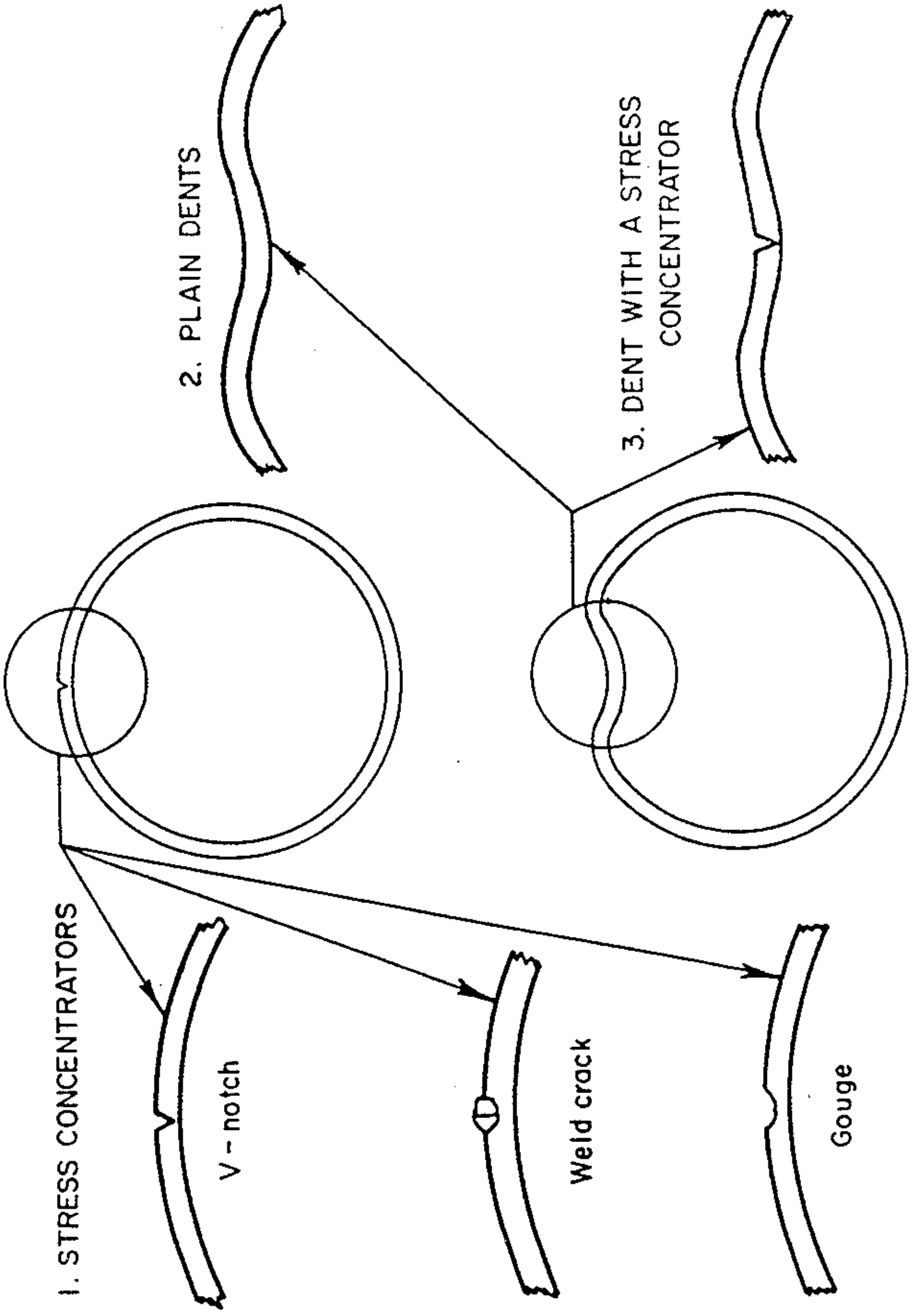
INITIAL FLAW





FLAW EXTENSION
AT NEAR-FAILURE
PRESSURE LEVEL





I. STRESS CONCENTRATORS
V – notch
Weld crack
Gouge
2. PLAIN DENTS
3. DENT WITH A STRESS CONCENTRATOR

MECHANICAL DAMAGE QUESTIONS

- Should guidelines be developed for puncture resistance of pipelines?
- Is fatigue of mechanical damage of concern?

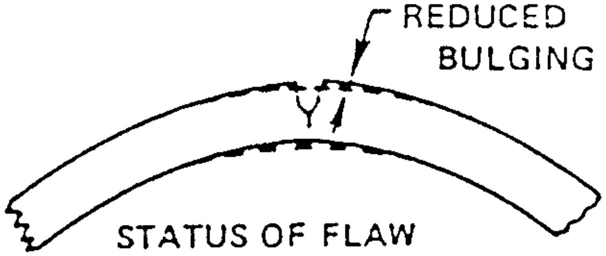
BENDING LIMITS QUESTIONS

- How should guidelines address differences between limit states and damage states?
- How should guidelines address uncertainties in axial and bending loads?

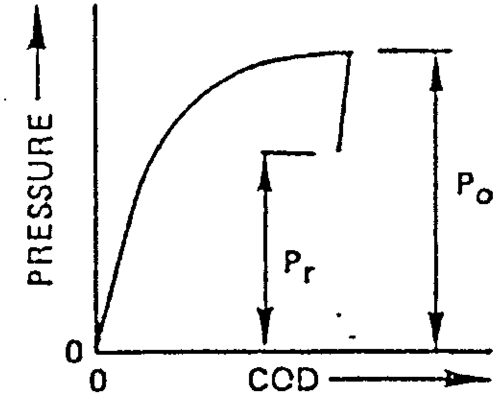
SLEEVE REPAIR METHODS

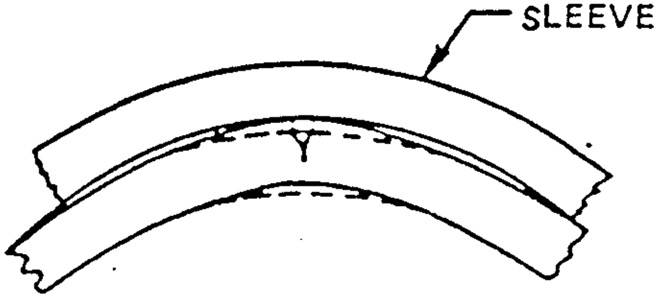
- Sleeve repair procedure depends on defect type, loading, and likely failure mechanism
- Steel and composite sleeves are effective, even for offshore use

DEFECT BEHAVIOR

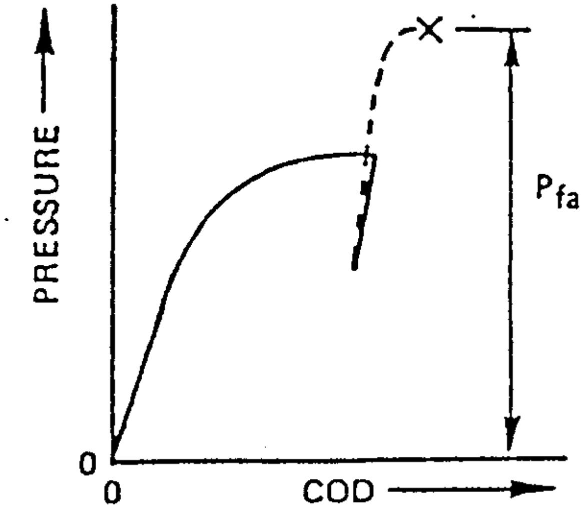


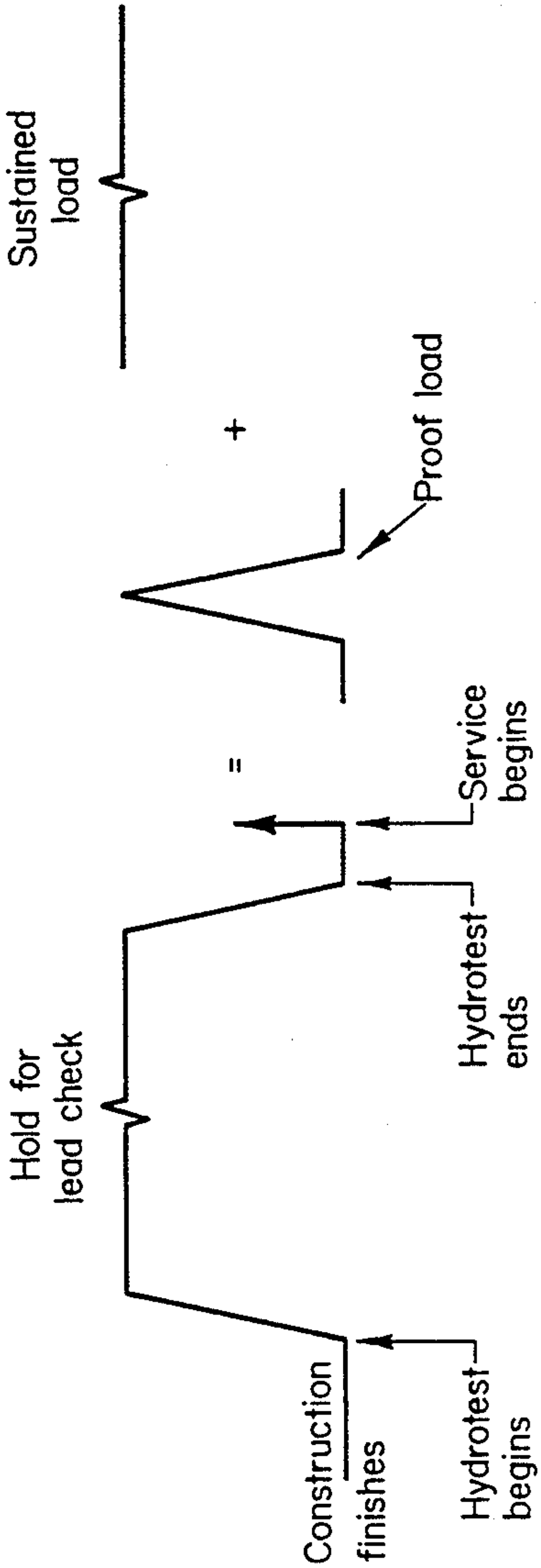
STATUS OF FLAW
UPON REDUCTION OF
PRESSURE FROM NEAR-
FAILURE LEVEL





FIT OF REPAIR
SLEEVE AT
REDUCED PRESSURE LEVEL




Hold for lead check
Construction finishes
Hydrotest begins
Hydrotest ends
Service begins
=
Proof load
+
Sustained load

J-TEARING THEORY

- J α rate of change in potential energy with crack length
- Crack initiation occurs if

$$J_{applied} = J_{critical}$$

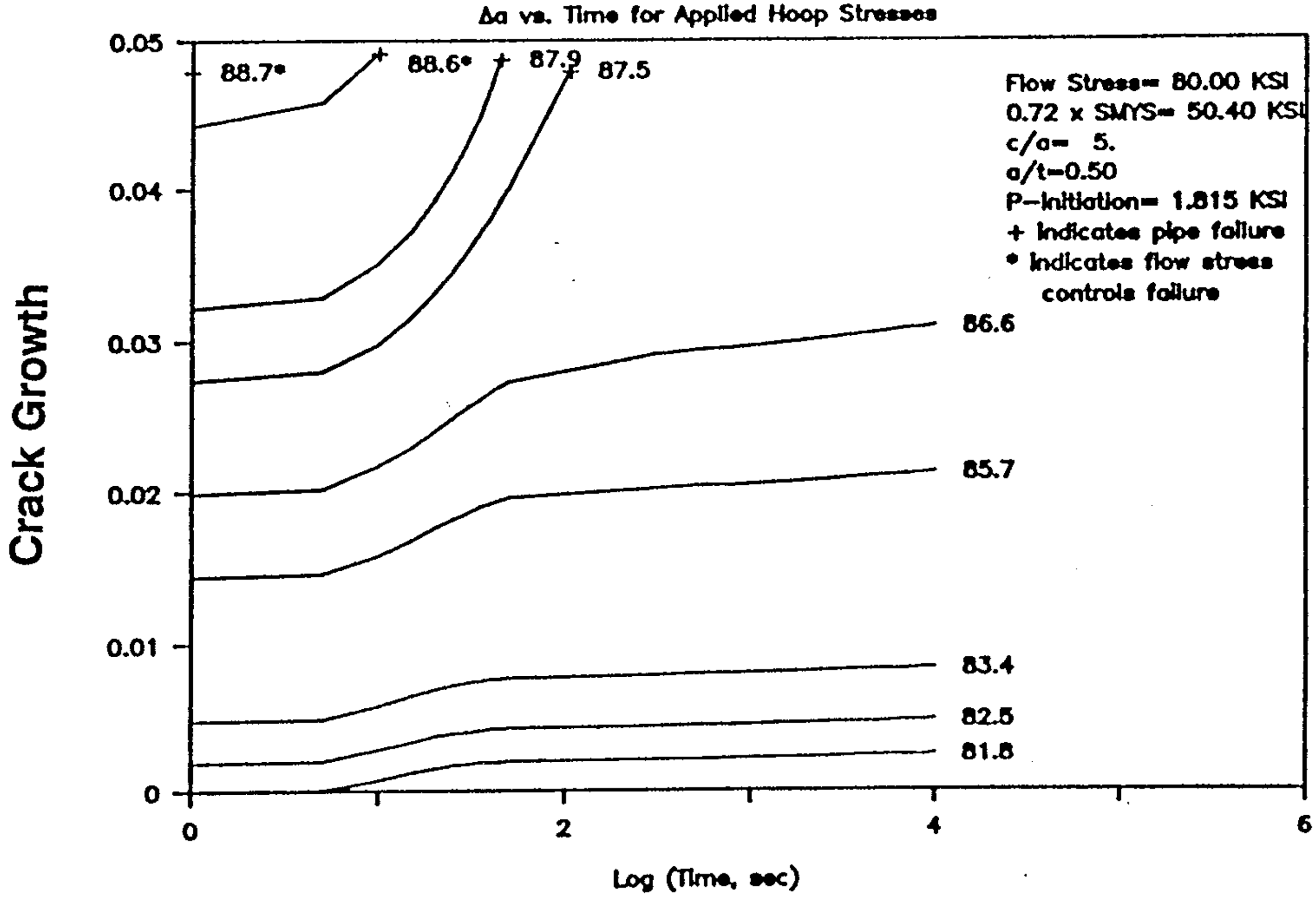
- Stable crack growth occurs if

$$\frac{dJ}{da}_{applied} \leq \frac{dJ_R}{da}$$

where J_R = material resistance curve

RESULTS

Predictions



Time dependent growth

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